CALIFORNIA
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California Renewables Portfolio Standard Renewable Generation Integration Cost Analysis

PHASE III: RECOMMENDATIONS FOR IMPLEMENTATION

CONSULTANT REPORT

Prepared For:

California Energy Commission
Public Interest Energy Research Program

Prepared By:

California Wind Energy Collaborative

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Arnold Schwarzenegger, *Governor*

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PREFACE

The Public Interest Energy Research (PIER) Program supports public interest energy research, development and demonstration (RD&D) that will help improve the quality of life in California by bringing environmentally safe, affordable and reliable energy services and products to the marketplace.

The PIER Program annually awards up to $62 million to conduct the most promising public interest energy research by partnering with RD&D organizations including individuals, businesses, utilities, and public or private research institutions.

PIER brings new energy services and products to the marketplace and creates state-wide environmental and economic benefits. PIER funding efforts are focused on the following RD&D program areas:

- Energy Innovations Small Grant
- Residential and Non-Residential Buildings End-Use Energy
- Industrial/Agricultural/Water End-Use Energy Efficiency
- Renewable Energy Technologies
- Environmentally-Preferred Advanced Generation
- Energy-Related Environmental Research
- Energy Systems Integration (formerly Strategic Energy Research)

What follows is the final report for the **[Contract Name,] 500-00-029**, conducted by the **California Wind Energy Collaborative**. The report is entitled **California Renewables Portfolio Standard Renewable Generation Integration Cost Analysis:** PHASE III: RECOMMENDATIONS FOR IMPLEMENTATION**.** This project contributes to the **Renewable Energy Technologies** program.

For more information on the PIER Program, please visit the Commission's Web site at: http://www.energy.ca.gov/research/index.html or contact the Commission's Publications Unit at 916-654-5200.

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EXECUTIVE SUMMARY

Introduction

With the adoption of the California Renewable Portfolio Standards (RPS) under Senate Bill 1078, the legislation envisioned annual procurements of new renewable resources through a bid selection process. Proposed renewable generation projects are expected to compete against one another to supply the IOUs with electricity, following a "least-cost, best-fit (LCBF) process. The California Public Utilities Commission (CPUC) was charged with establishing and monitoring the LCBF process. The Energy Commission was tasked with providing input on the technical evaluation of integration costs.

The technical review effort became known as the RPS Integration Cost Study, a multi-phased study to develop, quantify and define procedures needed for routine calculation of the indirect integration costs for eligible renewable generators. In Phase I, a fair, transparent and independent methodology was developed to assess integration costs for existing renewable generators. With review and feedback from industry, the estimates for integration costs were adopted and recommended as initial values to use for upcoming RPS procurement process. Phase II work concentrated on evaluating renewable generator attributes (new technology, location of resource, etc) that can potentially improve and/or change initial Phase I results. The focus was on wind & geothermal resources since these resources are anticipated to achieve the greatest market penetration in the near-term. In the Phase III effort, the recommended methodologies are summarized a formalized process for evaluation of integration costs is documented. This report is the culmination of the Phase III effort and provides detailed recommendations for performing integration cost analyses of various renewable generating resources for the state.

Purpose

The ultimate purpose of the CEC RPS Integration Cost Study is to develop and define the procedures needed for routine calculation of the indirect integration costs for eligible renewable generators. This report documents findings of the RPS Integration Cost Study and the methodologies for evaluating the integration costs of renewable generators. It is important to note that integration costs as discussed in this report are just a subset of the potential indirect costs. The recommended calculation procedures are suitable for routine application on a continuing basis as part of the resource procurement process. Other indirect costs not addressed include investments in new transmission capacity and cost associated with remarketing electricity already purchased in long term supply contracts.

Project Objective

The third report in the study, this report focuses on developing and defining procedures needed for routine calculation of the indirect integration costs for eligible renewable generators. The Integration team also provides specific recommendations for implementation.

- Create a fair and transparent methodology for evaluating integration costs, specifically capacity credit, regulation costs and load following
- Perform analysis using the method on a full-year generation dataset and multi-year dataset and present results
- Recommend calculation procedures suitable for routine application on a continuing basis as part of the resource procurement process
- Recommend process for conducting routine assessment of integration costs

Results

- A fair and transparent methodology for evaluating integration costs, specifically capacity credit, regulation costs and load following was created.
- A detailed calculation procedure is provided along with data handling requirements
- Simplified evaluation methods developed and explored. Results provided for comparison and review.
- Analysis was performed using the method on a full-year generation dataset (one-minute and hourly generation data).
- Modified cost adders are provided based on full-year dataset along with new capacity credit values.
- A process for conducting routine assessment of integration costs is recommended.

Conclusions & Recommendations

A systematic approach is recommended to perform evaluation of integration costs under Phase III. The following are primary recommendation for implementation:

- CEC or CPUC should identify dedicated personnel and resources to perform the functions of the Integration Cost Analyst (ICA) on a routine basis.

- Mechanisms must be established at the CaISO and IOUs to provide generation data on a timely basis to the ICA for analysis and to the CEC/CPUC. Data handling and storage protocols are also needed to ensure standardization, completeness and data quality
- Integration cost reports should be prepared during the 1st quarter of each calendar year and contain capacity credit, regulation and load following analysis for each generator type, resource areas and technology. Trend analysis should provide understanding of impact of increasing penetration by renewable generators.
- CEC or CPUC should periodically engage technical experts and the industry to document the changes to performance and other attributes of each renewable technology. Changes should be incorporated in the evaluation of integration costs.

ABSTRACT

In support of the Renewable Portfolio Standards, the Energy Commission was tasked with providing input on the technical evaluation of integration costs. The technical review effort became known as the RPS Integration Cost Study, a multi-phased study to develop, quantify and define procedures needed for routine calculation of the indirect integration costs for eligible renewable generators. The RPS Integration Cost Study was completed over the course of eighteen months. Under Phase I, the goal was to develop initial methodologies for evaluating the integration costs for existing renewable generation sources in California and compare their characteristics with non-renewable generation sources. Phase II concentrated on evaluating key attributes of renewable generators that might affect integration costs. Attributes such as developing technology, geographic issues and other technical aspects were considered. Phase III formalized the evaluation process and provided recommendations for implementation. The Renewables Portfolio Standards (RPS) Integration Methods Group is led by the California Wind Energy Collaborative (CWEC) and includes staff and researchers from the California Independent System Operator (Cal-ISO), Oak Ridge National Laboratory, National Renewable Energy Laboratory and other technology consultants in consultation with staff from the Energy Commission.

The ultimate goal of the RPS Integration Cost Study is to develop and define a fair, transparent and unbiased methodology to assess integration costs for all renewables. Phase III objectives include:

- Formalizing a process using developed methodologies to conduct a fair and transparent evaluation of integration costs, specifically capacity credit, regulation costs and load following.
- Performing analysis using the methods on a full-year generation dataset and multi-year dataset and present results, includes evaluation using simplified methods.
- Recommending calculation procedures and data handling suitable for routine application on a continuing basis as part of the resource procurement process
- Recommending process for conducting routine assessment of integration costs

The Phase III report represents a culmination of the Phase III activities and provides detailed recommendations for performing integration cost analyses of various renewable generation resources under the RPS requirement. The methodology developed initial estimates of integration costs that are intended for use in the upcoming RPS procurement process. Though there are concerns with adopting these numbers, they represent “acceptable” preliminary figures for use in the bid selection process. The intent is to revisit these results as new data becomes available and incorporated to provide the maximum benefits of integrating renewable technologies.

1.0 Introduction

1.1. Background

California has a large and diverse electric power supply network, which is critical for the economic and social well being of the state. In recent years, the California electric system was traumatized by a series of events that created power shortages, led to massive increases in the cost of electricity, caused the bankruptcy of Pacific Gas and Electric Company, and led to severe financial hardship for the state's other Investor Owned Utilities (IOUs). One response to those dark times was the enactment of the Renewables Portfolio Standard (RPS, Senate Bill 1078)1. This law provides a means for improving supply diversity, while simultaneously reducing dependence on volatile fossil fuel resources. The primary goal of the RPS legislation is to expand and promote the economic use of California's abundant renewable energy resources.

California IOUs must supply an increasing portion of their energy mix from renewable energy sources, as a result of the RPS requirements. These energy sources are decoupled from traditional fuel markets and offer consistent pricing over long time periods, which are based primarily on capital recovery. California is blessed with significant renewable resources and remains a global leader in the application of these technologies. The state's renewable resource potential is more than sufficient to achieve the RPS goal of 20% renewable energy generation, although transmission capability constrains our ability to tap renewable energy in several key resource areas.

The RPS legislation envisioned annual procurements of new renewable resources through a bid selection process. Proposed renewable generation projects are expected to compete against one another to supply the IOUs with electricity, following a "least-cost, best-fit" (LCBF) process. The California Public Utilities Commission (CPUC) is charged with establishing and monitoring the LCBF process. According to the enabling legislation, 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. Integration Costs

This report documents methodologies and procedures for evaluating the integration costs of renewable generators. It is important to note that integration costs as discussed here are just a subset of the potential indirect costs, which include investments in new transmission capacity and costs associated with remarketing electricity already purchased in long term supply contracts (Figure 1.1). As defined by statute, *integration costs* are the "*indirect costs associated with ongoing utility expenses from integrating and operating eligible renewable energy resources*." Other efforts have focused on transmission and remarketing costs; this report will discuss only methodologies and procedures recommended for calculating the indirect costs of integration.

The California Energy Commission (CEC) was tasked with technical evaluation of integration costs. That technical review effort became known as the RPS Integration Cost Study and its findings are the subject of this report. The ultimate goal of the CEC RPS Integration Cost Study was to develop and define the procedures needed for routine calculation of the indirect integration costs for eligible renewable generators. The results obtained from those calculations are intended to inform and guide the CPUC during the LCBF bid selection process. The variety of ways that integration cost results might be incorporated into the bid selection process was not a specific topic of the RPS Integration Cost Study; however, this report discusses how the study results might be used and provides recommendations.

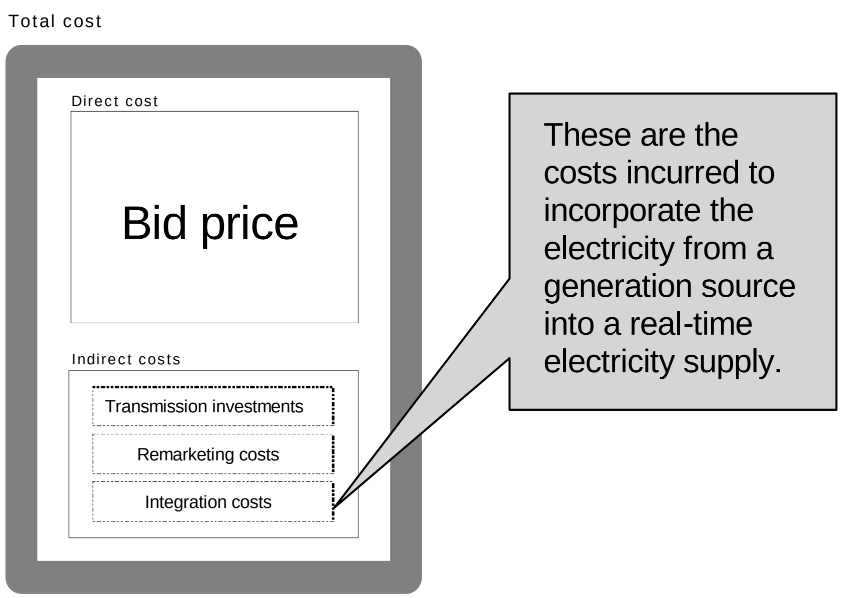

Figure 1.1 How Integration Costs Fit In The Least-Cost, Best-Fit Process.

1.3. Development of Methodologies

The RPS Integration Cost Study focused on the development of methodologies for evaluating integration costs that can be applied to the selection of RPS eligible generation projects. Because project selection is a public process for California, the methodology was intended to:

- 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

The final methodologies presented in this report achieve all of the goals identified above, with one notable exception. The input data needed for performing the integration cost analysis must be obtained from the California Independent System Operator (CaISO) or from one or more of the IOUs. This data is considered proprietary information and cannot be released into the public domain without violation of confidentiality. Significant effort was spent to identify means for public release of power generation data, but those efforts were ultimately unsuccessful.

The RPS Integration Cost Study has documented quantitative methodologies for evaluating the integration costs of renewable technologies. The recommended calculations and procedures must be suitable for routine application on a continuing basis as part of the resource procurement process. This report provides final recommendations for evaluating integration costs. It presents a detailed methodology for estimating integration costs, which have been divided into three primary topic areas: capacity credit, regulation, and load following.

The RPS Integration Cost Study was completed over the course of eighteen months. A team was assembled to perform the study in late January of 2003. This group subsequently presented draft methodologies in a public forum in April of that year. Data for existing renewable generators was provided by CaISO to the study team in mid-July, and Phase I analysis results were presented in a draft report and a public meeting on 12 September 2003. Subsequently the public comments were reviewed and incorporated in the final version of the Phase I report2, which was published in December. A second public meeting to review the Phase I results and address public comments was held in February 2004. The final Phase I report was subsequently reviewed and adopted by the CEC.

The Phase II effort focused on technical attributes of renewable generators and was completed in March 2004. Due to funding limitations, the Phase II effort was focused on geothermal and wind energy resources, which represent the bulk of the expected near-term RPS market. This report is the culmination of the Phase III effort, the goal of which was to provide a comprehensive set of methodologies for calculation of indirect costs associated with integration of renewable generators under the RPS requirements.

The Phase I report documented 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 stipulated that the approach should apply equally and fairly to all renewable generators eligible under the RPS. Furthermore, the methodology must clearly define the analysis approach including the data requirements. The documentation should also provide a step-by-step approach to show how the data would be processed for each generator type. These goals were largely achieved during the Phase I effort, with the exception of the capacity credit analysis. In later phases, additional effort was focused on capacity analysis that has resulted in documentation of a comprehensive approach.

During Phase II of the project, the team focused on evaluating key attributes of renewable generators that might affect integration costs. Ultimately the CEC decided to focus the attribute analysis on geothermal and wind energy technologies because those resources were anticipated to achieve the greatest market penetration in the near-term. The goals of the attribute analysis were to identify technical and geographic issues that could affect integration costs. These studies provide guidance into modeling California's geothermal and wind resources by geographic area and also provide information about technical aspects of each generator type, which is important for calculating the integration costs.

In the final Phase III effort the recommended methodologies were summarized and a formalized process for evaluation of integration costs was documented. This report is the culmination of the Phase III effort and provides detailed recommendations for performing integration cost analyses of various renewable generating resources by the state of California.

1.4. Systematic Evaluation of Integration Costs

This report summarizes each of the recommended methods for estimating capacity credit, regulation cost, and load following impact. Considerable effort was spent to develop a set of procedures that were as simple as possible to implement and understand. The resulting integration cost calculations are amenable to computer automation and require minimal human processing effort. This report recommends a systematic approach to evaluation of integration costs that can be routinely applied and updated.

With the recommended approach the CEC or the CPUC, must designate one or more staff to assume the role of the Integration Cost Analyst (ICA). The ICA will be required to obtain data from CaISO and the IOUs, evaluate integration costs, and periodically publish updated results. A schematic of the integration analysis approach is provided in Figure 1.2.

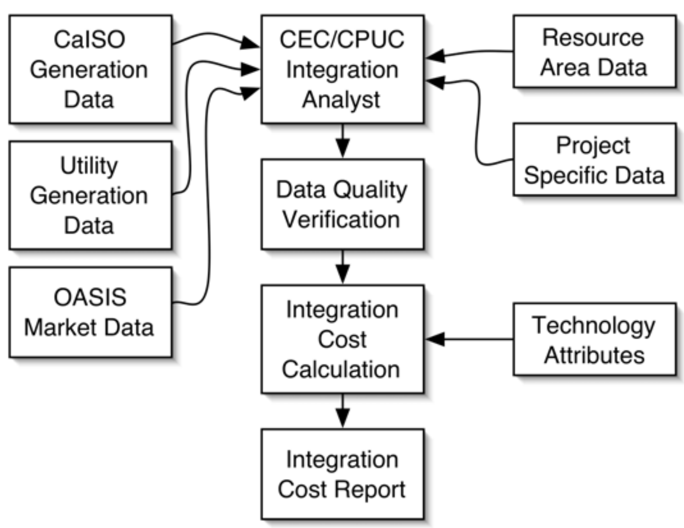

Figure 1.2 A Schematic Of The Recommended Integration Cost Analysis Process

Calculation of integration costs is inherently dependent upon timely access to reliable data. For this reason, the ICA will need to receive generation data from the CaISO and the IOUs on a regular basis. It is recommended that the generation data be documented monthly in arrears for the previous month. These data should be stored in a standardized database and submitted to the ICA in electronic format. A simplified data flow schematic is shown in Figure 1.3.

The necessary CaISO energy market data can already be obtained from its OASIS website. The CaISO and IOU generation data are not currently available from web based servers and a system is needed to provide the ICA with generation data. The data might be provided on a secure website or submitted electronically through other means. Initially some development effort will be necessary to designate data sources and prepare the database software needed to retrieve and store power generation records. However, once the system has been configured, data supply is essentially an accounting function that should require infrequent human intervention.

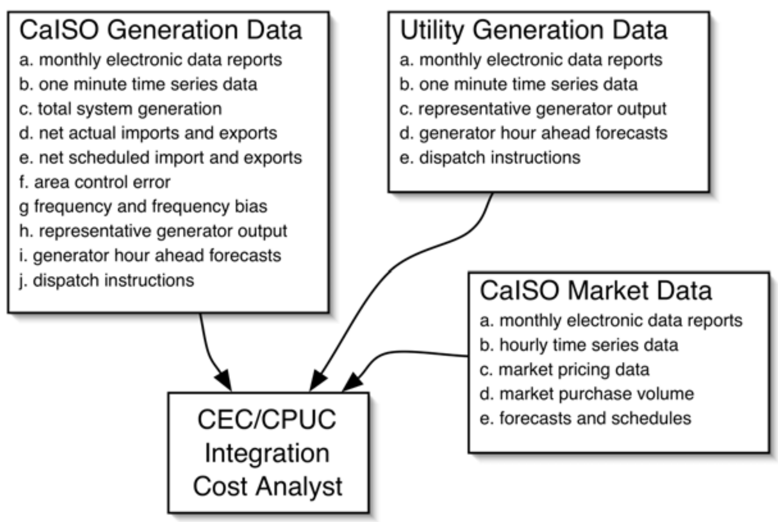

Figure 1.3 A Schematic Of The Recommended Integration Cost Analysis Data Flow

The methodology for calculation of integration costs is sufficiently well defined that it can be applied on a routine basis. The basic calculation approach has been divided into three major topic areas: capacity credit, regulation cost, and load following.

- Capacity Credit - The capacity credit analysis provides insight into the value a generator provides to system reliability.
- Regulation Cost - The regulation analysis procedure evaluates the costs associated with short-term, minute-to-minute fluctuations in generator output.

- Load Following - The load following methodology assesses the relative impact of renewable generator forecast errors and their impact on the short term energy market.

A detailed methodology for performing each of these analyses has been defined along with the data pathway. The capacity credit and load following analyses are both based on hourly data, which may be obtained from several different sources as shown in Figure 1.4. A complete set of hourly data is assembled by combining the hourly data from the OASIS market database with hourly averages calculated from the one minute generation data provided by the CaISO and the IOUs. The regulation analysis uses the one minute data directly in its calculations, in addition to the hourly market data.

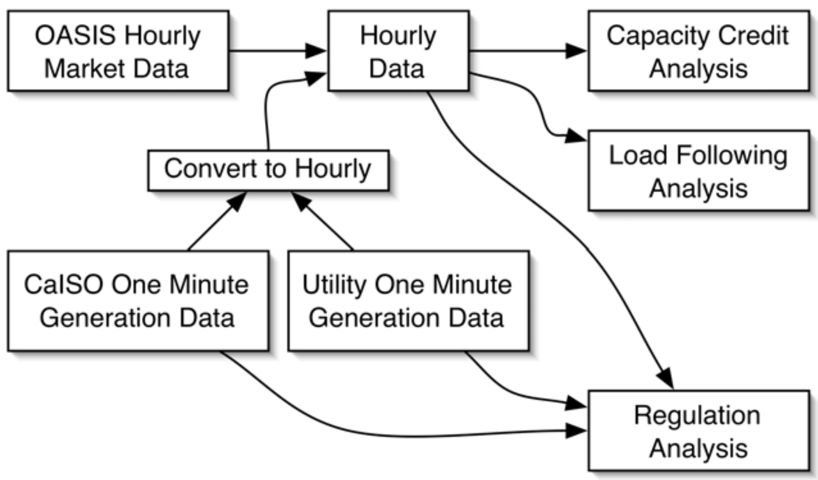

Figure 1.4 A Schematic Of The Integration Analysis Data Processing Pathway

The following sections of this report provide details of the integration cost analyses. The report documents input data requirements and recommended methodologies for analyzing and evaluating the data. In addition, the report discusses how generator attributes may be incorporated into the integration cost analysis. Finally, the report outlines approaches for using the integration cost analysis results to support bid selection as part of the LCBF process.

2.0 Project Approach

2.1. Data Requirements

2.1.1. One Minute Data

This data contains generator and electrical system measurements stored at one minute intervals. To maintain confidentiality the representative generator values must be aggregates including two or more plants with similar operating characteristics. Data aggregation has sometimes been perceived negatively because of the assumption that certain generator characteristics become improperly magnified or diluted. Data aggregation can parallel the real-world aggregated behavior of a large number of generators, but this remains a valid concern and underscores the need to carefully assemble aggregates so that important generator attributes are preserved.

Each aggregation should be identifiable by the generator type, its geographic location, and technology type; for example, "geothermal-flash-imperial" referring to an aggregate of geothermal plants, using flash technology, located in Imperial County. The following one minute data are necessary to perform the integration analysis and must be provided by the CaISO and/or the IOUs:

- System Data
  - Total Load (MW)
  - Total Generation (MW)
  - Area Control Error (MW)
  - Actual Frequency (Hz)
  - Scheduled Frequency (Hz)
  - Actual Interchange (MW)
  - Scheduled Interchange (MW)
  - Dynamic Interchange Schedule (MW)
  - Total Regulation (MW)
  - Deviation From Preferred Operating Point (MW)
- Generator Power Output Data (MW)
  - Aggregated Renewable Generation And Dispatch (if applicable)
  - Representative Conventional Generators And Dispatch (if applicable)

2.1.2. One Hour Data

This data is composed primarily of measurements recorded at one hour intervals, but will also include data stored at one minute intervals which have been converted to hourly averages. Much of the hourly data can be directly obtained from the OASIS website, which provides access to the CaISO's public database. OASIS is an acronym for Open Access Same-Time Information System. It is the CaISO's web accessible public database at http://oasis.caiso.com/. OASIS contains current and archived market data for energy and transmission in California.

OASIS provides hourly values of California's actual system load, scheduled load, hour ahead forecasted load, day ahead forecasted load, and two day ahead forecasted load. The forecasted values are the CaISO's predictions of load. The scheduled values are determined by the scheduling coordinators and submitted to the CaISO. The hour ahead values are actually set 150 minutes before the specified time so that the CaISO has time to review and incorporate them into the system.

The following hourly data are available from OASIS:

- Regulation Up, Pre-Rational Buyer, Procured (MW)
- Regulation Down, Pre-Rational Buyer, Procured (MW)
- Regulation Up Price, Pre-Rational Buyer, Procured ($/MW)
- Regulation Down Price, Pre-Rational Buyer, Procured ($/MW)
- Regulation Up, With Rational Buyer, Procured (MW)
- Regulation Down, With Rational Buyer, Procured (MW)
- Regulation Up Price, With Rational Buyer, Procured ($/MW)
- Regulation Down Price, With Rational Buyer, Procured ($/MW)
- Regulation Up, With Rational Buyer, Self-Provided (MW)
- Regulation Down, With Rational Buyer, Self-Provided (MW)
- Regulation Up Price, With Rational Buyer, Self-Provided ($/MW)
- Regulation Down Price, With Rational Buyer, Self-Provided ($/MW)

Regulation can be categorized in several nonexclusive ways:

- Regulation Up (Frequently Referred To Simply As "Reg Up") And Regulation Down ("Reg Down")
- Pre-Rational Buyer And Rational Buyer
- Self-Provided And Procured

2.2. Database Management

This section discusses a number of database issues and provides several recommendations to aid the integration cost analysis. The data used to support the RPS Integration Cost Study were provided by the CaISO, which acts as the central storehouse for information about California's electricity grid. Every few seconds, the CaISO receives measurements from nearly 200,000 individual transmission and power generation assets located throughout the state. To manage the vast flow of information the CaISO operates a massive database called the Plant Information (PI) system.

The PI system continually records data from tens of thousands of sources. The sheer size of the database can make it difficult to find a specific set of records. To perform a database query the user must identify a specific generator using an alphanumeric name, or "PI tag". Initially the RPS Integration Cost Study team identified various generation types of interest, but no corresponding PI tags were known at that time. The PI system lacks a central index of tags, so finding the correct generator PI tags is a largely manual process of sifting through thousands of tags. Changes in the PI database over time resulted in PI tag identifiers in 2002 that were different from those in 2001 and earlier.

The CaISO database contains records from both individual generators and aggregations of several units. Some of the data provided to the CaISO is aggregated by the IOUs and municipal utilities internally. Data for individual generators may not exist in the PI system if that unit has been previously aggregated by the utilities. A great deal of dispatch and generation data for individual plants is therefore unavailable to the CaISO and the PI system cannot be used to obtain those records. For this reason it will be necessary for the ICA to obtain data directly from the IOUs or from plant operators and owners.

It is recommended that the ICA, the CaISO, and the IOUs jointly prepare a comprehensive list of the generators and database tags for all renewable facilities.

2.3. Data Quality

While the quality of data stored by the PI system was generally good, deviations can occur because of telemetry and instrumentation errors. When this occurs, power generation values sometimes drop to zero and, during other times, remain constant at its last good reading. Such errors inherently impact regulation analysis and must be corrected before the data is aggregated with other data; once data are combined, dropouts and constant readings can be impossible to detect and correct. Some effort will be necessary to perform data quality verification before aggregation. This may entail development of automated data quality review software and tools.

It is recommended that the ICA, the CaISO, and the IOUs jointly develop a process for evaluating data quality prior to aggregation of individual units.

3.0 Project Outcomes

3.1. Capacity Credit Analysis

3.1.1. Power Demand

Electricity is a unique commodity because it has two different units of value. Electric generation facilities provide energy value, but they also deliver capacity value. At any given time the power grid must have enough generating capacity to supply load demand. The system ultimately delivers energy to consumers, but without sufficient generating power the grid can become unstable and collapse into blackout. Power, or capacity, is critical to assure the reliability of the electric system. A generator's ability to deliver power when needed provides capacity value that is separate and distinct from the energy it delivers. The addition of new generating capacity will provide a value to the grid, because it increases system reliability during peak demand periods.

The value of capacity varies tremendously depending upon the system load and is highest when demand nears peak levels. For this reason, it is important to understand the electrical demand patterns, which exhibit strong seasonal and diurnal trends. In this effort, we reviewed data for statewide electrical power demand for a three year period extending from 2001 to 2003. These data were sorted to determine peak demand and the top twenty demand hours of each year are tabulated in Table 3.1. These data show that the months of July and August are the most common peak demand periods, but that June and September also rank as peak months.

Table 3.1 Summary Of California Peak Demand Hours for Three Years From 2001 to 2003.

Date & Time	Demand (MW)	Date & Time	Demand (MW)	Date & Time	Demand (MW)
8/7/01 15:00	41155	7/10/02 14:00	42008	7/21/03 14:00	42581
8/7/01 16:00	41017	7/10/02 15:00	41813	8/25/03 14:00	42506
8/7/01 14:00	40493	7/9/02 15:00	41636	7/17/03 14:00	42502
8/8/01 15:00	40488	7/9/02 16:00	41480	7/21/03 15:00	42346
8/27/01 15:00	40439	9/23/02 16:00	41165	7/14/03 15:00	42227
8/17/01 15:00	40384	7/9/02 14:00	41162	8/25/03 13:00	42218
7/2/01 15:00	40241	7/10/02 16:00	41092	7/21/03 13:00	42184
8/27/01 16:00	40173	7/10/02 13:00	41007	7/17/03 15:00	42143
8/8/01 14:00	40149	6/5/02 16:00	40986	8/26/03 14:00	42107
7/2/01 16:00	40073	9/23/02 15:00	40984	7/17/03 13:00	42037
7/3/01 15:00	40065	7/9/02 17:00	40935	8/18/03 14:00	42007
8/17/01 14:00	40017	6/5/02 15:00	40858	7/14/03 14:00	41968
8/8/01 16:00	39953	8/9/02 16:00	40638	8/25/03 15:00	41905
8/16/01 15:00	39900	8/9/02 15:00	40625	8/26/03 13:00	41826
8/27/01 14:00	39899	8/12/02 16:00	40625	7/14/03 16:00	41655
8/17/01 16:00	39847	7/12/02 15:00	40614	8/18/03 13:00	41613
7/3/01 14:00	39741	7/10/02 17:00	40520	8/18/03 15:00	41433
8/16/01 16:00	39733	7/12/02 16:00	40488	7/16/03 15:00	41412
7/2/01 14:00	39690	8/12/02 15:00	40429	9/5/03 14:00	41394
7/3/01 13:00	39650	9/3/02 15:00	40418	8/25/03 12:00	41368

The statewide demand data were converted to a non-dimensional form called a demand factor. The demand factor was calculated for each hour by dividing the hourly demand value by the peak power demand of each year. The sorted hourly demand data were plotted and are shown in Figure 3.1 and Figure 3.2. These graphs show power demand as an average hourly fraction of the maximum system demand during the year and illustrate that system demand is typically above 80% of maximum for less than five hundred hours per year.

System reliability is strongly linked to the demand factor and the value of a generator's capacity depends on its ability to deliver power when the system most needs it. The demand factor over a three year period from January 2001 through December 2003 is presented in Figure 3.3 as a function of time. This graph shows clearly the peak demand period occurring between mid-May and mid-October. This graph also shows that there is considerable variation within the summer period as to the particular day or week that peak demand occurs.

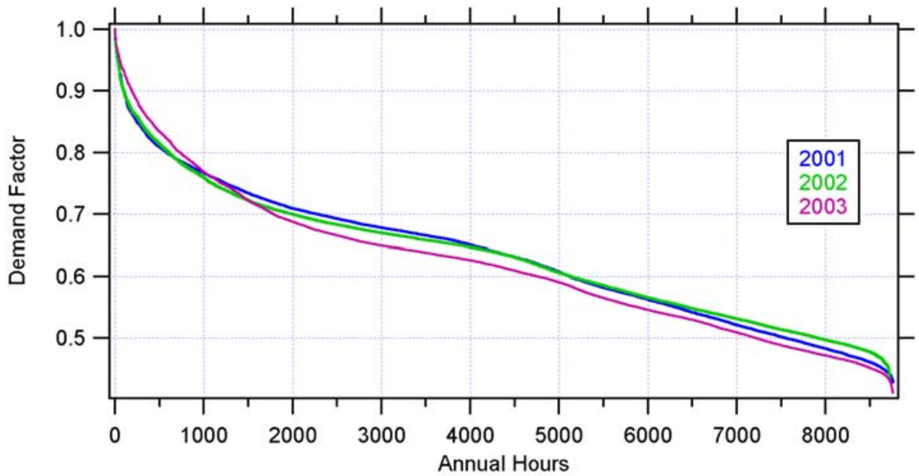

Figure 3.1 **Comparison In Demand Factor For Three Years From 2001 To 2003**

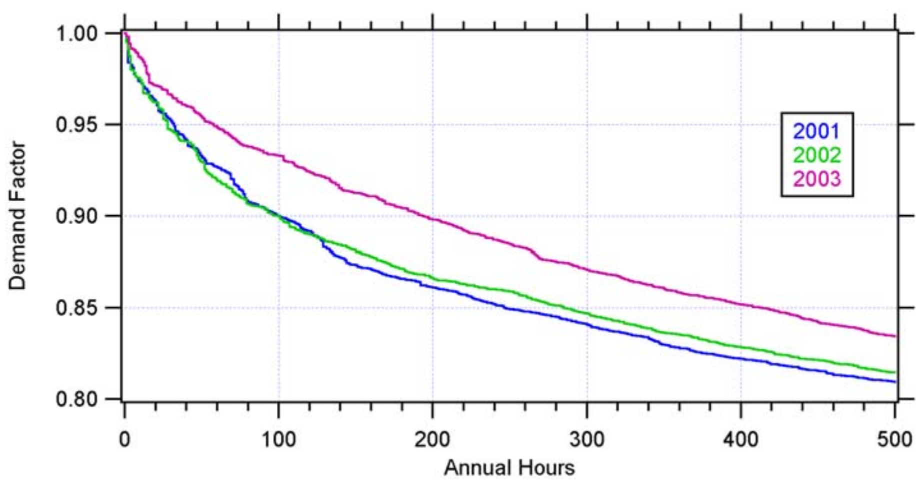

Figure 3.2 **Comparison In Demand Factor For Three Years From 2001 To 2003**

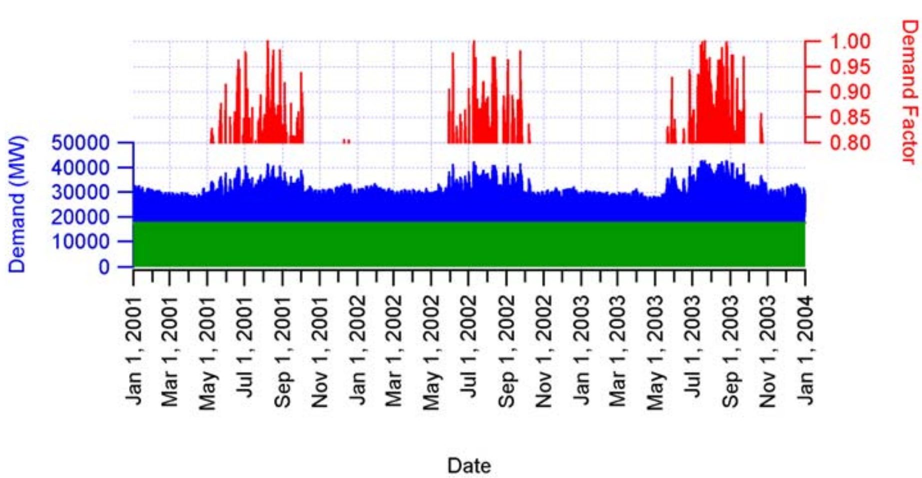

Figure 3.3 **California Power Demand For 2001 Through 2003**

3.1.2. Definition of Capacity Credit

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. In the past, utilities have been reluctant to assign a value for capacity from renewable generators, largely because of the intermittent nature of some resources. However, there are analytical methods for correctly accounting for the value that intermittent generators provide to system reliability.

Evaluating the value of capacity provided by intermittent generators is more complicated than for conventional resources. As used here, the term *capacity credit* will define the capacity a given generator adds to the electrical system, as compared to the capacity of a natural gas reference unit that would add the same level of system reliability. It represents the value of a generator's contribution to the reliability of the overall electrical supply system. The capacity credit of a specific generator is a function of the reliability of that generator and system demand. No generator is perfectly reliable, so every type 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.

3.1.3. Effective Load Carrying Capability

The preferred method for determining the capacity credit is to calculate the *effective load carrying capability* (ELCC). ELCC has been used for many years and can be applied to a wide variety of generators, not just renewables. This approach is well-grounded in electric power system reliability theory and applied methods. The ELCC is a way to measure a power plant's capacity contributions based on its impact on system reliability. It is often used as a way to compare different power plants, and can be easily applied to intermittent generators as well. The ELCC considers each generator in an electrical system and its probability of being unavailable because of mechanical problems, other malfunctions, or, in cases of intermittent renewables, resource unavailability. The probability that any generator can fail at a given moment is non-zero and, consequently, all power plants have an ELCC that is less than rated capacity (barring unusual plants with artificially low rated capacity with respect to actual achieved capacity).

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 *might* be 425 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 *loss of load expectation* (LOLE) or the *loss of load probability* (LOLP). 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:

$$LOLE = \sum_{i=1}^{N} P\left[C_i < L_i\right] \qquad \text{[Equation 3.1]}$$

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:

$$LOLE' = \sum_{i=1}^{N} P\left[(C_i + g_i) < L_i\right] \quad \text{[Equation 3.2]}$$

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).

$$\sum_{i=1}^{N} P(C_i < L_i) = \sum_{i=1}^{N} P\left[(C_i + g_i) < (L_i + \Delta C_i)\right] \quad \text{[Equation 3.3]}$$

Calculating the ELCC of the renewable plant amounts to finding the values ΔC_i that satisfy Equation 3.3. 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 3.3 that increasing values of ΔC_i are associated with declining values of LOLE. Unfortunately, it is not possible to analytically solve Equation 3.3 for ΔC_p. The solution for ΔC_p involves running the model for various test values of ΔC_p until the equality in Equation 3.3 is achieved to the desired accuracy.

Although the level of detail of the input data varies between models, hourly electric loads and generator data are 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.

3.1.4. ELCC Model Revisions and Updated Results

3.1.4.1. Direct Use of Hourly Generation Values versus Probabilistic Distributions

The Phase I analysis used an electric production reliability model to calculate the ELCC of the renewable generators. A probabilistic method was applied to represent intermittent renewable generators in the reliability model[3,4]. Discussions at the Public

Workshops in Phase I suggested that we take a planning view of the reliability and capacity value of the existing renewable generators in California. Additional discussion suggested that the modeling should consider a typical week per month, for which the appropriate availability statistics would be calculated and fed to the reliability model. This procedure has been tested for wind generators, and does a good job of capturing the relevant statistical distributions that describe the wind production throughout the year. For conventional units, or for renewable technologies that behave like conventional generators, this approach (or one very similar) has been used for many decades to model multiple-block generators.

We received a number of comments that were critical of the Phase I capacity results for solar resources. Our investigation revealed that during the top 200 hours, solar generation sometimes was significantly less than the rated (maximum) output. This implies that this resource would not achieve a 100% capacity value, as suggested by some parties during the Phase I workshops.

During the Phase III effort we performed a series of additional simulations using newly acquired data for hydro resources. These simulations also explored alternative modeling specifications for the intermittent renewable generators. The probabilistic approach does not lend itself to an accurate assessment of past performance when combined with one typical week per month representation of the renewable resources. The probabilistic approach is more appropriate as an indicator of future performance, where there are considerable uncertainties surrounding the timing of the power delivery from these resources.

In response to comments received and subsequent analysis work we moved towards a more straightforward approach to modeling the renewable generators. In addition, because of the unique characteristics of solar generation, it became apparent that the probabilistic approach used in the Phase I analysis may be responsible for some of the anomalies in the solar capacity values.

Upon examination of the statistical distributions calculated for solar, we found that several periods of relatively low solar output coincided with moderate-to-high periods in the aggregation used for the probabilistic approach. For wind resources, these differences can be interpreted as the uncertainty that would logically surround future power production and its timing. But for solar, this resulted in a lower statistical expected value during times of relatively high system risk. This translated into ELCC values for solar that were questioned during the Phase I work. We found a similar, but smaller, impact on the geothermal resource aggregate.

The modeling method used in the Phase III calculations of ELCC was relatively simple. Instead of constructing statistical distributions for the renewable resources, we used the actual hourly generation in the model. This is much easier to model and is more transparent than the probabilistic method used in Phase I. However, this approach does not consider alternative timing of the power delivery from the renewable resource, as does the probabilistic method. When multiple years of data are analyzed, this is not a significant limitation. Therefore the single-year estimates that we provide in this report should be considered as such, and would be expected to vary somewhat from year to year.

3.1.4.2. Incorporation of the Hydro System

We also received new hydro data from the CEC for the Phase III effort. However, because of data confidentiality, we were unable to obtain actual hourly generation from the CEC. The CAISO was unable to identify the tags necessary to provide specific hourly hydro output for 2002, so this data set was unavailable for this work. Instead, we obtained monthly minimum and maximum flows and rough estimates of pond-storage and pumped hydro data that were representative of conditions in 2002 from the CEC. In the new simulations, our model performed an optimal dispatch on the hydro, utilizing a peak-optimization algorithm to dispatch as much controllable hydro as possible during system-critical times. A significant portion of the hydro energy is run-of-river, which is uncontrollable and subject to nature. This is similar to wind and solar, although hydro is less variable than wind and has different characteristics than solar. But ultimately, these forms of generation are not dispatchable. The impact of the hydro system on the hourly risk profile is significant, and is evident in the ELCC results.

The results of the revised ELCC calculations appear in Table 3.2. The wind capacity values have changed somewhat. The geothermal and solar values are significantly different than the Phase I results. Because of the statistical smoothing that occurs in the probabilistic approach of Phase I, it is not possible to predict in advance which method will produce higher ELCC estimates.

Table 3.2 Revised Capacity Credit For Wind, Solar, And Geothermal Using Actual Hourly Profiles.

Resource	ELCC (%)
Geothermal	83.0
Solar	89.5
Wind (Altamont)	23.0
Wind (San Gorgonio)	23.5
Wind (Tehachapi)	25.2

To assess the impact of the hydro system (run of river, dispatchable hydro, and pumped storage), we reran these cases by disabling all hydro units, as shown in Table 3.3. The results of this were not entirely unexpected, but the magnitudes of the changes were. Solar experienced a slight, insignificant decrease in ELCC as compared to the hydro case. However, all the wind resource areas had increases in ELCC, ranging from about

3% (Altamont) to nearly 8% (San Gorgonio). Geothermal also experienced a large increase (9%).

Table 3.3 Revised Capacity Credit For Wind, Solar, And Geothermal Using Actual Hourly Profiles Without Hydro Resources.

Resource	ELCC (%)
Geothermal	92.0
Solar	88.4
Wind (Altamont)	26.1
Wind (San Gorgonio)	31.1
Wind (Tehachapi)	29.1

Run-of-river hydro is similar to solar or wind because it is not dispatchable. Because of constraints on river flows, and because of the variability of natural water run-off through the year, the system risk profile (hourly LOLP) changes. Because this is a largely uncontrollable resource, its altered risk profile will have limited benefit during high-risk hours. However, the controllable hydro, consisting of pondage (dispatchable hydro) and pumped storage, can be used to mitigate system risk. It is not possible *a priori* to determine the impact of removing the hydro system from the simulations because the run-of-river-induced change in the risk profile is largely random, and may be larger or smaller than changes that are induced by dispatchable hydro.

The interpretation of these results is aided by referring to Figure 3.4. This graph is based on two simulations. Both simulations include all renewable resources. However, one case includes the hydro system, whereas the other does not. The difference between the simulations illustrates the powerful effect that the hydro system has on shifting the risk profile. The consequence of this shifting risk pattern is discussed further in Appendix A in the context of simple methods to approximate ELCC.

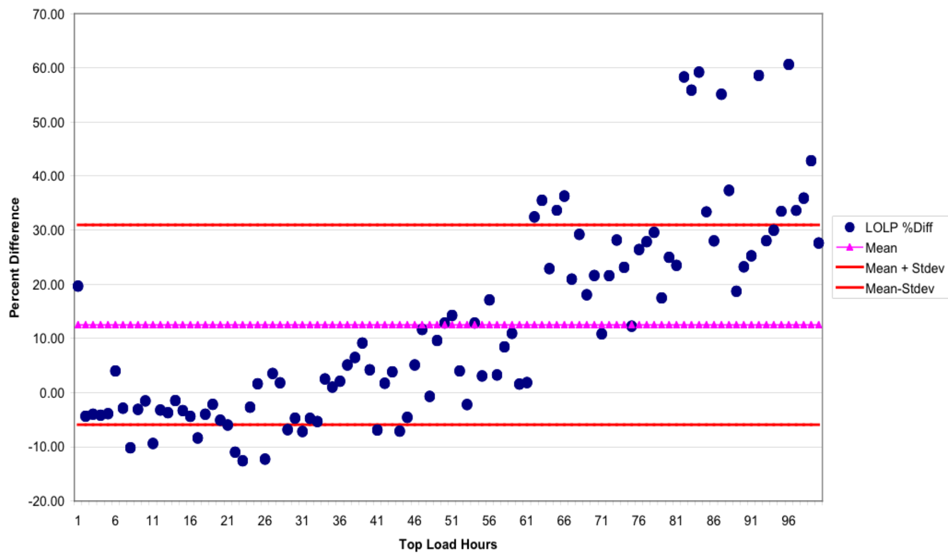

Figure 3.4 Difference In LOLP With And Without Hydro Resources.

3.1.5. Step-by-Step ELCC Capacity Analysis Methodology

The ELCC modeling requires a production/market simulation or reliability model that is capable of representing the California power supply system and calculating LOLP, LOLE, or another similar reliability metric. The overall approach is to run the model with all generators included and adjusting loads so that a target reliability level is met. This is often one day in ten years LOLE, but could be another reliability target if desired. The renewable generator is then replaced with varying levels of a benchmark unit. When sufficient generation levels of the benchmark unit is added to bring the annual LOLE back to the reliability target, the amount of generation is noted, and is the ELCC of the renewable generator. In the Phase I work, we used a combined cycle natural gas unit as the primary benchmark. The benchmark could also be a simple combustion turbine, if that is the unit used to determine the cost of capacity. The detailed step-by-step approach is as follows in Table 3.4.

Table 3.4 Step-By-Step Description Of ELCC Capacity Analysis Methodology.

1.	Develop a time series that represents hourly generation from the candidate resource.
2.	Add the candidate resource to the supply model of the California system.
3.	Ensure that existing renewables are present in the supply model.
4.	Run the reliability model.
5.	Note the annual loss of load expectation. We want a target of 1 day/10 years, which equates to 2.4 hours/year LOLE. It is unlikely that we will obtain our target 1 day/10 years in this initial run. The reliability metric is sometimes (erroneously) displayed as annual LOLP by the model.
6.	Adjust the hourly loads, if necessary. If the LOLE exceeds 2.4 hours/year (this is highly unlikely in the base case) then pro-rate the hourly loads downward and rerun the model. If the LOLE is less than 2.4 hours/year, then pro-rate the hourly loads upward and rerun the model. Continue repeating steps 4-6 until the reliability target has been met.
7.	The final modeling run from step 6 is the base case, and represents the reliability target of 1 day/10 years LOLE. Save this load set.
8.	Remove the renewable generator of interest. Although not strictly necessary, you can rerun the model at this point. If the model is run, the reliability will decrease (LOLE will increase).
9.	Incrementally add the gas benchmark unit. If the reliability model makes it easy to run alternative, multiple scenarios, the gas benchmark unit can be added incrementally in a batch of modeling runs. Alternatively, some models allow the user to specify a target output and a “rule” for changing inputs so that the goal is reached. In any case, each incremental addition of the reference unit will result in a new annual LOLE value. At each of these steps, the model should save total gas capacity for this step and the annual LOLE. This set of runs must add sufficient gas capacity to bring the LOLE down to the benchmark reliability level of 1 day/10 years, or lower. The results of these iterative steps can be inserted in a spreadsheet.
10.	The ELCC of the generator of interest is the gas capacity that corresponds to the case that matches the original reliability target.

3.1.6. Limitations of the ELCC Method for Steam-Constrained Geothermal

The difficulty of using actual hourly data for steam-constrained geothermal is that the data doesn't tell us why the geothermal output is less than potential capacity. If the generation is reduced because of a steam constraint, then that reduction should be taken into account when calculating the ELCC, reducing ELCC accordingly.

However, if the geothermal generation is responding to dispatch instructions, then it is possible that full output was achievable, and the ELCC calculation should ignore this shortfall. This difficulty could be overcome if the hourly data stream were to represent potential output, subject to the steam constraint at the site. In principle, this could also apply to gas-assist solar units or other generation that can respond to dispatch signals because data from these generators might not be accompanied by dispatch instructions that limited output.

For wind generation, we assume that the wind generation produces its maximum attainable power output, given the wind speed in the appropriate wind resource area. Although some turbines may be out of service, either planned or unplanned, we had no data available to evaluate this impact. Therefore, the ELCC calculation should use the actual generation time series for the year.

3.1.7. Simplified Capacity Credit Methodologies

Several simplified capacity credit methodologies were developed and examined to replace the ELCC calculation. These methodologies ranged from simple to complex, and generally involved a trade-off between simplicity and transparency on the one hand, and precision and complexity on the other hand. In other words, better methods tended to be more complex.

The simplified methods that best approximated the ELCC ultimately approached the complexity of the ELCC calculation itself. Because of this and other reasons discussed further below, there is no recommendation for an alternative method to the complete ELCC calculation.

Appendix A discusses the general issues with simplified capacity credit methodologies, describes several methodologies with varying complexity and accuracy, and details one of the more advanced methodologies that was developed and investigated.

3.2. Regulation Analysis

3.2.1. Ancillary Services

Ancillary services are the corrective actions needed to integrate electricity from generation sources into a larger, real-time electricity supply. The CaISO purchases ancillary services to 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. *Regulation* and *load following (supplemental energy)* are the two key ancillary services required to perform this function.5

Terminology associated with ancillary services has not been standardized across the utility industry and this sometimes has led to confusion. 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, in its notice on regional transmission organizations (RTOs), proposed to require that RTOs operate real-time balancing markets.6 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.

3.2.2. Definition of Regulation and Load Following

Loads within a control area can be decomposed into three elements, as shown for a hypothetical weekday morning in Figure 3.5. 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.

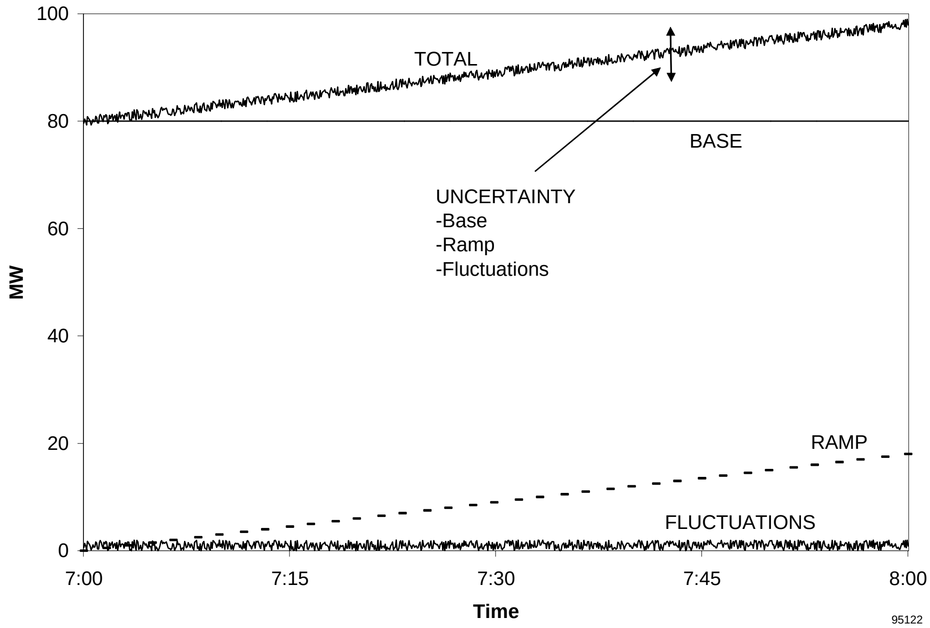

Figure 3.5 Decomposition Of Hypothetical Weekday Morning Load.

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[7,8,9] as follows:

- *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.

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. A 15-minute rolling average is recommended here to separate regulation from load following. The rolling average for each 1-minute interval should be calculated as the mean value of the seven earlier values of the variable, the current value, and the subsequent seven values:

$$\text{Load Following}_t = \text{Load}_{\text{estimated-}t} = \text{mean}\,(L_{t-7}, L_{t-6}, \ldots, L_t, L_{t+1}, \ldots, L_{t+7}) \quad \text{[Equation 3.4]}$$

$$\text{Regulation}_t = \text{Load}_t - \text{Load}_{\text{estimated-}t} \qquad \text{[Equation 3.5]}$$

This method is somewhat arbitrary and imperfect.[5] It is arbitrary in that the time-averaging period (15 minutes as recommended here) 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.10 The 15-minute rolling average is recommended because it provides good temporal segregation and captures the characteristics of California's supplemental energy market.

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. 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. If consistent, robust short-term forecasts are available and verified for all of the renewable generation technologies, this analysis can be performed without the use of a 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.

3.2.3. Regulation Analysis Methodology

The regulation analysis methodology quantifies the regulation impacts of loads and generating resources within a 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.

The regulation requirement of the entire system is first determined by taking the standard deviation of the 1 minute regulation values (Equation 4.2) for total system load. It is then possible to 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 individual generators. 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 Appendix C, meets these criteria. It was developed to analyze the impacts of nonconforming loads on power system regulation and works equally well when applied to non-dispatchable or uncontrolled generators. The recommended allocation method does not require knowledge of each individual's contribution to the overall requirement. Specific individuals' contributions can be calculated based upon the total requirement and the individuals' performances. Because regulation is composed of short, minute-to-minute fluctuations, 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:

$$\sigma_T = \sqrt{\sum \sigma_i^2} \qquad \text{[Equation 3.6]}$$

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:

$$\text{Share}_i = \left(\frac{\sigma_i}{\sigma_T}\right)^2 \qquad \text{[Equation 3.7]}$$

The more general allocation method[5], presented in $Share_i = \dfrac{\sigma_T^2 + \sigma_i^2 - \sigma_{T-i}^2}{2\sigma_T}$

[Equation 3.8], 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 dependent 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.

$$Share_i = \frac{\sigma_T^2 + \sigma_i^2 - \sigma_{T-i}^2}{2\sigma_T} \qquad \text{[Equation 3.8]}$$

The general allocation method ($Share_i = \dfrac{\sigma_T^2 + \sigma_i^2 - \sigma_{T-i}^2}{2\sigma_T}$ [Equation 3.8]) is recommended for analysis of the impacts of various individual renewable generators on the overall system's regulation requirements.

Calculated hourly regulation requirements are compared with actual hourly regulation purchases by the CaISO and hourly regulation self-provided by scheduling coordinators. Typically, three standard deviations of regulating reserves are carried to assure adequate CPS performance (see Appendix B). Total regulation requirements are then allocated back to individuals. Hourly regulation costs are used to allocate the cost of regulation back to individuals. All of the CaISO's regulation requirements are allocated based upon the short-term variability impacts of the loads and renewable generators.

3.2.4. 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.

At a minimum, the data list must include 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 data list should include 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 element 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 are used to determine practical quantities and costs of procured regulating resources. Scheduling coordinators are also allowed to self-provide regulation. The amount of self-provided regulation must be added to the amount of purchased regulation to obtain the total regulation amount. There is no price associated with self-provided regulation so the market price of the purchased regulation for the same hour is used to calculate the total dollar value of regulation for each hour.

- 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

3.2.5. Step-by-Step Regulation Analysis Methodology

The following is a step-by-step listing of the regulation analysis. Inputs are explicitly listed if they are raw data or if they are output generated in a previous step.

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

$ACE(t) = [NI_A(t) - NI_S(t)] - 10ß[(F_A(t) - F_S(t)] - I_{ME}(t)$ [Equation 3.9]

$NI_A(t) = G(t) – L(t)$ [Equation 3.10]

Table 3.5 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

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

$$L_{s_2}(t)=\overline{L_{15}}(t)=\frac{\sum_{x=-7\,\min}^{7\,\min} L\,(t+x)}{15}$$ [Equation 3.11]

$$g_{i,ave}(t)=\overline{g_{i,15}}(t)=\frac{\sum_{x=-7\,\min}^{7\,\min} g_i(t+x)}{15}$$ [Equation 3.12]

Table 3.6 Estimate Short Term Forecast From Rolling Average Surrogate

Inputs

	Data description		Units	Sampling rate
a.	L	total system load	MW	1 minute
b.	g_i	power generation of generator of interest	MW	1 minute

Outputs

	Data description		Units	Sampling rate
a.	L_{ave}	short term load forecast	MW	1 minute
b.	$g_{i,ave}$	short term forecast of generator of interest	MW	1 minute

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

$r_L\ (t)=L(t)-L_{ave}(t)$ [Equation 3.13]

$r_i(t)=g_i(t)-g_{i,ave}(t)$ [Equation 3.14]

Table 3.7 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_i	regulation component of generator of interest	MW	1 minute

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.

$$\Delta r_i(t) = r_L(t) - r_i(t) \quad \text{[Equation 3.15]}$$

Table 3.8 Calculate Total System Regulation Less Resource Of Interest

Outputs

	Data description		Units	Sampling rate
a.	Δr_i	total system regulation without the generator of interest	MW	1 minute

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

$$\sigma_T(t) = \underset{x=0\to 59\,\text{min}}{\sigma}\left(r_L(t+x)\right) \quad \text{[Equation 3.16]}$$

$$\sigma_i(t) = \underset{x=0\to 59\,\text{min}}{\sigma}\left(r_i(t+x)\right) \quad \text{[Equation 3.17]}$$

$$\sigma_{T-i}(t) = \underset{x=0\to 59\,\text{min}}{\sigma}\left(\Delta r_i(t+x)\right) \quad \text{[Equation 3.18]}$$

Table 3.9 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_i	standard deviation of regulation component of generator of interest	MW	1 hour
c.	σ_{T-i}	standard deviation of regulation of system without generator of interest	MW	1 hour

Allocate the regulation share to the resource of interest.

$$\hat{R}_i(t) = Share_i(t) = \frac{\sigma_T^2(t) + \sigma_i^2(t) - \sigma_{T-i}^2(t)}{2\sigma_T(t)} \qquad \text{[Equation 3.19]}$$

Table 3.10 Allocate Regulation Share For Each Generator Type

Outputs

	Data description		Units	Sampling rate
a.	$\hat{R}_i$	regulation share of generator of interest	MW	1 hour

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.

$$R_i(t) = \frac{\hat{R}_i(t) R_{actual}(t)}{\sigma_T(t)} \qquad \text{[Equation 3.20]}$$

Table 3.11 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_i	regulation requirement of generator of interest	MW	1 hour

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

$$COST_R(t) = R_i(t) \cdot RATE_R(t) \quad \text{[Equation 3.21]}$$

Table 3.12 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.	$COST_{R,i}$	regulation cost of generator of interest	$	1 hour

3.3. Load Following Analysis

3.3.1. Definition of Load Following

In Section 3.2.2, we discussed how California's system loads and generation can be decomposed into three components: base load, load following, and regulation. Load following refers to intra- and inter-hour changes in electrical generation and load, and differs from regulation in three important respects. First, it occurs over longer time intervals than regulation, ten minutes or more rather than minute-to-minute. Second, the load following patterns of individual customers can be highly correlated with each other, whereas regulation patterns are largely uncorrelated. Third, load following changes are often predictable and have similar day-to-day patterns.

3.3.2. Market Settled Costs

Since the CaISO supplemental energy market operates at a load following time scale, integration costs associated with the market were denoted as load following integration costs. Participants in this hour ahead energy market submit bids for delivery of energy at a certain cost and at a certain time. The hour ahead market bids are due 150 minutes prior to the opening of each market cycle. For each cycle, the supplemental energy market generates a "stack" of bids from participating generators.

When actual load demand and scheduled generation differ, an *energy imbalance* occurs. Energy is purchased as needed from the bid stack to compensate for the imbalance. Recall from Section 3.2 that very short term deviations are captured by regulation. The CaISO uses a different resource – AGC generators – to compensate for these short term deviations, which include instantaneous schedule deviations and ramping of dispatched units in real-time.

An automated system is used to handle imbalance energy and select the most economic mix of generators from the bid stack. CaISO's current system is the Balancing Energy and Ex-Post Pricing (BEEP) system and the stack of participating energy bids is called the BEEP stack. Every ten minutes, BEEP determines the amount of energy needed and builds a list of corresponding dispatch instructions from the BEEP stack. These instructions not only compensate for scheduling deviations, but re-center regulating units (i.e., adjust their operation so that they have "maneuverability" for later instructions) and maintain a proper balance for the participating generators. The dispatch instructions are reviewed, finalized, and then sent to the scheduling coordinators using the Automated Dispatch System (ADS).

The hour ahead market pays generators for energy that is provided according to specified rules and procedures. The CaISO has developed explicit market based methods for settlement (payments or charges) of energy deliveries for controllable generators (conventional, biomass, geothermal) and for intermittent resources (wind, solar, hydro). There are explicit settlement processes that can be applied to any generator that deviates from its schedule without specific dispatch instructions (uninstructed deviations) or fails to follow dispatch instructions.

Since the CaISO has rules and procedures in place for the settlement of imbalance energy caused by deviations from schedules and dispatch instruction, these costs are settled explicitly by the market and are not considered integration costs in this analysis. Integration costs as defined in this work are those costs implicitly borne by the system that are not already allocated to a specific generator or load. Imbalance energy is not considered an integration cost because it is settled explicitly by the market and any costs incurred by the system are charged back to specific generators.

3.3.3. Load Following Analysis Methodology

The load following analysis methodology focuses on implicit costs associated with integration of renewable energy. Explicit, market settled costs are not considered. Integration of large amounts of renewable generators could potentially increase errors between scheduled and actual generation. Increases in generation scheduling error could potentially change the composition or size of the supplemental energy market's generator bid stack. If such a distortion of the stack occurred it could shift the market to marginal generators with higher costs. That would increase the price of energy in the market and thus create implicit costs imposed on the entire system by the renewable generators.

The analysis methodology first determines the system forecasting and scheduling errors for the benchmark case without renewable generators. The system forecast error is the difference between CaISO's hour ahead forecast of system load and actual load. The system scheduling error is the difference between the amount of generation scheduled by the scheduling coordinators and actual load. Scheduling coordinators typically schedule significantly less generation than is needed for on-peak load and rely upon the hour ahead market to provide the balance. Forecast and scheduling errors in the benchmark case provide an indication of the variability inherent in operating the utility grid and are important because they define the normal range of errors without renewable generation.

The difference between the system forecasted load and the system scheduled generation is defined as the scheduling bias. If generation is consistently scheduled less than the forecasted load, then there is an implied confidence that the hour ahead market can economically make up the difference. The scheduling bias, then, is an indicator of the generator bid stack depth.

In the next stage of the analysis, the scheduling errors for each renewable generator of interest is calculated. The total forecast error including the renewable generator of interest is calculated by combining the system forecast error (without renewables) with the additional scheduling error produced by the renewable generator of interest. The forecast error including the renewable generator is then compared against the benchmark forecast error and reviewed to identify significant differences between them. If the difference is small, then the impact on forecast error and the bid stack are small.

The total forecast error including the renewable generator is also compared with the scheduling bias. As discussed above, the scheduling bias serves as a good proxy for the depth of the generator stack. If the total forecast error including the renewable generator is small relative to the scheduling bias, then the resources required to correct the error are well within the bid stack and the generator under analysis should not significantly affect the size or composition of the stack.

3.3.4. Step-By-Step Load Following Analysis Methodology

The following is step-by-step listing of the load following analysis that was used.

1. Calculate the system forecast error, defined as the difference between the hour ahead forecast prepared by CaISO and the actual system load (8760 hourly values).

$$e_{Forecast}(t) = L_{HA\_Forecast} - L_{Actual} \qquad \text{[Equation 3.22]}$$

Calculate the system scheduling error, defined as the difference between the hour ahead generation schedule provided by the scheduling coordinators and the actual system load (8760 hourly values).

$$e_{Schedule}(t) = L_{HA\_Schedule} - L_{Actual} \qquad \text{[Equation 3.23]}$$

Calculate the system scheduling bias, defined as the difference between the hour ahead forecast prepared by CaISO and the hour ahead generation schedule provided by the scheduling coordinators (8760 hourly values).

$$e_{Bias}(t) = L_{HA\_Forecast} - L_{HA\_Schedule} \qquad \text{[Equation 3.24]}$$

Calculate the hour ahead schedule of the generators of interest assuming a "worst-case" simple persistence model. The hour ahead schedule is prepared 150 minutes ahead of time. The persistence model assumes that generation at t+150 is equal to output at the present time t, using hourly averaged one minute data (8760 hourly values). For some renewable resources such as solar, a more appropriate worst-case forecast is assuming that generation for a given time the next day is equal to generation for the same time today.

$$g_{i,HA}(t) = \frac{\sum_{x=1\text{min}}^{60\text{ min}} g_i(t-150)}{60} \quad \text{and for solar} \quad g_{S,HA}(t) = \frac{\sum_{x=1\text{min}}^{60\text{ min}} g_i(t-1440)}{60} \qquad \text{[Equation 3.25]}$$

where:

g_i is actual generation, and

$g_{i,HA}$ is the hour ahead schedule

Table 3.13 Calculate Hour Ahead Schedule For Each Resource.

Inputs

	Data description		Units	Sampling rate
a.	g_i	power generation of generator of interest	MW	1 hour

Outputs

	Data description		Units	Sampling rate
a.	$g_{i,HA}$	hour ahead schedule of generator of interest	MW	1 hour

Calculate the scheduling error for the generator of interest. The scheduling error is defined to be the difference between the hour ahead schedule and the 15 minute rolling average value. The scheduling error is an hourly average of one minute data (8760 hourly values).

$$e_i(t) = \frac{\sum_{x=1\min}^{60\min} \left[g_{i,HA}(t+x) - g_{i,ave}(t+x) \right]}{60} \quad \text{[Equation 3.26]}$$

Table 3.14 Calculate The Resource Scheduling Error

Inputs

	Data description		Units	Sampling rate
a.	$g_{i,ave}$	average generation of generator of interest	MW	1 minute

Outputs

	Data description		Units	Sampling rate
a.	e_i	scheduling error of generator of interest	MWh	1 hour

3.4. Incorporating Generator Attributes

3.4.1. Introduction

There are two complementary approaches which can be applied to evaluate the impact of different attributes. The first method evaluates existing historical generator data and the second uses models which simulate the generator and its characteristics. With the first approach, different generator aggregates are analyzed to determine the impacts from a particular attribute of interest. An example of this would be the aggregation of wind generators by resource region in order to assess their capacity credit. The results of this study show significant effects of the "geographic" attribute on the capacity credit for wind generators. With the second approach, representative generator data is built from simulations using computational models. At present, this approach has limited applicability, but over time it can become a powerful predictive tool.

3.4.2. Assessing Impacts from Historical Data

Power generation datasets characteristic of a particular attribute can be assembled by selecting generators which possess the attribute of interest and aggregating generation data from them. The integration costs methodologies can then be applied to the aggregates of the selected historical data to determine integration costs. By analyzing data over a number of years, the effect of any anomalous years of data is mitigated and trends in integration costs due to factors such as increasing penetration can be identified. Good selection of generators for aggregation is critical to this method.

The primary advantage of aggregating selected historical data is that the analysis is based on actual generation data. Simulated data can easily follow the gross power generation patterns of a generator, but can lack the necessary temporal resolution, improperly correlate generation as a result of inappropriate scaling, and fail to capture other characteristics that significantly affect integration costs. Furthermore, actual data implicitly includes the effects of the complete interactions of the entire electrical system. In particular, the effect of increasing penetration of intermittent generators is extremely difficult to model because of the complexity of California's electrical system, the diversity of its generation portfolio, and the lack of comparable systems that already have high penetration levels of intermittent generation. Because the level of penetration is implicitly included in historical power generation data, its effect on integration costs can be projected by extrapolating trends from several years of data analysis. Currently, there are few years of data from which to project trends. Fortunately, the current levels of penetration are relatively low and have a correspondingly small effect on integration costs; as penetration levels increase over the coming years, data will simultaneously accumulate and be available for analysis.

Reliance on actual generator data is also the primary source of difficulties with this method. Developments in new resources areas or with burgeoning technologies may have insufficient – if any – amounts of existing representative data. The data aggregates must be composed of an adequately large number of generators with enough diversity that they are not skewed toward attributes other than the one of interest. Furthermore, it is desirable to have several years of data, not only to identify trends associated with particular technologies or resource areas, but to mitigate the effect of anomalous years.

3.4.3. Assessing Impacts Using Computational Models

Power data can also be constructed using computational models to simulate operational and physical properties of generators. Such simulated data address some of the shortcomings of using actual historical data. They can project the effect of newly implemented technologies and resource areas which currently lack existing generation. Also, variables can be carefully controlled, so the effects of individual attributes can be easily isolated.

Simulation models present a number of concerns. Although power generation data is not required, the models still require detailed input data to generate accurate results. Data used by the models must be identified, assembled, and verified. Also, accurate modeling requires specific expertise and knowledge of the engineering and operation of the generator. Models must be sufficiently detailed to capture the characteristics of the attribute of interest when compared to generators that are otherwise similar. There are several possible sources for existing models including plant owners, operators, power purchasers, and renewable energy consulting firms.

Before adopting a model for use in integration cost analysis, the model must be reviewed to verify its accuracy. This is a critical step, requiring thorough study.

Historical generation data must be used in the verification process as much as possible. Once the model is satisfactorily verified and representative data are available from field operations, the model can be used.

3.4.4. Incorporating Generator Attributes of Specific Renewable Resource Types

The Phase II reports for geothermal and wind energy detail significant generator attributes that affect power production. They are summarized in Appendices D and E.

The most significant geothermal technologies are the basic energy conversion cycles: dry steam, flash steam, water cooled binary, and air cooled binary. The first three cycles should produce steady power output characteristic of base-load generators. Air cooled binary plants, however, are dependent on ambient air temperature and exhibit significant diurnal and seasonal variation in power output. Geothermal resources are concentrated in a number of locations across California including regions in the Modoc Plateau, Napa and Sonoma Counties, eastern Sierras, and Imperial Valley.

For analyses of geothermal generator attributes, data aggregates could be constructed as described in Section 3.4.2. Examples of such data aggregates constructed to represent selected significant geothermal technologies and regions are presented in Table 3.15. The generators comprising the aggregates were selected from the CEC's list of generators in California11. Attribute analyses could also employ ambient air temperature data, which could be assembled through publicly accessible meteorological data from NOAA.

Table 3.15 Example Of Geothermal Generator Aggregations By Resource Area And Type.

Attribute(s) of Interest	Selected Generators (as listed in CEC's list of California generators)
The Geysers (dry steam plants)	All 21 plants listed with dry steam as the primary fuel
Imperial Valley, double flash plants	Gem Resources T0021 Gem Resources T0022 Del Ranch, Ltd (Niland #2) Elmore, Ltd (Niland #3) Heber Geothermal Company Leathers LP (Niland #4) Salton Sea Power Generation LP #3 Second Imperial Geothermal Vulcan/BN Geothermal
Inyo County, double flash plants	Coso 1-9
Imperial Valley, binary plants	Ormesa I Ormesa II Ormesa IE Ormesa IH
Long Valley, binary plants	Mammoth Pacific 1-3

Wind plants are concentrated in five regions in California: Altamont Pass, San Gorgonio Pass, the Tehachapi Mountains, Solano County, and Pacheco Pass. Regional aggregates for Altamont, San Gorgonio, and Tehachapi have already been assembled and were used during this study. These regional datasets were complete aggregates, including all the wind plants within each region.

This report can offer only limited discussion of the generator attributes of the remaining RPS eligible resources. Complete generator attribute studies are recommended for solar, biomass, and small hydro.

The vast majority of solar capacity in California is composed of solar thermal plants with a gas generator backup. As a result, there is very little data for other types and configurations of solar plants, including solar photovoltaic. The solar generation data that is available from CaISO cannot distinguish between power from the solar concentrator and power generated by the gas backup. A gas generator backup is a plant attribute that can significantly affect integration costs. However, how it should be considered and valued is unclear given that a non-RPS eligible resource is used for power generation.

3.5. Application of Integration Cost Results

3.5.1. CPUC Rank Ordering Process

The purpose of the RPS Integration Study was to develop the methodologies and procedures necessary for assessing integration costs. This section provides a brief overview of how the results might be applied to LCBF bid selection based upon the CPUC ruling12 from June 2003 discussing the following approach for rank ordering bids:

First Ranking: The purpose of the first ranking is to identify the bid price that will be compared with the market price referent. Bids are ranked according to the product-specific market price referent:

1) The price referent reflects the value of two time-differentiated products, baseload and peaking. As RPS implementation continues to be developed, we will explore methods that more accurately reflect the value of energy and capacity on a time-differentiated basis. We will also examine methods of assessing a resource's ability to provide value to the utility on a time-differentiated basis, such as ELCC.

2) For as-available bids, capacity values and allocation are set in advance by product and technology, subject to update in later phases of this proceeding and with reference to the ongoing CEC Integration Study, using:

    a) Commission-approved capacity values, in $/kW-year, based on a combustion turbine, consistent with the standard method the Commission has used for Qualifying Facility (QF) capacity, as discussed by ORA and CalWEA. Use of other generation technologies for the capacity proxy will be considered in the upcoming Collaborative Staff and workshop processes described above in the discussion of Market Price Referents.

    b) Commission-approved capacity allocation values currently in use for QFs, subject to update to more accurately reflect the capacity needs of the obligated utilities.

    c) Capacity payments for as-available products are to be made in accordance with current Commission policy, to be reviewed in the next phase of this proceeding, and reflecting performance requirements.

3) Alternatively, as-available bidders can elect not to use these Commission-established capacity values, and bid an all-in price to supply the baseload or peaking product.

4) Bidders of firm products will not have recourse to Commission-established capacity values, and will bid an all-in price to supply the baseload or peaking resource.

5) All bids, regardless of whether they take advantage of Commission-established capacity values, are to be compared to the product-specific market price referent on an all-in basis.

6) Projects that already have preexisting SB 90 awards should not also be eligible for or receive SEPs. While it is difficult to fairly account for the SB 90 awards in the RPS process, projects with SB 90 awards may participate in the RPS solicitations to the extent that they are eligible and that they fulfill the solicitation requirements. When submitting bids in a solicitation, SB 90 award projects must declare that they possess an award, and choose whether they wish to relinquish their award prior to execution of a contract resulting from the solicitation. A bidder that chooses to relinquish its SB 90 award, and is otherwise eligible for SEPs, would be eligible for SEPs like other bidders. A project that chooses to keep its SB 90 award would be ineligible for SEPs. Similarly, projects receiving PGC funds from the Existing Renewable Facilities Program under section 383.5(c) would not qualify for SEPs. The choice must be made at the time of bid submittal, and will be applied whether the project would or would not receive SEP when its bid is compared to the appropriate market price referent. In either case, the utility should not add the expected or adjusted PGC amount to the project's bid when ranking the project.

   Added consideration must be given to projects that are already on-line and have begun receiving payments from the CEC for their SB 90 award. If such a project is otherwise eligible for SEPs as determined by the CEC, then the bidder must also choose at the time of their bid submittal to either keep their SB 90 award or relinquish it if they are successful in the RPS solicitation, as described above. If the bidder chooses to relinquish their SB 90 award to compete for SEPs, and if they qualify for SEPs, then any PGC funding the project has received from its SB 90 award should be netted out of its SEP by the CEC. If a project is not among the winners in a solicitation, it is not required to relinquish its SB 90 award.

   We recognize that the CEC will be establishing rules for eligibility and distribution of Supplemental Energy Payments from SB 1078 funds, and recommend that the CEC adopt requirements consistent with this decision.

<u>Second Ranking</u>: Bids are re-ordered based on integration and transmission costs

1) CEC Integration Study working group methods are used to determine total integration costs for each short-listed contract;

   a) The results of Phase I of the CEC integration study will reveal the integration impacts of present generation in specified areas. These results can act as a proxy for the integration effects of adding new resources in those same areas, if Phase II results are not available prior to the first RPS solicitation, as discussed in the TURN/SDG&E Joint Principles.

   b) Results of Phase II of the CEC Integration Study will provide integration values for future resource additions at specific sites.

c) Intermittent resources utilize the ISO's Amendment 42 and internalize costs into bids; no further utility calculation of schedule deviations is needed, as discussed in the TURN/SDG&E Joint Principles.

d) Remarketing costs are determined using the utilities' own power dispatch models, which are under consideration in the general procurement proceeding. Results and methods shall be made available to the PRG for complete review.

2) Transmission costs will be assessed using the most appropriate process of those available, depending primarily upon whether the project is in the ISO development queue;

a) Direct Assignment facilities are included the MPR, and therefore need to be included in the bid.

b) Network facilities: For bidders already in the ISO Queue, the standard ISO System Integration Study (SIS) and Facility Study (FS) will yield sound estimates of network facility costs.

c) Otherwise, for bidders not in the ISO queue with completed cost estimates (i.e., the SIS and FS), PG&E proposes an annual transmission plan that is a workable alternative. PG&E's proposal is a reasonable starting point for the utilities to prepare their plans, although we do modify PG&E's proposal to improve its linkage with our Transmission OII (I.00-11-001).

d) Each proposed developer provides basic interconnection information to the transmission OII, to be defined in that proceeding.

e) Utilities develop a proxy bid price using approved methods, as described in PG&E's Transmission Least Cost and Best Fit Appendix A (Ex. RPS –7).

i) Taking the interconnection information submitted by the bidder into the transmission OII, the utility will prepare an annual cost assessment plan to be made available at least 90 days prior to that year's RPS solicitation.

ii) In the transmission OII, each utility will specify what information it requires of developers to perform this assessment, and the OII will standardize the approach. The OII will also be the forum in which renewable developers will have the opportunity to dispute the results of these cost assessments.

3.5.2. Application of Existing Study Results

Integration cost analysis results from this study are used in the second ranking of the LCBF process. The Phase I results for regulation and load following showed negligible values for integration costs for all of the resources evaluated. Those results remain unchanged. We recommend that no costs be added for regulation or load following impacts until the proposed ICA publishes updated values at a future date.

The capacity credit analysis has been revised and updated during Phase III. For near-term LCBF bid evaluations we recommend application of the revised capacity credit for wind, solar, and geothermal, which use actual hourly profiles and includes hydro resources. These values are summarized in Table 3.2.

3.5.3. Application of Future Integration Cost Analysis Results

We recommend that the ruling be original ruling be modified to read:

<u>Second Ranking</u>: Bids are re-ordered based on integration and transmission costs

1) CEC Integration Study working group methods are used to determine total integration costs for each short-listed contract;

   a) The results of Phase I of the CEC integration study will reveal the integration impacts of present generation in specified areas. These results can act as a proxy for the integration effects of adding new resources in those same areas, ~~if Phase II results are not available prior to the first RPS solicitation~~, as discussed in the TURN/SDG&E Joint Principles.

   b) Results supplied by the Integration Cost Analyst and updated on a periodic basis ~~of Phase II of the CEC Integration Study~~ will provide integration values for future resource additions at specific sites.

   c) Intermittent resources utilize the ISO's Amendment 42 and internalize costs into bids; no further utility calculation of schedule deviations is needed, as discussed in the TURN/SDG&E Joint Principles.

   d) Remarketing costs are determined using the utilities' own power dispatch models, which are under consideration in the general procurement proceeding. Results and methods shall be made available to the PRG for complete review.

4.0 Recommendations

4.1. Integration Cost Analyst

The CEC/CPUC should identify staff to perform the functions of the Integration Cost Analyst. These staff would have responsibility for routine monitoring of integration costs and preparation of reports as needed to support the RPS. The recommended analysis methodologies are designed for automation and we anticipate that performing the calculation will require approximately three working days (24 labor hours) per month. On a monthly basis, the Integration Cost Analyst will obtain generation data from CaISO and the IOUs, perform verifications for accuracy, process the monthly data, and update the database. The Integration Cost Analyst will also prepare annual reports documenting the analysis results. It is recommended that an annual integration cost report be published during the first quarter of each calendar year. That effort is estimated to require approximately two weeks (80 labor hours) to perform.

4.2. Generation Data Reporting

The CEC/CPUC should receive generation data reports on a monthly basis to support the ongoing integration cost analysis. This data should be provided by the CaISO and IOUs in a standardized format as requested by the Integration Cost Analyst. Timely access to generation data is critical for the Integration Cost Analyst to perform the integration cost analysis work. Experience during this study has shown that data access and reporting must become routine functions within CaISO and the IOUs.

4.3. Integration Cost Reporting

It is recommended that an integration cost report be prepared during the first quarter of each calendar year. The report is intended to provide accurate and useful data to support the RPS. The format of the report would provide data and trends for integration costs. The report should document the results from the capacity credit, regulation, and load following analysis for each generator type, including subdivision of the results by resource area and technology. The report should also provide trend analysis to assist with understanding the impact of increasing penetration by renewable generators.

4.4. Technology Attributes

Power generation technologies change over time and it is recommended that the CEC or CPUC periodically engage technical experts to document the changes and attributes of each renewable. Evaluations for geothermal and wind energy were prepared to support this work and additional studies are necessary for each of the other renewable generators. It is recommended that technical studies be prepared for solar and biomass to document the attributes of these generators. Thereafter the studies should be updated on a regular basis, perhaps as part of the annual integration cost report.

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GLOSSARY

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
ICA	Integration Cost Analyst
IOU	Investor Owned Utility
ISO	Independent System Operator
LCBF	Least-Cost, Best-Fit
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	Dollars per Megawatt for one hour of capacity

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
LCBF	least-cost, best-fit
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

APPENDIX A: SIMPLIFIED CAPACITY CREDIT METHODOLOGIES

The goal of any simplified capacity credit method is to provide a measure of the adequacy contribution of any generating resource. For the purpose of the RPS Integration Cost Study, the goal is to provide a way to assess the capacity contribution of generators that approximates the ELCC as closely as possible. Other properties that a robust capacity measure should also possess:

- independent of the order in which resources are evaluated
- transparent
- simple
- consistent in the way it treats different units
- consistent in the way it treats similar units
- result in a relatively high value for resources that are most helpful during peak periods
- result in relatively lower values for resources that are less helpful during peak periods
- provide a metric that can be used to rank different resources
- reflect the risk-reduction contribution of different generating units, renewable, nonrenewable, intermittent, and non-intermittent
- be sensitive to different load shapes and resource profiles, and differentiate among them
- have the ability to be updated periodically to take changing system conditions into account, such as those mentioned above, demand-side management or conservation, or other influences of load shape
- be reflective of ELCC values calculated by a reliability model (but may not match ELCC precisely)

The outcome of the public workshops during the Phase I work suggested that scheduled maintenance from conventional units should be eliminated from the modeling. Whether this should continue is a policy question, but workshop participants suggested that in principle, the capacity value of renewable generators should be independent from conventional maintenance scheduling.

Although ELCC is the preferred method to evaluate capacity credit, it has a number of weaknesses and does not fulfill all of the objectives listed above. ELCC is highly nonlinear, and is sensitive to many influences. The ELCC of a particular generating unit can depend upon characteristics of other units' availability, capacity, and maintenance schedules. There can be complex interactions between resources. For example, a redispatch of the hydro system can alter the risk profile (LOLP) and can therefore change the ELCC of another plant, such as an intermittent renewable plant. Therefore, the ELCC of a resource can be dependent on the order that multiple resources are added to the system. This is particularly true for intermittent resources such as solar, wind, or run-of-river hydro. Because of the nature of these resources, there can be complex interactions between them in the reliability calculation.

There are a number of approaches that can be taken to approximate the capacity credit of an intermittent renewable generator. These approaches range from simple to complex, and generally involve a trade-off between simplicity and transparency on the one hand, and precision and complexity on the other hand. In other words, better methods tend to be more complex.

The PJM RTO (Pensylvania-New Jersey-Maryland Regional Transmission Organization) adopted a simple method to calculate wind capacity credit. Since this is a summer-peaking system, the method ignores all winter production from a wind plant. During the peak season, defined as the hours starting at 3:00 PM to 6:00 PM, June through August, the wind plant capacity credit is the capacity factor during this period. This is similar to the approach that is implicit in the Standard Offer contracts in California. These contracts pay renewable generators based on their generation during the summer peak period. The PJM approach has not yet been validated with ELCC comparisons, although PJM has indicated its intent to do so.

This simple method can miss many high-risk hours. So if that is what the method is attempting to capture, it may not work well. A simple improvement is to calculate the intermittent generator's capacity factor over a set of peak hours, such as the top 10% of load hours. This will generally capture the high-risk hours that may be missed by a PJM-like method. This will also adjust for years when the peak period moves from one month to another, as illustrated in Table 3.1. In 2001, the top 20 peak hours all occurred in July or August. In 2002 peak demand in July, September, and June rank above all hours of August. And in 2003, as in 2001, June does not appear in the top 20 peak hours.

We can further improve our method by analyzing the renewable generator's performance based on a weighted set of hours that can dynamically capture shifting peak periods. For example, in Figure 3.2 it is apparent that in 2003 the California load was relatively higher during the top 500 hours than during 2001. Using the demand factor can help determine weights that will approximate the varying level of risk that occurs during the top peak hours.

Another incremental improvement would be to develop a set of hourly weights that are related to LOLP or another reliability index. This requires at least a single run of a reliability model that is capable of calculating hourly LOLP. However, it does capture the hourly risk profile, which is the ultimate objective of a capacity credit metric.

We investigated a number of algorithms based on these principles. Because of the significant impact of hydro resources and their ability to shift risk, we did not find an alternative method that we could recommend at this time. Because the California Energy Commission staff maintains a current database for the ProSym model, utilizing this data and model to calculate ELCC should not be a burdensome exercise. Throughout the RPS Integration Cost Study we have had difficulties in either obtaining or verifying data because of confidentiality concerns, or because of the difficulty of extracting the data from the CAISO PI system. The database that is maintained by the CEC staff may still suffer from some shortcomings, but we believe that this data set is the most accurate available for the California system, and could be used as the basis for ELCC calculations. With many models, some combination of script and/or command files can direct the model to perform specific tasks that are repetitive in complex calculations such as ELCC. Although the ELCC procedure is iterative and non-deterministic in its execution, this should not be a significant deterrent.

A.1 Detailed Description of a Candidate Simplified Capacity Credit Methodology

Because of the complicated interactions of the hydro resources, intermittent resources, and hourly LOLP, we have doubts about the ability to find a simple algorithm that can approximate ELCC for renewable generators in California. To illustrate this difficulty, we utilized the no-hydro reliability cases discussed in Section 3.1.4.2. With a modest effort, we were able to construct a simplified method that does a very good job of estimating the ELCC of wind, solar, and geothermal. We were unable to replicate these results using the hydro simulations.

This simplified method can be built into a spreadsheet. There are three required hourly data streams for the top 876 load hours of the year.

- Hourly LOLP or LOLE from a reliability model
- Hourly generation from the renewable generator of interest
- Rated capacity for the renewable generator of interest

The method calculates the capacity factor of the renewable generator over the top 10% of load hours and a logarithmic reliability share as described below. This estimation method has two distinct steps (Steps 2 and 3, below) that are subsequently combined with a linear regression (Step 4). The regression calculates the coefficients of an equation that does a very good job of estimating the ELCC. However, because we were only able to analyze a single year of data, we do not know if this approach is robust.

Table A.1 Step-by-step description of a simplified capacity credit methodology.

1.	Assemble the following data from the reliability model runs:
	a. Hourly LOLP for the top 10% of load hours of the year (876 hours in a normal year).
	b. Hourly system loads for the same hours (or use full year data if needed to identify the top 10% of load hours).
	c. Hourly generation from the renewable generator to be evaluated, for the same hours.

2.	Calculate the reliability contribution estimate (RCE) from the renewable resource for each hour.
	a. Calculate the total risk during the top 876 hours by finding the total of the 876 probabilities from Step 1a. This represents an estimate of the total risk during the top hours.
	b. For each LOLP value in Step 1a, calculate 1/abs[log(LOLP)]. This approximates the exponential decline in risk, starting from the peak hour and moving towards hour 876.
	c. Calculate the total of all the values in the previous step. Use this to calculate a new data series that sums to 1. We now have a new *risk share* estimate for the system.
	d. For each hour, multiply the renewable output from Step 1c (in MW) by the risk share from the previous step. Then calculate the sum of all these numbers. The result is the MW contribution, weighted by the risk shares, from this renewable resource.
	e. Calculate the percentage of this MW contribution to the rated capacity of the renewable generator. Save this result for use in Step 4.
	f. Repeat for all renewable generators. These results are then assembled into vector X1.
3.	Calculate the capacity factor for the renewable generator of interest for the top 876 load hours. Repeat for all renewable generators. These results are then assembled into vector X2.
4.	Calculate a regression equation that uses the results from Steps 3 and 4 to estimate ELCC. The form of the regression is:
	$\log(Y) = B0 + B1 * \log(X1) + B2 * \log(X2) + B3 * \log(X3)$ [Equation A.1] where: *X1* and *X2* are defined above *X3* is the coefficient of variation (standard deviation/mean) of the power output over the top 876 hours, expressed in percent (i.e., *X3* = 100*stdev/mean) *Y* = ELCC

When this was carried out for our non-hydro case we obtained,

$$\log(Y) = -0.27666 - 0.88859 * \log(X1) + 2.07854 * \log(X2) - 0.04002 * \log(X3) \quad \text{[Equation A.2]}$$

(-1.6) (-2.0) (4.2) (-1.3)

The numbers in parentheses indicate the t-statistic for the appropriate coefficient estimate. Generally, a t-statistic magnitude exceeding 2.0 indicates significance greater than the 90% level. The adjusted R^2 is 0.997, and the F-statistic is 452.3, indicating that the equation is statistically significant. Table A.2 shows the ELCC as calculated by the no-hydro case and the regression fit (ELCC estimate).

Table A.2 Comparison of ELCC (no hydro) and simple model results.

Resource	ELCC (%)	Fit (%)
Geothermal	92.04	91.49
Solar	88.44	88.60
Wind (Altamont)	26.14	25.70
Wind (San Gorgonio)	31.08	31.96
Wind (Tehachapi)	29.11	28.92

The regression equation says that ELCC is a function of (a) hourly LOLP, (b) renewable capacity factor during the peak period (top 10% of load hours of the year), and (c) the variability of the renewable resource. Although this is vastly simplified relative to a full ELCC calculation, it brings the important system characteristics into the approximation. Resources that provide relatively high capacity during peak hours and high-risk hours receive a relatively high capacity value. A resource that delivers little capacity during these times will receive little or no capacity value.

When the same procedure is used to develop another statistical model for the hydro case, the simplified method does not work well, as illustrated in the following table. Similar results for other techniques were obtained.

Table A.3 Comparison of ELCC (including hydro) and simple model results.

Resource	ELCC (%)	Fit (%)
Geothermal	83.00	84.03
Solar	89.50	85.84
Wind (Altamont)	23.0	20.61

Wind (San Gorgonio)	23.5	27.40
Wind (Tehachapi)	25.20	24.80

The purpose of this exercise is to demonstrate a "simple" method for calculating capacity credit that can be applied in a spreadsheet. However, the limitation of this approach is that it doesn't work when the hydro dispatch is introduced into the reliability model. We do not have a high sense of confidence that a simplified method exists that can capture ELCC with the hydro system.

APPENDIX B: CONTROL PERFORMANCE STANDARDS[1]

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 is:

$$ACE = (NIA - NIS) - 10ß\ (FA - FS) - IME \qquad \text{[Equation B.3]}$$

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, 10ß (F_A - F_S), is a function of frequency. The 10ß represents a control area's frequency bias (ß's sign is negative) where ß 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 *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

1 North American Electric Reliability Council. *NERC Operating Manual.* Princeton, NJ, November 2002.

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.

APPENDIX C: REGULATION ALLOCATION METHODOLOGY

This regulation impact allocation method2 was developed by Oak Ridge National Laboratory to deal with nonconforming loads. 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 C.1. If the two loads are perfectly correlated negatively, their regulation impacts would add as shown in the middle of Figure C.1. 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 C.1).

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.

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2 Kirby, B. and E. Hirst, "Customer Specific Metrics for the Regulation and Load-Following Ancillary Services", ORNL/CON-474, Oak Ridge National Laboratory, Oak Ridge, TN, January 2000.

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 C.2).

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.

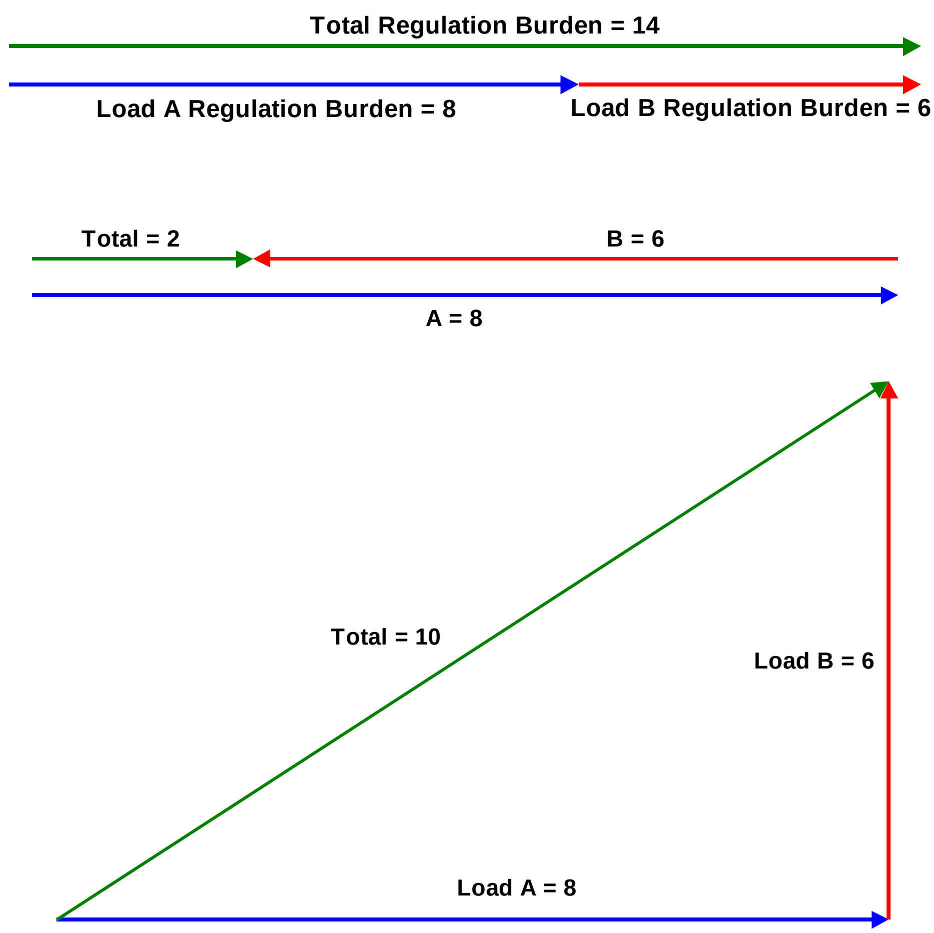

Figure C.1 The relationships among the regulation components (A and B) and the total if A and B are positively correlated (top), negatively correlated (middle), or uncorrelated (bottom).

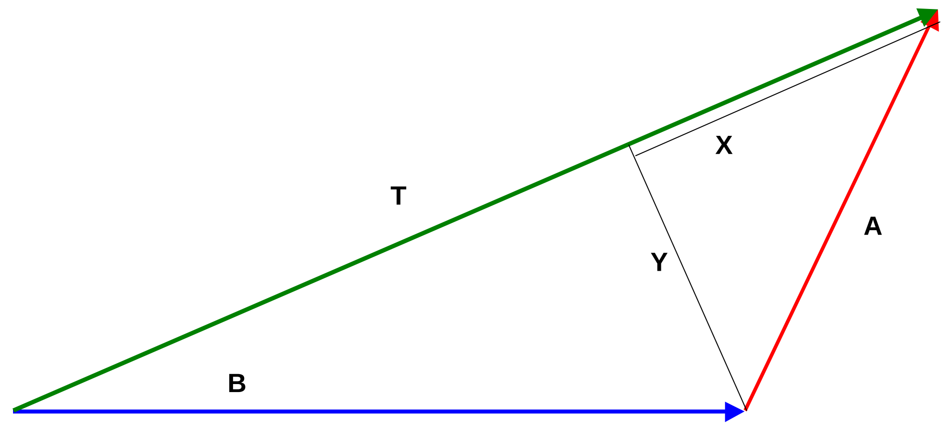

Figure C.2 The relationship among the regulation impacts of loads A and B and the total (T) when A and B are neither perfectly correlated nor perfectly uncorrelated.

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:

$A^2 = X^2 + Y^2$ [Equation C.1]

$B^2 = (T - X)^2 + Y^2$ [Equation C.2]

Subtract Equation C.2 from Equation C.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,

$X = (A^2 - B^2 + T^2)/2T$ [Equation C.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 C.3). We can solve Equation C.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.

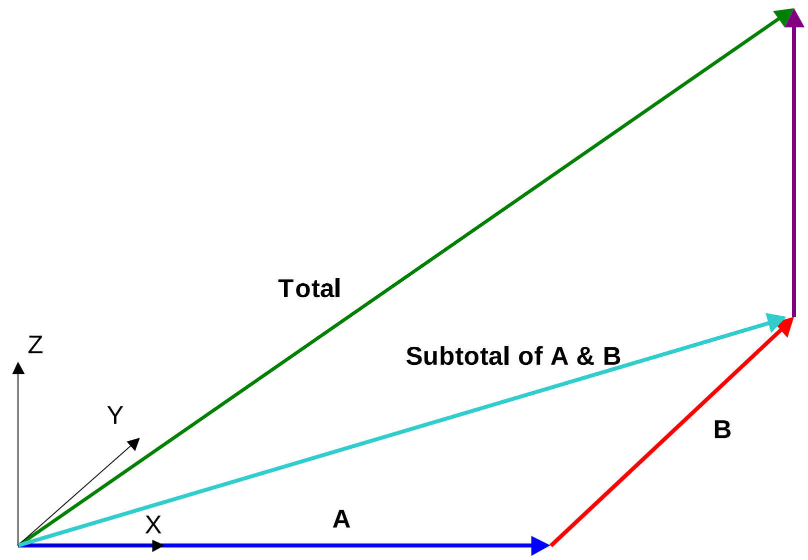

Figure C.3 Application of vector-allocation method to the case with more than two loads.

APPENDIX D: GEOTHERMAL ENERGY TECHNOLOGY ATTRIBUTES

D.1 Overview

Geothermal power plants convert the natural heat of the earth to electrical energy. The three necessary elements of a hydrothermal system are heat, water, and permeability. Exploitation of geothermal reservoirs for power generation typically involves drilling wells into the reservoir, producing hot water (either as vapor or liquid), converting the thermal and mechanical energy of the water to electricity, and disposing of the water either by injection or evaporation. There are three basic types of plants for converting the energy of geothermal fluids to electricity:

- Dry-steam
- Flash-steam
- Binary

Dry-steam plants are used in fields where wells yield only vapor-phase water. There are just a handful of such fields in the world, but they include the oldest (Larderello, Italy, which has generated electricity since 1904) and the largest (The Geysers, in Sonoma and Lake Counties of California, with a current gross capacity of approximately 1,000 MW).

Flash-steam power plants are used in fields where wells yield some mixture of vapor- and liquid-phase water. Such resources are much more common than dry-steam fields.

Binary power plants use a secondary working fluid to extract heat from the geothermal fluids. Geothermal reservoirs suitable for binary plants typically have lower temperatures than reservoirs that supply dry-steam or flash-steam plants. In these plants, the working fluid is boiled in a heat exchanger and piped to a turbine in a vapor phase. It is then condensed downstream of the turbine before returning to the heat exchanger. The condenser may be either water-cooled or air-cooled if no external supply of cooling water is available.

Different elements of the three basic plant types discussed here may be combined in various forms of hybrid facilities. The optimal design for a particular site depends on the thermodynamic properties of the geothermal fluid, both under initial conditions and under conditions that are expected to evolve with the exploitation of the reservoir.

D.2 Characteristic Output Patterns

Geothermal power plants are usually considered as base-load facilities, for several reasons:

- The source of energy (the earth's heat) is available 24 hours a day, 365 days per year. This distinguishes geothermal energy from solar and wind energy, for which the source of energy is intermittent and dependent on the weather.

- Geothermal wells are usually operated in a steady mode, within a narrow range of flow. This avoids thermal stresses to the casing which would result from repeatedly shutting the wells in or from operating two-phase wells at widely varying wellhead pressures.
- Well-managed geothermal plants have historically provided a very steady power supply. Notable exceptions include air-cooled binary plants (which usually operate reliably, but with significant seasonal and diurnal oscillations in output) and plants with insufficient resource (which may decline in later years of the project life). These exceptions are discussed further below.

Geothermal plants have some flexibility to regulate well flow for load-following purposes, either at individual wells or at the inlet of combined flow to the plant. However, starting up geothermal plants or wells after a complete shutdown typically requires several hours or days for warm-up and stabilization. In addition, some self-flowing (artesian) geothermal wells do not maintain positive wellhead pressure when shut in, and they may require special equipment and procedures to re-establish flow.

Flash-steam plants and water-cooled binary plants characteristically come closest to the ideal of steady, base-load output. Figure D.1 shows ten years of power output (gross and net) of a typical flash-steam plant. The data have been plotted as percentages of the nominal maximum gross capacity of the plant. The data show some variations related to problems and repairs of particular wells and plant components, as well as occasional additions of make-up wells. The most recent output has been slightly below full capacity, but this could probably be rectified by the drilling of another well. The scattered points below the main trend lines are usually due to scheduled plant maintenance or curtailments for transmission-line work. Parasitic losses (the difference between gross and net output) are about 10%, including transmission-line losses to the point of sale. Seasonal variations in output are negligible. Diurnal oscillations are on the order of 1% to 2% (these are not shown in Figure D.1, which plots daily averages of power output).

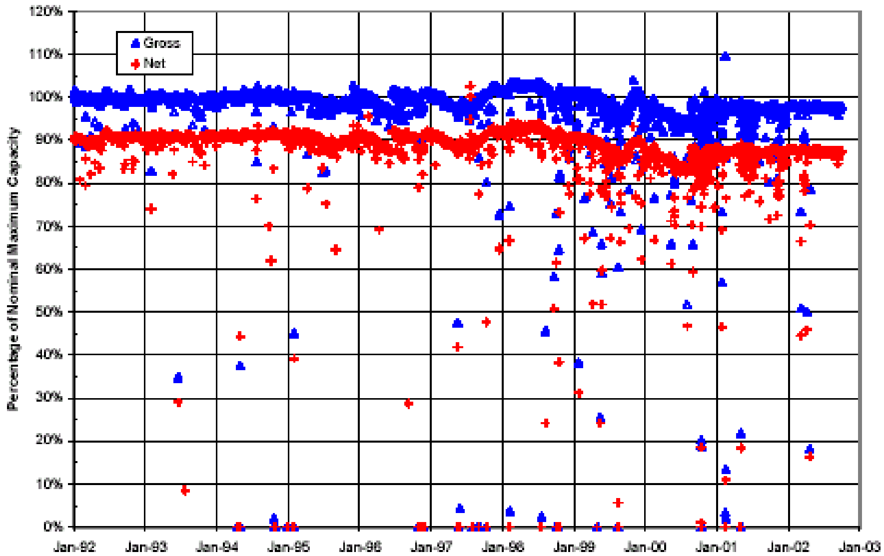

Figure C 4 Example of base-load production from a flash-steam plant.

The steadiness of the output of flash-steam plants and water-cooled binary plants is a function of three criteria: (1) adequate resource, (2) good maintenance practices for the plant and wells, and (3) the use of evaporative cooling towers supplied with water from a constant-temperature source (for a flash-steam plant, the condensed geothermal steam). Although the data in Figure D.1 are for a dual-flash plant, similarly steady power output would be expected for any flash-steam plant or water-cooled binary plant, provided these three criteria are met. For water-cooled binary plants, the percentage of parasitic losses would typically be higher, because of the need to run production-well pumps.

In principle, dry-steam plants could also achieve steady production. However, there is only one dry-steam geothermal field in the United States (The Geysers), and this field has deviated substantially from steady production for a number of site-specific reasons. In view of the size of this field (about 1,000 MW out of a total of about 1,850 MW of gross capacity for all the geothermal plants in California), it is worth considering as a special case. Figure D.2 is a plot of the performance history of The Geysers. The plot shows the steam production in thousands of pounds per hour (klb/hr) and net power output based on assumed average conversion factors from steam rates to MW. Also shown is the total amount of injection, consisting of cooling-tower blow-down water, water from stream run-off, and (in recent years) treated sewage effluent from adjacent communities.

Power production from The Geysers began in 1960 with the operation of one unit with a capacity of 12 gross MW. By 1988, a total of 29 units were installed, with a combined capacity of 2,100 gross MW (about 1,900 net MW). However, actual output peaked in 1987 at about 1,550 net MW. Thereafter, output started declining at about 5% per year, tapering to about 3% per year in recent years. Since 1988, ten generating units have been retired, and the remaining 19 plants have a combined nominal capacity of 1,656 gross

MW (about 1,500 net MW). Actual recent output has been approximately 1000 gross MW (900 net MW), and further declines are expected.

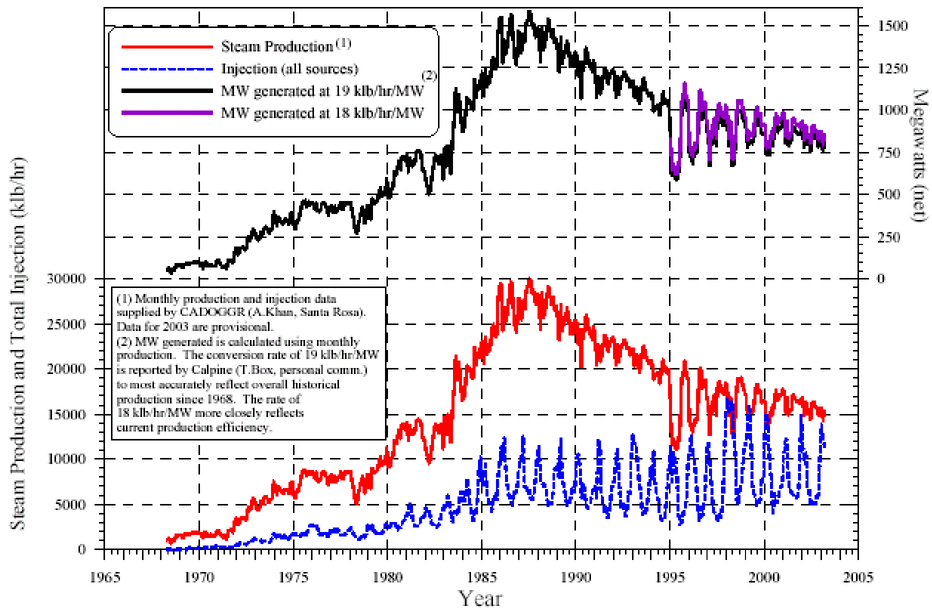

Figure C 5 Performance history of the Geysers Field in California.

The failure to maintain constant output at The Geysers resulted primarily from the construction of a greater amount of plant capacity than the reservoir could support. The sustainable capacity of the reservoir was poorly understood at the time that commitments for new plant construction were being made in the 1980s. This lack of understanding was exacerbated by the fact that different portions of the field were developed by different operators that did not share information about reservoir performance. Much progress has been made in interconnecting pipelines to make better use of available steam. As Figure D.2 illustrates, the power output of The Geysers has shown much less variation under this program of integrated field management. The output varies seasonally due to changes in ambient temperature and humidity over a range of about 25 MW (roughly 3% of plant capacity). Although steam production is gradually declining, the plants in recent years have been operated primarily as base-load facilities, with little variation in output on a day-to-day basis.

Figure D.3 shows the performance history of the Coso geothermal field, which, as discussed above, has nine flash-steam units with a total gross capacity of 300 MW. The ninth unit came online in mid-1990, though steady output at 300 MW was not achieved until 1995. Periods of production at less than the full plant capacity have had a variety of causes, some contractual, some reservoir-related. The decline from 300 MW that started in late 2000 is primarily due to declining productivity of existing wells. Additional drilling could possibly stop or even reverse this decline, but it is not clear that such drilling would be economically justified. The operator (a subsidiary of Caithness Energy, LLC) is successfully meeting the obligations of its power sales contract and its financing covenants. The decline at Coso is following a trend that is very predictable. As at The Geysers, there is little unanticipated variation in output on a day-to-day basis, and the plants are routinely operated as base-load facilities.

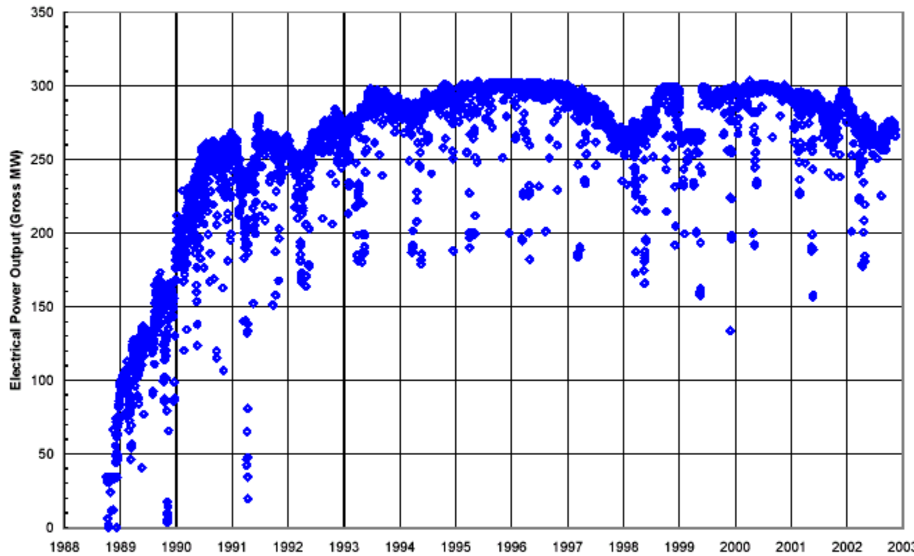

Figure C 6 Performance history of the Coso Field, Inyo County, California (Source: Caithness Energy LLC, used by permission).

Air-cooled binary plants have an output pattern that is also very predictable, but the pattern does exhibit considerable seasonal and diurnal variation. Figure D.4 shows the seasonal variation in the output of a 10-year-old, air-cooled binary plant. As in Figure D.1, gross and net output are plotted as percentages of the maximum gross capacity. Because the efficiency of condenser depends on the temperature difference between the working fluid and ambient air temperatures, the plant achieves its maximum output in the winter, when air temperatures are low. For this plant, gross output in mid-summer is about half of the winter maximum. Also, the spread between gross and net is greater in the summer, primarily because the fans in the air-cooled condensers use more power. The performance parameters for any given plant would vary depending on climate and age of equipment, and an air-cooled binary plant with later technology could probably improve on the output patterns in Figure D.3. However, the dependence on air-cooling makes this category of binary plant inherently more variable than a plant that uses evaporative cooling.

Figure D.5 illustrates the daily oscillation in the output of an air-cooled binary plant. In this figure, power output over a 24-hour period is plotted as a percentage of the maximum net power achieved when ambient temperatures are lowest (assumed to be midnight on a winter night). The output at midnight in summer would be about 85% of the maximum value. At noon, the contrast between winter and summer is even greater, with outputs at 85% and 50% (respectively) of the maximum value. Again, the actual performance parameters for a particular plant would vary based on climate and age of equipment. Also, in making percentage comparisons between plants, it is important to know whether the reference point is a gross MW maximum, a net MW maximum, or a nominal MW value. This is illustrated in Table D.1, which shows the output range of a nominal "25-MW" plant under various operating conditions. Because of the variation in parasitic load, the percentages based on gross MW and net MW are different for a particular set of conditions, and those conditions are unlikely to match the design specifications on which the nominal MW rating is based.

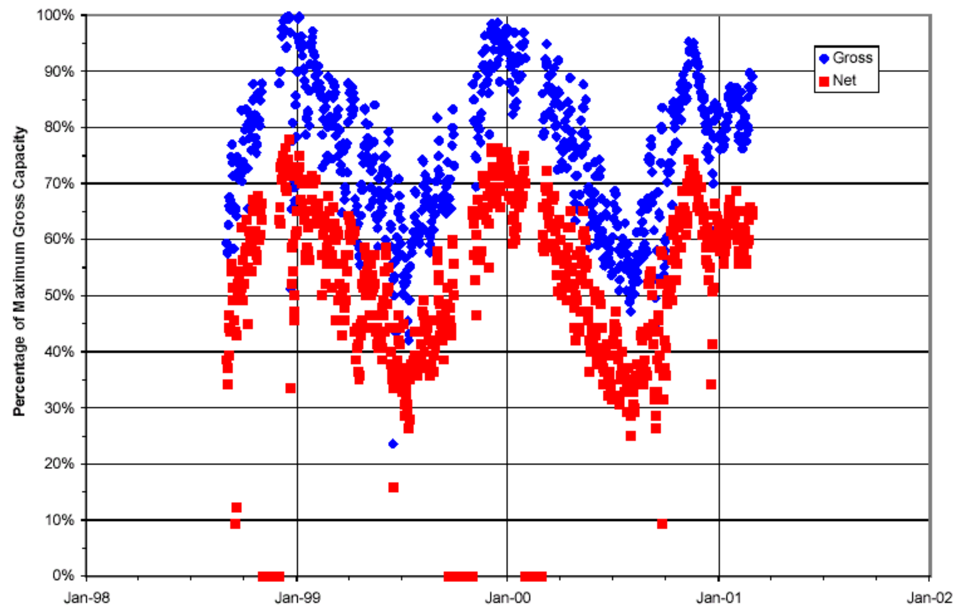

Figure C 7 Seasonal variation in output of an air-cooled binary plant.

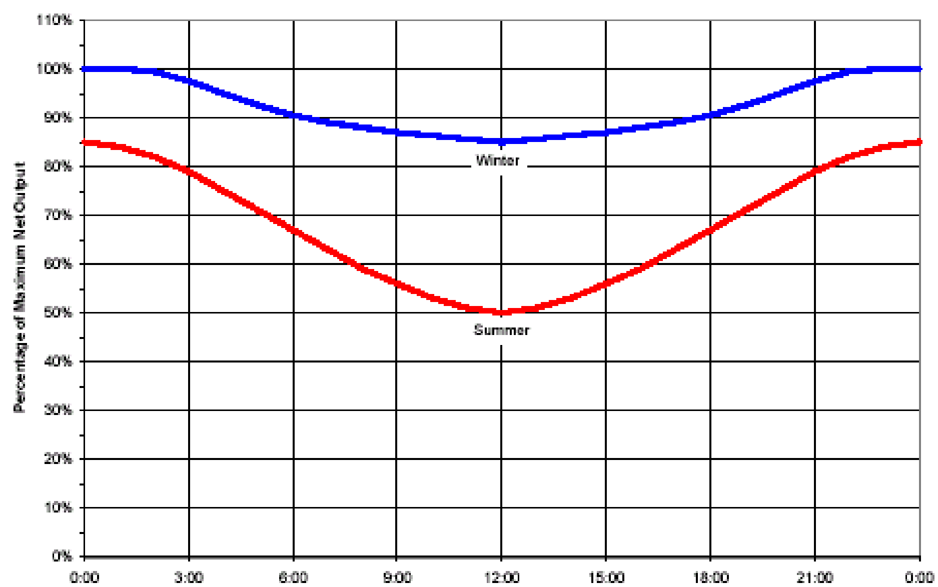

Figure D 8 Typical daily oscillation in output of an air-cooled binary plant.

Table D.1 Output of nominal "25-MW" air-cooled binary plant.

Condition	Gross MW	Percent of Maximum Gross MW	Parasitic Load (% of Gross MW)	Net MW	Percent of Maximum Net MW
Maximum Output (Winter Night)	30	100%	20%	24	100%
Winter Average	29	97%	25%	22	90%
Annual Average	27	90%	30%	19	80%
Summer Average	25	83%	35%	16	67%
Minimum Output (Summer Mid-Day)	20	67%	40%	12	50%

D.2.1 Outage Rates and Variation in Electrical Generation

Geothermal plants characteristically have very low outage rates. Plant availabilities (the fraction of the time that the facilities are on line) are typically 95% or greater. This is because the technology of geothermal plants is quite mature, and the equipment usually operates reliably. There are decades of experience in the operation of dry-steam and flash-steam plants, and many binary facilities have been in operation since the 1980s. Key factors that affect outage rates of geothermal plants would include:

1. The amount of surplus productive capacity at the wellhead. Geothermal operators usually try to maintain some surplus (on the order of 5% to 25%), so that one or more wells can be taken off line if necessary with little or no impact on the output of the plant.

2. The ratio of the production or injection capacity of the most prolific wells to the total production or injection required. If a facility relies heavily on a few prolific wells, it is vulnerable to any upset in the operation of those wells.

3. The modularity of the plant facilities. Geothermal plants consisting of several modular turbine-generator units can better avoid periods of complete shutdown, because some units can continue operating while others are off line. For example, the field-wide output at Coso (**Error! Reference source not found.**) has seldom dropped below 50 % of installed capacity (even during overhaul season in the spring), because the overhauls of the different units are staggered.

4. The degree of interconnection of pipelines. Larger fields (such as The Geysers, the Salton Sea, and Coso) typically have multiple plant sites, each with their respective pipeline systems for the production and injection of geothermal fluids. Pipeline interconnections help maintain higher outputs by allowing operators to make the best use of available production and injection capacity. This is particularly valuable during periods when specific plants or wells are off line for maintenance.

5. The chemistry of the geothermal fluid. Fluids that have higher potential for scaling or corrosion are likely to cause a higher incidence of down time or periods of reduced output. Also, chemical constituents that require greater complexity in mechanical equipment can contribute to higher outage rates. Examples would include gas compressors for the removal of non-condensable gas (NCG) from the condensers, equipment for the abatement of hydrogen

sulfide emissions to the atmosphere, and crystallizer-clarifier equipment for the processing of high-salinity brine.

6. The length of the transmission line. Some geothermal facilities are connected to the grid by long sections of dedicated transmission line. This increases their vulnerability to outages related to transmission-line maintenance, as well as to weather-related factors such as lightning strikes and wind.

7. The age of the equipment. One would typically expect older equipment to have a greater incidence of downtime. (Of course, this factor is not unique to geothermal facilities.)

The factors listed above can affect both forced and unforced outage rates. Items 1 to 4 relate to the amount of spare capacity in wells, plants, and pipeline systems. They affect the degree of flexibility the operator has in dealing with unscheduled breakdowns (forced outages) and in scheduling planned maintenance (unforced outages). Items 5 to 7 relate to the quality of the geothermal resource and surface facilities. They affect the likelihood that unscheduled outages will occur in the first place, and they influence the operator's judgment as to how often preventative maintenance is required.

D.3 Methodologies to Quantify Uncertainties

Predicting the performance of geothermal facilities (both existing and proposed) requires resolving uncertainties as to the capacity of the reservoir. The methodologies applied depend on the amount and quality of the information available. These methodologies can be classified into three categories:

1. Volumetric estimation

2. Decline-curve analysis

3. Reservoir simulation

Volumetric estimation relates the capacity of the reservoir to its size and temperature, as indicated by geological, geochemical and geophysical data and the results of drilling. The simplest estimates in this category are rules of thumb based on reservoir area (for example, megawatts per square mile). More sophisticated estimates may involve mapping out the distribution of temperatures at various depths, to take reservoir thickness into account. All volumetric estimates are based (either implicitly or explicitly) on the amount of heat in place and some assumption about a recovery factor (that is, the proportion of reservoir heat that can be recovered as electricity). Such estimates are typically made prior to the decision on the size of plant to be built.

Decline-curve analysis involves an extrapolation of future output based on the historical performance of an existing facility. Such extrapolations are often made to estimate requirements for make-up drilling. The technique can be applied to individual wells or to groupings of wells ranging up to the entire well field. As its name implies, the technique presumes that the parameter being extrapolated (such as flow rate or temperature) is declining, even though the decline may be very gradual. It also presumes that there is no fundamental change in operations (such as developing a new portion of the reservoir or changing the injection strategy). Decline-curve analysis is of limited use in projecting the performance of an initial reservoir development, except by analogy to other reservoirs in similar geologic settings.

Reservoir simulation uses numerical techniques to forecast reservoir performance. It entails subdividing the reservoir into grid blocks, defining the properties of each block (such as the permeability, temperature, and pressure), and using a computer to apply the mathematical equations that govern fluid flow and heat transfer under assumed development scenarios. The grid system should be calibrated by using the simulator to match the initial state of the reservoir, including specification of boundary conditions for the system. If a project has already been operating, a history match to the performance of the reservoir under exploitation enhances the quality of the calibration. Because the behavior of the simulated reservoir is controlled by fundamental laws of physics, it is possible to use numerical simulation to quantitatively estimate the effect of major changes, such as developing a new area or changing the injection strategy. For this reason, numerical simulation is a much more powerful tool than volumetric estimation (which depends on an assumed recovery factor) or decline-curve analysis (which can only extrapolate based on existing conditions).

D.4 Future Outlook of Geothermal Energy in California

As part of a study currently in progress for the Public Interest Energy Research (PIER) program of the California Energy Commission (GeothermEx, 2003), GeothermEx has developed estimates of the electric generation potential available from each of the known geothermal fields in California. These estimates have been based on Monte Carlo volumetric analyses for each field. For the present study, we have estimated the amounts of geothermal generating capacity that could reasonably be expected to be on line by certain milestone years: 2005, 2008, and 2017. These are the same years used in the Renewable Resources Development Report (RRDR) issued in November 2003 by the Renewables Committee of the California Energy Commission (CEC, 2003).

Table D.2 summarizes GeothermEx's estimates of generating potential (potential gross MW) for each geothermal field in California and the incremental amounts of generating capacity to be expected by each of the milestone years. For each field, the estimate of potential gross MW is the most likely value from Monte Carlo analysis. For fields that are already under production, the capacity of existing plants has been subtracted from the potential gross MW to yield an incremental gross MW available. It has been assumed that all of this incremental potential can be developed by 2017. The timing of when this potential comes on line is based on our familiarity with the status of development work for each project.

Table D.2 Geothermal resource potential in California.

County	Field	Potential Gross MW	Existing Plants Gross MW Installed	Incremental Gross MW Available	Incremental Gross MW Additions 2005	2008	2017	Incremental Gross MW Total
Sonoma & Lake	The Geysers	1,400	1,000	400	-	200	200	400
Siskiyou	Medicine Lake	304	0	304	-	98	206	304
Lake	Sulphur Bank	43	0	43	-	25	18	43
Modoc	Lake City / Surprise Valley	37	0	37	10	10	17	37
Napa	Calistoga	25	0	25	-	10	15	25
Lassen	Honey Lake	8	6	2	-	2	-	2
Imperial	Salton Sea	1,750	350	1,400	-	200	1,200	1,400
Imperial	East Mesa	148	73	75	15	15	45	75
Imperial	Heber	142	100	42	8	8	26	42
Imperial	Brawley - North	135	0	135	-	60	75	135
Imperial	Brawley - East	129	0	129	-	50	79	129
Imperial	Niland	76	0	76	-	30	46	76
Imperial	Brawley - South	62	0	62	-	25	37	62
Imperial	Mount Signal	19	0	19	-	10	9	19
Imperial	Dunes	11	0	11	-	6	5	11
Imperial	Superstition Mountain	10	0	10	-	6	4	10
Imperial	Glamis	6	0	6	-	-	6	6
Inyo	Coso	355	300	55	-	25	30	55
Mono	Long Valley	111	40	71	-	30	41	71
San Bernardino	Randsburg	48	0	48	-	15	33	48
Ventura	Sespe Hot Springs	5	0	5	-	-	5	5
Total		4,824	1,869	2,955	33	825	2,097	2,955

The table shows that California has approximately 4,800 MW of gross generating potential from geothermal sources. Of this amount, plant capacity of approximately 1,850 MW is already on line, with the largest concentrations at The Geysers, the Salton Sea, and Coso. The amounts incremental gross MW available in milestone years 2005, 2008, and 2017 are approximately 30 MW, 800 MW, and 2,100 MW, respectively. The largest concentrations of incremental power available for new development are at the Salton Sea, The Geysers, Medicine Lake, and the cluster of fields around Brawley (North, South, and East Brawley). All of these are likely to use flash-steam plants, except for The Geysers, which would use dry-steam plants. Thus, the major sites to be developed would primarily supply base-load generation. At The Geysers, the increment of power generation from new plants would be superimposed on a gradually declining base; that is, field-wide generation would be expected to continue to decline, but at a higher level. Most of the remaining sites listed in Table D.2 have lower reservoir temperatures and would likely be developed with air-cooled binary plants. As discussed previously, these plants would exhibit daily and seasonal variations in output. However, while they are more numerous, they represent less than 20% of the incremental geothermal power available in California.

Another observation from Table D.2 is that relatively little of the available incremental capacity is likely to come on line by 2005. The East Mesa and Heber projects have recently changed ownership, and the new operator will likely make changes in plant equipment that could yield increases in output on the order of what is shown in Table D.2. The developer of Lake City has been conducting temperature-gradient drilling to delineate the reservoir, and could plausibly get a small plant on line quickly if a power sales contract can be negotiated. Unit 6 at the Salton Sea will be a significant addition to California's installed geothermal capacity, but this plant is not scheduled to come on line until 2006.

APPENDIX E: WIND ENERGY TECHNOLOGY ATTRIBUTES

E.1 Introduction

During 2003 the CEC evaluated renewable resources within the state and developed estimates for how they might be developed through the RPS process. The CEC published a Renewable Resources Development Report, which provides estimates of California wind resources growth through 2017. The report provides data on both the total installed wind power capacity and the geographical location. Capacity growth estimates were prepared for both baseline and accelerated implementation scenarios. The baseline scenario assumes the RPS goal of 20% renewable energy is met in 2017, while the accelerated scenario assumes that goal will be reached in 2010.

The CEC data indicate that new capacity in the Tehachapi region could represent about 70% of new wind development (Figure E.1). The San Gorgonio Pass region has the next largest share with 15%, while the Solano County and San Diego County resource areas each add 6%, and the Altamont Pass region provides a final 3%.

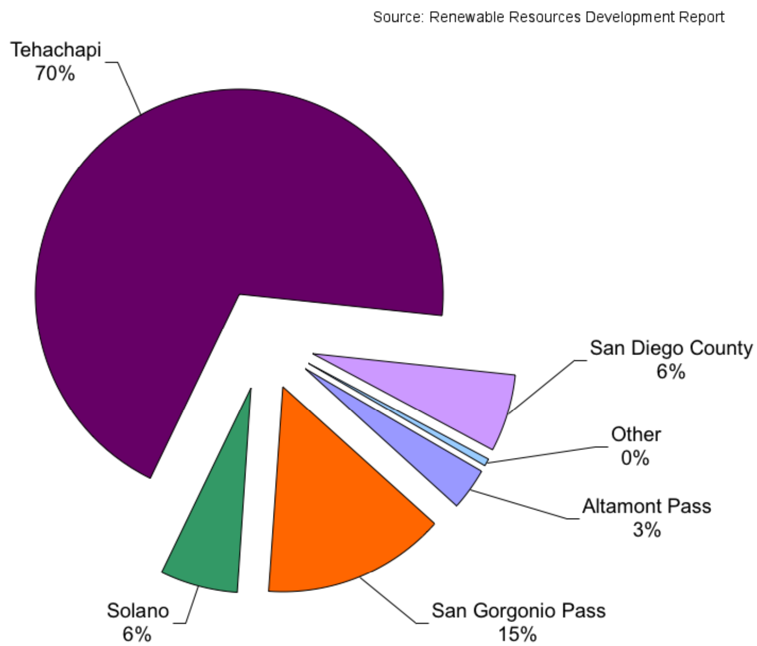

Figure E 9 Estimated share of wind energy growth by resource area for both RPS scenarios.

E.2 Technology Impacts

E.2.1 Specific Power

Specific power is an important parameter governing the performance of a wind turbine system, and is defined as the rated power in watts divided by the swept area of its rotor in square meters (W/m^2). In general terms a turbine with a high specific power will be more economic in sites with higher wind speeds, while those with lower specific power are more suitable for low wind regimes. A summary of specific power for a number of selected utility scale wind turbines is provided in Table E.1. This data shows that the specific power of existing, commercially available wind turbine generation equipment is within a range between 300 and 500 W/m².

Table E.1 Specific power of selected wind turbines.

Manufacturer	Rated Power (MW)	Rotor Diameter (m)	Specific Power (W/m2)
NEG Micon	1.650	82.0	312
GE Wind	1.500	77.0	322
Vestas	1.800	80.0	358
Gamesa	1.800	80.0	358
Nordex	2.300	90.0	362
Suzlon	1.250	66.0	365
NEG Micon	1.500	72.0	368
Vestas	0.660	47.0	380
GE Wind	1.500	70.5	384
Mitsubishi	1.000	57.0	392
Mitsubishi	0.600	44.0	395
Nordex	0.600	43.0	413
NEG Micon	2.750	92.0	414
NEG Micon	0.750	48.0	414
Bonus	1.300	63.0	417

Manufacturer	Rated Power (MW)	Rotor Diameter (m)	Specific Power (W/m2)
GE Wind	0.900	52.0	424
NEG Micon	0.900	52.0	424
GE Wind	3.600	104.0	424
Bonus	2.300	82.4	431
Bonus	0.600	42.0	433
Bonus	1.000	54.2	433
Nordex	1.000	54.0	437
Enercon	4.500	114.0	441
Bonus	2.000	76.0	441
NEG Micon	4.200	110.0	442
Nordex	1.300	60.0	460
Enercon	1.800	70.0	468
Vestas	3.000	90.0	472
Nordex	2.500	80.0	497
NEG Micon	2.500	80.0	497

Manufacturers are beginning to offer several different rotor sizes for a given wind turbine model. GE Wind Energy, NEG Micon, and other major wind turbine manufacturers are offering machines whose specific power can be better optimized to localized site conditions. There is also a trend toward development of turbines with relatively low specific power output. This trend has been pushed forward by the market in Germany, where large rotor designs are economically viable and high levels of installed wind capacity leave few remaining high wind energy resources for new construction.

Power curves can be compared between turbines through the use of the capacity factor, defined as the actual power divided by the peak power. A comparison of power curves for both current and past technology shows that new machines have significantly better performance characteristics (Figure E.2), with higher capacity in lower wind speeds. The power curves are not individually identified, because they are presented here as typical examples of current and past technology.

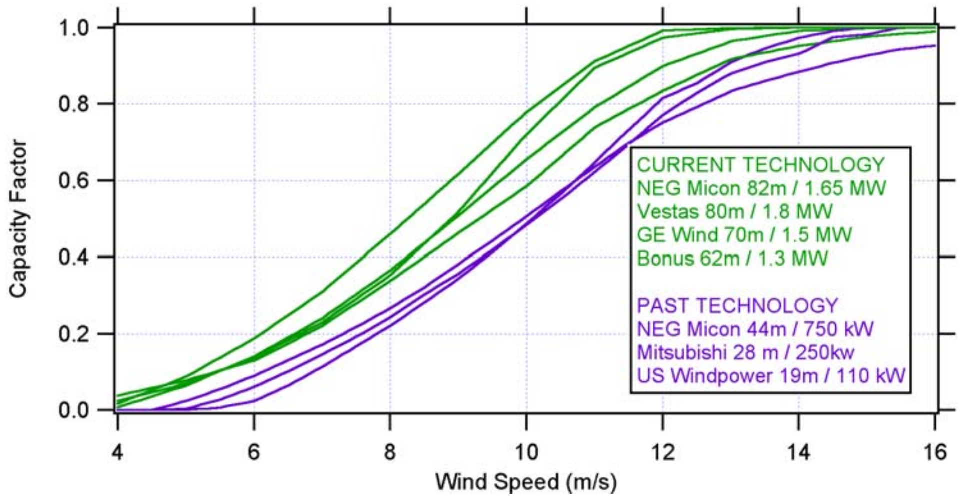

Figure E 10 Power curves for examples of current and past technology.

E.2.2 Power Regulation

Wind power increases as the cube of the wind velocity and it is necessary to regulate the aerodynamic efficiency of the rotor in high winds to prevent excessive power in the drive train. Historically two main design approaches were used to regulate power in high winds. The simplest approach used the basic aerodynamic stall properties of the rotor blades and is called fixed pitch. The blade pitch angle, defined as the angle between the chord line at the blade tip and the plane of rotation, remains constant in fixed pitch rotors and the blades are simply bolted to the rotor hub. With second approach, called variable pitch, a turntable bearing is mounted between the hub and the blade root. This allows the blades to pitch and change their orientation relative to the plane of rotation.

Variable pitch improves wind turbine performance and operational characteristics, which has led to its adoption as by nearly all manufacturers for megawatt scale applications. The performance of variable pitch machines is enhanced because they can automatically compensate for changes in air density and soiling of the blade surfaces. Both effects can substantially reduce the peak power of fixed pitch wind turbines. Variable pitch turbines also use blade pitch for starting and stopping the turbine, thereby reducing braking requirements and torque transients in the drive train.

Modern wind turbines reach rated power when the wind speed is between 12 and 14 m/s (Figure E.2). Power output is directly proportional to air density when the wind speed is below the rated wind speed (defined as the wind speed at which the turbine reaches rated power). For fixed pitch turbines the rated power output is also directly proportional to air density; however, variable pitch turbines can adjust the blades and will be able to achieve their rated power even with low air density. This feature provides significant performance improvement during the windy, but hot summer afternoons. Air density data for a Tehachapi wind site in summer 2002 is presented in Figure E.3. These data show 4-6% variations in air density for the summer months, with the lowest density occurring during the mid-afternoon peak. The graph also presents the system demand factor, defined as the total CaISO system load divided by the peak power requirement for the year 2002. This data shows that periods of low air density are often coincident with peak demand periods.

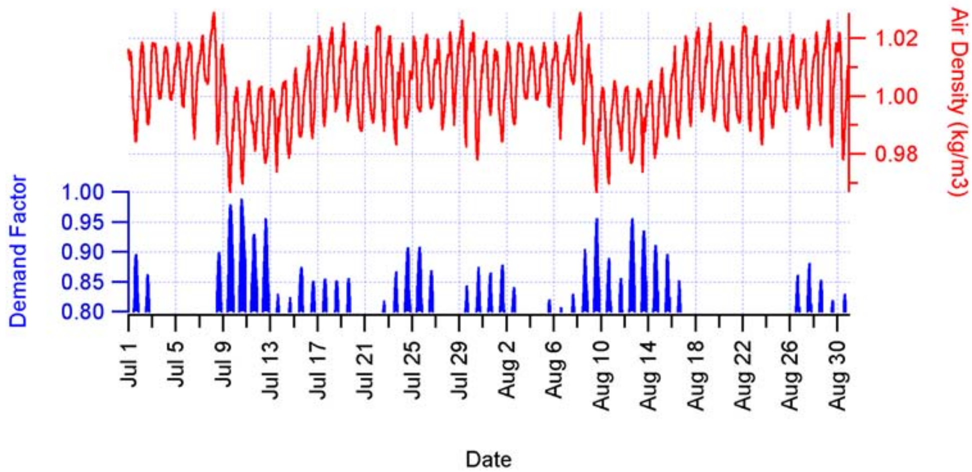

Figure E 11 Tehachapi air density variation during July and August of 2002.

E.2.3 Variable Speed Operation

Variable speed operation is another design factor which can improve performance characteristics. A variable speed turbine will perform better in light wind conditions, due to improvement in aerodynamic efficiency. Figure E.4 presents a comparison in power curves for an example megawatt scale wind turbine rotor operating with variable and constant speed. There is a considerable improvement in turbine performance for wind speeds below 8 m/s. Variable speed turbines will exhibit higher power output earlier in the day during low wind conditions, which will tend to improve the overall capacity during peak demand hours.

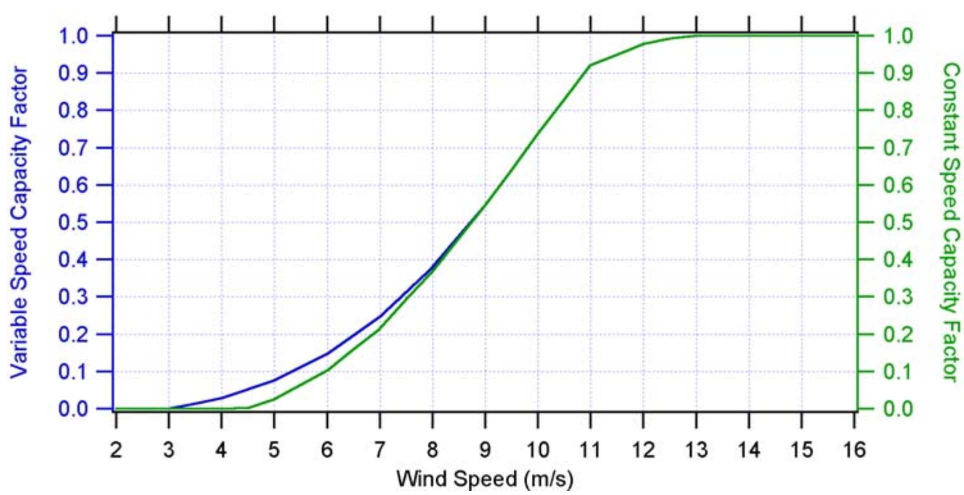

Figure E 12 Power curves for variable and constant speed rotors.

E.3 Wind Power Generation and System Demand

We evaluated the performance of several representative 1 MW wind turbines with different rotor diameters (Table E.2). The specific powers of the first three model turbines (50 to 70 m) bracket the existing range (509 to 260 W/m²), while the fourth model (90 m) explores a design region that is not commercially available at the present time.

Table E.2 Specific power of model wind turbines.

Turbine Model Type	Rated Power (MW)	Rotor Diameter (m)	Specific Power (W/m2)
50 m	1.000	50	509
60 m	1.000	60	354
70 m	1.000	70	260
90 m	1.000	90	157

A graph of the average annual capacity is provided in Figure E.5 for several rotor sizes and reference wind speeds. The graph is based upon an assumed 100% wind plant efficiency; actual capacities will be lower. This chart shows the strong effect of rotor diameter on turbine capacity and the performance improvements obtained by wind turbines with large rotors. The average annual capacity factor for the Tehachapi wind resource region from six years of WPRS data is 26%. Comparing that result with Figure E.5 shows that the 50 m rotor and 7 m/s site average provide a reasonable model for the Tehachapi region as a whole.

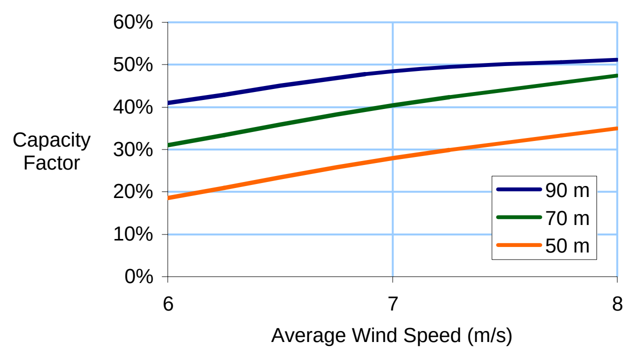

Figure E 13 Turbine average annual capacity factor as a function of wind speed and rotor diameter.

E.3.1 Wind Generation and Demand

Average statewide power demand was obtained from CaISO and these data were converted to a non-dimensional form. The demand factor was calculated for each hour by dividing the value by the peak power for the year 2001. Thus, the graphs show power demand as a average hourly fraction of the maximum system demand. Time series plots of wind turbine capacity factor and statewide demand factor are shown in Figure E.6 for a summer peak period and in Figure E.7 for a summer non-peak period. These graphs illustrate the effects of site average wind speed and rotor size on generator capacity over time. The graphs show clearly how larger rotors reach rated power earlier, and maintain it over a longer period, thereby improving average capacity factor and load matching.

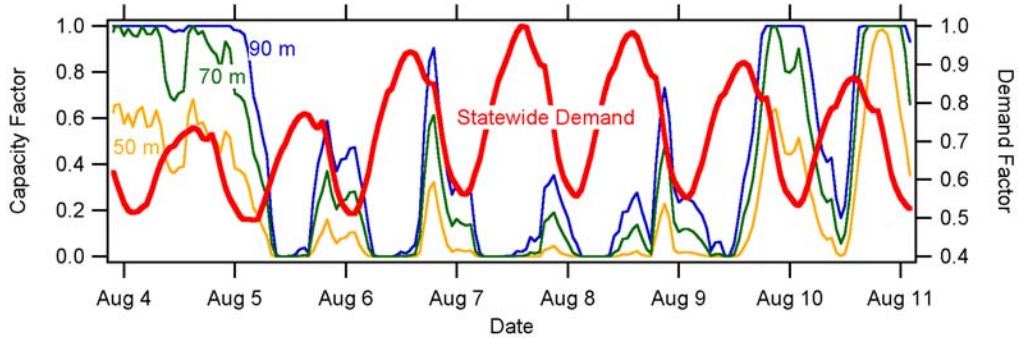

Figure E 14 Turbine capacity and statewide demand during a summer peak period at the 7 m/s reference site.

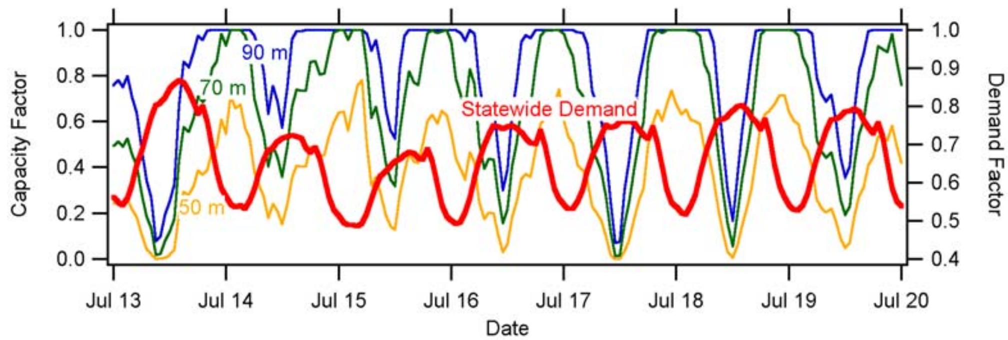

Figure E 15 Turbine capacity and statewide demand during a summer non-peak period at the 7 m/s reference site.

A graph of average wind turbine capacity factor as a function of statewide demand factor is provided in Figure E.8. These graphs show that the periods of highest wind capacity correspond well with periods of high system demand (0.85 to 0.95).

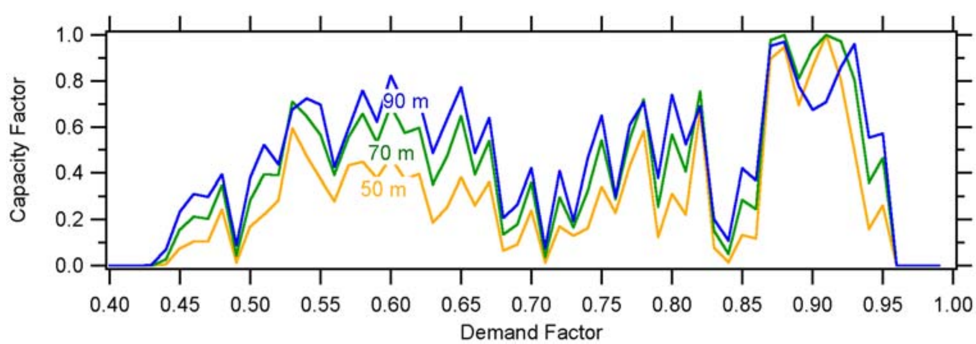

Figure E 16 Average capacity factor as a function of demand factor at the 7 m/s reference site.