Arnold Schwarzenegger
Governor

INTERMITTENCY ANALYSIS PROJECT:

SUMMARY OF PRELIMINARY RESULTS FOR THE 2006 BASE AND 2010 TEHACHAPI CASES

PIER INTERIM PROJECT REPORT

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Intermittency Analysis Project Team

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The team also recognizes the efforts of various transmission study groups including the Tehachapi, Imperial, Western Electricity Coordinating Council (WECC) and Frontier Line working groups and continues to seek collaborative feedback on the remaining project efforts.

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Preface

The Public Interest Energy Research (PIER) Program supports public interest energy research and development 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, managed by the California Energy Commission (Energy Commission), conducts public interest research, development, and demonstration (RD&D) projects to benefit California.

The PIER Program strives to conduct the most promising public interest energy research by partnering with RD&D entities, including individuals, businesses, utilities, and public or private research institutions.

PIER funding efforts are focused on the following RD&D program areas:

- Buildings End-Use Energy Efficiency
- Energy Innovations Small Grants
- Energy-Related Environmental Research
- Energy Systems Integration
- Environmentally Preferred Advanced Generation
- Industrial/Agricultural/Water End-Use Energy Efficiency
- Renewable Energy Technologies
- Transportation

The Intermittency Analysis Project: Summary of the Preliminary Results for the 2006 Base and 2010 Tehachapi Cases is an interim report by the IAP team performed under a work authorization (MR-017) through the California Wind Energy Collaborative (CWEC) at the University of California, Davis. The information from this project contributes to PIER's Renewable Energy Technologies Program.

For more information about the PIER Program, please visit the Energy Commission's website at www.energy.ca.gov/pier or contact the Energy Commission at 916-654-5164.

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Abstract

The California Energy Commission's Public Interest Energy Research (PIER) Program has assembled an industry team to tackle the challenges of integrating renewables into the future 2020 transmission system. The Intermittency Analysis Project (IAP) examines the statewide system impacts of higher levels of intermittent renewables on the California electricity and transmission infrastructure, and recommends technical and operational strategies for mitigating impacts that are found based on the analysis. Response options provide a framework for system operators, utilities and infrastructure planners to gauge the needs of the future 2020 system. Working with various agencies and California utilities to ensure coordination and to review results and findings, the IAP team has also incorporated recent results and input from other regional study groups in California as well as lessons learned from the international perspective. Goals include providing a detailed technical analysis, addressing potential operational strategies, developing a set of utility "best practices" for integrating intermittent renewables, and if problems are found, assessing potential mitigation options.

This interim report focuses on the assessment methodology, scenarios and highlights some of the preliminary findings presented at a Commission staff workshop on August 15, 2006. Project completion is anticipated in spring of 2007.

Keywords: Intermittency analysis, renewable integration, renewable portfolio standards, renewable transmission benefit ratio, transmission impacts, wind energy in California

Executive Summary

Introduction

This interim report on the Intermittency Analysis Project (IAP) summarizes the results of the project through August 15, 2006. The report provides details on the analysis methodology taken by the team, transmission simulation tools used, as well as assumptions made in developing the 2010 and 2020 scenarios. Continuing efforts describe the actions that will be taken to complete the project.

Purpose

The IAP examines the statewide impacts of higher levels of intermittent renewables on the California electricity and transmission infrastructure. These higher levels are in response to meeting the Renewable Portfolio Standard (RPS) of 20 percent renewable energy by 2010 and the accelerated target of 33 percent renewable energy by 2020. The project will attempt to quantify impacts on the grid as a result of increasing renewable penetration. Potential mitigation options as well as operational response strategies will be demonstrated using production cost modeling and load flow simulation tools. These options provide a framework for system operators, utilities and infrastructure planners to gauge transmission and grid needs for the future as more renewable energy generation is installed in California.

The project conducted power flow and production cost simulations to establish a 2006 baseline, and to develop renewable resource portfolios and infrastructure for 2010 and 2020. Load flows were prepared using PowerWorld software. Production costs were modeled using General Electric's Multi-Area Production Simulation (GE-MAPS™) modeling software to evaluate grid operation with increasing levels of wind and solar generation in the generation mix. All datasets were prepared in consultation with utility stakeholders and at the end of the project will be provided to the Western Electricity Coordinating Council (WECC) and utilities for ongoing study needs.

Project Objectives

The IAP focuses on five objectives:

1. Statewide transmission planning options to meet policy;
2. Identifying the positive and negative quantitative impacts of various options on transmission reliability, congestion and mix of renewable technologies;
3. Developing the tools and analysis methods to evaluate renewables along with conventional generation;
4. Providing a common perspective for evaluating different technologies competing for limited system resources, and

5. Providing a common forum for commissions, utilities and developers to examine the location and timing of new generation/transmission projects and the public benefits of these resources.

Project Outcomes

This interim report describes the project outcomes through the August 15, 2006 staff workshop. Based upon the initial analysis:

- There are quantifiable changes in the total cost of energy production in California from the added production of intermittent renewables;
- The time and duration of operational constraints that may result in intermittent renewable energy not being delivered have been identified;
- Estimates of the potential impacts of intermittent renewables on regulation, load following and unit commitment have been made;
- Projections on future transmission, resource and capacity planning needs can be made;
- Changes in sulfur oxide (SO_x), nitrogen oxide (NO_x), and carbon dioxide (CO_2) emissions due to changes in operations with increasing intermittent renewables resources were modeled;
- Changes in transmission congestion, both in timing and of duration; were identified; and
- Insights were identified on the impact of intermittent renewables on operational and reliability performance measures.

Interim Conclusions

As a result of the work completed up to the August 15, 2006 staff workshop and the comments received from the workshop, the IAP project will address four renewable resource scenarios with varying amounts of wind and solar:

- 2006 base case
- 2010 Tehachapi case with 20 percent renewables and 3,000 megawatts (MW) of new wind capacity at Tehachapi
- 2010 accelerated case planning toward 33 percent renewables
- 2020 case with 33 percent renewables.

Conclusions will be made at the completion of the entire project. Some current observations include:

- The increase in system variability appear small since changes in load and wind are rarely coincident or in the same direction.

- The summer period had more hours of change than the other seasons. This is primarily a weather related phenomenon due to higher ambient temperature changes in the summer which impact both demand in summer and wind generation.
- As higher wind and solar penetrations are reached, there will be a need for more operational flexibility in other generators to load follow and operate, differently. Current results show that this increased need for flexibility appears to be within the existing system capabilities.
- Continuing long-term planning and analysis of the statewide system is needed to determine the existence of and the magnitude of potential problems.

Recommendations

This project provides a piece of the larger transmission planning and system operations picture. As renewable penetration levels increase, continuing long-term planning and analysis of the statewide system is needed to determine the existence of and the magnitude of potential problems. Technology, policy and the environment (market and infrastructure) need to be assessed in a holistic fashion.

Benefits to California

Upon completion, the IAP project is anticipated to provide information and benefits in support of attaining the state's accelerated RPS targets. These include:

1. A vision of the "in-state future transmission grid" (infrastructure and operating services) and the mix of renewable resources (wind, solar, geothermal, biomass) needed to accommodate the RPS renewable penetration levels.
2. Recommendations for a portfolio of renewable resources to meet the 20 percent RPS target by 2010 and the 33 percent goal by 2020.
3. Unified transmission infrastructure solutions and intermittency mitigation measures that transcend utility service boundaries to achieve an economically robust and reliable grid.
4. Quantified system performance and impacts based on the "future grid solutions" that can later be converted into integration cost adders.
5. Integrated transmission expertise from various California utilities, industry, state agencies, and consultants to form a consolidated statewide system of solutions, mitigation measures, and intermittency management strategies.
6. Delineation of the physical transmission limits from policy and contract limits in order to push intermittent renewable resource penetration levels and to provide future market structure recommendations.
7. Estimates on emission (SO_x, NO_x, CO_2) benefits for the state based on study scenarios.
8. Identification of the technology, policy and market gaps that may be barriers to meeting RPS goals.

1.0 Introduction

California has one of the most diverse electricity supply systems in the nation with a large potential to generate electricity from renewable sources, such as wind, geothermal, biomass, hydroelectric and solar. With renewable energy policies such as the Renewable Portfolio Standard (RPS) and the *2005 Energy Action Plan II*, the challenge facing the state will be how best to integrate and manage renewable energy resources with traditional generation while ensuring a reliable electricity system.

The California RPS requires investor-owned utilities to have 20% of its generation from renewable energy by 2010. In addition, the State Energy Action Plan has set a state goal of 33% renewable energy by 2020. A few of the main challenges facing the state in trying to achieve these targets include:

- Building sufficient transmission infrastructure to support and sustain the renewable energy development envisioned for 2020
- Balancing the need to integrate increasing levels of renewable energy while minimizing adverse impacts on the surrounding environment
- Developing tools with the industry to properly integrate variable renewable resources including wind and solar while maintaining grid reliability

The Intermittency Analysis Project (IAP) is tailored to present a statewide perspective for the transmission infrastructure and services needed to accommodate the renewable penetration levels defined in the state's renewable energy policy. The IAP project is technical in nature and is intended to provide a future perspective through 2020 on the potential operational needs and impacts to meet future growth and demand. As a result, certain assumptions on technology availability, system conditions and constraints, as well as market constraints have to be made.

Questions that the IAP project seeks to address include:

- What are the impacts of increasing levels of renewable energy generation on system reliability and dispatchability, with a particular focus on wind and solar energy?
- What will the future system look like and where will the resources come from?
- How will the future grid need to respond (i.e. market structure, services, and technologies)?

In this project, power flow and production cost modeling are conducted, first, to establish the operational baseline of the California grid as of 2006 and then second, to develop the renewable resource mixes for 2010 and 2020 scenarios emphasizing in-state resources. Renewable portfolio mixes, as well as the transmission needed to interconnect the resources will be evaluated in the scenarios based on a transmission benefit criteria. The modeling builds and expands on previous Commission funded transmission studies that focused on connecting statewide renewable resource potential and transmission considerations.

The IAP effort leverages work conducted by the California Wind Energy Collaborative (CWEC) *RPS Renewable Generation Integration Cost Analysis Multi-year Report*, the Consortium for Electric Reliability Technology Solutions (CERTS) *Assessment of Reliability and Operational Issues for Integration of Renewable Generation*, and the *Strategic Value Analysis (SVA) for Integrating Renewable Technologies in Meeting Target Renewable Penetration* work by Davis Power Consultants (DPC). Under the SVA project, PIER and DPC assessed the availability of renewable resources and defined an approach that minimizes transmission infrastructure changes and maximizes benefits for integrating renewables onto the California grid by avoiding congestion. Availability of inter-and intra-state renewable resources and transmission requirements were also modeled using the SVA approach to alleviate, or at least minimize, transmission constraints.

For a more details on state energy policy and project efforts relative to this report, please see the publications listed in Reference section of this report.

The IAP project will address four renewable resource scenarios with varying amounts of wind and solar:

- 2006 base case
- 2010 Tehachapi case with 20% renewables and 3,000 MW of new wind capacity at Tehachapi
- 2010 accelerated case planning toward 33% renewables
- 2020 case with 33% renewables.

The materials in this report focus on the *Intermittency Analysis Project* assessment methodology, the renewable resource scenarios that were developed and some highlights of preliminary findings presented at a Commission staff workshop on August 15, 2006. Specifically, results and discussion will focus on the 2006 Base and the 2010 Tehachapi cases. Project completion is anticipated in spring of 2007 along with a detailed report.

2.0 Analysis Methodology & Project Approach

2.1 Renewable Resource Potential and Availability

IAP incorporates previous work which identified in-state renewable resource locations and availability. Renewable resources included in the IAP portfolios were evaluated for both "locational" and "temporal" benefits in relation to transmission and used a basic approach developed as part of the *Strategic Value Analysis for Integrating Renewable Technologies in Meeting Target Renewable Penetration* (Figure 2-1). The process steps include:

1. Review renewable resource assessments for the state to generate a set of gross and technical resource potential and their locations for each renewable type. These assessments are included in *California Wind Resources* and in the *Renewable Resources Development Report*.
2. Conduct transmission impact analysis for the system.
3. Apply economic filters such as current costs of energy and type of technology to reduce the technical resource potential to an economic potential, as contained in *Strategic Value Analysis – Economics of Wind Energy in California*.
4. Refine economic potential by combining it with a transmission impact analysis as described in *Draft Report on 2010 and 2017 WTLRs*.
5. Evaluate and prioritize resource areas for the most significant impact on alleviating congestion on the electrical grid within a certain timeframe (i.e. to meet 2010 or 2020 goals) as well as other non-energy economic drivers/benefits such as jobs and reduction of pollutants.
6. Integrate all resources into a combined analysis to include all renewables assessed as described in *Strategic Value Analysis for Integrating Renewable Technologies in Meeting Target Renewable Penetration*.

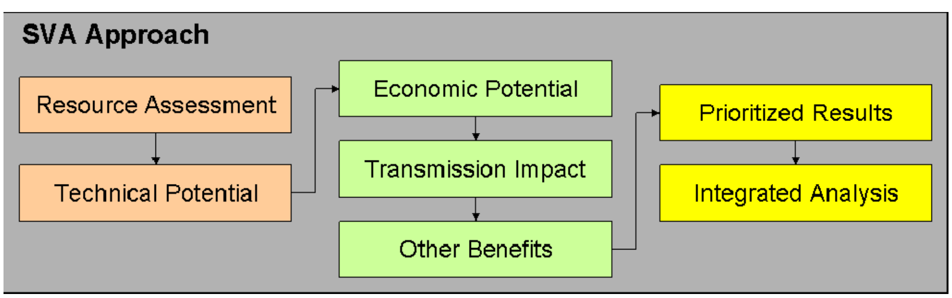

Figure 2-1. Renewable resource and transmission integrated analysis approach

2.2 Data Sources

Data from a variety of sources are used to construct the California statewide transmission dataset for the future scenarios as summarized in Table 2-1.

The load data was scaled for 2006 and 2010 conditions by the ratio of peak loads based on historical years, 2002 through 2004. Hourly load data, both forecasted and actual, came from California Independent System Operator (CaISO) for 2002 through 2004. CaISO also provided load data in megawatts (MW) sampled at 4-second intervals for 400 days in the same three-year analysis period.

Table 2-1. IAP data and resources for transmission models

Data Description	Source
Hourly load (forecasted & actual) for 2002–2004 4-second load (MW) data samples for 400 days during the 2002-2004 period	CaISO
Wind data (forecasted & actual) 1-minute MW data for wind in 51 selected time periods for *existing* and *new potential* wind sites in CA	AWS Truewind – modeled data
Historical solar insolation database Hourly solar insolation measurements & satellite assessed data Hourly solar generation for new resource potential in Mojave areas 1-minute solar insolation variability data for select locations	NREL, Stirling Energy Systems, State University at Albany
Hourly and 15-minute PV generation data for 2004 aggregated by zip code	CPUC-SGIP
Historical hourly and 1-minute generation data for existing renewable facilities from 2002-2004; OASIS database	CWEC, CaISO

AWS TrueWind provided wind data for the 2002–2004 period, covering hourly wind MW (forecast and actual) and 1-minute wind MW data for 51 selected time periods for a large number of existing and future wind plant sites in California. Focus areas for future wind resources in California identified for this study are shown in Figure 2-2.

Solar data was assembled from a variety of sources. Hourly and 1-minute generation data for the Sungen and Luz facilities from 2002 through 2004 was provided by the CaISO and CWEC, who led the Energy Commission's previous effort on developing a methodology to quantify integration costs of the existing levels of renewable energy in California. Using historical insolation data from 2002 to 2004 provided by the National Renewable Energy Laboratory's (NREL) national solar monitoring program, Stirling Energy Systems produced hourly solar MW data for potential sites near Mojave. The California Public Utility Commission's Self-Generation Incentive Program (SGIP), administered by Southern California Edison (SCE), supplied hourly and 15-minute photovoltaic (PV) generation data for 2004, aggregated by zip code. Onsite data also came from a number of local projects throughout California. To account for sub-hourly variability in solar data, the Atmospheric Sciences Research Center at the State University at Albany provided 1-minute solar insolation data at a representative location for the months of January and July 2002. Using this data, representative solar profiles were complied for multiple sites throughout California.

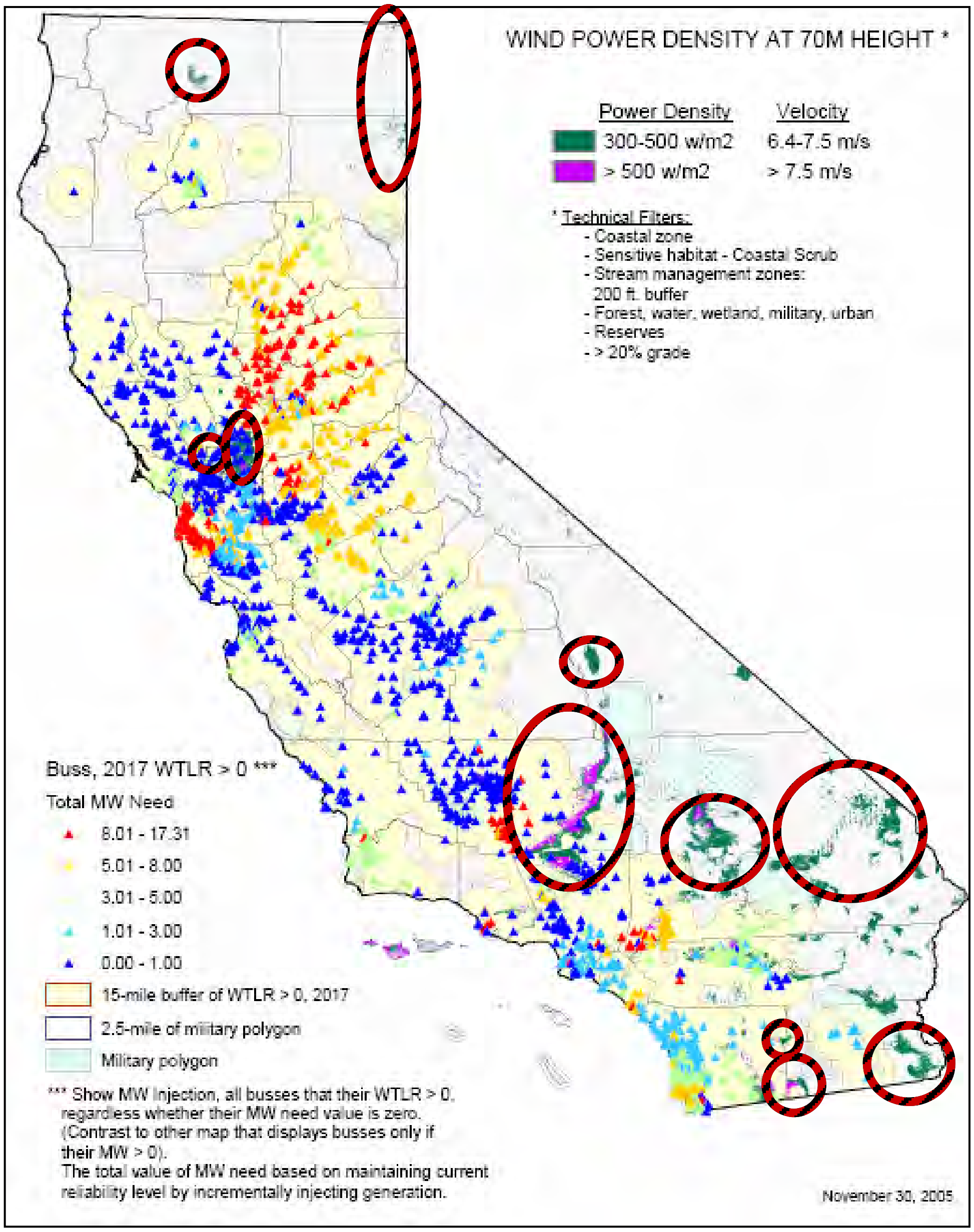

Figure 2-2. Focus areas for future wind sites

Historical load, wind, and solar MW are thus related and correspond to time of day and weather. The load data from each of the 2002 through 2004 historical years is scaled to match the projected peak load for 2006, 2010 and 2020. As a result, for the analysis of each scenario, all three years versus only one year of historical performance data is used to account for variations from year to year. For example, for the 2010 Tehachapi case the three years of data generated include:

- 2010 peak load using 2002 load, wind, and solar profiles

- 2010 peak load using 2003 load, wind, and solar profiles
- 2010 peak load using 2004 load, wind, and solar profiles

2.3 Transmission Assessment

Potential transmission impacts due to deploying new renewable resources are assessed using a transmission reliability metric developed by the DPC team which includes Davis Power Consultants, PowerWorld and Anthony Engineering. This metric is called the Aggregated Megawatt Contingency Overload (AMWCO).

The AWMCO metric is based on standard reliability measures from the North American Electric Reliability Council (NERC) "N-1" contingency approach. This "N-1" approach examines the impact that the loss of a generator, transmission line or substation has on the reliability of the electricity system. The AWMCO is a relative measure and is defined as the weighted sum of the number of overloads and the percentage the lines are overloaded. The larger the AWMCO value, the weaker the transmission element is. The AMWCO for the California grid can be measured by summing over all transmission elements. Using this contingency approach and incorporating forecasted load growth, expected new generation and transmission capacity, a forecast of potential overload situations or "hot spots" can be determined for various analysis years.

The DPC team created factors to prioritize generation source locations and compare transmission benefits. First, areas where transmission is relatively weak were identified and correlated to potential renewables locations. "Hot spots" are then determined by running a series of contingency analyses which look at over 5000 transmission lines, transformers and power plants in the state. Using PowerWorld, power flow simulations were conducted that applied the AMWCO approach to compare and to prioritize locations for adding new power plants (renewable as well as conventional generation) which would alleviate congestion and provide a net benefit to the grid.

The AMWCO is used to determine the Renewable Transmission Benefit Ratio (RTBR). The RTBR is the difference in AMWCO between the renewables case and base case, divided by the total added renewables. The more negative the RTBR, the more the transmission reliability is improved by the addition of renewable energy capacity at that particular location. The RTBR is expressed by the equation:

$$RTBR = \frac{AMWCO_{renewables} - AMWCO_{base}}{\sum MW_{renewables}}$$

where:

- $AMWCO_{base}$: Base Case [MW]
- $AMWCO_{renewables}$: system with new installed renewables [MW]
- $MW_{renewables}$: additional renewable capacity [MW]

An RTBR < 0 indicates improved transmission system reliability.

The results of a number of transmission impact analyses are then combined with all renewable resources studied (wind, geothermal, biomass, solar) to arrive at the final integrated statewide portfolio mix. Results include:

- Generation mixes for scenario analysis specifying capacity in MW, generator type and location.
- Prioritized resource areas by location and benefit to transmission.
- Recommendations for potential transmission upgrades and new transmission needs.
- Estimated transmission implementation cost projections (does not include right of way or land use costs).
- Levelized cost of energy (LCOE) projections for 2006, 2010, and 2020.

Based on the transmission load flow modeling, renewable resource portfolios containing a mix of renewables are developed for each of the scenarios identified under the IAP. Four renewable resource scenarios are evaluated under the IAP project. Each scenario has varying amounts of wind and solar which meet policy targets. The scenarios are:

1. 2006 Base case.
2. 2010 Tehachapi case with 20% renewables and 3,000 MW of wind at Tehachapi.
3. 2010 Accelerated case planning toward 33% renewables.
4. 2020 33% Renewables case.

The 2006 case represents the operational baseline for the California grid and consists of 2005 information scaled to 2006. The 2010 Tehachapi case targets the inclusion of 3,000 MW of wind capacity at Tehachapi, to test the potential grid impacts of a high concentration of wind in a particular region. The 2010 Accelerated case serves as a sensitivity case for planning toward 33 percent renewable energy penetration. The 2020 case provides a perspective on a 33 percent renewable portfolio mix and the necessary accompanying transmission infrastructure. For both the 2006 and 2010 Tehachapi scenarios, 96 percent of the wind and solar generation is found in CaISO's control area.

2.4 Operational Impact Assessment

Once the load flows are completed and the resource mixes are established, production cost modeling is conducted on all four scenarios using General Electric's Multi-Area Production Simulation (GE-MAPS™) modeling software. The GE team consists of GE Energy, Rumla Inc. and AWS Truewind. This level of modeling helps evaluate grid operation with increasing levels of wind and solar generation; identify and quantify system performance and operation issues; and identify and evaluate potential mitigation strategies and options if necessary.

Based on the analysis of these scenarios, the anticipated results from the production cost modeling include the following:

- Projections on future transmission, resource and capacity planning needs;
- Estimates of the potential impact of intermittent renewables on regulation, load following and unit commitment;
- Changes in transmission congestion, both in timing and of duration;
- Impact of intermittent renewables on operational and reliability performance measures;
- Changes in SO_x, NO_x and CO_2 emissions due to changes in operations with increasing intermittent renewables resources;
- Insight on time and duration of operational constraints that may result in intermittent renewable energy not being delivered, and
- Quantifiable changes in the total cost of energy production in California from the added production of intermittent renewables

The IAP analysis spans across the operational and planning time horizons with a focus on a 2020 33% renewable energy scenario. Several different time scales are involved in grid operations and planning as illustrated in Figure 2-3. For example, frequency and regulation are performed on a second-to second basis. Unit commitment of generating units and forecasting are planned on a day-ahead or multi-day-ahead basis. Load growth and transmission planning are performed at even greater intervals, spanning years.

Anticipated statistical analysis to compare Base to future years include:

1. Statistical Analysis over multiple time periods (hourly and sub-hourly) covering the planning to operations timeframes.
2. Production Cost Simulation with MAPS performing hour-by-hour simulation of grid operations for an entire year.
3. Quasi-Steady-State Simulation with PSLF to evaluate minute-by-minute power flows for entire WECC grid over several hours.
4. Transient Stability Simulation with PSLF if transient stability issues are identified.

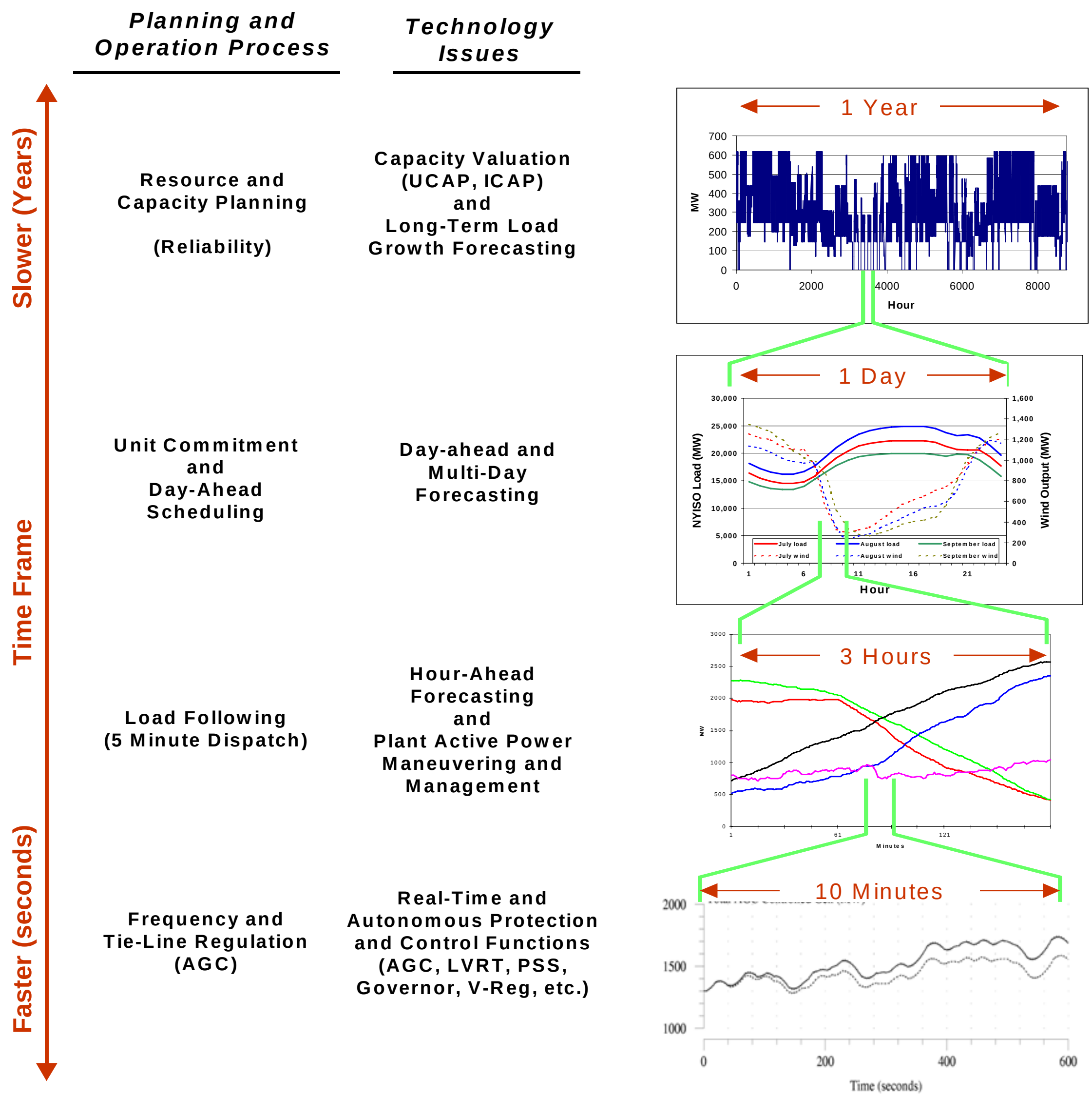

Figure 2-3. Time Scales for grid planning and operations

3.0 IAP Preliminary Findings – 2006 and 2010 Scenarios

Preliminary findings were reported by the IAP team at a public workshop held on August 15th, 2006 at the Energy Commission. Results provided are drawn from the work presented and highlight the 2006 Base Case and the 2010 Tehachapi case with 20 percent renewables. The next and final IAP workshop currently anticipated in February 2007 will feature the 2010 Accelerated and 2020 33% cases.

The 2006 Base case represents the operational baseline for the existing California grid. The 2010 Tehachapi case targets the inclusion of 3,000 MW of wind capacity in the Tehachapi region of south eastern California and is designed to test for potential grid impacts given a large concentration of wind resources in a particular region. For both the 2006 Base and 2010 Tehachapi scenarios, 96% of the wind and solar generation are in the CaISO control area. Table 3-1 summarizes the non-hydro renewable resource mix for the 2006 and 2010 Tehachapi scenarios. Renewable resources by technology and capacity for the 2010 scenario are provided in Appendix A.

Table 3-1. Peak non-hydro renewable resource mix for the 2006 base and 2010 Tehachapi scenarios (MW)

	2006 Base Case	2010 Tehachapi
Peak California Load	58,634	64,297
Peak CAISO Load	48,494	53,178
Geothermal	2,398	4,130
Biomass	764	1,184
Solar (CSP and PV)	332	1,864
Total Wind	2,156	7,550
Wind at Tehachapi	760	3,787

3.1 2006 Base Case – Transmission Analysis

In developing the 2006 Base case, WECC approved 2005 summer base cases from the various California utilities (e.g., PG&E, SCE, SDG&E) were used and combined into one consistent and contiguous statewide transmission dataset. Information from municipal utilities (i.e., SMUD, LADWP, IID) was incorporated as it was made available. LADWP data was modeled after the SCE information. For 2006, loads were escalated by 3% from 2005. In addition, any available data on planned transmission upgrades and expansions by the CaISO and California utilities were incorporated into the model.

Based on historical performance, wind generation was modeled at both 60% and 100% of installed wind capacity on the grid to compare system performance. For example, in July 2004, wind generation averaged about 50% of total connected wind capacity during the top 5% of the highest load hours (Figure 3-1).

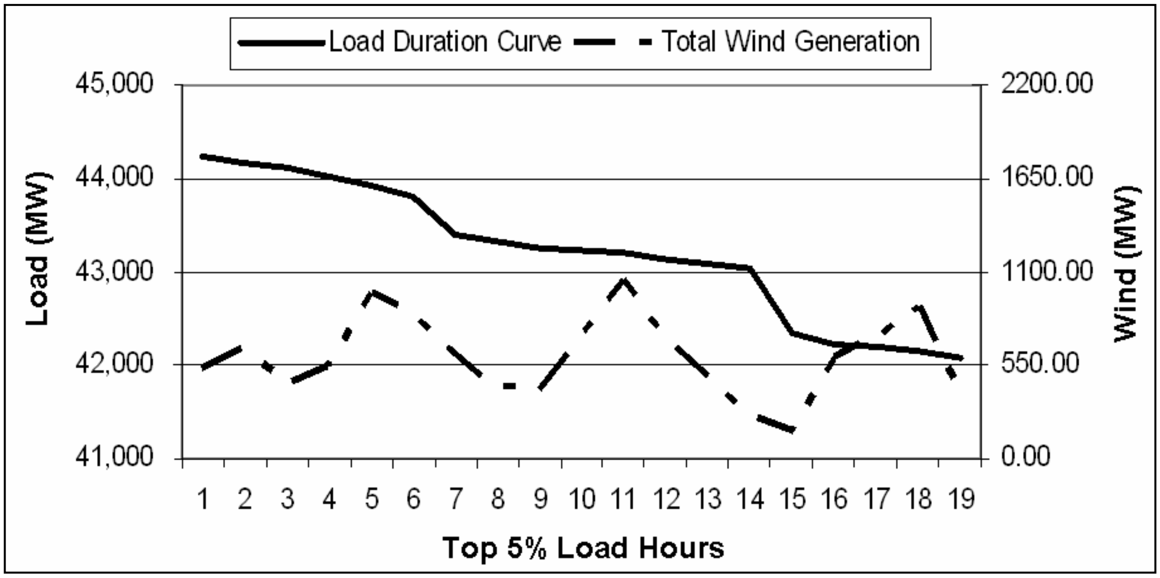

Figure 3-1. Top 5% load hours and corresponding wind

Using 60% is somewhat higher than historical wind generation during high peak demand periods, while 100% provides a maximum penetration in terms of line loading and demand for VARs, as is typically used in transmission planning. The range provides perspective on how variability and certain assumptions impact system planning.

AMWCO analysis results for the statewide 2006 Base case with existing wind locations are summarized in Table 3-2. The RTBR was calculated for the aggregated wind generation at 60% and 100% of connected wind capacity. The RTBR is the difference in AMWCO between the base case and each renewables case, divided by the installed renewable energy capacity. A RTBR less than zero indicate that transmission reliability is improved by the addition of renewable energy capacity. At 60% capacity, the aggregated wind generation resulted in a RTBR of -2.17. At 100%, the RTBR is still negative but slightly less negative than at 60%. This indicates that there is still a benefit to the system but some transmission upgrades on the system may be needed to improve wind generation export assuming 100% penetration at all times. The slight negative RTBR numbers also indicate that the existing wind penetration levels and locations currently have an overall beneficial effect on the transmission system. The goal for the future will be to improve or at least maintain the overall statewide conditions with 2010 and 2020 plans.

Table 3-2. 2006 Base case summer peak wind transmission analysis

	No Wind	60% Wind Capacity	100% Wind Capacity
Wind MW	0	1,287	2,145
AMWCO	15,899	13,100	11,966
RTBR	---	-2.17	-1.83

Variability of the wind resources changes with location as well as with the seasons. To establish a baseline and understand the impact of additional wind in these areas as well as seasonal variations, four of the major wind sites in the state are evaluated separately. The four areas are presented in terms of their RTBR values and compared to the state overall Base case. The areas include:

- Altamont Pass in northern California.
- Solano in northern California.
- Tehachapi Pass in southern California.
- San Gorgonio in southern California.

As indicated in Figure 3-2 and summarized in Table 3-3, Solano, Altamont, and San Gorgonio have high negative RTBRs indicating positive transmission reliability benefits, as they are located near load centers. Under the 2006 Base case and existing transmission infrastructure, wind energy development in Solano has the most benefit on the grid in serving load and alleviating transmission congestion. Tehachapi is essentially neutral, as the region is more remote and far from load. Again, a negative RTBR indicates that system reliability may be improved by addition of the resource. Based on these initial comparisons, there is a baseline understanding of the impacts of the individual resources in the area and on the statewide grid. The impacts and benefits of significant development concentrated in any one location, especially in the remote locations, can now be compared to this base reference condition.

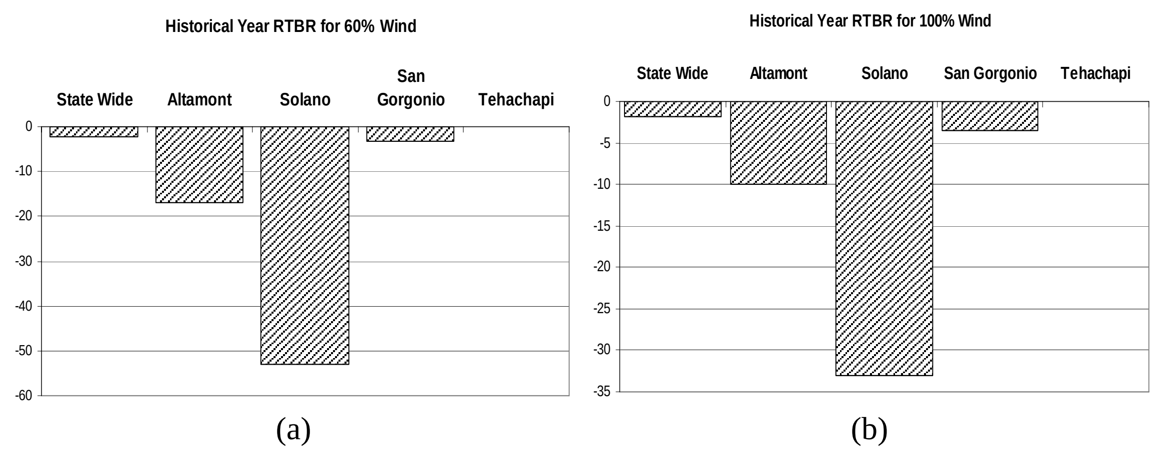

Figure 3-2. RTBR comparison for wind resource at a) 60% and b) 100% for 2006 base

Table 3-3. RTBR for 60% and 100% Wind - 2006 Base Case Summer Peak

Region	60% Case RTBR	100% Case RTBR
Altamont	-17	-10
Solano	-53	-33
San Gorgonio	-3.3	-3.5
Tehachapi	-0.02	-0.03
Statewide	-2.17	-1.83

Figure 3-3 shows an AMWCO duration curve for the system based on operations across the historical years referenced. The statistical median hour AMWCO is shown at 16,494. A few hours experience unusually high level of overloads but the rest of curve is fairly flat.

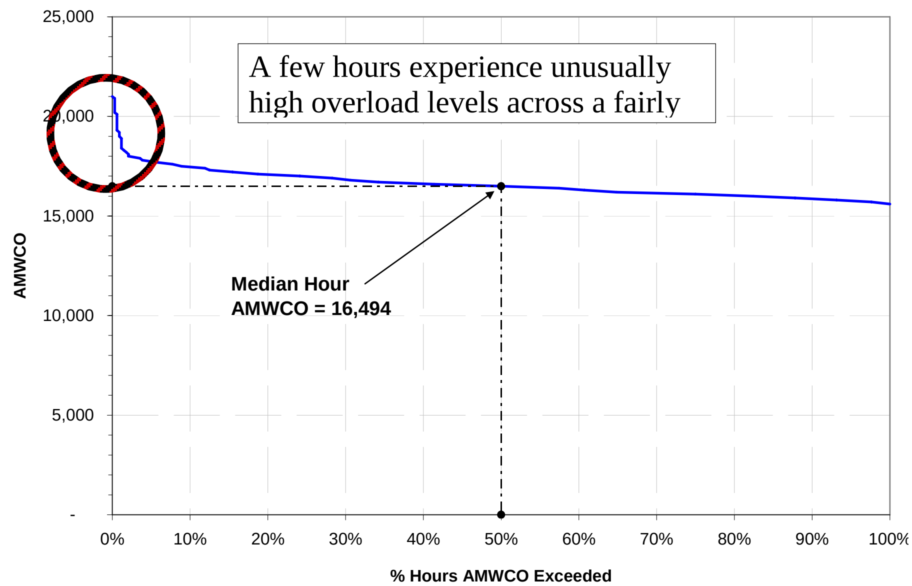

Figure 3-3. System AMWCO load duration curve for 2006 base highlighting periods where excessive overloads are experienced

3.2 2006 Base Case – Statistical Analysis

Temporal trends for wind and solar are captured in the 2006 Base case hourly analysis. As shown in Figure 3-4 and 3-5, some statistical trends and observations include:

- Wind resources exhibit a diurnal pattern, more during the hot summers where terrain effects dominate versus the winters where climate or meteorological conditions are more random.
- Wind generation tends to not be as correlated with load, especially during the summer seasons.
- Solar correlates with peak load but availability is more limited during winter months with production later in the morning and ending sooner in the afternoon.
- Wind and solar seem to be complementary, that is, wind generates when solar is unavailable and vice versa.
- Overall wind penetration at 2.2% throughout the year with maximum wind penetration of 3.5% during low load periods (10^{th} decile). *(Note: for this discussion, wind penetration is defined as average wind output divided by average load, in MW, for a given period.)*

- Overall solar penetration was 0.3% throughout the year with maximum generation occurring in peak load hours.

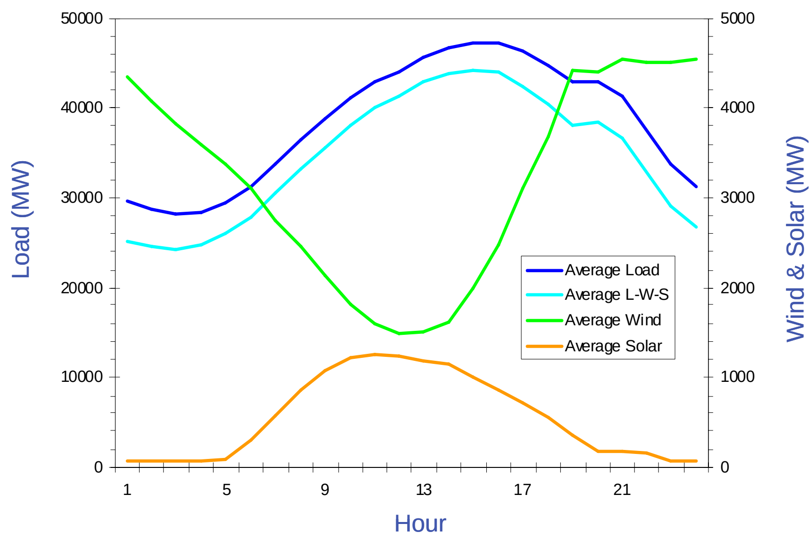

Figure 3-4. Typical monthly summer wind and solar temporal patterns (from July 2003)

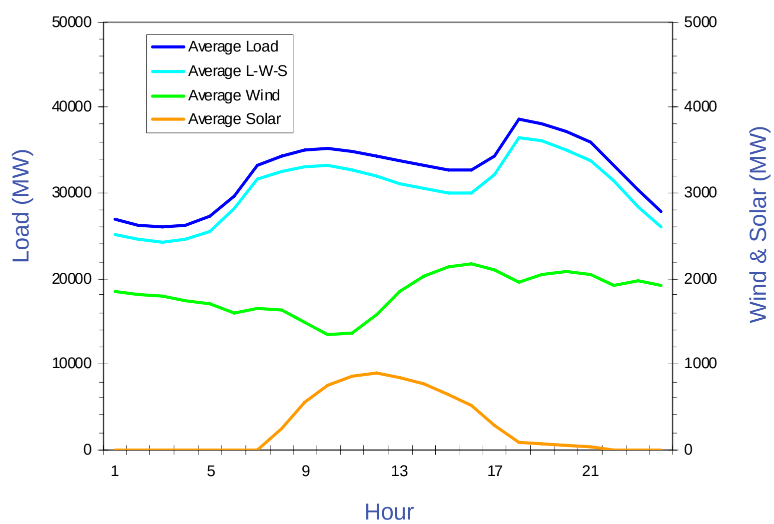

Figure 3-5. Typical winter wind and solar monthly temporal patterns (based on January 2002)

Figure 3-6 shows the load duration curves for load and load minus wind and solar (L-W-S) in terms of megawatts (MW) across the historical 3-year period (26,300 hrs). To facilitate analysis, the curves are parsed into 10 deciles of 2,630 hours each, where each decile captures a certain condition on the grid. For example, the first decile represents the 10% of hours with the highest loads and the tenth (last) decile represents the 10% of hours with the lowest loads (i.e. minimum load).

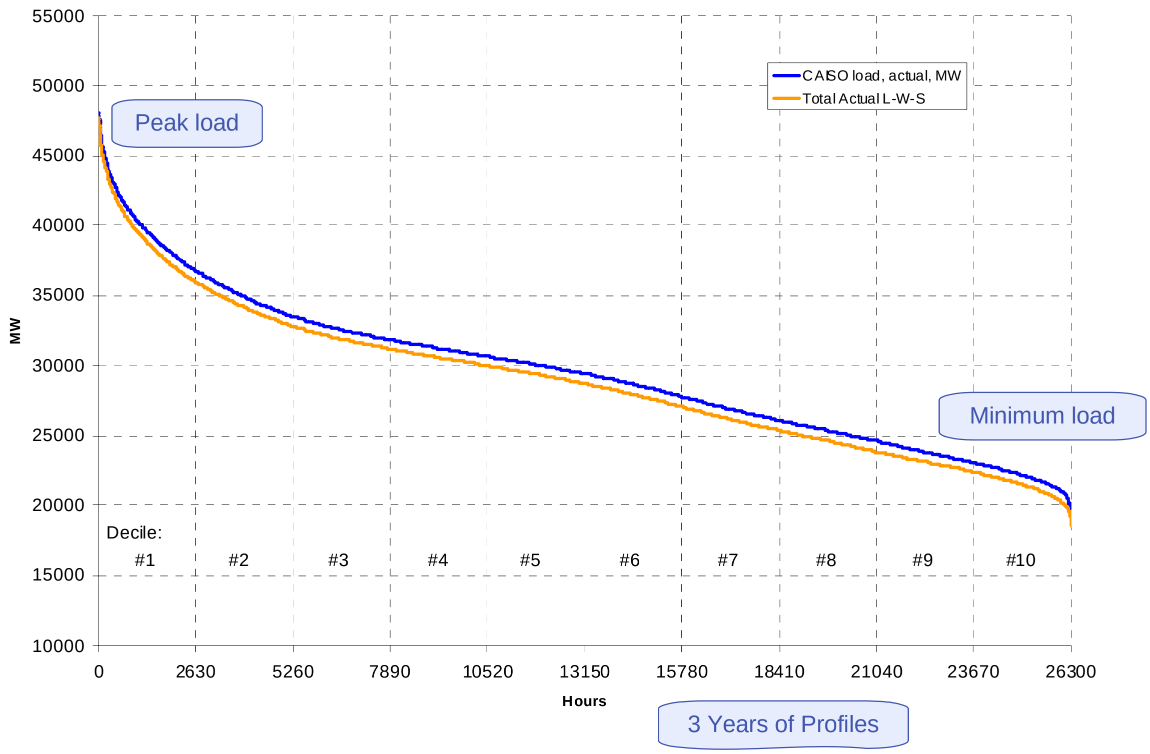

Figure 3-6. 2006 hourly load duration curves showing load alone vs. load minus wind minus solar (L-W-S)

Figure 3-7 shows the hour-to-hour variability in each decile. The maroon (dark) bar represents the range of hourly changes in load, while the yellow (light) bar on the right represents the range of hourly changes in load minus wind and solar (L-W-S). The maroon and yellow bars also represent 1-sigma (1σ) change values, while the "whiskers" represent the maximum and minimum in hourly change values for each decile. The maximum load rise for 2006 was captured in the 5th decile. Maximum rise in load was 6,123 MW/hour; and for L-W-S, it was 6,091 MW/hour. Some noticeable average impacts of wind and solar appeared in deciles 4, 5, 7 and 8, while the largest maximum swings between load and load minus wind and solar occurred in the 10th decile. See Appendix B for tabularized data.

These interim results show that at current penetration levels, variable resources (wind and solar) have some observable but insignificant impacts on hourly operations; however, the frequency of those excursions appear small at current levels of wind and solar generation.

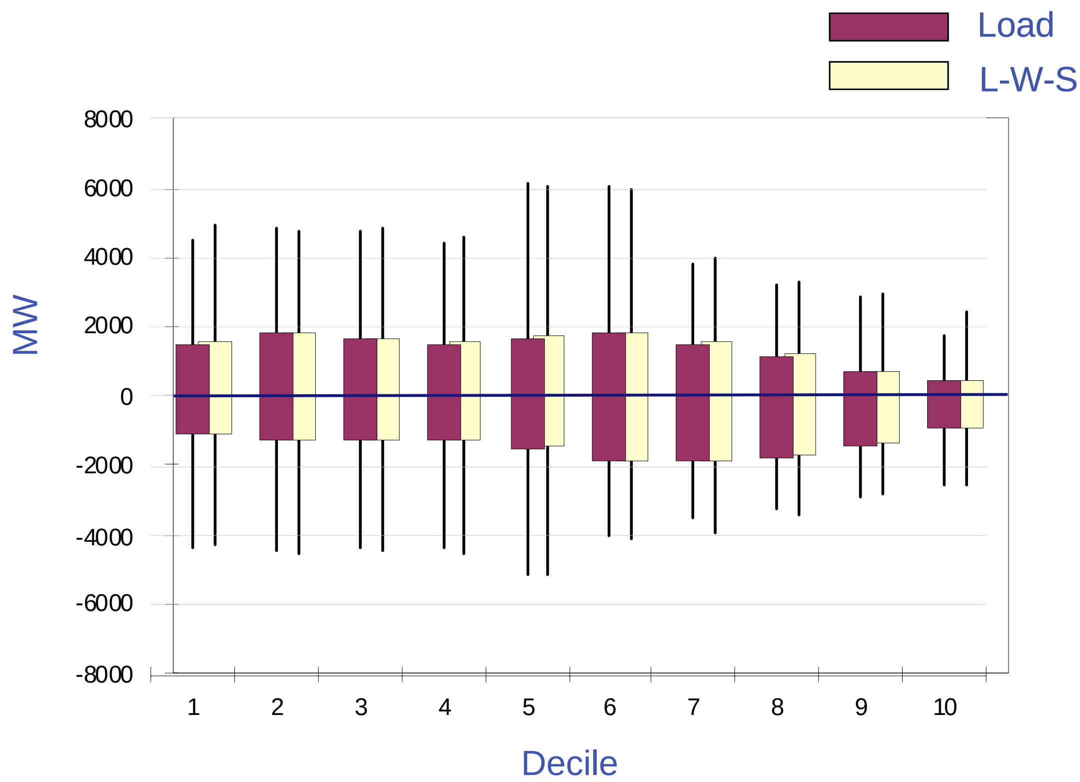

Figure 3-7. 2006 statistical hour-to-hour variability in load as compared to load minus wind minus solar (L-W-S)

3.3 2010 Tehachapi Case – Transmission Analysis

For this scenario, a 2010 renewable resource mix consisting of 20 percent generation from renewables, with 3,000 MW of wind at Tehachapi, was developed to assess the impact of variability. The power flow simulations were conducted for spring, summer and fall cases in order to capture the seasonal variations under various renewable energy penetration levels, utility loads and generation dispatch, and to assess the reliability of the transmission grid under different operating conditions. Specifically, the seasonal periods are as follows:

- *SPRING*: On-peak period in May, when wind and hydro generation are generally high and load is lower than normal.
- *SUMMER*: Peak load hours in July.
- *FALL*: Off-peak times in November, with minimum utility loads and some problems with minimum generation.

Some modifications were made to individual utility load flow cases. For instance, SDG&E's load flow assumed a worse case scenario with the Encina and South Bay generating plants being out of service at the same time. This results in more imports over SDG&E's 500 kV transmission lines. With the consultation and agreement of SDG&E, the higher imports were changed in the load flow to power being replaced on an in-kind basis to maximize in-state infrastructure and resources.

Another limitation of the utility load flow cases is that they include high transmission flows designed to stress the high voltage transmission lines. These cases limit grid access of in-state renewables, reduce generation from in-area resources, and may result in additional VAR and voltage problems because of limited in-area resources. While understandable from a utility load flow perspective, it is somewhat at odds with the objectives of this study which is focused on in-state renewables and transmission infrastructure investment.

Other assumptions/limitations include:

- Adding generation to maintain a 15% reserve margin and to account for plant retirements and load growth, consistent with Energy Commission Electricity Analysis Office projections. The added generation was all fueled by natural gas and amounted to 1,795 MW of combustion turbines and combined cycle natural gas plants (Table 3-4).
- Modeling of proposed transmission improvements from Midway to Tehachapi as recommended by the Tehachapi Study Group's November 2005 report to the California Public Utilities Commission (CPUC) as illustrated in Figure 3-8. *(NOTE: Subsequent to this recommendation, CaISO has recently developed an alternate configuration for this interconnection. For the purposes of this intermittency study, the recommendation is consistent and should be adequate to assess the system impacts.)*
- Modeling of transmission improvements in the Imperial Valley, similar to the Imperial Irrigation District's (IID) Green Path proposal. About 800 MW of geothermal capacity was added and interconnected at Devers.
- Using utility datasets for the summer cases to build a consistent set for the 2010 Tehachapi scenario. The summer case had more detailed and consistent topology. Loads, generation and interchange were modified from this set to match the spring and fall while the transmission configuration used summer profiles.

Table 3-4. Non-renewables generation added to 2010 Tehachapi case

Name	Type	Fuel Type	Maximum MW
ELCENTSW	GT	Natural Gas	50
HAYNES	GT	Natural Gas	150
VALLEYSC	CC	Natural Gas	400
VALLEYSC	CC	Natural Gas	400
HELM	CC	Natural Gas	250
HELM	CC	Natural Gas	280
MC CALL	CC	Natural Gas	265
Total			1,795

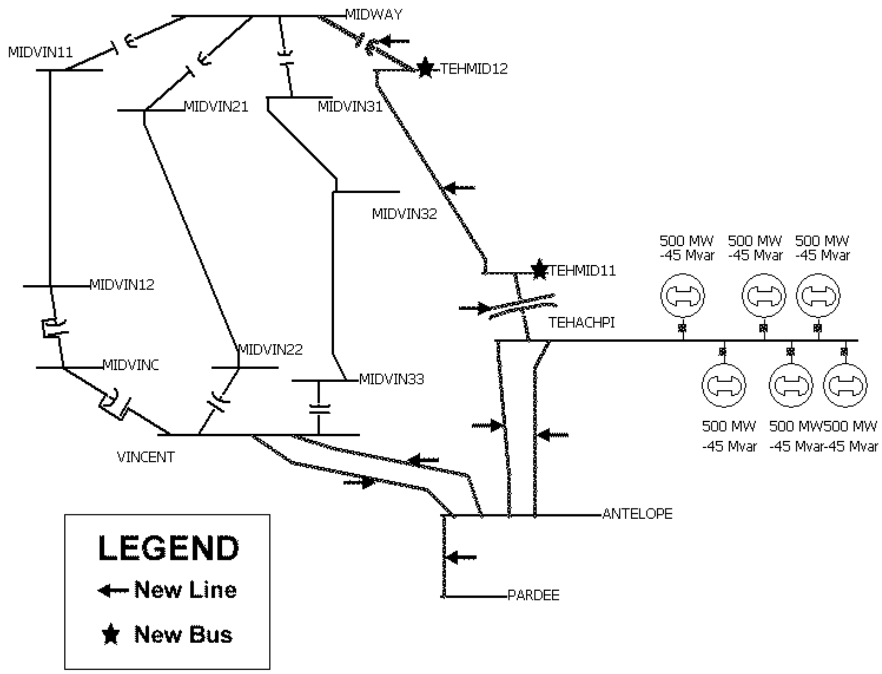

Figure 3-8. Modeled transmission improvements at Tehachapi

Table 3-5 summarizes the major transmission and grid improvements for the 2010 Tehachapi case and illustrated in Figure 3-8.

Table 3-5. Grid improvements modeled for 2010 Tehachapi case

Line (Voltage)	# of Segments	# of Transformers
500	8	2
230	8	6
161	0	1
115	49	9
Below 110	13	14
Total	**78**	**32**

Table 3-6 records the number of overloads by season for the 2010 Tehachapi case. As illustrated, overloads occurred more in the spring and summer than in the fall and more on radial lines or single lines that connect a generator or load to the grid.

Table 3-6. Overloads by base year vs. 2010 Tehachapi scenario

	2006 Base Summer (60%)	2010 Tehachapi Summer (60%)	2010 Tehachapi Spring (60%)	2010 Tehachapi Fall (60%)
Non-Radial Overloads	10	5	2	0
Radial Overloads	38	8	2	3

RTBR results for the 2010 Tehachapi scenario are summarized by seasons (spring, summer and fall) in Figures 3-9 through Figure 3-11. As indicated, impacts differ depending on technologies, location of technology and the season. For instance, biomass resources, a base-load renewable resource, had negative RTBRs for both spring and summer but had a positive RTBR in the fall case. Again, negative RTBR indicates overall benefit on system reliability while a positive RTBR indicates an adverse impact on the system reliability. The positive or "stressed" condition caused by the biomass resource may be attributed to minimum load conditions and high south-to-north flows on SP15 during the fall. Both PV and CSP (concentrated solar) resources had negative RTBRs during summer and spring conditions but had a less beneficial, neutral RTBR during the fall for similar reasons. In contrast, Altamont wind capacity exhibited a positive spring RTBR but negative RTBRs in summer and fall, despite having a low correlation to peak load during summer months. Positive spring RTBR for Altamont may be attributed to high spring hydro run-off conditions. Additional resources in SDG&E and San Gorgonio areas exhibited negative RTBRs for all seasons indicating that developing generation near and around those locations may have value to the system as far as improving transmission reliability.

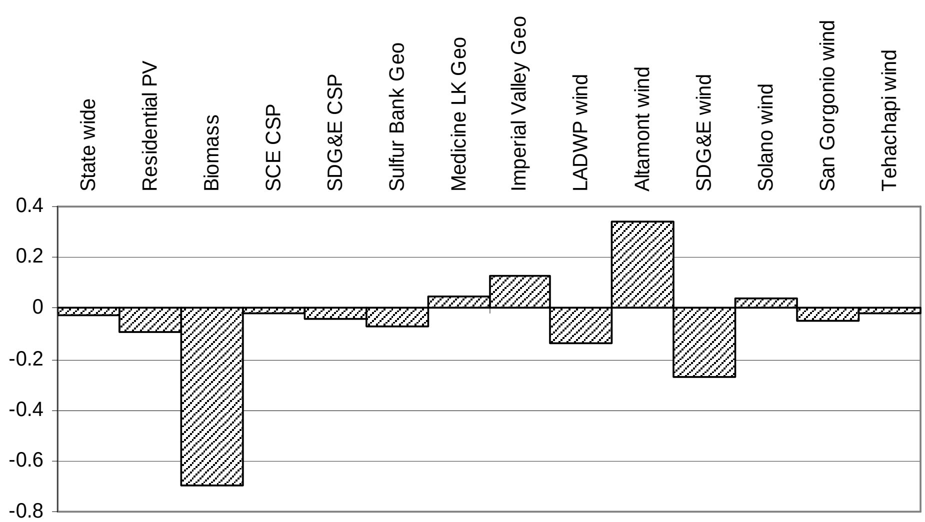

Figure 3-9. 2010 Spring Tehachapi RTBR

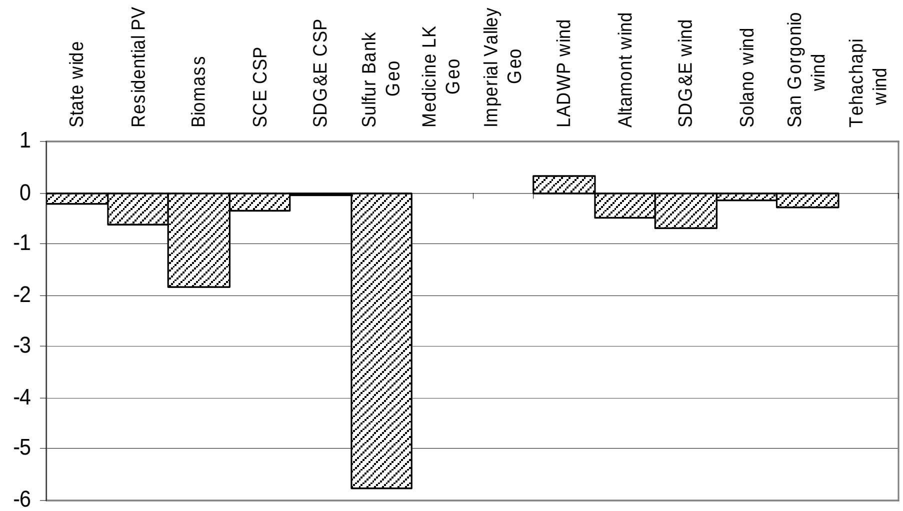

Figure 3-10. 2010 Summer Tehachapi RTBR

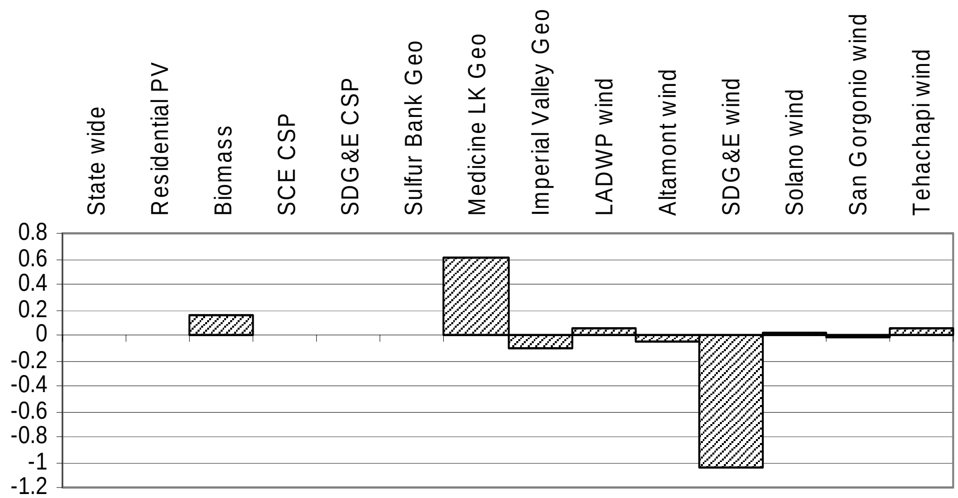

Figure 3-11. 2010 Fall Tehachapi RTBR

Table 3-7 summarizes the resources with both positive RTBRs and neutral RTBRs for each of the three seasons. As planning continues toward a 2020 perspective, areas exhibiting consistent positive and neutral RTBRs in 2010 may indicate locations that will require additional transmission upgrades. Or if resources permit, planning an alternative location closer to projected demand may be necessary.

Table 3-7. Summary of resources and regions with positive RTBR or "Stressing System Conditions" and neutral RTBR by season

Region	Resource	Spring	Summer	Fall
Medicine Lake	Geothermal	X	Neutral	X
Imperial Valley	Geothermal	X	Neutral	
Sulfur Bank	Geothermal			Neutral
LADWP	Wind		X	X
Altamont Pass	Wind	X		
Solano	Wind	X		X
Tehachapi	Wind		Neutral	X
Central Valley	Biomass			X
SDG&E	CSP		Neutral	Neutral
SCE	CSP			Neutral
Residential	PV			Neutral

The assessment shows the interdependency of all grid connected generation, renewable and non-renewable, and the importance of understanding seasonal and locational impacts on the statewide system. This information offers some perspective for developing future 2010 and 2020 transmission options.

3.4 2010 Tehachapi Case – Statistical Analysis

The statistical analysis based on production simulations of the 2010 Tehachapi case incorporated 7,550 MW of new wind and 1,864 MW of new solar resources (Table 3-1). Figure 3-12 shows hourly load duration curves for the 2010 Tehachapi scenario. There is a consistent 3,000 to 4,000 MW difference between the curves in all deciles as compared to the 2006 Base Case (Figure 3-6). Figure 3-13 compares wind and solar hourly penetration levels for 2006 and 2010. Consistent with 2006 trends, solar penetration is highest at peak load (2.2% in the 1st decile) and wind penetration is highest during light load (20% in the 10th decile). Indeed, wind penetration in the 2010 Tehachapi scenario increases with each decile, except for decile 7. In terms of hourly variability, both wind and solar contribute to increased variability in 2010 as depicted in Figure 3-14. The change is most significant in the 10th decile, or light load period.

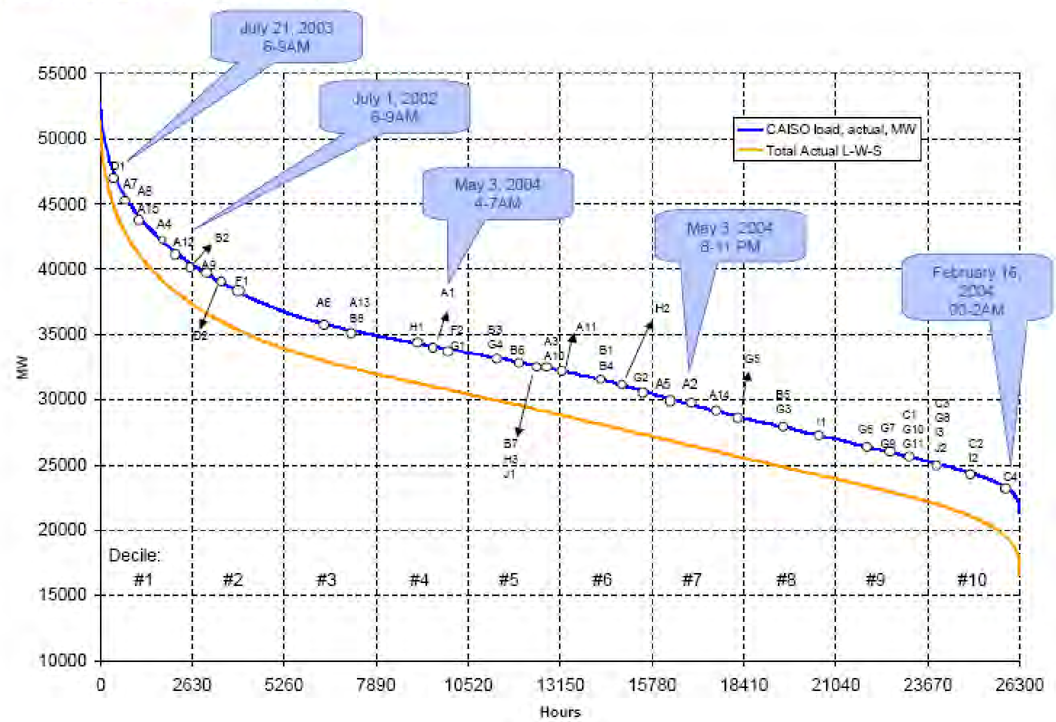

Figure 3-12. 2010 hourly load and L-W-S duration curves with 50 assessment periods

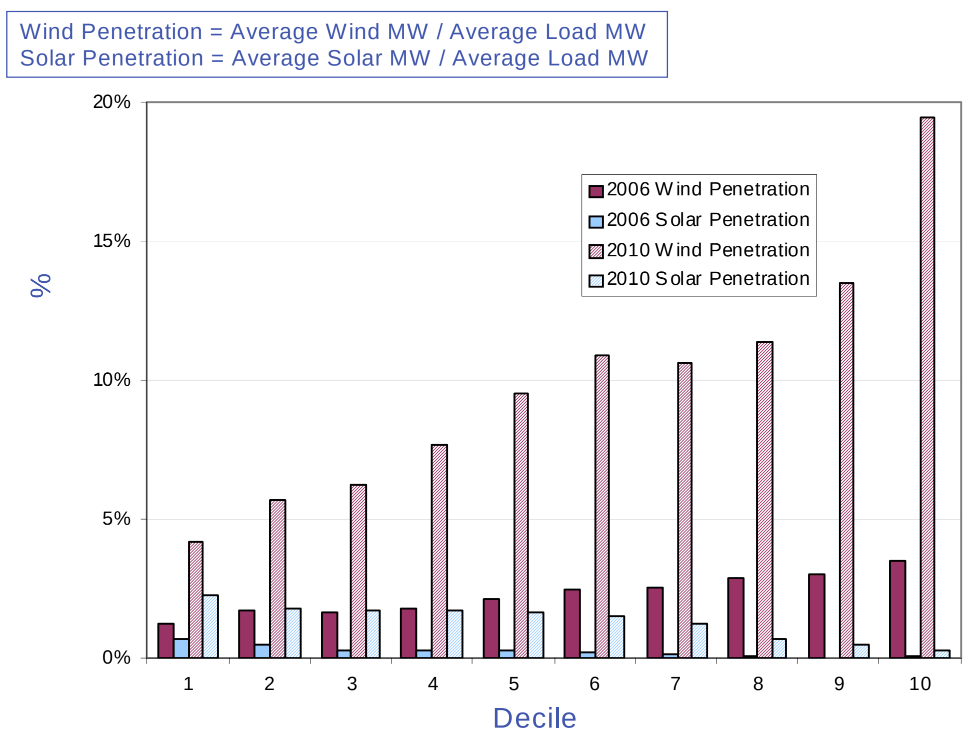

Figure 3-13. Comparison of 2006 and 2010 hourly wind and solar penetration

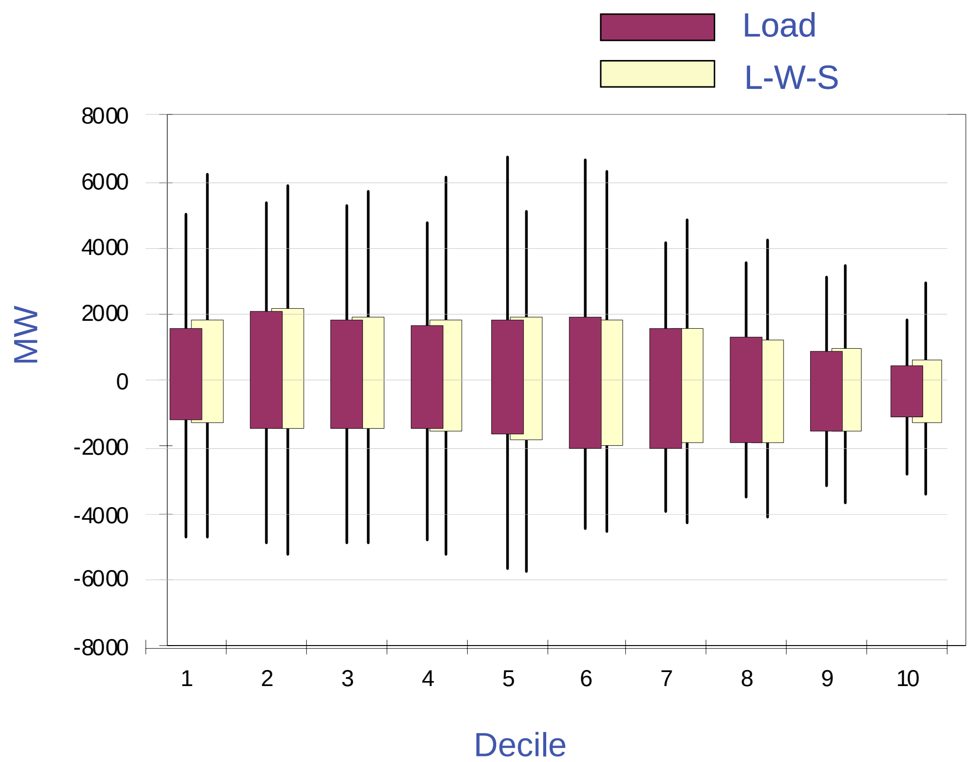

Figure 3-14. 2010 statistical hour-to-hour variability in load as compared to load minus wind minus solar (L-W-S)

Statistical analysis and production cost models are combined to capture the hour-by-hour and minute-by-minute impacts on operation. The statistical analysis also involved searching through the hourly data for periods that warrant more detailed analysis. For example, 50 different sample periods are assessed for 2010 to look at sub-hourly system impacts (Table 3-8). The characteristics of such periods include:

- Large changes in load over 1-hour and 3-hour periods.
- Periods of high wind and solar generation.
- Periods of high penetrations of wind and solar.
- Low load periods.
- Large changes in wind and solar over 1-hour and 3-hour periods.
- Periods of high wind with low wind variability.

Data was aggregated into 3-hour blocks and the top 20 3-hour blocks for each category (largest change in load, periods of high wind and solar generation, low load periods, etc.) was compiled. Fifty specific 3-hour periods were selected and differentiated by year, season, time of day, changes driven by load, wind or solar, and direction of changes, whether up or down. The 50 periods are cataloged in Table 3-8 and overlaid on the load duration curve in Figure 3-12.

Sub-hourly statistical analysis was conducted on these 3-hour periods for each season similar to the 1-hour data set. The seasons are classified by the Gregorian calendar. The largest 3-hour change in MW represents the biggest group, with 15 periods, followed by the group of high wind capacity with low wind variability with 11 periods and the largest 1-hour change in capacity with eight periods. Of the 50 periods, spring is reflected in 20, followed by summer with 17, winter with eight and fall with five. For each 3-hour period, 1-minute MW output profiles were developed for wind and solar resources, and 1-minute load data was obtained from the CaISO.

Table 3-8. Selected periods for sub-hourly analysis

	Year	Season	Month	Day	End Hour
Large 3-Hour Delta MW (Group A)	2004	Spring	5	3	7
	2004	Spring	5	3	23
	2004	Fall	10	28	7
	2004	Summer	7	19	9
	2004	Summer	9	6	23
	2004	Summer	9	7	22
	2003	Summer	7	21	10
	2003	Summer	8	12	10
	2003	Summer	7	19	10
	2003	Summer	6	26	23
	2003	Spring	5	28	23
	2002	Summer	7	1	9
	2002	Summer	7	9	23
	2004	Spring	4	27	23
	2004	Summer	8	10	10
Large 1-Hour Delta MW (Group B)	2004	Winter	1	30	6+1
	2002	Winter	1	30	18+1
	2003	Spring	4	10	7+1
	2004	Winter	12	31	17+1
	2003	Spring	4	7	19+1
	2003	Winter	2	9	18+1
	2002	Winter	2	14	22+1
	2003	Spring	5	28	22+1
Low Load Periods (Group C)	2002	Fall	10	14	4+1
	2003	Winter	2	2	6+1
	2002	Fall	10	27	23+1
	2004	Winter	2	16	1+1
Largest 3-hr Delta W+S (D)	2003	Summer	7	21	19
	2004	Fall	11	29	18
Largest 1-hr Delta W+S (F)	2004	Summer	6	24	19+1
	2003	Fall	10	31	17+1
High Wind MW with Low	2002	Summer	7	3	22+1

	Year	Season	Month	Day	End Hour
	2002	Summer	6	27	23+1
	2002	Summer	6	19	2+1
	2002	Spring	6	3	22+1
	2003	Summer	7	3	24+1
	2003	Summer	6	20	24+1
	2003	Spring	5	15	4+1
	2003	Spring	5	24	24+1
	2003	Winter	3	17	24+1
	2004	Spring	5	10	24+1
	2004	Spring	5	18	24+1
Highest Wind MW (Group H)	2002	Spring	5	20	18+1
	2003	Spring	5	8	18+1
	2004	Spring	5	28	19
Highest Wind Penetration (Group I)	2002	Spring	6	18	2+1
	2003	Spring	5	15	2+1
	2004	Spring	5	29	1+1
Highest Wind+Solar MW (J)	2004	Spring	5	28	17
Highest Wind+Solar	2004	Spring	5	29	1+1

Note: The +1 indicates that the ending time for this period was increased by one hour to place the most interesting hour in the middle of the period.

Comparing the variability (1-sigma, σ) for the full year for the 2006 and 2010 Tehachapi cases shows that wind and solar generation has some impacts for 1-minute and 5-minute periods, and somewhat more impact on hourly periods, as shown in the Change columns of Table 3-9. However, it is interesting to note that wind and solar generation reduced the extreme one-hour load rise for the time periods analyzed. For the 2006 Base case, the load only maximum is 6,123 MW whereas the L-W-S maximum is 6,091 MW. For 2010 Tehachapi, the load only maximum is 6,714 MW versus 6,312 MW for L-W-S.

Table 3-9. 2006–2010 Statistical analysis: Full year variability

	2006 Load	2006 L-W-S	Change	2010 Load	2010 L-W-S	Change
σ 1-Hour Δs (MW)	1436	1451	15	1575	1623	48
σ 5-Min Δs (MW on 15-Min RA)	189.3	189.9	0.3	207.6	214.5	6.9
σ 1-Min Δs (MW from 15-Min RA)	44.8	44.9	0.1	49.1	50.7	1.6
Max, Min 1-Hour Δs (MW)	6123, -5122	6091, -5155	-32, -33	6714, -5617	6312, -5713	-402, -96
Max, Min 5-Min Δs (MW on 15-Min RA)	526, -480	550,-481	24, -1	577,-527	699, -522	122, 5
Max, Min 1-Min Δs (MW from 15-Min RA)	803, -305	803, -306	0, -1	881,-334	887,-323	6,11

Wind and solar have greater impacts on variability during light load periods, as demonstrated in Table 3-10. In comparison to the full year, the statistical hourly MW change (1-sigma, σ) is higher during light load conditions, as are the maximum and minimum hourly change. Variability in the 5-minute period is also significantly higher. However, variability in the 1-minute time period remains comparable to the full year, at 1.1 MW and 1.6 MW, respectively.

Table 3-10. Light load (10th Decile) variability

	2006 Load	2006 L-W-S	Change	2010 Load	2010 L-W-S	Change
σ 1-Hour Δs (MW)	669	699	30	734	933	199
σ 5-Min Δs (MW on 15-Min RA)	86.5	89.2	2.7	94.9	109.1	14.2
σ 1-Min Δs (MW from 15-Min RA)	40.8	40.9	0.1	44.8	45.9	1.1
Max, Min 1-Hour Δs (MW)	1707, -2567	2448, -2613	741, -46	1871, -2815	2939, -3427	1068, -612
Max, Min 5-Min Δs (MW on 15-Min RA)	154,-257	174,-257	20, 0	169,-282	231,-259	62, 23
Max, Min 1-Min Δs (MW from 15-Min RA)	200,-194	198,-193	-2,1	219,-213	213,-228	-6, -15

The results of the statistical analysis are augmented with results from the production simulation analysis. Production simulations were performed with three types of renewable energy scenarios and cost-base bid model assumptions summarized in Table 3-11.

Table 3-11. Production simulation assumptions

Renewable Energy Scenarios	Cost-base Bid Assumptions
• No new renewables after 2006 • Only new biomass and geothermal after 2006 • New non-hydro renewables after 2006	• $5.70/mmBTU natural gas • $6.50/mmBTU distillate oil • $1.50/mmBTU coal

The statistical analysis provides the requirements for system maneuverability and flexibility for incorporating additional wind and solar generation, while the production modeling identifies the mix of resources available at a particular time to satisfy maneuverable and flexibility requirements. More specifically:

- One-hour delta-MW is an indication of schedule flexibility.
- Five-minute delta-MW measures changes in load following requirements and economic dispatch.
- One-minute delta-MW measures regulation requirements.

The increase in standard deviation (1-sigma, σ) of changes over time is a measure for determining the need for additional flexibility because of increased variability, and multiplying the standard deviation (sigma) by three captures 99.7 percent of all events, given a normal statistical population (3-sigma, 3σ).

Table 3-12 reproduces the results from Table 3-9 with 3-sigma deviation. Results show that variability in the 2010 Tehachapi scenario increases by 3 percent across all time frames as compared to 2006. One-hour impacts from wind and solar are 45 MW in 2006 and 144 MW in 2010; 5-minute impacts are 1 MW in 2006 and 21 MW for 2010; and 1-minute impacts are relatively modest for both the 2006 and 2010 scenarios, at 0.3 and 5 MW, respectively.

Table 3-12. Changes in flexibility requirements: Full year

	2006			2010		
	Load	Change due to Wind & Solar	Increased Requirement (3σ)	Load	Change due to Wind & Solar	Increased Requirement (3σ)
σ 1-Hour Δs (MW)	1436	15 (+1%)	45	1575	48 (+3%)	144
σ 5-Min Δs (MW on 15-Min RA)	189.3	0.3 (+0.2%)	1	207.6	6.9 (+3%)	21
σ 1-Min Δs (MW from 15-Min RA)	44.8	0.1 (+0.2%)	0.3	49.1	1.6 (+3%)	5

Table 3-13 reproduces Table 3-10 with 3-sigma deviation for variability results in all time frames for light load conditions (10th decile). The variability impacts are more noticeable for the light load period: 27 percent for the 1-hour period, 15 percent for the 5-minute period, and 3 percent for the 1-minute time frame. The hourly variability impacts with wind and solar is 90 MW for 2006 and 597 MW for 2010; 5-minute impacts are 8 MW for 2006 and 43 MW for 2010. As before, it is interesting to see that the 1-minute impacts are similar to the full year.

Table 3-13. Changes in flexibility requirements: Light load period (10th Decile)

	2006			2010		
	Load	Change due to Wind & Solar	Increased Requirement (3σ)	Load	Change due to Wind & Solar	Increased Requirement (3σ)
σ 1-Hour Δs (MW)	669	30 (+4%)	90	734	199 (+27%)	597
σ 5-Min Δs (MW on 15-Min RA)	86.5	2.7 (+3%)	8	94.9	14.2 (+15%)	43
σ 1-Min Δs (MW from 15-Min RA)	40.8	0.1 (+0.2%)	0.3	44.8	1.1 (+3%)	3

The addition of the new renewable resources changes how other generating resources are committed and dispatched. An example is provided of a light load case of February 16th at 2 a.m. to assess the potential unit commitment and dispatch impacts resulting from the 2010 Tehachapi scenario. Figure 3.15 illustrates the resource stack for the following three situations:

- No new renewables.
- New non-variable renewables (includes only geothermal and biomass).
- All new renewables (includes geothermal, biomass, wind, solar).

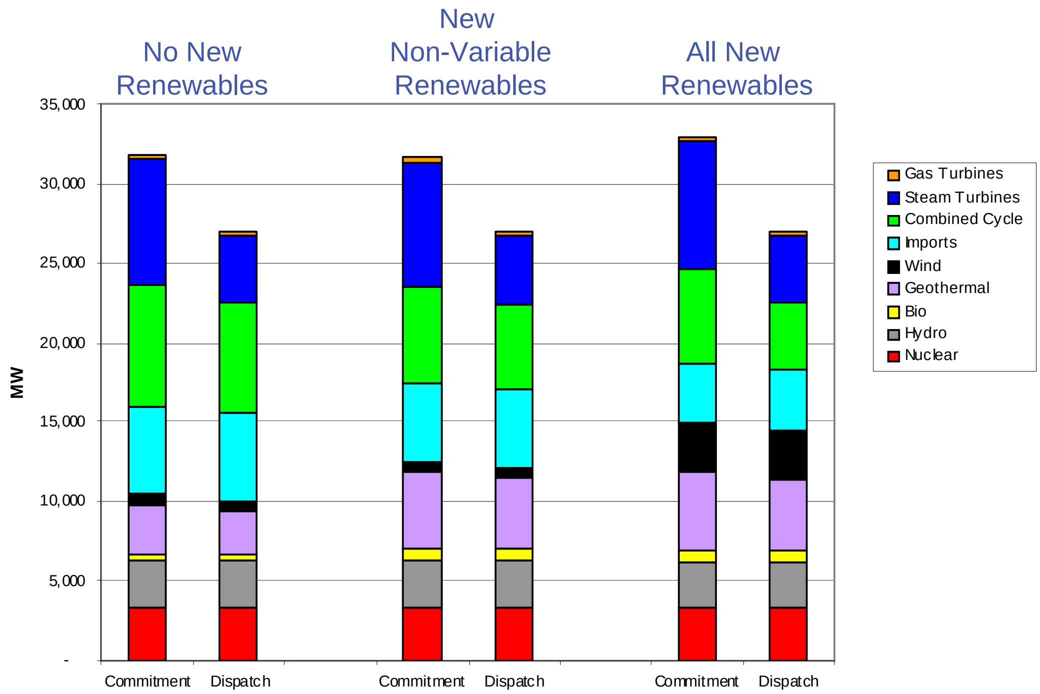

Figure 3-15. 2010 February 16, 2:00 am - light load commitment and dispatch example

Electricity demand at this time is 24,189 MW. Again, multiplying the standard deviation by three, the 1-hour change is increased by nearly 600 MW (from 2,202 MW to 2,799 MW) when new renewables are added. The 5-minute delta is increased from 285 MW to 327 MW, while the 1-minute delta remains relatively unchanged. Note that there is no available solar in the resource stack, given the 2 a.m. time.

Some observations at light load include:

- The stack of units that can participate in day-ahead scheduling is reduced by about 4,000 MW, from 21,927 MW to 17,961 MW, when all new renewables are included in the mix. Because imports are being reduced in the day-ahead time frame, one question is whether others are absorbing the impact of more intermittent energy resources in California.
- For hour-ahead scheduling, the stack of units that can participate is reduced by over 2,000 MW in the all-renewables scenario as compared to the no renewables scenario, from 16,418 MW to 14,175 MW.
- Somewhat surprisingly, the commitment and dispatch of intra-hour maneuverable units at light load is not changed much by the additional renewables, from 8,227 MW in the "no renewables" case to 8,236 MW in the "all new renewables" case.
- Similarly, the amount of regulating reserves remains unchanged when all new renewables are included in the mix as compared to the "no renewables" case (3,696 MW).

Table 3-14 summarizes these findings.

Table 3-14. Light load operability

	Statistics from 10th (Light Load) Decile Data				Estimated from Unit Commitment Stack 02:00 February 16, 2004			
	Mean Load (MW)	3σ 1-Hour Δs (MW)	3σ 5-Min Δs (MW on 15-Min RA)	3σ 1-Min Δs (MW from 15-Min RA)	MW Day-Ahead Units (Sum of rating of units participating in day-ahead unit commitment and scheduling)	MW Hour-Ahead Units (Sum of rating of units that can be rescheduled in hour-ahead time frame)	MW Intra-Hour Units (Sum of rating of units that can be rescheduled intra-hour (5-min economic dispatch and AGC)	MW Regulating Up Range (Sum of difference between rating and dispatch of units capable of intra-hour maneuvering)
No Renewables	24189	2202	285	135	21927	16418	8227	3696
New Non-Variable Renewables	24189	2202	285	135	19158	14175	8236	3684
All Renewables	24189	2799	327	138	17961	14175	8236	3696

Further analysis on the 2010 Tehachapi case has been conducted using Quasi Steady-State (QSS) simulation analysis. QSS involves studying select 3-hour periods on a minute-to-minute basis, where all loads and outputs of wind and solar plants vary. Economic dispatch will be done at 5-minute intervals, and various limits (such as ramp rate limits) will be imposed. The QSS analysis will quantify the estimated regulation and load following impacts and limitations, and will test various operating mitigation strategies for high levels of intermittent renewable energy generation. The need for further Transient Stability Analysis is still being determined. At this stage of the analysis, no intermittency related transient stability issues have been identified. If required, transient stability analysis would be used to examine various mitigation techniques through wind plant controls, other system controls and added resources. The stability analysis would also evaluate the frequency and AGC response to intermittent renewable energy generation on a 10-minute basis.

3.5 Status of 2010 Accelerated and 2020 33% Cases

Load flows and transmission analysis for the 2010 Accelerated and 2020 33% cases have been completed. Figure 3-16 shows the additional renewable resource mix by capacity modeled in the 2020 33% scenario.

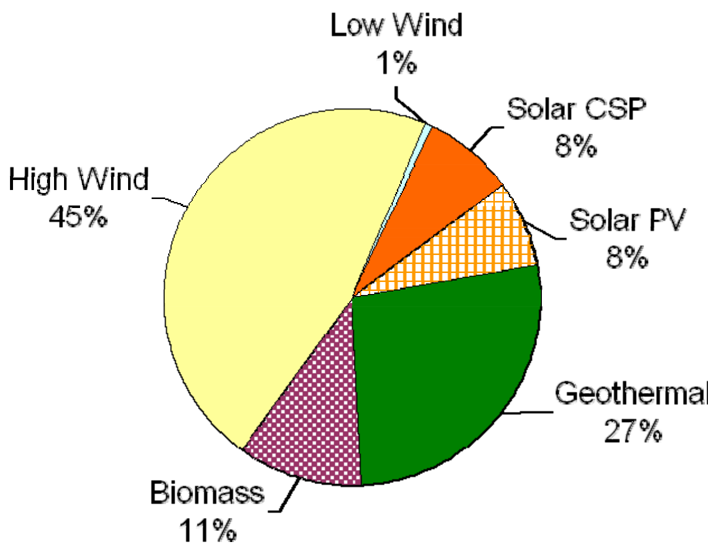

Figure 3-16. 2020 – 33% renewable portfolio mix and incremental capacity

The 2010 Accelerated case serves as an interim case to stress the transmission infrastructure and to build toward the 2020 case. It is purely a hypothetical case and is not designed to accelerate renewable energy targets or to advocate for 33% renewable energy by 2010. The 2010 Accelerated assumptions for load growth, unit retirements, transmission infrastructure as well as general operational environment (i.e., in-state, out-of-state, WECC) are consistent with the 2010 Tehachapi case (Figure 3-17); however, the goal in this case is to plan toward a 33% penetration. Utilities and transmission planners felt that this approach would provide a better perspective toward building a sustainable transmission infrastructure for 2020 by highlighting transmission hot spots, as well as performance concerns and limitations, with the infrastructure that is expected to be in place in 2010 (Figure 3-17).

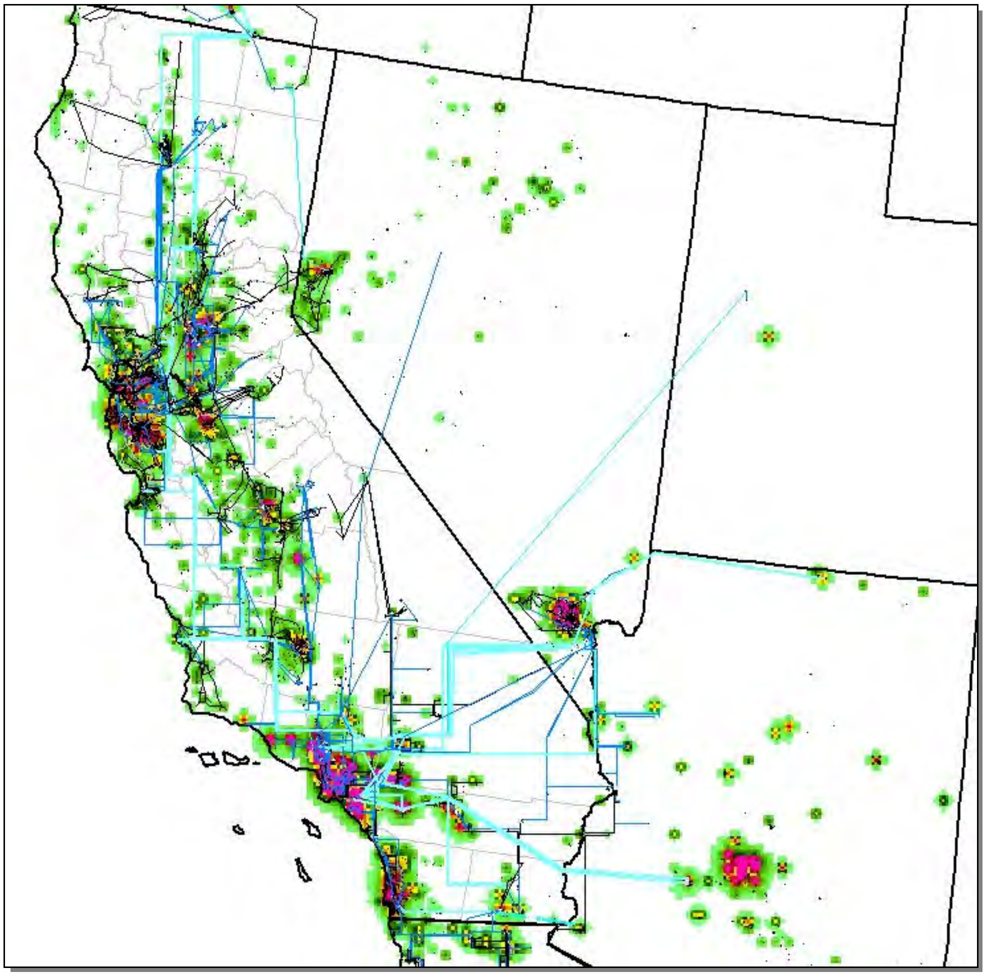

Figure 3-17. 2010 Tehachapi scenario load centers and transmission environment

Two approaches will be taken for the 2010 Accelerated case:

- Determine how much additional renewable energy over 20% can be accommodated without expanding the grid. Preliminary load modeling suggests a number of new "hot spots" and congestion areas as well as reductions on net imports can be seen as the 2010 Tehachapi infrastructure is loaded with additional renewables. From the load flow modeling, transmission planned for the 2010 Tehachapi case will likely be insufficient to reach the 33% level in the 2010 Accelerated case.
- Incrementally add new transmission consistent with 2020 plans to obtain 33% penetration as well as to see how the system responds using production cost modeling.

These cases are currently under evaluation.

The 2020 case will utilize the 33% renewable mix developed and will focus on transmission hot spots highlighted in the 2010 Accelerated case, as well as additional new transmission necessary to integrate planned resources to attain 33%. Statistical analysis work is currently underway for these remaining cases and will proceed similar to the 2010 Tehachapi case.

First, statistical analysis on the hourly load and wind and solar generation will be performed, followed by the production simulations, and then the QSS and transient stability analysis, as needed

A final report covering all four scenarios will be issued at the end of the project in spring of 2007. Results will also be presented at the second and final IAP workshop, tentatively scheduled for February of 2007.

4.0 Conclusions

To meet California's renewable energy targets, various working groups are coming together to assess renewable integration needs. The IAP project is one such group with the goal to assess the impact of increasing renewables on the future grid. Specifically, the IAP project focuses on transmission infrastructure and operations strategies necessary to accommodate 20% renewables in 2010 and 33% renewables by 2020. The efforts will help provide a vision of the "in-state future transmission grid" (infrastructure and operation services) and the mix of renewables and traditional generation resources.

Led by a team of industry experts, the IAP group has been teaming with utilities and the CaISO to develop renewable energy scenarios and to analyze the results produced by the state-of-the-art transmission planning models. Preliminary results were reported by the IAP team at a public workshop held on August 15th at the Energy Commission. These preliminary results focus on two of the scenarios, one highlighting the 2006 Base Case and the other on the 2010 Tehachapi – 20% renewable case. Assessments are currently underway for the 2010 Accelerated and 2020 cases and results will be presented in spring of 2007.

Current work has produced:

- A portfolio of renewable resources with transmission interconnection and operations to meet 20% renewable penetration targets by 2010 and 33% by 2020.
- Unified and consistent statewide transmission dataset for modeling efforts including utilities, WECC, and CaISO planning needs.
- Quantified system performance and impacts based on a "future grid" perspective which can be used to gauge system performance and cost considerations.
- Provides a transmission metric (AMWCO) for assessing the temporal and economic benefits of either a renewable or conventional generator on the grid.
- Helps identify technology, policy and market gaps that may be barriers to meeting RPS goals.

Observations based on preliminary findings thus far include:

- The increase in system variability appear small since changes in load and wind are rarely coincident or in the same direction.
- The summer period had more hours of change than the other seasons. This is primarily a weather related phenomenon due to higher ambient temperature changes in the summer which impacts both demand in summer and wind generation
- As higher wind and solar penetrations are reached, there will be a need for more operational flexibility in other generators to load follow and operate, differently. Current results show that this increased need for flexibility appears to be within the existing system capabilities.

- As higher wind and solar penetrations are reached, there will be a need for more operational flexibility in other generators to load follow and operate, differently. Current results show that this increased need for flexibility appears to be within the existing system capabilities.
- Continuing long-term planning and analysis of the statewide system is needed to determine the existence of and the magnitude of potential problems.

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Glossary

AGC	automated generator control
AMWCO	aggregate megawatt contingency overload
CAISO	California Independent System Operator
CPUC	California Public Utilities Commission
CSP	concentrated solar photovoltaic
CWEC	California Wind Energy Collaborative
DPC	Davis Power Consultants
DWR	Department of Water and Power
GE-MAPS	General Electric's Multi-Area Production Simulation
IAP	Intermittency Analysis Project
ICAP	installed capacity
IID	Imperial Irrigation District
LADWP	Los Angeles Department of Water and Power
LVRT	Low voltage ride through
mmBTU	million British Thermal Units
MW	megawatt
PG & E	Pacific Gas and Electric
PIER	Public Interest Energy Research
PSS	power system stabilizer
PV	photovoltaic
QSS	quasi-steady-state
RA	rolling average
RD&D	research, development and demonstration
RPS	Renewable Portfolio Standard
RTBR	Renewable Transmission Benefit Ratio

SCE	Southern California Edison
SDG&E	San Diego Gas and Electric
Sigma	standard deviation
SMUD	Sacramento Municipal Utility District
SP 15	south of Path 15
SVA	Strategic Value Analysis
UCAP	uniform capacity
VAR	voltage-ampere reactive
V-Reg	voltage regulation
WECC	Western Electricity Coordinating Council

Appendix A

2010 Tehachapi Case Resource Mix

Location	Technology	MW	C. F. %	Energy (MWh)
Salton Sea	Geothermal	800	90.0%	6,307,200
Mount Signal	Geothermal	19	90.0%	149,796
Heber	Geothermal	42	90.0%	331,128
Brawley North	Geothermal	135	90.0%	1,064,340
Sulfur Bank	Geothermal	43	90.0%	339,012
Medicine Lake Telephone Flat	Geothermal	175	90.0%	1,379,700
Urban, Agr, Veg	Biomass	228	90.0%	1,797,552
Tehachapi	High Wind	3,000	37.0%	9,723,600
Riverside	High Wind	1,370	37.0%	4,440,444
SDGE	High Wind	150	37.0%	486,180
Solano	High Wind	275	37.0%	891,330
Altamont	High Wind	132	37.0%	427,838
LADWP Wind	High Wind	120	37.0%	388,944
All	Res Solar	50	20.0%	876,000
Other CSP	CSP	250	27.0%	591,300
SCE CSP	CSP	300	27.0%	709,560
SDG&E CSP	CSP	500	27.0%	1,182,600
Total New Resources 2010		**7,589**		**31,086,524**

Appendix B

2006 Hourly Statistics

(Preliminary, May Change for Final Report)

Each Bin (Load)	1	2	3	4	5	6	7	8	9	10	All year
P_Load (Max)	48113.5	36776.3	33502.6	31858.7	30654.6	29429.7	27776.0	26093.2	24615.4	23073.6	48113.5
P_Load (Min)	36778.9	33504.8	31859.9	30655.7	29429.8	27776.7	26093.2	24616.4	23073.8	19443.1	19443.1
Sigma (Delta L)	1253.5	1555.3	1470.9	1363.1	1555.2	1816.4	1663.3	1435.9	1075.3	668.9	1436.3
Delta L (Max)	4529.3	4854.2	4775.9	4374.8	6123.0	6070.9	3823.8	3245.1	2862.1	1706.5	6123.0
Delta L (Min)	-4334.4	-4445.8	-4382.4	-4371.6	-5122.3	-4017.0	-3535.5	-3199.9	-2868.1	-2567.1	-5122.3
Delta L (Avg)	225.2	317.3	209.3	129.9	116.6	-19.4	-178.1	-261.5	-309.3	-228.6	0.2
Load (Avg.)	40162.9	34994.6	32598.0	31240.2	30062.7	28656.8	26910.6	25352.7	23839.9	22058.5	29587.2
Load F-A (Avg)	156.9	313.4	140.8	178.4	147.4	93.5	35.6	-1.9	-24.1	59.2	109.9
Load F-A (Sigma)	1317.8	1023.1	745.7	704.3	639.7	672.0	622.7	557.9	589.4	520.2	781.1
Load F-A (Max)	5824.7	6533.2	4761.5	4813.4	3790.9	3585.2	4172.8	2531.2	3840.6	2208.4	6533.2
Load F-A (Min)	-6281.2	-3896.0	-3063.2	-3400.1	-3422.8	-3588.7	-2759.4	-2777.6	-1940.3	-1674.5	-6281.2

Each Bin (L-W-S)	1	2	3	4	5	6	7	8	9	10	All year
P_L-W-S (Max)	47736.2	35985.0	32800.0	31197.2	29993.8	28722.4	27068.3	25376.5	23849.1	22406.8	47736.2
P_L-W-S (Min)	35988.1	32800.7	31197.3	29994.3	28722.4	27068.7	25376.6	23850.7	22407.2	18567.2	18567.2
Sigma (Delta L-W-S)	1294.4	1546.6	1456.4	1398.8	1587.0	1828.5	1699.9	1446.4	1048.9	698.9	1451.0
Delta L-W-S (Max)	4924.3	4728.7	4857.2	4580.7	6090.8	5981.0	3946.6	3240.9	2914.2	2447.8	6090.8
Delta L-W-S (Min)	-4294.7	-4533.4	-4450.4	-4592.1	-5155.4	-4173.7	-3956.1	-3451.9	-2814.0	-2613.0	-5155.4
Delta L-W-S (Avg)	241.6	320.0	183.1	149.5	128.5	-52.7	-146.0	-265.4	-307.1	-250.3	0.1
Load_L-W-S (Avg.)	39397.6	34243.5	31937.5	30590.7	29386.4	27927.0	26188.3	24619.5	23135.7	21373.8	28879.5
Wind (Avg.)	492.0	571.3	520.8	549.3	611.3	692.6	662.6	704.5	698.6	745.7	624.9
Solar (Avg.)	252.9	156.4	104.8	88.2	77.1	61.1	44.2	24.5	5.6	13.3	82.8
Wind Penetration	0.012	0.017	0.016	0.018	0.021	0.025	0.025	0.029	0.030	0.035	0.022
Solar Penetration	0.006	0.005	0.003	0.003	0.003	0.002	0.002	0.001	0.000	0.001	0.003
L-W-S F-A (Avg)	231.5	447.6	247.0	300.8	275.9	261.4	201.6	184.5	141.6	269.0	256.1
L-W-S F-A (Sigma)	1339.4	1059.7	803.2	749.1	713.8	738.8	684.4	660.6	635.9	570.5	829.0
L-W-S F-A (Max)	6402.1	6554.7	4462.6	4518.7	3958.8	3396.6	4686.7	4973.7	3978.8	2321.2	6554.7
L-W-S F-A (Min)	-6442.8	-3954.0	-3035.8	-3205.0	-3343.1	-3555.5	-2667.8	-1773.2	-1742.9	-1700.6	-6442.8
Wind F-A (Avg)	-78.7	-127.9	-111.5	-125.8	-133.9	-169.9	-159.1	-176.8	-171.1	-202.7	-145.7
Wind F-A (Sigma)	196.5	227.3	229.6	240.0	246.1	254.3	260.0	261.4	273.4	284.7	250.9
Wind F-A (Max)	536.5	629.8	645.6	706.9	617.9	697.9	719.9	701.2	611.9	712.5	719.9
Wind F-A (Min)	-1104.4	-1134.2	-992.4	-1083.1	-1058.8	-1078.5	-1072.7	-1079.3	-1135.5	-1136.6	-1136.6
Solar F-A (Avg)	-14.1	-4.1	-1.1	2.6	5.5	4.6	4.1	0.8	0.4	-3.0	-0.4
Solar F-A (Sigma)	60.0	60.5	52.9	55.0	53.9	51.4	48.6	39.2	25.0	37.5	49.8
Solar F-A (Max)	305.8	285.6	205.1	237.1	278.2	225.2	210.1	222.9	174.9	130.9	305.8
Solar F-A (Min)	-174.8	-245.8	-240.7	-658.7	-717.0	-724.4	-656.1	-670.8	-342.7	-547.9	-724.4

2010 Hourly Statistics

(Preliminary, May Change for Final Report)

Each Bin (Load)	1	2	3	4	5	6	7	8	9	10	All year
P_Load (Max)	52760.8	40328.5	36738.4	34935.8	33615.6	32272.3	30458.9	28613.4	26993.0	25302.3	52760.8
P_Load (Min)	40331.2	36740.9	34937.1	33616.6	32272.3	30459.6	28613.4	26993.9	25302.4	21321.1	21321.1
Sigma (Delta L)	1374.6	1705.5	1613.0	1494.8	1704.9	1992.3	1823.9	1574.6	1179.2	733.5	1575.0
Delta L (Max)	4966.8	5323.1	5237.1	4797.4	6714.4	6657.3	4193.1	3558.5	3138.5	1871.3	6714.4
Delta L (Min)	-4753.0	-4875.2	-4805.7	-4793.9	-5617.1	-4405.0	-3877.0	-3509.0	-3145.1	-2815.1	-5617.1
Delta L (Avg)	247.0	347.9	229.5	142.4	128.6	-22.1	-195.3	-286.8	-339.2	-250.7	0.2
Load (Avg.)	44042.1	38374.6	35746.6	34257.5	32966.4	31424.7	29509.8	27801.4	26142.5	24189.0	32445.0
Load F-A (Avg)	172.1	343.6	154.4	195.7	161.7	102.4	39.1	-2.1	-26.4	65.0	120.5
Load F-A (Sigma)	1445.0	1122.0	817.8	772.3	701.4	736.9	682.9	611.8	646.4	570.4	856.5
Load F-A (Max)	6387.3	7164.2	5221.4	5278.4	4157.0	3931.5	4575.8	2775.7	4211.5	2421.7	7164.2
Load F-A (Min)	-6887.9	-4272.2	-3359.1	-3728.5	-3753.4	-3935.3	-3025.9	-3045.9	-2127.7	-1836.3	-6887.9

Each Bin (L-W-S)	1	2	3	4	5	6	7	8	9	10	All year
P_L-W-S (Max)	51417.7	37347.8	33908.9	31990.6	30431.6	28853.9	27211.3	25537.2	23952.7	22222.4	51417.7
P_L-W-S (Min)	37348.6	33909.4	31990.9	30431.7	28855.9	27211.3	25538.3	23953.0	22223.8	16587.4	16587.4
Sigma (Delta L-W-S)	1541.0	1785.9	1670.4	1694.3	1818.4	1870.2	1747.0	1540.1	1210.6	933.2	1623.4
Delta L-W-S (Max)	6233.8	5882.7	5725.1	6108.1	5143.5	6312.2	4852.2	4283.2	3464.3	2939.2	6312.2
Delta L-W-S (Min)	-4752.1	-5236.0	-4857.8	-5283.3	-5713.2	-4507.2	-4303.1	-4100.1	-3728.4	-3427.4	-5713.2
Delta L-W-S (Avg)	298.3	334.9	243.4	148.0	68.3	-53.3	-150.9	-302.9	-286.2	-298.3	0.2
Load_L-W-S (Avg.)	41209.7	35433.6	32889.1	31210.1	29655.0	28032.8	26377.7	24741.0	23102.4	20758.5	29340.5
Wind (Avg.)	1707.2	2017.7	2060.4	2388.2	2810.7	3045.3	2800.3	2806.1	3120.0	4039.8	2679.7
Solar (Avg.)	926.8	638.1	560.0	548.6	488.9	423.8	319.4	182.4	110.8	49.6	424.8
Wind Penetration	0.041	0.057	0.063	0.077	0.095	0.109	0.106	0.113	0.135	0.195	0.091
Solar Penetration	0.022	0.018	0.017	0.018	0.016	0.015	0.012	0.007	0.005	0.002	0.014
L-W-S F-A (Avg)	243.6	590.7	547.6	595.5	763.2	843.7	708.2	640.8	796.0	1346.8	707.7
L-W-S F-A (Sigma)	1542.9	1353.9	1263.6	1235.9	1292.5	1349.7	1297.5	1261.5	1238.2	1174.5	1331.2
L-W-S F-A (Max)	7168.0	7090.3	6798.7	7184.6	6731.6	7132.1	6606.0	7091.2	7602.1	5068.0	7602.1
L-W-S F-A (Min)	-7644.8	-3940.9	-3740.9	-3620.8	-4528.4	-3921.1	-4194.6	-3672.4	-3688.1	-4065.1	-7644.8
Wind F-A (Avg)	-132.4	-271.9	-343.0	-427.0	-613.7	-759.5	-652.4	-622.6	-761.2	-1287.0	-587.1
Wind F-A (Sigma)	637.8	747.5	808.9	890.4	994.7	1044.5	1018.7	1023.8	1030.0	1078.6	987.3
Wind F-A (Max)	2571.4	2966.2	3131.6	2976.7	3330.1	3447.9	3578.6	2654.7	3613.7	3860.6	3860.6
Wind F-A (Min)	-2935.4	-3467.4	-3581.5	-4297.2	-4195.8	-4390.3	-4638.9	-4675.0	-4114.4	-4249.5	-4675.0
Solar F-A (Avg)	-6.6	-10.4	-3.7	-5.9	18.3	9.8	0.9	1.7	0.4	-4.4	0.0
Solar F-A (Sigma)	170.8	146.7	176.0	175.6	186.0	171.2	152.0	109.9	90.6	61.3	149.7
Solar F-A (Max)	897.9	766.8	843.7	865.2	863.2	790.1	1000.0	925.2	851.4	638.1	1000.0
Solar F-A (Min)	-341.8	-394.4	-501.3	-484.7	-467.4	-446.3	-458.1	-427.2	-478.5	-483.1	-501.3