ASSESSMENT OF RELIABILITY AND OPERATIONAL ISSUES FOR INTEGRATION OF RENEWABLE GENERATION

In Support of the
California Energy Commission
2005 Integrated Energy Policy Report

Final Consultant Report

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FOREWORD

The project team greatly appreciates all the public comments filed or shared with the Energy Commission during the May 10 and February 3, 2005 workshops.

The project team would also like to thank and acknowledge the following individuals (in alphabetical order) for their participation at these workshops as either a presenter or panelist: Ellen Allman (Caithness Energy), James Caldwell (PPM Energy), Jorge Chacon (Southern California Edison), Dave Hawkins (California Independent System Operator), Joseph Kloberdanz (San Diego Gas and Electric), Sarah Majok (Sacramento Municipal Utilities District), Yuri Makarov (California Independent System Operator), Jeff Miller (California Independent System Operator), Mauri Miller (California Wind Energy Association), Nicholas Miller (GE Energy), Steve Munson (Vulcan Power), Cliff Murley (Sacramento Municipal Utilities District), Nancy Rader (California Wind Energy Association), Harold Romanowitz (Oak Creek Energy), Jan Strack (San Diego Gas and Electric), Chifong Thomas (Pacific Gas & Electric), Jane Turnbull (League of Women Voters), and Bob Zavadil (Utility Wind Interest Group).

Internet web links to transcripts and presentation materials from these workshops are found in Appendix B of this report.

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EXECUTIVE SUMMARY

California has led the nation in the development of renewable resources. The California Renewables Portfolio Standard was passed by the California legislature in September 2002, mandating that energy production from renewable resources account for 20 percent of annual energy production by 2017.[1] In May 2003, the California Energy Commission, California Public Utilities Commission, and the California Power and Conservation Financing Authority called for the acceleration of that timetable by setting the goal of 20 percent by 2010 with adoption of the Energy Action Plan.

Renewable resources offer the benefits of price stability, resource diversity, reduced dependence on fossil fuels, and reduction in environmental impacts. These benefits are important for California consumers. Prudent facilitation of a substantial increase in renewables requires proactive identification, analysis, and development of options to address potential operational and resource integration issues that might otherwise hinder and delay achievement of statewide policy goals for renewable development.

Project Findings

This study is based on a review of experiences and best practices of other regions that have integrated large amounts of renewables, input from grid operators and stakeholders in California, and analysis of the impact of renewables integration on key operating metrics. The study identified nine specific operational and reliability issues that must be addressed to ensure successful integration of an expanded renewables portfolio. These issues are:

1. Load Following
2. Minimum Loads
3. Reserves and Ramping
4. Load and Generation Forecast Variability
5. Storage
6. Frequency and Voltage Requirements
7. Resource Deliverability
8. Transmission Import Capability
9. Planning and Modeling

The first four issues were supported by quantitative analysis; the last five issues were evaluated qualitatively. For the quantitative analysis, recorded hourly system load data, together with recorded production data from California's existing renewables portfolio, were used to develop a baseline load profile representing 2004 operations. Forecasts were developed for 2010 loads and renewables production based on California Energy Commission forecasts for both electrical demand and renewables energy production, by resource type, to meet the accelerated Renewable Portfolio Standard goal of 20 percent renewables by 2010. These hourly load profiles were used to evaluate the impacts of the accelerated renewables development on the first four issues identified above. The analysis methodology computed the net remaining load to be served by non-renewable resources by subtracting forecast hourly renewable production from forecast hourly loads. Parametric sensitivity studies which varied the mix of renewable resources in 2010, and the estimated wind energy profiles, were also performed on the first four issues.

The study results indicate that expanding the contribution of renewable resources to meet the 2010 Renewable Portfolio Standard goal will create the following operating characteristics, compared with 2004:

1. Load Following: The average daily load swing (from minimum to peak load) will increase by nearly 1,000 MW, with load growth accounting for 600 MW and growth in renewable generation accounting for the remaining 400 MW.

2. Minimum Loads: The average residual minimum load (after inclusion of renewable generation) in 2010 will be 1,100 MW lower than in 2004, while the lowest forecast residual minimum will be nearly 3,000 MW lower than in 2004.

3. Reserves and Ramping: Load ramping requirements for 2010 will generally be greater than in 2004, with the maximum upward ramping requirements increasing by 300 MW for a single hour ramp, 600 MW for three hour ramps, and 1,300 MW for the largest six hour ramp. Moreover, the number of larger ramps will increase in 2010, with ramps exceeding 12 gigawatts (over a six hour period), occurring 270 times in 2010 compared with 170 times in 2004, and ramps exceeding 16 GW occurring 28 times in 2010 compared with one time in 2004.

4. Load and Generation Forecast Variability: The variability of renewable energy production is higher in 2010 than in 2004. The 2010 daily change in total renewable production ranges from a minimum of minus 4.5 GW to a maximum of 3.5 GW with a standard deviation of 1.4 GW.

The remaining five issues were addressed qualitatively in the study based on stakeholder input. Observations and key findings are summarized below:

5. Storage: This is one option, among others, for addressing minimum load conditions. Statewide coordination of pumped storage strategies is likely to improve operational integration of increased renewables.

6. Frequency and Voltage Requirements: Generation attributes relating to frequency, as well as the minimum levels of performance required for grid reliability, have not been assessed. Existing frequency response standards do not adequately address these issues. Standards for Low Voltage Ride-Through are being developed by the Western Electricity Coordinating Council.

The Low Voltage Ride-Through standard and machine characteristics need to be taken into account by utilities in transmission planning.

7. Resource Deliverability: A comprehensive, statewide evaluation of deliverability is lacking. There is inadequate information on the extent to which the grid design is adequate for deliverability during non-peak time periods. Utility-specific studies considering deliverability over a range of operating conditions are also lacking. Utilities need to review transmission plans to assure resource deliverability over a variety of load and generation patterns to loads within and outside of utility service area.

8. Transmission Import Capability: There is no comprehensive region-wide peak and non-peak evaluation of the grid's performance and potential impacts on transfer capability, as a result of a changing resource mix. Such an evaluation would help California utilities and others in the Western Electricity Coordinating Council to better understand what, if anything, they need to do to maintain existing transmission path ratings.

9. Planning and Modeling: Western Electricity Coordinating Council modeling tools, operational and planning procedures and development of non-traditional base cases need review. Executive leadership within the Western Electricity Coordinating Council is required to accelerate progress in addressing these issues. Data from wind developers is needed to support these studies. More monitoring is required to obtain needed meteorological data.

Proposed Solutions Set and Policy Options for Mitigating Reliability and Operational Issues for Integration of Renewable Resources

Based on the study's analysis, ten specific solution sets and policy options were developed to mitigate the nine operational and reliability issues. These solutions are presented below:

Issue Solution Option & Action Required		Load Following	Minimum Loads	Reserves and Ramping	Load and Generation Forecast Variability	Storage	Frequency and Voltage Requirements	Resource Deliverability	Transmission Import Capability	Planning and Modeling
A	Establish requirements for controllable generation	X	X	X		X				
B	Enable load to participate in real time dispatch	X	X		X	X				
C	Renegotiate existing contracts for additional dispatchability and minimum load turndown (i.e. Department of Water Resources and Qualifying Facilities)	X	X			X				
D	Modify California Independent System Operator Automatic Generator Control algorithm to make effective use of controllable hydro generation and	X	X	X	X	X		X		

Issue Solution Option & Action Required		Load Following	Minimum Loads	Reserves and Ramping	Load and Generation Forecast Variability	Storage	Frequency and Voltage Requirements	Resource Deliverability	Transmission Import Capability	Planning and Modeling
	controllable loads									
E	Modify Western Electricity Coordinating Council and California Independent System Operator interchange scheduling protocols, policies and procedures to enhance the use of renewable resources	X		X	X					
F	Ensure adequate generator performance standards are in place with clarity of implementation to ensure system performance						X			X

	Issue Solution Option & Action Required	Load Following	Minimum Loads	Reserves and Ramping	Load and Generation Forecast Variability	Storage	Frequency and Voltage Requirements	Resource Deliverability	Transmission Import Capability	Planning and Modeling
G	Actively manage generation output which exceeds planned levels, or when total generation exceeds load (e.g., during minimum loads)	X	X	X	X					
H	Improve transmission studies							X	X	X
I	Improve modeling of renewable generation							X	X	X
J	Improve production forecasting	X	X		X					

Recommended Next Steps

The study team researched solution options to address the operational issues to integrate renewables without adverse impact on reliability or operations. These solution options provide the California Energy Commission with a list of action items that are recommended for follow up activities. The following tables groups the action items into four categories – Coordination, Studies, Research, and Monitoring. For each grouping specific Action Items/Deliverables are enumerated along with suggested organization to lead the activity and coordinate as noted.

Coordination

Lead	Coordinating Parties	Action Item/Deliverable
Consortium for Electric Reliability Technology Solutions Study Team	Meet with California Energy Commission work groups and California Independent System Operator's new renewables work group	Share and discuss results of this study
California Independent System Operator	Coordination with Control Area Utilities	Automated generation control modifications required to achieve greater participation of hydro resources on automated generation control
California Independent System Operator	Coordination with Western Electricity Coordinating Council and Market Participants	Energy scheduling protocol changes that could facilitate integration of renewables.
California Energy Commission	Coordination with the state's utilities and California Independent System Operator	A strategy to maximize the use of existing pumped storage facilities.
California Independent System Operator	Work with the Western Electricity Coordinating Council Member systems	Expand the availability of off-peak and shoulder peak cases and study of intermittent resource impacts.
California Wind Energy Association	Coordinate with control area operators and transmission owners	Assure all necessary data and information required for studies is available.

Studies

Lead	Role of Coordinating Parties	Action Item/Deliverable
California Energy Commission	Work with the state's control area operators and utilities	Identification of impacts of Department of Water Resources contract drop-off, Qualified Facilities drop-off, Mohave plant shut down and other known resources changes on the identified operational issues.
California Independent System Operator	Work with the Western Electricity Coordinating Council Member systems	Determination of need for a frequency response standard.
Southern California Edison	Tehachapi Study Group	Detailed ongoing wind Integration Study for Tehachapi development

Research

Lead	Coordinating Parties	Action Item/Deliverable
California Independent System Operator	Research Initiative	▪ Attribute Requirements - Define current and future control area attribute requirements. ▪ Minimum Load - Develop a forecast of future minimum load problems (number of events annually and depth of problem)
California Energy Commission/California Independent System Operator	Utility and Industry Stakeholders	Research and test alternative pricing schemes for operating attributes and integrate with market design.
California Independent System Operator	Research Initiative	Load as a Provider of Resource Attributes – Determine: ▪ The resource attributes that could be provided by dispatchable load, ▪ Pricing of those key attributes, ▪ Infrastructure requirements to integrate load as a controllable device, and ▪ Automatic load control requirements
California Energy Commission	Research or Deployment Initiative	Improve Production Forecasting – Initiate a research, evaluation, and deployment initiative to: ▪ Investigate best practices and tools for wind energy forecasting, and ▪ Identify Wind monitoring requirements and deploy needed monitoring equipment
California Energy Commission	Research Initiative	Increase Interregional Transfer Capability – Investigate new tools/solutions to increase interregional transfer capability.

Monitoring

Lead	Coordinating Parties	Action Item/Deliverable
California Energy Commission	Performance Monitoring	Establish the necessary processes to monitor and track the metrics identified in Solutions A-J

Progress on these actions items needs to be tracked and reported to the California Energy Commission on an ongoing basis to make necessary course corrections in subsequent *Integrated Energy Policy Reports*.

PROJECT BACKGROUND AND PURPOSE

California has led the nation in the development of its renewable resources. The California Renewables Portfolio Standard (RPS) was passed by the California legislature in September 2002 mandating energy production from renewable resources to account for 20 percent of the annual energy production by 2017. In May 2003, the California Energy Commission (Energy Commission), California Public Utilities Commission (CPUC), and California Power and Conservation Financing Authority (California Power Authority) called for the acceleration of renewable integration setting the goal of 20 percent by 2010 with the adoption of the Energy Action Plan.

Renewable resources offer the benefits of price stability, resource diversity, reduced dependence on fossil fuels, and reduction in environmental impacts. These benefits are important for California consumers. Substantial increase in renewables requires proactive identification, analysis, and development of options to address potential operational and resource integration issues that might otherwise hinder and delay achievement of statewide policy goals for renewables development. Integration issues may result from the intermittent nature of certain renewable resources and require assessment and development of strategies to address operational and reliability integration issues. They may also result from the location of the resource, as renewables are frequently located remote from customer loads and require the development of new transmission and interconnections to deliver the output of renewable resources to consumers. The focus of this study is to address operational and reliability issues for integration of renewables.

There are many strategic policy issues related to reliability and operations for integration of renewables in California. Historically, these issues have been addressed individually and often litigiously. As the type and level of renewables in the energy mix increases, the number of reliability and operational issues are expected to increase. To meet the objectives of the RPS and accelerate development of renewables, California needs a comprehensive and stable predictable policy framework for operational integration of new renewables.

The objectives of this study are to:

1. Review and assess papers and studies related with integration of renewable resources.

2. Catalog experiences associated with renewables integration in California and other selected regions and determine best practices and lessons learned which will foster renewables integration in California.

3. Catalog California-specific operational integration and reliability issues through dialogue with key utilities, stakeholders, and independent system operators.

4. Conduct stakeholder workshops to seek input and validate findings.

5. Summarize and quantify operational issues, where possible.

6. Evaluate alternatives to address reliability and operational integration issues, including resource management, operating procedures, and regulatory policies. Assess pros and cons for alternative policy options.

7. Prepare a final report to support the Energy Commission's *2005 Integrated Energy Policy Report* (IEPR).

METHODOLOGY AND PROJECT APPROACH

The initial review of relevant studies and papers provided a catalog of experiences and issues from California and internationally. The most relevant studies and papers that were reviewed for this study are listed in the Appendix.

Interviews were held with key stakeholders to validate the catalog of operating and reliability issues. A summary of the stakeholder feedback is included in the January 17, 2005 Consultant Paper *Assessment of Reliability and Operational Issues for Integration of Renewable Generation – Background Material for California Energy Commission Stakeholder Workshop.*[2]

A stakeholder workshop was held on February 3, 2005 to review the initial stakeholder issues list to determine if there were issues that should be added or removed. The initial list included the following 12 items:

1. Load Following
2. Minimum Loads
3. Reserves and Ramping
4. Load and Generation Forecast Variability
5. Storage
6. Frequency and Voltage Requirements
7. Resource Deliverability
8. Transmission Import Capability
9. Planning and Modeling
10. Compliance with NERC Standards
11. Voltage Support
12. Retirement of Older Plants

Based on feedback received at the workshop, and in subsequent written comments from the stakeholders, the last three items were dropped from the issues list because these issues were either technical in nature, were being addressed through standards and guidelines, or were uncertain as to their magnitude and timing.

Summary descriptions of the remaining nine issues addressed in this study are outlined below.

Summary Description of Issues

1. Load Following (LF)
   - Current LF demand is significant
   - The LF demand is increasing
   - Supply is eroding due to new generator attributes and aging plant retirements

2. Minimum Loads
   - High levels of off-peak energy result in operating problems for the control area operator (CAO), Transmission System Owner (TSO), and load-serving entity (LSE).
   - Exports of excess generation may not always be an option.
   - Managing minimum loads requires off-peak energy production curtailments.

3. Reserves and Ramping
   - Intermittent resources production is generally less than nameplate capacity and is highly variable.
   - Some intermittent resource types do not provide the same operating attributes as conventional generation resources for meeting reliability standards.

4. Load and Generation Forecast Variability
   - Forecast accuracy affects reserve requirements.
   - Online reserves may be either too high or too low depending on load and generation production forecast variability.

5. Storage
   - Storage is not available during spring run-off months to mitigate minimum load condition.
   - Additional storage and load control could facilitate integration of intermittent resources.

6. Frequency and Voltage Requirements
   - Voltage ride-through standards for generation have been adopted by the Western Electricity Coordinating Council (WECC).

7. Resource Deliverability
   - Interconnections standards do not address deliverability capability to move power to different regions.
   - Full benefit and integration of renewable resources may not be achieved without addressing deliverability.

8. Transmission Import Capability
   - Reduced inertia and variability in generating performance could negatively impact existing transmission path ratings into California and throughout the WECC.

9. Planning and Modeling
   - Detailed generator modeling data is needed to support studies
   - Off-peak system conditions need to be studied to analyze transmission system loadings and vulnerabilities.

ANALYSIS OF RELIABILITY AND OPERATIONAL ISSUES

The project team obtained 2004 recorded data for both hourly system load and hourly renewable energy production by resource type from the California Independent System Operator (CA ISO) for use in analyzing the first four issues:

1. Load Following
2. Minimum Loads
3. Reserves & Ramping
4. Load and Generation Forecast Variability

Issues 5 through 9 involve data, technical evaluations and modeling that is specific to utilities and control areas, and detailed analysis needs to be performed by utilities and control area operators. However, the project team does make observations on what needs to be done and by whom as a follow up to this study.

Analytical Methodology

In order to estimate the impact of an expanding portfolio of renewable generation on the reliability and operational control characteristics of the California electric grid, two sets of residual hourly load curves were developed for comparison and analysis. This analysis is based on CA ISO data only because of the complexity that would have been involved in gathering and synchronizing hourly data from the several control areas that operate within California. The CA ISO's control area represents approximately 75 percent of the total California grid and is representative of issues facing California. For the 2004 base year an hourly, chronological residual load profile was developed by subtracting the hourly total recorded renewable energy production from the corresponding hourly system load. The resulting residual hourly load was then considered to be the load that is to be served by non-renewable generation. Implicit in this analysis is an assumption that all renewable energy production would be dispatched first, ahead of all non-renewable energy production. While this is not a feature of the Renewable Portfolio Standard (RPS) process, it is a reasonable construct in order to investigate the full impact of renewable production.

An hourly, chronological residual load profile was similarly developed from a forecast of the 2010 load and forecasts of the hourly production from each of the five major renewable energy sources, each scaled up to their estimated production levels based on the Energy Commission's *Renewable Resources Development Report*.[3] Using these two hourly chronological residual load profiles, analyses were performed to assess the impact on key metrics that describe operations and reliability of the grid. The results of those assessments are presented below. A more detailed description of the development of these residual load profiles is included in Appendix A.

Analytical Results

A summary of the analysis results for the first four issues follows below. The analysis is organized by defining the issue, outlining the focus and methodology for analysis, presenting the results, and providing findings.

Load Following

Issue

The CAO is responsible for ensuring that the control area is operated within WECC and North American Electricity Reliability Council (NERC) standards. This includes meeting minute-to-minute changes in both load and generation on the grid to constantly balance load and generation. There are three time periods of interest in addressing load following:

1. Frequency and tie-line regulation (automated generation control, or AGC) is addressed by controlling generation in the time period ranging from seconds to ten minutes;

2. Load following (so-called five or ten minute dispatch) addresses the load and generation changes which occur in the time period ranging from minutes to several hours; and,

3. Unit commitment and day-ahead scheduling address the changes in load and generation anticipated in the daily planning processes, typically from several hours to 24 hours in advance.

Focus

Previous studies (by the Energy Commission and others)[4] have indicated that for the time period of frequency and tie-line regulation, the addition of renewable and intermittent generation have only a very small impact. Isolating the impact of renewable and generation variations from the variations in load (which are always occurring), indicate that the variations in generation are slower to occur, and frequently self-cancel due to the numerical diversity of resources. For instance, second-to-second variation in the power output of an individual wind generator occurs for a variety of reasons. However, when many wind generators are connected to the grid, the individual short term variations are generally uncorrelated, and tend to cancel each other out, resulting in only a small impact on overall grid regulation needs.

For the longer time period variations, such as several hours or the diurnal patterns, the energy output of similar types of intermittent generation are correlated and can impact the control requirements on the system operator. For instance, solar generation exhibits a daily generation swing cycle, with low or no power (except for the case of supplemental firing) during the night-time hours, and near-full power during the daylight hours. This daily swing of power output, while predictable, must be managed in the context of the grid's requirement to balance generation changes minute–to-minute with the load changes. For wind generation, the variation in output is less correlated with the load, and varies with wind patterns and location of generating sites.

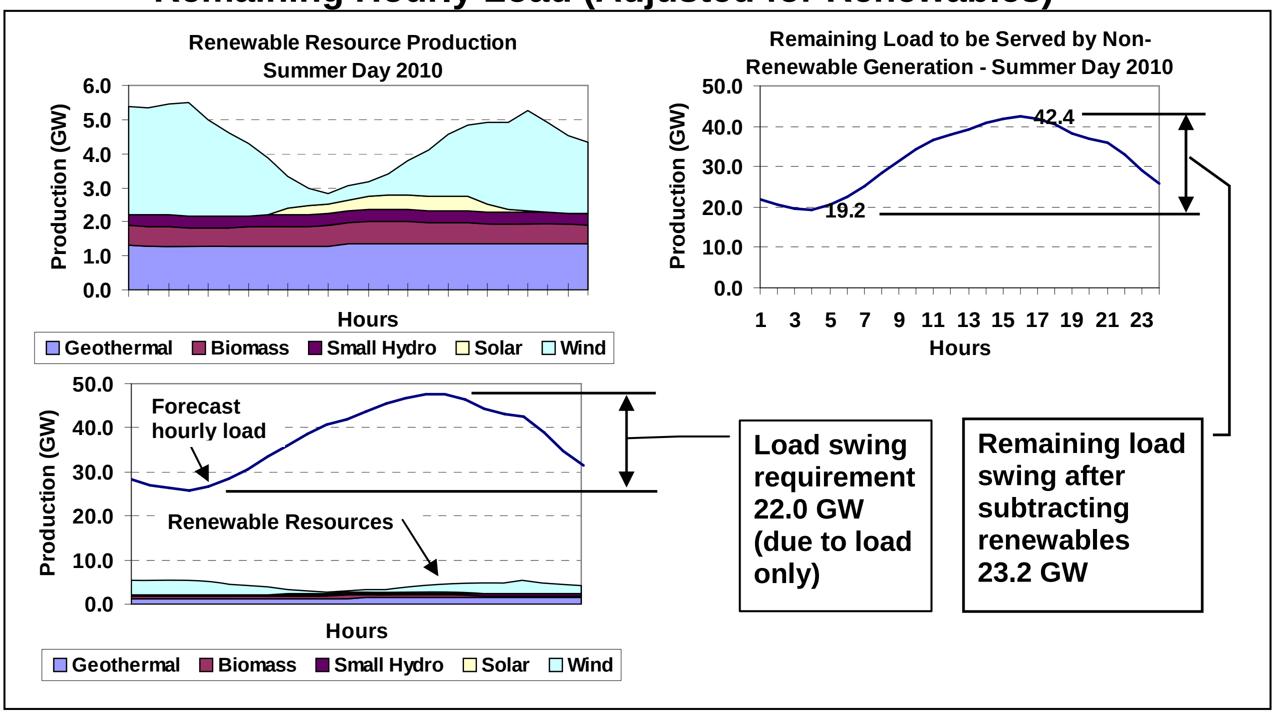
Methodology

To assess the potential impact of renewable generation on these daily load following requirements, a numerical assessment of the total daily swing in controllable generation was performed using historical hourly load patterns and historical generation production based on 2004 CA ISO data.

In the analysis it was assumed that renewable generation would be dispatched first, with all other non-RPS generation (including existing large hydro generation) dispatched thereafter. Relying on this assumption, it was possible for each forecast hour of 2010 to simply reduce the forecast hourly load by the forecast total RPS generation production estimate for that hour, resulting in a remaining load which would then be served by all other non-renewable generation Figure 1 illustrates the construction of the residual load for 2010.

The data in this report for the figures and tables are drawn from the CA ISO hourly recorded data for calendar year 2004 for both load and renewable generation. For the year 2010 assessment, the recorded CA ISO 2004 hourly loads were scaled up to match the Energy Commission's forecast of the CA ISO area for 2010. For the 2010 forecast renewable energy production by resource type, the recorded 2004 hourly production records for each renewable type were scaled up based on the Energy Commission's estimate of projected incremental renewable resource additions in the CA ISO area.

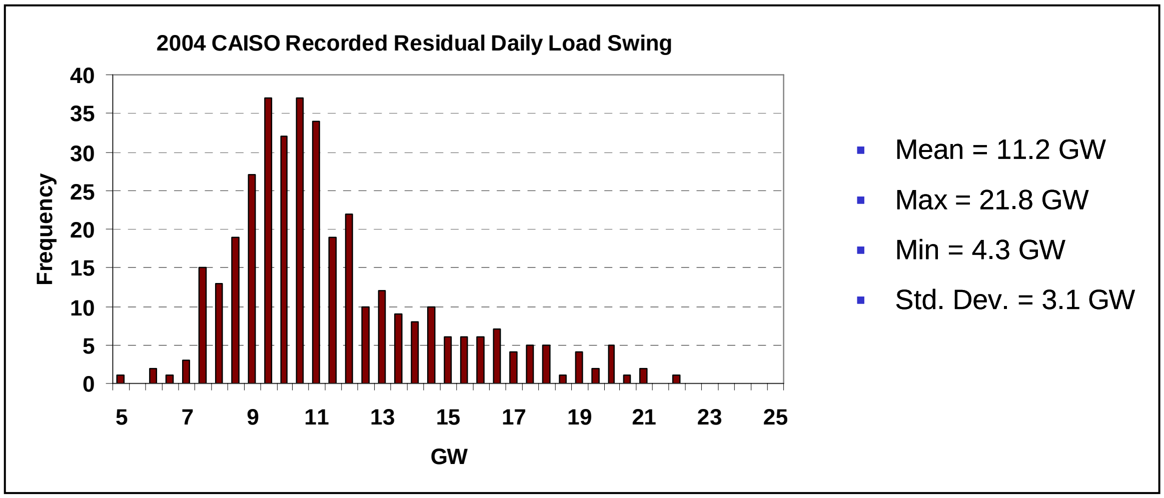
Figure 1
Remaining Hourly Load (Adjusted for Renewables)



Source: CA ISO hourly recorded data for 2004 for load and renewable generation

To establish a baseline for comparison of daily load swings, the CA ISO 2004 recorded hourly generation output of geothermal, biomass, small hydro, solar, and wind plants (representing the existing renewable portfolio) were subtracted from the CA ISO 2004 recorded hourly load data to develop remaining hourly load which would then have to be met by dispatching non-RPS generation. The daily swing from the minimum residual hourly load to the maximum residual hourly load represents the generation control range required for each day. By "bucketing" the daily controllable generation swing requirements for the entire year, a histogram of load-following requirements was developed, in 500 MW increments, and is illustrated in Figure 2. For example, there were 37 days when the daily ramp was between 10,000 and 10,500 MW and one day when this ramp was between 21,500 and 22,000 MW.

Figure 2
2004 CA ISO Recorded Daily Load Swing



Source: CA ISO hourly recorded data for 2004 for load and renewable generation

Forecast for 2010

To estimate the impact of the RPS portfolio on the future load following requirement, the CA ISO 2004 recorded hourly loads were scaled to the 2010 Energy Commission forecast level (for the CA ISO control area) using a load growth scaling factor of 5.2 percent. Next, using the hourly recorded production levels for the various renewable generation types, the 2010 production levels were developed by scaling each resource type to its 2010 forecast level. A detailed description of the methodology used to develop the estimates for renewable energy production for 2010 is included in Appendix A. Table 1 summarizes the 2004 actual and 2010 forecast production levels for each of the renewable generation types.

Table 1
Renewable Energy Production
2004 Actual and 2010 Estimated

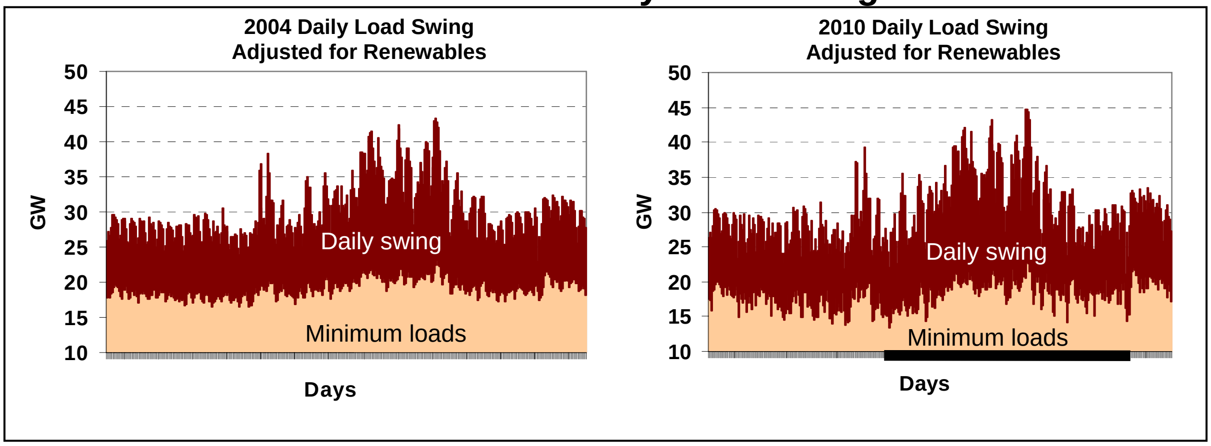
CAISO Energy Mix						
	2004 Actual (GWh)	2004 Actual (%)	Renewable Additions (GWh)	Renewable Additons (%)	2010 Total Renewable (GWh)	2010 Total Renewable (%)
	(a)	(b)	(c)	(d)	(a+c)	(e)
Biomass	3,261	17%	1,460	9%	4,720	13%
Geothermal	8,359	43%	3,670	22%	12,030	33%
Small Hydro	3,284	17%	-	0%	3,280	9%
Solar	708	4%	180	1%	890	2%
Wind	4,013	20%	11,440	68%	15,450	42%
Total	19,625	100%	16,800	100%	36,370	100%

Note: Totals may not add due to rounding

Source: CA ISO hourly recorded data for 2004 for load and renewable generation

Figure 3 summarizes the chronological residual load profiles for recorded 2004 and forecast 2010, showing the daily minimum and maximum loads, and the amount of daily swing associated with each load profile.

Figure 3
2004 and 2010 Daily Load Swings



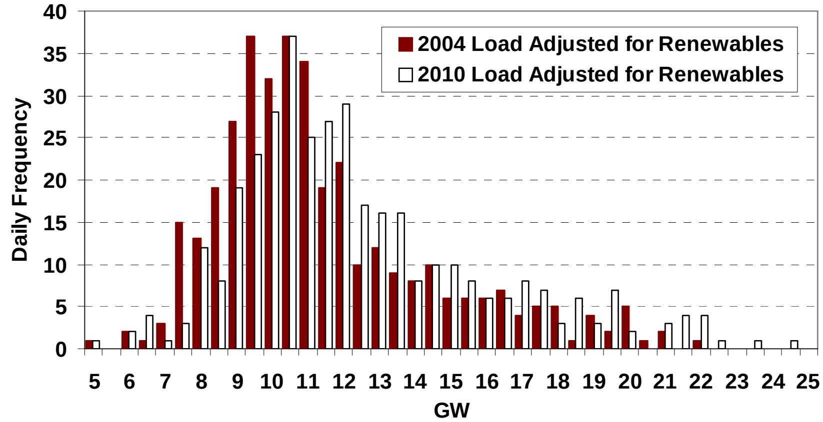
Source: CA ISO hourly recorded data for 2004 for load and renewable generation

Figure 3 illustrates that the daily minimum loads will be lower in 2010 than they were in 2004.

Analysis

Comparing the forecast 2010 daily swing requirement with the 2004 daily swing requirement, shown in Figure 4, illustrates that the maximum daily swing increases by nearly 2,200 MW, and the average daily swing requirement increases by about 1,000 MW.

Figure 4
Daily Load Following Requirement



Daily Swing (GW)

	2004	2010
Maximum	21.8	24.1
Average	11.2	12.2

2010 increase over 2004 (Note: Numbers may not add due to rounding)

- Maximum = 2.2 GW; 1.1 GW due to load and 1.1 GW due to increased renewable
- Average = 1.0 GW; 600 MW due to load and 400 MW due to increased renewable
- Changes in renewable mix, for example, increasing the penetration of solar from current forecast, will reduce the future remaining daily load swings

Source: CA ISO hourly recorded data for 2004 for load and renewable generation

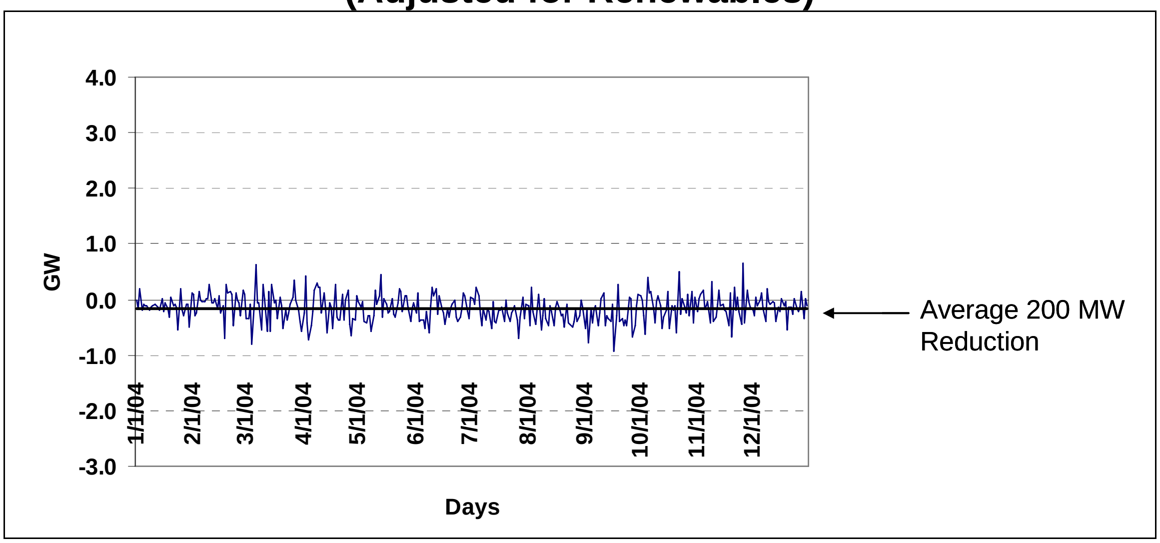
For the peak increase in daily swing requirement, the load growth from 2004 to 2010 accounts for 1,100 MW of the increase, while the growth in renewable generation accounts for the remaining 1,100 MW of increase. Similarly, the load growth accounts for 600 MW of increase in the average swing requirement, while the growth in renewable generation accounts for the remaining 400 MW.

Discussion

The increase in renewable generation in the California energy mix will increase the magnitude of the daily swing to be served by controllable generation to meet WECC and NERC control performance standards. The level of the swing increase will be highly dependent upon the mix of renewable generation that ultimately serves California's future load. For instance, based on the RPS assumptions, wind will play a dominant role in the increase in renewable energy sources, and wind is arguably the energy source which is least correlated to the daily load swing. Thus, with large amounts of wind energy in the future mix, the requirement for controllable generation will be larger. Given the size of California's electricity system, the increase in peak load swings are not significant. However, the pattern of load swings may be less predictable. If a less cyclic energy source, such as geothermal, were to provide the greatest amount of incremental energy supply, then lesser amounts of controllable generation would be required. If solar were to be a larger part of the mix (i.e., double the current forecast), the swings could almost completely be mitigated due to the high load and production correlation.

Recorded renewable production in 2004 and the Energy Commission scenario of forecast production in 2010 provide an example of how the load swing is influenced by the mix of renewable generation. The integration of the 2004 renewable production actually reduced the average daily load swing by 200 MW as illustrated in Figure 5 below. This figure presents the differential between the load swing without renewable generation and the load swing with renewable generation, with a higher daily load swing being portrayed as a positive value. Note that for 2004, the average of the daily load swings is negative, which means the load swings were reduced by the addition of renewable generation.

Figure 5
2004 Delta in Daily Load Swing
(Adjusted for Renewables)

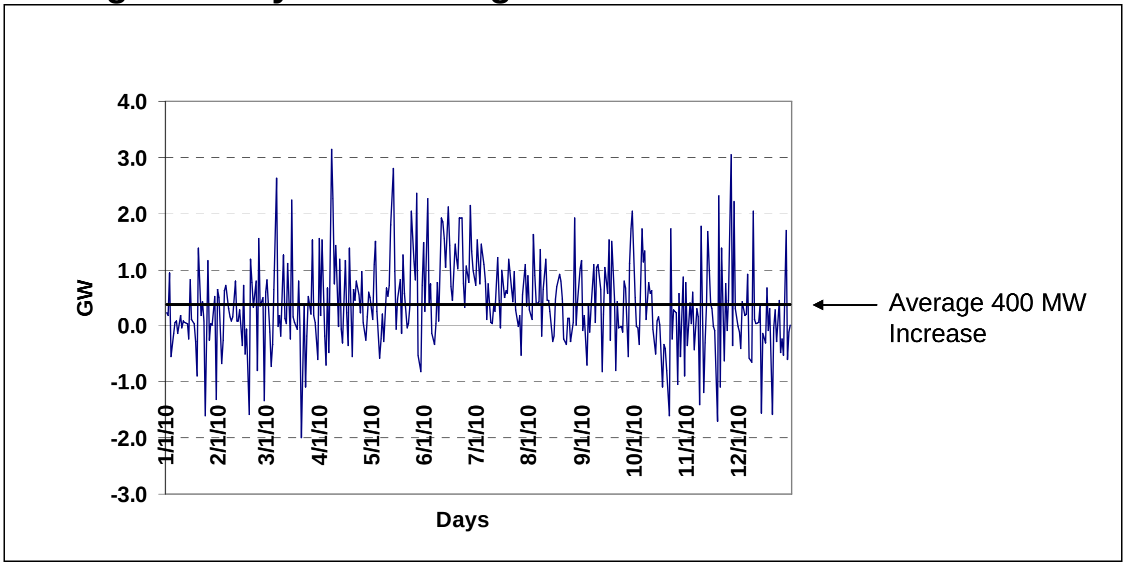


Source: CA ISO hourly recorded data for 2004 for load and renewable generation

Resources which are somewhat positively correlated with the load, including solar and small hydro amounting to 21 percent of the mix, contributed to this reduction.

The 2010 assessment compared the difference in daily load swing given the integration of accelerated RPS generation in the 2005 to 2010 time period. Specifically, the difference compared the case assuming 2010 forecast chronological hourly load with recorded 2004 renewable production and secondly with forecast 2010 renewable generation. Integration of the RPS energy increased the daily load swing by 400 MW as demonstrated by the positive average daily load swing shown in Figure 6, below.

Figure 6
Change in Daily Load Swing with Accelerated RPS Generation



Source: CA ISO hourly recorded data for 2004 for load and renewable generation

The increase in RPS intermittent generation contributes to this increase in the daily load swing. Additional dispatchable control range will be required from the non-RPS resources to successfully integrate this renewable energy mix.

Meeting the need for the forecast levels of controllable generation can be managed through improved day-ahead planning and procurement of future energy resources. Energy supplies which are unable to cycle during the off-peak periods, or to ramp in accordance with control area operator instructions, would be ill-suited to supply California's future energy needs; whereas, generators which could be readily cycled down and up as needed would better fit into the required energy mix. This suggests that there must be some attention paid to the availability of attributes (such as controllability and ramping capability) of both future generation and contract additions to the utilities' portfolios, as well as to the quantities of each generation attribute that are included in the utility portfolio.

Findings

1. The forecast 2010 maximum daily load swing, as compared to 2004, will increase the requirement for controllable generation by nearly 2,200 MW and is attributed to the following:
   - Forecast load is estimated to increase by nearly 1,100 MW
   - Renewable generation is estimated to increase by 1,100 MW

2. The forecast 2010 average requirement for daily controllable generation due to load and resource changes is estimated to increase by 1,000 MW, compared to 2004.
    - The average change in daily load swing due to load increase is estimated to be approximately 600 MW
    - The average change in daily load swing due to RPS integration is estimated to be approximately 400 MW

3. The changes in controllable generation requirements are not significant but volatility will increase.

4. Some changes in renewables mix, for example, increasing the penetration of solar from current forecast, will reduce the future increase in swings.

Actions and Policy Options

1. The control area operator should establish "attribute requirements" for controllable generation.

2. The control area operator along with the Energy Commission should forecast future needs for control attributes (and that future level would become the metric for performance monitoring).

3. The load serving entities should be required to provide sufficient generation to meet the attribute requirements of the control area operator. Close coordination will be required where multiple load serving entities are located within a single control area.

4. Generation management procedures and communication infrastructure requirements (between the control area operator and generation facility) must be in place if insufficient generation to meet the attribute requirements is not provided.

Minimum Loads

Issue

When total off-peak power production (after reducing controllable generation to minimum levels) exceeds loads, it is referred to as a minimum load problem. High levels of off-peak production (e.g., from base load, existing contracts, hydro runoff/run of the river and intermittent energy resources) pose operating challenges for the control area operator, the transmission operator, and the energy supplier (retail supplier) and may require generation curtailment, reduction in imports, increase in off-peak sales, or increase in off-peak loads (pump storage or retail customer load).

Focus

Minimum load conditions can take on two different characteristics:

1. Total generation may need to be reduced in output and may result in reducing some generation that typically is not curtailed, or that may incur some operational costs to curtail for short periods overnight. This is considered an economic minimum load condition.

2. Total generation may already be reduced to the minimum secure levels of production from the individual generators and any further reduction in total generation will require removal of some generation from operation. This is considered a physical minimum load condition.

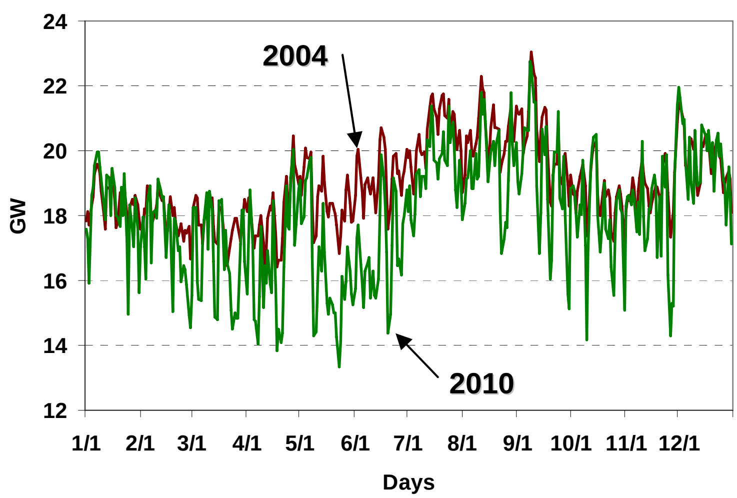
This assessment did not attempt to identify situations described by either 1 or 2 above – instead it identified the impact of the addition of non-dispatchable renewable generation on the total level of present and forecast future minimum load generation.

Methodology

To estimate the impact of the accelerated renewables development on future minimum load conditions, the forecast hourly energy production from the renewable generation was modeled to be non-dispatchable. Deducting this total hourly generation from the 2010 forecast hourly load, a residual load profile was developed which would be served by the remaining non-RPS portfolio. By comparing the present daily and seasonal minimum residual loads with the forecast daily and seasonal minimums, the general direction of the minimums can be determined.

Figure 7 illustrates the impact of the present renewable portfolio on the daily and seasonal minimum loads for both the recorded 2004 year and for forecast 2010. This analysis indicates an average reduction of 1,100 MW in residual minimum load available for non-renewable generation in 2010 compared to 2004, with the greatest reduction being 3,000 MW.

Figure 7
2010 Daily Minimum Residual Loads are Lower Than in 2004



2010 residual minimum loads
Average down 1.1 GW
Greatest reduction 3.0 GW

Source: CA ISO hourly recorded data for 2004 for load and renewable generation

Thus, the forecast growth of renewable generation per the RPS goals will further intensify the operational challenges associated with minimum system loads.

Table 2 below shows the residual minimum load after inclusion of renewable generation in 2010 compared to that in 2004. The reduction in minimum loads is an average of 1,100 MW and 3,000 MW when comparing the absolute minimums.

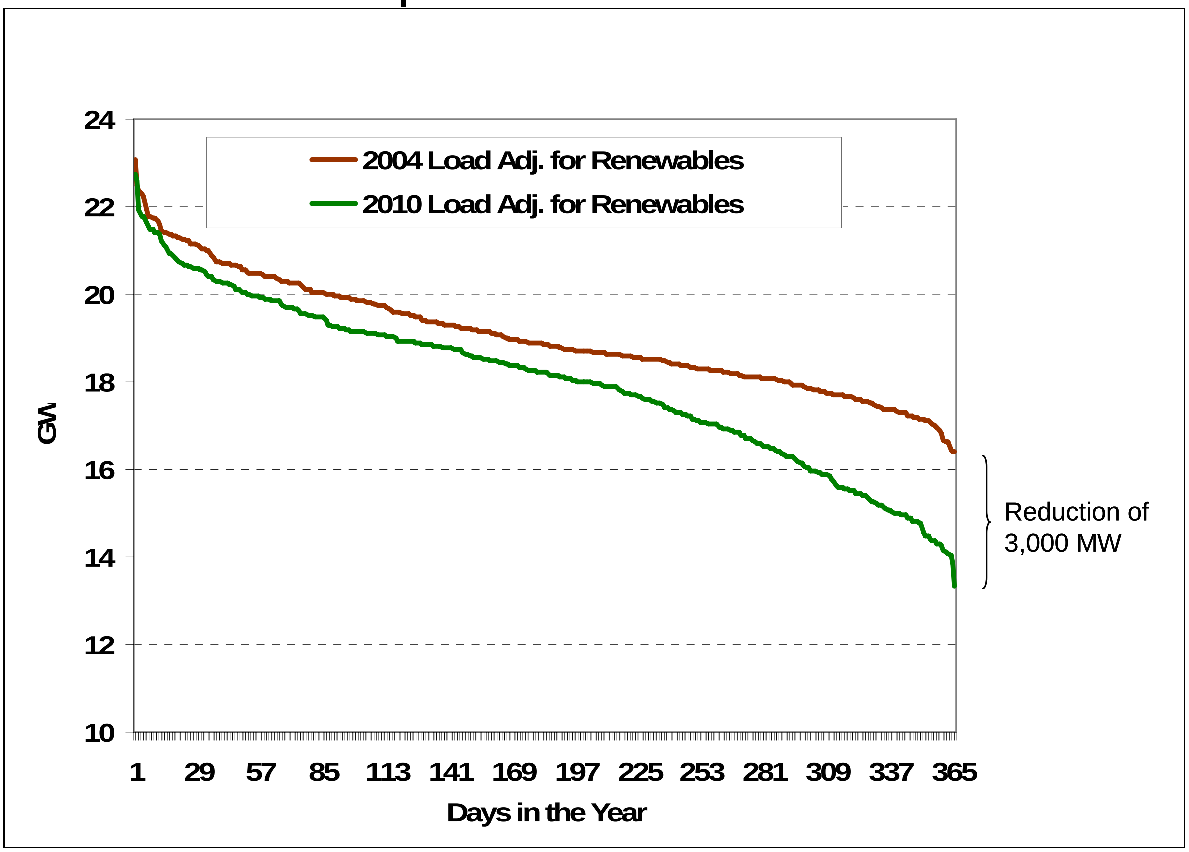
Table 2
Residual Minimum Loads with Renewables

Residual Minimum Load Adjusted for Renewables (GW)	**2004**	**2010**	**Reduction in Minimum Loads**
Average	19.1	18.0	1.1
Maximum	23.1	22.7	0.4
Minimum	16.4	13.4	3.0

Source: CA ISO hourly recorded data for 2004 for load and renewable generation

Figure 8 compares minimum loads with renewables in 2004 and 2010 (i.e., the results of Figure 7 and Table 2) in a load duration curve. As illustrated, the minimum loads for 2010 are 3,000 MW lower than for 2004.

Figure 8
Comparison of Minimum Loads



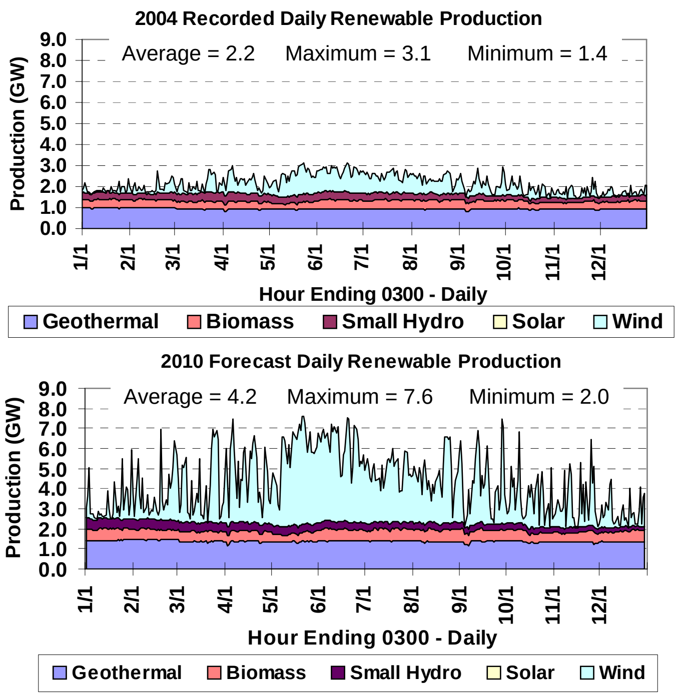
Source: CA ISO hourly recorded data for 2004 for load and renewable generation

Analysis

Since the daily minimum loads for 2010 are lower than for 2004 for nearly every day of the year, while the daily maximum loads are the same or higher, there will be a need for greater cycling capability in the controllable generation portfolio than is required to serve the 2004 load. For the most extreme forecast days in 2010, there will be a need to reduce generation output by up to an additional 4,000 MW on a daily basis for nearly two calendar months, which coincides with high run-off and high wind periods.

Figure 9 illustrates the recorded 2004 and projected 2010 energy production from the RPS portfolio, reflecting the high levels of production in late spring, which coincides with the spring hydro runoff season. The correlation of these two high production events will create significant pressure on the control area operator to manage the generation during the lightly loaded early morning hours.

Figure 9
2004 Recorded and 2010 Forecast
Daily Renewable Production



2010 production compared to 2004

- Average increases by 2.0 GW
- Maximum increases by 4.5 GW
- Minimum increases by 0.6 GW
- Production greatest in May and June and lowest in the fall

Source: CA ISO hourly recorded data for 2004 for load and renewable generation

Discussion

To manage the greater range of daily generation swing and the lower nighttime minimum generation levels estimated for 2010 several factors need to be considered:

1. Operating combined cycle gas turbine (CCGT) plants around-the-clock or base loaded may result in lowest unit production costs but higher system costs when requirements such as the full generation cycling and minimum generation turn-down requirements of the forecast 2010 energy mix are considered.

2. Continuation of energy procurement contracts on a 24-hour per day, 7 days per week basis (24x7), such as the Department of Water Resources – California Energy Resources Scheduling (DWR-CERS) contracts, would further aggravate the minimum load conditions. Replacing these contracts upon expiration with

generation that matches load profile will mitigate minimum loads and facilitate new renewables integration.

3. Exporting excess energy through off-system sales is an attractive option but the typical trading partners may be less able to accommodate California's excess off-peak energy as they, too, may be adding renewables.

4. Enhanced use of existing pumped storage facilities should help to mitigate the minimum load problem (see the discussion on Storage, below).

5. Enabling end-use customers to participate in real-time dispatch and load shifting through price signals or other initiatives for off-peak load building will improve minimum load operations.

6. Finally, there may need to be changes made to the energy market to ensure that generation which provides the necessary operational and turn-down flexibility needed by the system operator to effectively manage the grid are adequately compensated. A purely spot energy market price may not be sufficient to value these additional operational attributes goingforward.

Findings

With development of the additional renewable generation to meet RPS, the daily and seasonal minimum loads will be lower in 2010 than they were in 2004, essentially for all days of the year. To meet these lower loads without jeopardizing grid reliability, the operating performance of controllable generators will have to provide sufficient flexibility (e.g., cycling and turn down capability) to the grid operator. Changes in energy contracting may be required.

Policy Options

1. The control area operator should establish the existing attribute requirements for controllable generation (see Appendix D).

2. The control area operator along with the Energy Commission should forecast future needs for control attributes (and that future level would become the metric for monitoring planning and performance).

3. The load serving entities should be required to provide sufficient generation to meet the attribute requirements of the control area operator.

4. Determine what impact the following will have on the expected minimum load conditions:

- DWR-CERS contracts expiring: Over 2,000 MW of state signed 7x24 (i.e., 7 days per week, 24 hours per day) contracts drop off starting 2010.
- Qualifying Facilities contracts expiring
- Shutdown of Mohave Generating Station
- More flexible contracts with coal suppliers

5. Work with market suppliers to develop more flexible products that match load shapes.

6. Explore opportunities for seasonal exchanges with the Pacific Northwest or other regions of the WECC.

7. Develop a state-wide coordinated pump storage strategy.

8. Develop a market with appropriate price signals to end use customers during periods of minimum load.

9. Generation management procedures and communication infrastructure requirements (between the CAO and generation facility) must be in place if insufficient generation to meet the attribute requirements are not provided.

10. Develop the necessary policies and procedures to clearly identify the priority order of managing resources during minimum load conditions

Reserves and Ramping

Issue

Adequate supply of generation reserves and ramping capability is essential to maintain operating margins for safe and reliable operation. Installed reserve capacity includes both stand-by and operating reserves and can be brought on/off-line at short notice to balance deviations between actual/forecast of generation or load. Reserve calculations are impacted by the methodology used to incorporate capacity in operations and resource planning. For example, which metric should be used in reserve calculations: nameplate capacity, dependable operating capacity, expected load carrying capability, or expected production?

Focus – Reserves

The Energy Commission has already conducted work to estimate the effective capacity value of renewable generation for long term planning purposes.[5] This assessment assumes that the effective capacity values already determined for the California renewables.

Implicit in the methodology used to determine effective capacity value is the assumption that the planned generation is available to serve load at any time it is not otherwise forced or scheduled to be offline for maintenance. (For intermittent generation, this unavailability exception is broadened to include those time periods when the generation is unable to produce energy due to lack of prime mover energy, such as periods of no sun or wind.) Thus for generation which is otherwise not energy-limited, it is expected that the generation will be available to serve load when called upon. During actual operation, the control area operator must balance the reliability need to provide sufficient capacity to cover load variations and contingencies with the cost of keeping reserve generation on-line. With the addition of intermittent generation, such as wind, with its greater variability in output, it will fall to the control area operator to maintain sufficient operating reserve (spinning and non-spinning) to meet WECC and NERC standards.

Purpose of Operating Reserve

Operating reserve is required to assist real-time operations in managing the uncertainty and contingencies related with operating the grid, such as load and resource variations and forced outages of lines and resources. WECC requires adequate operating reserves to cover regulation requirements, non-firm imports, on-demand obligations and the largest contingency. Contingency reserve is the greater of: 1) the loss of the largest generator or transmission line from a single contingency or 2) the sum of 7 percent for load served from thermal and 5 percent for load served from hydro generation.

Knowledge of Operating Reserve

WECC requires that operating reserves be calculated so that the amount available which can be fully activated in the next ten minutes will be known at all times.

Managing Operating Reserves in Real-Time

- Hourly regulation requirements will require CAO to continuously adjust the operating reserves (up or down).
- Forecast errors (load and resource) will require CAO to continuously adjust operating reserves (up or down).
- Contingencies (forced outages of lines or generation) will require CAO to replace their operating reserves within 60 minutes.

Discussion

In real-time, operating reserve requirements are impacted by the decision on how much of the energy from intermittent resources is counted as firm capacity. Below are three options in which intermittent energy resources can be incorporated into the daily and hourly energy and capacity planning:

1) Incorporate energy production forecast in the plans based on nameplate ratings;

2) Incorporate the day-ahead forecast hourly quantity of energy in the plan; and

3) Incorporate none of the day-ahead forecast hourly quantity of energy in the plan (i.e., plan based on zero output from the intermittent resource)

Option 1 recognizes full nameplate capacity of all resources in the plan. For example, an intermittent generation facility with 100 MW of installed capacity will be assumed to produce 100 MW every hour. While recognizing full capacity of the generation, it will nearly always overstate the actual energy production and available capacity. Since capacity is overstated, offsetting additional reserves are required in order not to have an adverse reliability impact.

Option 2 relies on expected intermittent resource output in the daily plan. This will result in some variation around the forecast either an excess of energy resources (which means more to sell and possibly some operational impact, but typically little reliability impact), or a deficiency of energy resources (which means more to buy, and occasionally an adverse reliability impact). However, the impact is much less than Option 1.

Option 3 values the intermittent resources in the daily plan at zero. Thus any actual energy produced will be in excess of the plan, requiring continuous rebalancing . This will result in excess energy having to be sold (or not produced), with little reliability, but some operational, impact. The operational impacts result from the need for some dispatchable resources to operate at or near their minimum limits and making them less responsive to the control area's 10 or fifteen minute response requirements. This will especially be true during minimum load periods), but there would not be an energy deficiency due to overestimation of intermittent generation (which means no adverse reliability impact). Under this option, the control area will nearly always be carrying excess amounts of unloaded generation, but technically not excessive reserves, since operating reserves is unloaded generation (or generation off line) that can be activated within ten minutes minus the non-firm energy (i.e., intermittent resources).

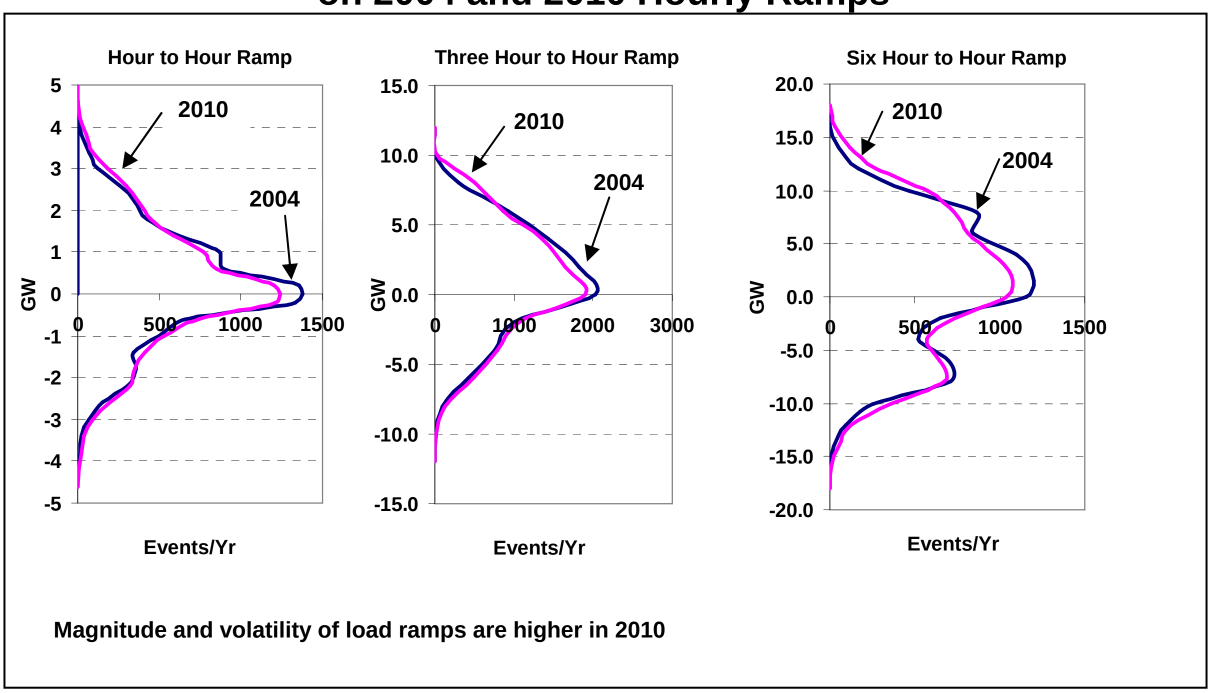
Additionally, operating reserves are defined by the greater of the largest contingency, or 7 percent thermal and 5 percent hydro of the load requirement. Assuming the intermittent generation was: 1) counted on at or near its nameplate capacity, 2) the CAO defined the generation as a single contingency (e.g., on a single collector station), and 3) the generation capacity exceeded the reserve requirement based on the percent of load, the reserve requirement would be higher defined by the largest contingency criteria.

There are, of course, many degrees of flexibility between these extremes, such as including some portion, but not all of the hourly forecast intermittent energy. One of the key objectives to successfully integrating RPS resources is to maximize operating efficiency while operating within reliability standards. To achieve that optimum balance point requires good historical trends, accurate real-time weather data, operating experience and improved forecast techniques. As we attempt to improve resource efficiency there will be greater dependency on the non-RPS resources to provide greater flexibility and to posses the necessary attributes (e.g., quick start, fast ramp capability).

Focus – Ramping

To illustrate the impact of the residual load changes, the hourly ramp, the three-hour ramp, and the six-hour ramping requirements are analyzed. Figure 10 illustrates the change in the ramping requirements for recorded 2004 contrast with forecast 2010.

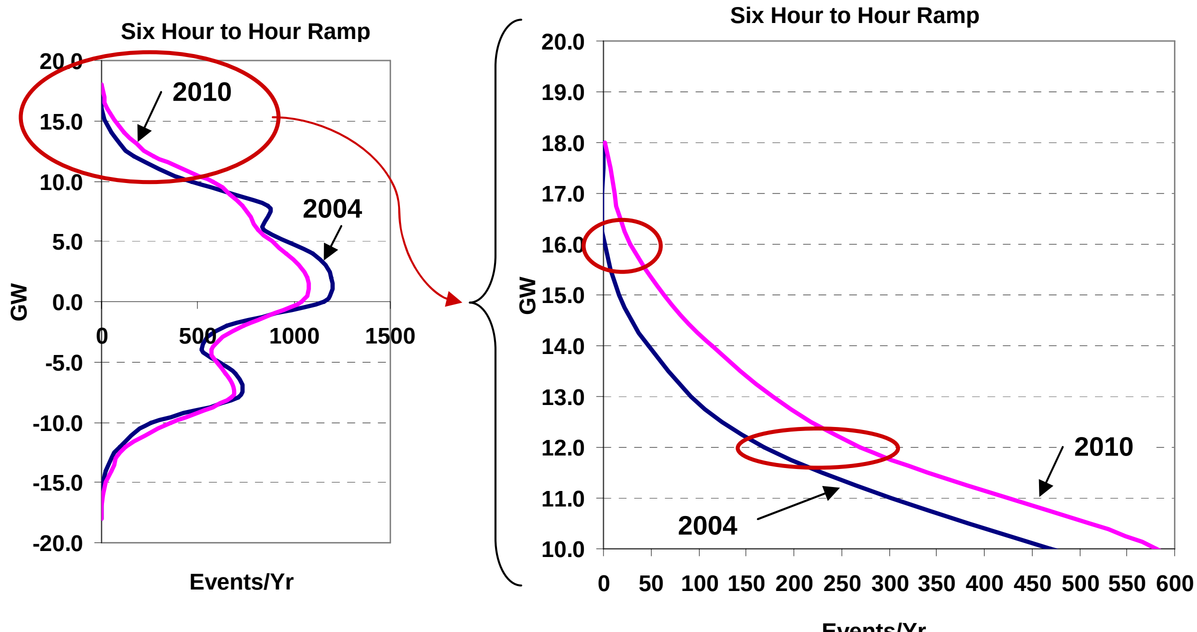
Figure 10
Renewable Production Impact
on 2004 and 2010 Hourly Ramps



Source: CA ISO hourly recorded data for 2004 for load and renewable generation

The most significant change in ramping requirements is observed in the six-hour ramping requirements as presented in Figure 11. This figure focuses on the largest upward ramps over the six hour period. With the expanded renewables production in 2010, the largest upward ramps can be expected to occur more often than today. Ramps up to 12 gigawatts (GWs) will occur 100 more times than in 2010, and ramps up to 16 GW will occur 27 more times.

Figure 11
Comparison of 2004 and 2010 Load Ramps
After Adjustment For Renewable Production



6 hour load ramps

- Ramps up to 16 GW occurred one time in 2004 and 28 times in 2010
- Ramps up to 12 GW occurred 170 times in 2004 and 270 times in 2010

Source: CA ISO hourly recorded data for 2004 for load and renewable generation

Figures 10 and 11 illustrate that with the addition of renewable generation there will be a greater need for upward ramping capability and a smaller need for increased downward ramping capability in the generation portfolio of 2010.

Because thermal generation typically ramps at approximately 1 percent of capacity per minute (except during emergency conditions), in order to achieve a ramp of 500 MW in a single hour approximately 830 MW of unloaded generation capacity is required at the beginning of the ramping hour (830 MW x 1 percent x 60 minutes = 500 MW). This requirement for unloaded generation is in addition to the CAOs requirement for spinning and operating reserves, because this unloaded generation will be progressively loaded up during the hour to meet the ramping requirement. (Note that while the assessment is based on hourly data, it is possible that there are even faster ramping requirements within the hour due to changes in load or generation.)

As these figures illustrate, the overall ramping requirements are greater with renewable generation. This increase should be manageable if the mix of future non-RPS generation has the ability to ramp up and down to follow dispatch instructions. The need to dispatch renewables may be infrequent but the ability to do so will provide CAO with needed operating flexibility for reliability management. It will be important for both the control area operator and the load serving entities to carefully assess the need for controllability in procured generating resources. (See Appendix E for a list of generation attributes).

Policy Options

1. The control area operator will need to carefully assess the existing needs for controllability and ramping capability. (See Appendix E.)

2. The load serving entities should be required to provide a resource mix which will meet the control attributes established by the control area operator.

3. Reserves
   - Immediately start monitoring and tracking forecast and actual performance for all intermittent resources by:
     - Consistent standardized method and metric
     - Developer, region, LSE and CAO
     - Day-ahead, 12-hours ahead, 6-hours ahead and 3-hours ahead

   - Deploy best available metering to support better forecasts.

   - Perform benchmarking study to identify best-in-class for forecast models, processes and techniques.

   - Assure that the portion of the LSE and CAO resource portfolio used to provide operating reserves has the necessary attributes (e.g., quick start, fast ramp, cycle) to enhance efficiency while ensuring reliable operations.

   - Monitor and track compliance with the WECC reserve standard.

Load and Generation Forecast Variability

Issue

Accurately forecasting both the day-ahead and hour-ahead load and generation is important in maintaining reliable operation and achieving economic efficiency.

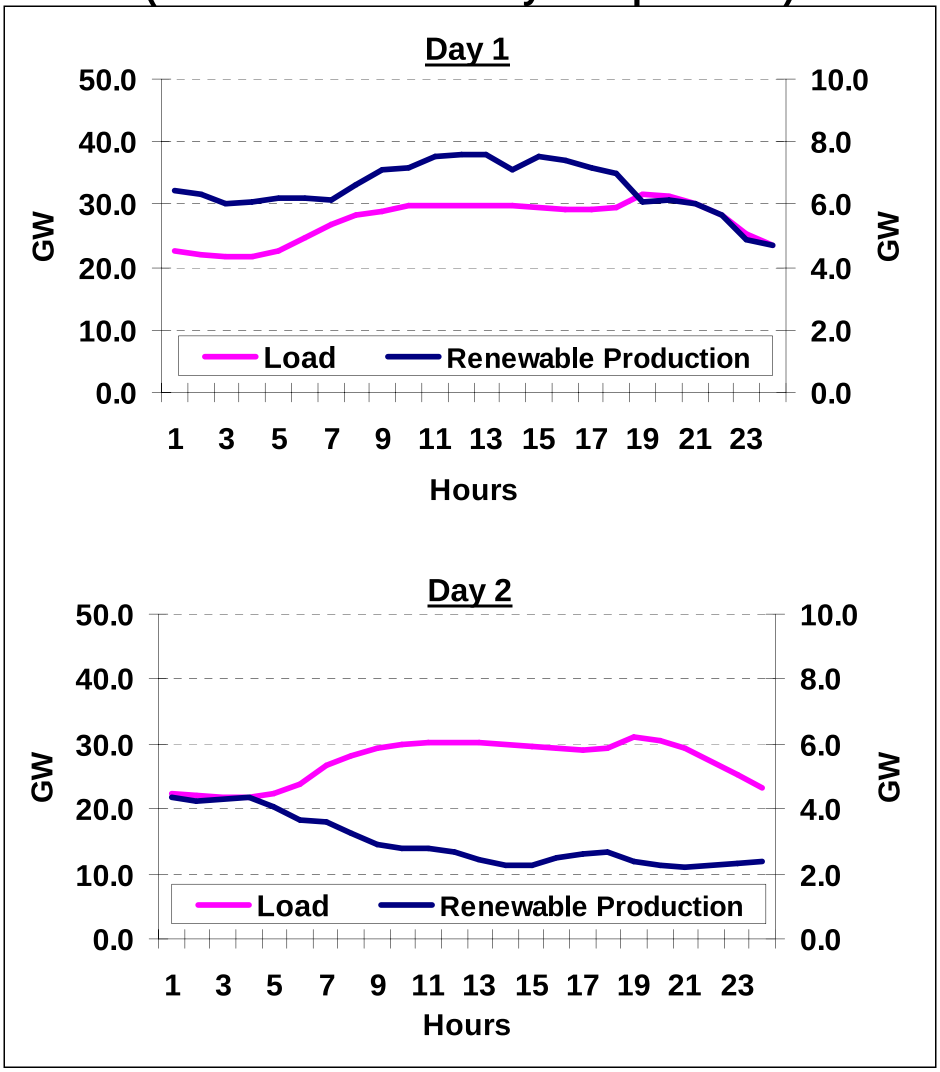
Discussion

A common way for utilities and CAOs to forecast renewable generation is to assume tomorrow's generation will be the same as today's latest recorded information. This is known as the persistence model approach and is currently utilized by CAOs as alternative forecasting methodologies have failed to improve forecast error.

Applying the persistence model to the forecast CA ISO renewable generation in 2010,[6] the difference in renewable generation at the time of daily system peak demand can be examined from one day to the next. The difference in daily production is quantified with perfect foresight given the 2010 forecast hourly renewable generation.

This is illustrated by examining the change in renewable production between two consecutive dates in April 2010, as shown in Figure 12. The forecast wind production on April 2 at time of peak is 6.1 GW. The forecast wind production at time of peak for the next day (April 3) is 2.4 GW. However, if a persistence model is used, the operating plan would have assumed a production of 6.1 GW on April 3 versus the actual production of 2.4 GW, resulting in a forecast error of 3.7 GW.

Figure 12
Forecast Load and Renewable Production
(Two Consecutive Days – April 2010)

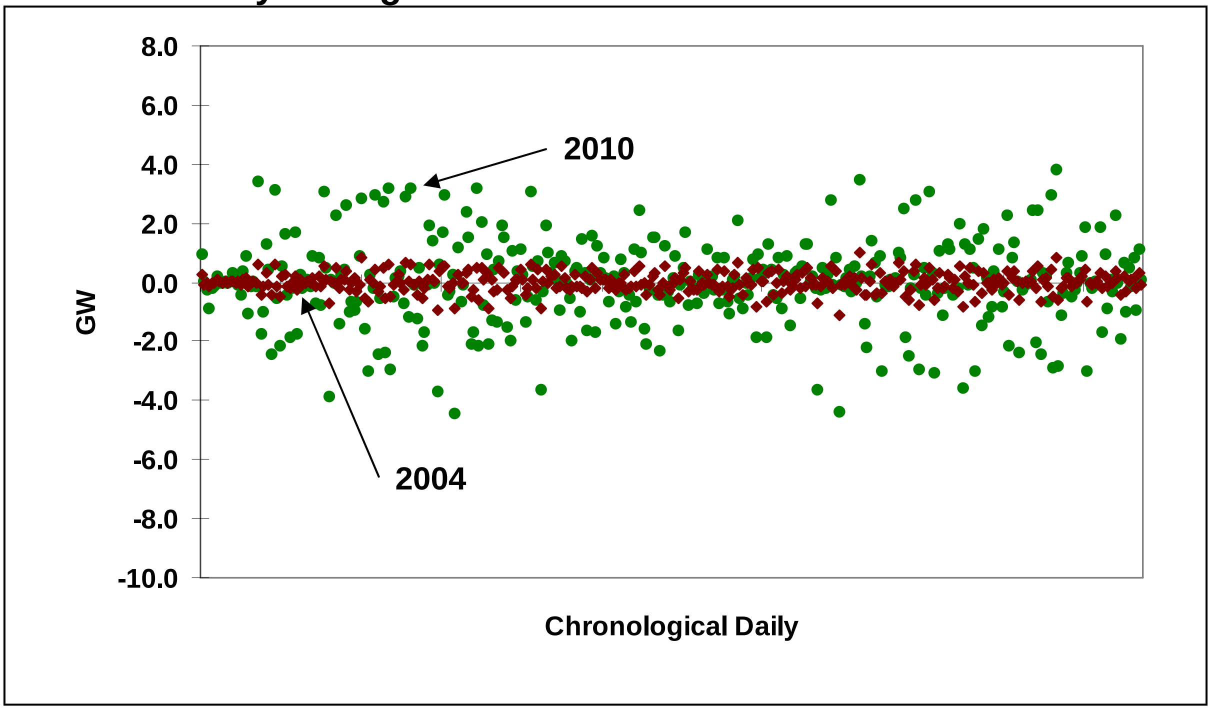


Source: CA ISO hourly recorded data for 2004 for load and renewable generation

A chronological x-y plot of the daily change in CA ISO renewable production, at time of the system peak load, is presented in Figure 13 for both recorded 2004 and forecast 2010. For this figure, each point represents the change from the preceding day's renewable production at the time of the daily system peak. Thus, if the renewable production increases from one day to the next, the plot will change in a positive direction. Conversely, if the renewable production decreases from one day to the next, the plot will change in a negative direction.

As this figure illustrates, the variability of renewable energy production is higher in 2010 than in 2004. Daily change in total renewable production ranges from a minimum of minus 4.5 GW to a maximum of 3.5 GW with a standard deviation of 1.4 GW.

Figure 13
Daily Change in Renewable Production at Peak



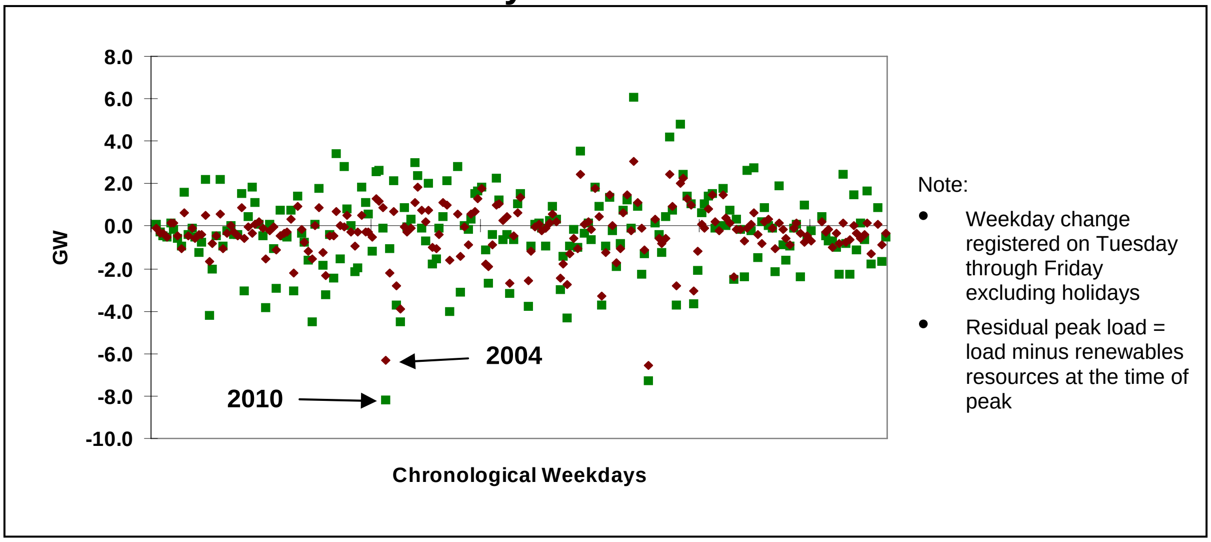
Source: CA ISO hourly recorded data for 2004 for load and renewable generation

This expected variance in renewable energy production from one day to the next will have significant operational implications for the CAO. It makes improved forecasting techniques over the persistence model imperative so that generation commitment and dispatch decisions can be made in a timely manner to balance generation and load in real time.

The required attributes of replacement controllable generation, including start-up time and ramping capability, will depend on both the lead time and accuracy of production forecasting models.

Figure 14 presents the change in weekday residual peak load at the time of the daily peak, in a similar presentation as the preceding figure. This figure illustrates that the daily peak load will have greater volatility in 2010 than in 2004, suggesting an increased value in improved renewable energy forecasting.

Figure 14
2004 and 2010 Daily Chronological Change in Weekday Residual Peak Load



Source: CA ISO hourly recorded data for 2004 for load and renewable generation

Methodology to Reduce Forecast Error

State-of-the art wind forecasting techniques and monitoring systems need to be investigated and employed to insure successful integration of the accelerated RPS generation.

The accuracy of the intermittent energy forecast is critically important to the effectiveness of incorporating intermittent energy into the grid operation, with a perfectly accurate forecast being the goal. Furthermore, because forecasts typically improve in accuracy with reduced time horizons between forecast and actual, scheduling protocol changes which can reduce the time lag between preparing the forecast and energy plans, and the actual operation, are beneficial.

Finally, it must be noted that intermittent resources are neither the sole source of unpredictability, nor are they necessarily the largest source of hourly uncertainty. Load forecasting is imprecise at best, with error rates up to several percent on extreme load days. Furthermore, generation and transmission forced outages can easily remove several hundred MWs of capability from the grid, requiring significant resource rebalancing. So, while intermittent resources introduce some uncertainty in the daily plan, they are neither the sole, nor necessarily the most significant, causes of that uncertainty. It is the role of the grid operator to manage the grid in the face of that uncertainty, at the lowest practicable cost.

Much work has been done in recent years to improve the tools used to forecast wind energy and to improve the sources of raw data for such forecasting tools (such as installation of meteorological monitoring stations in the right locations). With these improvements have come more accurate forecasts of hourly wind energy. To the extent that improvements can be made to both the weather monitoring capabilities at California's wind sites, and to the forecasting models which use that data, California will facilitate integration of intermittent wind generating resources into its electric grid, with fewer operational and reliability impacts.

With improved wind forecasts, California can more confidently incorporate the hourly forecasts of wind production into its daily and hourly resource planning, with the expectation that any real-time adjustments will be both small, and readily manageable.

Findings

California's goal of expanding the role of renewable generation resources to provide 20 percent of the state's energy by 2010, and which includes a greatly expanded role for wind generation, can most effectively be supported by a continued focus on improving the monitoring and modeling of renewable energy and improving wind forecasting tools and techniques, as well as critically evaluating scheduling protocol changes which would shorten the lead time between forecasting, scheduling, and actual operation.

Actions and Policy Options

1. Implement state-of-the-art wind production forecasting.
2. Continue efforts to improve wind monitoring and data gathering.
3. Evaluate changes in CA ISO protocols to allow later forecasting of intermittent energy for daily and hourly planning.

Analysis Sensitivities and Alternatives

At the May 10, 2005, Energy Commission Renewable Integration workshop, several stakeholders commented on the possible impact of different renewable resource mix assumptions other than the one used for the CERTS May Progress report. Four different alternative scenarios were selected for additional analysis and comparison to the base case used in the May Progress report. The four alternative scenarios are:

1. Increased geothermal energy mix, offsetting a like amount of Tehachapi wind energy;
2. Increased solar energy mix, offsetting a like amount of Tehachapi wind energy;

3. Altered mix of wind sources (increased Altamont energy, decreased Tehachapi energy); and
4. Replace the entire Tehachapi energy production with the California Wind Energy Collaborative/NREL energy model[7] (scaled to the same energy production as in the 2010 base case for Tehachapi).

The results of these four alternative sensitivities are presented in Appendix C. This additional analysis does change the findings, policy options, and solution sets presented in this report.

The reliability and operational issues 5-9 were analyzed qualitatively by the study team.

Storage

Issue

Storage has been identified as one means of mitigating minimum load impacts.

Focus

The state presently has over 4,000 MW of pump storage capability. This capability is under the control of several different organizations and they are located in two separate control areas, the CA ISO and the Los Angeles Department of Water and Power (LADWP). The portion that is within the CA ISO control area is controlled by three entities, Southern California Edison (SCE), Pacific Gas and Electric (PG&E) and DWR, who may require the use of these facilities for their own resource needs or, in the case of SCE and PG&E, to turn over dispatch to the CA ISO.

Furthermore, during certain times of the year, some of these pumped storage facilities may have limited or no pumping capability due to both water flow-through requirements, such as during the spring runoff season, and due to low fore bay water levels which prevent use in the pumping mode.

Analysis

Two questions were considered with regard to storage:
1. Should storage be required as an adjunct to further development of renewable resources?
2. Is the present storage capability being used effectively?

With regard to the first question, it was the consensus of the stakeholders that expansion of the state's energy storage capability should be considered separately from the expansion of renewable generation. There are many options for managing the combined energy production from both the RPS and non-RPS portfolios, of which expanding or enhancing the use of storage is but one option. Thus, linking storage to expanded renewables is not warranted. Moreover, storage, if it is needed, can be economically justified on its own merits.

Second, the scope of this assessment limited our ability to examine the extent to which the combined pumped storage capability of the state was now being used to enhance operational flexibility. However, due to the diversity of operators and their respective grid interests, it is likely that a more holistic strategy for operation of all the pumped storage facilities in the state would yield a more efficient overall operation.

Finally, there exist contractual options to achieve additional pumped storage-like capability through day-night and seasonal energy exchanges with other regions of the West. These options have been used in the past and may still be available if conditions warrant their use again in the future.

Findings

Storage is but one option in a large portfolio of generation control options available to the state. Before any substantial effort is expended in exploring the development of additional storage alternatives, the CAOs should identify the generation attributes needed to effectively manage the grid in 2010, and the quantities required of each of those identified attributes. The load serving entities should then be required, with the active participation of the Energy Commission, the CPUC and stakeholders, to identify resource portfolios that will meet the control area operator's needs for capacity, energy, and the other generation attributes identified. Additional storage, if it is required, would then be an option to provide some of the generation attributes.

Policy Option

Develop a state-wide coordinated pump storage strategy.

Frequency and Voltage Requirements

Issue

The WECC has determined the need for a low voltage ride-through (LVRT) standard. On March 3-4, 2005, the WECC Planning Coordination Committee (PCC) voted on and approved the LVRT performance standard, as modified. At the April 6-8, 2005 meeting; WECC Board approved the LVRT performance standard, as modified by PCC. The standard is scheduled to be implemented in March of 2006. There is no recommended policy option on LVRT, as it is already being addressed through the WECC.

The Federal Energy Regulatory Commission (FERC) is also currently in the process of establishing a LVRT standard at a national level. The American Wind Energy Association (AWEA) has taken a leadership role in sponsoring an LVRT standard at FERC. The LVRT standard will impact system design and operations, for example the size of a substation, number of collector stations to interconnect intermittent generation, or fault current propagation. This proposal needs to be evaluated by utilities and assess system specific impacts and guidelines to plan a reliable system conforming to adopted standards.

As a result of the new WECC LVRT standard being implemented, and any changes in the standard that may result from the FERC activities, each transmission owner and CAO will now have to assess how the standard will impact their planned grid interconnections and expansion.

The frequency response of generating resources in WECC has been deteriorating over the last two decades for various reasons and is not uniquely related to the introduction of renewable resources onto the system. The reliability authorities (e.g., transmission owner, CAO and reliability regions) collectively, through an open process, need to perform the necessary evaluations and assessments to accurately determine those generation attributes that relate to frequency, as well as the minimum acceptable performance level of the attribute, that are essential to grid reliability. Based on their findings, a process could be initiated to establish a frequency response and/or ride-through standard.

Policy Option

Generation attributes that relate to frequency, as well as the minimum levels of performance required for grid reliability, have not been assessed. Existing frequency response standards do not adequately address these issues.

Resource Deliverability

Issue

Currently, utilities and generators perform and comply with interconnection standards and requirements to connect generation. Interconnection standards, however, do not address deliverability, which is the ability to move power freely across the interconnected grid.

For the investor-owned utilities which are under the CPUC jurisdiction, there is an established process to evaluate deliverability under the resource procurement process. The deliverability evaluation process only requires an assessment at the time of the annual peak demand. That process may be adequate to insure deliverability for some of the RPS resources that are either base loaded or whose energy production correlates well with the load demand, but for some intermittent resources, such as wind, the peak production periods may not be during the summer months or the on-peak hours of the day. As a result, when simulation and power flow studies are performed at time of peak they will reflect limited production from some intermittent resources and therefore may miss potential problems. It is only when the resources become operational and attempt to deliver maximum energy production onto the grid, during non-studied hours, that the problems start showing up. At that time, the only recourse for the system operator is to implement some form of generation curtailment or congestion management protocol resulting in stranded generation. The net impact of this inadequate deliverability assessment is that the state, and ultimately the consumer, may not realize the full benefit from the RPS resources.

Policy Options

1. The reliability authorities (e.g., transmission owner and CAOs) collectively need to perform a more comprehensive state-wide deliverability evaluation to ensure the grid is adequately designed for resource deliverability during the non-peak time periods (e.g., spring time and evenings).

2. Utilities need to study their systems to assure deliverability of renewable generation over a range of operating conditions. This may result in requirements for additional investments beyond the first point of interconnections (capacitors, transformers, and debottlenecking projects) which need supportive regulatory policy to address cost recovery.

Transmission Import Capability

Issue

The frequency response of generating resources in WECC has been deteriorating over the last two decades and reduced inertia and variability in generating performance in this area could negatively impact existing transmission path ratings into California and throughout WECC. This reduced performance is a result of: 1) many generating resources throughout the WECC operating at base load (i.e., coal), leaving limited upward capability, 2) nuclear resources, under regulatory mandate, operating with their governors blocked (non-responsive), 3) modified combustion control systems on conventional thermal resources and 4) the design characteristics of the new combined cycle plants.

With the above in mind, under the sponsorship of Governors Richardson and Schwarzenegger and the Western Governors Association's commitment to a viable economy and a clean and healthy environment in the West. The WGA membershave agreed to collaborate in the exploration of opportunities to develop a clean, secure, and diversified energy system for the West and to capitalize on the region's immense energy resources. Western Governors will examine the feasibility of achieving a goal to develop 30,000 MW of clean energy in the West by 2015. California alone, under the accelerated RPS, is expected to add almost 7,000 MW of RPS resources by 2010. The significant portion of those resources may provide limited or no contribution to the necessary frequency response required to effectively manage an integrated grid.

There are three major items that will affect the transfer capability of a transmission path: 1) the thermal capability of installed facilities, 2) the voltage support between source and sink and 3) the dynamic performance of generation resources during a likely contingency event. A significant change in the operational resource mix, at times, could potentially have a negative impact on the transfer capability of some transmission paths. The impact, if any, may not be noticed during peak periods when there is approximately 150,000 MW of connected generation, but an issue could arise during the many non-peak hours of the year.

This is not an issue caused by RPS resources, but the impact of a significant change in the WECC resource mix, as a result of the above commitment, needs to be evaluated, especially during non-peak hours and seasons.

Policy Option

The reliability authorities (e.g., WECC members, transmission owner and control area operators) collectively need to perform a comprehensive region-wide peak and non-peak evaluation of the grid's performance and potential impacts on transfer capability, as a result of a changing resource mix. This will assist California utilities and others in WECC better understand what, if anything, they may need to do to maintain existing transmission path ratings.

Planning and Modeling

Issue

Lack of detailed modeling data to support studies and off-peak study cases to analyze transmission system loadings.

It has been the practice of WECC since 1996 that the grid will not be operated under conditions that have not been studied. This practice has worked well for WECC and the reliability of the region. The challenge of the future is whether we have the necessary data, information, tools and processes to effectively study the expected operation of the interconnected grid. The following are some of the concerns of those organizations responsible for performing both the planning and operational studies:

- Most transmission planning is done for peak load day conditions, not peak power transfer conditions.
- Develop off-peak and shoulder peak WECC study cases in order to study transmission loading patterns.
- Planning models don't adequately capture the performance of the wind generators.
- Detailed modeling data for some intermittent resources to support studies, such as dynamic voltage and frequency performance, are lacking.
- Intermittent resource production data available to allow analysis is absent.
  - Meteorological data to support real time wind forecasting is absent.
- Good forecasts of wind production by time of day to build into power flow studies are lacking.

So, if local and regional grid studies are performed with the above concerns, will we unintentionally find ourselves operating in unstudied conditions and potentially suffer the consequences?

Policy Options

1. A WECC member from a California entity, at the executive level, should be requested to sponsor an initiative at the WECC to address and correct the following concerns:
   - Modeling tools
   - Operational and planning study procedures
   - Development of non-traditional base cases

2. A representative from the wind industry, such as AWEA, should be requested to work with wind developers to assure all necessary and available data required to study the grid performance is provided to those reliability authorities who have responsibility to perform both local and regional studies.

3. The state should deploy or cause to be deployed the necessary monitoring devices and infrastructure to acquire the necessary meteorological data.

DEVELOPMENT OF SOLUTION SETS AND POLICY OPTIONS FOR MITIGATING RELIABILITY AND OPERATIONAL ISSUES

The study team researched solution options to address the issues to integrate renewables without adverse impact on reliability or operations. A list of solution options and actions were developed, including the relevance to each issue, and is provided in Table 3 below. For each solution a matrix was developed identifying the proposed action, the likely owner(s), where research is required, and the suggested metric to be used. Solution options A through J are described below.

Table 3
Summary of Solutions

Issue Solution Option & Action Required		Load Following	Minimum Loads	Reserves and Ramping	Load and Generation Forecast Variability	Storage	Frequency and Voltage Requirements	Resource Deliverability	Transmission Import Capability	Planning and Modeling
A	Establish requirements for controllable generation	X	X	X		X				
B	Enable load to participate in real time dispatch	X	X		X	X				
C	Renegotiate existing contracts for additional dispatchability and minimum load turndown	X	X			X				
D	Modify CA ISO AGC algorithm	X	X	X	X	X		X		
E	Modify WECC and CA ISO interchange scheduling protocols, policies and procedures to enhance the use of renewable resources	X		X	X					
F	Ensure adequate generator performance standards are in place with clarity						X			X

Issue Solution Option & Action Required		Load Following	Minimum Loads	Reserves and Ramping	Load and Generation Forecast Variability	Storage	Frequency and Voltage Requirements	Resource Deliverability	Transmission Import Capability	Planning and Modeling
	of implementation to ensure system performance									
G	Actively manage generation output which exceeds planned levels, or when total generation exceeds load	X	X	X	X					
H	Improve transmission studies							X	X	X
I	Improve modeling of renewables							X	X	X
J	Improve production forecasting	X	X		X					

Solution A - Establish Requirements for Controllable Generation

While there has been a lot of discussion on the need for controllable generation, there are no metrics or criteria that define how much is needed. Defining requirements for controllable generation -- magnitude, duration, timing by season and day -- will assist the generation stakeholders and market participants to take these requirements into account in their business models. Adequate quantification and tracking of controllable generation requirements will address several of the issues discussed, e.g., load following, minimum loads, reserves and storage. The CA ISO/CAO should take the lead in defining requirements and Energy Commission research support is recommended to define metrics, monitor and track performance against requirements as well as trends.

Actions Required	Owner	Research	Metric
Establish attributes requirements for current controllable generation	CAO		
Forecast future need for control attributes	CAO/ Energy Commission	Yes	CAO determines quantities of various attributes required, those levels become the measurement metrics
Monitor and track requirements needs	CAO		
Acquire sufficient generation with necessary attributes to meet AGC and load following requirements in procurement process	LSE		

Solution B - Enable Load to Participate in Real-Time Dispatch

There is minimal load participation in real time dispatch. Experts have opined that small amounts of load participation -- of the order of 5 to 10 percent -- can go a long way in improving market efficiency, mitigating market power, and reducing the control requirements for generation. To facilitate load participation, there are several steps involved -- transparent pricing that is the responsibility of the CA ISO/CAO, infrastructure to enable load participation which will require regulatory support as well as actions by LSEs, and a plan based on research and analysis to establish targets and timetable for load participation and subsequent tracking. This is not unlike what has been done with renewables through establishment of the RPS.

Actions Required	Owner	Research	Metric
Provide energy settlement price for real time attributes	CAO		
Standards - Monitor, publish recorded, and forecast future requirements	CAO/ Energy Commission	Yes	
Infrastructure - Enable load participation in real time dispatch (Automatic Load Dispatch)	LSEs, CAO, Load Customer, Energy Commission	Yes	Percent of attribute requirements provided by load

Solution C - Renegotiate Existing Contracts for Additional Dispatchability and Minimum Load Turndown

Many of the existing contracts hamper the ability to manage real time operation even though the underlying resources being used to meet contract needs have operational flexibility that could be utilized. This will require contract renegotiations by LSEs and CDWR-CERS.[8]

Actions Required	Owner	Research	Metric
LSEs responsible for providing dispatch flexibility renegotiate as required	LSE and CDWR-CERS		Percent of achievable attributes from existing contracts
Regulatory approval of renegotiated contracts to meet CA ISO control area requirements (regulatory review consistent with system needs)	CA ISO (system needs assessment), CPUC Approval		

Solution D – Modify CA ISO AGC Algorithm

Currently, there are some very responsive hydro resources that are not available to the CAO for real-time control. This is due to the existing AGC control logic not effectively complying with the submitted energy schedules and causing water schedule violations. Modify and enhance the AGC algorithms to correct this deficiency thereby providing a low cost solution of capturing additional regulation and load following capability.

Actions Required	Owner	Research	Metric
Specify hydro resource and controllable load availability	LSE		
Modify CA ISO AGC algorithm to effectively use controllable hydro and load to supply AGC and meet hourly energy scheduling targets	CA ISO		Percent of AGC being provided by hydro and MW of load providing ALC
Explore options to enhance use of load for ALC (Automatic Load Control)	CA ISO/Energy Commission	Yes	
Explore options to enhance availability of hydro for AGC usage	LSE/Energy Commission	Yes	

Solution E – Modify WECC and CA ISO Interchange Scheduling Protocols, Policies and Procedures to Enhance the Use of Renewable Resources

The current interchange scheduling protocols and timetable (20 minute ramps, 2-1/2 hour cutoff for schedule updates etc.) were designed in an era when most of the generation was “controllable." With the transition to a market system and increasing contribution of intermittent resources in CA and throughout the WECC, these protocols and guidelines need to be updated. This will involve WECC operating committees working with CAOs and developing metrics and a system for monitoring progress. Protocols that need to be addressed include, for example, ability to update next 2 to 4 hour production forecast on a more frequent basis without penalties.

Actions Required	Owner	Research	Metric
Modify energy scheduling protocol to allow longer ramping times (e.g., 40 minutes rather than 20 minutes)	WECC		Compliance with NERC CPS and percent reduction in regulation requirements
Review of operating reserve standard, greater amounts or intermittent resources in daily generation plan	WECC		
Modify protocols to allow full use of dynamic scheduling of resources between control areas	CAO		
Assess the potential and complexity of modifying CA ISO scheduling protocols to reduce lead times for hour ahead and day ahead scheduling	CA ISO		
Modify market rules to allow for more frequent scheduling updates for intermittent resources	CA ISO Market Participant		
Investigate best practices in wind energy forecasting, and implement in California for daily/hourly production planning	CAO/ Energy Commission	Yes	Compliance with NERC CPS and percent reduction in regulation requirements
Evaluate the normal wind production forecasting error, to assess whether additional operating reserves are needed to backstop wind in the hourly plan	CAO/Energy Commission	Yes	
Establish system to track wind production forecast accuracy	CAO		

Solution F – Ensure Adequate Generator Performance Standards are in Place with Clarity of Implementation to Ensure System Performance

In April of this year to ensure grid reliability, the WECC Board approved a low voltage ride-through performance standard that is scheduled to be implemented in March of 2006.

The frequency response of generating resources in WECC has been deteriorating over the last two decades for various reasons and is not uniquely related to the introduction of renewable resources onto the system. The reliability authorities (e.g., transmission owner, CAO and reliability regions) collectively need to perform the necessary evaluations and assessment to accurately determine those generation attributes that relate to frequency, as well as the minimum acceptable performance level of the attribute, that are essential to grid reliability.

Actions Required	Owner	Research	Metric
Monitor and track the CAOs frequency response performance during system disturbances	CAO/WECC surveys		Metric, as established in WECC survey
Monitor performance to WECC generator voltage performance standard	CAO/WECC via RMS		Compliance with new standard, effective 2006
Determine if there is a need for a governor frequency response and ride-through standard	CAO/WECC		

Solution G – Actively Manage Generation Output which Exceeds Planned Levels, or When Total Generation Exceeds Load

Research methodologies for generation management and determine if their application is appropriate for California. Germany has implemented methodologies whereby a portfolio of generators can be "controlled" to limit output in the event of over generation that threatens reliability.

Actions Required	Owner	Research	Metric
For current and forecast years, identify those periods when generation would exceed hourly loads (minimum loads)	CAO/Energy Commission	Yes	Minimum load hours per year and MWh/hr
Identify capability of reducing power output from generating resources, such as wind, coal, nuclear, gas, and hydro during minimum load periods	LSEs		
Establish monitoring systems to track performance of LSEs and CAO in managing generation during minimum load periods	LSE and CA ISO		
Establish criteria to economically and efficiently manage generation during minimum load periods	CA ISO and CPUC		
Assess impact of geographic diversity to mitigate wind generation feathering impacts on system operation (sudden loss of large amounts of wind generation)	Energy Commission	Yes	Minimum load hours per year and MWh/hr
Assess resource development (including resource type, new designs, and geographic diversity) impacts on system development	Energy Commission annual assessment		
Develop a state-wide strategy to maximize the efficient use of the existing pumped storage facilities	Energy Commission	Yes	
Determine the need for additional storage facilities	Energy Commission	Yes	

Solution H – Improve Transmission Studies

Historically, studies focus on assuring reliability during peak load conditions. With the changing resource mix, it is important to expand the focus of transmission studies and for utilities to identify and fix vulnerabilities that may be present during non-peak system conditions. Utility actions may involve additional investments on the transmission system to address local voltage support, deliverability, congestion management, bottlenecks and reliability. This will require a coordinated effort between utilities, CAO and WECC as well as support of regulators to make the necessary investments for strengthening the grid.

Actions Required	Owner	Research	Metric
Develop off-peak and shoulder peak WECC study cases	CA ISO request WECC PCC		
Investigate impacts on transfer capability of changing the resource portfolio toward renewables	CA ISO request WECC PCC		
Investigate new tools/solutions to increase interregional transfer capability	Energy Commission or WECC	Yes	
Investigate alternative projects/proposals to expand grid	Energy Commission/CPUC and CA ISO	Yes	
Perform routine transmission system loading vulnerability assessments	LSE/CAO		

Solution I – Improve Modeling of Renewables

Accurate data and information related to renewable resources need to be readily available to those entities required to perform the necessary grid reliability studies, including the deployment of the necessary monitoring devices and necessary infrastructure.

Actions Required	Owner	Research	Metric
Assure all necessary data and information required for simulation and power flow studies is available	AWEA		
Deployment of the necessary monitoring devices and infrastructure to acquire meteorological data	Energy Commission	Yes	Actual deployment vs. required deployment

Solution J - Improve Production Forecasting

Integration of large amounts of intermittent renewable resources increases the forecast error and variability of renewable energy production from one day to the next or one hour to the next. This variability and volatility in production presents challenges to system operators and reliability managers. Research to improve production forecasting – better wind data, improved methodologies to correlate wind data and production data, survey of state-of-the-art methodologies in use – is needed as part of California's renewable development effort.

Actions Required	Owner	Research	Metric
Investigate best practices in wind energy forecasting and implement with state-of-the-art forecasting tools	CAO/Energy Commission	Yes	Hourly and daily forecast errors
Continue efforts to improve wind monitoring and data gathering	CAO/Energy Commission	Yes	

RECOMMENDED NEXT STEPS

The study team researched solution options to address the operational issues to integrate renewables without adverse impacts on reliability or operations. These solution options provide the Energy Commission with a list of action items that are recommended for follow up activities. The following tables of this section of the report identifies key activities, such as coordination, studies and research that require a handoff to the appropriate organization, individual, or group to take ownership of the action items identified in the various solutions.

Coordination

Lead	Coordinating Parties	Action Item/Deliverable
CERTS Study Team	Meet with Energy Commission work groups and CA ISO's new renewables work group	Share and discuss results of this study
CA ISO	Coordination with Control Area Utilities	AGC modifications required to achieve greater participation of hydro resources on AGC
CA ISO	Coordination with WECC and Market Participants	Energy scheduling protocol changes that could facilitate integration of renewables.
Energy Commission	Coordination with the state's utilities and CA ISO	A strategy to maximize the use of existing pumped storage facilities.
CA ISO	Work with the WECC Member systems	Expand the availability of off-peak and shoulder peak cases and study of intermittent resource impacts.
CALWEA	Coordinate with CAOs and TOs	Assure all necessary data and information required for studies is available.

Studies

Lead	Coordinating Parties	Action Item/Deliverable
Energy Commission	Work with the state's CAOs and utilities	Identification of impacts of DWR contract drop-off, QF drop-off, Mohave plant shut down and other known resources changes on the identified operational issues.
CA ISO	Work with the WECC Member systems	Determination of need for a frequency response standard.
SCE	Tehachapi Working Group	Detailed ongoing wind Integration Study for Tehachapi Development

Research

Lead	Coordinating Parties	Action Item/Deliverable
CA ISO	Research Initiative	▪ Attribute Requirements - Define current and future control area attribute requirements. ▪ Minimum Load - Develop a forecast of future minimum load problems (number of events annually and depth of problem)
Energy Commission/CA ISO	Utility and Industry Stakeholders	Research and test alternative pricing schemes for operating attributes and integrate with market design.
CA ISO	Research Initiative	Load as a Provider of Resource Attributes – Determine: ▪ The resource attributes that could be provided by dispatchable load, ▪ Pricing of those key attributes, ▪ Infrastructure requirements to integrate load as a controllable device, and ▪ Automatic load control requirements

Lead	Coordinating Parties	Action Item/Deliverable
Energy Commission	Research or Deployment Initiative	Improve Production Forecasting – Initiate a research, evaluation, and deployment initiative to: ▪ Investigate best practices and tools for wind energy forecasting, and ▪ Identify Wind monitoring requirements and deploy needed monitoring equipment
Energy Commission	Research Initiative	Increase Interregional Transfer Capability – Investigate new tools/solutions to increase interregional transfer capability.

Monitoring

Lead	Coordinating Parties	Action Item/Deliverable
Energy Commission	**Performance Monitoring**	**Establish the necessary processes to monitor and track the metrics identified in Solutions A-J**

Progress on these actions items needs to be tracked and reported to the Energy Commission on an ongoing basis to make necessary course corrections in subsequent IEPRs.

APPENDIX A
ANALYSIS METHODOLOGY AND SUPPORTING DETAIL

2010 CA ISO Chronological Hourly Renewable Energy Production

The CA ISO control area data was used for the purpose of quantifying the operational issues of integrating 2010 accelerated RPS generation. 2004 actual hourly renewable production data aggregated by region within the CA ISO control area was supplied confidentially to the Electric Power Group by the CA ISO solely for purposes of this study.[9]

The renewable energy supply scenario to meet statewide accelerated RPS demand contained in the *Energy Commission Renewable Resources Development Report* (Energy Commission Report)was utilized for this study. Resource type and location data for both energy and capacity is derived from this report[10]. The Energy Commission scenario for total statewide additional renewable supply to meet accelerated RPS goal totaled 24,800 GWh and the breakdown is shown in Table 4 below.

Table 4
Renewables Additions to Meet RPS by 2010

	(GWh)	(%)
Biomass	2,165	9
Geothermal	5435	22
Small Hydro	0	0
Solar	265	1
Wind	16,935	68
Total	24,800	100

Source: Energy Commission

Of the 24,800 GWh of additional renewable energy, 16,800 GWh[11] was attributable to the CA ISO control area.

The Energy Commission scenario statewide cumulative renewable resource energy demand and percentage mix by location and by year is provided in Table 5. A breakdown of renewable resource additions contained in the Energy

Commission Report is provided in Tables 5 and 6. Table 5 provides the energy production and mix from renewable resource additions. Table 6 provides capacity mix and capacity factors from renewable resource additions.

For the 2010 analysis, 68 percent of total California renewable resource additions are attributable to the CA ISO control area.

Table 5
Renewable Capacity Additions by Location and Resource (GWh)

Renewable Capacity Additions by Location and Resource - GWh					
All Regions					
Year	**Biomass**	**Geothermal**	**Solar**	**Wind**	**Total**
2005	925	945	-	4,250	6,120
2008	1,955	3,345	-	12,550	17,850
2010	2,165	5,435	265	16,935	24,800
2017	2,475	7,985	395	19,755	30,610
PG&E and small utilities in Northern California					
Year	**Biomass**	**Geothermal**	**Solar**	**Wind**	**Total**
2005	400	-	-	1,120	1,520
2008	555	900	-	1,800	3,255
2010	555	1,255	-	1,815	3,625
2017	865	2,310	-	1,875	5,050
SCE and small utilities in Southern California					
Year	**Biomass**	**Geothermal**	**Solar**	**Wind**	**Total**
2005	365	945	-	2,520	3,830
2008	1,190	2,445	-	9,525	13,160
2010	1,400	4,180	265	13,895	19,740
2017	1,400	5,675	395	16,655	24,125
SDG&E and Escondido utilities					
Year	**Biomass**	**Geothermal**	**Solar**	**Wind**	**Total**
2005	160	-	-	610	770
2008	210	-	-	1,225	1,435
2010	210	-	-	1,225	1,435
2017	210	-	-	1,225	1,435
All Regions					
Year	**Biomass**	**Geothermal**	**Solar**	**Wind**	**Total**
2005	15%	15%	0%	69%	100%
2008	11%	19%	0%	70%	100%
2010	9%	22%	1%	68%	100%
2017	8%	26%	1%	65%	100%
PG&E and small utilities in Northern California					
Year	**Biomass**	**Geothermal**	**Solar**	**Wind**	**Total**
2005	26%	0%	0%	74%	100%
2008	17%	28%	0%	55%	100%
2010	15%	35%	0%	50%	100%
2017	17%	46%	0%	37%	100%
SCE and small utilities in Southern California					
Year	**Biomass**	**Geothermal**	**Solar**	**Wind**	**Total**
2005	10%	25%	0%	66%	100%
2008	9%	19%	0%	72%	100%
2010	7%	21%	1%	70%	100%
2017	6%	24%	2%	69%	100%
SDG&E and Escondido utilities					
Year	**Biomass**	**Geothermal**	**Solar**	**Wind**	**Total**
2005	21%	0%	0%	79%	100%
2008	15%	0%	0%	85%	100%
2010	15%	0%	0%	85%	100%
2017	15%	0%	0%	85%	100%

Source: Energy Commission

Table 6
Renewable Capacity Additions by Location and Resource - MW

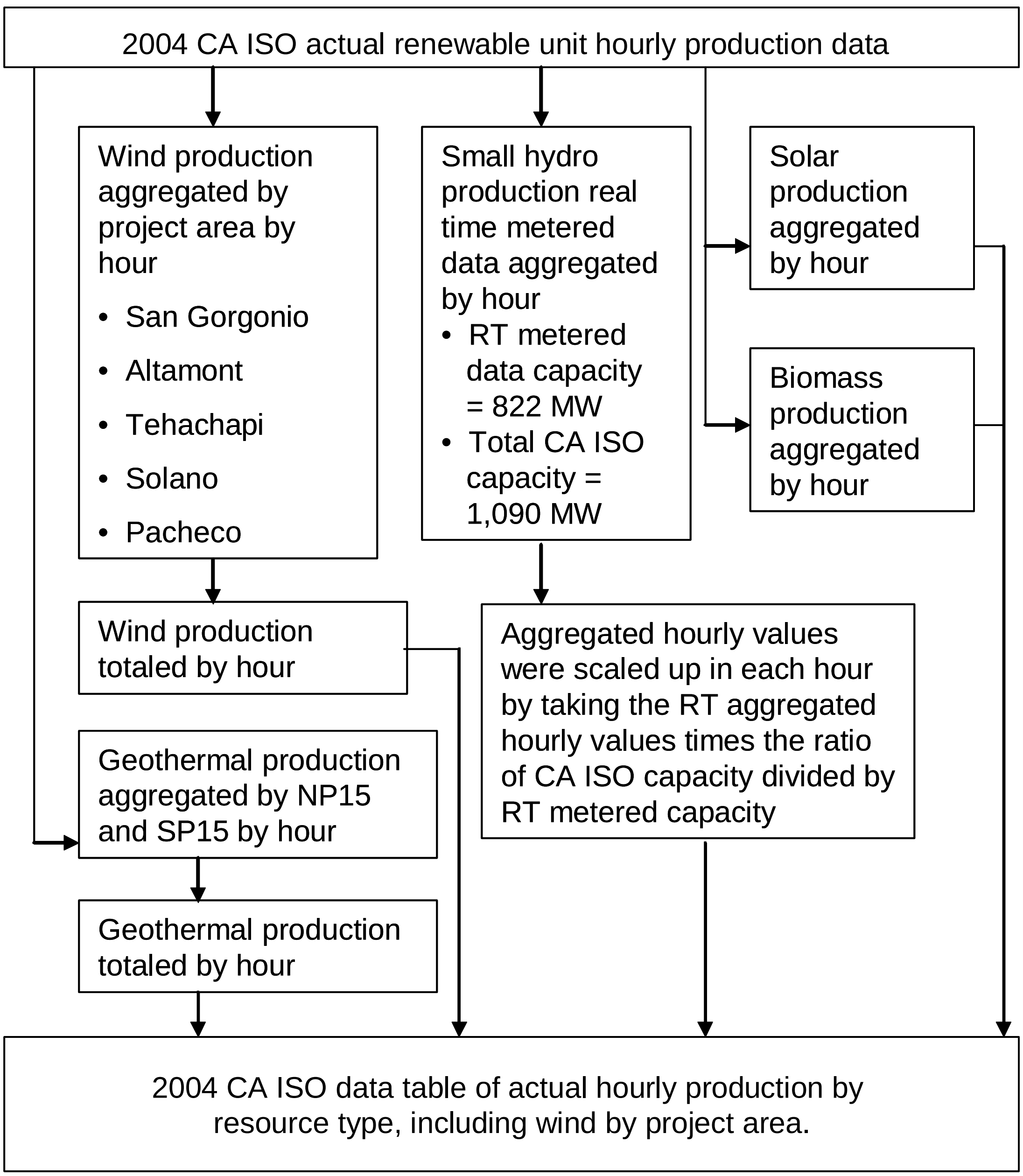
Renewable Capacity Additions by Location and Resource - MW					
All Regions					
Year	**Biomass**	**Geothermal**	**Solar**	**Wind**	**Total**
2005	125	120	-	1,390	1,635
2008	272	425	-	4,095	4,792
2010	302	690	120	5,525	6,637
2017	347	1,015	180	6,445	7,987
PG&E and small utilities in Northern California					
Year	**Biomass**	**Geothermal**	**Solar**	**Wind**	**Total**
2005	55	-	-	365	420
2008	75	115	-	585	775
2010	75	160	-	590	825
2017	120	295	-	610	1,025
SCE and small utilities in Southern California					
Year	**Biomass**	**Geothermal**	**Solar**	**Wind**	**Total**
2005	50	120	-	825	995
2008	167	310	-	3,110	3,587
2010	197	530	120	4,535	5,382
2017	197	720	180	5,435	6,532
SDG&E and Escondido utilities					
Year	**Biomass**	**Geothermal**	**Solar**	**Wind**	**Total**
2005	20	-	-	200	220
2008	30	-	-	400	430
2010	30	-	-	400	430
2017	30	-	-	400	430

All Regions				
Year	**Biomass**	**Geothermal**	**Solar**	**Wind**
2005	84%	90%	N/A	35%
2008	82%	90%	N/A	35%
2010	82%	90%	25%	35%
2017	81%	90%	25%	35%
PG&E and small utilities in Northern California				
Year	**Biomass**	**Geothermal**	**Solar**	**Wind**
2005	83%	N/A	N/A	35%
2008	84%	89%	N/A	35%
2010	84%	90%	N/A	35%
2017	82%	89%	N/A	35%
SCE and small utilities in Southern California				
Year	**Biomass**	**Geothermal**	**Solar**	**Wind**
2005	83%	90%	N/A	35%
2008	81%	90%	N/A	35%
2010	81%	90%	25%	35%
2017	81%	90%	25%	35%
SDG&E and Escondido utilities				
Year	**Biomass**	**Geothermal**	**Solar**	**Wind**
2005	91%	N/A	N/A	35%
2008	80%	N/A	N/A	35%
2010	80%	N/A	N/A	35%
2017	80%	N/A	N/A	35%

CA ISO 2004 Actual Renewable Energy Production

CA ISO 2004 actual hourly renewable energy production was aggregated according to the flow chart in Figure 15. Production total by resource type is shown in Table 7, column (a), and totaled 19,625 GWh. Geothermal generation represents the largest source of renewable generation in 2004 or 43 percent of the total. The remaining generation is diversified among biomass, small hydro, and wind with solar representing only 4 percent of the total.

Figure 15
2004 CA ISO Actual Renewable Unit Hourly Production Data



CA ISO control area renewable additions of 16,800 GWh were added to the actual 2004 production to estimate the 2010 total renewable generation of 36,370 GWh as shown in Table 7.

Table 7
CA ISO Energy Mix

CAISO Energy Mix						
	2004 Actual (GWh)	2004 Actual (%)	Renewable Additions (GWh)	Renewable Additons (%)	2010 Total Renewable (GWh)	2010 Total Renewable (%)
	(a)	(b)	(c)	(d)	(a+c)	(e)
Biomass	3,261	17%	1,460	9%	4,720	13%
Geothermal	8,359	43%	3,670	22%	12,030	33%
Small Hydro	3,284	17%	-	0%	3,280	9%
Solar	708	4%	180	1%	890	2%
Wind	4,013	20%	11,440	68%	15,450	42%
Total	19,625	100%	16,800	100%	36,370	100%

Note: Totals may not add due to rounding

The majority of CA ISO accelerated RPS resources additions come from wind and geothermal assumed to be 68 and 22 percent, respectively.

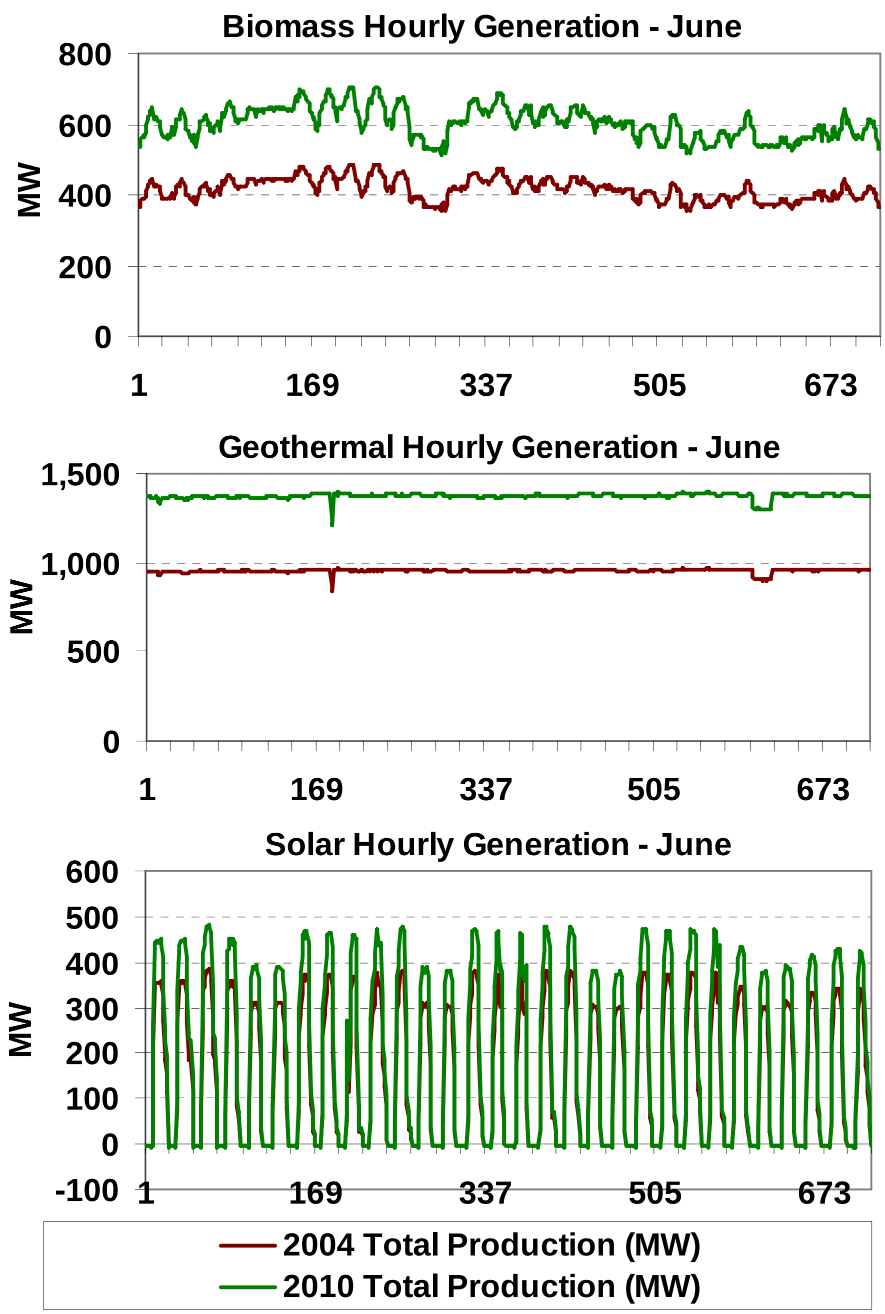
The CA ISO actual chronological hourly renewable production profile for 2004 was utilized to scale up the hourly values to represent the 2010 renewable production. The methodology used by resource type is discussed in the following section.

2010 CA ISO Chronological Hourly Resource Profiles

Biomass, Geothermal, and Solar

Hourly profiles, by resource type, were calculated by multiplying the actual hourly aggregated 2004 generation values by the ratio of 2010 energy divided by 2004 actual energy as provided in Table 7. Generation profiles for the month of June are provided for illustration in Figure 16 by resource technology.

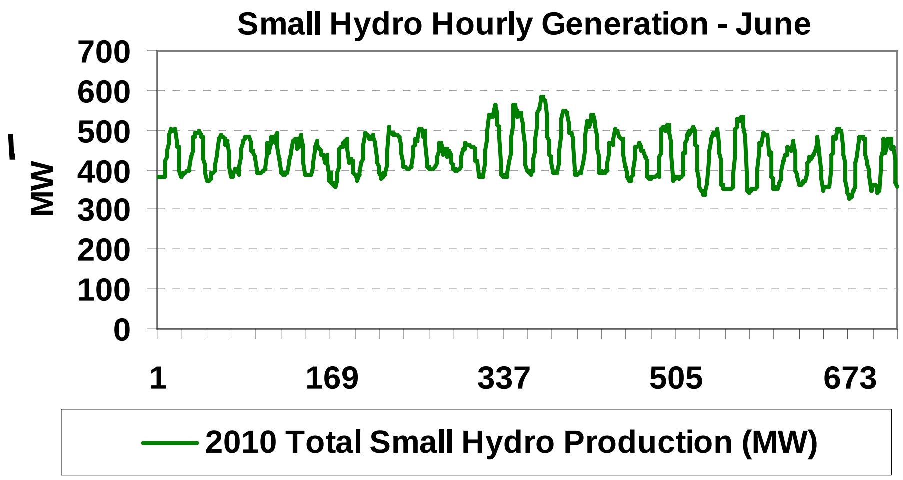
Figure 16
Total Production (MW) 2004 and 2010



Small Hydro

No incremental small hydro was identified in the accelerated RPS scenario. The 2004 actual hourly profile was assumed to be unchanged in 2010 and is illustrated for the month of June in Figure 17.

Figure 17
2010 Total Small Hydro Production (MW)



2004 CA ISO actual wind production totaled 4,013 GWh and is shown by project area in Table 8. Installed wind capacity is based on AWEA[12] wind energy resource installed capacity. Historical capacity factors are in the mid twenties.

Table 8
2004 Wind Production by Location

	2004			
Service Area	**AWEA Wind Capacity (MW)**	**CA ISO Wind Energy (Gwh)**	**Coincident Maximum Recorded Wind Energy (MWh)**	**Capacity Factor**
PG&E & small utilities	**684**	**1,528**		**25%**
- Altamont	548	972		20%
- Pacheco	16	21		15%
- Solano	120	534		51%
SCE & small utilities	**1,225**	**2,485**		**23%**
- Tehachapi	609	1,292		24%
- San Gorgonio	616	1,193		22%
SDG&E & small utilities	-	-		
Total	**1,909**	**4,013**	**1,472**	**24%**

Pacific Gas & Electric (PG&E) actual energy production would imply a capacity factor exceeding 100 percent using the AWEA Solano capacity of 60 MW for PG&E. Actual allocation of Solano capacity by county and control area is unknown. Therefore, an assumption was made to increase PG&E Solano capacity by 60 MW, allocated from SMUD, in order to reasonably reconcile with CA ISO actual 2004 energy production.

California statewide wind accelerated RPS resource additions total 5,525 MW and are shown by project area in Table 9. Total energy production is 16,935 GWh. These resources are assumed to have a 35 percent capacity factor based on the Energy Commission scenario forecast.

Table 9
2005 to 2010 Wind Additions

Service Area	2005 to 2010 Wind Additions		
	Capacity (MW)	Energy (GWh)	Capacity Factor
PG&E & small utilities	**590**	**1,815**	**35%**
- Altamont	186	573	35%
- Pacheco	4	12	35%
- Solano	400	1,230	35%
SCE & small utilities	**4,535**	**13,895**	**35%**
- Tehachapi	3,730	11,435	35%
- San Gorgonio	805	2,460	35%
SDG&E & small utilities	400	1,225	35%
Total	**5,525**	**16,935**	**35%**

CA ISO forecast 2010 wind generation totals 5,631 MW and produces 15,453 GWh of generation as shown in Table 10. Both capacity and energy was assumed to be equal to actual 2004 plus the California statewide accelerated RPS values multiplied by the CA ISO/CA ratio.

Table 10
CA ISO Wind Generation

Project Area	CA ISO Wind Generation							
	2004				2010			
	AWEA Installed Capacity (MW)	Wind Energy (Gwh)	Coincident Wind Energy (MW)	Capacity Factor	Installed Capacity (MW)	Wind Energy (Gwh)	Coincident Wind Energy (MW)	Capacity Factor
PG&E & small utilities	684	1,528		25%	1,083	2,754		29%
- Altamont	548	972		20%	674	1,359		23%
- Pacheco	16	21		15%	19	29		18%
- Solano	120	534		51%	390	1,365		40%
SCE & small utilities	1,225	2,485		23%	4,279	11,872		32%
- Tehachapi	609	1,292		24%	3,122	9,017		33%
- San Gorgonio	616	1,193		22%	1,157	2,855		28%
SDG&E & small utilities	-	-		0%	269	828		35%
Total	1,909	4,013	-	24%	5,631	15,453	5,457	31%

CA ISO 2010 hourly wind data has an installed wind capacity of 5,631 MW with a maximum coincident production of 5,457 MW and an average capacity factor of 31 percent.

Hourly generation profiles, by project area, were calculated by multiplying the 2004 actual hourly aggregated generation values by the ratio of 2010 energy divided by 2004 actual energy as provided in Table 10. For some hours the hourly generation values exceeded the project area installed wind capacity. In these hours the energy production was limited to the installed capacity. All other hours were multiplied by a scalar factor, capped at the installed capacity, until the integrated energy equaled the forecast energy by project area. The magnitude of project area specific scalar factors is shown in Table 11 and was deemed negligible for study purposes.

San Diego has no historical wind generation profile. Therefore, San Gorgonio was used as a proxy for calculating the San Diego wind profile.

Table 11
Scalar Factors

Service Area	Project Area	Hourly Scalar
PG&E & small utilities	Altamont	1.000
PG&E & small utilities	Pacheco	1.000
PG&E & small utilities	Solano	1.017
SCE & small utilities	San Gorgonio/SD	1.001
SCE & small utilities	Tehachapi	1.008
SDG&E & small utilities	Total	1.030

Sample week generation profiles for the three largest project areas are shown in Figures 18 through 20 below.

Figure 18
Wind Generation 2004 & 2010 Tehachapi

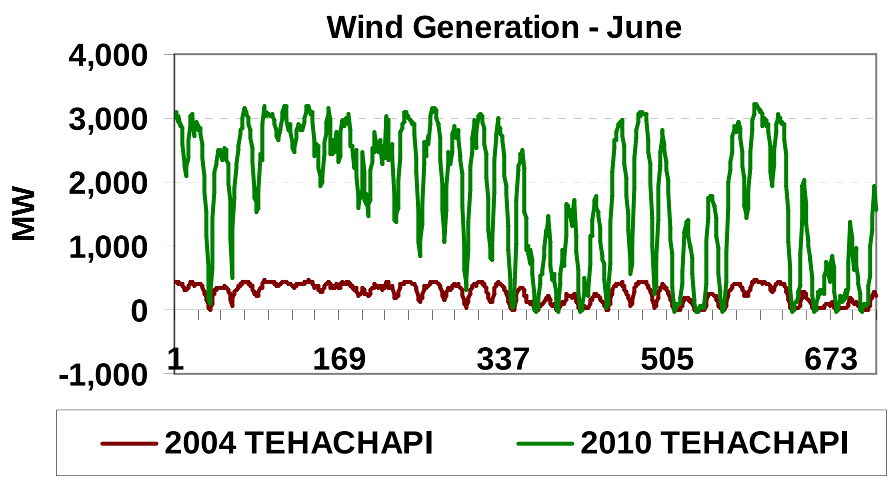


Figure 19
Wind Generation 2004 & 2010 San Gorgonio

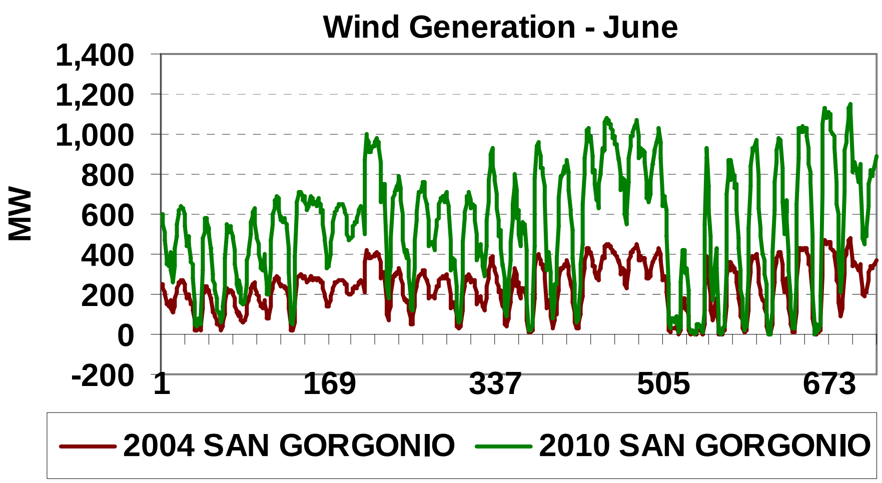
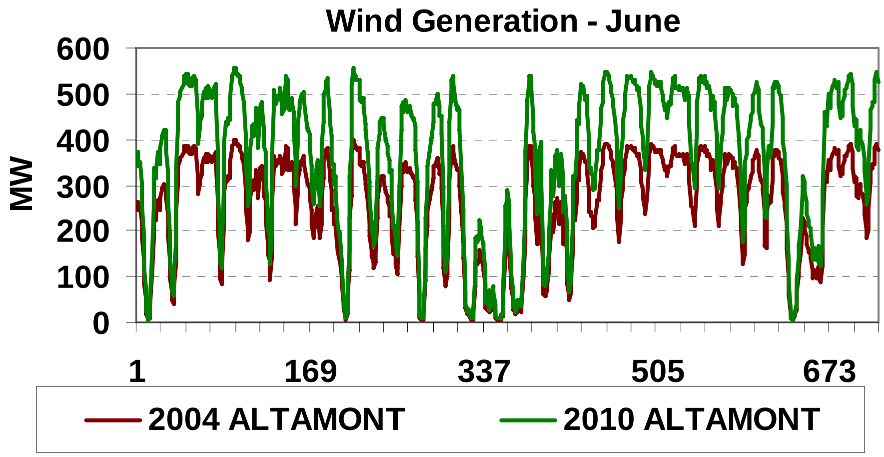


Figure 20
Wind Generation 2004 & 2010 Altamont



Appendix B
California Energy Commission
Workshop Links
(February 3, 2005 and May 10, 2005)

For the reader's convenience, listed below are reference links to the materials presented at the February 3 and May 10 Workshops. All links may be found at the California Energy Commission's website in support of the Energy Commission's 2005 IEPR process.

Committee Workshop on Transmission - Renewables Integration Issues #1
February 3, 2005

http://www.energy.ca.gov/2005_energypolicy/documents/index.html#020305

Notice for the Workshop

Agenda and List of Issues and Questions for the Workshop

Transcript of Committee Workshop
<http://www.energy.ca.gov/2005_energypolicy/documents/2005-02-03_workshop/2005-02-03_TRANSCRIPT.PDF> (June 29, 2005)

Documents, Reports and Presentations

"Wind Generation Operating Issues: CA ISO Perspective & Experience". (Corrected) Presentation by Yuri Makarov and David Hawkins, CA ISO.

"Wind Generation Operating Issues: CA ISO Perspective & Experience". Presentation by Yuri Makarov and David Hawkins, CA ISO

"Intermittency Management and High Penetration Renewables". Presentation by Nicholas W. Miller and James P. Lyons, GE Energy.

"Assessment of Reliability and Operational Issues for Integration of Renewable Generation". Presentation by Jim Dyer, Electric Power Group.

Assessment Of Reliability and Operational Issues for Integration of Renewable Generation: *Background Material for California Energy Commission Stakeholder Workshop - Consultant Report*. Energy Commission publication # CEC-100-2005-004. Dated: January 17, 2005.

Public Comments

Comments Submitted on the Committee Workshop.

Committee Workshop On Renewables Operational Integration Issues #2. May 10, 2005

http://www.energy.ca.gov/2005_energypolicy/documents/index.html#051005

Notice for the Workshop - revised.

Agenda and Panel Questions for the Workshop

Transcript of the Workshop

Documents, Reports and Presentations

Assessment of Reliability and Operational Issues for Integration of Renewable Generation - Draft Consultant Report. Energy Commission publication # CEC-700-2005-009-D.

"WECC Low Voltage Ride Through Standard". Presentation by Jeffrey Miller, CA ISO.

"Assessment of Reliability and Operational Issues for Integration of Renewable Generation". Presentation by Jim Dyer, Electric Power Group. Updated.

"Wind Generation Forecasting: Status and Prospect for Improving System Integration". Presentation by Robert Zavadil, EnerNex Corp.

APPENDIX C
ANALYSIS SENSITIVITIES AND ALTERNATIVES

Assessment of 2010 Operational Issues for Variations in the Renewable Portfolio Energy Resource Mix

Introduction

At the May 10, 2005, Energy Commission Renewable Integration workshop, several stakeholders commented on the possible impact of different renewable portfolio energy resource mix assumptions other than the one used for the CERTS May Progress report.
[http://www.energy.ca.gov/2005_energypolicy/documents/index.html#051005]
Four different alternative scenarios were selected for analysis and comparison to the base case used in the May Progress report. Each of the four alternative scenarios maintained the 2010 total renewable energy production, but not necessarily the capacity. However, because the analysis methodology focuses on the residual load after deducting the renewable resource production, the total amount of renewable capacity does not affect the result. The four alternative scenarios are:

1. Increased geothermal energy mix, offsetting a like amount of Tehachapi wind energy;
2. Increased solar energy mix, offsetting a like amount of Tehachapi wind energy;
3. Altered mix of wind sources (increased Altamont energy, decreased Tehachapi energy); and
4. Replace the entire Tehachapi energy production with the California Wind Energy Collaborative/National Renewable Energy Laboratory (NREL) energy model[13] (scaled to the same energy production as in the 2010 base case for Tehachapi).

For each of these four alternative scenarios, an analysis was performed on the residual load after deducting the renewable resource production, and three key operational metrics were assessed:

1. Load following impacts;
2. Minimum load impacts; and
3. Ramping impacts (focusing on the six hour-to-hour ramp requirements)

Summary of Findings

Increasing either geothermal[14] or solar energy compared to the 2010 Energy Commission renewable portfolio scenario base case, and displacing a like amount of proposed Tehachapi wind energy production, reduces the need for additional controllable generation to manage load following, minimum load, and ramping issues.

Altering the Energy Commission RPS scenario year 2010 base case mix of solar, geothermal, wind and small hydro generation will alter the magnitude of the key operational metrics assessed in the CERTS May Progress report. The changes in the key operational metrics resulting from the three alternative energy mix scenarios are presented in Table 12. For the following three key operational metrics, the energy mix change that had the largest incremental benefit is discussed below:

- Load following – residual daily load swing

  Displacing some wind[15] generation with solar generation will decrease the maximum and average residual daily load swings by 114 MW and 54 MW for each 100 MW of solar added, respectively. Displacement of wind generation with geothermal produces similar reductions in residual daily load swings.

- Minimum load –
  - Daily annual average - Displacing some wind generation with solar generation will increase the average residual minimum load by 33 MW for each 100 MW of solar added. (Higher minimum loads will generally be easier for the operators to manage than lower minimum loads.)

  - Daily annual minimum - Displacing some wind generation with geothermal generation will increase the daily annual minimum load by 174 MW for each 100 MW of geothermal added.

- Ramping – 6 hour-to-hour

  Displacing some wind generation with solar generation will reduce ramping requirements. The number of events with ramps up to 16 GW is reduced by 2.7 occurrences per year for every 100 MW of solar added (replacing an equivalent amount of wind energy).

Replacing the scaled, recorded wind energy production at Tehachapi with the wind energy production model developed by the California Wind Energy Collaborative/NREL reduces the average residual daily load swing by 100 MW, and the maximum residual daily load swing by 1.0 GW. The six hour-to-hour ramps for the Wind Collaborative model were essentially the same as for the recorded wind energy production models at the 12 GW and 16 GW ramp levels. The results are summarized in Table 13. It should be noted, however, that the significant reduction in maximum residual daily load swing may result from the use of non-load-correlated wind patterns in the Wind Collaborative profiles. Overall, however, the conclusion is that the operational metrics based on the Wind Collaborative wind energy patterns are similar to those developed by CERTS using scaled recorded 2004 wind energy production.

The results of these four alternative sensitivities analysis does change the findings, policy options, and solution sets presented in this report.

Table 12
Impact of 100 MW Shift in Renewable Resource Mix

Impact of 100 MW Shift in Renewable Resource Mix[1]			
	Case 1 Geothermal Offsetting Tehachapi Wind	**Case 2** Solar Offsetting Tehachapi Wind	**Case 3** Altamont[2] Wind Offsetting Tehachapi Wind
Load Following			
Residual Daily Load Swing			
Maximum (MW)	+ 98	+ 114	- 3
Average (MW)	+ 39	+ 54	- 2
Minimum Load			
Daily			
Average (MW)	+ 23	+ 33	+ 2
Minimum (MW)	+ 174	+ 73	- 15
Ramping			
6 hour-to-hour			
# of events up to 16 GW	+ 2.4	+ 2.7	0

1 Plus improvement in metric minus degradation in metric

2 Similar results are observed if Solano is substituted for Altamont

Table 13
Impact of Using California Wind Collaborative Wind Profile

Case 4 - CA Wind Energy Collaborative Profile			
	2010 Base Case	Case 4 Value	Case 4 Change from Base Case[4]
Load Following[1]			
Residual Daily Load Swing			
Maximum (GW)	24.1	23.0	-1.0
Average (GW)	12.2	12.1	-0.1
Minimum Load[2]			
Daily			
Average (GW)	18.0	18.0	0.0
Minimum (GW)	13.4	13.8	0.4
Ramping[3]			
6 hour-to-hour			
# of events up to 16 GW	28	30	2

1 Negative delta decreases control range requirement

2 Positive delta decreases need for downward control range off-peak

3 Positive delta increases need for controllable ramp rate capability

4 Difference may not add due to rounding

APPENDIX D
GENERATION RESOURCE ATTRIBUTES

Resource Attributes	Needed for Reliability	Needed for Operational Integration	Description of Attribute	Impact(s) of Not Providing Quantity
Energy	X	X	Ability to produce energy of a suitable quality for delivery to the grid	Inability to meet load
Fast start-up capability	X	X	The ability to meet energy and capacity needs in the short-term (minutes)	Inability to meet NERC CPS and DCS standards
Dependable Start-up capability, with predictable start-up time	X		The ability to provide replacement capacity when requested	Inability to meet NERC CPS
Ramping (Normal and Fast Capability)	X	X	The ability to adjust production (up and down) to accommodate planned and unplanned changing conditions (i.e., DCS events, scheduled interchange)	Inability to meet NERC CPS
Automatic Generation Control (AGC)	X	X	The ability to meet changing energy needs on a continuous basis very short-term (seconds)	Inability to meet NERC CPS and DCS standards
Ride Through Capability - Voltage	X		The ability to withstand a short-term (seconds) voltage decay without it impacting production	Avoid making a grid problem an adequacy of supply problem.

Resource Attributes	Needed for Reliability	Needed for Operational Integration	Description of Attribute	Impact(s) of Not Providing Quantity
Ride Through Capability - Frequency	X		The ability to withstand a short-term (seconds) frequency deviation without it impacting production	Avoid making a grid or interconnection problem an adequacy of supply problem. Inability to meet WECC generator performance standards for over/under frequency performance
Short Circuit Contribution	X		Ability to contribute to the short circuit duty required to clear faulted equipment from the grid	Avoid cascading events
Predictability	X	X	Ability to accurately forecast production in the short-term (hour-ahead)	Avoid making a forecast error problem an adequacy of supply problem
Controllability	X	X	Ability to control the output of the generator to a set profile	Avoid making an individual generator control problem a grid control problem
Reliability	X		Ability to provide the desired generator characteristics with a high degree of certainty	Low reliability will reduce the capacity value of a specific generator, requiring higher reserves to protect against the loss of that generator.

Resource Attributes	Needed for Reliability	Needed for Operational Integration	Description of Attribute	Impact(s) of Not Providing Quantity
Voltage and VAR Support	X		Ability to maintain a voltage and VAR schedule during steady state conditions, and to provide predictable voltage support during transient conditions on the grid	Comply with WECC standard
Power System Stabilizer	X		Ability to contribute to the interconnected system dampening requirements	Comply with WECC standard
Governor Response (Droop)	X		Ability to contribute to the interconnected system frequency support requirements during transient conditions (in sub-second and second time frames)	Comply with WECC standard
Dispatchability		X	Ability to adjust production (up and down and on/off) to meet the changing conditions of load and intermittent resources	Inability to meet NERC CPS and DCS
Reserves/ Location	X	X	Ability to have adequate deployable resources to meet un-expected events (e.g., forced outages, high forecast errors)	Compliance with WECC MORC and inability to meet NERC CPS and DCS standards
Resource Location	X	X	Ability to have generating resources strategically located to mitigate grid problems and to reduce transmission infrastructure costs	Potential for stranded load or generation pockets under certain conditions and higher transmission infrastructure costs

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[6] Development of the 2010 forecast hourly renewable generation is discussed in Appendix A.

[7] California Wind Energy Collaborative/NREL energy model for Tehachapi wind resource provided by Michael Milligan, NREL, on May 9, 2005.

[8] CDWR-CERS contract portfolio begins to drop off significantly starting in 2010. Contract renegotiations impacting the portfolio prior to 2010 could improve operating flexibility.

[9] The provision of information by the CA ISO for purposes of this study does not necessarily constitute agreement by the CA ISO with the findings or recommendations in this report. Further, publication of this report does not make public the underlying information provided by the CA ISO.

[10] Commission Report, November 2003; 2003-11-24_500-03-080F, Tables 15 and 16.

[11] Draft Staff White Paper, July 30, 2004, 2004-07-30_100-04-003D, Appendix A (2). Estimation of energy Requirements to meet California's RPS by 2010, Column M, Row 168.

[12] http://www.awea.org/projects/california.html.

[13] California Wind Energy Collaborative/NREL energy model for Tehachapi wind resource provided by Michael Milligan, NREL, on May 9, 2005.

[14] Or other base load resource could be substituted.

[15] Displaced wind generation is from the Tehachapi project area.