California Renewables Portfolio Standard Renewable Generation Integration Cost Study: Multi-Year Analysis

Sacramento, California

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Agenda

- Overview & Background
- Multi-Year Analysis
  - Capacity Credit
  - Regulation
  - Load Following
- Recommendations
- Open Discussion

Analysis Team

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Extended Group

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- Gary Allen, *Southern California Edison*
- Tom Miller, *Pacific Gas & Electric Company*
- Don Smith, *CPUC – Office of Ratepayer Advocates*
- Ed Kahn, *Analysis Group*
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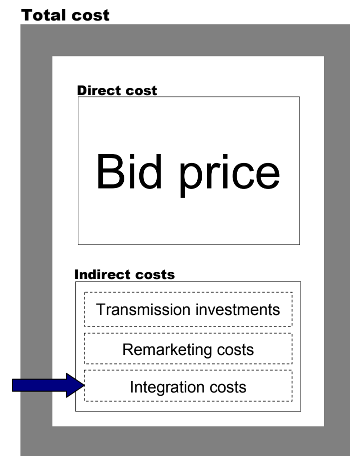
California Renewables Portfolio Standard

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



Phase I

- Defined categories of integration costs
  - Capacity credit
  - Regulation
  - Load following
- Defined methodologies for valuation
- Performed one year analysis of 2002 for biomass, geothermal, solar, and wind
  - Used actual system and aggregated generation data provided by CaISO
  - Majority of data was confidential
- Final report released December 2003; workshop in February 2004

Phase II

- Studies of technologies and site characteristics that impact integration costs.
- Geothermal study conducted by Jim Lovekin, GeothermEx, Inc.
- Wind study conducted by Kevin Jackson, Dynamic Design Engineering, Inc.
- Reports submitted to CEC in mid 2004.

Phase III

- Recommendations for implementation of integration cost calculation
  - Practical questions
    - Who will perform the integration cost calculations?
    - How often will the cost calculations be updated?
    - How will the data be obtained and verified?
    - How can integration cost valuation be practically incorporated into the RPS bid evaluation process?
  - Establish an Integration Cost Analyst
    - Collects and collates all the necessary data components
    - Periodically updates and publishes integration cost calculations
  - Establish a regular data flow from CalSO and IOUs
    - Data should be sent to the Analyst on a regular, frequent basis to keep data extraction simple and data flow timely
    - Data flow can be easily automated
- Minor revisions to capacity credit methodology and results

Multi-Year Analysis

- Perform integration cost calculation for 2002 – 2004
- Motivations:
  - Verify applicability of methodologies over additional years
  - Verify consistency of data over several years
  - Examine changes in integration costs over a multi-year period

Multi-Year Analysis Data

- Began with a new dataset from CaISO
  - One-minute generation data was again aggregated to preserve confidentiality
  - Aggregates were expanded so that they would be more representative of their type of generator
  - Encountered new data quality problems
- Pursued two approaches for addressing data quality issues
  - Manually inspect all non-aggregated data
    - Extremely time intensive given the large volume of data
  - Use data from other sources to augment CaISO dataset
    - No other practical sources for one-minute data

Multi-Year Analysis

- Solution: Obtained high quality hourly data from PG&E and SCE.
  - Used hourly IOU data directly in capacity credit and load following calculations
  - Used hourly high-quality data from SCE and PG&E as bases of comparison to "scrub" one-minute data from CaISO for regulation analysis

Capacity Credit

California RPS Integration Cost Study: Multi-Year Analysis

Capacity Credit

- A measure of a generator's contribution to the overall system reliability.
- Reliability model used to calculate effective load carrying capability (ELCC) for each renewable generator
  - Reliability model: Elfin
  - Directly used hourly generation data from IOUs for each intermittent renewable resource (solar and wind)
  - Used capacity and forced outage data for non-intermittent renewable resources; similar to conventional generators

ELCC Calculation Overview

- Calibrated system load so that the system (with all renewables and without the hypothetical gas benchmark unit) is at a standard risk (1 day/10 years LOLE) with renewables
- Compared each renewable generator, one at a time, to a hypothetical gas benchmark plant
  - This was done by removing the renewable resource of interest, then substituting the hypothetical gas plant at several alternative sizes until the reliability target was met

California RPS Integration Cost Study: Multi-Year Analysis

Modeling Changes From Previous Analyses

- In Phase I
  - Used probabilistic distributions for generation profiles of intermittent resources
  - Hydro modeling: Used monthly hydro, no separation of run-of-river vs. dispatchable hydro
- In Phase III
  - Directly used hourly values for generation profiles of intermittent resources
  - Hydro modeling: Monthly CEC data dispatched by model
- Multi-Year Analysis
  - Directly used hourly values for generation profiles of intermittent resources
  - Hydro modeling: Directly used hourly values from CaISO data

Multi-Year Capacity Credit Results

Resource	2002		2003		2004	
	ELCC relative to annual peak generation	ELCC relative to reported nameplate capacity	ELCC relative to annual peak generation	ELCC relative to reported nameplate capacity	ELCC relative to annual peak generation	ELCC relative to reported nameplate capacity
Medium Gas	100%	100%	100%	100%	100%	100%
Biomass	98%	98%	98%	98%	98%	98%
Geothermal (north)	108%	108%	109%	109%	109%	109%
Geothermal (south)	109%	109%	109%	109%	109%	109%
Solar	82%	88%	68%	83%	75%	79%
Wind (Northern Cal)	33%	24%	37%	25%	44%	30%
Wind (San Gorgonio)	42%	39%	28%	24%	27%	25%
Wind (Tehachapi)	29%	26%	34%	29%	29%	25%

Comparison With Previous Results For 2002

Renewable Resource	Phase I & III Relative ELCC (%)	Multi-Year Relative ELCC* (%)
Biomass	98	98
Geothermal (no steam constraint)	103	109
Solar	90	82
Wind: Altamont/Northern California	23	33
Wind: San Gorgonio	24	42
Wind: Tehachapi	25	29

*based on annual peak value

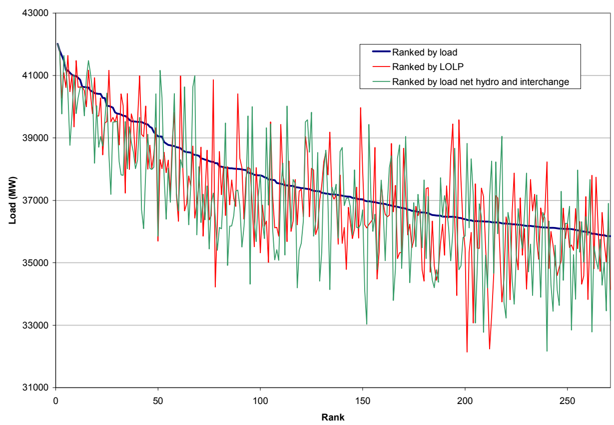
Solar and wind ELCC values do not match closely.

Nameplate Capacity

- Solar nameplate capacities are lower than its annual peaks. This is likely because the solar plants' gas-assist generators are not included in their nameplate capacities.
- The nameplate capacities of the Northern California wind aggregate provided by PG&E are significantly higher than its annual peaks.

Resource	2002			2003			2004		
	Nameplate capacity provided by IOU (MW)	Annual peak generation (MW)	Difference	Nameplate capacity provided by IOU (MW)	Annual peak generation (MW)	Difference	Nameplate capacity provided by IOU (MW)	Annual peak generation (MW)	Difference
Solar	379	407	-7%	379	463	-22%	379	401	-6%
Wind (Northern Cal)	679	489	28%	679	463	32%	680	462	32%
Wind (San Gorgonio)	357	325	9%	362	317	12%	362	332	8%
Wind (Tehachapi)	652	584	10%	659	568	14%	659	571	13%

Hydro and Interchange Affect The Risk Profile



Interchange and hydro significantly affect the risk profile.

Capacity Credit Excluding Hydro & Imports

Resource	2002		2003		2004	
	ELCC relative to annual peak generation	ELCC relative to reported nameplate capacity	ELCC relative to annual peak generation	ELCC relative to reported nameplate capacity	ELCC relative to annual peak generation	ELCC relative to reported nameplate capacity
Medium Gas	100%	100%	100%	100%	100%	100%
Biomass	98%	98%	98%	98%	98%	98%
Geothermal (north)	108%	108%	109%	109%	109%	109%
Geothermal (south)	109%	109%	109%	109%	109%	109%
Solar	91%	98%	72%	88%	77%	82%
Wind (Northern Cal)	26%	19%	28%	19%	39%	26%
Wind (San Gorgonio)	38%	35%	22%	19%	28%	26%
Wind (Tehachapi)	30%	27%	29%	25%	31%	27%

Peak Capacity Factors

Based on annual peak generation; weekdays, 12 p.m. - 6 p.m.

Resource	2002		2003		2004	
	May through Sept	June through Sept	May through Sept	June through Sept	May through Sept	June through Sept
Biomass	88%	93%	82%	87%	85%	90%
Geothermal (north)	91%	91%	94%	95%	90%	90%
Geothermal (south)	88%	87%	88%	88%	88%	89%
Solar	85%	90%	70%	76%	85%	89%
Wind (Northern Cal)	27%	27%	29%	30%	37%	35%
Wind (San Gorgonio)	41%	39%	28%	26%	34%	30%
Wind (Tehachapi)	36%	33%	28%	28%	33%	29%

Peak Capacity Factors

Based on IOU reported rated capacities; weekdays, 12 p.m. - 6 p.m.

Resource	2002		2003		2004	
	May through Sept	June through Sept	May through Sept	June through Sept	May through Sept	June through Sept
Biomass	88%	93%	82%	87%	85%	90%
Geothermal (north)	91%	91%	94%	95%	90%	90%
Geothermal (south)	88%	87%	88%	88%	88%	89%
Solar	91%	97%	86%	93%	90%	94%
Wind (Northern Cal)	19%	19%	20%	20%	25%	24%
Wind (San Gorgonio)	37%	36%	25%	23%	31%	28%
Wind (Tehachapi)	32%	30%	24%	24%	29%	25%

California RPS Integration Cost Study: Multi-Year Analysis

Comparison of Peak Capacity Factors and ELCC Excluding Hydro and Interchange

- Based on IOU reported rated capacities
- Peak defined as June through September, weekdays, 12 p.m. to 6 p.m.

	2002		2003		2004		3-Year Average	
Resource	ELCC (% of rated capacity)	Peak capacity factor	ELCC (% of rated capacity)	Peak capacity factor	ELCC (% of rated capacity)	Peak capacity factor	ELCC (% of rated capacity)	Peak capacity factor
Biomass	98	93	98	87	98	90	98	90
Geothermal (north)	108	91	109	95	109	90	109	92
Geothermal (south)	109	87	109	88	109	89	109	88
Solar	98	97	88	93	82	94	89	95
Wind (Northern Cal)	19	19	19	20	26	24	21	21
Wind (San Gorgonio)	35	36	19	23	26	28	27	29
Wind (Tehachapi)	27	30	25	24	27	25	26	26

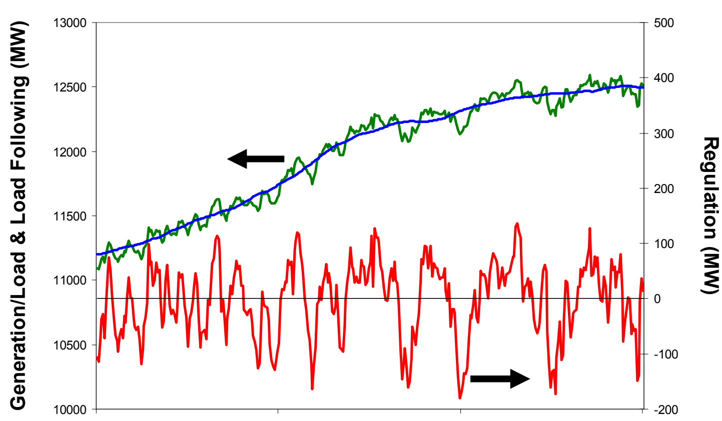
Capacity Credit Analysis Summary

- ELCC results, including inter-annual variations, are corroborated by comparison of ELCC (net hydro and interchange) with peak capacity factors.
- The metric is based on the generation resources' capacities; there appear to be discrepancies in the nameplate capacities.

Regulation

Regulation and Load Following

Generation and load can be decomposed into base, loading following, and regulation components.



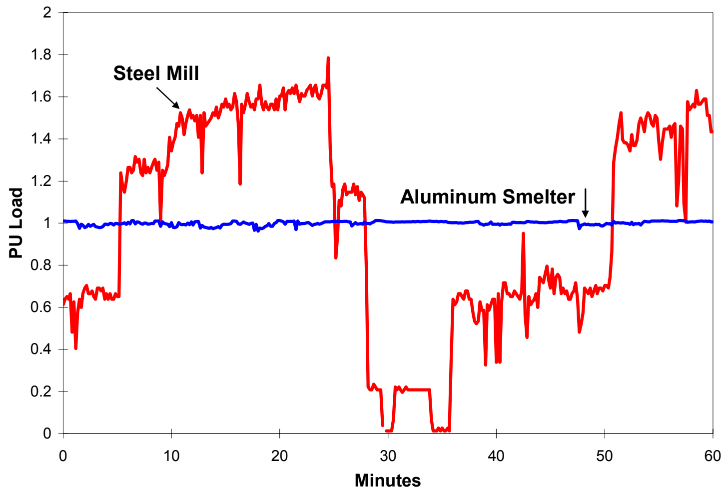
Regulation and Load Following

- Both address the time varying characteristic of balancing generation and load under normal operations
- The "system" only has to compensate for the aggregation
- The aggregation is composed of individual loads and generators with *diverse* characteristics

Regulation & Load Following Characteristics

Regulation	Load Following
Random, uncorrelated	Largely correlated
Matches generation minute to minute	Longer term analogue to regulation; occurs over 5 minutes to hours
Maximum swing (MW) is small	Swing can be 10-20 times more
Ramp rate (MW/min) can be 5-10 times more	Ramp rate is slow
Formally defined	FERC did not require in Order 888 tariffs
Provided by regulation capacity market	Provided by hourly and sub-hourly energy markets

Diversity in Regulation Demand



Aggregation Benefits Regulation

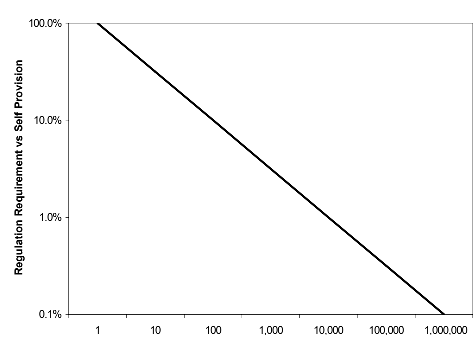
Unlike energy, individual intrahour fluctuations are generally uncorrelated

Energy requirement:

$$\mu_{SYSTEM} = \sum \mu_{INDIVIDUAL}$$

Fluctuations:

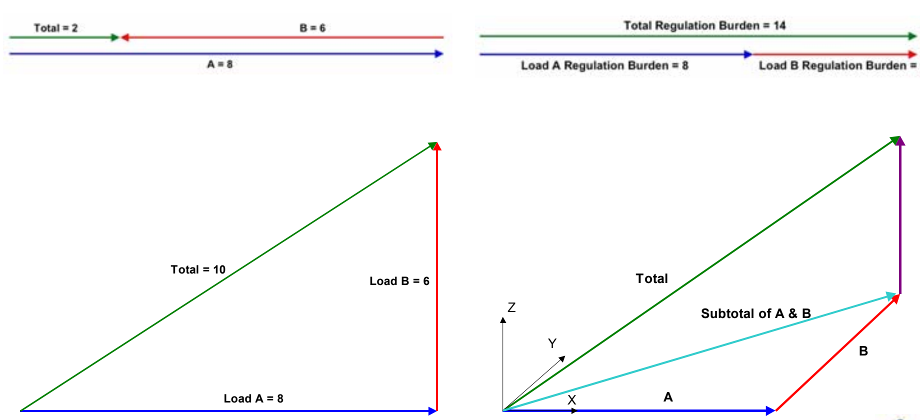
$$\sigma_{SYSTEM} = \sqrt{\sum \sigma^2_{INDIVIDUAL}}$$



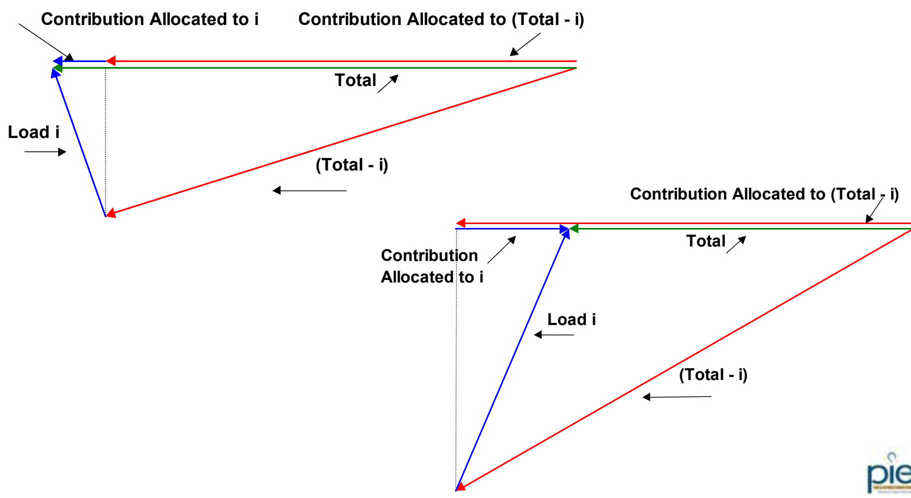
Regulation Must Be Properly Allocated

- A proper allocation method:
  - Recognizes positive and negative correlations (pay loads that reduce total regulation)
  - Is independent of subaggregations
  - Is independent of order in which loads are added to system
- We developed a Regulation Vector Allocation Method that meets these objectives

Allocation Is Simple When Burdens Are Completely Correlated or Uncorrelated



Generalized Method Treats Arbitrary Correlations



Numerical Implementation Of Vector Allocation Method

$$\sigma_{i\_allocation} = \frac{\left(\sigma_{Total}^{2} + \sigma_{i}^{2} - \sigma_{Total-i}^{2}\right)}{2 * \sigma_{Total}}$$

- Handles correlated and uncorrelated components
- Independent of sub-aggregation
- Independent of order
- Disaggregate as many (few) components as desired

Overview of Methodology

- Data required:
  - One-minute generation and load data
  - Hourly amounts and costs of actual regulation purchases
- Determine hourly individual and total system regulation requirements
  - Separate regulation from load following
  - Hourly standard deviations
- Allocate individual hourly regulation requirements
- Scale individual regulation requirements to actual purchase amounts
- Apply actual prices to determine hourly individual regulation costs

Phase I Regulation Results

- In Phase I, the total system was modeled as just the load instead of the net of load and generation.
  - This understates the variability of the generators.
  - In the multi-year analysis, the total system is modeled as the net of load and generation.
- There was also a one minute misalignment in the Phase I San Gorgonio data.

	Regulation Cost ($/MWh or mills/kWh)	
Resource	**Original**	**Corrected**
Total System	-0.42	-0.44
Total Load	-0.42	-0.41
Medium Gas	0.08	-0.28
Biomass	0.00	-0.09
Geothermal	-0.10	-0.17
Solar	0.04	-0.47
Wind (Altamont)	0.00	-0.22
Wind (San Gorgonio)	-0.46	-0.08
Wind (Tehachapi)	-0.17	-0.53
Wind (Total)	-0.17	-0.33

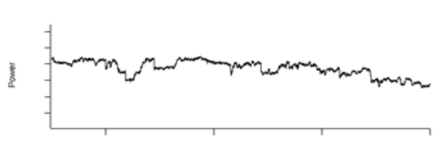
Multi-Year Regulation Results

Resource	Regulation Cost ($/MWh or mills/kWh)			
	Phase I, corrected 2002	2002	2003	2004
Total System	-0.44	-0.42	-0.47	-0.39
Total Load	-0.41	-0.41	-0.46	-0.36
Biomass	-0.09	-0.09	-0.13	-0.12
Geothermal	-0.17	-0.11	-0.03	-0.02
Solar	-0.47	-0.44	-0.47	-0.37
Wind (Northern California)	-0.22	-0.24	-0.40	-0.33
Wind (San Gorgonio)	-0.08	-0.09	-0.43	-0.58
Wind (Tehachapi)	-0.53	-0.57	-0.70	-0.56
Wind (Total)	-0.33	-0.36	-0.53	-0.47

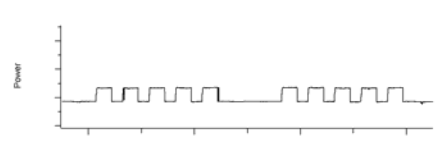
Negative values denote a cost to the system

Generation Data Excerpts

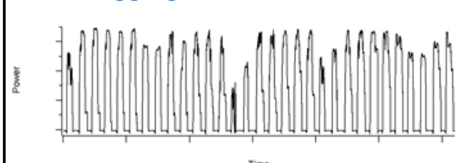
Biomass Aggregate Winter 2004, 1 week



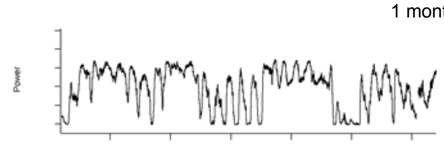
Geothermal Aggregate Winter 2002, 2 weeks



Solar Aggregate Summer 2004, 1 month



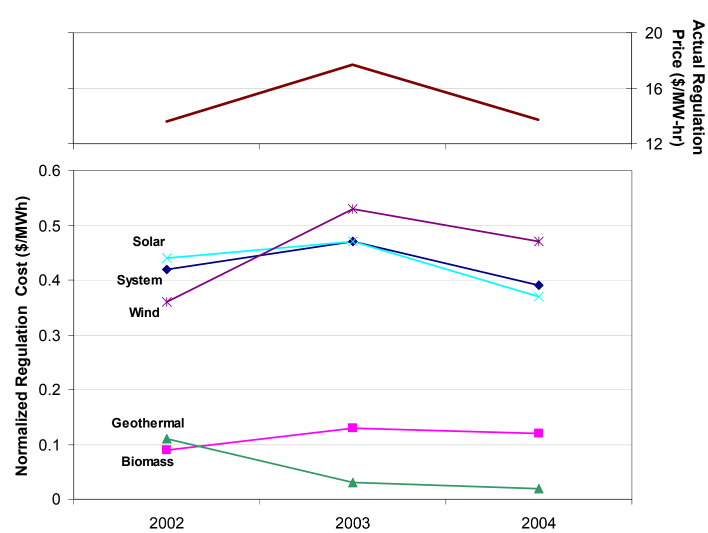
Wind Aggregate San Gorgonio, Summer 2003, 1 month



Regulation Purchases by CaISO

	2002	2003	2004
Regulation up, self provided (MW-hr)	1,855,270	1,769,493	1,972,175
Regulation down, self provided (MW-hr)	2,078,057	1,797,975	2,073,533
Regulation up, procured (MW-hr)	1,659,438	1,116,009	1,109,265
Regulation down, procured (MW-hr)	1,627,342	1,488,440	1,255,973
Total regulation (MW-hr)	7,220,107	6,171,916	6,410,947
Total value ($)	98,270,561	109,357,025	88,141,708
Average regulation price ($/MW-hr)	13.61	17.72	13.75

Inter-Annual Variation



Summary of Regulation Results

- Results between previous and multi-year datasets are consistent
- Inter-annual cost variation tracks the actual regulation price trend
- Regulation impacts and costs of all renewables were quite small

Load Following

Load Following

- In California, deviations between the generation and load requirements are compensated through the CalSO supplemental energy market.
- The system operator must compensate for aggregate generation scheduling and load forecasting error; individual errors must be viewed in the context of the full system.
- Market participants provide CalSO with bids for the hour ahead energy market and create a "stack" of available generators.
- The price of supplemental energy is determined each market interval based on the bids in the stack. This price applies to all supplemental energy purchases during that interval.
- Market participants are paid for supplemental incremental and decremental energy. A generator that fails to follow its schedule may incur INCs or DECs, but those will be settled by the market.

These market costs are explicit.

Load Following: Indirect Costs

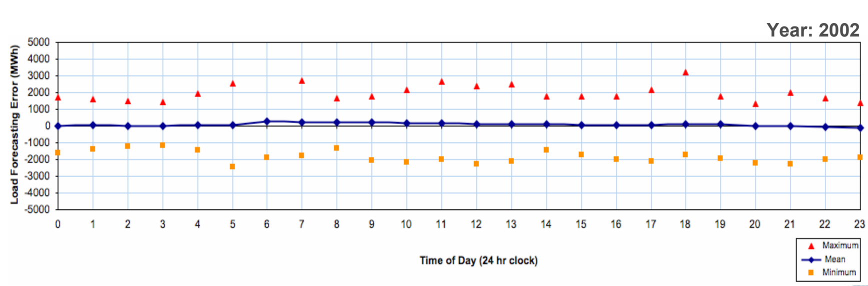
- If certain generators affect the size or composition of the stack, they can change the cost for all supplemental energy purchases. This would be an indirect integration cost for load following services.
- The purpose of the load following analysis was to determine if renewable generators affected the size or composition of the stack thereby possibly creating an indirect cost for load following services.

Load Following Analysis

- Bids and schedules for the hour ahead market are provided 150 minutes ahead of time.
- Data:
  - Load (actual , forecasted, and scheduled) data from CalSO
  - Hourly generation data from PG&E and SCE
- Resource schedules for the hour ahead market were derived by using a simple persistence model.
  - The load following analysis used two persistence models:
    - Geothermal, biomass, and wind schedules were derived by simply shifting actual generation forward by 2.5 hours.
    - Solar schedules were derived by shifting actual generation forward by 24 hours.

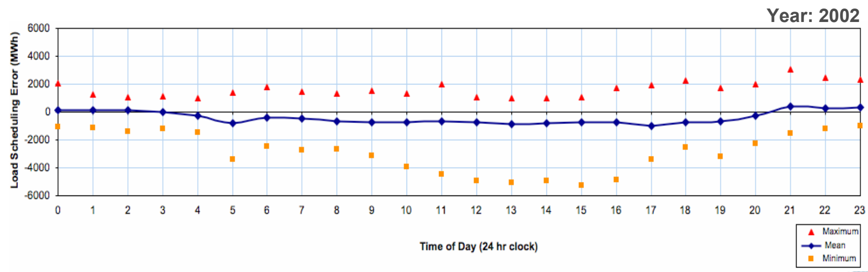
Forecasted Hour Ahead Load

- CalSO provides a forecast of total system load for the hour ahead market.
- The forecast represents the best estimate of the generation required in the hour ahead market.
- The load forecasting error is equal to the forecast load minus the actual load.

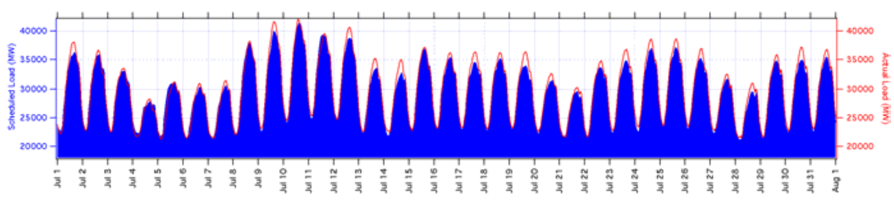


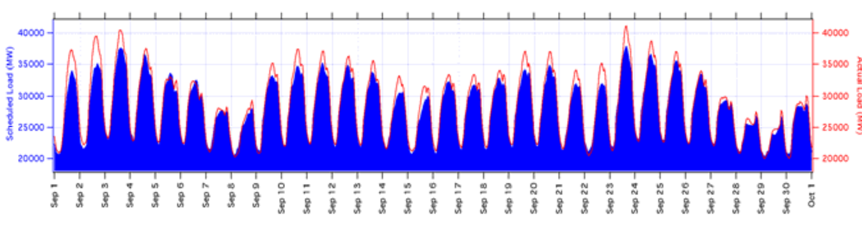
Scheduled Hour Ahead Load

- Hour ahead schedules are submitted to CalSO by the scheduling coordinators.
- The scheduled load is strongly biased relative to the actual load. Scheduled load can be as much as 5000 MW less than the actual load.
- The load scheduling error is defined as the scheduled load minus the actual load.

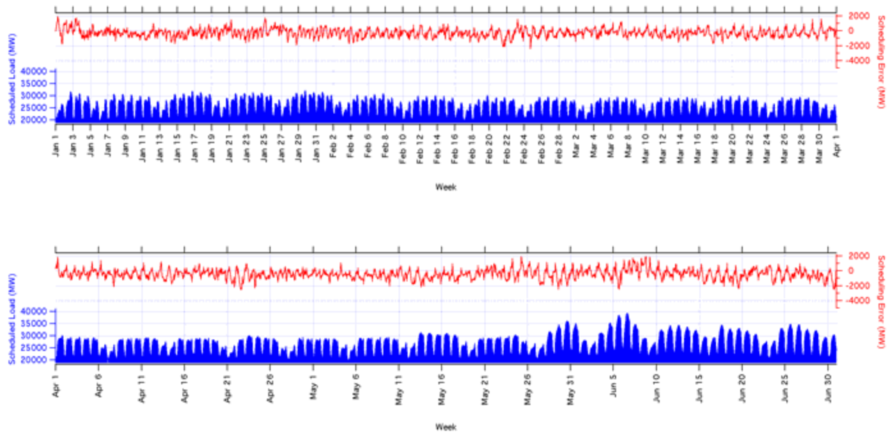


Scheduled Hour Ahead Load in 2002

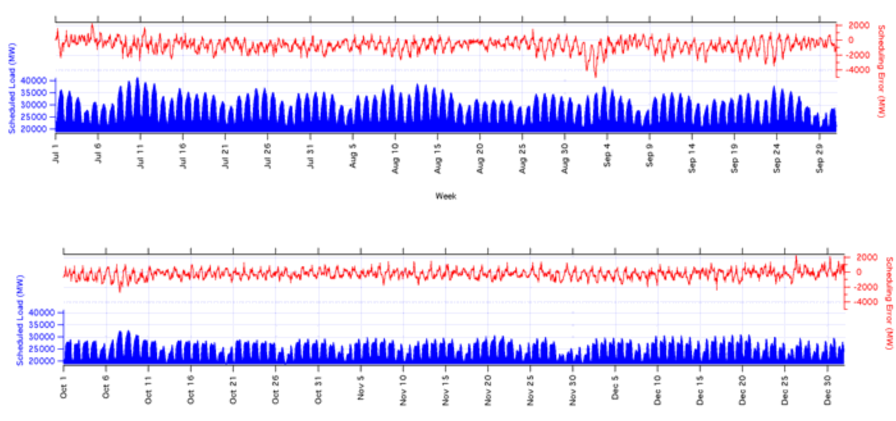




Scheduling Error in 2002

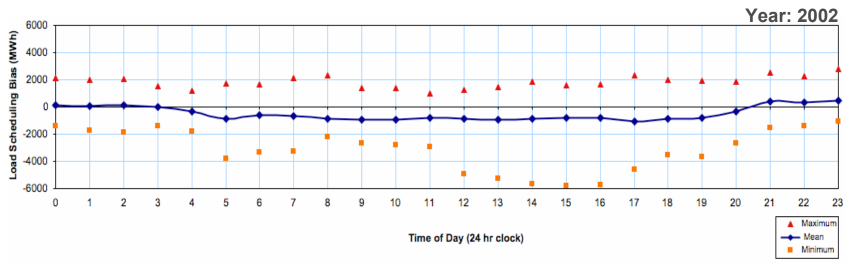


Scheduling Error in 2002



Scheduling Bias

- The scheduled load is strongly biased relative to the forecasted load.
- The scheduling bias is defined as the scheduled load (from the scheduling coordinators) minus the forecasted load (from CalSO).
- The scheduling coordinators consistently schedule less generation than is needed according to the load forecast by CalSO.
- In 2002, the average scheduling bias between the peak hours of noon and 6:00 pm was -880 MW. In the 2002-2004 multi-year period, it was -621 MW.



Load Following Analysis

- Calculated the load forecast error.
- Calculated the generation scheduling error based on a simple persistence model.
- Calculated the combined load forecast error and resource generation scheduling error.
- Calculated the scheduling bias.
- Compared the average minima and maxima of the above during peak hours (12 p.m. to 6 p.m.).

Load Following Results

Error	2002 Peak Hours		2003 Peak Hours		2004 Peak Hours	
	Average Minimum (MW)	Average Maximum (MW)	Average Minimum (MW)	Average Maximum (MW)	Average Minimum (MW)	Average Maximum (MW)
Load forecast alone	-1945	2112	-1600	2151	-1439	1529
Load scheduling alone	-4747	1302	-4021	2158	-3700	1776
Scheduling bias	-5337	1708	-3336	1534	-3016	1634
Combined load forecast and renewable resource scheduling error						
Biomass	-1944	2115	-1603	2157	-1432	1536
Geothermal	-1947	2112	-1599	2149	-1442	1529
Solar	-1897	2055	-1631	2153	-1467	1541
Wind (Northern Cal)	-1946	2148	-1591	2203	-1419	1554
Wind (San Gorgonio)	-1930	2142	-1581	2163	-1443	1545
Wind (Tehachapi)	-1931	2177	-1569	2181	-1435	1544

Load Following Results

Error	COMPARED TO LOAD FORECAST ERROR					
	2002 Peak Hours		2003 Peak Hours		2004 Peak Hours	
	Average Minimum	Average Maximum	Average Minimum	Average Maximum	Average Minimum	Average Maximum
Load forecast alone	100%	100%	100%	100%	100%	100%
Load scheduling alone	244%	62%	251%	100%	257%	116%
Scheduling bias	274%	81%	208%	71%	210%	107%
Combined load forecast and renewable resource scheduling error						
Biomass	100%	100%	100%	100%	100%	100%
Geothermal	100%	100%	100%	100%	100%	100%
Solar	98%	97%	102%	100%	102%	101%
Wind (Northern Cal)	100%	102%	99%	102%	99%	102%
Wind (San Gorgonio)	99%	101%	99%	101%	100%	101%
Wind (Tehachapi)	99%	103%	98%	101%	100%	101%

Comparison with Previous Results

ERROR	Phase I: 2002 Peak Hours				Multi-Year: 2002 Peak Hours			
	AVERAGE MINIMUM		AVERAGE MAXIMUM		AVERAGE MINIMUM		AVERAGE MAXIMUM	
	MW	Compared to load forecast error alone (%)	MW	Compared to load forecast error alone (%)	MW	Compared to load forecast error alone (%)	MW	Compared to load forecast error alone (%)
Load forecast alone	-1909	100%	2220	100%	-1945	100%	2112	100%
Scheduling bias	-5076	266%	1747	79%	-5337	274%	1708	81%
Combined load forecast and renewable resource scheduling error								
Biomass	-1897	99%	2218	100%	-1944	100%	2115	100%
Geothermal	-1878	98%	2221	100%	-1947	100%	2112	100%
Solar	-1870	98%	2220	100%	-1897	98%	2055	97%
Wind (Northern Cal)	-1909	100%	2272	102%	-1946	100%	2148	102%
Wind (San Gorgonio)	-1898	99%	2226	100%	-1930	99%	2142	101%
Wind (Tehachapi)	-1884	99%	2281	103%	-1931	99%	2177	103%

Preliminary Ramping Capability Analysis

- The system operator must compensate for aggregate generation scheduling and load forecasting error; individual errors must be viewed in the context of the full system.
- How much ramping capability is there within the control area compared to how much is required?
  - How do the ramping requirements of renewables compare to the total system requirement?
- Performed an analysis for 2002

Determining Available Ramping Capability

- Data on available generator ramping capability is proprietary and difficult to obtain
- Estimated ramping capability for CaISO control area in 2002 through publicly available data (Platts/RDI BaseCase)
  - Data covers thermal generators, but not hydro or nuclear units

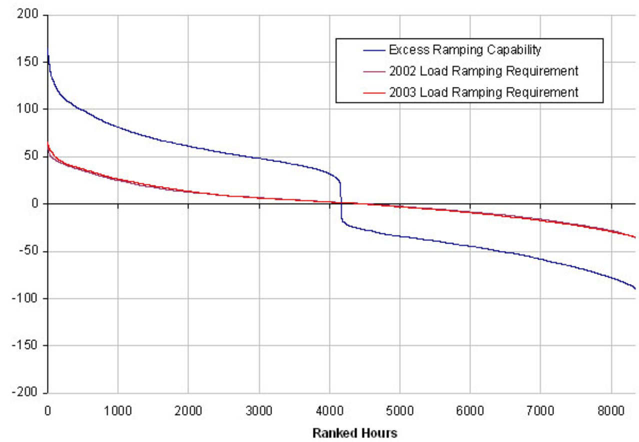
Load	
Peak load (MW)	42,352
Average load (MW)	26,573
Measured Thermal Generation	
Number of generators	133
Total capacity (MW)	24,232
Highest coincident output (MW)	17,541
Largest unit capacity (MW)	761
Average unit capacity (MW)	182
Average unit output (MW)	41
Additional Generation	
Hydro (MW)	13,100
Nuclear (MW)	4,600
Other (MW)	3,700

Determining Available Ramping Capability

Measured thermal generation	Ramping capability (MW/min)
Fastest unit MW/min ramp capacity (up/down)	8.6 / -7.8
Average unit MW/min ramp capacity (up/down)	1.6 / -1.6
Total capacity (up/down)	215 / -214
Total simultaneous capacity (up/down)	168 / -175
Maximum used capability (up/down)	42 / -66

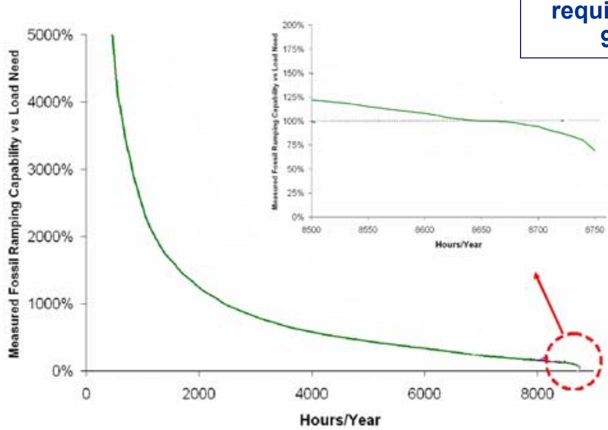
- Estimated maximum output, minimum non-zero operating output, and ramping capability (up and down) of each generator from data
- Ramping capability estimates are conservative
  - Generators may have capability that did not appear over the year
  - Only hourly changes could be deduced
- Calculated each generator's hourly ramping capability in the direction of the current total system ramp as limited by the generator's output at that hour, maximum output, and minimum non-zero output
- Calculated hourly total system ramping capability in the direction of the current total system ramp by summing all of the generators' hourly ramping capability

Ramping: System Capability and Load Requirement

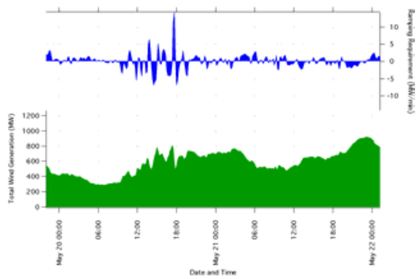


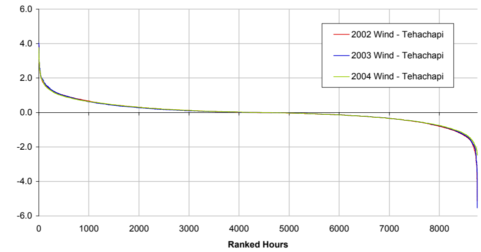
Simultaneous System Ramping Capability and Load Ramping Requirement

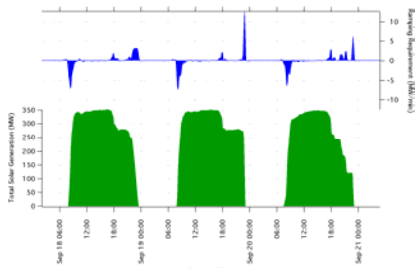
Thermal ramping capability exceeds load ramping requirements more than 97% of the time

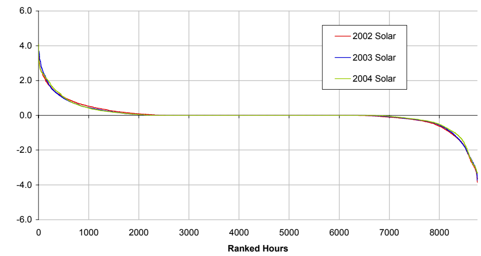


Wind and Solar Ramping Requirements

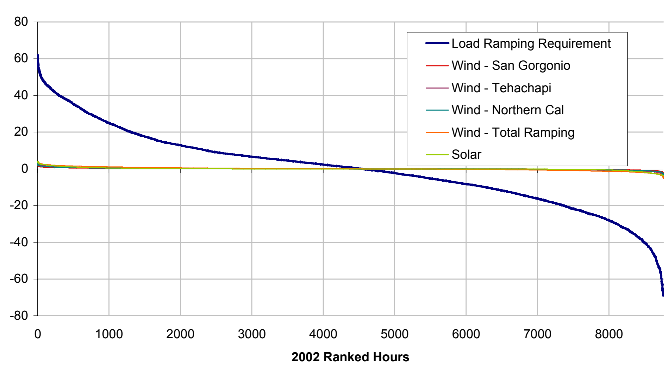








Wind and Solar Ramping Requirements



The ramping requirements of wind and solar are significantly lower than the ramping requirement of load.

Load Following Analysis Summary

- The results of the multi-year scheduling error analysis is consistent with the Phase I 2002 results.
- The generation scheduling errors of the renewables are significantly smaller than the load scheduling error.
- The consistently large scheduling bias implies a deep supplemental energy bid stack that can accommodate the generation scheduling error of renewables.
- Preliminary analysis shows that there is a very large amount of ramping capability available.
- The ramping requirement of the total load is much smaller than the total ramping capability.
- The ramping requirements of solar and wind are much smaller than the ramping requirement of the total load.

Recommendations

Recommendations: Integration Cost Analyst (ICA)

- As previously recommended for implementation of regular integration cost analysis, CEC or CPUC should identify staff to perform the functions of an Integration Cost Analyst (ICA).
- The ICA performs and reports on integration cost analysis on a frequent, regular basis.
- Previously, it was proposed that the ICA be responsible for all data collection and processing, too. Given the data issues encountered during this study, it is recommended that data handling be distinguished as a separate task. The ICA would necessarily still have some data related duties and would coordinate closely with the entity handling data issues.

Recommendations: Data Handling Entity

- Obtaining and processing data was by far the most onerous and time consuming task of the study.
- In previous recommendations, data handling was to be the responsibility of the ICA.
- The type of data required for integration cost analysis is increasingly needed for other studies. Given the growing need and the complexity of issues (technical and legal) involved with obtaining high quality data, it is recommended that an entity be identified and committed to the acquisition and handling of data.
- Responsibilities:
  - Coordinate with CaISO, IOUs, and other data sources to ensure that necessary data is recorded with adequate fidelity
  - Collect and collate data on a regular, frequent basis to keep data extraction simple and data flow timely
  - Verify data quality by reviewing unaggregated data and/or comparing data from different sources (e.g., verify CaISO one minute data with high quality hourly IOU data)
  - Coordinate with ICA and other data users to ensure that data needs are met

Open Discussion

Discussion

- Who should assume the responsibilities of the data handling entity?
- Who should assume the responsibilities of the Integration Cost Analyst?
- How can the integration cost methodologies be applied to future scenarios?
- How can accurate values for rated capacity be obtained?