CALIFORNIA ISO

California Independent
System Operator

Market Monitoring Report
Annual Report Summary

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Discussion Points

- 2005 Market Highlights
- Review of Market Performance
- Generation Investment and Load Growth
- Significant Market Events in 2005
- RTMA Performance

2005 Market Highlights

- Overall, CAISO markets were competitive and stable.
- Congestion costs reduced significantly.
- Concern that new generation investment over the next several years may not keep pace with demand growth and retirements.
- Significant market events in 2005:
  - Inter-tie bidding and settlements under RTMA “bid or better” rules (Amendment 66).
  - Load scheduling requirement (Amendment 72).
  - Gulf Coast Hurricanes – impact on natural gas and energy prices.
- RTMA performance consistent with design objectives but opportunities exist for future enhancements.

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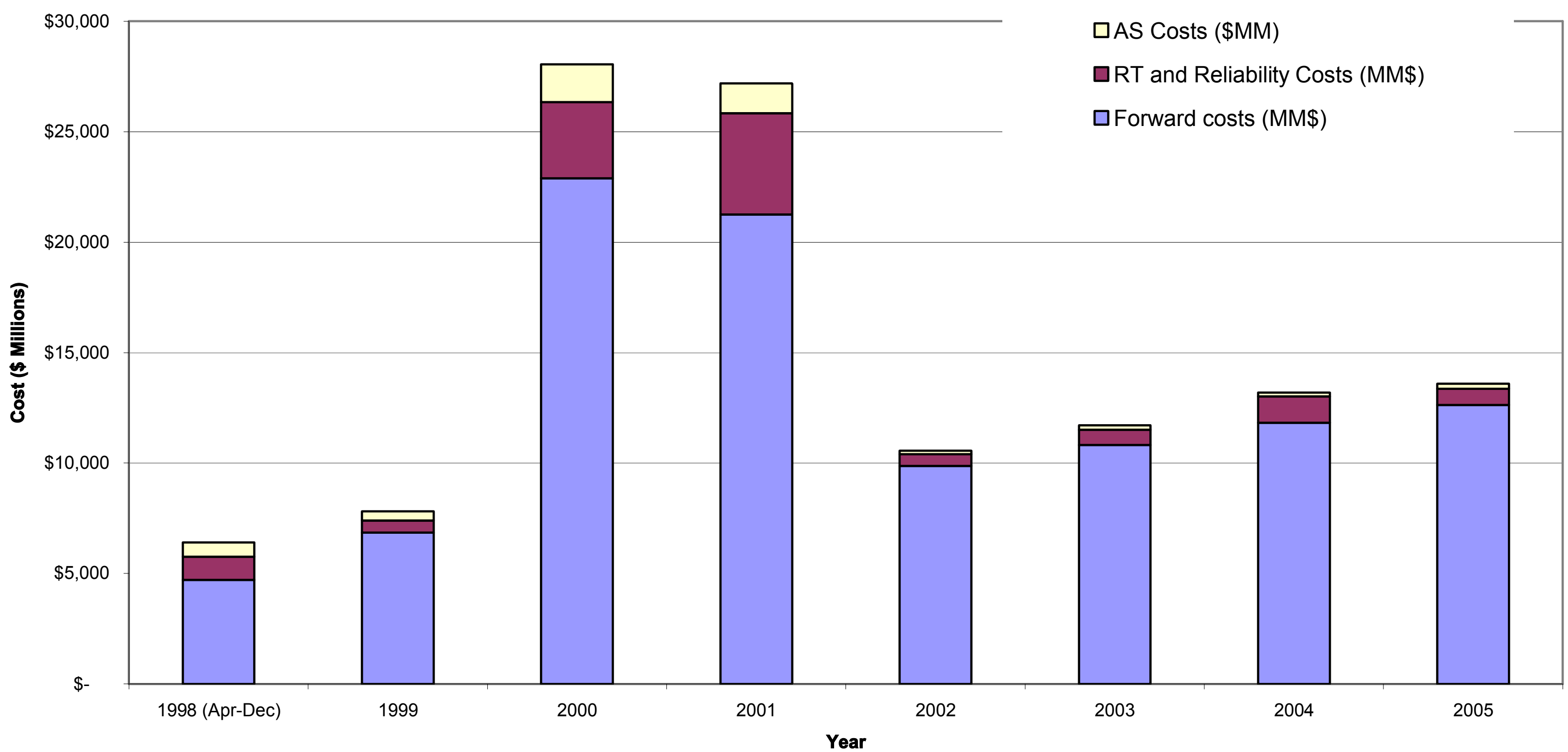
Review of Market Performance

- Total Wholesale Energy and A/S Costs



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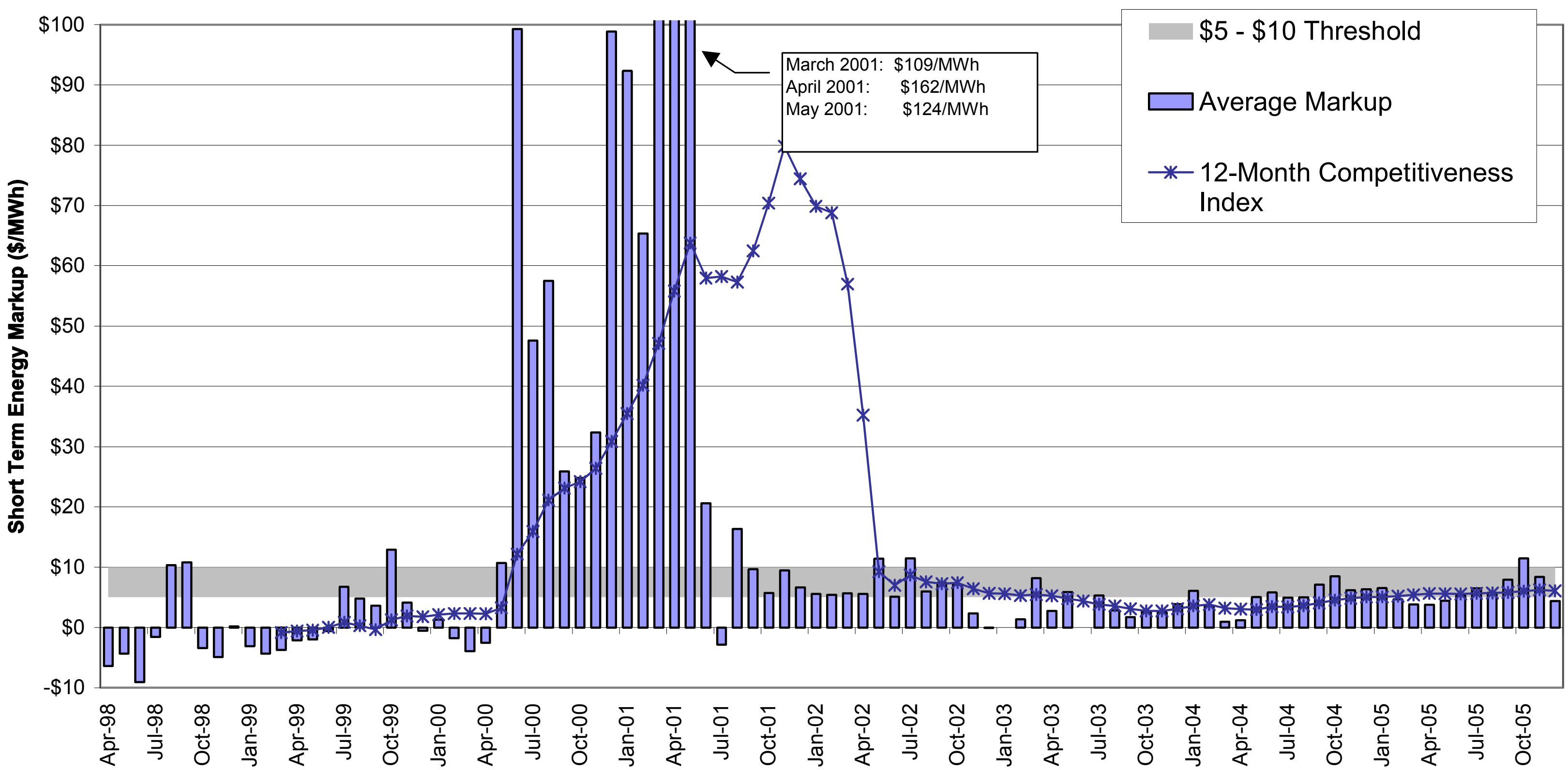
Review of Market Performance

- All-in Price
  - All in price is expressed in $/MWh of load in CAISO control area.
  - Total increase of 4.5% in 2005 compared to 2004.

	2002	2003	2004	2005	Change '04-'05
Est. Forward-Scheduled Energy Costs, excl. Interzonal Congestion and GMC	$ 40.92	$ 45.77	$ 48.21	$ 52.35	$ 4.13
Interzonal Congestion Costs	$ 0.18	$ 0.12	$ 0.23	$ 0.23	$ (0.00)
GMC (All charge types, including RT)	$ 1.00	$ 1.00	$ 0.90	$ 0.84	$ (0.06)
Incremental In-Sequence RT Energy Costs	$ 0.49	$ 0.63	$ 1.47	$ 1.60	$ 0.13
Explicit MLCC Costs (Uplift)	$ 0.26	$ 0.54	$ 1.21	$ 0.52	$ (0.68)
Out-of-Sequence RT Energy Redispatch Premium	$ 0.02	$ 0.19	$ 0.43	$ 0.15	$ (0.28)
RMR Net Costs (Include adjustments from prior periods)	$ 1.60	$ 1.95	$ 2.67	$ 1.95	$ (0.73)
Less In-Sequence Decremental RT Energy Savings	$ (0.08)	$ (0.29)	$ (0.86)	$ (1.11)	$ (0.25)
Total Energy Costs	$ 44.39	$ 49.90	$ 54.27	$ 56.53	$ 2.26
A/S Costs (Self-Provided A/S valued at ISO Market Prices)	$ 0.68	$ 0.86	$ 0.77	$ 0.96	$ 0.20
ISO-related Costs (Transmission, Reliability, Grid Mgmt.)	$ 4.15	$ 5.00	$ 6.82	$ 5.15	$ (1.68)
Total Costs of Energy and A/S ($/MWh load)	**$ 45.07**	**$ 50.76**	**$ 55.04**	**$ 57.49**	**$ 2.46**
A/S Costs % of All-In Price Index	1.5%	1.7%	1.4%	1.7%	7.9%

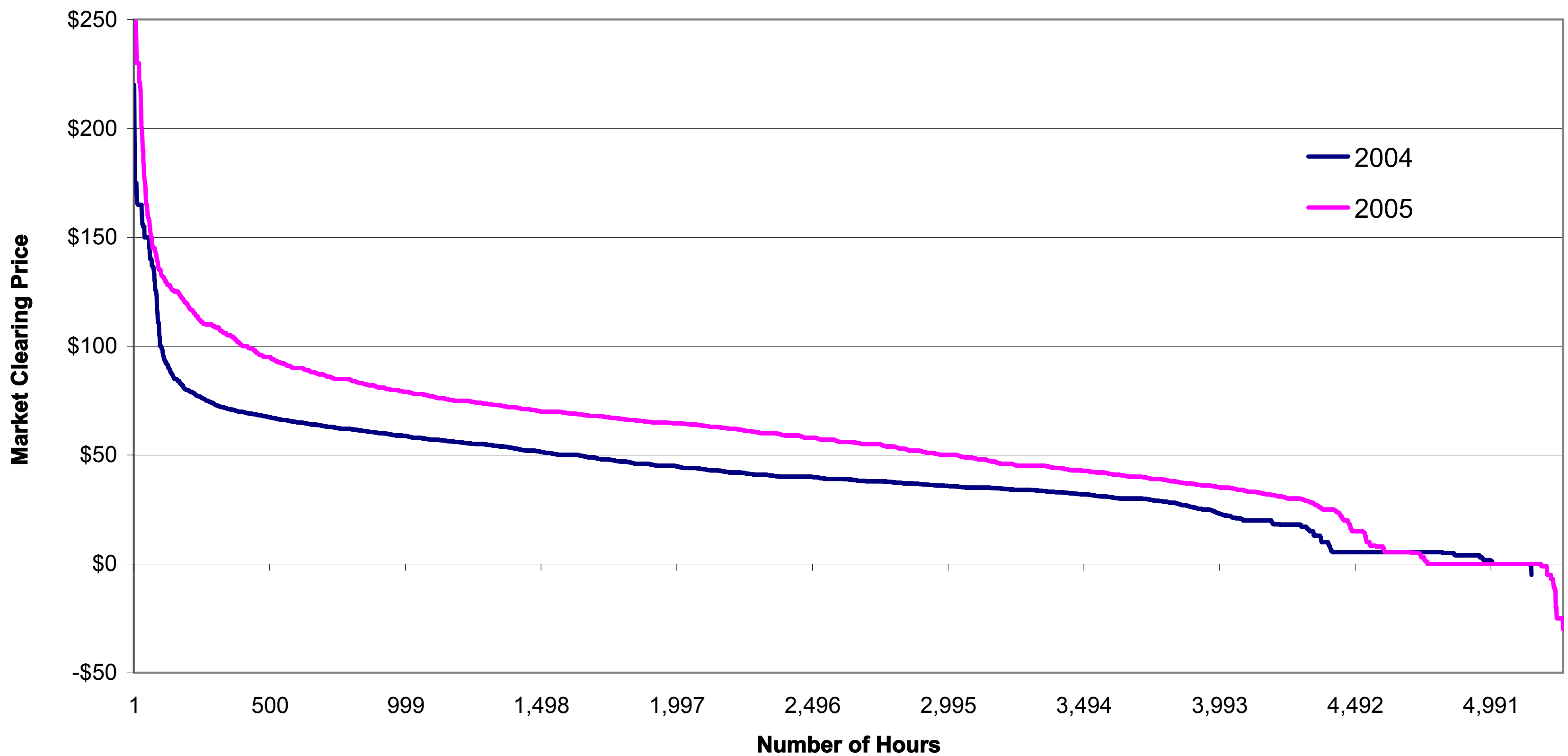
Review of Market Performance

- 12-month market competitive index



Review of Market Performance

- Real-time price duration curve for SP15



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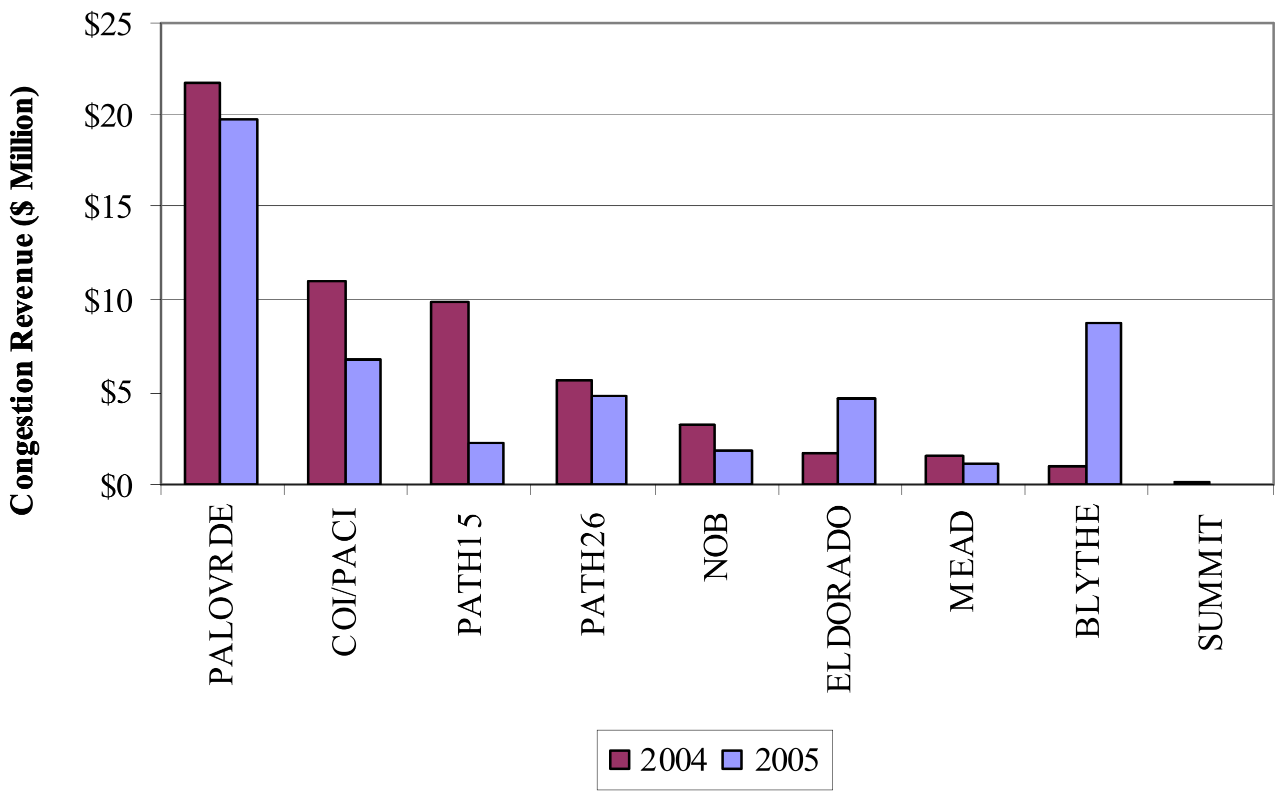
Review of Market Performance

- Inter-Zonal Congestion Costs

Year	Total Inter-Zonal Congestion Cost ($ Million)
2000	$ 391.4
2001	$ 107.1
2002	$ 41.8
2003	$ 26.1
2004	$ 55.8
2005	$ 54.6



Review of Market Performance

- Annual Intra-Zonal Congestion Costs

	MLCC			RMR			R-T Redispatch			Total		
	2003	2004	2005	2003	2004	2005	2003	2004	2005	2003	2004	2005
January	$6	$12	$8	$0	$3	$3	$1	$4	$6	$7	$19	$16
February	$6	$13	$4	$1	$4	$3	$0	$7	$3	$7	$23	$10
March	$6	$20	$3	$0	$4	$4	$1	$8	$3	$7	$31	$10
April	$4	$18	$6	$1	$4	$5	$2	$5	$3	$7	$27	$14
May	$1	$22	$14	$3	$3	$5	$0	$4	$2	$3	$28	$20
June	$2	$25	$7	$2	$3	$2	$0	$2	$0	$4	$30	$9
July	$3	$29	$13	$2	$6	$4	$0	$11	$1	$5	$47	$18
August	$13	$29	$15	$4	$5	$7	$9	$15	$1	$25	$50	$23
September	$10	$23	$7	$3	$4	$7	$6	$12	$3	$19	$39	$17
October	$11	$21	$13	$6	$4	$7	$8	$18	$4	$25	$43	$24
November	$9	$29	$12	$2	$5	$4	$2	$9	$6	$13	$44	$22
December	$9	$33	$13	$3	$4	$2	$17	$8	$5	$29	$45	$20
Totals	$78	$274	$115	$27	$49	$53	$46	$103	$36	$151	$426	$204

Review of Market Performance

- Average Hourly A/S Prices and Volumes

	Year	RD	RU	SP	NS	Average A/S Price
Price ($/MW)	1999	20.84	20.22	7.07	4.35	11.97
	2000	50.15	77.28	44.07	32.46	41.03
	2001	42.33	66.72	34.69	30.03	36.42
	2002	13.76	13.41	4.66	2.15	7.08
	2003	18.43	18.08	6.62	4.20	9.81
	2004	10.95	17.95	7.25	4.43	8.63
	2005	16.05	20.94	10.45	3.98	10.72
						Total Volume
Volume (MW)	1999	769	903	942	735	3,687
	2000	594	633	818	861	3,479
	2001	614	492	1,148	862	3,420
	2002	469	460	775	763	2,524
	2003	416	381	767	722	2,309
	2004	408	395	817	782	2,427
	2005	363	386	841	839	2,428

Generation Investment and Load Growth

- Average load has seen moderate growth, while peak load had volatile jumps in growth over past five years.
- Declining weather-adjusted load factors (ratio of peak load to average hourly load) indicate growing "peakiness" of California load (CEC 2005 IEPR).

Year	Avg. Load (MW)	% Chg.	Annual Total Energy (GWh)	Annual Peak Load (MW)	% Chg.
2001	25,384		222,364	38,975	
2002	26,065	2.7%	228,329	42,352	8.7%
2003	26,329	1.0%	230,642	42,581	0.5%
2004	26,975	2.5%	236,301	45,044	5.8%
2005	26,992	0.1%	236,450	45,380	0.7%

Note: Figures adjusted to account for leap year and changes in load footprint.

Generation Investment and Load Growth

- Generation additions and retirements by zone show a net increase of 2,845 MW in 2005.

	2001	2002	2003	2004	2005	Projected 2006	Total Through 2006
SP15							
New Generation	639	478	2,247	745	2,376	352	6,837
Retirements	0	(1,162)	(1,172)	(176)	(450)	(1,580)	(4,540)
Net Change	639	(684)	1,075	569	1,926	(1,228)	2,297
NP26							
New Generation	1,328	2,400	2,583	3	919	89	7,322
Retirements	(28)	(8)	(980)	(4)	0	(215)	(1,235)
Net Change	1,300	2,392	1,603	(1)	919	(126)	6,087

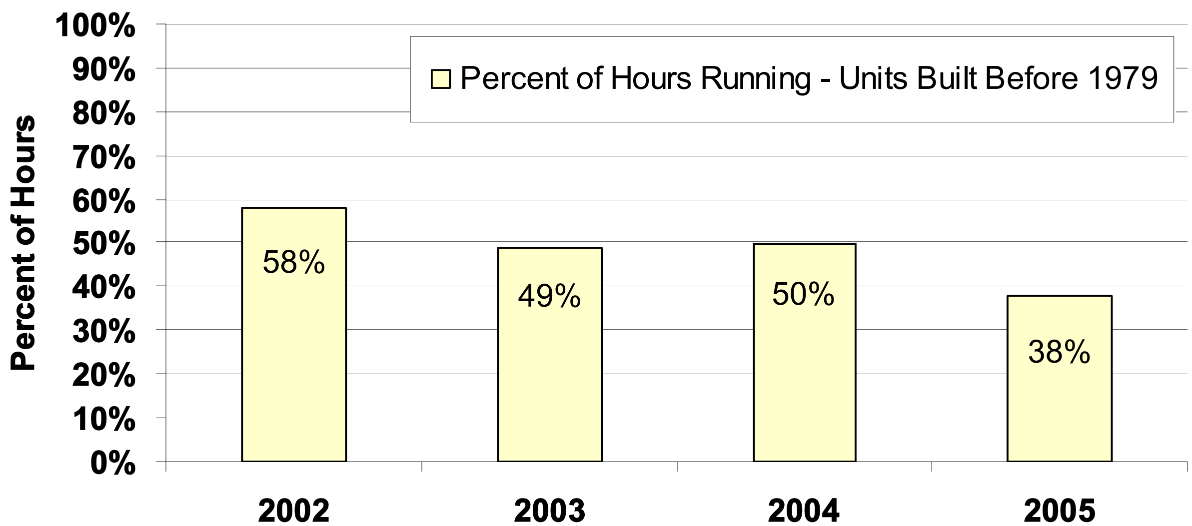
- Forward-looking, net change in California capacity will decline by 5,300 MW for 2006 – 2008 as load continues to grow (CEC 2003 Report, Tables 2-1 and 2-2).

Generation Investment and Load Growth

- Long-term Contracting Remains Key to Revenue Adequacy and Generation Investment.
  - CEC reports that IOUs have completed agreements to purchase over 2,700 MW of new or turn-key power plants (CEC 2005 IEPR on p.44).
  - Also, IOUs have signed over 80 long-term energy contracts, however only 2,000 MW are for 5+ years (CEC 2005 IEPR).

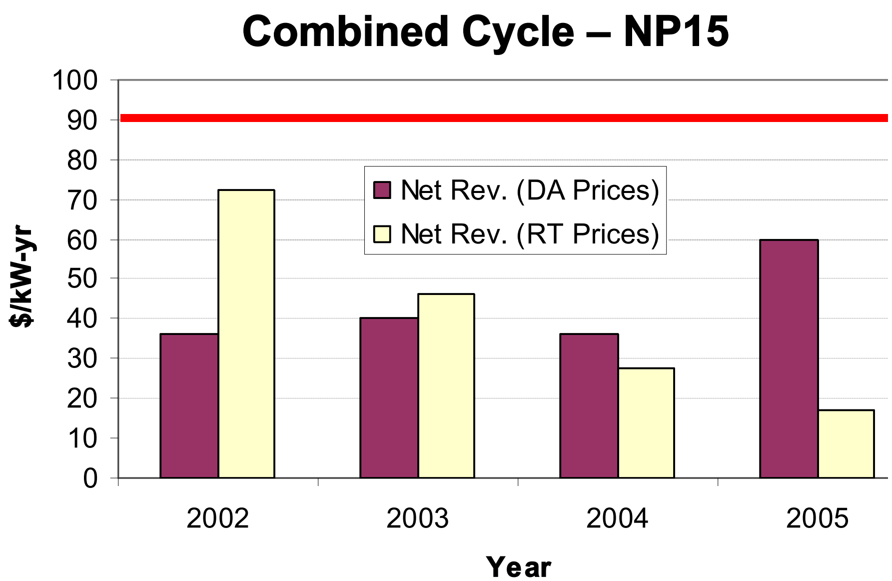
Generation Investment and Load Growth

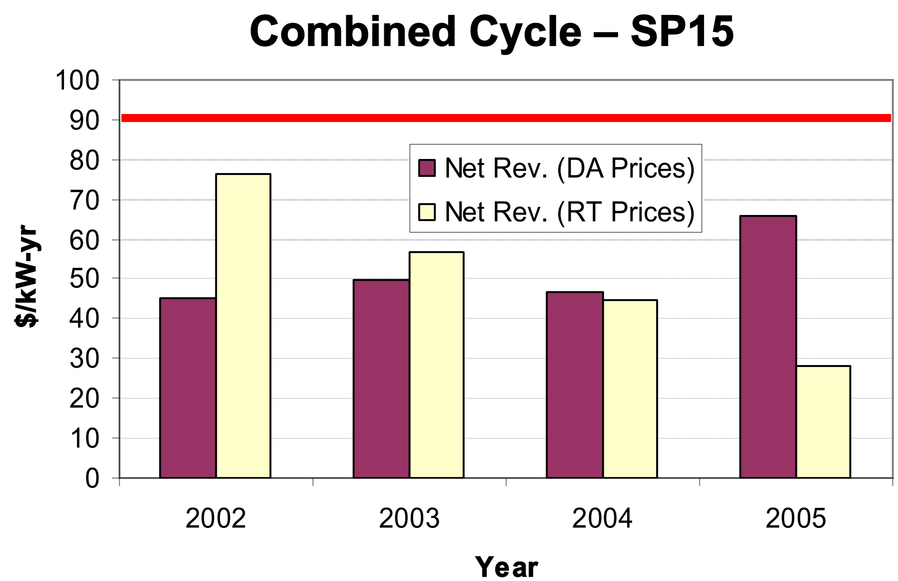
- Long-term Contracting Remains Key to Revenue Adequacy and Generation Investment.
  - Procurement efforts to increase long-term contracts (10+ years) would improve incentives for investment.
  - CAISO currently relies on older units in load pockets that are at risk of retiring. New generation will be needed in these areas as retirements ensue.



Generation Investment and Load Growth

- Spot market revenues continue to fall well short of the annualized fixed cost of new generation.





- Revenue simulation for CC unit compared to benchmark $90/kW-yr cost recovery figure reported by CEC.

Generation Investment and Load Growth

- **IOU Procurement Framework**
  - "Energy-only" market framework has not provided sufficient revenues from spot market to attract new investment.
  - System-level Resource Adequacy Requirements are good start, but allow imports and Liquidated Damages Contracts to satisfy requirement, substituting for capacity contracts with generation internal to the CAISO control area.
  - Local Resource Adequacy Requirements needed to provide revenue adequacy, and incentive for investment, to internal generation.

Generation Investment and Load Growth

- **IOU Procurement Framework (con't)**
  - Procurement efforts to increase long-term contracts (10+ years) would improve incentives for investment. CEC 2005 Energy Report reports that IOUs have signed only 2,000 MW of energy contracts w/ terms greater than 5 years.
  - CAISO currently relies on older units in load pockets that are at risk of retiring. New generation will be needed in these areas as retirements ensue.

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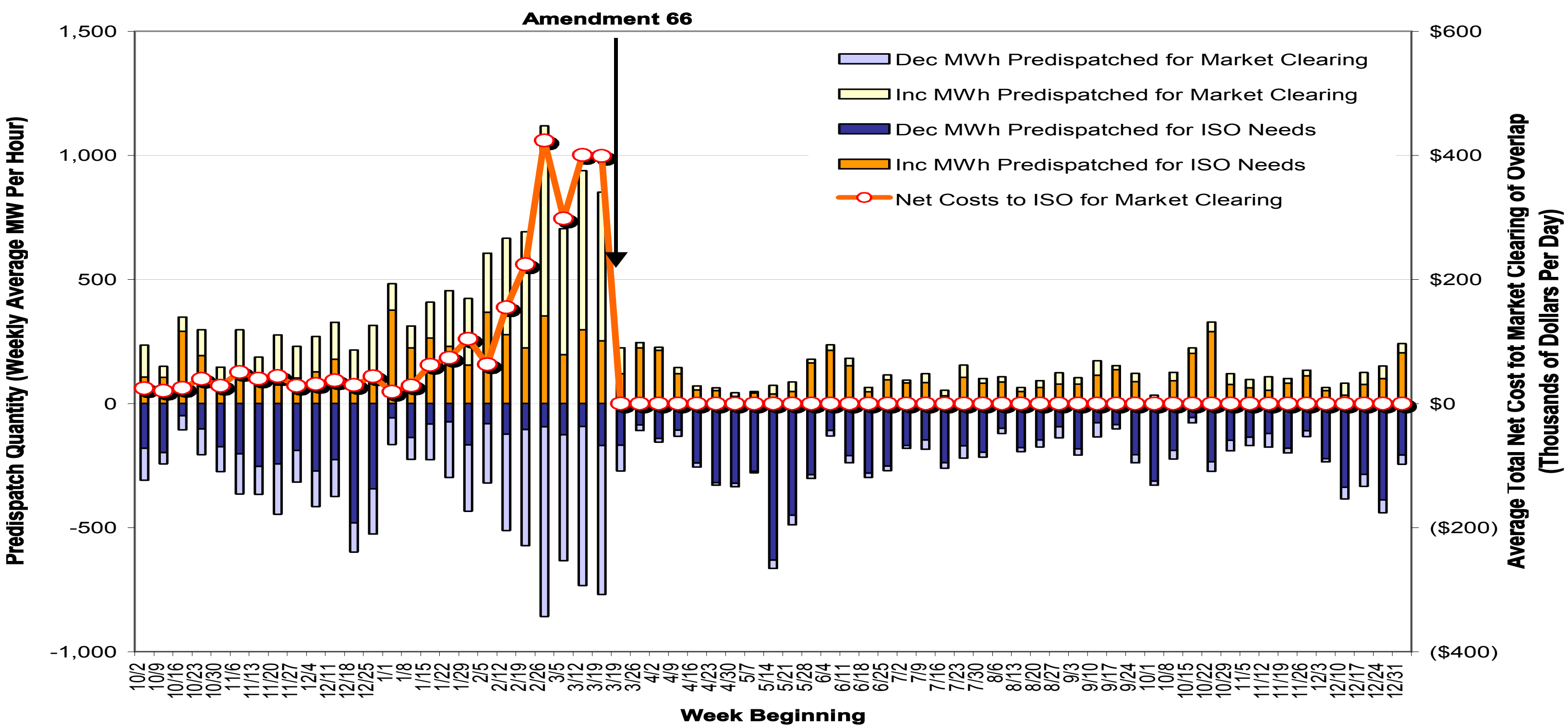
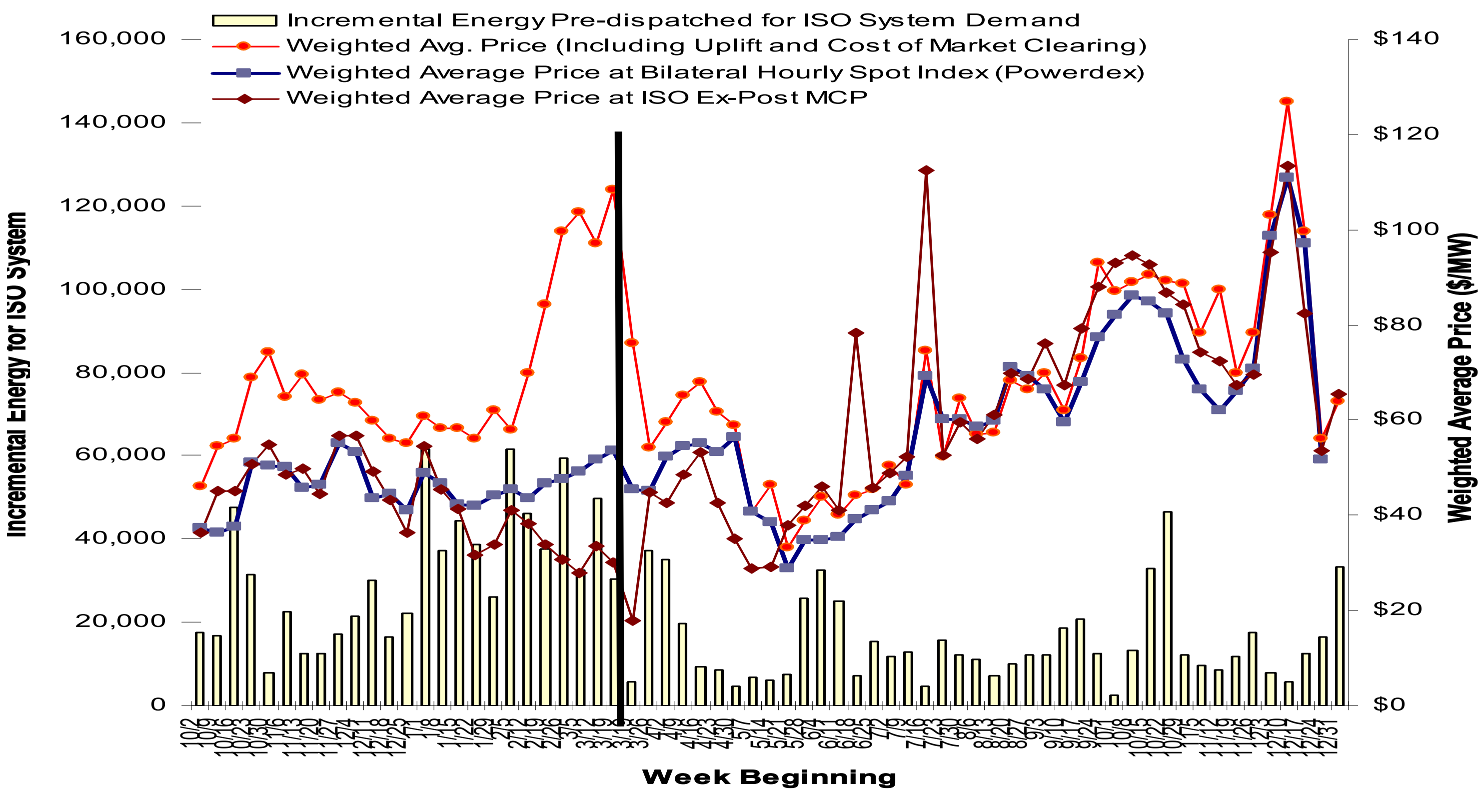
Significant Market Events in 2005

- Inter-tie bidding and settlement.
  - Originally, import/export bids were cleared against each other in the pre-dispatch and settled 'bid or better'.



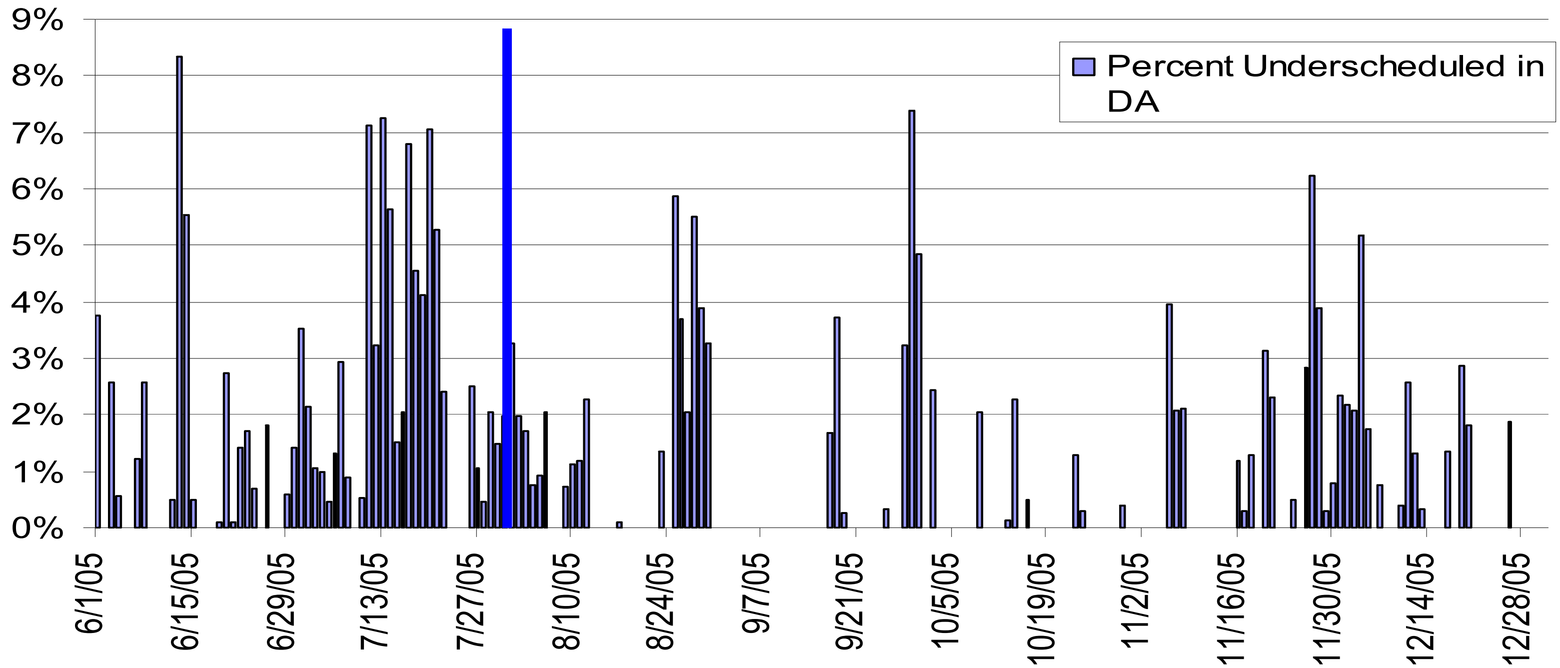
Significant Market Events in 2005

- Inter-tie bidding and settlement.
  - Since implementation of ‘as-bid’, uplift costs have declined, and have observed price convergence between pre-dispatch and RT.



Significant Market Events in 2005

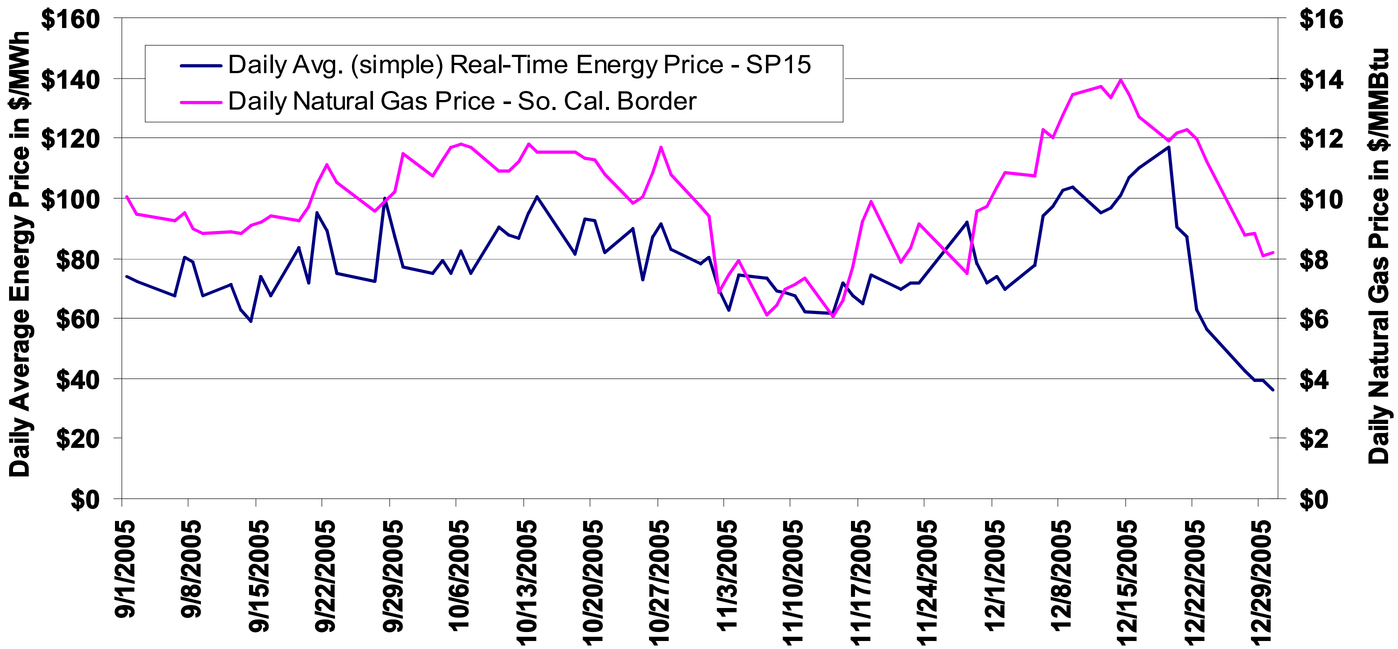
- Load scheduling in Day-Ahead.
  - CAISO Grid Operations identified in Summer 2006 that load was significantly under-scheduled in the Day-Ahead.



  - By end of 2005, total load scheduled in DA had increased to within the 95% threshold.

Significant Market Events in 2005

- Natural gas prices and impact on Real-Time market.
  - Natural gas prices spiked in last quarter of 2005, nearing $14/MMBtu, as a result of two hurricanes.
  - Real-time electricity prices increased during this time, reflecting increase in gas cost.



  - **In 2006, gas prices have moderated to around $7/MMBtu.**

Significant Market Events in 2005

- RTMA Performance.
  - RTMA has increased the volatility of prices and dispatches within each operating hour
    - Increased volatility the result of features of RTMA designed to increase the responsiveness of prices and dispatches.
    - Fluctuations in prices and dispatches under RTMA closely mirror actual system imbalance conditions.
  - Performance of RTMA seems to have improved since it was implemented on October 1, 2004, due to numerous modifications, however significant volatility in the morning ramping hours remains.
  - The absence of a fully optimized day ahead energy market may account for a higher level of real time market price and dispatch volatility (more re-dispatch required in real time).

Significant Market Events in 2005

- RTMA Performance – Unresolved issues.
  - Further assessment of the interactions between regulation energy and RTMA dispatch to better understand why RTMA has not resulted in a significant reduction in the use of regulation;
  - Further assessment of price and dispatch volatility within the first few pricing intervals of each hour;
  - Establishing a relationship between load bias, regulation energy, 5-minute dispatch volatility, and pre-dispatched tie bids; and
  - Additional benchmarking with data from other ISOs.

Significant Market Events in 2005

- RTMA Performance – Lessons learned for MRTU.
  - Dispatch software should recognize non-compliant units.
  - Default prices should reflect market conditions when applied.
  - Operator interaction with market inputs should be tracked and periodically assessed to determine impact on operational and market outcomes.
  - Data generated by market software should be easily accessible for analysis by various ISO departments across large periods of time ("saved-cases" do not lend to analysis of trends or performance w/o time lags and overhead).