



California ISO
Your Link to Power

Market Performance Report December 2009

January 25, 2010

ISO Market Services

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Executive Summary

This report contains the highlights of the month of December 2009. For a more detailed explanation of the technical characteristics of the metrics included in this report please download the Market Performance Metric Catalog, which is available on the CAISO web site at <http://www.caiso.com/179d/179ddbce22760.html>.

Highlights for December 2009:

- The average energy demand was lower than one year ago.
- Natural gas prices increased largely in December.
- The day-ahead market saw an increasing trend in the energy prices in December.
- Real-time energy prices were moderate in most of the days in December.
- The cumulative total congestion rent for interties in December was approximately \$10.3 million, and the cumulative total congestion rent for branch group and market scheduling limit was approximately \$3.78 million.
- Net revenue adequacy for congestion revenue rights was in deficit of \$5.75 in December, a significant deterioration with respect to November's deficit of 3.13 million.
- The monthly ancillary service average cost to load in December slightly increased to \$0.36/MWh from \$0.33/MWh in November.
- The total RUC procurement cost declined to \$18,703 in December from \$31,590 in November.
- The total volume of exceptional dispatch decreased to 71,500 MWh in December from 76,300 MWh in November.

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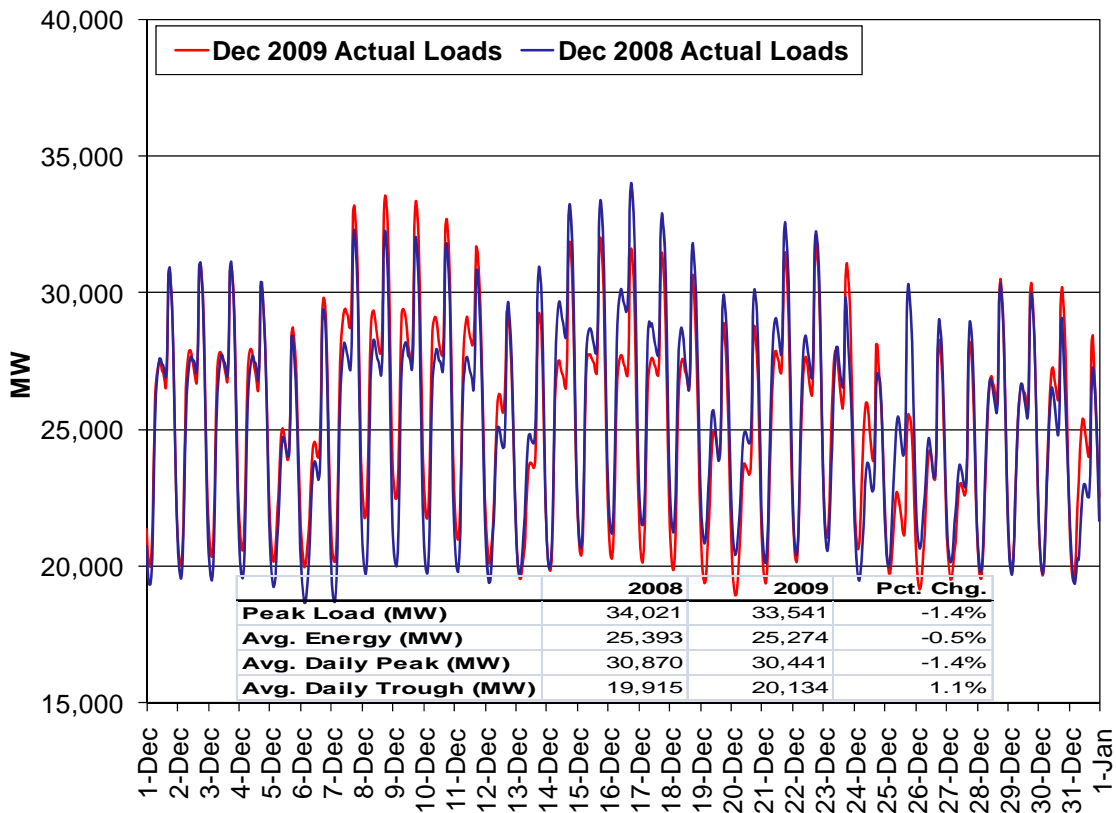
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Market Characteristics

Loads

The first few days of December 2009 saw higher loads than December 2008 due to extremely cold weather. The load curves were showing the traditional winter pattern of late evening peak. The loads in December 2009 averaged 0.5 percent lower than one year ago.

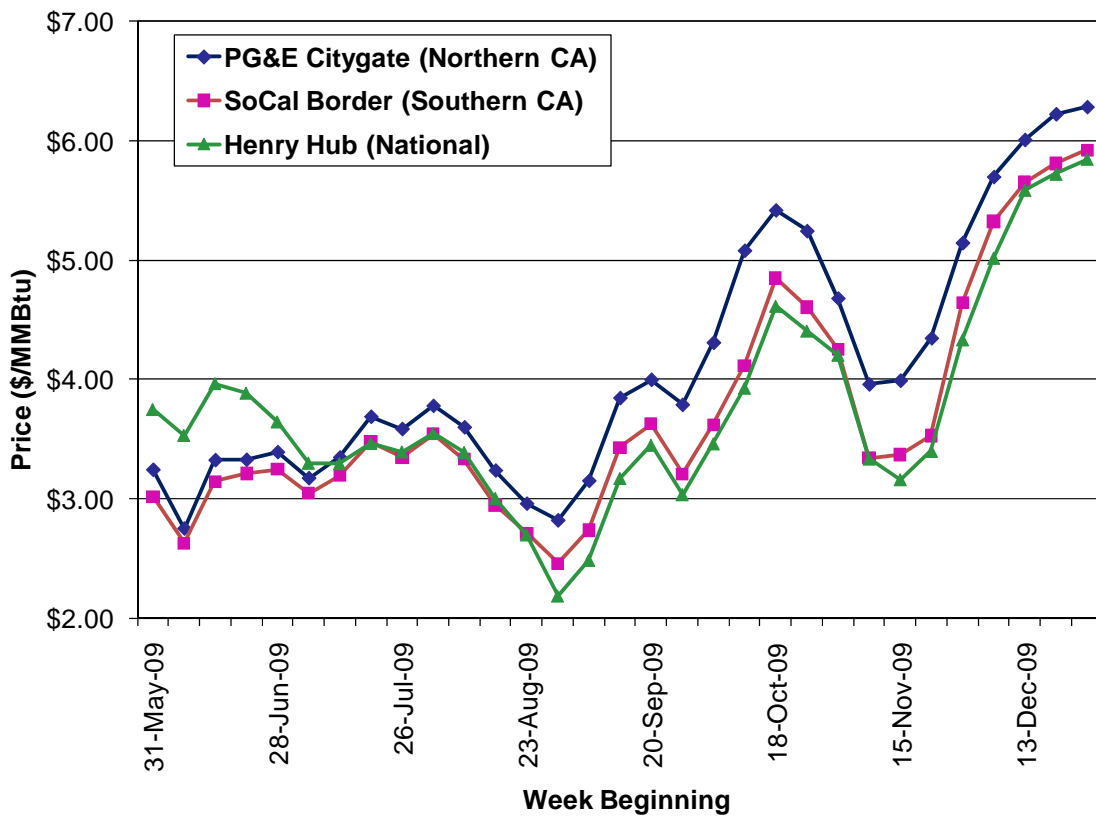
Figure 1: System Load Comparison – December 2009 vs. December 2008



Natural Gas Prices and Inventories

The natural gas prices increased largely in December 2009. The California Composite Average gas price jumped to \$5.94 per MMBtu on December 31, increasing by 21 percent from \$4.91 per MMBtu on December 1. The natural gas price uptick, according to the Energy Information Administration (EIA), was mainly driven by colder than usual wintry weather and rising crude oil prices. A large amount of natural gas had been withdrawn from the underground storage in December due to frigid temperatures. As of January 1, 2010, the working gas in underground storage in the West decreased by 83 Bcf to 434 Bcf compared with 517 Bcf on December 4, 2009.

Figure 2: Weekly Average Natural Gas Spot Prices – June 2009 to December 2009



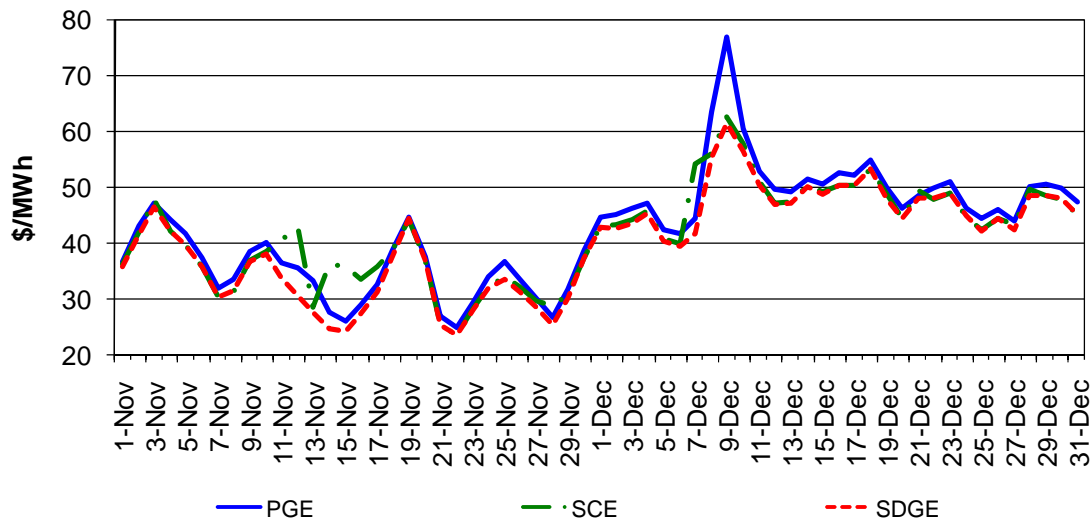
Market Performance Metrics

Energy

Day-Ahead Prices

The energy prices in the day-ahead (DA) market had an increasing trend in December, especially in the first half of the month, as shown in Figure 3. The monthly average price among the three default Load Aggregation Points (LAPs) increased 41 percent to \$48.5/MWh in December from \$34.4/MWh in November. The increase in the monthly average default LAPs price was mainly due to the increase in natural gas prices. During the month, prices in the three default LAPs converged well with exceptions on three days due to congestion on two branch groups. On December 7, the SCE_PCT_IMP branch group was binding in several hours, driving the daily average energy price \$10/MWh higher in the SCE LAP than in the other two default LAPs. On December 8 and 9 the Pacific Northwest experienced severe cold temperatures which drove up the demand for power in that region. To meet this demand, scheduling coordinators were importing power from California, Nevada and Arizona, as a result, the flows on the Pacific AC intertie (PACI) were in the south to north direction in both on-peak and off-peak hours. Usually in winter months flows on PACI intertie are in the north to south direction in on-peak hours and in south to north directions in off-peak hours. The unusual flow pattern and path capacity derates motivated by planned outages caused congestion on the Los Banos North branch group. On December 8, the Los Banos North branch group was derated due to the scheduled outages of Moss Landing - Los Banos 500 kV line, and then on December 9 it was derated due to the outage of Los Banos-Midway #2 500 kV line. On average, the congestion elevated the energy price in the PG&E area by \$7/MWh and \$15/MWh on December 8 and 9, respectively. For the month of December, energy prices fell into the range between \$39/MWh and \$77/MWh in the DA market.

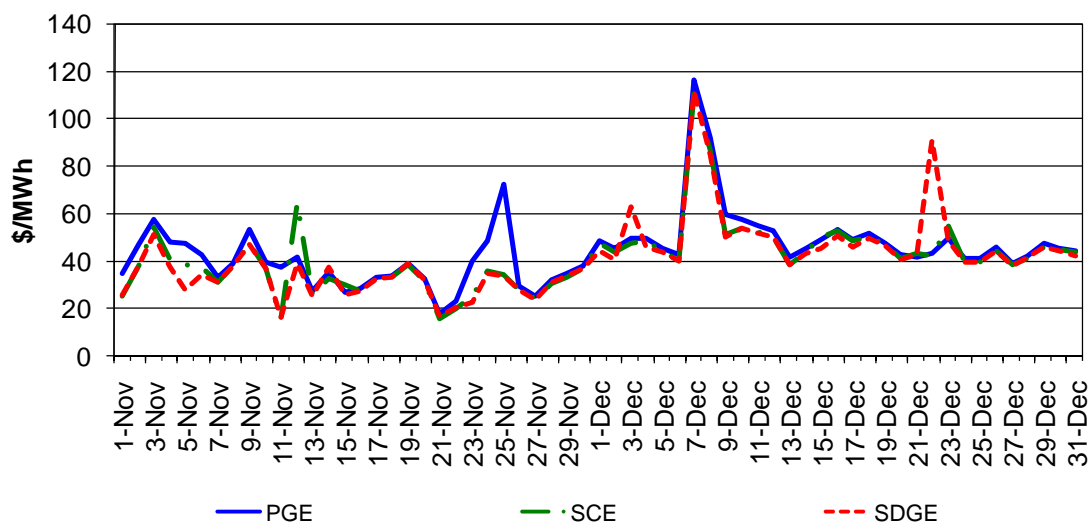
Figure 3: Day-Ahead Weighted Average LAP Prices (All Hours)



Real-Time Prices

The real-time market saw less divergence on the energy prices for all three default LAPs in December than in November, as shown in Figure 4. On December 3, a nomogram was binding in several intervals, resulting in elevated energy prices in the SDG&E area. On December 22, congestion on the SDGE_CFE import branch group caused a \$50/MWh higher price in the SDG&E area. The limit of this branch group was biased in real time to preserve a reliability margin, which was further impacted with the loss of 200 MW of generation in the area.

Figure 4: RTD Weighted Average LAP Prices (All Hours)



With a cold weather snap, the system tackled a myriad of transmission outages on December 7 and 8, to the extent that CAISO had to declare a grid warning notice. During this time there were also several generation units tripping offline. Inclement weather also made real-time load difficult to forecast, coming above day-ahead schedules. Then conditions deteriorated as Palo Verde was derated to reflect the forced outage of the North Gilla-Hassayampa 500 kV line, reducing imports into Southern California. This was further impacted with reduced imports from the Northwest. All these resulted in limited supply and multiple price spikes during this two-day period. Other than those days, the real-time energy prices were moderate for the month, falling into the range between \$37/MWh and \$60/MWh.

Figure 5 shows the daily frequency of price spikes by price range for all three default LAPs in the five-minute Real-Time Dispatch (RTD). In percentage terms, the frequency of prices over \$250/MWh increased to 0.86 percent on December from 0.36 percent in November. As explained in the last paragraph, high frequency of price spikes was observed on December 7 and 8. Extreme prices (over \$1000/MWh) increased in December to 0.03 percent, from 0.004 percent in

November. As mentioned on the previous page, the extreme prices on December 22 occurred when the SDGE_CFE import branch group got congested.

Figure 5: Daily Frequency of RTD LAP Positive Price Spikes

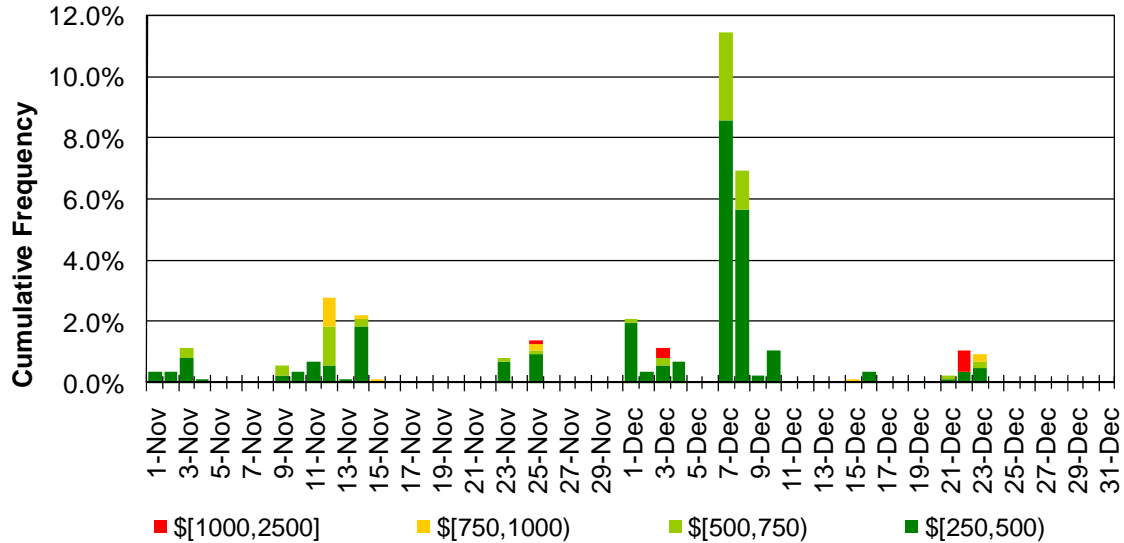
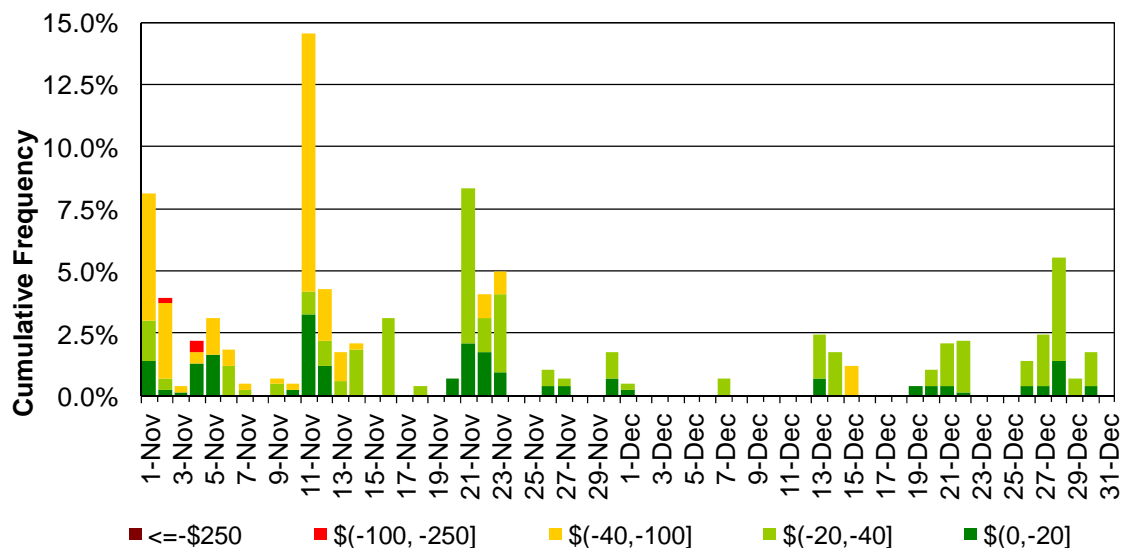


Figure 6 shows the daily frequency of negative prices by price range for all three default LAPs in the five-minute RTD. The frequency of negative prices declined to 0.77 percent in December from 2.29 percent in November. These negative prices were largely driven by overgeneration conditions during the early-morning hours, except on December 15 when congestion on Los Banos North created price separations.

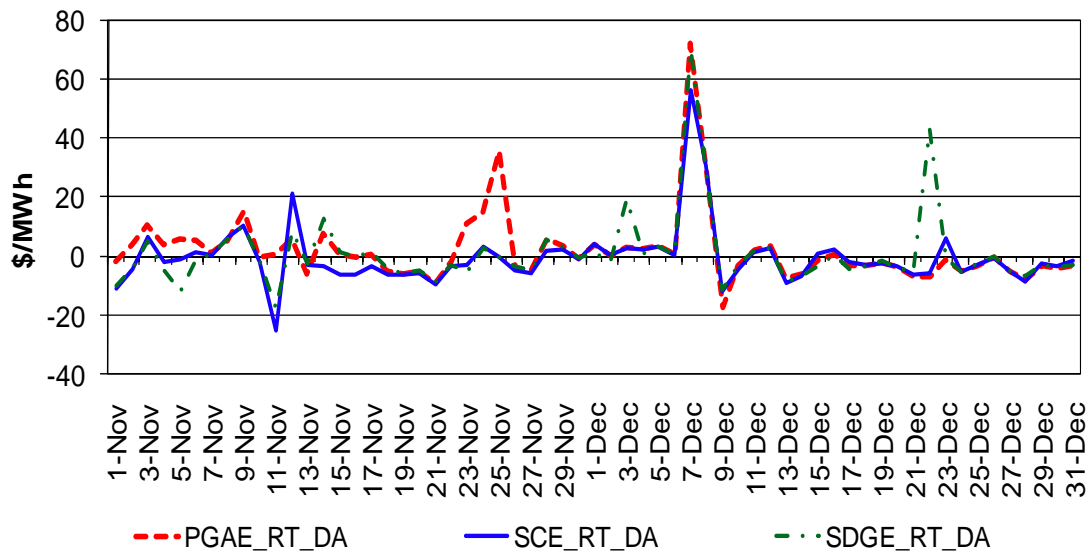
Figure 6: Daily Frequency of RTD LAP Negative Price Spikes



Price Convergence

Figure 7 illustrates the difference between the DA energy price and the five-minute RTD energy price for the three default LAPs for the months of November and December 2009, where the positive difference indicates that the RTD price is higher than the DA price, and vice versa. For December, RTD prices were much higher than the DA prices in all three default LAPs on just two days. As mentioned in the previous section, the daily average RTD prices were very high in all three default LAPs on December 7 and 8, subtracting by the moderate DA prices, resulting in high price differences on these two days. The daily average RTD prices were high in the SDG&E LAP on December 3 and 22, due to the congestion on different transmission facilities, which also led to high price differences for SDG&E LAP on these two days. With the exception of these days in December, the average energy price was lower by \$2.76/MWh, \$1.93/MWh, and \$2.89/MWh in the RTD than in the DA markets in the PG&E, SCE, and SDG&E areas, respectively.

Figure 7: Daily LAP Price Difference (All Hours)



Congestion

Congestion Rents on Interties

Figure 8 below illustrates daily Integrated Forward Market (IFM) congestion rents by intertie for November and December 2009. The cumulative total congestion rent for interties in December was approximately \$10.3 million, up from \$8.4 million in November. Most of the congestion occurred on Palo Verde (71 percent), Mead (20 percent) and El Dorado (5 percent) interties.

Figure 8: IFM Congestion Rents by Intertie (Import)

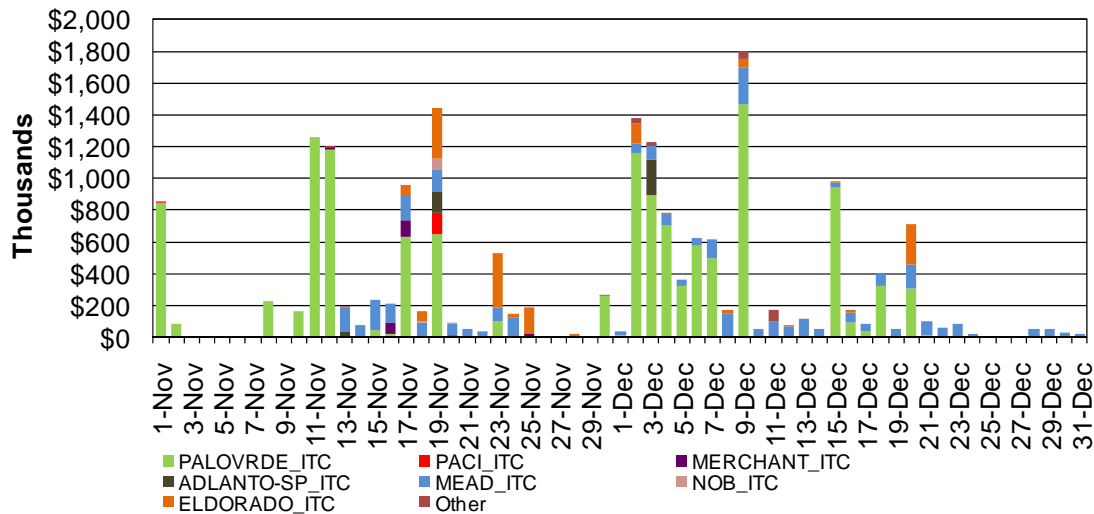


Table 1 shown on the next page provides a breakout of the IFM cleared value (MW), average shadow price (\$/MWh) and number of congested hours by intertie. The average shadow price on Palo Verde intertie was \$19/MWh in December, which was higher than \$14/MWh in November. More than 75 percent of the total congestion rent on Palo Verde occurred during the first 10 days of the month, mostly due to path capacity derates driven by both planned and forced outages. The planned outage of the Serrano-Valley 500 kV line from November 30 till December 7 reduced capacity on Palo Verde intertie by 500 MW. On December 9 the Palo Verde intertie capacity was reduced to half of its nominal value due to a forced outage of the North Gila – Hassayampa 500 kV line.

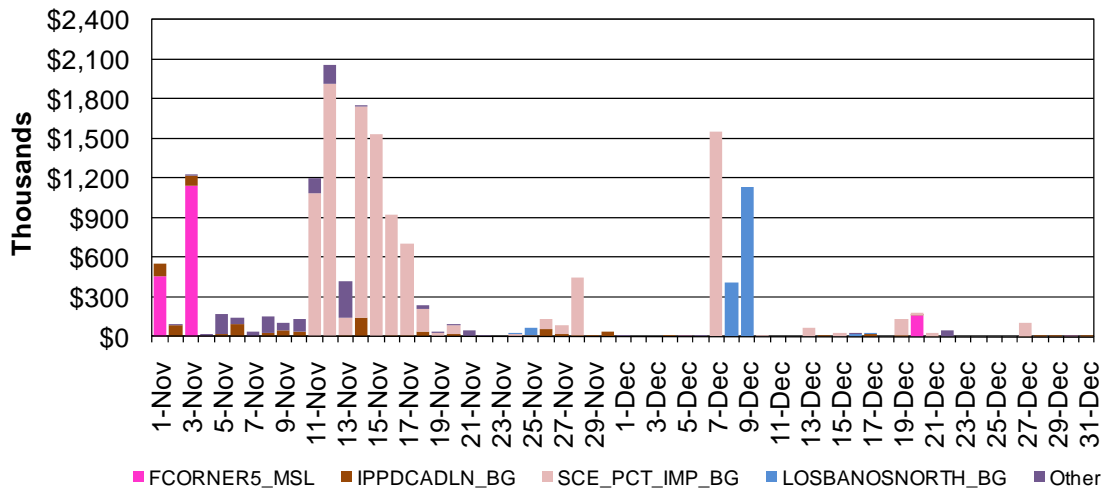
Table 1: IFM Congestion Statistics by Intertie (Import)

Intertie	Average Cleared Value (MW)	Shadow Price (\$/MWh)	Number of Congested Hours
ADLANTO-SP_ITC	1124	10	20
BLYTHE_ITC	189	4	8
ELDORADO_ITC	1113	9	56
IID-SCE_ITC	586	6	13
MEAD_ITC	901	8	298
PALOVRDE_ITC	2252	19	198
PARKER_ITC	179	18	35

Congestion Rents on Branch Group and Market Scheduling Limit

Figure 9 illustrates IFM congestion rents on selected branch groups and market scheduling limits. For the month of December, the total congestion rent for branch group and market scheduling limit decreased significantly to \$3.78 million from \$12.5 million in November. Of the total, the majority of rents occurred on the Southern California Edison Percent Import (SCE_PCT_IMP) (51 percent) branch group, and the Los Banos North (41 percent) branch group.

Figure 9: IFM Daily Congestion Rents by Branch Group and Market Scheduling Limit



Of the total congestion rents on the SCE_PCT_IMP branch group, more than 80 percent of rents occurred on December 7. The SCE_PCT_IMP branch group constraint enforces a limit on the total imports permitted into the Southern California Edison (SCE) area. On December 7, a few units in the SCE area were out of service and the SCE area load had to import more generation. This increased requirements for imports resulted in significant congestion rents on the SCE_PCT_IMP branch group. About 98 percent of the total congestion rents on Los Banos north branch group occurred on December 8 and 9. On these days the Los Banos branch group was derated due to several outages as mentioned in previous sections.

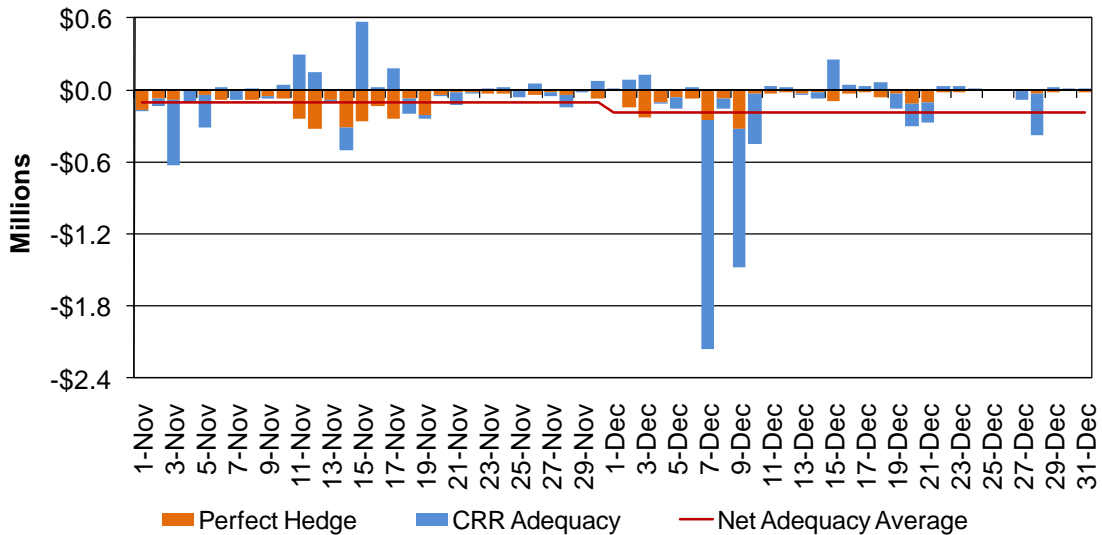
Table 2: IFM Congestion Statistics by Branch Group and Market Scheduling Limit

Branch Group	Average Cleared Value (MW)	Shadow Price (\$/MWh)	Number of Congested Hours
FCORNER5_MSL	840	21.82	9
HUMBOLDT_BG	43	33.59	2
IPP-IPPGEN_MSL	470	7.64	2
IPPCADLN_BG	647	1.91	63
LOSBANOSNORTH_BG	2,499	20.54	31
MKTPCADLN_MSL	605	7.99	10
SCE_PCT_IMP_BG	6,016	9.90	33
WSTWGMEAD_MSL	183	3.41	3

Congestion Revenue Rights

Figure 10 illustrates the revenue adequacy for Congestion Revenue Rights (CRRs) for the months of November and December 2009. In comparison to the daily average revenue deficit of \$104,399 of November, the month of December saw a daily average shortfall of \$185,498.

Figure 10: Daily Revenue Adequacy of Congestion Revenue Rights



Revenue deficiencies were observed in 16 days the month. The most significant deficiencies occurred on December 7 and 9. On December 7, Palo Verde intertie was derated to about 2794 MW for outage reasons; there were also outages of transmission lines that drove congestion on a nomogram and on the other two transmission lines. The derate on Palo Verde also drove deficiencies in the first week of December and together with other outages represented less transmission capacity available in the energy market in comparison to the transmission capacity release through CRRs, which had these elements at nominal values in the CRR model. Furthermore, the SCE_PCT_IMP branch group was binding on this day as well. This constraint was recently enforced in the energy market. With a looking-ahead timeframe for releasing CRRs, however, this same constraint had not been enforced in the release of CRRs for December. In order to guarantee revenue adequacy, the same set of constraints needs to be enforced in both the CRR and energy markets. Having a CRR market with fewer transmission constraints enforced exposes the market to revenue deficiencies. It is worth mentioning that not enforcing this branch group in the CRR markets may or may not result in revenue deficiencies, but enforcing it in the CRR market eliminates a systematic gap that exposes the market to revenue deficiencies. In the case of December 7, the enforcement of the SCE_PCT_IMP contributed to revenue deficiencies as well. December 9 also saw marked shortfalls when Palo Verde intertie was derated to 1440 MW due to the forced outage of the North Gilla-Hassayampa line. On this day the Los

Banos North was also congested and had been derated to reflect the outage of the Los Banos-Midway 2 line.

More deficiencies were also observed in this month: i) on December 19 due to the binding of the SCE_PCT_IMP branch group; ii) on December 20 due to a derate on Palo Verde to about 2700 MW, compounded with the heavy derate on Four Corners to 840 MW; and iii) on December 28 due to outages of two transmission lines that affected congestion on the La Fresa-Hinson line. For the month of December, the outages provided under the 30-day rule were considered as pro-rata derates if the outage had duration of 10 days or less, or modeled explicitly as outages otherwise. Planned outages of three different transmission interfaces were modeled in the CRR network with pro-rata derates. Also, the global derating factor used for December was of 15 percent; these two factors were largely insufficient to attain CRR revenue adequacy in December.

A monthly summary for revenue adequacy is provided in Table 3. Overall, the total dollars collected from the IFM were insufficient to cover the net payments to CRR holders and the cost of the perfect hedge. About 11.9 percent of congestion rents were needed to cover the cost of the perfect hedge. On net, total congestion revenues were in deficit of \$5.75 million, a significant deterioration with respect to November's deficit of \$3.13 million. The auction revenues credited to the balancing account for December were \$3.2 million, which were insufficient to offset the CRR deficiency. After using all auction revenues for the month, December saw a net deficiency of \$2.55 million that will be allocated to measured demand.

Table 3: CRR Adequacy Statistics for December

Concept	Amount
IFM Congestion Rents	\$16,394,070.53
CRR Payments	\$20,192,919.76
CRR Adequacy	-\$3,798,849.22
Perfect Hedge	-\$1,951,605.18
Net Revenue Adequacy	-\$5,750,454.40
Revenue Adequacy Ratio	74.03%
Annual Auction Revenues	\$941,127.25
Monthly Auction Revenues	\$2,255,185.00
Monthly Net Balance	-\$2,554,142.15

Ancillary Services

IFM (Day-Ahead) Average Price

In the IFM market for each trading interval, the ISO procures two types of regulation reserves: regulation up and regulation down. The ISO has developed a new functionality to vary its regulation requirements in the IFM for different hours of the day.¹ This new procedure was created to procure regulation capacity in line with the expected operating conditions throughout the operating day to increase the efficiency of the markets and enhance the reliability of the system. Figure 11 below shows the IFM hourly average ancillary service requirement for regulation up and regulation down for December 2009. The regulation up and regulation down requirement are usually higher in the ramping up hours. And the regulation up requirement is also higher in the hours when many generating units are shut down.

Figure 11: IFM (Day-Ahead) Hourly Average Regulation Requirement

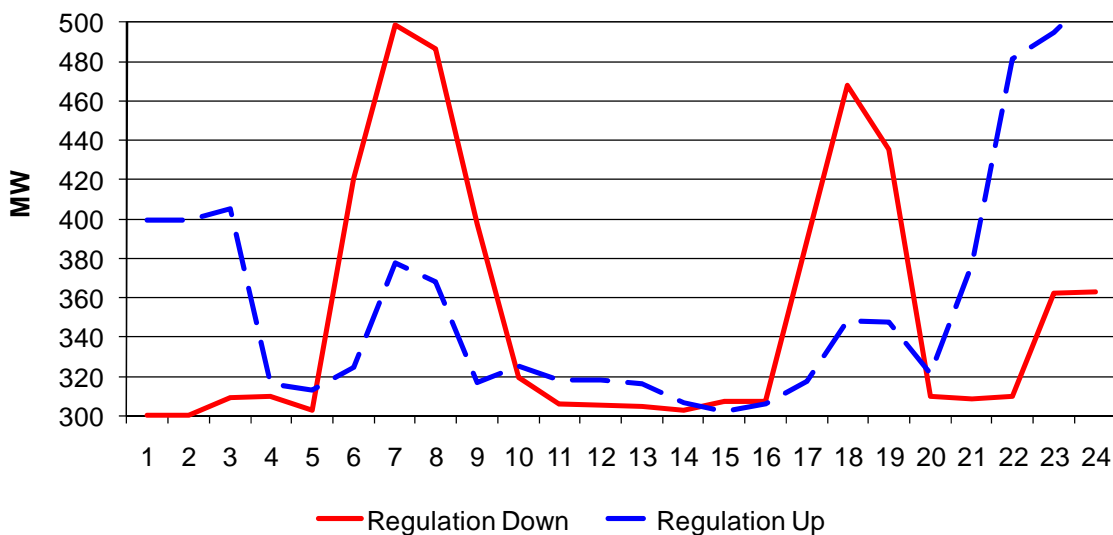


Table 4 shows the monthly IFM average ancillary service procurements and prices for November and December 2009. The average procurement increased for all four types of ancillary services. Regulation down and non-spin ancillary services saw an increase in average price. The regulation down ancillary service saw the highest increase, about 18 percent, whereas the non-spin saw the lowest increase of about three percent. The increase in average price on regulation down and non-spin was mainly due to increase in requirements. The regulation up ancillary service saw a decline by six percent and spin saw a

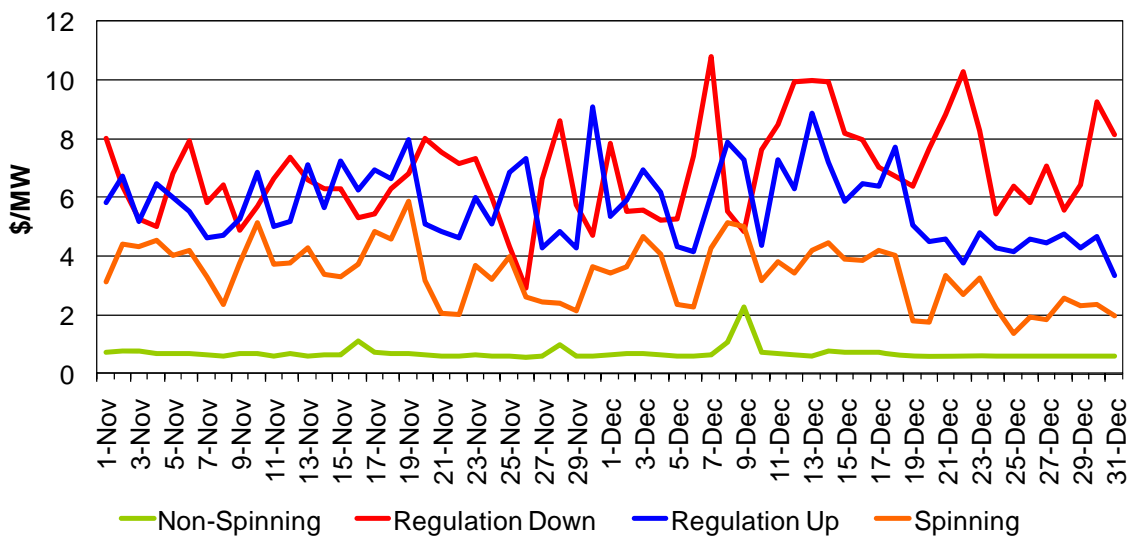
¹ For more details, please refer to the Technical Bulletin 2009-12-02: AS Procurement-Regulation, which is posted on the CAISO website at www.caiso.com/2494/2494c16876b0.pdf

decline of 10.96 percent. Figure 12 below shows the daily IFM average prices for November and December 2009.

Table 4: IFM (Day-Ahead) Monthly Average Ancillary Service Procurement and Price

	Average Procured				Average Price			
	Reg Up	Reg Dn	Spin	Non-Spin	Reg Up	Reg Dn	Spin	Non-Spin
Dec-09	371	355	802	806	\$5.54	\$7.40	\$3.21	\$0.70
Nov-09	357	347	746	751	\$5.92	\$6.28	\$3.60	\$0.68
Percent Change	3.93%	2.51%	7.52%	7.24%	-6.40%	17.95%	-10.96%	3.23%

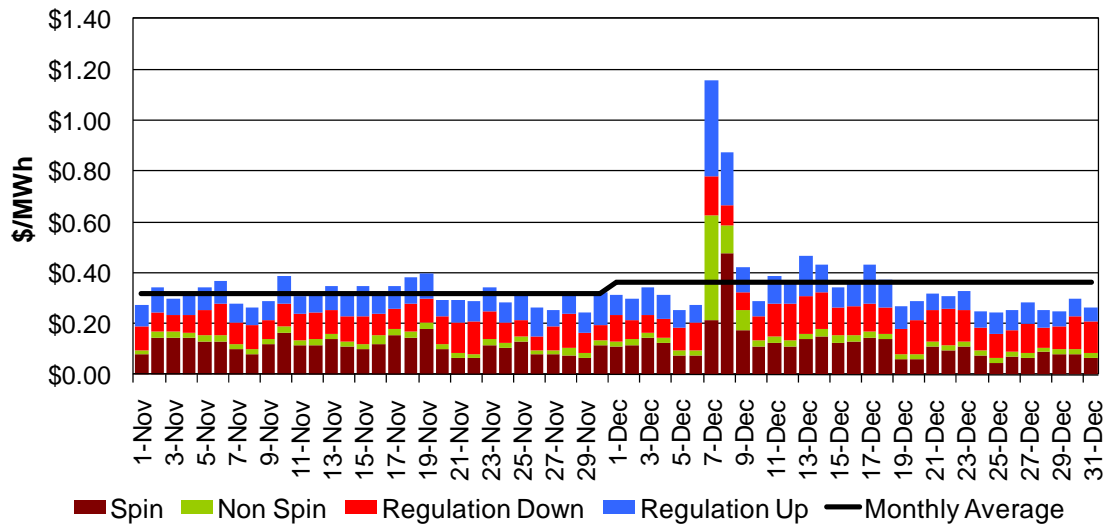
Figure 12: IFM (Day-Ahead) Ancillary Service Average Price



AS Cost to Load

Figure 13 below shows the total system (day-ahead and real-time) average cost to load for ancillary services procured in November and December 2009. The monthly average cost to load in December increased to \$0.36/MWh, up from \$0.33/MWh in November. The increase in cost to load on December 7 and 8 was due to the increase in opportunity cost to provide ancillary services in the real-time market. The increase in opportunity cost was driven by higher real-time energy prices, which are explained in previous sections.

Figure 13: System (Day-Ahead and Real-Time) Average Cost to Load

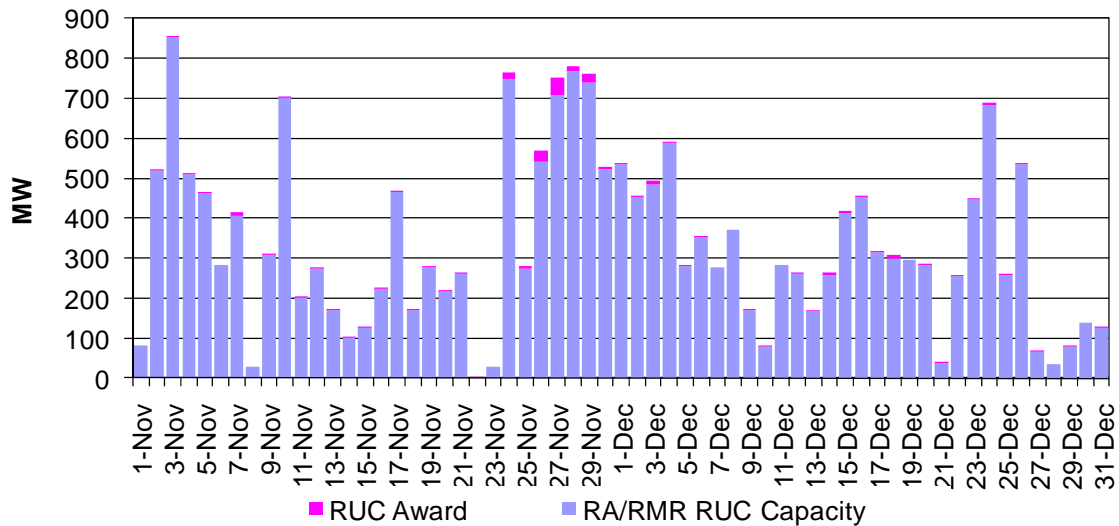


Residual Unit Commitment

RA/RMR RUC Capacity vs. RUC Award

Figure 14 shows the daily average RA or RMR RUC capacity and RUC award for November and December 2009. The monthly average RUC capacity for December fell 18.9 percent to 301 MW from November's 371 MW. The percentage of RUC capacity procured from RA or RMR units increased to 99.4 percent in December from 98.5 percent in November.

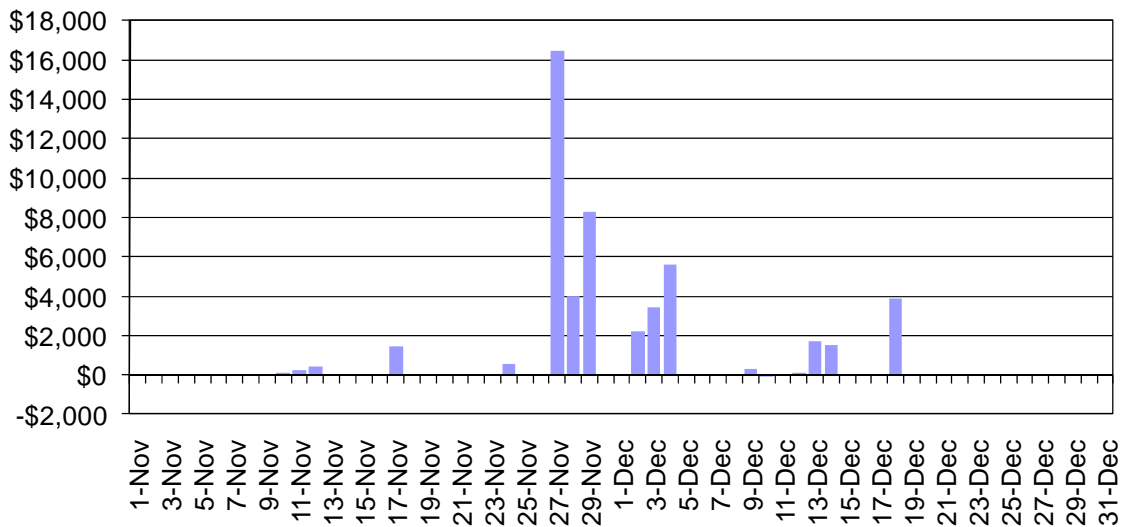
Figure 14: RA/RMR RUC Capacity vs. RUC Award (All Hours)



Total RUC Cost

Figure 15 shows the daily cost of RUC procurement for each trading day in November and December 2009. The total RUC procurement cost for December fell 40.8 percent to \$18,703 from November’s \$31,590. This was because less RUC capacity was procured from non-RA or non-RMR units for the month. On December 10, 2 MW of RUC capacity was procured from a non-RA and non-RMR unit in HE 16; the RUC LMP at that unit was negative due to the negative congestion component driven by the congestion on the La Fresa-Hinson 230 kV line. This resulted in a RUC cost of -\$16 on that day.

Figure 15: Total RUC Cost



Market Intervention

Exceptional Dispatch

For the months of November and December 2009, Figure 16 shows the volume of exceptional dispatch broken out by market type: day-ahead, real-time incremental dispatch and real-time decremental dispatch. The total volume of exceptional dispatch decreased to 71,500 MWh in December from 76,300 MWh in November. In absolute terms, the total volume of real-time incremental exceptional dispatches accounted for approximately 58 percent of the total volume of all exceptional dispatches in December. Generally, all day-ahead exceptional dispatches are unit commitments at the resource physical minimum. The real-time exceptional dispatches are among one of the following types: a unit commitment at physical minimum, an incremental dispatch above the day-ahead schedule, and a decremental dispatch below the day-ahead schedule.

Figure 16: Total Exceptional Dispatch Volume (MWh) by Market Type

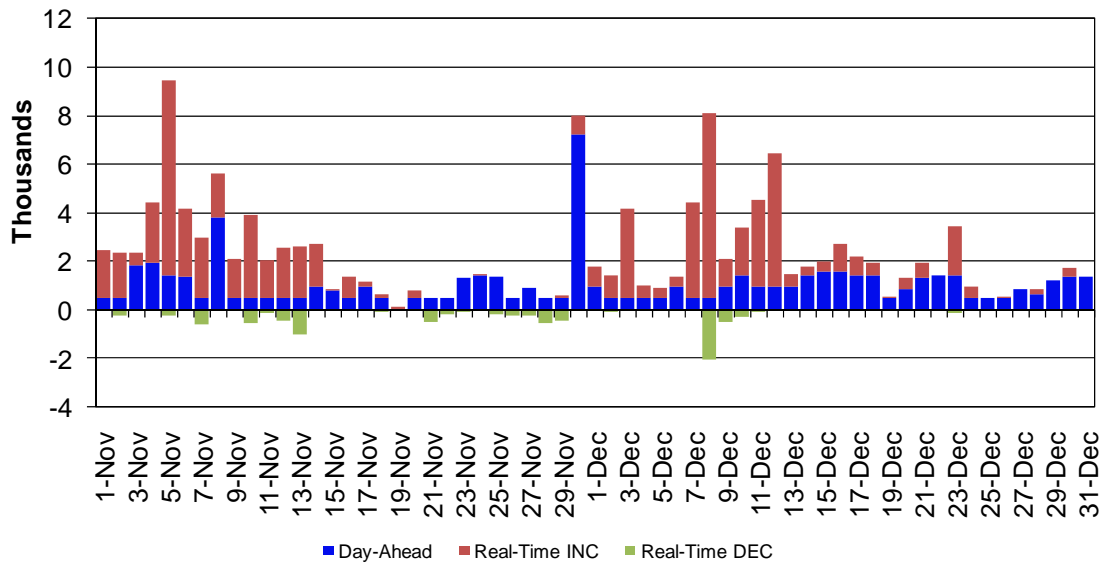
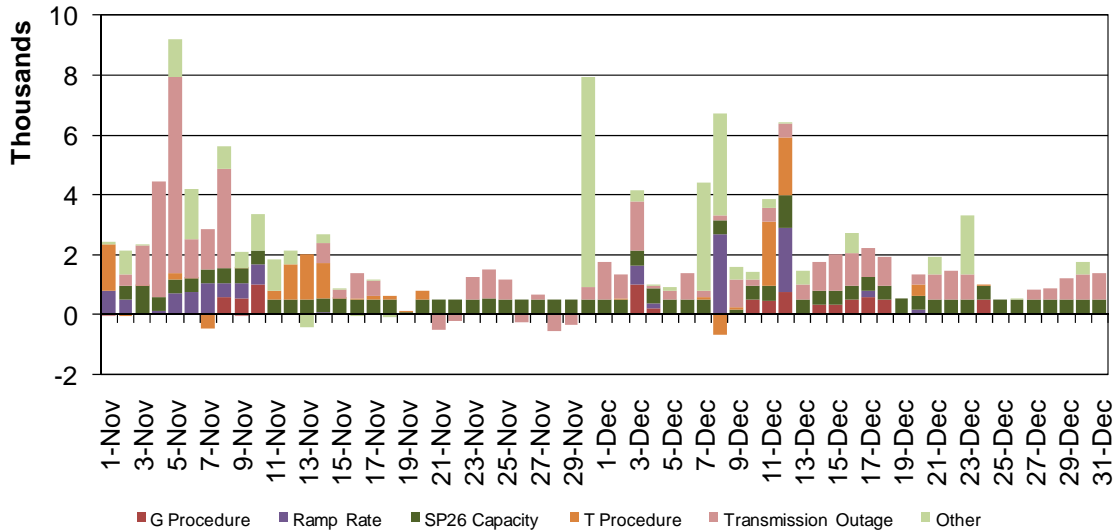


Figure 17 shows the volume of the exceptional dispatch broken out by reason.² The majority of the exceptional dispatch volume in December was driven by transmission outages (30 percent) and capacity requirements in the SP26 area (23 percent). The exceptional dispatch instructions in real-time market for a transmission outage reason were driven by various outages.

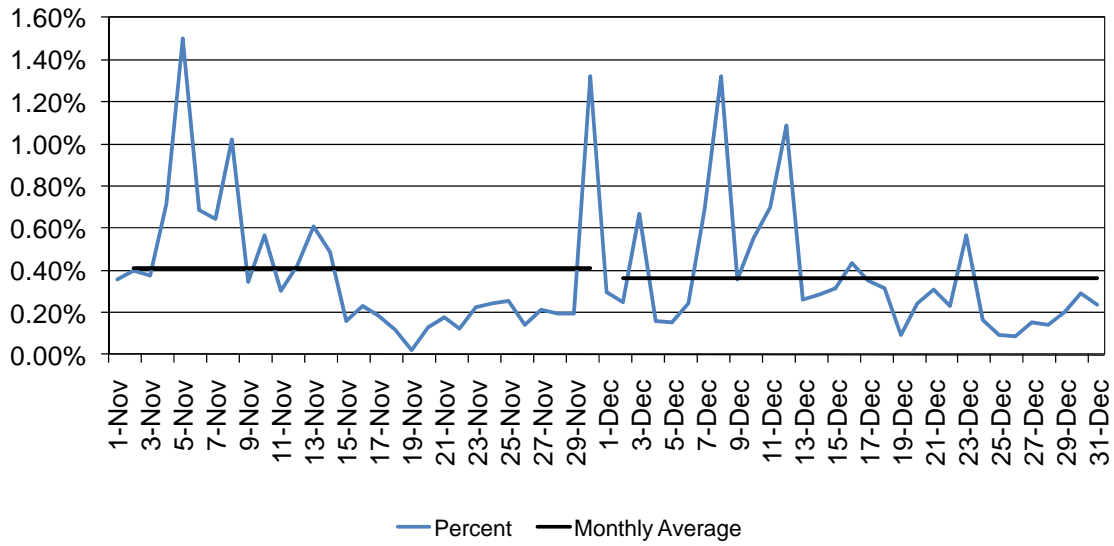
Figure 17: Total Exceptional Dispatch Volume (MWh) by Reason



² For details regarding the reason of exceptional dispatch please read the White paper on exceptional dispatch published on the CAISO website.

Figure 18 shows the total exceptional dispatch as a percent of load, together with the average percentage for each month. In December the monthly average percentage dropped to 0.36 percent from 0.41 percent in November.

Figure 18: Total Exceptional dispatch as Percent of Load



Market Disruption

A market disruption is an action or event that causes a failure of a California Independent System Operator Corporation (ISO or CAISO) market, related to system operation issues or system emergencies.³ Pursuant to Section 7.7.15 of the CAISO tariff, the ISO can take one or more of a number of specified actions in the event of a market disruption, to prevent a market disruption, or to minimize the extent of a market disruption.

For each of the CAISO markets, Table 5 lists the number of market disruptions and the number of times that the ISO removed bids (including self-schedules) in December. Table 5 indicates that there were a total of 42 market disruptions in December, 2009, slightly increasing by five occurrences compared with last month. The RTPD failures (including HASP failures) accounted for approximately 60 percent of total market disruptions in this month.

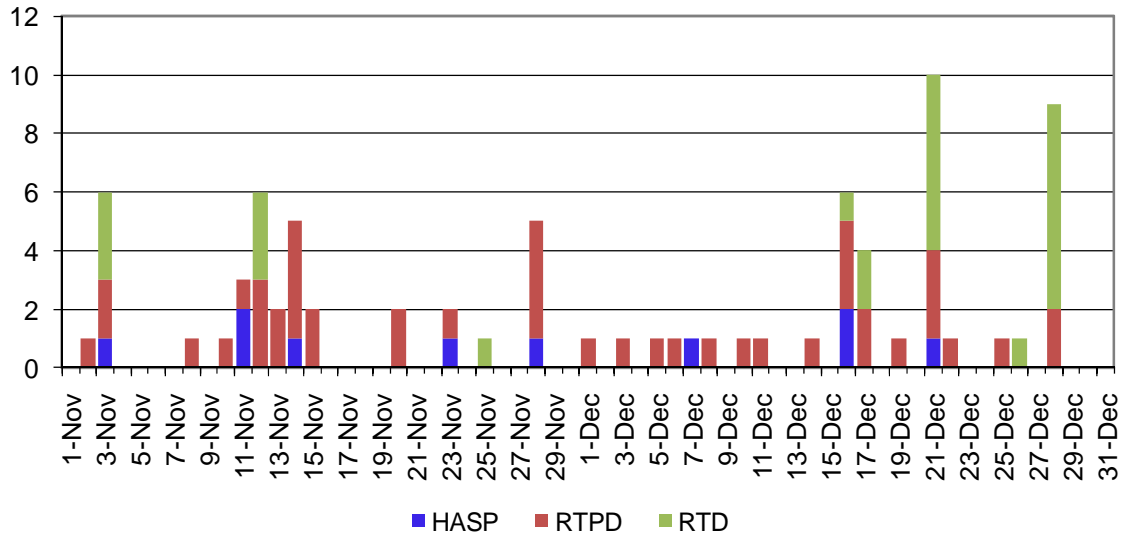
Figure 19 shows the frequency of HASP, RTPD, and RTD failures in December. On December 21, there was an outage of the Lightweight Directory Access Protocol (LDAP) server in hour ending 19. This outage caused three consecutive RTPD failures (including one HASP failure) and six consecutive RTD failures in hour ending 19. The issue was resolved subsequently. On December 28, the LDAP server experienced outage again in hour ending 11 and resulted in two consecutive RTPD failures and six consecutive RTD failures in hour ending 11. There was one RTD failure in interval 10 hour ending 11, which was not related to the above issue. A fix from the vendor has already been deployed into the system to prevent such issue.

Table 5: Summary of Market Disruption

Type of CAISO Market	Market Disruption or Reportable Events	Removal of Bids (including Self-Schedules)
Day-Ahead		
IFM	0	0
RUC	0	0
Real-Time		
Real-Time Pre-Dispatch Interval 1	2	0
Real-Time Pre-Dispatch Interval 2	5	0
Real-Time Pre-Dispatch Interval 3	15	0
Real-Time Pre-Dispatch Interval 4	3	0
Real-Time Dispatch	17	0

³ These system operation issues or System Emergencies are referred to in Sections 7.6 and 7.7, respectively, of the CAISO Tariff. CAISO Tariff, Appendix A, definition of Market Disruption. Capitalized terms not otherwise defined herein have the meanings set forth in the CAISO Tariff.

Figure 19: Frequency of Market Disruption



Blocking of Intertie Schedules

Figure 20 and Figure 21 show the volume in MW of blocking imports and exports on interties, respectively, while Table 6 lists the main statistics of intertie blocking on an hourly basis. For December, there were seven days on which blocking of interties were needed. The highest volume was observed on December 7, a day on which the system was struggling with inclement weather.

Figure 20: Daily Volume of Blocking Imports on Interties

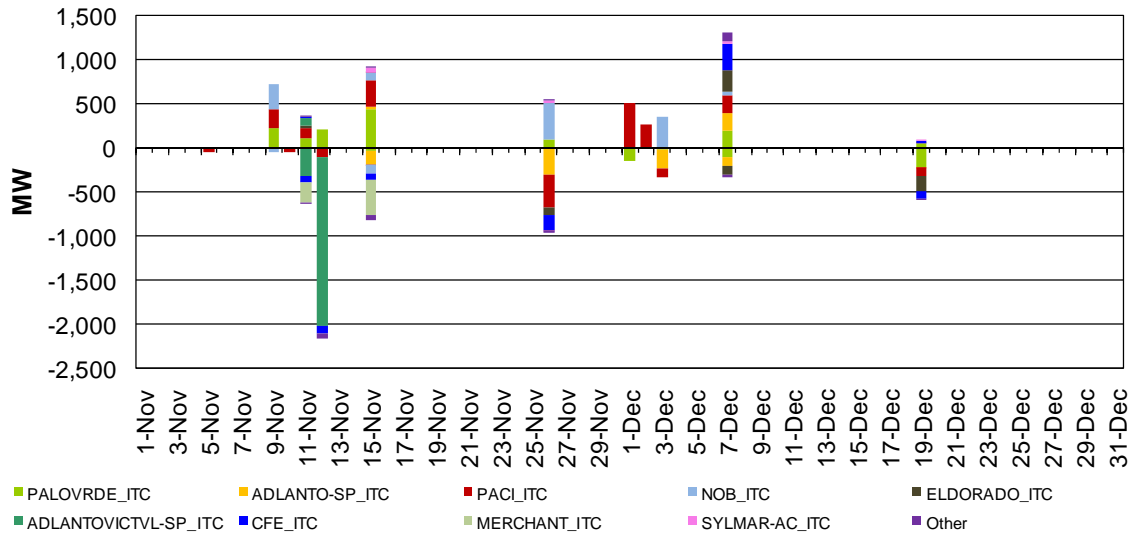


Figure 21: Daily Volume of Blocking Exports on Interties

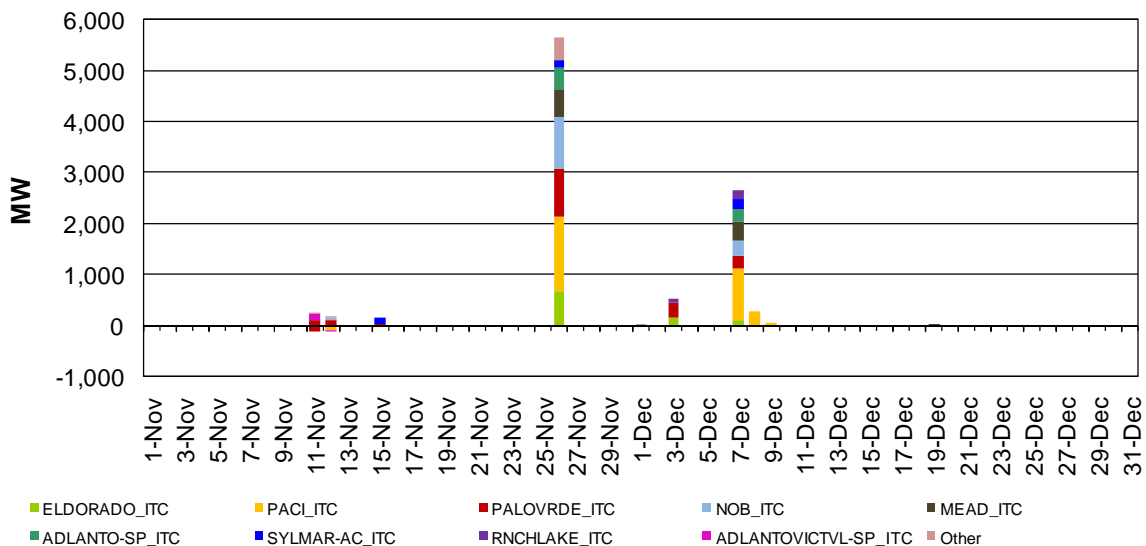


Table 6: Statistics for Hourly Intertie Blocking

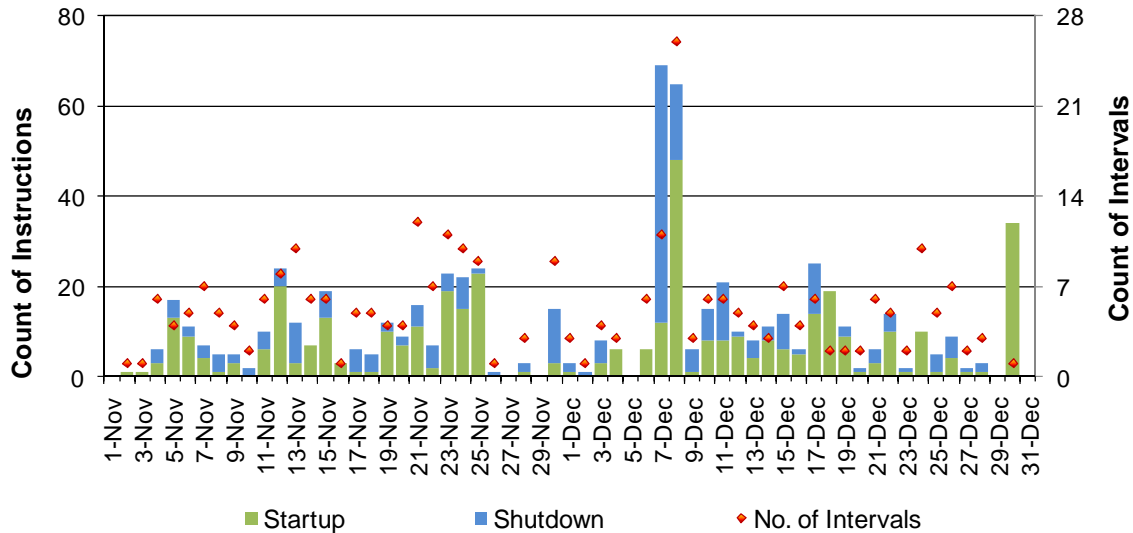
Trade Date	Trade Hour	Direction	No. Ties	No. Schedules	Net Volume (MW)
11/5/2009	17	I	1	1	50
11/9/2009	2	I	3	5	488
11/9/2009	10	I	1	1	125
11/9/2009	12	I	1	1	50
11/9/2009	18	I	1	3	111
11/10/2009	10	I	1	1	50
11/11/2009	23	E	3	7	368
11/11/2009	23	I	9	17	981
11/12/2009	23	E	5	6	261
11/12/2009	23	I	5	55	2371
11/15/2009	23	E	3	3	165
11/15/2009	23	I	12	26	1734
11/26/2009	16	E	15	70	5419
11/26/2009	17	E	3	3	219
11/26/2009	16	I	10	28	1209
11/26/2009	17	I	3	4	295
12/1/2009	18	E	1	1	40
12/1/2009	18	I	1	2	140
12/1/2009	19	I	1	1	515
12/2/2009	18	I	1	5	275
12/3/2009	17	E	3	4	531
12/3/2009	17	I	3	5	333
12/3/2009	18	I	1	6	348
12/7/2009	21	E	8	17	2658
12/7/2009	21	I	12	24	1649
12/8/2009	7	E	1	1	275
12/9/2009	7	E	1	1	50
12/19/2009	2	E	2	2	17
12/19/2009	2	I	7	13	667

December saw a total of eight hours with intertie blocking, down from 11 hours observed in November. This is equivalent to a frequency of 1.07 percent of all HASP runs. In addition, the total blocked volume on interties in December declined by 46 percent, to 7,498 MW on December from 13,896 MW in November. Similarly, the number of schedules impacted by blocking interties declined fairly to 82 in December from 231 in November.

Blocking of Commitment Instructions

Figure 22 shows the count of commitment instructions that were blocked in any of the four RTPD runs in December; it also includes the count of the different 15-minute intervals in which instructions were blocked. The instructions are grouped by startups and shutdowns, while the count of intervals are for periods in which any of these two types of instructions were blocked.

Figure 22: Daily Count of Commitment Instructions Blocked in RTPD



The number of commitment instructions blocked in December increased to 391, from 273 of November. About 60 percent of all instructions blocked in December was for startups. This fair increase was due largely to the events on December 7 and 8. As explained in previous sections, on these two days the system was struggling with inclement weather, multiple transmission and generation outages, and a derate on Palo Verde that limited imports. Also, December 30 saw a high frequency of startups being blocked because STUC produced infeasible results with erroneous instructions for 34 long-start units.