Market Performance Report November 2009

December 22, 2009

ISO Market Services

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Executive Summary

This report contains the highlights of the month of November 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 November 2009:

- The average energy demand was relatively unchanged compared with one year ago.
- Natural gas prices declined in the first half of November and then increased in the second half of the month.
- The day-ahead market saw a declining trend in the energy prices in the first half of November, thanks largely to the declining natural gas prices.
- Real-time energy prices were generally stable in November except for a few days.
- The cumulative total congestion rent for interties in November was approximately $8.4 million, and the cumulative total congestion rent for branch group and market scheduling limit was approximately $12.5 million.
- Net revenue adequacy for congestion revenue rights was in deficit of $3.13 million in November, a significant deterioration with respect to October's surplus of $0.74 million.
- The monthly ancillary service average cost to load in November slightly increased to $0.32/MWh from $0.31/MWh in October.
- The total RUC procurement cost increased to $31,590 in November from October's $13,893.
- The majority of the exceptional dispatch volume in November was driven by transmission outages (47 percent) and capacity requirements in the SP26 area (23 percent).

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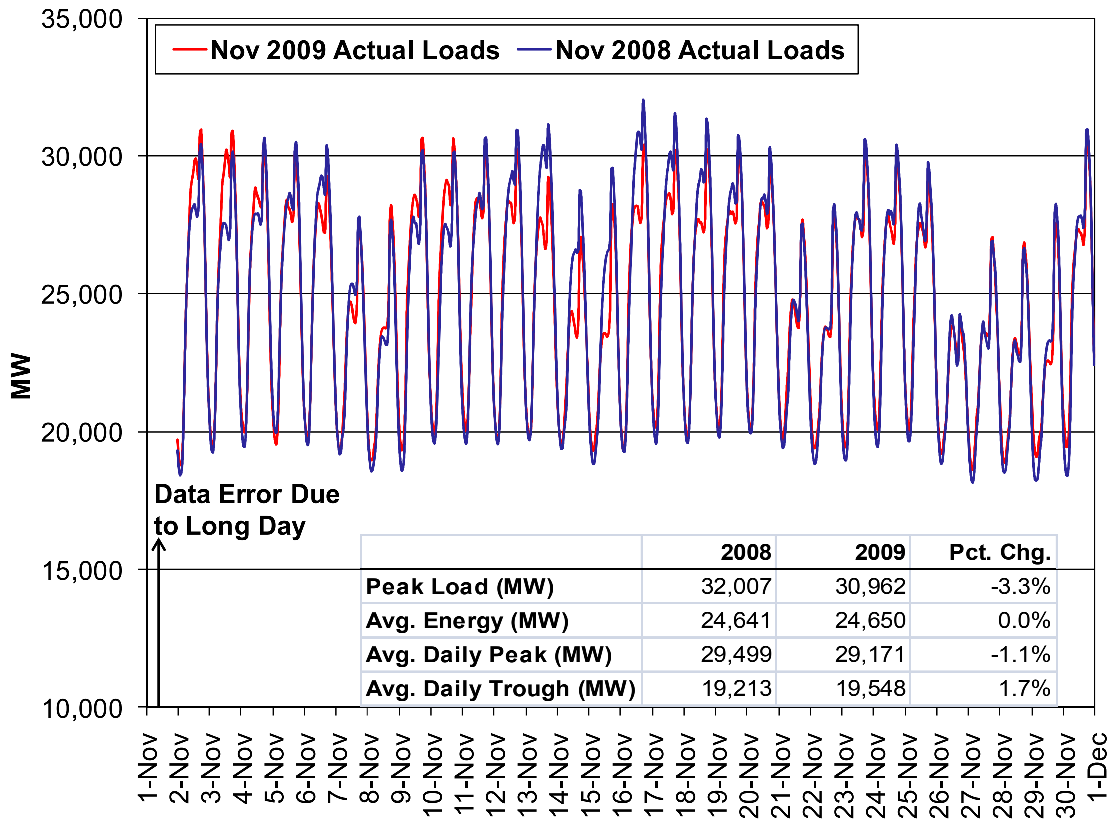
Market Characteristics

Loads

November's load patterns were typical for this time of year with average daily peaks below 30,000 MW. The loads were lower during the holidays than the other days in November. Average energy demand in this month was relatively unchanged compared with November's average energy demand in 2008.

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

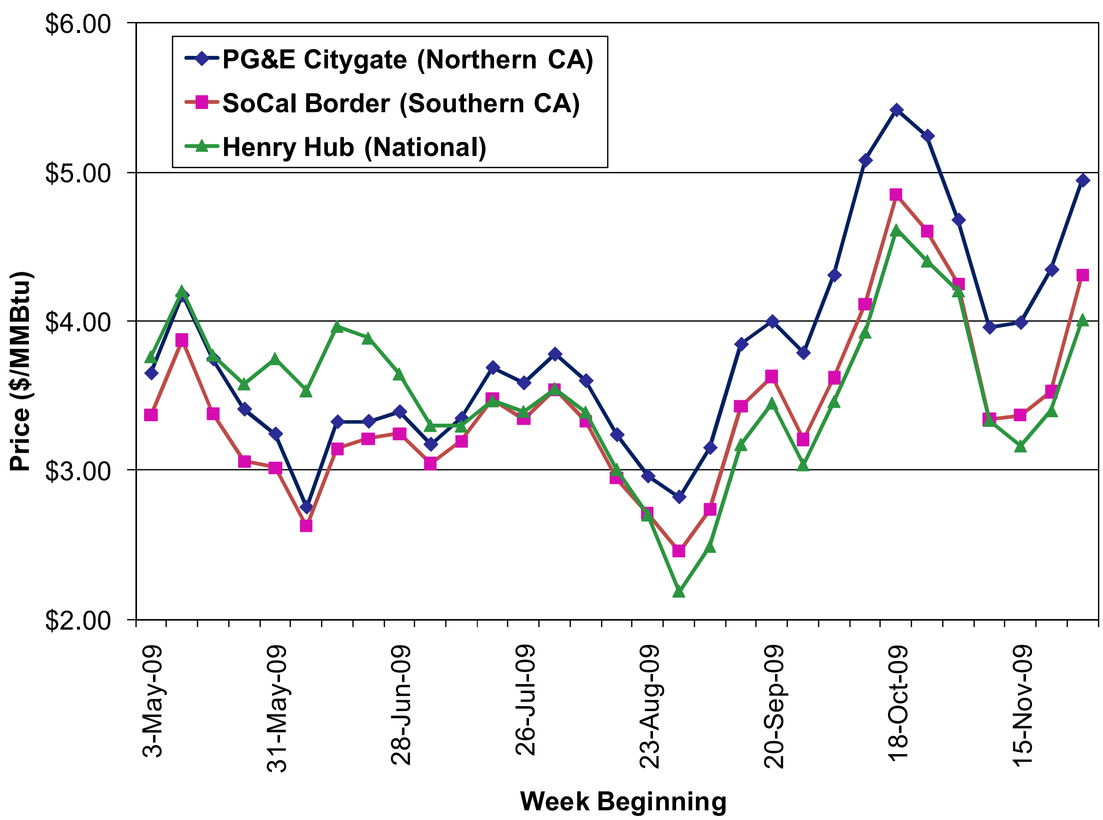


	2008	2009	Pct. Chg.
Peak Load (MW)	32,007	30,962	-3.3%
Avg. Energy (MW)	24,641	24,650	0.0%
Avg. Daily Peak (MW)	29,499	29,171	-1.1%
Avg. Daily Trough (MW)	19,213	19,548	1.7%

Natural Gas Prices and Inventories

In November, natural gas prices continued the declining trend until the week of November 15. As the Energy Information Administration (EIA) stated, milder-than-normal temperatures and the decrease in industrial demand contributed to this decline. Starting from the week of November 15, natural gas prices rebounded due to rising crude oil prices and continued injection demand to exploit the arbitrage opportunities. The California Composite Average gas price ended at $4.98 per MMBtu on November 30, an increase of 30 cents compared with $4.68 per MMBtu on October 30. As of November 30, the working gas in underground storage in the West increased to 526Bcf, which is 16.9 percent above the five-year average.

Figure 2: Weekly Average Natural Gas Spot Prices – May 2009 to November 2009



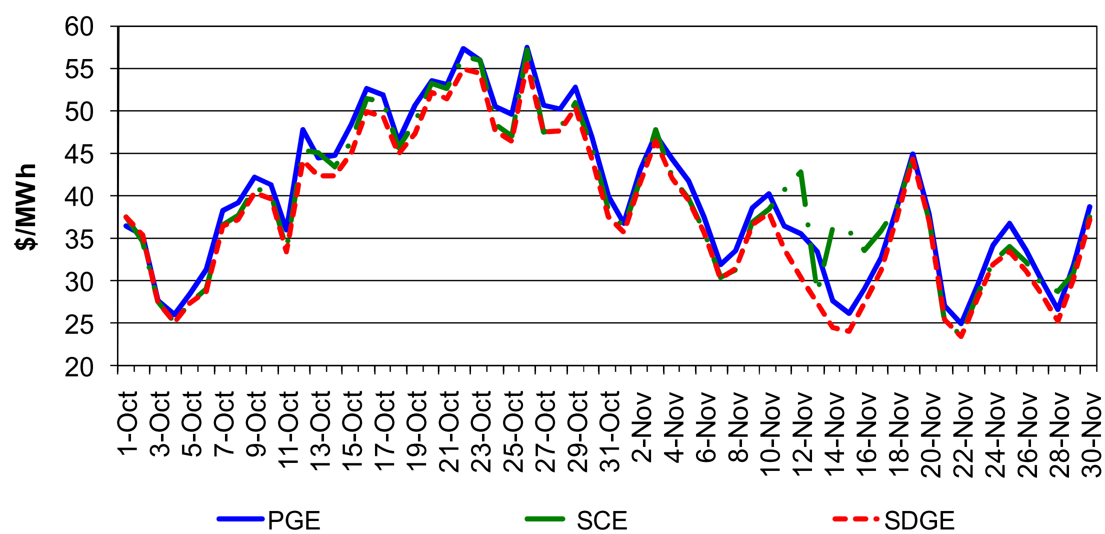
Market Performance Metrics

Energy

Day-Ahead Prices

The energy prices in the day-ahead (DA) market had a declining trend in the first half of November, as shown in Figure 3. The monthly average price among the three default Load Aggregation Points (LAPs) fell 21.2 percent to $34.4/MWh in November from $43.6/MWh in October. During the month, the prices in three default LAPs diverged on several days due to congestion on different branch groups. Starting on November 11, the ISO began enforcing the import limit that applies specifically to the SCE area (SCE_PCT_IMP branch group) in the market model, so that congestion related to this limit may be managed via the market optimization. [1] This branch group was congested from November 11 to November 17, elevating the energy prices in the SCE area. On November 12 and 13, congestion on Path 26 and Path 15 elevated the energy price in the PG&E LAP. These two branch groups were derated due to the scheduled outages of Midway-Vincent #3 and Los Banos-Midway #2 500 kV lines respectively. The energy prices were moderate in the day-ahead market for the month of November, falling into the range between $23/MWh and $48/MWh.

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



[1] For more details, please refer to the Technical Bulletin 2009-12-01 posted on the CAISO website at http://www.caiso.com/2479/247997c52e0f0.pdf

Real-Time Prices

Real-time (RT) energy prices were less variable in November than in October. The prices in the three default LAPs converged well with a few exceptions, as shown in Figure 4. On November 1, 2, 11, and from November 4 to 6, congestion on Path 26 elevated the energy prices in the PG&E area. This branch group was derated due to the planned outage of Midway-Vincent #3 500 kV line, and it was also dynamically biased for modelling and reliability reasons. From November 4 to November 6, the congestion on Victorville branch group further exacerbated the price divergence among the three default LAPs. This branch group was actively biased for modelling and reliability purposes during those days. On November 12, the SCE_PCT_IMP branch group was congested, elevating the energy prices in the SCE area. From November 23 to 25, Los Banos North branch group was congested due to derates driven by the outage of Tesla-Los Banos #1 500 kV line, elevating the energy prices in the PG&E LAP. For the month, the real-time energy prices were moderate, falling into the range between $15/MWh to $73/MWh.

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

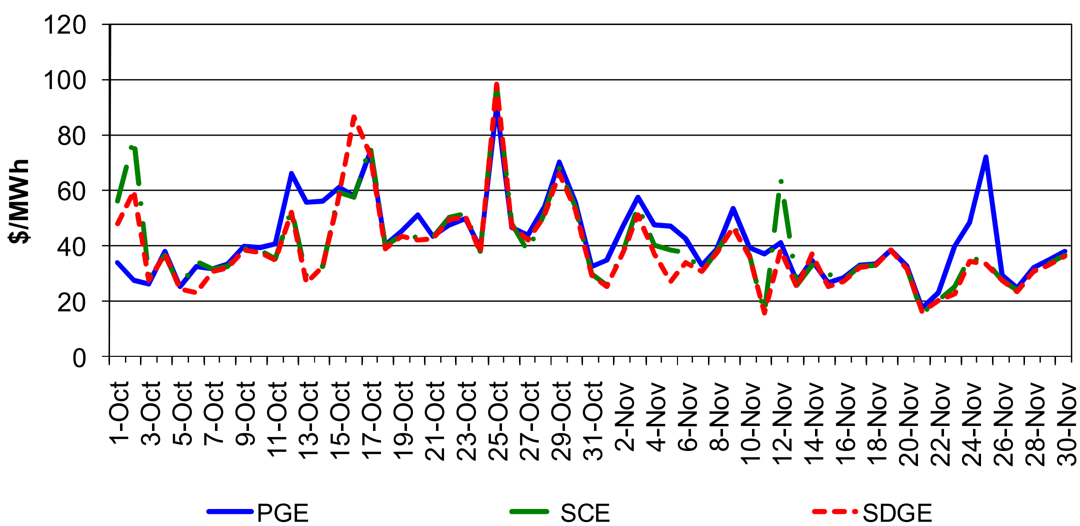


Figure 5 on the next page shows the daily frequency of price spikes by price range for all three default LAPs in the five-minute Real-Time Dispatch (RTD). In percentage terms, the frequency of prices over $250/MWh decreased from 1.24 percent in October to just 0.36 percent in November. Extreme prices (over $1000/MWh) decreased by a half, with only one occurrence (0.004 percent) in November. As shown in Figure 5, this extreme price was observed on November 25 when Los Banos North branch group was binding.

Figure 5: Daily Frequency of RTD LAP Positive Price Spikes

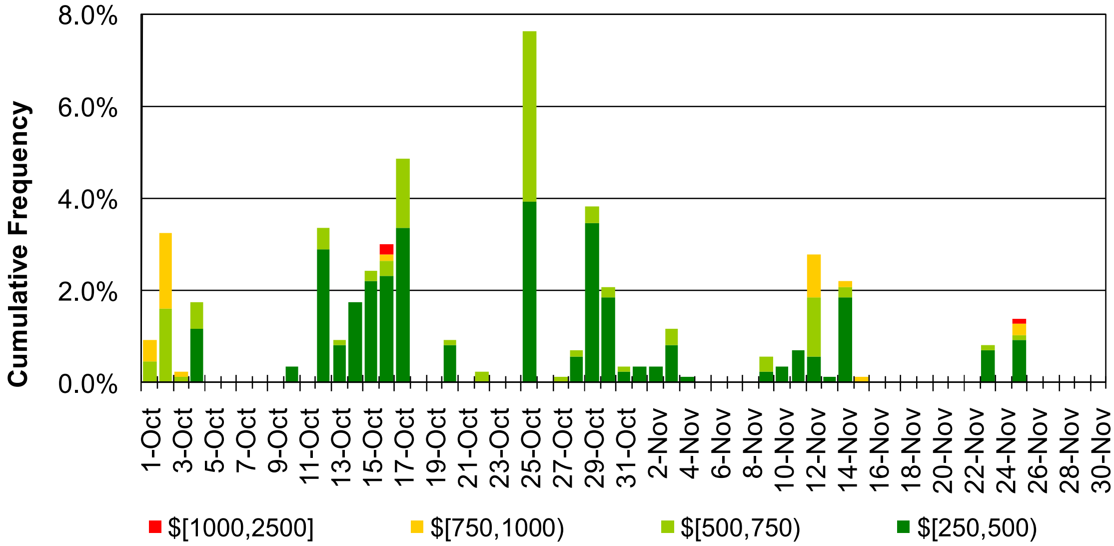
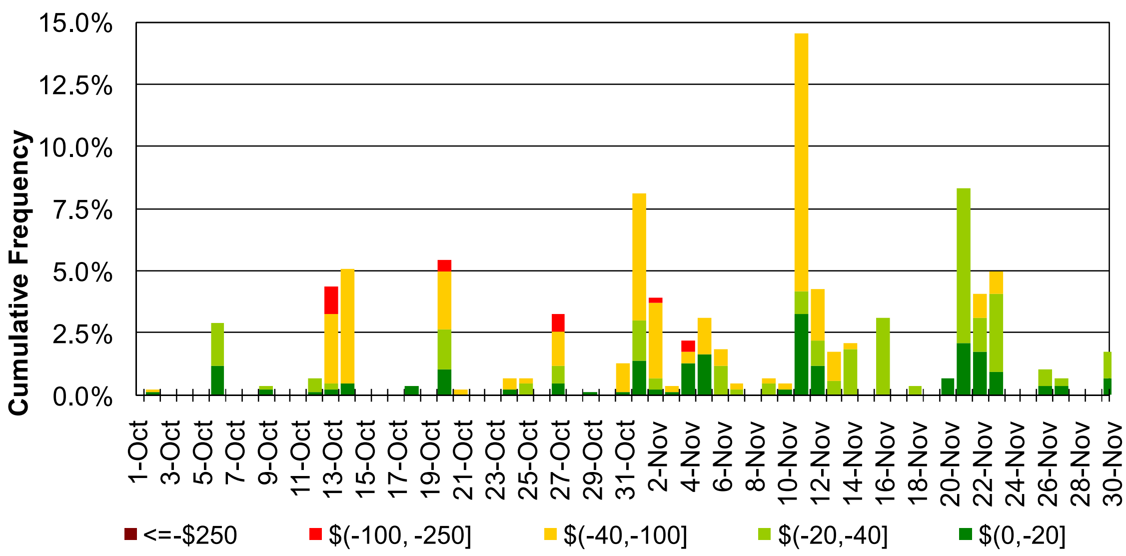


Figure 6 shows the daily frequency of negative prices by price range for all three default LAPs in the five-minute RTD. The frequency of negative prices increased to 2.29 percent in November from 0.82 percent in October. These negative prices were mainly observed as a result of congestion on either Path 26 or Los Banos North branch groups. On several occasions, the real-time market was dynamically managing Path 26 to maintain its reliability limit. In the last several days of the month, negative price spikes were also a result of overgeneration.

Figure 6: Daily Frequency of RTD LAP Negative Price Spikes



Price Convergence

Figure 7 illustrates the difference between DA and RTD energy prices for the three default LAPs for the months of October and November 2009. A positive difference indicates that the RTD price is higher than the DA price, and vice versa. The price for the PG&E default LAP was $2.87/MWh higher in the RTD than in the DA on average for November, increasing 37 percent from a difference of $2.09/MWh in October. For the SCE and SDG&E default LAPs, their energy prices were lower in the RTD than in the DA market on average for the month, $1.94/MWh and $1.44/MWh respectively. As mentioned in the previous section, the large positive differences between the RTD price and the DA price for PG&E LAP between November 23 and November 25 were due to real-time congestion on Los Banos North branch group that elevated the RTD prices in the PG&E LAP on those days. Also, the large negative price difference for SCE LAP occurred on November 11, when the SCE_PCT_IMP branch group was enforced in the market for the first time, which resulted in high prices in the SCE in the DA.

Figure 7: Daily DLAP Price Difference (All Hours)

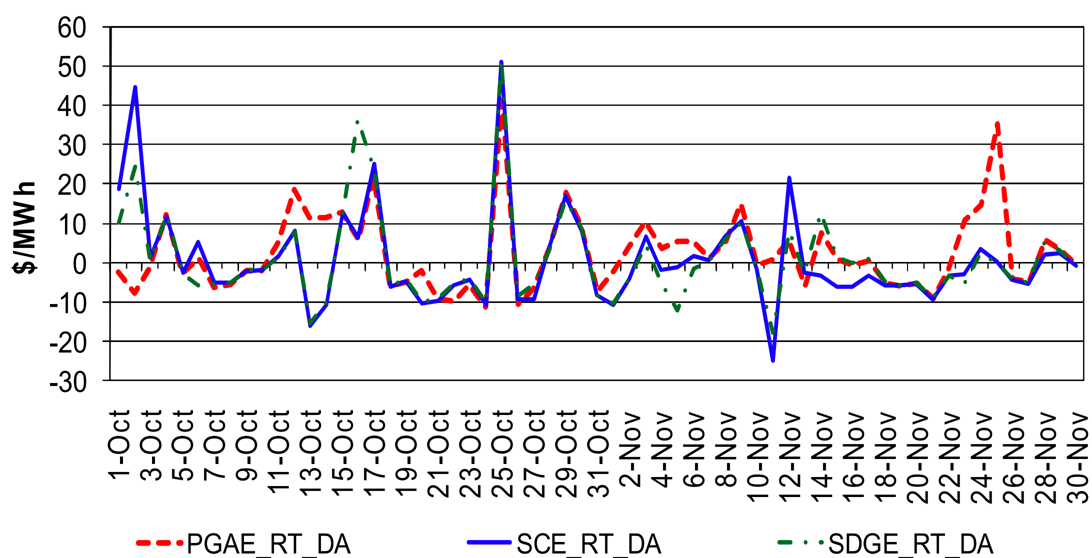
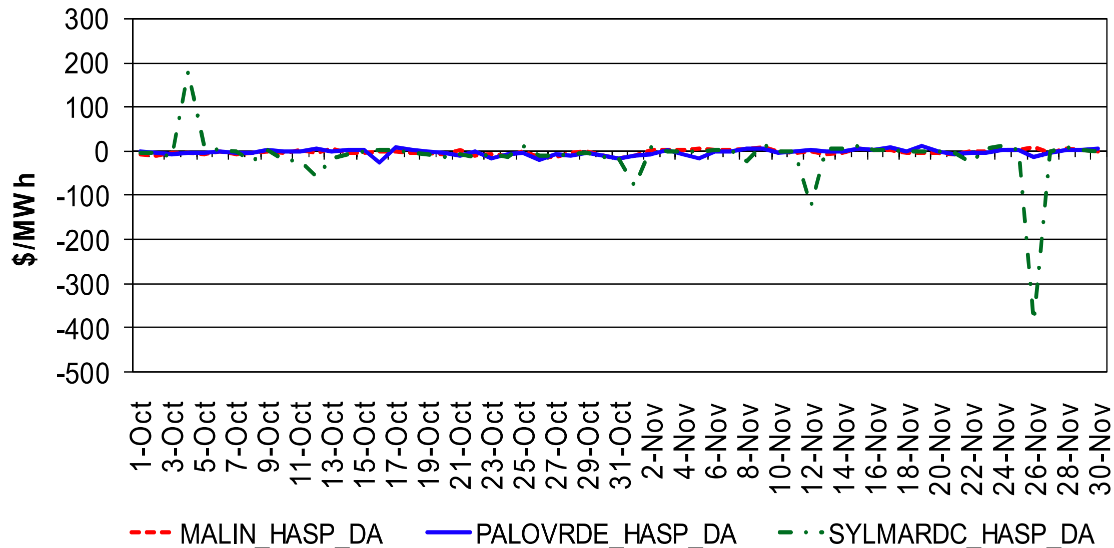


Figure 8 presents the difference between the HASP hourly average price and the DA hourly average price for three selected interties (Malin, Palo Verde, and Sylmar), where the positive difference indicates that the HASP price is higher than the DA price, and vice versa. The HASP prices and DA prices converged well in November with a few exceptions on Sylmar intertie. The large price divergence between DA and HASP on the Sylmar intertie on November 1, 12 and 26 was due to very low prices in the HASP run since the prices in the DA were moderate. On November 1 and 12, Path 26 was congested in HASP, depressing the energy prices in the SCE and SD&GE areas. This in conjunction with congestion on NOB_ITC resulted in low negative prices at Sylmar intertie. On November 26, NOB_ITC was congested in HASP due to a derate driven by the forced outages of two converters on Celilo, resulting in low negative prices at the Sylmar intertie.

Figure 8: Daily Intertie Price Difference (All Hours)



Congestion

Congestion Rents on Interties

Figure 9 below illustrates daily Integrated Forward Market (IFM) congestion rents by intertie for October and November 2009. The cumulative total congestion rent for interties in November was approximately $8.4 million, down from $11.32 million in October. Most of the congestion occurred on Palo Verde (65 percent), Mead (15 percent) and El Dorado (12 percent) interties.

Figure 9: IFM Congestion Rents by Intertie (Import)

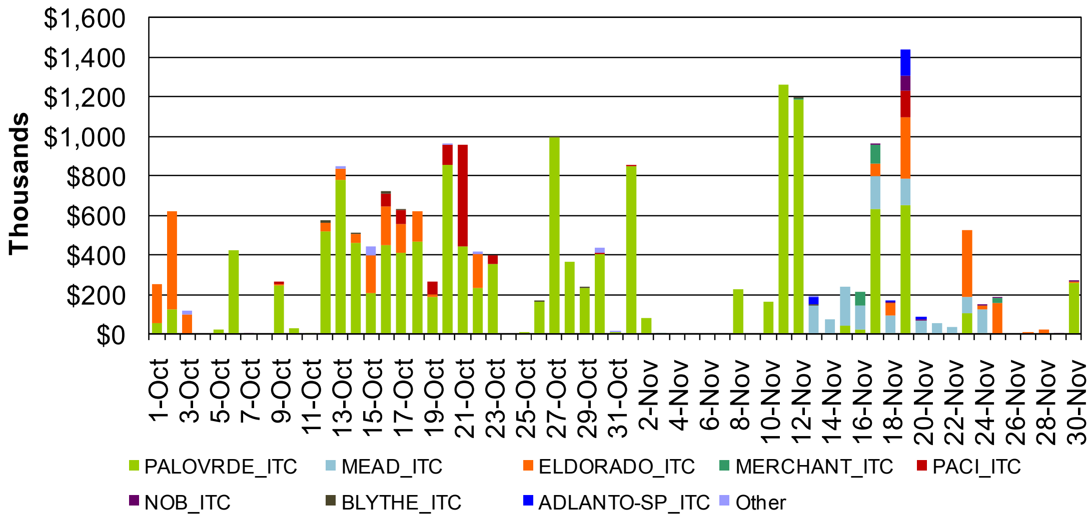


Table 1 shown on the next page provides a breakout of the IFM cleared value (MW), average shadow price ($/MWh) and number of congested hours by intertie. The average shadow price on Palo Verde intertie was $14/MWh in November, which was slightly higher than $10/MWh in October. The highest congestion rents on Palo Verde were observed on November 11 and 12. This may be due to the activation of the SCE_PCT_IMP branch group limit on November 11, compounded with a derate on Palo Verde intertie on November 12. Total congestion rents on Palo Verde intertie were 35 percent less, reaching 5.5 million on November from $8.5 million in October. The congestion rents are calculated as the sum of the product of shadow price and flow limit for all hours.

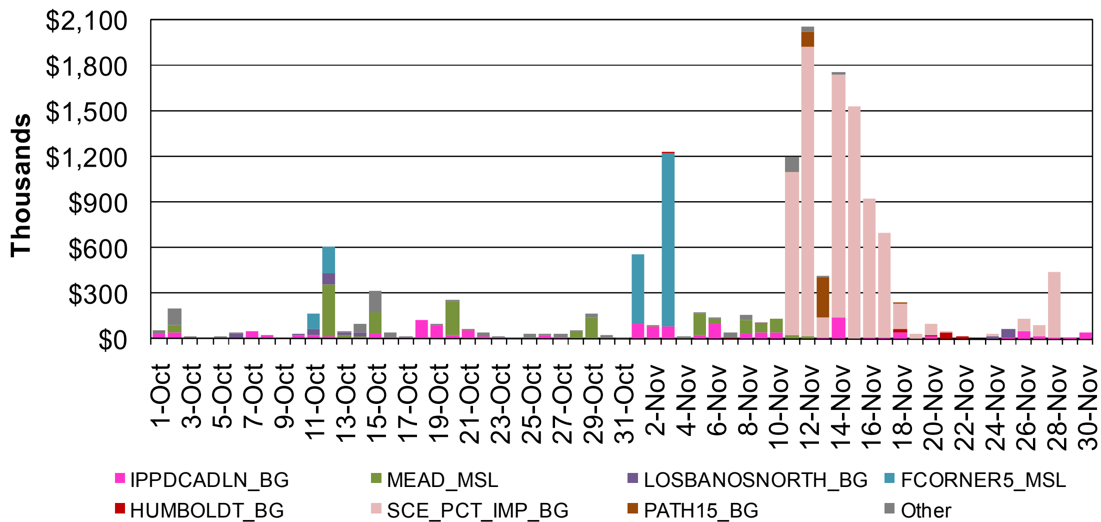
Table 1: IFM Congestion Statistics by Intertie (Import)

Intertie	Average Cleared Value (MW)	Shadow Price ($/MWh)	Number of Congested Hours
ADLANTO-SP_ITC	1158	5	34
BLYTHE_ITC	73	70	23
ELDORADO_ITC	1189	10	86
IID-SCE_ITC	586	2	1
MEAD_ITC	994	8	173
MERCHANT_ITC	797	5	51
NOB_ITC	568	4	42
PACI_ITC	1893	6	11
PALOVRDE_ITC	2551	14	157

Congestion Rents on Branch Group and Market Scheduling Limit

Figure 10 illustrates IFM congestion rents on selected branch groups and market scheduling limits. For the month of November, the total congestion rent for branch group and market scheduling limit increased significantly to about $12.5 million from $2.67 million in October. Of the total, the vast majority of rents occurred on the brand-new branch group SCE_PCT_IMP (70 percent), followed by Four Corners market scheduling limit (13 percent) and IPPDCADLN branch group (7 percent).

Figure 10: IFM Daily Congestion Rents by Branch Group and Market Scheduling Limit



On November 11, the ISO began enforcing the SCE_PCT_IMP branch group. This limit ensures that SCE imports do not exceed 60 percent of its load.[2] Since April 1 through October 22, system conditions were such that the SCE import limit was not exceeded. Therefore, no actions were necessary to ensure that the limit was honored. However, as of October 22, conditions were such that it was necessary to perform an increased level of exceptional dispatch to maintain the real-time imports within the limit. As of November 11, the ISO began enforcing the import limit in the market so that the ISO congestion related to this limit was managed through the market optimization. Congestion rents on SCE_PCT_IMP branch group for November was $7.4 million and was collected mainly in the period of November 11 through November 17, when the limit was new for the market. However, after this period congestion on this branch group diminished fairly as the market adjusted to internalize and account for its impact.

Also, congestion rents on Four Corners market scheduling limit accrued on November 1 and 3 when its limit was derated about 50 percent to reflect the outage of the Four Corners 1AA bank.

[2] For more details, please refer to the Technical Bulletin 2009-12-01 posted on the CAISO website at http://www.caiso.com/2479/247997c52e0f0.pdf

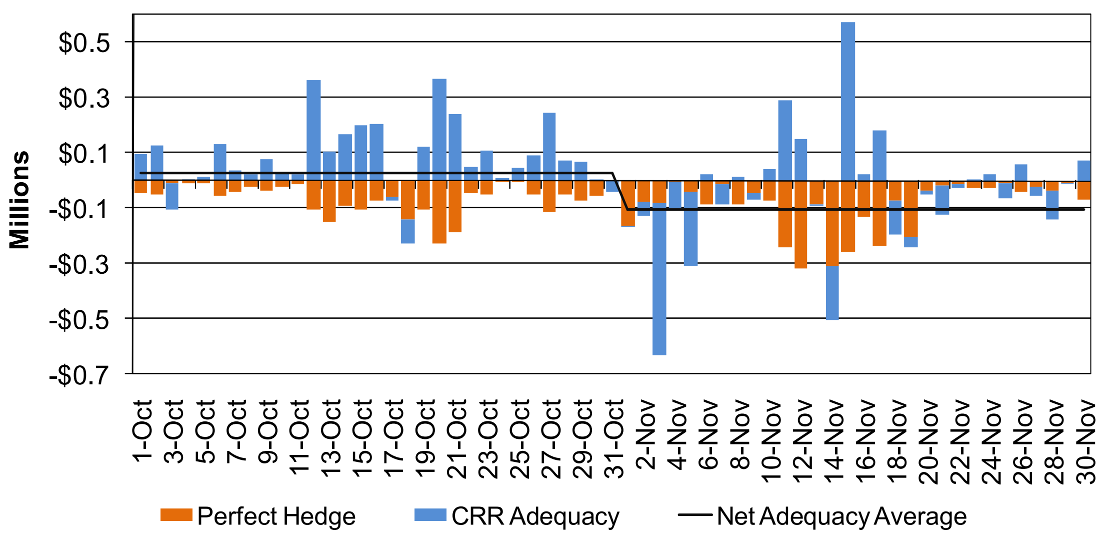
Table 2: IFM Congestion Statistics by Branch Group and Market Scheduling Limit

Branch Group	Average Cleared Value (MW)	Shadow Price ($/MWh)	Number of Congested Hours
ADLANTOSP_MSL	1217	2	14
FCORNER5_MSL	800	49	41
HUMBOLDT_BG	43	93	27
IPPDCADLN_BG	644	5	303
LOSBANOSNORTH_BG	1720	5	9
MEAD_MSL	1460	6	55
MKTPCADLN_MSL	605	5	29
PATH15_BG	3488	4	24
PATH26_BG	1002	3	30
SCE_PCT_IMP_BG	6731	11	120
SDGEIMP_BG	1150	3	2
WSTWGMEAD_MSL	171	4	25

Congestion Revenue Rights

Figure 11 illustrates the revenue adequacy for Congestion Revenue Rights (CRRs) for the months of October and November 2009. In comparison to the daily average revenue surplus of $25,817 for October, November saw a daily average revenue deficiency of $104,399.

Figure 11: Daily Revenue Adequacy of Congestion Revenue Rights



Revenue deficiencies were observed in all days of the month with the exception of November 11, 15, 26 and 30. The most significant deficiencies occurred on November 3, 5, 14 and 19. Throughout the month, Palo Verde intertie was slightly derated to reflect the outage of a transmission element of the Navajo-Crystal 500 kV line. In addition, Palo Verde was further derated on November 2 through 5 and on November 17, 19, 21 and 30 to accommodates other outages. Also, in the first several days of November, the Four Corners market scheduling limit was derated by 50 percent to reflect the outage of the Four Corners 1AA bank. This drove the high deficiency on November 3. Throughout the month, the cost of perfect hedge, which is the payment reversal for congestion associated to ETCs, CVRs and TORs, reduced by $2.8 million the congestion rents available to pay off all CRR entitlements.

For the month of November, 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 November was of 15 percent; these two factors were insufficient to attain CRR revenue adequacy in November. The monthly summary 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 12.9 percent of congestion rents were needed to cover the cost of the perfect hedge. On net, total congestion revenues were in deficit of $3.13 million, a significant deterioration with respect to October's surplus of $0.74 million. The auction revenues credited to the balancing account for November were $2.13 million, which were insufficient to offset the CRR deficiency. After using all auction revenues for the month, November has a net deficiency of $1 million to be allocated to measured demand.

Table 3: CRR Adequacy Statistics for November

Concept	Amount
IFM Congestion Rents	$21,985,786.32
CRR Payments	$22,283,280.84
CRR Adequacy	-$297,494.52
Perfect Hedge	-$2,834,484.86
Net Revenue Adequacy	-$3,131,979.38
Revenue Adequacy Ratio	87.53%
Annual Auction Revenues	$888,515.64
Monthly Auction Revenues	$1,242,280.00
Monthly Net Balance	-$1,001,183.74

Ancillary Services

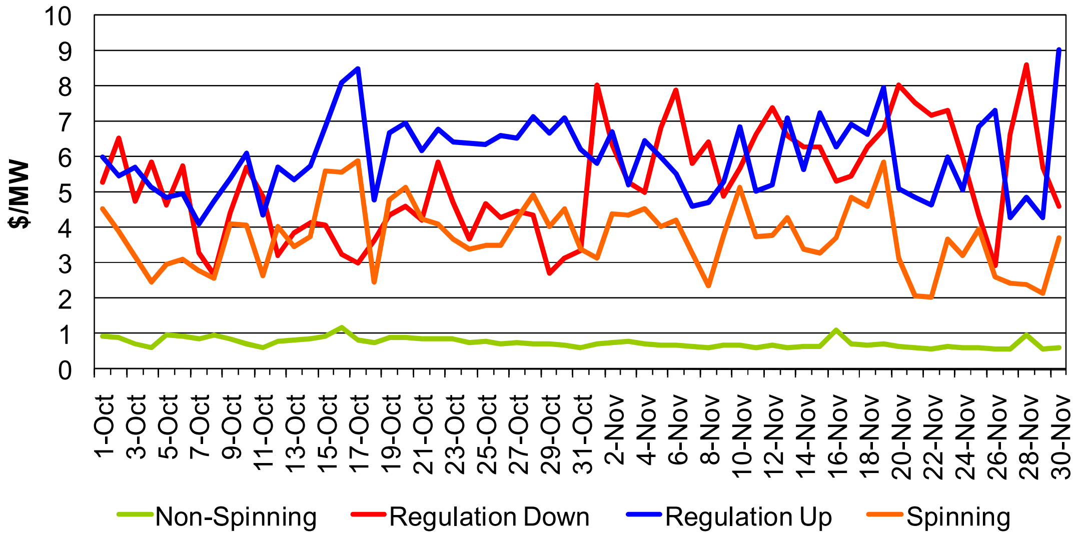
IFM (Day-Ahead) Average Price

Table 4 shows the monthly IFM average ancillary service procurements and prices for October and November 2009. The average procurement slightly increased for regulation up, and declined for the other three types of ancillary services. The average prices for the upward ancillary services declined in November compared with October. But the average price for regulation down increased 45.6 percent to $6.27/MWh in November from October's $4.31/MWh. As mentioned in the previous section, the day-ahead energy price had a decreasing trend in November. The decrease in energy price drove up the opportunity cost to provide regulation down ancillary services, hence increases the monthly average regulation down price. [3] Figure 12 below shows the daily IFM average prices for October and November 2009.

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

	Average Procurred				Average Price			
	Reg Up	Reg Dn	Spin	Non-Spin	Reg Up	Reg Dn	Spin	Non-Spin
Nov-09	357.00	346.53	745.98	751.45	$5.92	$6.27	$3.60	$0.68
Oct-09	353.22	351.37	771.06	771.63	$6.06	$4.31	$3.89	$0.81
Percent Change	1.07%	-1.38%	-3.25%	-2.62%	-2.41%	45.66%	-7.40%	-16.52%

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

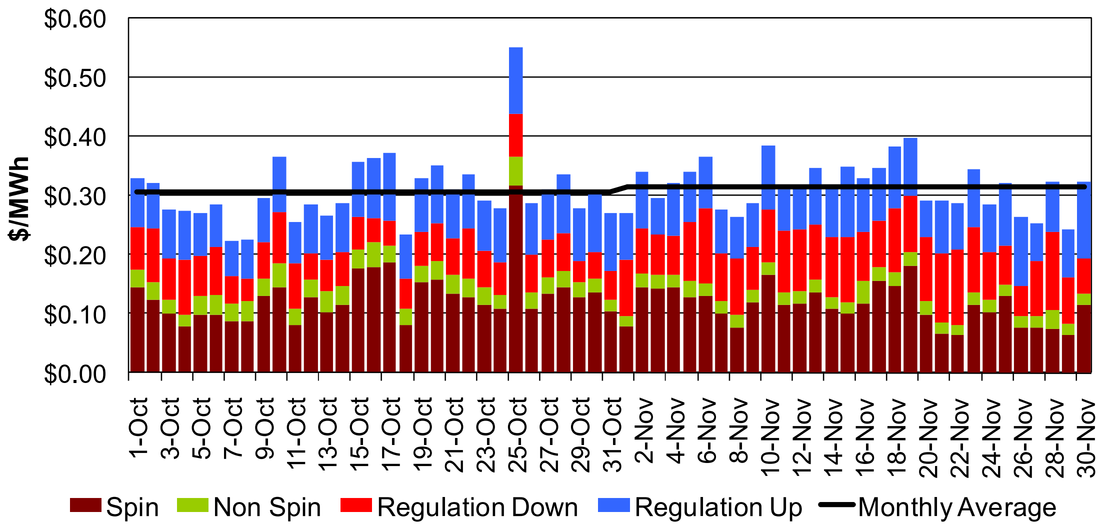


[3] The concept of opportunity cost is explained in detail in Section 4.3 of the Market Operations Business Practice Manual.

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 October and November 2009. The monthly average cost to load in November increased to $0.32/MWh, up slightly from $0.31/MWh in October.

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

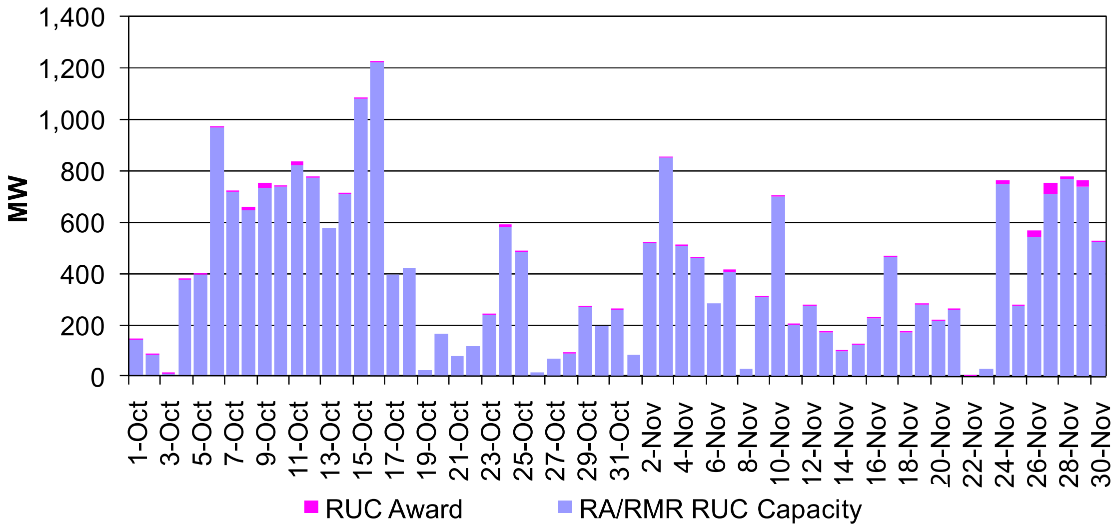


Residual Unit Commitment

RA/RMR RUC Capacity vs. RUC Award

Figure 14 shows the daily average RA or RMR RUC capacity and RUC award for October and November 2009. The monthly average RUC capacity for November fell 14.8 percent to 371 MW from October's 436 MW. And the percentage of RUC capacity procured from RA or RMR units declined to 98.5 percent in November from 99.3 percent in October.

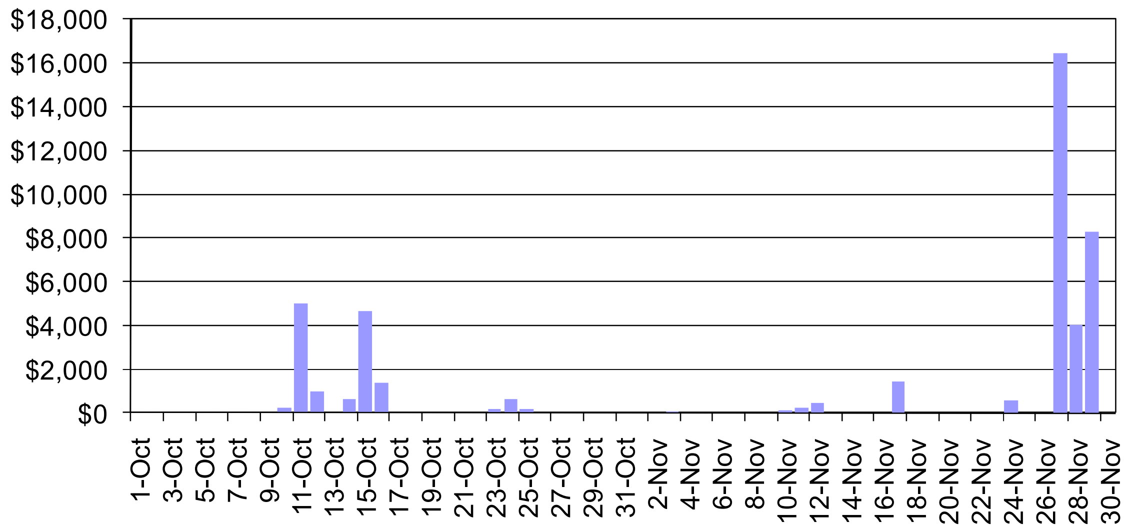
Figure 14: RA/RMR RUC Capacity vs. RUC Award (All Hours)



Total RUC Cost

Figure 15 shows the daily cost of RUC procurement for each trading day in October and November 2009. The total RUC procurement cost for November was more than double of that for October, increasing to $31,590 from October's $13,893. This was because more RUC capacity was procured from non-RA or non-RMR units in November than in October, and it was procured at higher prices. Approximately 91 percent of RUC cost of the month occurred on three days, from November 27 to November 29, while G-217 was binding, elevating the LMPs in that area.

Figure 15: Total RUC Cost



Market Intervention

Exceptional Dispatch

For the months of October and November 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 real-time incremental exceptional dispatches accounted for approximately 55 percent of the total volume of all exceptional dispatches (in absolute value) in November. 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

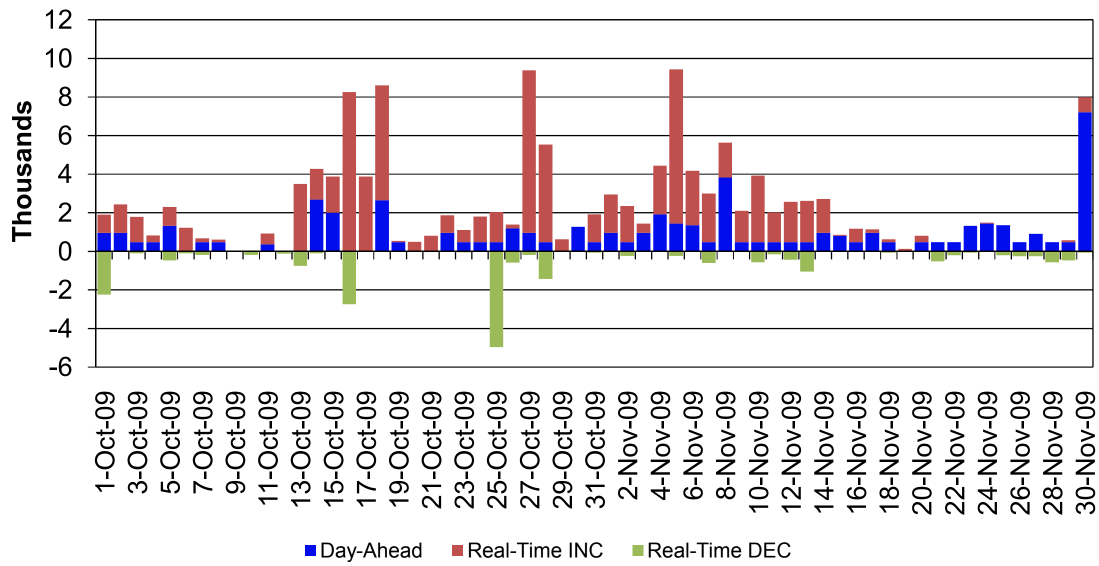
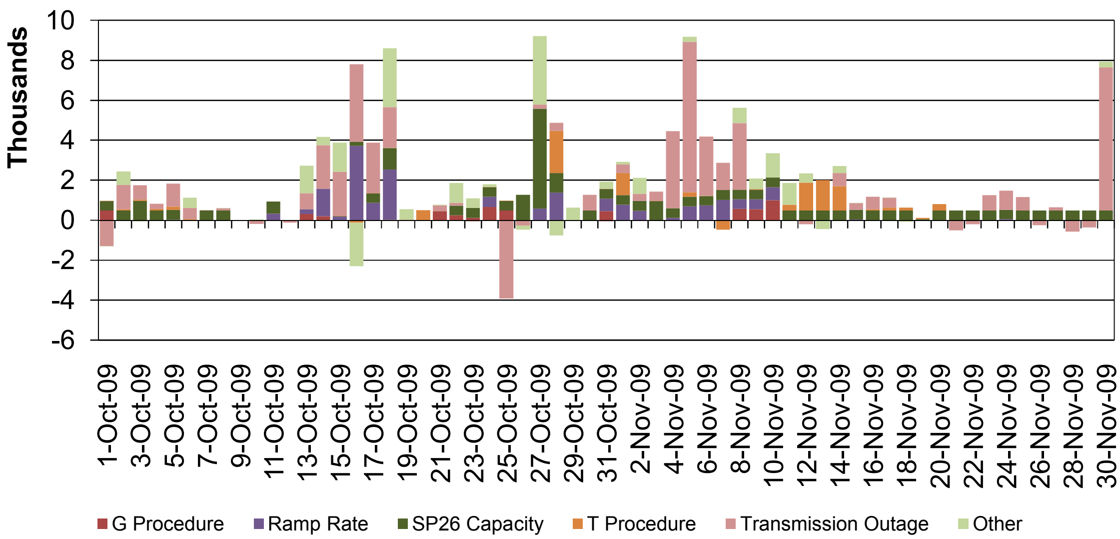


Figure 17 shows the volume of the exceptional dispatch broken out by reason.[4] The majority of the exceptional dispatch volume in November was driven by transmission outages (47 percent) and capacity requirements in the SP26 area (23 percent). On November 5, the exceptional dispatch volume had a jump, mainly due to the outage of the Eldorado-Mohave 500 kV line on that day. On November 30, the outage of Serrano-Valley 500 kV line resulted in a large volume of exceptional dispatches in SCE area, mostly in the day-ahead market.

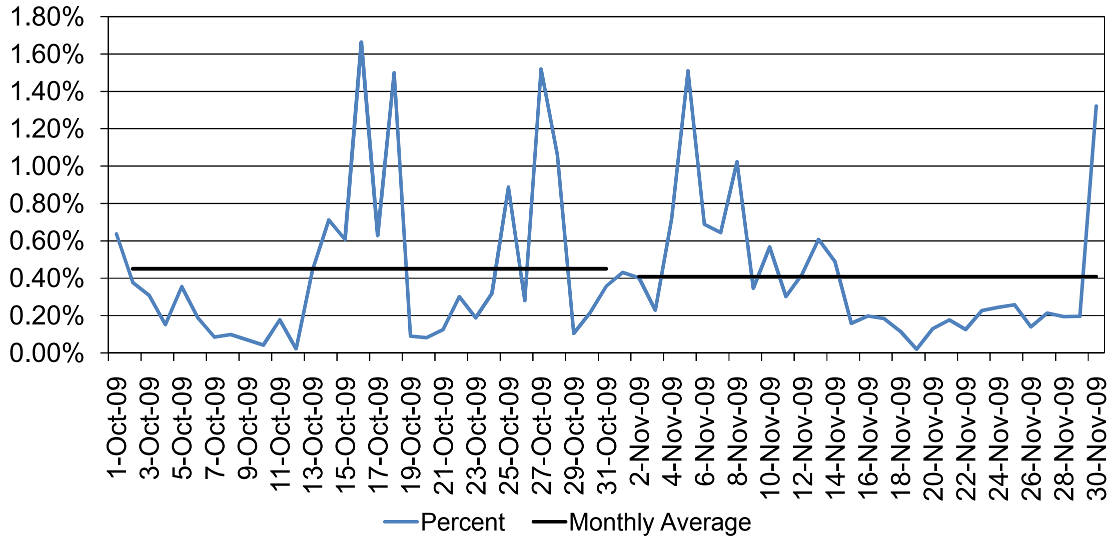
Figure 17: Total Exceptional Dispatch Volume (MWh) by Reason



4 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 and it also shows the average percentage for each month. In November the monthly average percentage dropped slightly from October.

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.[5] 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) during the time period covered by this report. Table 5 indicates that there were a total of 37 market disruptions in November, 2009. The RTPD failures (including HASP failures) accounted for approximately 81 percent of total market disruptions in this month.

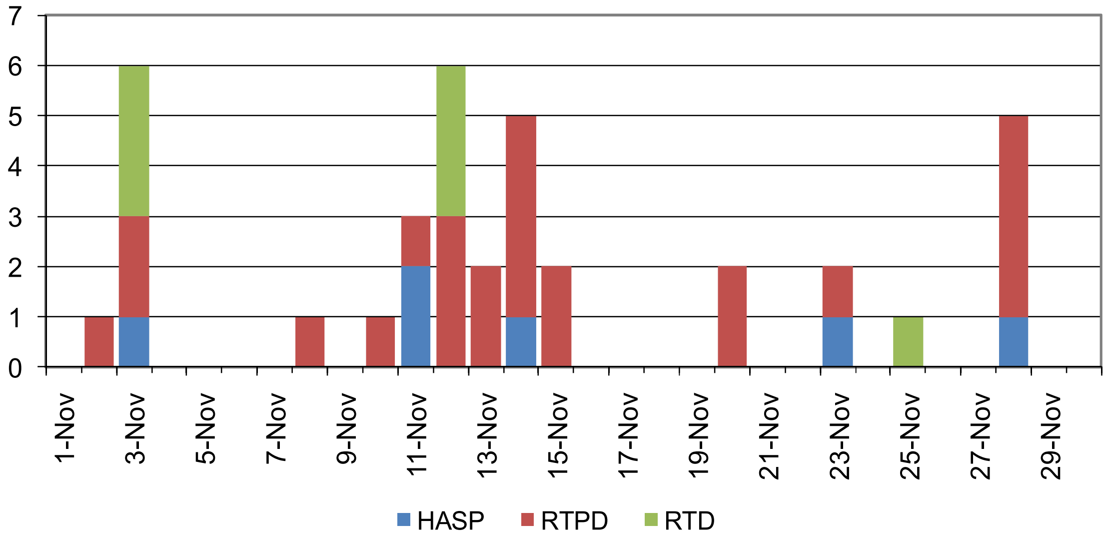
Figure 19 shows the frequency of HASP, RTPD, and RTD failures in November. On November 3, there were a total of 6 RTD and RTPD failures (including 1 HASP failure) in hour ending 1. This was caused by the deployment of the new database (DB 43) in real-time market. On November 12, a new intertie constraint was introduced into the market and this resulted in a total of 6 RTD and RTPD failures in hours ending 21 and 22 during the transition period. On November 28, three RTPD failures and one HASP failures were due to missing bids. One RTPD failure was due to missing broadcast.

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	1	0
Real-Time Pre-Dispatch Interval 2	6	0
Real-Time Pre-Dispatch Interval 3	21	0
Real-Time Pre-Dispatch Interval 4	2	0
Real-Time Dispatch	7	0

[5] 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



Intertie Blocking

Figure 20 and Figure 21 show the volume in MW of blocking imports and exports, respectively, on interties, while Table 6 lists the main statistics of intertie blocking on an hourly basis. For November, there were seven days in which blocking of interties was needed. The highest volume was observed on November 12 and 26.

Figure 20: Daily Volume of Blocking Imports on Interties

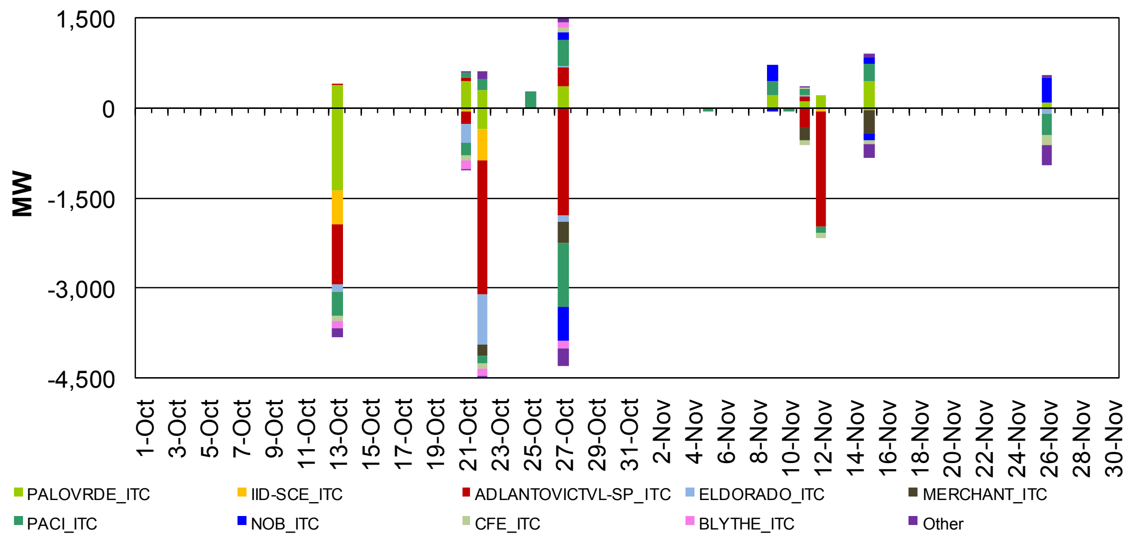
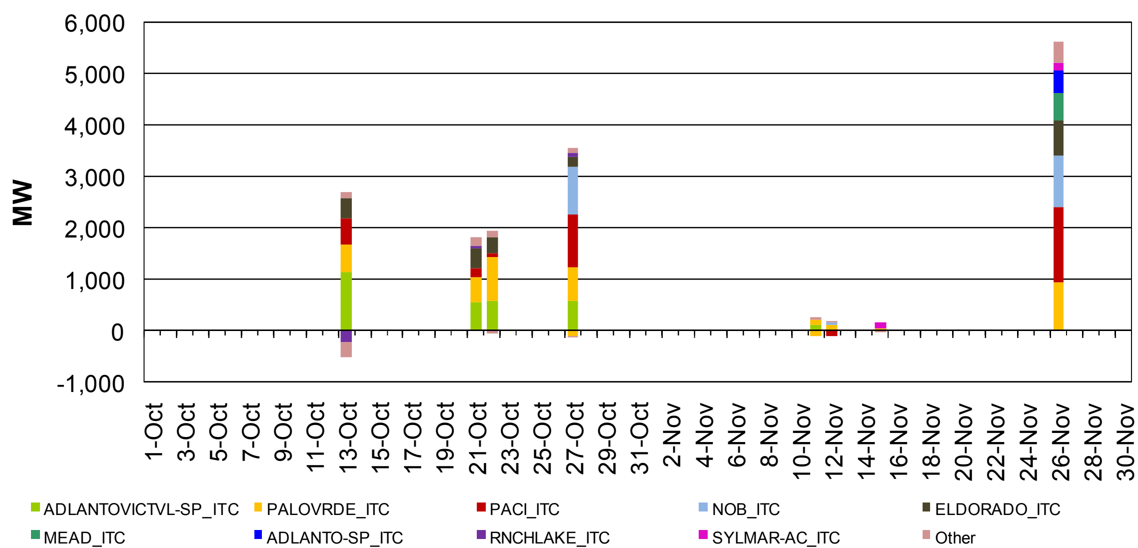


Figure 21: Daily Volume of Blocking Exports on Interties



On November 12, there was a need for blocking interties in HASP because of their excessive decremental schedules were leading to large swings that made difficult to manage both the area control error (ACE) and congestion in real time. Similarly, on November 26, all interties were fully blocked in HE 16 for reliability reasons as the market outcome required moving over 5,000 MW of interchanges. Market participants were required to revert to their DA schedules. This blocking was needed to have the system properly equipped to deal with the upcoming ramp-up for the evening peak.

Table 6: Statistics for Hourly Intertie Blocking

Trade Date	Trade Hour	Direction	No. Ties	No. Resources	Net Volume (MW)
10/13/2009	19	E	13	38	3225
10/13/2009	19	I	9	80	4230
10/21/2009	11	E	10	28	1814
10/21/2009	11	I	11	30	1648
10/22/2009	13	E	11	31	1999
10/22/2009	13	I	13	104	5087
10/25/2009	20	I	1	5	275
10/27/2009	8	E	10	49	3665
10/27/2009	1	I	2	3	649
10/27/2009	8	I	15	93	5145
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

November saw a total of 11 hours with intertie blocking, up from 6 hours observed during October. This is equivalent to a frequency of 1.52 percent of all HASP runs. However, the total blocked volume on interties during November declined by about 50 percent, from 27,737 MW in October to 13,896 MW in November. Similarly, the number of resources impacted by blocking interties declined to 231 in November from 461 in October. Blocking on interties can be either on a whole intertie, blocking by default all resources on the intertie, or partial, in which only specific schedules are blocked. It is worthwhile to mention that these statistics are based on all resources which are blocked and have a delta between DA awards and HASP schedules. In instances where the whole intertie was blocked, some resources may not have any delta between DA awards and HASP schedules and, therefore, the blocking has no impact on such resources.