California Independent
System Operator Corporation

Memorandum

To: ISO Board of Governors

From: Jim Detmers, Vice President of Operations

Date: September 2, 2009

Re: **Briefing on Exceptional Dispatch**

This memorandum does not require Board action.

EXECUTIVE SUMMARY

The California Independent System Operator Corporation (ISO) has committed to reducing the volume of exceptional dispatches that occur outside of market mechanisms. In keeping with that commitment, Management formed an exceptional dispatch strike team to focus on:

1. Reviewing and improving the existing processes;
2. Analyzing data on frequency, magnitude, and root causes of exceptional dispatches;
3. Identifying immediate improvement opportunities; and
4. Determining potential long-term solutions, which may include software, tariff or market rule changes.

The team focused on potential improvements to reduce day-ahead exceptional dispatches with particular emphasis on reducing exceptional dispatches issued prior to the day-ahead market. In this regard, we identified reliability constraints that could be incorporated into the market process. This not only reduced day-ahead exceptional dispatches but also increased automation of the process, and enhanced reliance on market mechanisms.

The team also identified, and is reviewing, other opportunities for further reductions. Some of these involve potential software enhancements and, while feasible, may not be realized in the immediate future. While it is clear that exceptional dispatches will be significantly reduced, it is also clear that not all exceptional dispatches can be eliminated.

DISCUSSION AND ANALYSIS

Seasonal differences and improvement in software-related causes

The team reviewed data to identify recurring causes for exceptional dispatches. We quickly identified seasonal differences in data. For example, we noted that the percentage of transmission outage-related exceptional dispatches was high in May and June, but not in the summer months, when the number of outages are reduced. In contrast, exceptional dispatches increased to meet reliability criteria associated with ISO operating procedures in July. While we found some underlying causes were present in varying measures year-round, others were more seasonal. Some measures will work to reduce exceptional dispatches consistently throughout the year. But as operating conditions change, additional issues may surface and need to be resolved. Exceptional dispatches related to seasonal operating differences may mean we need more analysis as operating environments change.

The team also noted a significant reduction in exceptional dispatches particularly in real-time due to software limitations as variances have been corrected. The following Table represents the percentage of occurrence for exceptional dispatch causes, both in real-time and in the day-ahead for two time periods, May-June and July.

Table 1 - Exceptional Dispatch by Cause [1]

RT	Generation Procedure	Market Disruption	Other	Ramp Rate	Software Limitation	System	Trans Outage	Trans Procedure	Total
May - June	4	186	57	55	149	109	51	164	775
Percent	0.52%	24.00%	7.35%	7.10%	19.23%	14.06%	6.58%	21.16%	100.00%
July	8	21	29	26	39	20	24	294	461
Percent	1.74%	4.56%	6.29%	5.64%	8.46%	4.34%	5.21%	63.77%	100.00%

DAM	Generation Procedure	Market Disruption	Other	Ramp Rate	Software Limitation	System	Trans Outage	Trans Procedure	Total
May - June	140	0	57	1	25	63	211	16	513
Percent	27.29%	0.00%	11.11%	0.19%	4.87%	12.28%	41.13%	3.12%	100.00%
July	241	0	21	1	20	45	15	16	359
Percent	67.13%	0.00%	5.85%	0.28%	5.57%	12.53%	4.18%	4.46%	100.00%

Process improvements

The team proposed potential process improvements relative to consistency and data quality. Where we expected a process change to be effective, we implemented and monitored that change. When possible, the team looked for solutions that were based in market mechanisms to decrease the chance for error and increase consistency. The team also sought to enhance the overall process by continuous improvement in logging with a separate focus in that area.

[1] All data contained in this report is preliminary and subject to change. While every attempt is made to ensure all tables and figures (charts) included in this report are complete and accurate, the data is not settlement quality.

Enforcing capacity requirements

In the July Market Surveillance Committee meeting, as well as the July ISO Board of Governors meeting, market participants expressed concern regarding exceptional dispatches that occurred prior to the day-ahead market. Many of these dispatches were related to generating capacity requirements associated with specific ISO operating procedures (i.e., for transmission and generation constraints). These operating procedures specify capacity requirements that must be met in certain areas due to outages or limitations. If the market mechanisms cannot be utilized, then operators must issue exceptional dispatches to ensure the capacity is available. Currently, the ISO does not have a means to enforce these capacity requirements in the integrated forward market, though the team continues to explore that option. The team was able to develop a means to enforce these nomograms in the residual unit commitment process (RUC), which is a capacity commitment mechanism.

To date, Operations has implemented nomograms in RUC for two such procedures (*G-217, South of Lugo Generation Requirements*, and *G-219 SCE Local Area Generation Requirement for Orange County*). These procedures correlate the magnitude of area load and the amount of generating capacity needed in the respective areas. Operations created a nomogram to maintain the appropriate relationship between available local generation and capacity requirements.

Implementing capacity requirement nomograms in RUC

A nomogram compares two or more values and determines limits, within established parameters. In the case of G-217 and G-219, the nomogram compares *area load* to the *generation capacity* needed to withstand the next contingency (i.e., loss of transmission capacity into the local area), as required by reliability criteria. This nomogram compared these variables within the South of Lugo and Orange County areas and is designed to secure enough generating capacity in the area to respond to contingencies.

Because the nomogram identifies a capacity requirement, the team selected RUC as a starting point to enforce the nomogram rather than the integrated forward market, which determines energy requirements. This approach has significant advantage in that RUC follows the integrated forward market and allows the normal running of the integrated forward market, thereby giving the market mechanisms the opportunity to commit resources that may also satisfy the nomogram requirements. RUC then commits any additional capacity requirements required to satisfy the reliability requirements.

On July 26, 2009, the ISO stopped issuing exceptional dispatch instruction to resources associated with the G-217 and G-219 operating procedure prior to the day-ahead market. As a result, the frequency of day-ahead exceptional dispatches has been significantly reduced without significantly increasing the amount of capacity committed in RUC. As noted above, the ISO is exploring how the capacity requirements can also be enforced in the integrated forward market, thereby eliminating the amount of additional commitment necessary in RUC to meet the reliability criteria.

Market participant comments

Many market participants expressed appreciation for reducing exceptional dispatches. Some market participants, including some of the same market participants expressing general support, noted concern about the dispatching generating units at minimum load to satisfy the nomogram requirements and are not being optimized in the integrated forward market. The amount of minimum load generated through this process has been relatively small, but could arguably be cause for concern if conditions change appreciably.

The team decided that the use of the G-217 and G-219 nomograms was successful and should be continued with possibly additional capacity based nomograms developed for enforcement in RUC. The next step is to continue stakeholder input through the business practice manual revision process so that the practice can be memorialized in the applicable ISO business practice manual and in any corresponding operating procedures. Once that process is complete, the ISO will proceed to enforce other nomograms in RUC.

Focus shifted to Real-Time and Software

After making progress in reducing the frequency of exceptional dispatch commitments in the day-ahead time frame, the team shifted its focus to addressing the causes for real-time exceptional dispatches. A large share of the real-time exceptional dispatches was due to software issues and market disruptions that occurred in hour-ahead scheduling process (HASP) and in the real-time market. As previously noted, these software variances have been identified and corrected and a number of market disruptions have decreased in frequency (refer to Table 1 above). One specific area of improvement is the reduction of the HASP failures and the direct correlation in the reduction of real-time exceptional dispatches on the interties.

The team identified other longer term improvements that will give positive results both in the day-ahead market and in real-time. These include a multi-day commitment, resolving the impact of differences between the five minute real-time dispatch and the hourly pre-dispatch, better ramping options, multi-stage generation modeling, the ability to model remedial action schemes, and pump modeling. The team also identified voltage related problems as a continuing cause of exceptional dispatches.

Additional findings and results

The following chart (*Figure 1*) shows the frequency of exceptional dispatches since May 1 and clearly indicates a sharp reduction in the pre-day-ahead market commitments after the late-July implementation of the G-217 and G-219 nomograms in RUC.

The team also observes that in many cases one or two resources were responsible for a large number of exceptional dispatches due to the need for operations to move the unit from interval to interval and involve for relatively small amounts of energy. This is especially true in real-time exceptional dispatches. Following are two charts (*Figures 2* and *3*), which show the number of exceptional dispatches as a percent of total system load, and the MW volumes of exceptional dispatch for total minimum load (day-ahead market and real-time market), plus real-time-incremental and decremental dispatches. These two charts confirm that the overall volume and magnitude of exceptional dispatch are decreasing, which may not be obvious by considering only the frequency of dispatches.

Figure 1 – Exceptional Dispatch Frequency[2]

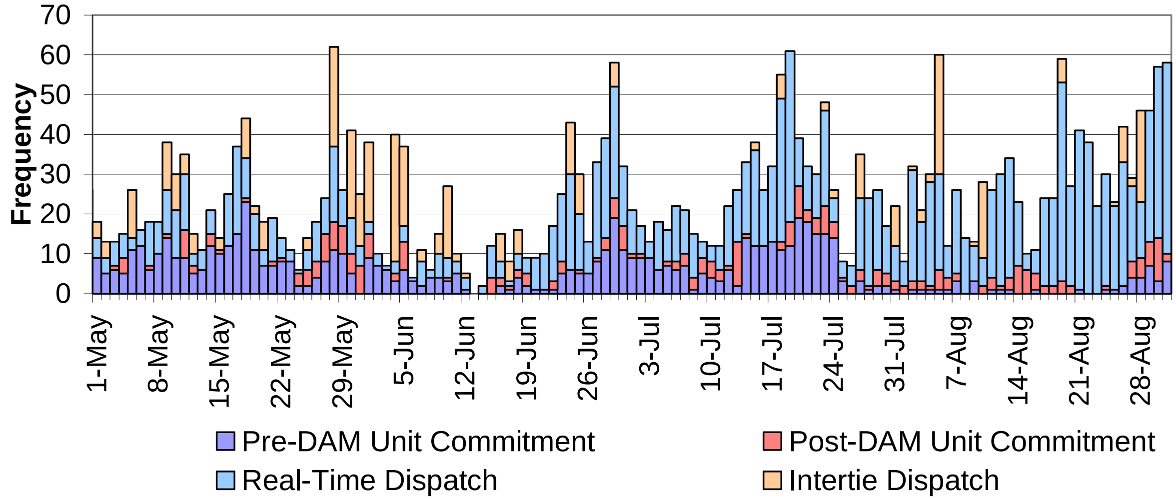


Figure 2 - Total Exceptional Dispatch as a Percent of Total Load

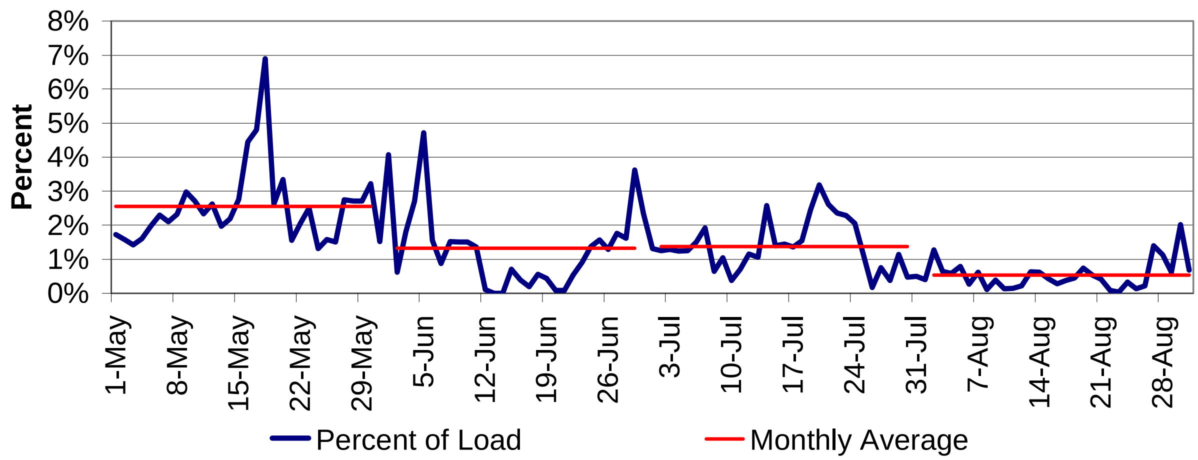
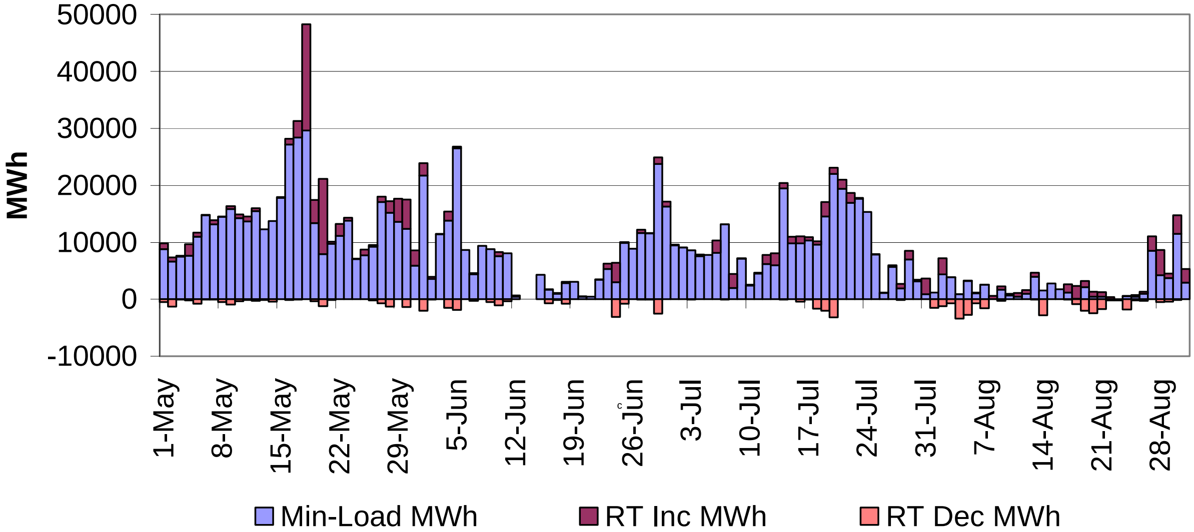


Figure 3 - MW volumes of Exceptional Dispatch for total minimum load (DAM and RT), Plus RT-Incremental and Decremental dispatches



CONCLUSION

The team has made substantial progress and is focused on additional improvements. Management will continue to emphasize market-based solutions for reducing exceptional dispatches. Management has scheduled an exceptional dispatch workshop on September 29 to present its current findings, discuss the efforts taken to date to decrease exceptional dispatches and discuss proposed enhancements.