Exceptional Dispatch Report

Table 2: September 2023

Market Analysis and Forecasting November 15, 2023

CAISO
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Introduction

This report is filed pursuant to FERC's September 2, 2009, and May 4, 2010, orders in ER08-1178. These orders require two monthly Exceptional Dispatch reports—one issued on the 15th of each month and one originally issued on the 30th of each month. Both Table 1 and Table 2 reports will be issued on the 15th of each month due to the availability of necessary data. This report provides data on the frequency, reasons and costs for Exceptional Dispatches issued in September 2023.

This report contains a price impact analysis as prescribed by FERC in its September 2 order. The price impact analysis for the month of December is presented in Appendix B. This report also includes mitigation analysis for September 2023 required by section 34.11.4 of the CAISO tariff. This analysis compares those Exceptional Dispatches subject to bid mitigation (i.e. Exceptional Dispatches to address noncompetitive constraints and Delta Dispatch), and determines the cost difference between the Exceptional Dispatch bid mitigation settlement rules and what the settlement amount would have been had the Exceptional Dispatches not been subject to bid mitigation. The Exceptional Dispatch bid mitigation analysis for September is presented in Appendix C.

The Nature of Exceptional Dispatch

The CAISO can issue exceptional dispatch instructions for a resource as a pre-day-ahead unit commitment, a post day-ahead unit commitment or a real-time exceptional dispatch. A pre-day-ahead unit commitment is an exceptional dispatch instruction committing a resource at or above its physical minimum (Pmin) operating level in the day-ahead market. A post-day-ahead unit commitment is an exceptional dispatch instruction committing a resource at or above its (Pmin) operating level in the real-time market. A real-time exceptional dispatch instructs a resource to operate at or above its physical minimum operating point. A real-time exceptional dispatch above the resource's day-ahead award is an incremental exceptional dispatch instruction and a real-time exceptional dispatch below the day-ahead award is considered a decremental dispatch instruction. The CAISO issues exceptional dispatch instructions to maintain the reliability of the grid when the market software cannot do so. Whenever the CAISO issues an exceptional dispatch instruction, the operator logs the dispatch and the associated reason. Reliability requirements are calculated for both local area and the system wide needs, and are classified into various requirements including local generation, transmission management, non-modeled transmission outages, ramping and intertie emergency assistance. Whenever the CAISO issues an exceptional dispatch instruction, the operators log these instructions and the associated reason for each instruction.

Most of the generation procedures are internal to the CAISO and not available publically on the CAISO website; however, all of the transmission procedures are available on the CAISO website.[1]

Additional reasons for exceptional dispatch instructions in 2023 include Software Limitation. Software Limitation is used when an exceptional dispatch instruction was issued to bridge schedules across days for resources with a minimum down time of 24 hours, as the CAISO software does not handle multi-day commitment. For instance, a resource has a day-ahead schedule from 0600 till 2300, and then is shut down in 2400. If this resource had a minimum down time of 24 hours and it is required the following day, then the CAISO issues an exceptional dispatch to commit this resource in 2400 so it can be dispatched economically in the following day. Software Limitation was also used for exceptional dispatches to manually issue shut down instructions to a resource because of a temporary Automatic Dispatch System ("ADS") failure, or similar issues. Interconnection Reliability Operating Limits (IROL) are system operating limits that are established to prevent instability, uncontrolled separation or cascading as described in operating procedure 3100. System Operating Limit (SOL) are the facility ratings, system voltage limits, transient stability limits, and voltage stability limits that are used in the operating horizon – any of which can be the most restrictive limit at any point in time, pre – or post – contingency. Control Point (CP) are imposed to protect the area transmission network against N – 1 contingencies. There were a few other reasons used to explain exceptional dispatch instructions in September, which are self-explanatory.

The data in Table 1 is based on a template specified in the September 2009 order.[2] This table contains all the information published in Table 1 of the first report for September 2023. In addition, it contains volume (MWh) and cost information. Each entry in Table 1 is a summary of exceptional dispatches classified by (1) the reason for the exceptional dispatch; (2) the location of the resource by Participating Transmission Owner (PTO) service area; (3) the Local Reliability Area (LRA) where applicable; (4) the market in which the exceptional dispatch occurred (day-ahead vs. real-time); and (5) the date of the exceptional dispatch. For each classification the following information is provided: (1) Megawatts (MW); (2) Commitment; (3) Inc or Dec; (4) Hours; (5) Begin Time; (6) End Time; (7) Total Volume (MWh); (8) Min Load Cost; (9) Start Up Cost; (10) CC6470; (11) ED Volume (MWh INC/DEC); (12) CC6470 INC; (13) CC6470 DEC; (14) CC6482; (15) CC6488; and (16) CC6620. Each column is defined:

[1] A list of all of the CAISO's Operating Procedures and all the publicly available Operating Procedures are available at the following link: http://www.caiso.com/thegrid/operations/opsdoc/index.html

[2] The data in Table 1 is principally SLIC information supplemented with data from the Market Quality System (MQS) and Settlements database. The volume and cost information is based on t+51B Recalculation Statements.

- The MW column shows the range of exceptional dispatch instruction in MW for the classification.
- The Commitment column specifies if there was a unit commitment for the classification.
- The INC/DEC/NA column specifies if there was an incremental dispatch (INC), a decremental dispatch (DEC), or only a unit commitment (NA). The Begin Time and End Time columns show the start and end time of exceptional dispatch for the classification respectively.
- The Hours column is the time difference between begin time and end time rounded up to the next hour.
- The total volume column shows the total MWh dispatch quantity dispatched for that classification. This quantity includes the minimum load quantity, the imbalance energy quantity, and the exceptional dispatch quantity.
- The Min-Load Cost column shows eligible minimum load cost for the classification.
- The Start-Up Cost column shows the eligible start up cost for the classification. The CAISO does not explicitly pay resources for its start up and minimum load costs; however, it ensures that resources are compensated adequately through its bid cost recovery.[3]
- The CC6470 column shows the total imbalance energy costs for the classification. This cost contains the portion of exceptional dispatch instruction settled as optimal energy due to its bid price being less than the LMP in the relevant settlement interval.
- The ED Volume MWh (MWh INC/DEC) column shows the incremental or the decremental portion of the real-time exceptional dispatch MWh for the classification. The CC6470-INC shows that portion of incremental exceptional dispatch instruction settled at the resource LMP.
- The CC6470-DEC column shows that portion of decremental exceptional dispatch instruction settled at the resource specific LMP. Both these charge codes are portions of the real-time instructed imbalance energy charge code (6470). [4]
- The CC6482 column shows the real-time excess cost for the classification.[5]
- The CC6488 column shows the real-time exceptional dispatch uplift settlement for the classification.[6] The CC6620 shows the bid cost recovery payment for the classification. This cost is shown for all pre-day-ahead unit commitments only.

[3] For further details regarding the Bid Cost Recovery process please refer to section 11.8 of the CAISO tariff.

[4] For further details please refer to the BPM configuration Guide: Real-Time Instructed Imbalance Energy Settlement published on the CAISO's website.

[5] For further details please refer to the BPM configuration Guide: Real Time Excess Cost for Instructed Energy Settlement published on the CAISO's website.

[6] For further details please refer to the BPM configuration Guide: Real Time Exceptional Dispatch Uplift Settlement published on the CAISO's website.

Charge codes 6470, 6470 INC, 6470 DEC, 6482 and 6488 are shown in Table 1 because all these charge codes pertain to real-time exceptional dispatch MWH quantities. The classification of data is further explained for example in Attachment A.

Exceptional dispatches with the reason “Reliability Assessment” were due to Real Time Contingency Analysis, Voltage Stability Analysis, and operating procedure number 7110. Reliability Assessment is the reason as explained in the operator procedure 2330C that encompasses Control Point (CP), Interconnection Reliability Operating Limit (IROL), System Operating Limit (SOL) and congestion related EDs. This reason is used to mitigate reliability issues identified through the real – time assessment tools such as Real Time Contingency Analysis (RTCA), Voltage Stability Analysis (VSA), Dynamic Stability Analysis (DSA) and/or Operating Procedure (OP) or offline study.

There was 1 instance of exceptional dispatches issued as a pre-day-ahead commitment. This pre-day-ahead commitment was also issued as a real-time exceptional dispatch.

Table 1: Exceptional Dispatches in September 2023

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Chart 2: Table of Exceptional Dispatches for Period 01/September/2023 – 30/September/2023

Number	Market Type	Reason	Location	Local Reliability Area	Trade Date	MW	Commitment	INC_DEC	Hours	Begin Time	End Time	Total MWH	Min Load Cost	Start Up Cost	CC6470	ED MWH (INC/DEC)	CC6470 INC	CC6470 DEC	CC6482	CC6488	CC6620
1	RT	Conditions beyond the control of the CAISO	PGAE	Fresno	9/3/2023	83	No	DEC	1	19:15	19:45	8.99	0.00	0.00	-85.23	0.00	0.00	0.00	0.00	0.00	0.00
2	RT	Conditions beyond the control of the CAISO	PGAE	Fresno	9/3/2023	83 - 300	No	INC	2	18:25	19:45	29.06	9005.79	0.00	-1946.93	15.21	-402.32	0.00	-65.17	0.00	0.00
3	RT	Conditions beyond the control of the CAISO	SCE	LA Basin	9/3/2023	45.24 - 45.58	Yes	INC	1	18:30	19:30	60.63	20262.17	0.00	-2357.48	0.00	0.00	0.00	0.00	0.00	0.00
4	RT	Fast Start Unit Management	SCE	LA Basin	9/11/2023	0	No	INC	1	0:10	1:05	-11.70	660.91	0.00	0.00	-11.70	0.00	0.00	0.00	0.00	0.00
5	RT	Fast Start Unit Management	SCE	LA Basin	9/15/2023	0	No	INC	1	21:45	22:45	-15.04	905.73	66.08	0.00	-15.04	0.00	0.00	0.00	0.00	0.00
6	RT	Load Forecast Uncertainty	PGAE	Bay Area	9/3/2023	200	No	INC	2	17:50	19:30	268.52	0.00	0.00	-6642.80	246.00	-5722.09	0.00	-4701.65	0.00	0.00
7	RT	Load Forecast Uncertainty	PGAE	Bay Area	9/4/2023	133	No	INC	1	18:00	19:00	138.63	0.00	0.00	-6892.02	0.00	0.00	0.00	0.00	0.00	0.00
8	RT	Load Forecast Uncertainty	PGAE	Fresno	9/11/2023	83 - 407	No	INC	3	15:30	18:00	-50.83	19533.13	0.00	-148.88	42.99	-2401.31	0.00	-475.04	0.00	0.00
9	RT	Load Forecast Uncertainty	PGAE	Fresno	9/22/2023	83	No	INC	2	12:50	14:00	25.20	5565.22	0.00	-397.44	0.00	0.00	0.00	0.00	0.00	0.00
10	RT	Load Forecast Uncertainty	SCE	Big Creek-Ventura	9/3/2023	74	No	INC	2	17:45	19:30	48.53	18010.43	2871.40	-2102.63	3.25	-138.56	0.00	-136.03	0.00	0.00
11	RT	Load Forecast Uncertainty	SCE	NA	9/3/2023	205 - 230	No	INC	2	17:50	19:30	455.59	0.00	0.00	-18040.03	318.80	-12394.47	0.00	-1173.93	0.00	0.00
12	RT	Load Forecast Uncertainty	SCE	NA	9/4/2023	125	No	INC	1	18:00	19:00	124.66	0.00	0.00	-6515.11	0.00	0.00	0.00	0.00	0.00	0.00
13	RT	Load Forecast Uncertainty	SDGE	San Diego-IV	9/3/2023	100	No	INC	2	17:40	19:30	34.09	19711.71	0.00	-1550.43	46.61	-1939.95	0.00	-2163.17	0.00	0.00
14	RT	Load Forecast Uncertainty	SDGE	San Diego-IV	9/11/2023	21 - 400	No	INC	3	16:20	19:00	7.48	9771.20	0.00	-668.58	7.31	-496.38	0.00	0.00	0.00	0.00
15	RT	Market Disruption	PGAE	Fresno	9/3/2023	83 - 300	No	DEC	2	18:00	19:15	-50.79	0.00	0.00	1604.98	-45.00	0.00	976.47	0.00	0.00	0.00
16	RT	Market Disruption	PGAE	Fresno	9/3/2023	49 - 300	No	INC	2	17:45	19:45	87.63	21125.33	747.50	-4761.09	67.38	-2239.56	0.00	-4962.08	0.00	0.00

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Number	Market Type	Reason	Location	Local Reliability Area	Trade Date	MW	Commitment	INC_DEC	Hours	Begin Time	End Time	Total MWH	Min Load Cost	Start Up Cost	CC6470	ED MWH (INC/DEC)	CC6470 INC	CC6470 DEC	CC6482	CC6488	CC6620
17	RT	Market Disruption	PGAE	NA	9/3/2023	300	No	DEC	2	18:20	19:30	83.60	1233.05	0.00	-2336.58	77.54	-2225.94	0.00	-234.36	0.00	0.00
18	RT	Market Disruption	SCE	LA Basin	9/3/2023	48.46	No	DEC	1	19:00	19:15	-7.57	0.00	0.00	292.02	0.00	0.00	0.00	0.00	0.00	0.00
19	RT	Market Disruption	SCE	LA Basin	9/3/2023	47.8 - 194	No	INC	3	17:50	20:00	675.87	36623.54	19807.65	-26827.28	584.14	-22733.20	0.00	-34556.70	0.00	0.00
20	RT	Market Disruption	SCE	NA	9/3/2023	100	No	DEC	2	18:00	19:30	148.49	0.00	0.00	-5738.55	123.35	-4622.10	0.00	-385.89	0.00	0.00
21	RT	Market Disruption	SCE	NA	9/3/2023	100 - 450	No	INC	4	17:50	21:05	404.65	7079.30	0.00	-14880.39	351.04	-12726.31	0.00	-427.83	0.00	0.00
22	RT	Market Disruption	SDGE	San Diego-IV	9/3/2023	50 - 400	No	INC	3	17:35	19:45	371.31	17756.37	0.00	-14794.39	356.40	-13928.47	0.00	-7709.46	0.00	0.00
23	RT	Other Reliability Requirement	PGAE	Fresno	9/24/2023	-315	No	DEC	1	16:00	16:30	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	RT	Other Reliability Requirement	SCE	LA Basin	9/1/2023	0	No	INC	1	5:45	6:45	-10.02	372.76	0.00	0.00	-10.02	0.00	0.00	0.00	0.00	0.00
25	RT	Planned Transmission Outage	PGAE	Bay Area	9/1/2023	54	No	INC	14	7:00	21:00	-38.80	65048.43	9382.76	1952.27	0.00	0.00	0.00	0.00	0.00	0.00
26	RT	Planned Transmission Outage	PGAE	Bay Area	9/15/2023	300 - 400	No	DEC	5	12:55	17:00	-53.49	-8837.17	0.00	-12355.72	-194.48	0.00	26606.08	0.00	-29257.37	0.00
27	RT	Planned Transmission Outage	PGAE	Bay Area	9/18/2023	22	No	INC	6	13:45	19:00	241.33	0.00	0.00	-25749.62	0.00	0.00	0.00	0.00	0.00	0.00
28	RT	Planned Transmission Outage	PGAE	Bay Area	9/21/2023	22	No	INC	3	14:40	17:00	15.59	0.00	0.00	-1784.73	0.00	0.00	0.00	0.00	0.00	0.00
29	RT	Planned Transmission Outage	PGAE	Bay Area	9/25/2023	495 - 530	No	DEC	18	6:00	0:00	-62.17	0.00	0.00	1886.30	-6.87	0.00	305.42	0.00	-7488.22	0.00
30	RT	Planned Transmission Outage	PGAE	Bay Area	9/25/2023	495 - 530	No	INC	11	5:45	16:00	171.16	0.00	0.00	-7680.13	0.00	0.00	0.00	0.00	0.00	0.00
31	RT	Planned Transmission Outage	PGAE	Bay Area	9/26/2023	495	No	DEC	24	0:00	0:00	-225.69	0.00	0.00	6934.99	0.00	0.00	0.00	0.00	-5370.86	0.00
32	RT	Planned Transmission Outage	PGAE	Bay Area	9/26/2023	495	No	INC	3	12:00	15:00	-11.55	0.00	0.00	291.47	0.00	0.00	0.00	0.00	0.00	0.00
33	RT	Planned Transmission Outage	PGAE	Humboldt	9/1/2023	15	No	DEC	1	21:45	22:00	-3.05	191.86	0.00	120.98	-0.29	0.00	11.63	0.00	-7.52	0.00

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34	RT	Planned Transmission Outage	PGAE	Humboldt	9/1/2023	15 - 30	No	INC	24	0:00	0:00	15.88	57749.86	0.00	-603.18	-0.65	0.00	23.04	0.00	-6.12	0.00
35	RT	Planned Transmission Outage	PGAE	Humboldt	9/2/2023	15	No	DEC	4	17:00	20:30	0.80	0.00	0.00	-27.52	0.00	0.00	0.00	0.00	-120.92	0.00
36	RT	Planned Transmission Outage	PGAE	Humboldt	9/2/2023	15 - 30	No	INC	21	0:00	20:45	1.06	40530.54	0.00	-38.06	0.00	0.00	0.00	0.00	0.00	0.00
37	RT	Planned Transmission Outage	PGAE	Humboldt	9/5/2023	15	No	DEC	4	18:00	22:00	9.69	7302.80	0.00	-487.97	0.00	0.00	0.00	0.00	0.00	0.00
38	RT	Planned Transmission Outage	PGAE	Humboldt	9/5/2023	15 - 30	No	INC	17	7:20	0:00	19.83	30124.05	1869.61	-2910.97	0.00	0.00	0.00	0.00	0.00	0.00
39	RT	Planned Transmission Outage	PGAE	Humboldt	9/6/2023	15 - 30	No	INC	12	0:00	11:30	7.70	27618.51	0.00	-248.17	0.00	0.00	0.00	0.00	0.00	0.00
40	RT	Planned Transmission Outage	PGAE	Humboldt	9/7/2023	15 - 45	No	INC	17	7:20	0:00	17.02	45916.06	0.00	-1293.96	-3.64	0.00	140.80	0.00	-50.80	0.00
41	RT	Planned Transmission Outage	PGAE	Humboldt	9/8/2023	30	No	DEC	12	11:00	23:00	-1.28	-29104.70	0.00	188.58	0.00	0.00	0.00	0.00	-911.84	0.00
42	RT	Planned Transmission Outage	PGAE	Humboldt	9/8/2023	15 - 30	No	INC	24	0:00	0:00	3.79	28941.64	0.00	-196.41	-0.64	0.00	26.95	0.00	-5.22	0.00
43	RT	Planned Transmission Outage	PGAE	Humboldt	9/9/2023	30	No	DEC	10	12:00	22:00	-1.07	-14900.28	0.00	85.35	0.00	0.00	0.00	0.00	-333.19	0.00
44	RT	Planned Transmission Outage	PGAE	Humboldt	9/9/2023	30	No	INC	24	0:00	0:00	0.78	51141.63	0.00	-112.79	0.00	0.00	0.00	0.00	0.00	0.00
45	RT	Planned Transmission Outage	PGAE	Humboldt	9/10/2023	30	No	DEC	9	14:00	23:00	3.04	-4351.29	0.00	-231.59	0.00	0.00	0.00	0.00	0.00	0.00
46	RT	Planned Transmission Outage	PGAE	Humboldt	9/10/2023	30	No	INC	24	0:00	0:00	2.03	29799.06	0.00	-79.25	0.00	0.00	0.00	0.00	0.00	0.00
47	RT	Planned Transmission Outage	PGAE	Humboldt	9/11/2023	15 - 45	No	DEC	13	7:00	20:00	-2.75	201.35	0.00	186.66	0.00	0.00	0.00	0.00	0.00	0.00
48	RT	Planned Transmission Outage	PGAE	Humboldt	9/11/2023	15 - 45	No	INC	15	0:00	15:00	19.12	24362.75	0.00	-617.66	-0.61	0.00	37.35	0.00	0.00	0.00
49	RT	Planned Transmission Outage	PGAE	Humboldt	9/13/2023	15	No	DEC	5	17:00	21:45	0.00	-4122.10	0.00	0.00	0.00	0.00	0.00	0.00	-417.75	0.00
50	RT	Planned Transmission Outage	PGAE	Humboldt	9/13/2023	15 - 30	No	INC	8	16:10	0:00	0.00	-216.95	0.00	0.00	0.00	0.00	0.00	0.00	-6.50	0.00
51	RT	Planned Transmission Outage	PGAE	Humboldt	9/14/2023	30	No	INC	24	0:00	0:00	-12.54	9154.80	1879.60	809.82	0.00	0.00	0.00	0.00	0.00	0.00

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52	RT	Planned Transmission Outage	PGAE	Humboldt	9/15/2023	30	No	DEC	10	13:00	23:00	-8.01	-31404.74	1878.76	513.04	0.00	0.00	0.00	0.00	-9318.97	0.00
53	RT	Planned Transmission Outage	PGAE	Humboldt	9/15/2023	30	No	INC	24	0:00	0:00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
54	RT	Planned Transmission Outage	PGAE	Humboldt	9/16/2023	30	No	INC	6	0:00	5:30	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
55	RT	Planned Transmission Outage	PGAE	Humboldt	9/25/2023	30	No	DEC	6	17:00	23:00	0.90	-4025.10	0.00	-19.12	0.00	0.00	0.00	0.00	0.00	0.00
56	RT	Planned Transmission Outage	PGAE	Humboldt	9/25/2023	30	No	INC	17	7:05	0:00	21.42	15023.51	0.00	-1048.46	0.00	0.00	0.00	0.00	0.00	0.00
57	RT	Planned Transmission Outage	PGAE	Humboldt	9/26/2023	30	No	INC	24	0:00	0:00	-1.27	36382.80	0.00	12.82	0.00	0.00	0.00	0.00	-2.11	0.00
58	RT	Planned Transmission Outage	PGAE	Humboldt	9/27/2023	30	No	INC	24	0:00	0:00	0.64	35122.56	0.00	-10.99	0.00	0.00	0.00	0.00	-0.11	0.00
59	RT	Planned Transmission Outage	PGAE	Humboldt	9/28/2023	30	No	INC	22	0:00	22:00	0.00	31658.22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
60	RT	Planned Transmission Outage	PGAE	Sierra	9/12/2023	20	Yes	INC	8	8:00	15:30	0.86	19238.55	610.76	-37.16	0.00	0.00	0.00	0.00	0.00	0.00
61	RT	Planned Transmission Outage	PGAE	Sierra	9/13/2023	100	No	DEC	1	13:00	14:00	0.03	0.00	0.00	-1.92	0.00	0.00	0.00	0.00	0.00	0.00
62	RT	Planned Transmission Outage	PGAE	Sierra	9/13/2023	20	No	INC	4	20:45	0:00	5.09	16124.65	0.00	-441.67	0.00	0.00	0.00	0.00	0.00	0.00
63	RT	Planned Transmission Outage	PGAE	Sierra	9/14/2023	20	Yes	INC	4	0:00	3:45	6.51	0.00	0.00	-523.99	0.00	0.00	0.00	0.00	0.00	0.00
64	RT	Planned Transmission Outage	PGAE	Sierra	9/28/2023	20	No	INC	10	7:15	17:00	12.40	9457.40	0.00	-670.62	0.00	0.00	0.00	0.00	0.00	0.00
65	RT	Planned Transmission Outage	PGAE	Stockton	9/18/2023	88.8	No	DEC	3	6:00	9:00	8.44	0.00	0.00	-247.78	0.00	0.00	0.00	0.00	0.00	0.00
66	RT	Planned Transmission Outage	PGAE	Stockton	9/18/2023	88.8	No	INC	5	9:00	14:00	1.71	14510.32	0.00	-37.65	0.00	0.00	0.00	0.00	0.00	0.00
67	RT	Planned Transmission Outage	PGAE	Stockton	9/19/2023	35 - 45	No	INC	11	8:30	19:30	-54.25	0.00	0.00	1183.00	-5.29	0.00	163.04	0.00	-41.41	0.00
68	RT	Planned Transmission Outage	PGAE	Stockton	9/26/2023	89	No	INC	18	5:30	22:45	-46.34	107749.41	22754.56	2177.69	0.00	0.00	0.00	0.00	-47.09	0.00
69	RT	Planned Transmission Outage	PGAE	NA	9/13/2023	-110	No	DEC	2	5:00	7:00	4.35	0.00	0.00	-158.24	0.00	0.00	0.00	0.00	0.00	0.00

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Chart 2: Table of Exceptional Dispatches for Period 01/September/2023 – 30/September/2023

Number	Market Type	Reason	Location	Local Reliability Area	Trade Date	MW	Commitment	INC_DEC	Hours	Begin Time	End Time	Total MWH	Min Load Cost	Start Up Cost	CC6470	ED MWH (INC/DEC)	CC6470 INC	CC6470 DEC	CC6482	CC6488	CC6620
70	RT	Planned Transmission Outage	PGAE	NA	9/13/2023	-110	No	INC	4	1:25	5:00	0.53	0.00	0.00	-22.61	1.83	-79.92	0.00	0.00	0.00	0.00
71	RT	Planned Transmission Outage	SCE	Big Creek-Ventura	9/28/2023	420	No	INC	8	7:45	15:30	-160.26	0.00	0.00	2820.15	0.00	0.00	0.00	0.00	0.00	0.00
72	RT	Planned Transmission Outage	SDGE	San Diego-IV	9/15/2023	30	No	DEC	1	14:00	15:00	-0.66	0.00	0.00	8.07	0.00	0.00	0.00	0.00	0.00	0.00
73	RT	Planned Transmission Outage	SDGE	San Diego-IV	9/15/2023	30	No	INC	7	9:40	16:00	22.72	4525.62	0.00	-6326.54	0.00	0.00	0.00	0.00	0.00	0.00
74	RT	Ramping Capacity	PGAE	Fresno	9/8/2023	84	No	DEC	2	18:55	20:00	-167.69	0.00	0.00	8316.46	-169.25	0.00	8400.22	0.00	0.00	0.00
75	RT	Ramping Capacity	PGAE	Fresno	9/27/2023	83 - 400	No	INC	2	15:10	17:00	-90.31	7552.80	0.00	794.69	0.00	0.00	0.00	0.00	0.00	0.00
76	RT	Ramping Capacity	SCE	LA Basin	9/1/2023	190 - 194	No	INC	5	16:30	21:30	3.80	0.00	0.00	-239.15	3.96	-246.73	0.00	0.00	0.00	0.00
77	RT	Ramping Capacity	SCE	LA Basin	9/8/2023	46	No	DEC	1	19:00	19:30	-88.68	0.00	0.00	5023.46	-88.70	0.00	5025.34	0.00	0.00	0.00
78	RT	Ramping Capacity	SCE	LA Basin	9/11/2023	190 - 194	No	INC	5	17:00	22:00	-24.98	0.00	0.00	1826.50	10.16	-767.18	0.00	0.00	0.00	0.00
79	RT	Ramping Capacity	SCE	LA Basin	9/12/2023	190 - 194	No	INC	5	17:00	22:00	9.92	0.00	0.00	-921.63	12.55	-1052.03	0.00	0.00	0.00	0.00
80	RT	Reliability Assessment	PGAE	Humboldt	9/6/2023	30	No	INC	13	11:05	0:00	0.65	17253.91	0.00	-32.10	0.00	0.00	0.00	0.00	0.00	0.00
81	RT	Reliability Assessment	PGAE	Humboldt	9/7/2023	30	No	INC	2	0:00	2:00	-0.40	3126.20	0.00	14.09	0.00	0.00	0.00	0.00	0.00	0.00
82	RT	Reliability Assessment	PGAE	Humboldt	9/11/2023	30	No	DEC	1	20:00	21:00	1.03	-226.51	0.00	-42.25	0.00	0.00	0.00	0.00	0.00	0.00
83	RT	Reliability Assessment	PGAE	Humboldt	9/11/2023	30	No	INC	3	21:00	0:00	0.00	1610.76	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
84	RT	Reliability Assessment	PGAE	Humboldt	9/12/2023	30	No	DEC	5	17:00	22:00	2.71	0.00	0.00	-102.89	0.00	0.00	0.00	0.00	0.00	0.00
85	RT	Reliability Assessment	PGAE	Humboldt	9/12/2023	30	No	INC	24	0:00	0:00	0.00	32058.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
86	RT	Reliability Assessment	PGAE	Humboldt	9/13/2023	30	No	INC	24	0:00	0:00	28.18	48380.17	0.00	-1659.12	0.00	0.00	0.00	0.00	0.00	0.00
87	RT	Reliability Assessment	PGAE	Humboldt	9/14/2023	30	No	DEC	5	17:00	22:00	-0.94	7629.04	0.00	71.86	0.00	0.00	0.00	0.00	0.00	0.00

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Chart 2: Table of Exceptional Dispatches for Period 01/September/2023 – 30/September/2023

Number	Market Type	Reason	Location	Local Reliability Area	Trade Date	MW	Commitment	INC_DEC	Hours	Begin Time	End Time	Total MWH	Min Load Cost	Start Up Cost	CC6470	ED MWH (INC/DEC)	CC6470 INC	CC6470 DEC	CC6482	CC6488	CC6620
88	RT	Reliability Assessment	PGAE	Humboldt	9/14/2023	30	No	INC	24	0:00	0:00	36.11	38798.92	0.00	-2624.15	0.00	0.00	0.00	0.00	0.00	0.00
89	RT	Reliability Assessment	PGAE	Humboldt	9/15/2023	30 - 60	No	INC	24	0:00	0:00	-0.15	46278.54	0.00	91.40	0.00	0.00	0.00	0.00	0.00	0.00
90	RT	Reliability Assessment	PGAE	Humboldt	9/16/2023	30 - 60	No	INC	24	0:00	0:00	-8.52	62560.46	0.00	389.81	0.00	0.00	0.00	0.00	0.00	0.00
91	RT	Reliability Assessment	PGAE	Humboldt	9/17/2023	30	No	INC	24	0:00	0:00	5.80	37865.59	0.00	-91.72	0.00	0.00	0.00	0.00	0.00	0.00
92	RT	Reliability Assessment	PGAE	Humboldt	9/18/2023	30	No	INC	24	0:00	0:00	1.36	36219.28	0.00	-44.27	0.00	0.00	0.00	0.00	0.00	0.00
93	RT	Reliability Assessment	PGAE	Humboldt	9/19/2023	30	No	INC	10	0:00	10:00	-0.40	16530.60	0.00	16.81	0.00	0.00	0.00	0.00	0.00	0.00
94	RT	Reliability Assessment	PGAE	Humboldt	9/28/2023	15 - 30	No	INC	2	22:00	0:00	-4.13	2158.51	0.00	124.47	0.00	0.00	0.00	0.00	0.00	0.00
95	RT	Reliability Assessment	PGAE	Humboldt	9/29/2023	15 - 30	No	INC	24	0:00	0:00	8.04	27294.87	0.00	-285.85	0.00	0.00	0.00	0.00	0.00	0.00
96	RT	Reliability Assessment	PGAE	Humboldt	9/30/2023	30	No	INC	24	0:00	0:00	0.00	34477.68	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
97	RT	Reliability Assessment	PGAE	NCNB	9/5/2023	60 - 70	No	DEC	5	18:40	23:00	-12.15	0.00	0.00	-1125.67	-13.18	0.00	-856.51	0.00	0.00	0.00
98	RT	Reliability Assessment	PGAE	NCNB	9/5/2023	70	No	INC	1	18:50	19:00	-0.93	0.00	0.00	-45.33	-0.93	0.00	-45.33	0.00	0.00	0.00
99	RT	Reliability Assessment	PGAE	Sierra	9/12/2023	20	No	INC	2	20:30	22:00	-22.18	3825.51	166.41	1288.46	0.00	0.00	0.00	0.00	0.00	0.00
100	RT	Reliability Assessment	PGAE	Sierra	9/14/2023	20	No	DEC	3	18:30	21:00	0.98	0.00	269.57	-167.55	0.00	0.00	0.00	0.00	0.00	0.00
101	RT	Reliability Assessment	PGAE	Sierra	9/14/2023	20	No	INC	3	21:00	23:30	1.94	7223.70	269.57	-316.05	0.00	0.00	0.00	0.00	0.00	0.00
102	RT	Reliability Assessment	PGAE	Sierra	9/15/2023	0 - 20	No	DEC	1	20:05	21:00	-24.05	-1907.53	0.00	995.24	-12.25	0.00	162.54	0.00	0.00	0.00
103	RT	Reliability Assessment	PGAE	Sierra	9/15/2023	20	No	INC	1	21:00	22:00	-10.98	0.00	0.00	753.92	0.00	0.00	0.00	0.00	0.00	0.00
104	RT	Reliability Assessment	PGAE	NA	9/7/2023	20	No	DEC	1	10:50	11:45	-4.27	0.00	0.00	-121.23	-4.23	0.00	-120.27	0.00	0.00	0.00
105	RT	Reliability Assessment	PGAE	NA	9/11/2023	-120	No	DEC	1	11:00	12:00	26.11	0.00	0.00	-1041.14	0.00	0.00	0.00	0.00	0.00	0.00

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Chart 2: Table of Exceptional Dispatches for Period 01/September/2023 – 30/September/2023

Number	Market Type	Reason	Location	Local Reliability Area	Trade Date	MW	Commitment	INC_DEC	Hours	Begin Time	End Time	Total MWH	Min Load Cost	Start Up Cost	CC6470	ED MWH (INC/DEC)	CC6470 INC	CC6470 DEC	CC6482	CC6488	CC6620
106	RT	Reliability Assessment	PGAE	NA	9/11/2023	-120	No	INC	2	9:55	11:00	19.69	0.00	0.00	-852.37	0.75	-33.48	0.00	0.00	0.00	0.00
107	RT	Reliability Assessment	PGAE	NA	9/13/2023	-110	No	INC	1	1:00	1:45	7.67	0.00	0.00	-336.65	11.00	-480.98	0.00	0.00	0.00	0.00
108	RT	Reliability Assessment	SCE	NA	9/1/2023	300	No	INC	6	16:40	22:00	-7.85	0.00	0.00	227.32	-2.00	0.00	72.10	0.00	0.00	0.00
109	RT	Reliability Assessment	SCE	NA	9/12/2023	46	No	DEC	1	23:55	0:00	-0.16	0.00	0.00	0.73	-0.15	0.00	0.24	0.00	0.00	0.00
110	RT	Reliability Assessment	SCE	NA	9/13/2023	46	No	DEC	8	0:00	8:00	-5.34	0.00	0.00	-32.41	-6.67	0.00	11.01	0.00	0.00	0.00
111	RT	Reliability Assessment	SCE	NA	9/13/2023	46	No	INC	1	5:00	6:00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
112	RT	Reliability Assessment	SCE	NA	9/14/2023	37	No	DEC	5	19:30	0:00	-12.96	0.00	0.00	21.95	-12.94	0.00	21.36	0.00	0.00	0.00
113	RT	Reliability Assessment	SCE	NA	9/15/2023	37	No	DEC	6	0:00	5:45	8.08	0.00	0.00	-361.90	0.00	0.00	0.00	0.00	0.00	0.00
114	RT	Reliability Assessment	SCE	NA	9/19/2023	0	No	DEC	3	7:20	10:00	-48.53	0.00	0.00	1554.79	0.00	0.00	0.00	0.00	0.00	0.00
115	RT	Reliability Assessment	SCE	NA	9/20/2023	45	No	DEC	3	21:00	0:00	-11.96	0.00	0.00	-255.95	-6.00	0.00	-112.88	0.00	0.00	0.00
116	RT	Reliability Assessment	SCE	NA	9/21/2023	4 - 45	No	DEC	24	0:00	0:00	-22.27	0.00	0.00	-1420.55	-22.54	0.00	-1430.47	0.00	0.00	0.00
117	RT	Reliability Assessment	SCE	NA	9/22/2023	4 - 6	No	DEC	8	0:00	8:00	0.10	0.00	0.00	-1.91	0.00	0.00	0.00	0.00	0.00	0.00
118	RT	Reliability Assessment	SCE	NA	9/29/2023	25 - 51	No	DEC	7	17:50	0:00	-30.61	0.00	0.00	25.60	-31.71	0.00	52.33	0.00	0.00	0.00
119	RT	Reliability Assessment	SCE	NA	9/30/2023	30 - 51	No	DEC	8	0:00	8:00	-28.39	0.00	0.00	-40.41	-32.00	0.00	52.80	0.00	0.00	0.00
120	RT	Reliability Assessment	SDGE	San Diego-IV	9/11/2023	36.88 - 38.38	No	DEC	3	18:00	21:00	2.20	0.00	0.00	-111.74	0.00	0.00	0.00	0.00	0.00	0.00
121	RT	Reliability Assessment	SDGE	San Diego-IV	9/11/2023	36.88 - 38.38	No	INC	7	15:50	22:00	45.49	0.00	0.00	-3579.92	0.00	0.00	0.00	0.00	0.00	0.00
122	RT	Software Limitation	PGAE	Sierra	9/14/2023	40	No	DEC	2	20:05	22:00	29.08	0.00	0.00	-2664.38	0.00	0.00	0.00	0.00	0.00	0.00
123	RT	Software Limitation	PGAE	Stockton	9/12/2023	238	No	INC	5	19:30	0:00	-39.50	0.00	0.00	1718.90	0.00	0.00	0.00	0.00	0.00	0.00

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Chart 2: Table of Exceptional Dispatches for Period 01/September/2023 – 30/September/2023

Number	Market Type	Reason	Location	Local Reliability Area	Trade Date	MW	Commitment	INC_DEC	Hours	Begin Time	End Time	Total MWH	Min Load Cost	Start Up Cost	CC6470	ED MWH (INC/DEC)	CC6470 INC	CC6470 DEC	CC6482	CC6488	CC6620
124	RT	Software Limitation	PGAE	Stockton	9/13/2023	238	No	INC	24	0:00	0:00	-101.44	2115.43	0.00	4811.69	-37.00	0.00	1951.75	0.00	0.00	0.00
125	RT	Software Limitation	PGAE	Stockton	9/14/2023	238	No	INC	6	0:00	6:00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
126	RT	Software Limitation	SCE	LA Basin	9/4/2023	0	No	INC	1	20:05	21:05	-16.70	873.62	91.37	154.15	-13.37	0.00	0.00	0.00	0.00	0.00
127	RT	Software Limitation	SCE	LA Basin	9/7/2023	0	No	INC	1	0:35	1:35	-13.37	604.55	0.00	0.00	-13.37	0.00	0.00	0.00	0.00	0.00
128	RT	Software Limitation	SCE	LA Basin	9/8/2023	0	No	INC	1	1:20	2:20	-13.37	704.89	0.00	0.00	-13.37	0.00	0.00	0.00	0.00	0.00
129	RT	Software Limitation	SCE	LA Basin	9/9/2023	0	No	INC	1	23:10	0:00	-11.70	579.30	0.00	0.00	-11.70	0.00	0.00	0.00	0.00	0.00
130	RT	Software Limitation	SCE	LA Basin	9/10/2023	0	No	INC	1	0:00	0:10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
131	RT	Software Limitation	SCE	LA Basin	9/14/2023	0	No	INC	1	22:45	23:45	-15.04	899.70	49.11	0.00	-15.04	0.00	0.00	0.00	0.00	0.00
132	RT	Unit Testing	PGAE	NA	9/26/2023	-126	No	DEC	1	14:10	14:55	-7.56	0.00	0.00	191.69	1.50	-43.03	0.00	0.00	0.00	0.00
133	RT	Unit Testing	SCE	LA Basin	9/4/2023	0.1	No	INC	1	8:55	9:10	0.02	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00
134	RT	Unit Testing	SCE	LA Basin	9/15/2023	74.94	No	INC	1	12:40	13:20	45.29	0.00	0.00	-1251.52	44.87	-1240.37	0.00	0.00	0.00	0.00
135	RT	Unit Testing	SCE	NA	9/15/2023	1.67	No	DEC	1	9:35	10:00	-1.76	0.00	0.00	46.02	0.00	0.00	0.00	0.00	0.00	0.00
136	RT	Unit Testing	SCE	NA	9/15/2023	160.09	No	INC	1	13:55	14:35	92.69	0.00	0.00	-20.02	91.72	-33.94	0.00	0.00	0.00	0.00
137	RT	Voltage Support	PGAE	Fresno	9/18/2023	-315	No	DEC	3	3:15	6:00	-152.69	0.00	0.00	5161.24	0.00	0.00	0.00	0.00	0.00	0.00
138	RT	Voltage Support	PGAE	Fresno	9/22/2023	-315	No	DEC	4	2:35	6:00	-201.84	0.00	0.00	7225.10	0.00	0.00	0.00	0.00	0.00	0.00
139	RT	Voltage Support	PGAE	Fresno	9/24/2023	-315	No	DEC	16	0:35	16:00	-509.39	0.00	0.00	19569.78	0.00	0.00	0.00	0.00	0.00	0.00
140	RT	Voltage Support	PGAE	Fresno	9/24/2023	-315	No	INC	8	8:00	16:00	-52.50	0.00	0.00	971.44	0.00	0.00	0.00	0.00	0.00	0.00
141	RT	Voltage Support	PGAE	Fresno	9/25/2023	-315	No	DEC	4	2:15	5:30	-154.16	0.00	0.00	6329.85	0.00	0.00	0.00	0.00	0.00	0.00

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Chart 2: Table of Exceptional Dispatches for Period 01/September/2023 – 30/September/2023

Number	Market Type	Reason	Location	Local Reliability Area	Trade Date	MW	Commitment	INC_DEC	Hours	Begin Time	End Time	Total MWH	Min Load Cost	Start Up Cost	CC6470	ED MWH (INC/DEC)	CC6470 INC	CC6470 DEC	CC6482	CC6488	CC6620
142	RT	Voltage Support	PGAE	Fresno	9/30/2023	-315	No	DEC	2	22:10	0:00	9.35	0.00	0.00	-418.18	0.00	0.00	0.00	0.00	0.00	0.00
143	RT	Voltage Support	PGAE	Humboldt	9/2/2023	15	No	DEC	2	20:30	22:00	1.31	0.00	0.00	-48.23	0.00	0.00	0.00	0.00	0.00	0.00
144	RT	Voltage Support	PGAE	Humboldt	9/2/2023	15 - 30	No	INC	3	20:45	23:30	0.19	3651.40	0.00	-3.12	0.00	0.00	0.00	0.00	0.00	0.00
145	RT	Voltage Support	PGAE	Humboldt	9/3/2023	15	No	INC	18	6:30	0:00	4.05	9128.50	667.72	-171.98	0.00	0.00	0.00	0.00	-0.23	0.00
146	RT	Voltage Support	PGAE	Humboldt	9/4/2023	15	No	INC	24	0:00	0:00	-3.28	13875.32	0.00	37.33	0.00	0.00	0.00	0.00	-1.80	0.00
147	RT	Voltage Support	PGAE	Humboldt	9/5/2023	15	No	INC	10	0:00	10:00	7.43	8398.22	0.00	-503.66	0.00	0.00	0.00	0.00	0.00	0.00
148	RT	Voltage Support	PGAE	Humboldt	9/19/2023	15	No	INC	6	18:00	0:00	0.00	4959.18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
149	RT	Voltage Support	PGAE	Humboldt	9/20/2023	15 - 30	No	INC	24	0:00	0:00	5.33	31863.54	0.00	-273.31	0.00	0.00	0.00	0.00	0.00	0.00
150	RT	Voltage Support	PGAE	Humboldt	9/21/2023	15 - 30	No	INC	24	0:00	0:00	-0.07	34730.20	0.00	3.01	0.00	0.00	0.00	0.00	0.00	0.00
151	RT	Voltage Support	PGAE	Humboldt	9/22/2023	15	No	DEC	6	17:00	23:00	1.36	0.00	0.00	-70.74	0.00	0.00	0.00	0.00	0.00	0.00
152	RT	Voltage Support	PGAE	Humboldt	9/22/2023	15	No	INC	24	0:00	0:00	0.00	15577.18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
153	RT	Voltage Support	PGAE	Humboldt	9/23/2023	15	No	INC	22	0:00	22:00	-5.70	31477.60	0.00	21.08	0.00	0.00	0.00	0.00	-9.34	0.00
154	RT	Voltage Support	PGAE	Sierra	9/22/2023	20	No	INC	4	2:40	6:00	11.68	7496.94	520.87	-403.63	0.00	0.00	0.00	0.00	0.00	0.00
155	RT	Voltage Support	PGAE	Sierra	9/24/2023	20	No	INC	14	2:40	16:00	7.53	13071.03	0.00	-254.45	0.00	0.00	0.00	0.00	0.00	0.00
156	RT	Voltage Support	PGAE	NA	9/26/2023	20	No	INC	7	16:15	23:00	-0.67	8734.86	477.06	404.21	0.00	0.00	0.00	0.00	0.00	0.00

Appendix A: Explanation by Example

All examples listed below are based on fictitious data. Many simplified assumptions are made to explain settlement charge codes, and not all assumptions are explicitly stated in these examples. For instance, settlement charge codes are calculated based on metered quantities, whereas in these examples, the dispatch quantities are assumed to be equal to metered quantities. These assumptions have been made to simplify the understanding of settlements calculations.

Example 1: Exceptional Dispatch Instructions Prior to DAM

In this fictitious example, the CAISO issued an exceptional dispatch instruction for resource A to be committed at its Pmin of 50 MW from hours ending 5 through 10 for a generation procedure 7630. Similarly, the CAISO issued additional instructions to resources B and C for the same reason in Table 2. Exceptional dispatches prior to the day-ahead market are commitments to minimum load. Here the dispatch levels are all at minimum load. Table 2 below also shows the commitment costs and the total volume (MWh) of exceptional dispatch instruction for each resource. The minimum load costs and start up costs, shown in Table 2 are the eligible minimum load and start up costs different from the bid-in minimum load and start up costs[7]. Only those quantities which relate to pre-day-ahead unit commitments are shown in this table.

Table 2: Instructions Prior to Day-Ahead Market

Date	Market	Resource	Location	Local Reliability Area (LRA)	Begin Time	End Time	Dispatch level (MW)	Reason	Total Volume (MWh)	Min-Load Cost	Start- Up Cost	CC6620 (BCR)
01-Jul-09	DA	A	SCE	LA BASIN	05:00	10:00	50	7630	300	$5000	$0	0
01-Jul-09	DA	B	SCE	LA BASIN	08:00	20:00	30	7630	390	$6000	$500	$4000
01-Jul-09	DA	C	SCE	LA BASIN	09:00	23:00	20	7630	300	$400	$1000	$1000

This data is summarized as shown in Table 3, which is the prescribed format specified in the FERC order on September 02, 2009. This summary classifies the data by reason, resource location, local reliability area, and trade date. The MW column in Table 3 is the range of MW; in this case the minimum instruction MW is 20 MW for resource C which occurs from hours ending 21 through 23. The maximum instruction occurs in hour ending 10. In this hour resource A is committed at 50 MW, resource B is committed at 30 MW and resource C is committed at 20 MW. This adds up to 100 MW. The MW column shows the minimum and maximum of the overlaps of all the exceptional dispatch instructions. The Commitment column shows whether a resource was committed between the begin time and end time. Commitments are broken out separately from energy dispatches. In the day-ahead however, the exceptional dispatches are nearly always just commitments, as in this example. The Begin Time column shows hour ending 5 as this was the hour ending for first dispatch of the day, and the End Time column shows hour ending 23, as this was the hour with last dispatch. It is also possible there might be hours between the begin time and the end time where there might not be exceptional dispatch instructions for the reason, meaning that the range between the begin time and end time can include null hours with no dispatch. The total volume (MWh) is the MWh quantity for each resource, which adds up to 990 MWh. Similarly, all cost information is sum of individual resource costs. Some resources bid-in zero start-up cost; as seen in this example, resource A bid in zero for its start up cost. Since the CAISO does not explicitly pay a resource for bid-in minimum load costs and start-up costs; these costs are recovered through the charge code CC6620 (Bid Cost Recovery), this table shows the summary of CC6620 for the classification. Here, it is the CC6620 for all three resources which adds up to $5000. This column shows the impact of exceptional dispatch on bid cost recovery for all pre-day-ahead exceptional dispatch commitments.

Table 3: FERC Summary of Instructions Prior to DAM

Number	Market Type	Reason	Location	Local Reliability Area (LRA)	Trade Date	MW	Commitment	INC/DEC	Hour	Begin Time	End Time	Total Volume (MWh)	Min-Load Cost	Start-Up Cost	CC6620
1	DA	7630	SCE	LA Basin	1-Jul-09	20-100	Yes	N/A	19	05:00	23:00	990	$11,400	$1,500	$5000

Example 2: Incremental Exceptional Dispatch Instructions in RTM

In this fictitious example the CAISO issued an exceptional dispatch instruction to resource A to be committed at its Pmin of 30 MW from hours 6:00 through 11:00 after completion of the day-ahead market for the transmission procedure 7110. This resource had no day-ahead award in those hours. The CAISO issued another exceptional dispatch instruction to resource B, to be dispatched at 40 MW from hours 7:00

[7] Please refer to the BPM configuration Guide: Bid Cost Recovery Settlements published on the CAISO's website for details about eligible minimum load and start up costs.

through 9:00 in real-time for the transmission procedure 7110. This resource had a day-ahead schedule of 20 MW from the day-ahead market, which implies this exceptional dispatch instruction was an incremental instruction and the exceptional dispatch MW was 20 MW. Similarly, the details of exceptional dispatch (ED) instruction for resource C are shown in Table 4. This table also shows volume (MWh) and various real-time charge codes associated with the exceptional dispatch instructions. The total MWh column for each resource shows all types of imbalance energy quantities for this resource between the begin time and end time which includes both the exceptional dispatch energy quantities and optimal energy quantities.

Resource A was committed at its Pmin so its total volume (MWh) is equal to its Pmin times the number of hours, which is calculated as 30 MW times 6 hours and is equal to 180 MWh. The resource Minimum load costs and the start up costs are its eligible commitment costs for that period. LMP at this resource is $10/MWh, so the charge code CC6470 is calculated at (180 MWh *$10/MWh) and is equal to $1,800. Since this resource is not dispatched above its Pmin, it has a zero volume (MWh) of exceptional dispatch. All charge codes associated with the exceptional dispatch increment or decrement quantities are zero.

Resource B is dispatched 20 MW above its day-ahead schedule, so its total volume (MWH) is calculated as 20 MW times 3 hours which is equal to 60 MWh. Since the resource was committed in the Day-Ahead Market there are no minimum load quantity and start up costs associated with this resource. The resource had a bid price of $100/MWh and the LMP at that resource was $10/MWh. All of 60 MWh is considered as exceptional dispatch incremental quantity shown in ED Volume (MWH INC/DEC) column. The charge code CC6470 INC is calculated as 60 MWh * resource LMP ($10/MWh) which is equal to $600. Since the only imbalance energy in this timeframe was the exceptional dispatch volume, the charge code CC6470 is equal to CC6470 INC. The charge code CC6488 is calculated as MWH quantity *(bid price – LMP), which is equal to $5400 (60 MWh *($10/MWh-$100/MWh)). Similarly, volumes and real-time charge codes are calculated for resource C.

Table 4: Incremental Exceptional Dispatch Instructions in RTM

Date	Market	Resource	Location	Local Reliability Area (LRA)	Begin Time	End Time	Dispatch level (MW)	Day-Ahead Award (MW)	Commitment	INC/DEC	ED (MW)	Reason	Total MWH	Min Load Cost	Start Up Cost	CC6470	ED MWH (INC/DEC)	CC6470 INC	CC6470 DEC	CC6482	CC6488
1-Jul-09	RT	A	PG&E	Humboldt	6:00	11:00	30	0	Yes	INC	30	7110	180	1000	50	1800	0	0	0	0	0
1-Jul-09	RT	B	PG&E	Humboldt	7:00	9:00	40	20	No	INC	20	7110	60	0	0	600	60	600	0	0	5400
1-Jul-09	RT	C	PG&E	Humboldt	12:00	15:00	50	50	No	INC	0	7110	0	0	0	0	0	0	0	0	0
1-Jul-09	RT	C	PG&E	Humboldt	16:00	20:00	50	40	No	INC	10	7110	50	0	0	300	20	300	0	0	200

This data is summarized as shown in Table 5 and is classified by reason, resource location, local reliability area, and trade date. The MW column in Table 5 is the range of MW; in this case the minimum instruction MW is 0 MW for resource C which occurs from hours ending 13 through 15. The maximum instruction occurs in hours ending 8 & 9, as during these two hours both resources A and B have an ED MW of 30MW and 20MW, respectively. This adds up to 50 MW. The MW column shows the minimum and maximum of the overlaps of all the exceptional dispatch instructions. The Commitment column shows whether a resource was committed between the begin time and end time. This column shows a commitment if there was a single commitment in the entire interval of exceptional dispatch. The Begin Time column shows the time of the first dispatch of the day. This is a time not a range. Similarly, the End Time column shows a time and not a range. Exceptional dispatches occurred between these two times. Since there was a commitment between the begin time and end time, the Commitment column displays yes for the summary. Similarly, the INC/DEC column shows an INC, as there was an incremental dispatch between the begin time and end time. As mentioned in the previous example, it is possible there might be hours between the begin time and end time where there were no exceptional dispatch instructions for the reason. Both volume and cost information columns are the summation for all the respective columns for resources A, B and C. For instance, the Total volume (MWh) column is calculated as summation of 180,60,0 and 50, which are the individual volumes (MWh) for resources A, B and C for time periods shown in Table 4.

Table 5: FERC Summary of ED Instructions in RTM

Number	Market Type	Reason	Location	Local Reliability Area (LRA)	Trade Date	MW	Commitment	INC/DEC	Hour	Begin Time	End Time	Total MWH	Min Load Cost	Start Up Cost	CC6470	ED MWH (INC/DEC)	CC6470 INC	CC6470 DEC	CC6482	CC6488
1	RT	7110	PG&E	Humboldt	1-Jul-09	0-50	Yes	INC	15	6:00	20:00	290	1000	50	1700	140	1500	0	0	11000

It is possible that the CAISO would dispatch a particular resource, for instance at 10 MW from hours ending 1 through 4, and all or part of its energy might settle as optimal energy. This situation occurs when the LMP at the resource pricing node is above the resource bid price. This cost will only be captured in charge code 6470. It is also possible that CAISO issues an exceptional dispatch for the resource to operate at a minimum of 10 MW which is its Pmin; however the market application might dispatch this resource above Pmin because the resource is economical. When this occurs, the charge code CC6470 and the total MWh quantity might overstate the actual exceptional dispatch MWh quantities. So, to best estimate the cost and volume (MWH) of exceptional dispatch, it is appropriate to consider only the following columns: ED MWh (INC/DEC), CC6470 INC, CC6470 DEC, CC6482, CC6488.

Example 3: Decremental Exceptional Dispatch Instructions in RTM

This example highlights decremental exceptional dispatch instructions in the real-time market. In this fictitious example, the CAISO issued an exceptional dispatch instruction to resource A to be committed at its Pmin of 20 MW from hours ending 15 through 20 after completion of the day-ahead market for the transmission procedure 7430. The CAISO issued additional exceptional dispatch instructions for resources B and C; details of those instructions are shown in Table 6. This table also includes volume (MWh) and cost information.

Resource A is committed in real-time at its Pmin, its total volume (MWh) is 20MW *6 hours which is equal to 120 MWh. This resource has a zero MW of incremental dispatch in all hours, so all other relevant cost and volume columns result in zeros. Resource B has a decremental MW of 20 MW in 3 hours, which results in 60 MWh of decremental volume. Since this resource is not committed in real-time, both the minimum load cost and start up costs are zero. This resource had a bid price of $50/MWh and LMP at the resource pricing node is $10/ MWh. Based on this information CC6470-Dec is calculated as 60 MWh *$10/MWh which is equal to $600. Since this resource has its ED volume (MWh) equal to its Total volume, CC6470 is equal to CC6470- DEC. The CC6488 is calculated as (60 MWh * ($50/MWh - $10/MWh)), which is equal to $2400. Resource C had a bid price of $10/MWh and the LMP at its pricing node is $50/MWh. Based on this information, volume and cost information is calculated for resource C.

Table 6: Decremental Exceptional Dispatch Instructions in RTM

Date	Market Type	Resource	Location	Local Reliability Area (LRA)	Begin Time	End Time	Dispatch level (MW)	Day-Ahead Award (MW)	Commitment	INC/DEC	ED (MW)	Reason	Total MWH	Min Load Cost	Start Up Cost	CC6470	ED MWH (INC/DEC)	CC6470 INC	CC6470 DEC	CC6482	CC6488
1-Jul-09	RT	A	PG&E	Fresno	15:00	20:00	20	0	Yes	INC	20	7430	120	$ 120	$ 100	$ -	0	$ -	$ -	$ -	$ -
1-Jul-09	RT	B	PG&E	Fresno	7:00	9:00	40	60	No	DEC	20	7430	(60)	$ -	$ -	$ 600	-60	$ -	$ 600	$ -	$2,400
1-Jul-09	RT	C	PG&E	Fresno	10:00	14:00	40	50	No	DEC	10	7430	(50)	$ -	$ -	$ 500	-50	$ -	$ 500	$ -	$2,000

This data is summarized according to FERC convention in Table 7. This summary classifies the data by reason, resource location, local reliability area, and trade date. Incs and decs are broken out separately. The inc entry is self-explanatory and similar to the previous example. Regarding the dec entry the MW column is the range of MW; in this case the minimum dec instruction is 10 MW (actually -10MW as it is a dec) for resource C which occurs from hours ending 10 through 14. The maximum instruction occurs from hours ending 7 through 9, when resource B was issued a dec instruction of 20 MW. The MW column shows the minimum and maximum of the overlaps of all the exceptional dispatch instructions. The Commitment column shows whether a resource was committed between the begin time and end time. The volume and cost information are summarized by INC and DEC classification.

Table 7: FERC Summary of Decremental ED Instructions in RTM

Number	Market Type	Reason	Location	Local Reliability Area (LRA)	Trade Date	MW	Commitment	INC/DEC	Hour	Begin Time	End Time	Total MWH	Min Load Cost	Start Up Cost	CC6470	ED MWH (INC/DEC)	CC6470 INC	CC6470 DEC	CC6482	CC6488
1	RT	7430	PG&E	Fresno	1-Jul-09	20	Yes	INC	6	15:00	20:00	120	$ 120	$ 100	$ -	0	$ -	$ -	$ -	$ -
2	RT	7430	PG&E	Fresno	1-Jul-09	10-20	Yes	DEC	8	7:00	14:00	(110)	$ -	$ -	$ (1,100)	$ (110)	$ -	$ (1,100)	$ -	$ (4,400)

Appendix B: Price Impact Analysis

In the September 2 FERC order, FERC requested the CAISO to perform price impact analysis on two distinct pricing nodes for the entire reporting period. The order also mentioned that the CAISO must pick two pricing nodes for the entire reporting period that are most affected by the exceptional dispatch instructions, and the two pricing nodes must belong to two load aggregation points (LAPs).

Based on this requirement the CAISO implemented a methodology to perform price impact analysis. First, the CAISO identified a heavily affected pricing node from each of the Pacific Gas & Electric (PGAE) LAP and Southern California Edison (SCE) LAP. These two pricing nodes had the maximum amount of exceptional dispatch volume (MWh) in their respective LAP. Point A is in PGAE LAP and point B is in SCE LAP. Please note these two points correspond to an actual pricing node in the CAISO system. Only one resource was connected to each of these pricing nodes. For each resource the following input parameters were obtained to perform the analysis:

Exceptional dispatch information: constrained level, constraint type, start of exceptional dispatch instruction and end of exceptional dispatch instruction.
Real-Time LMPs for each of the five minute intervals for the month.
Real-Time hourly bid set for each trade hour.
Day-Ahead award for the resources.

The exceptional dispatch intervals have a begin time and an end time which can span as small as one minute to as large as 24 hours. Since the market application dispatches resources on five-minute basis, the exceptional dispatch instructions for each of these resources were broken down into five-minute intervals. If the begin time or end time for an instruction was in the middle of the five-minute interval, that instruction was rounded up to the next five-minute interval. These five-minute intervals were then coupled with resource five-minute LMPs calculated by the real-time market application. Also, the hourly bid information and the hourly day-ahead schedule were put together to create a dataset that had all the information to perform price impact analysis.

An exceptional dispatch instruction can be classified as a start up instruction, an instruction to be dispatched at or above the constrained level, an instruction to be dispatched at or below a constrained level, an instruction to be dispatched at a fixed constrained level, or a shut down instruction. The Locational Marginal Price (LMP) is set by a resource which can provide the next incremental MW of energy. Based on this definition of LMP and the classification of exceptional dispatches based on constraint type, a resource may set the LMP in only those intervals in which the resource is eligible to move either up or down from its constrained level. Hence, in those intervals in which the resource was constrained up at its Pmax or the resource was exceptionally dispatched to its Pmax and forced to generate at that level, the resource was ineligible to set the price as it had no room to move up. Similarly, if the resource was constrained down at its Pmin, then the resource was not eligible to set the price. All those intervals in which the resource was ineligible to set the price were dropped from the dataset under consideration. From this dataset of only eligible intervals, for both pricing nodes A and B, LMPs were calculated for all intervals based on the resource dispatch level and the its bid set. The calculated LMP is equal to that bid price corresponding to the constrained MW segment.

Table 8 shows the price impact analysis information for node A, which is in the PGAE area. This table shows all the five minute intervals in which the resource at PNode A was issued an exceptional dispatch instruction and was eligible to set the price. Out of the 8,640 five-minute intervals in September, this resource was issued exceptional dispatch instructions in 45 five-minute intervals. This resource was eligible to set the LMP in 45 intervals. Out of the 45 intervals, resource calculated LMP was larger than the market LMP in 0 intervals. Out of the 45 intervals, resource calculated LMP was less than the market LMP in 45 intervals. This implies that if the CAISO could model the constraint for this exceptional dispatch, then this resource and all other pricing nodes associated with that constraint would observe an average decrease of $86.92/MWh.

Table 9 shows the price impact analysis information for node B, which is in the SCE area. This table shows all the five minute intervals in which the resource at PNode B was issued an exceptional dispatch instruction and was eligible to set the price. Out of the 8,640 five-minute intervals in September, this resource was issued exceptional dispatch instructions in 8 five-minute intervals. This resource was eligible to set the LMP in 8 intervals. Out of the 8 intervals, resource calculated LMP was larger than the market LMP in 8 intervals. In the 8 intervals, the average increase in five minute LMP was $90.71/MWh. Out of the 8 intervals, resource calculated LMP was less than the market LMP in 0 intervals. In the 8 intervals, the average increase in five minute LMP was $90.71/MWh.

Table 8: Price Impact Analysis Information for Pricing Node A in PGAE LAP

Number	Trade Date	Trade Hour	Interval	Market LMP	Eligible Flag	Calculated LMP	Change in LMP
1	9/15/2023	13	12	102.77	Yes	37.98	-64.79
2	9/15/2023	14	2	79.61	Yes	37.98	-41.63
3	9/15/2023	14	3	157.27	Yes	37.98	-119.29
4	9/15/2023	14	4	44.04	Yes	37.98	-6.06
5	9/15/2023	14	5	45.45	Yes	37.98	-7.47
6	9/15/2023	14	6	45.47	Yes	37.98	-7.49
7	9/15/2023	14	7	45.60	Yes	37.98	-7.62
8	9/15/2023	14	8	50.37	Yes	37.98	-12.39
9	9/15/2023	14	9	54.51	Yes	37.98	-16.53
10	9/15/2023	14	10	53.22	Yes	37.98	-15.24
11	9/15/2023	14	11	54.77	Yes	37.98	-16.79
12	9/15/2023	14	12	54.61	Yes	37.98	-16.63
13	9/15/2023	15	1	45.39	Yes	36.09	-9.30
14	9/15/2023	15	2	45.39	Yes	36.09	-9.30
15	9/15/2023	15	3	46.32	Yes	36.09	-10.23
16	9/15/2023	15	4	46.77	Yes	36.09	-10.68
17	9/15/2023	15	5	46.82	Yes	36.09	-10.73
18	9/15/2023	15	6	47.86	Yes	36.09	-11.77
19	9/15/2023	15	7	97.48	Yes	36.09	-61.39
20	9/15/2023	15	8	97.80	Yes	36.09	-61.71
21	9/15/2023	15	9	97.45	Yes	36.09	-61.36
22	9/15/2023	15	10	57.33	Yes	36.09	-21.24
23	9/15/2023	15	11	90.60	Yes	36.09	-54.51
24	9/15/2023	15	12	57.21	Yes	36.09	-21.12
25	9/15/2023	16	1	85.30	Yes	36.09	-49.21
26	9/15/2023	16	2	90.28	Yes	36.09	-54.19
27	9/15/2023	16	3	88.06	Yes	36.09	-51.97
28	9/15/2023	16	4	85.93	Yes	36.09	-49.84
29	9/15/2023	16	5	191.19	Yes	36.09	-155.10
30	9/15/2023	16	6	193.75	Yes	36.09	-157.66
31	9/15/2023	16	7	309.25	Yes	36.09	-273.16
32	9/15/2023	16	8	301.86	Yes	36.09	-265.77
33	9/15/2023	16	9	533.90	Yes	36.09	-497.81
34	9/15/2023	16	10	308.78	Yes	36.09	-272.69

Number	Trade Date	Trade Hour	Interval	Market LMP	Eligible Flag	Calculated LMP	Change in LMP
35	9/15/2023	16	11	298.99	Yes	36.09	-262.90
36	9/15/2023	16	12	276.47	Yes	36.09	-240.38
37	9/15/2023	17	1	272.49	Yes	36.09	-236.40
38	9/15/2023	17	2	232.82	Yes	36.09	-196.73
39	9/15/2023	17	3	193.53	Yes	36.09	-157.44
40	9/15/2023	17	4	214.74	Yes	36.09	-178.65
41	9/15/2023	17	5	55.62	Yes	36.09	-19.53
42	9/15/2023	17	6	58.81	Yes	36.09	-22.72
43	9/15/2023	17	10	68.11	Yes	36.09	-32.02
44	9/15/2023	17	11	69.42	Yes	36.09	-33.33
45	9/15/2023	17	12	64.88	Yes	36.09	-28.79

Table 9: Price Impact Analysis Information for Pricing Node B in SCE LAP

Number	Trade Date	Trade Hour	Interval	Market LMP	Eligible Flag	Calculated LMP	Change in LMP
1	9/15/2023	14	12	-15.00	Yes	75.64	90.64
2	9/15/2023	15	1	-14.98	Yes	75.64	90.62
3	9/15/2023	15	2	-14.99	Yes	75.64	90.63
4	9/15/2023	15	3	-14.98	Yes	75.64	90.62
5	9/15/2023	15	4	-15.12	Yes	75.64	90.76
6	9/15/2023	15	5	-15.12	Yes	75.64	90.76
7	9/15/2023	15	6	-15.13	Yes	75.64	90.77
8	9/15/2023	15	7	-15.20	Yes	75.64	90.84

Appendix C: Exceptional Dispatch Bid Mitigation Analysis

In September 2023, the ISO applied the exceptional dispatch bid mitigation to the exceptional dispatches. Table 10 shows the costs by instruction type in September. With exceptional dispatch bid mitigation, the costs for these types of exceptional dispatches were $5,473. Without the exceptional dispatch bid mitigation, the costs for these types of exceptional dispatches would be $5,552. The cost saving from the exceptional dispatch bid mitigation was $79.

Table 10: Bid Mitigation Analysis for September 2023

Type	Number of Resources	Costs without Bid Mitigation	Costs with Bid Mitigation	Cost Saving
TMODEL	1	$53	$52	$1
NONTMOD	1	$5,499	$5,421	$78
Total	2	$5,552	$5,473	$79