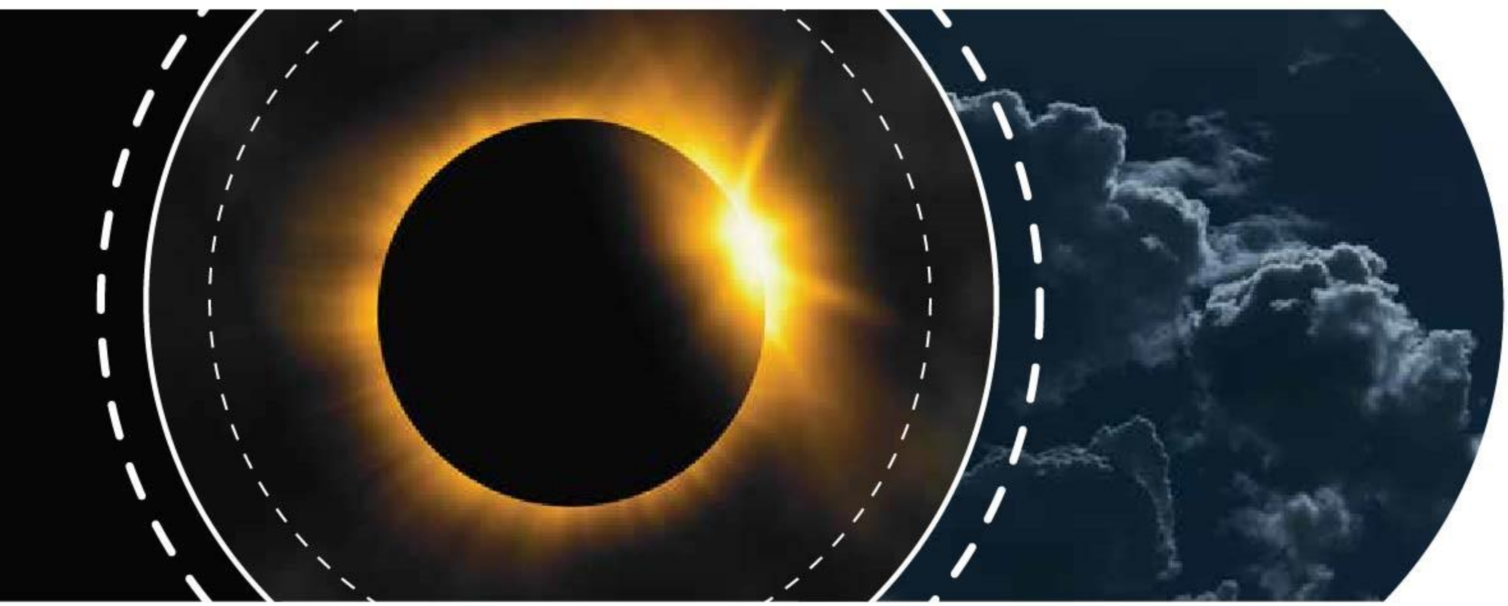
PERFORMANCE OF CALIFORNIA ISO'S SYSTEM DURING APRIL 8, 2024 ECLIPSE



California ISO

May 31, 2024

The following members of the CAISO contributed to the analysis of this report:

Ikram Laaguidi

Zhu Liang

Clyde Loutan

Lysha Matsunobu

Brian Murray

Zachary Ricciardulli

Monique Royal

Hudson Sangree

Miheer Shah

Jessica Stewart

Rebecca Webb

Katie Wikler

Kun Zhao

Amber Motley

Abhishek Hundiwale

Contents

List of Figures

Acronyms

ACE	Area Control Error
AGC	Automatic Generation Control
AVA	Avista
AVRN	Avangrid
AZPS	Arizona Public Service
BAA	Balancing Authority Area
BANC	Balancing Authority of Northern California
BPA	Bonneville Power Authority
BTM	Behind the Meter rooftop solar
CAISO	California Independent System Operator
CPS1	Control Performance Standard
DLAP	Default Load Aggregated Point
DOT	Dispatch Operating Point
DSW	Desert Southwest region
ELAP	EIM Load Aggregation Point
EPE	El Paso Electric
F	Fahrenheit
FMM	Fifteen Minute Market
FRD	Flexible Ramp Down
FRP	Flexible Ramp Product
FRU	Flexible Ramp Up
FSP	Forecast Service Provider
GNRC	Generic non-generating resource
HASP	Hour Ahead Scheduling Process
HE	Hour Ending
IFM	Integrated Forward Market
IPCO	Idaho Power Company
LADWP	Los Angeles Department of Water and Power
LESR	Limited Energy Storage Resource
LMP	Locational Marginal Price
LSE	Load Serving Entity
MW	Megawatt
MWh	Megawatt-hour
NEVP	NV Energy
NGR	Non-Generating resource
NOB	Nevada-Oregon Border
NR	Non-Spinning Reserve
NSI	Net Scheduled Interchange
NWMT	Northwestern Energy
OASIS	Open Access Same-Time Information System

OR	Operating Reserves
PACE	PacifiCorp East
PACW	PacifiCorp West
PDT	Pacific Daylight Time
PGE	Portland General Electric
PNM	Public Service Company of New Mexico
PNW	Pacific NorthWest region
PSE	Puget Sound Energy
PV	Photovoltaic
RCWEST	Reliability Coordinator West
RD	Regulation down
RTD	Real Time Dispatch (5-min) market
RTM	Real-Time Market
RU	Regulation up
RUC	Residual Unit Commitment
SCL	Seattle City Light
SMEC	System Marginal Energy Component
SOC	State of Charge
SR	Spinning Reserve
SRP	Salt River Project
TEPC	Tucson Electric Power
TIDC	Turlock Irrigation District
TPWR	Tacoma Power
VER	Variable Energy Resource
WALC	WAPA Desert Southwest Region
WEIM	Western Energy Imbalance Market
WECC	Western Electricity Coordinating Council

Executive Summary

On April 8, 2024, a total solar eclipse passed over the United States, tracing a path of totality from Texas to Maine. The balancing areas that are part of the Western Energy Imbalance Market (WEIM) experienced this event as a partial eclipse, with more limited effects than last year's annular (near total) eclipse on October 14, 2023.

Though the next eclipse relevant to the WEIM footprint will not occur for some time[1], there were many successes and opportunities for improvement identified from both recent eclipses that will be useful in preparation for demand response, extreme weather, and other high net-load ramping events.

The CAISO prepared for months for the eclipse and closely monitored its effects across the region, in partnership and coordination with entities in the West. In particular, the CAISO took proactive measures and applied experience from prior eclipse events to manage the eclipse, including additional procurement for regulation, charging storage resources ahead of time, and additional procurement of day-ahead commitment capacity.

This report details the CAISO's system and market performance and the impacts to the WEIM, Reliability Coordinator West (RC West) and other balancing authority areas (BAAs) because of the loss of solar generation during the eclipse. In summary:

The eclipse affected the WEIM footprint from 10 a.m. to 1 p.m. Pacific Daylight Time (PDT). Across the WEIM footprint, which covers much of the West, at maximum point of eclipse, the moon obscured from 16% to 89% of the sun's disc, depending on location. Most of the eclipse impacted the Desert Southwest region more significantly in contrast to the October eclipse, when the Pacific Northwest was most heavily impacted.

The CAISO balancing area experienced the maximum eclipse impact at 11:15 a.m. Major solar production areas of California were affected by a partial eclipse between 10:05 a.m. and 12:30 p.m. Within the CAISO BAA, the solar obscuration varied from 34% to 58%. The reduction in solar radiation directly affected the output of photovoltaic (PV) generating facilities, behind-the-meter (BTM) solar, as well as load and net load within the WEIM footprint.

The solar eclipse impacted load and BTM solar supply. The partial obscuration of the sun increased CAISO load by 2,134 MW. When the obscuration subsided and output of rooftop solar returned to normal levels, load decreased by 5,437 MW.

In comparison to the October 2023 eclipse, this eclipse saw less impact to grid-scale solar generation at the CAISO-system level. With respect to a comparable clear-sky day, the reduction in generation at eclipse maximum was 7,665 MW on April 8 versus 9,617 MW on October 14.

WEIM regions experienced varied impacts on solar generation and load, depending on levels of installed grid-scale solar and BTM rooftop solar. The Desert Southwest regions saw the largest impacts, with BTM

[1] There will be a total solar eclipse on March 30, 2033 with a path of totality over parts of Alaska. As a result, a partial solar eclipse will be observed in the western continental U.S.

solar increasing 2,152 MW from the point of minimum generation, during maximum eclipse impact, to post-eclipse generation. Load in the Desert Southwest fell by 1,851 MW when the obscuration subsided and output of rooftop solar returned to normal levels. The Desert Southwest also saw the largest impact to grid-scale solar, with a decrease of 1,483 MW from eclipse start to the eclipse maximum.

Solar production dropped from 11,351 MW at the start of the eclipse to 8,383 MW during maximum eclipse impact and then returned to full production of 11,887 MW. Smaller changes in magnitude, greater clear sky production, and the later morning impact of the April eclipse allowed these solar production ramps to be more easily anticipated and managed than during the October eclipse.

The high penetration of renewable resources in the CAISO's BAA can result in high eclipse effects. At the time of the eclipse, the CAISO BAA had 18,530 MW of grid-scale solar generation and 15,770 MW of behind-the-meter solar generation. WEIM entities had combined grid-scale solar capacity of 12,150 MW and 6,903 MW of behind-the-meter solar.

Solar curtailments played a major role in managing the magnitude of net-load ramps. Economic curtailments of solar generation, which tend to be more prevalent in April than October, occurred throughout the eclipse. Approximately 5,600 MW of solar curtailments took place as solar ramped up during the eclipse. The average solar generation ramps into and out of the eclipse were less than half the magnitude of the potential ramps the system could have seen without curtailments.

As solar production and load experienced steep changes, other supply technologies — including storage resources, gas-fired plants and imports — offset these changes. Battery storage resources, which have increased dramatically in the CAISO in the past three years, played a key role in offsetting the eclipse's effects. Battery storage resources provided over 3,000 MW of capacity in real time and supplied a significant portion of regulation capacity.

The CAISO's market effectively managed the eclipse effects and dispatched resources accordingly. This included managing storage resources to compensate for supply changes. Prices appropriately reflected system conditions, increasing when supply was tighter because of the loss of solar production. The maximum price in the real-time market was about $17/MWh during the eclipse event. As soon as solar began ramping up, prices dropped below $0/MWh due to excess solar production.

During the eclipse, the WEIM optimally enabled transfers to areas that needed them most. During the period of maximum obscuration, WEIM transfers into the CAISO and Southwest regions increased to 1,567 MW and 1,188 MW, respectively. At the same time there were higher than normal exports from the Pacific Northwest and Central/Mountain regions. Overall WEIM transfers reflected the economic and operational benefits that the interstate market offers to participating entities by maximizing supply diversity and transferring supply from where it was available to where it was needed most in real-time.

Introduction

The CAISO navigated the impacts of the partial solar eclipse through coordinated efforts among teams within the CAISO and close coordination with market participants and balancing authorities in the WEIM footprint. This report details the impacts observed on April 8 and how the measures described by the CAISO in its March 6 Solar Eclipse Technical Bulletin assisted with navigating the eclipse. It provides an analysis of market performance and operational performance during the eclipse.

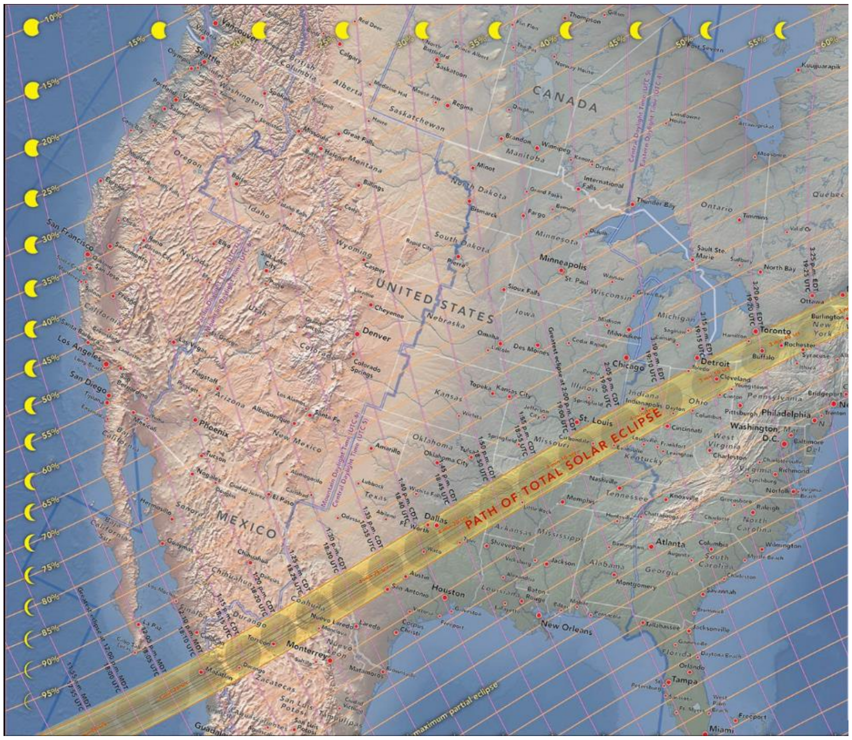
Solar Eclipse

On April 8, 2024 a total solar eclipse passed over the United States, darkening major population centers. No part of the WEIM footprint fell within the path of totality. The Desert Southwest and Southern California regions experienced the largest impact from the partial eclipse. Across the WEIM, the maximum solar obscuration varied from 16% to 89% depending on the distance from the path of totality. Major solar production areas of California were affected by a partial eclipse between 10:05 a.m. and 12:30 p.m.

Figure 1 shows the path of totality across the U.S.[2] The shaded yellow band marks regions that experienced total solar obscuration, and parallel yellow lines, extending outward from the band, denote decreasing levels of obscuration.

[2] Image retrieved from https://www.greatamericaneclipse.com/april-8-2024

Figure 1: April 8, 2024 total eclipse path and percent obscuration across the US



Impacts to CAISO Load and Renewables

Grid-Scale Solar Reduction

The path of the April 2024 eclipse was farther from most WEIM regions than the path of the October 2023 eclipse, but the April eclipse still had significant impacts to grid-scale solar production because levels of obscuration were greater near major solar generation regions. Additionally, time of day and sun angle differences from the October eclipse meant greater potential for impact. Solar obscuration is the percent reduction in solar irradiance reaching Earth's surface. Obscuration decreases proportionately to distance from the path of totality. Within the CAISO BAA, solar obscuration varied from 34% to 58% on April 8. Table 1 shows the start, maximum, and end times of the eclipse for the different grid-scale PV solar areas within the CAISO BAA and the approximate reductions in output at those times. The forecasted maximum regional impact was 32% to 51% of capacity, close to the observed maximum regional impact of 33% to 52% of capacity. Regional impacts are discussed in more detail below.

Table 1: Impacts of the eclipse for the different grid-scale PV solar within the CAISO BAA

Forecast Area	Eclipse Start Time (a.m.)	Eclipse Max Time (a.m.)	Eclipse End Time (a.m.)	Eclipse Max Obscuration	April 2024 Regional Capacity	Forecast Area Production at Eclipse Max[3]		Observed Area Production at Eclipse Max	
					MW	% of Cap	MW	% of Cap	MW
N. San Joaquin	10:16	11:15	12:18	34%	305	51%	154	42%	127
S. San Joaquin	10:10	11:14	12:20	41%	4,905	45%	2,215	52%	2,564
Mojave	10:08	11:14	12:23	48%	4,649	40%	1,852	46%	2,123
LA Basin	10:06	11:13	12:24	51%	224	38%	85	35%	79
Coachella/ Imperial Valley	10:05	11:14	12:26	56%	2,635	34%	897	37%	967
S. Nevada	10:11	11:19	12:30	52%	1,533	37%	566	46%	709
Colorado River Valley	10:07	11:16	12:28	56%	2,874	34%	968	33%	953
Yuma	10:08	11:18	12:31	58%	1,115	32%	358	43%	480
							7,095		**8,002**

Using the data from Table 1, the CAISO calculated the approximate amount of solar energy expected to be produced on April 8, assuming a full sun day with no clouds[4]. The table compares the forecasted eclipse impact with the observed impact.

There were some regions — such as the Los Angeles Basin, Coachella/Imperial Valley, and the Colorado River Valley — where the forecasts for the eclipse were close to observations. The Northern San Joaquin region saw greater impact to production than forecasted, while all other regions observed less impact to solar production than forecasted. A number of factors contributed to these deviations. As a note, Table 1 provides a regional summary of eclipse impacts and is identical to Table 1 in the pre-eclipse report excepting the final two columns. The penultimate column gives eclipse impact as a percentage of capacity, where percentage is calculated by observed production at eclipse maximum divided by the April 2024 regional capacity value.

Some of the discrepancies in estimated impact were due to changes in regional capacity. More than 500 MW of solar generating capacity was added since the preliminary solar forecast was created in January.

[3] The MW sum for the "area production at the eclipse maximum" (minimum area production) and "area production at eclipse end" are less than the minimum area production and production at the eclipse end time represented on the graph (8,383 MW) due to the eclipse maximum times varying by region.

[4] Based on approximate generation at eclipse maximum time from April 8, 2023, adjusted for capacity updates between 2023-2024, then adjusted for the eclipse maximum percent obscuration.

Yuma, in particular, had about 200 MW of solar capacity growth since the March pre-eclipse report publication date, contributing to its higher than forecasted production.

Most regions observed clear skies during the eclipse, a snapshot of which can be seen in Figure 2[5]. Thus, for regions with minimal change in solar resource capacity and clear sky conditions, much of the deviation between forecasted and observed eclipse impact arose from a bias in the preliminary forecast, which was used in eclipse preparation and as the basis for regional estimates. This bias is discussed in more detail along with discussion of Figure 3. Overall, there was more solar production observed at the point of maximum eclipse impact than forecasted, 7,095 MW forecasted versus 8,002 MW observed.

Figure 2: Cloud cover on April 8, 2024

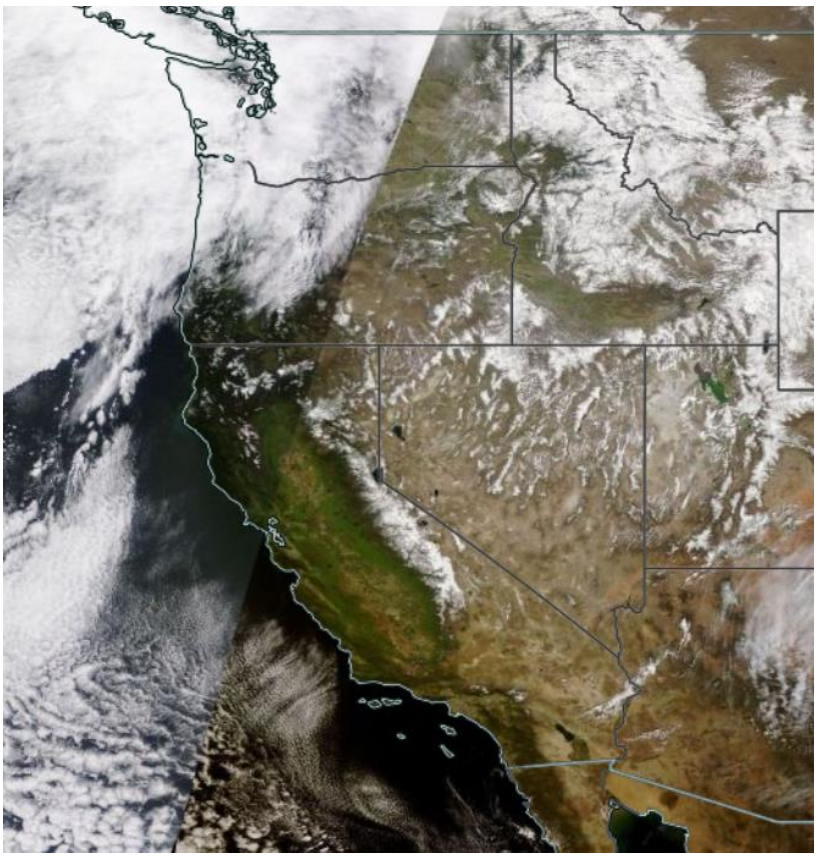


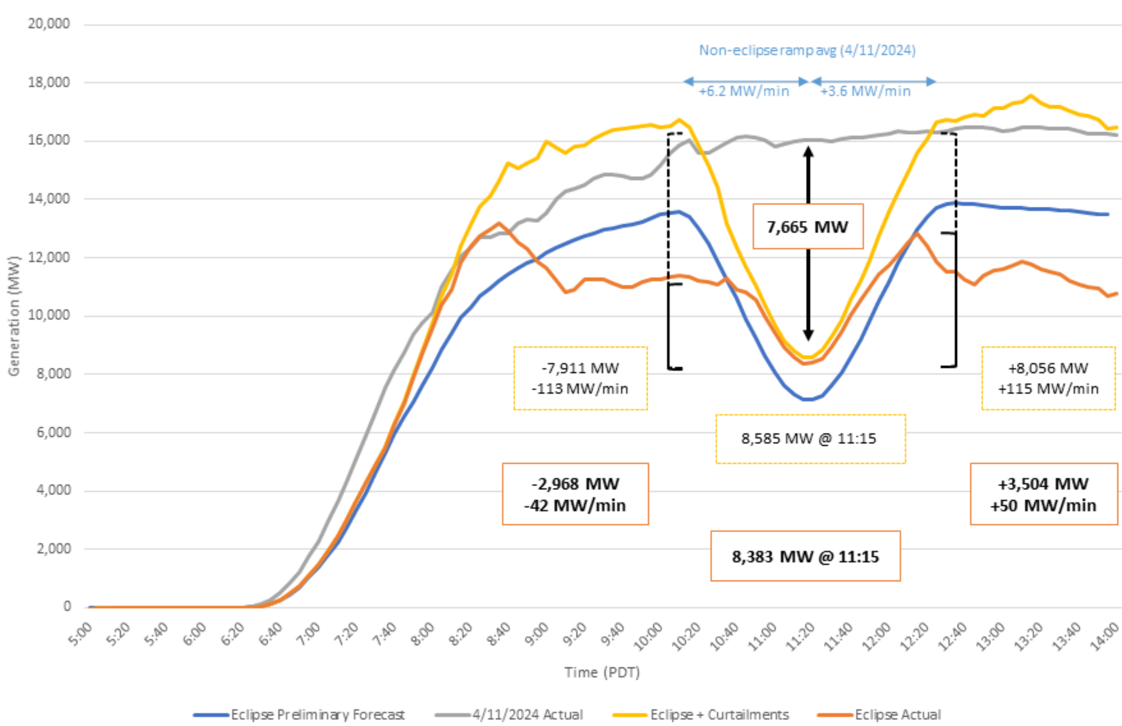
Figure 3 visualizes the forecasts and actuals of system-level solar generation on April 8. The preliminary solar forecast (blue line) estimated a significantly lower magnitude of generation than was realized (yellow line). The forecast methodology that was applied for the October eclipse was repeated for April, but with less accuracy. There were several contributing factors. First, and likely most impactful, the historical April day used as a reference was thought to have had a clear sky profile, but on further review had some high clouds present, reducing the baseline generation. While this impact was small for the historical day,

[5] True color image retrieved from NASA Worldview tool

because solar capacity has grown significantly in the past year, this error was exacerbated. The cloud cover present in the reference day, in contrast to mostly clear skies on April 8, helps explain the variation in error at the regional level despite clear under-forecasting at the system-level.

Second, as noted above, some solar generation capacity was added between the creation of the preliminary forecast and the eclipse. The regional distribution of the capacity changes affected the accuracy of the regional eclipse impact estimates. Third, varying levels of outages and curtailments of solar resources complicated the identification of true clear sky or maximum generating capacity profiles. Though solar generation can be reconstructed from the sum of solar resource curtailments and market-observed solar generation, curtailments add another source of potential error in data quality and accuracy. Because April tends to see more solar curtailments than October, this last point was more relevant in the April eclipse than in October.

Figure 3: April 8, 2024 eclipse CAISO system-wide solar generation



There was significantly more curtailment of solar generation during the April 8 eclipse than was present during the October 2023 eclipse. The impact of curtailments is visible in the difference between the orange and yellow lines in Figure 3. The CAISO sent supplemental dispatch and Dispatch Operating Target (DOT) instructions to many solar resources, reducing output across the fleet. The DOT instructions mitigated the magnitude of ramps. Observed ramps were roughly 60% less than the ramps that would have occurred without the instructions. The solar eclipse reduced production 2,968 MW from 10:05 a.m. to 11:15 a.m. resulting in an average ramp rate of -42 MW per minute. From 11:15 a.m. to 12:25 p.m. solar production ramped back toward normal levels, increasing 3,504 MW at an average ramp of +50 MW per minute. The ramp into the eclipse was slightly larger than in October, -42 MW per minute versus -40

MW per minute, but the ramp out of the eclipse was much less than in October, +50 MW per minute versus +109 MW per minute.

Curtailments of solar generation, which tend to occur on clear April days, were present going into and coming out of the eclipse. April 11, 2024 was chosen as a non-eclipse day for comparison as it had relatively little solar curtailment. In comparison to April 11, the minimum production at maximum eclipse impact reduced production by 7,665 MW. At the point of maximum eclipse impact, generation was 8,383 MW. Even at maximum eclipse impact, some solar curtailments occurred, with about 202 MW separating the yellow and orange lines in Figure 3.

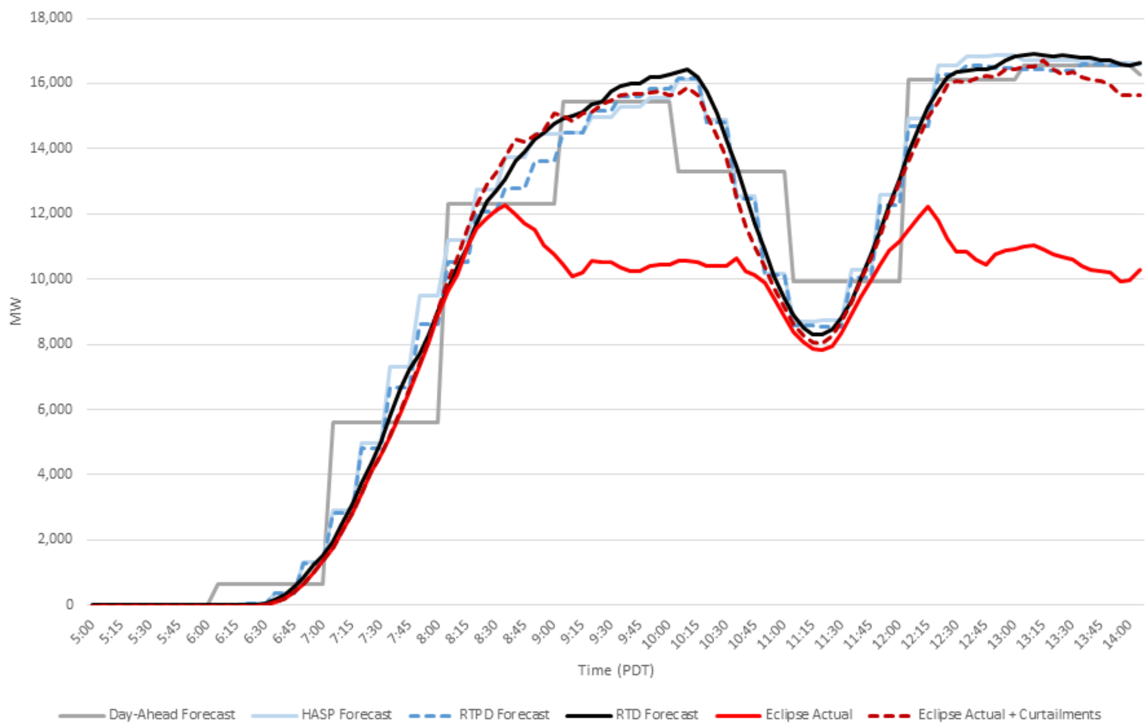
The average ramp of solar generation out of the eclipse was 115 MW per minute between 11:15 a.m. to 12:25 p.m. With solar curtailments included, the average ramp over the same period is 50 MW per minute. Considering that the orange line in Figure 3 peaks at 12:15 p.m. then begins to decrease with increased supplemental dispatch, another ramp worth noting is the average ramp of solar generation actuals over the period 11:15 a.m. to 12:15 p.m., which was 63 MW per minute. These differences in ramps are another demonstration of the impact of solar curtailments in this eclipse.

For future eclipse planning, or other related solar event forecasting, it is useful to note that there can be challenges to scaling up historical data during periods with frequent curtailments and that production profiles should be referenced relative to associated maximum generating capacity. As was observed in this eclipse, small errors or data impacts in historical profiles will be amplified with growth in solar capacity.

Apart from exceptional events, the CAISO mainly utilizes its persistence methodology for real-time dispatch (RTD) variable energy resource (VER) forecasts. The persistence methodology is run in the real-time market for solar and wind resources and utilizes a the current telemetry data from the individual resources to create the RTD forecast out 10 minutes. The CAISO opted to turn off the solar persistence forecast to ensure all advisory and binding RTD forecasts would include eclipse impacts. From 10 p.m. on April 7 to 3 p.m. on April 8, while solar persistence was off, RTD forecasts were provided by external vendors, who also provide VER forecasts at farther-out horizons. Wind persistence remained on during this period.

Figure 4 shows the solar forecast at various market horizons. Similar to Figure 3, both the solar actuals observed by the market (solid red line) and estimated solar generation from actuals plus curtailments (dashed red line) are provided. As forecasts capture the actual capability of solar generation, the dashed red line is the appropriate reference against which to evaluate the forecasts. Overall, forecasts performed well and progressed in a consistent manner from day-ahead (DA) to RTD. Going into the eclipse, RTD over-forecasted slightly but corrected and forecasted values much more closely on the ramp out of the eclipse and at the eclipse end. Because the day-ahead forecast uses an hourly average, the intra-hour turns in the eclipse cannot be captured very precisely. The eclipse minimum of the day-ahead forecast (gray stepped line) appears shifted compared to actuals because of the interval sampling and the eclipse maximum occurring early in the hour interval.

Figure 4: Comparing the DA, HASP, FMM and RTD forecasts for the eclipse.



Temperature and Wind Impacts

In addition to solar impacts, other weather-related effects of the eclipse are temperature and grid-scale wind generation. Table 2 shows the average observed temperature reductions based on obscuration percentages during the eclipse compared to the same hours on April 9 and 10, 2024.

Table 2: Approximate potential temperature impacts during the eclipse based on maximum obscuration

Obscuration level	Observed temperature reduction (˚F)
51-60%	1-2˚
41-50%	1˚ or less
31-40%	1˚ or less

A study[6] of the 2017 eclipse found that for eclipses that occur in the morning the temperature for the rest of the day is expected to warm more slowly compared to a non-eclipse day, even after the eclipse was

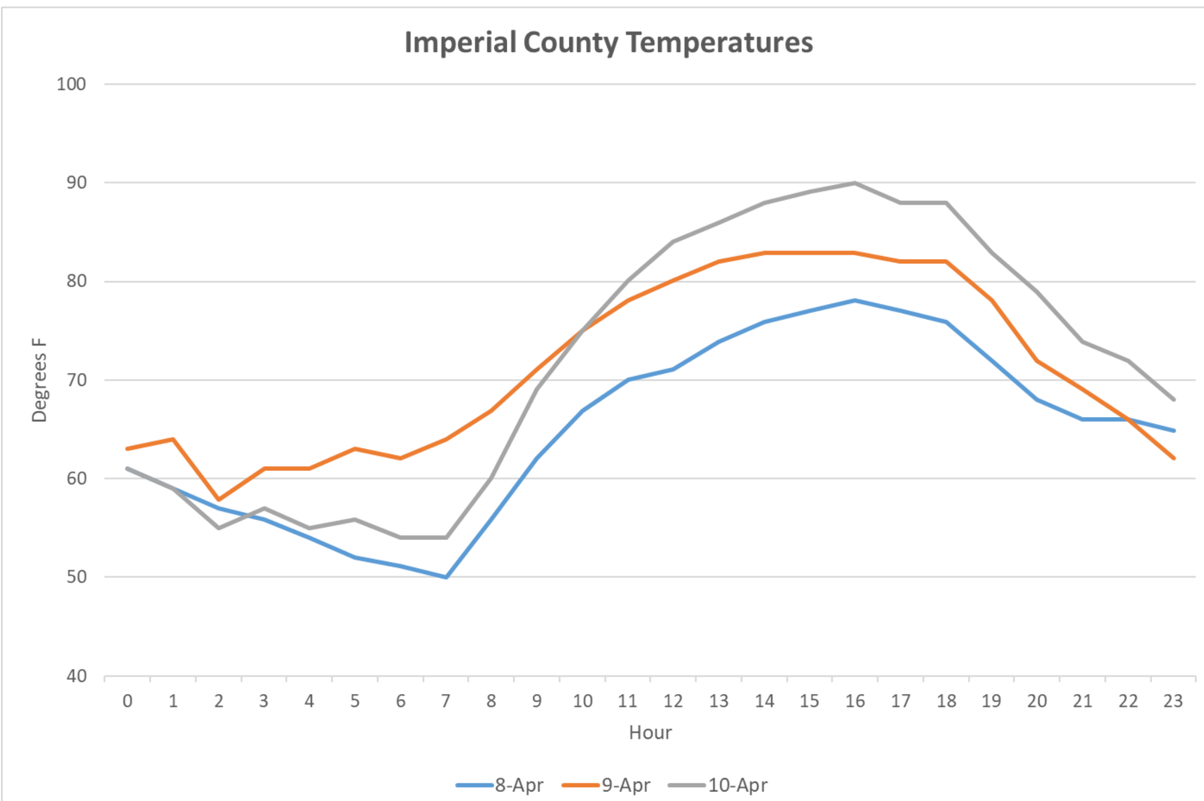
[6] Effect of 21 August 2017 solar eclipse on surface-level irradiance and ambient temperature | International Journal of Energy and Environmental Engineering (springer.com)

over, leading to a reduced maximum daily temperature. This impact was not conclusively seen across all of California due to the lower solar obscuration values. In addition, the temperature data analyzed for this eclipse was hourly, while other studies used temperature data on a shorter timescale, such as one-minute data, allowing for a more detailed analysis.

Data for the Imperial County Airport (KIPL), which had a solar obscuration of around 57%, is shown below in

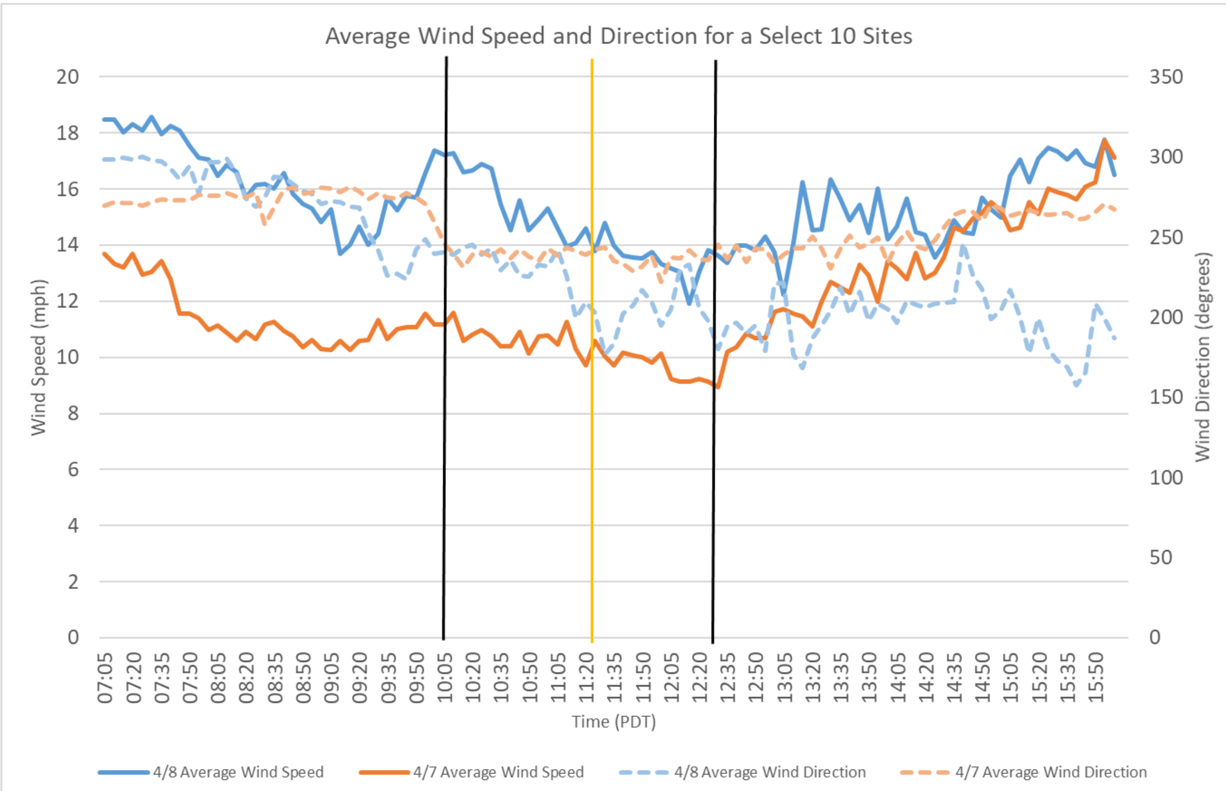
Figure 5. While the temperature during the rest of the day on April 8 was lower than the days after the eclipse, warming after the maximum obscuration did likely see a reduction compared to the non-eclipse days as well. This can be seen between hours 11 and 12 on the graph where the rate of heating is reduced compared to the non-eclipse days, which also likely impacted the rest of the day. This is more visible than the impacts of the October eclipse, despite the lower solar obscuration, because the sun was higher in the sky in the April eclipse than in October.

Figure 5: Imperial hourly observed temperatures for April 8-10, 2024



Eclipses also affect wind speed and direction, with the largest impacts closest to the path of totality. Wind speeds have decreased by approximately 2-6 mph near the path of totality during prior eclipses. Wind directions tend to rotate counter-clockwise during an eclipse from its start through maximum obscuration, and clockwise from maximum obscuration to the end of the eclipse. Figure 6 shows the wind speed and direction changes across California during the April 8 eclipse compared to a similar day.

Figure 6: Average wind speed and direction for selected 10 sites



The average wind speed (solid lines) and direction (dashed lines) for ten sites across California during the eclipse (blue) and a similar non-eclipse April day (orange). The black lines denote the start and end of the eclipse and the yellow line denotes the maximum obscuration time. Throughout California, wind speeds decreased by about 2-3 mph from the eclipse's start to maximum obscuration, but a near similar decrease of 1-2 mph was observed on the non-eclipse day. Wind speed only decreased about 1-2 mph from the eclipse's peak to its end, which is similar to the non-eclipse day. Wind direction shifted from 250 degrees to 200 degrees during the eclipse, which is a shift from west-southwest to south-southwest. After the eclipse, the wind direction remained around 200 degrees, so it cannot conclusively be noted that the eclipse caused the change in wind direction and not a shift in direction due to diurnal heating or other factors. The non-eclipse day did not experience any counter-clockwise rotation like the eclipse day did, with winds remaining consistently from 250 degrees or west-southwest. As a result of the minimal impacts to wind speed or wind direction compared to the non-eclipse day, there were similarly no definitive impacts to wind generation for the CAISO BAA observed as a result of the eclipse.

CAISO Load Forecast

There is more than 15,770 MW of BTM rooftop solar capacity in the CAISO footprint. On the eclipse day, partial obscuration of the sun reduced output of rooftop solar and increased load by 2,134 MW from 10:15 a.m. to 11:05 a.m., as shown in Figure 7. As obscuration of the sun subsided and output of rooftop solar returned to normal levels, load decreased 5,437 MW from 11:05 a.m. to 12:25 p.m.

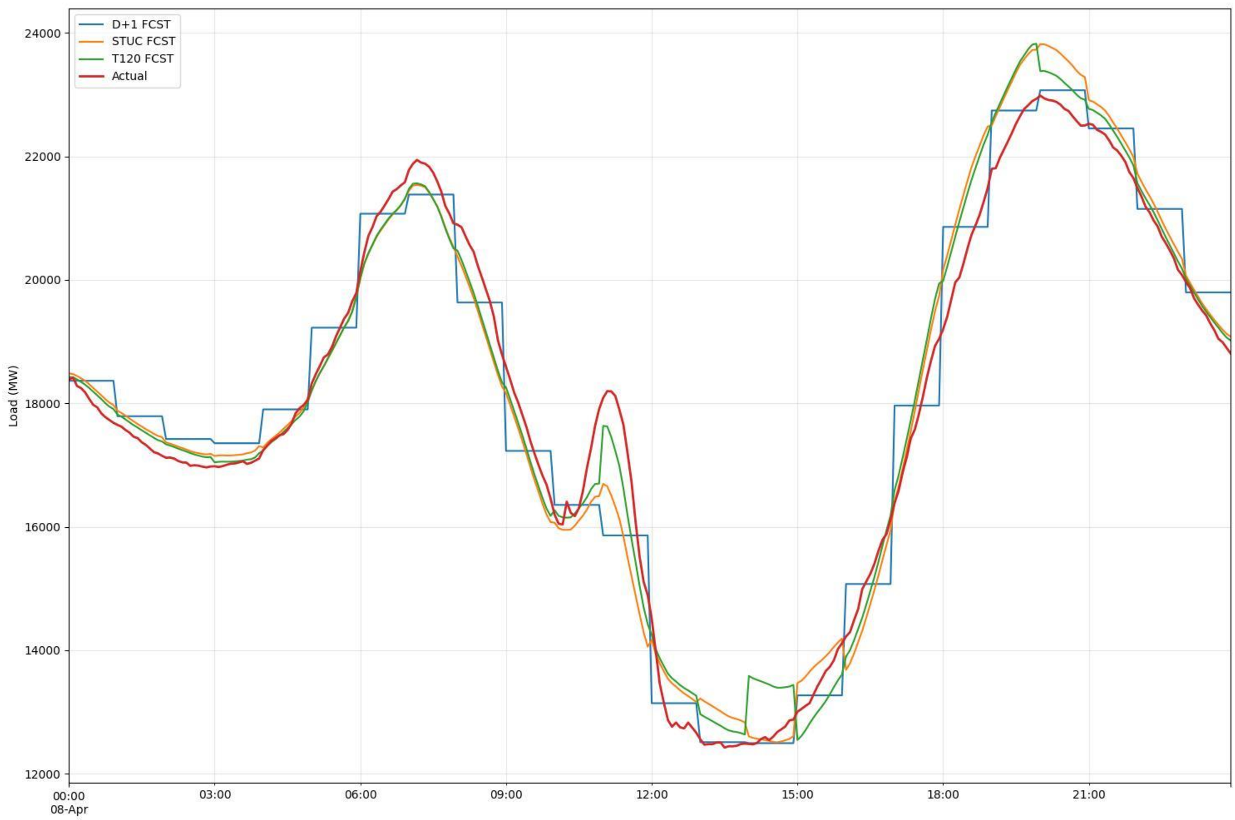
Table 3: CAISO eclipse gross load ramping data

	Start	End	Load Start	Load End	Total Ramp (MW)	Average Ramp (MW/min)	Max Ramp (MW/min)	Typical Ramp (MW/min)
Ramp Up	10:15	11:05	16,063	18,197	2,134	42.7	74.7	-23
Ramp Down	11:05	12:25	18,197	12,760	-5,437	-68.0	-129.4	-10

	Start	End	Load Start	Load End	Total Ramp (%)	Average 5 Min Ramp (%)	Max 5 Min Ramp (%)	Typical 5 Min Ramp (%)
Ramp Up	10:15	11:05	16,063	18,197	13.3	1.3	2.3	-2.9
Ramp Down	11:05	12:25	18,197	12,760	-29.9	-2.0	-3.8	-1.4

Load forecasts for the D+1 through T-120 timeframes can be seen in Figure 7 below. Day Ahead and STUC forecasts generally under-forecasted the eclipse impacts. The T-120 forecast moved upward during the eclipse period improving forecast accuracy during the eclipse maximum period. Forecasts from T-120 onward generally exhibited minimal movement in forecasted load maximum, and differed primarily in the timing of load maximum.

Figure 7: CAISO Day Ahead through T-120 load forecasts and actuals



Load forecasts for the T-60 through RTD timeframes can be seen in Figure 8 below. Forecasts generally performed well at capturing the timing and magnitude of the eclipse, with load forecasts coming in slightly below eclipse maximum load. The T-60 upward movement in the hours following the eclipse are discussed in *CAISO T-60 BTM Forecast and Impact to T-60 Load Forecast* section below.

Figure 8: CAISO T-60 through RTD load forecasts and actuals

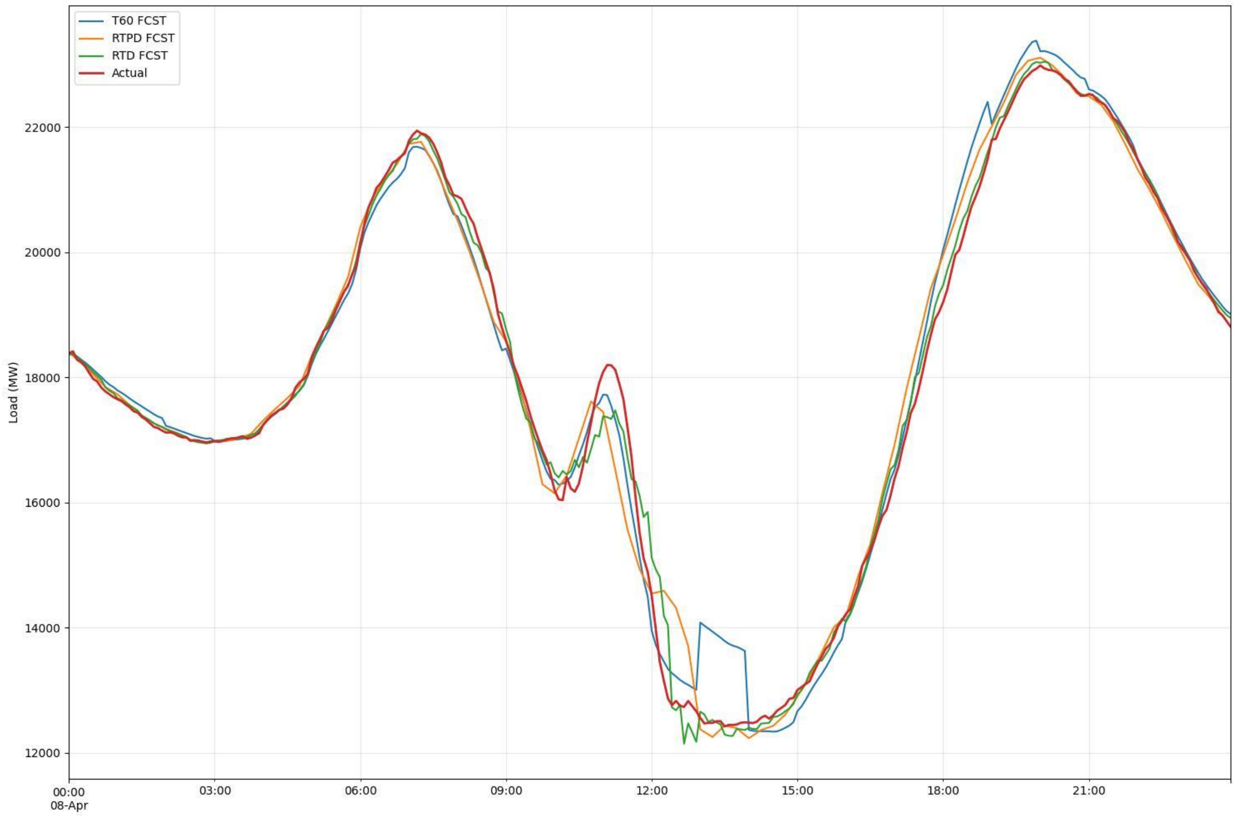
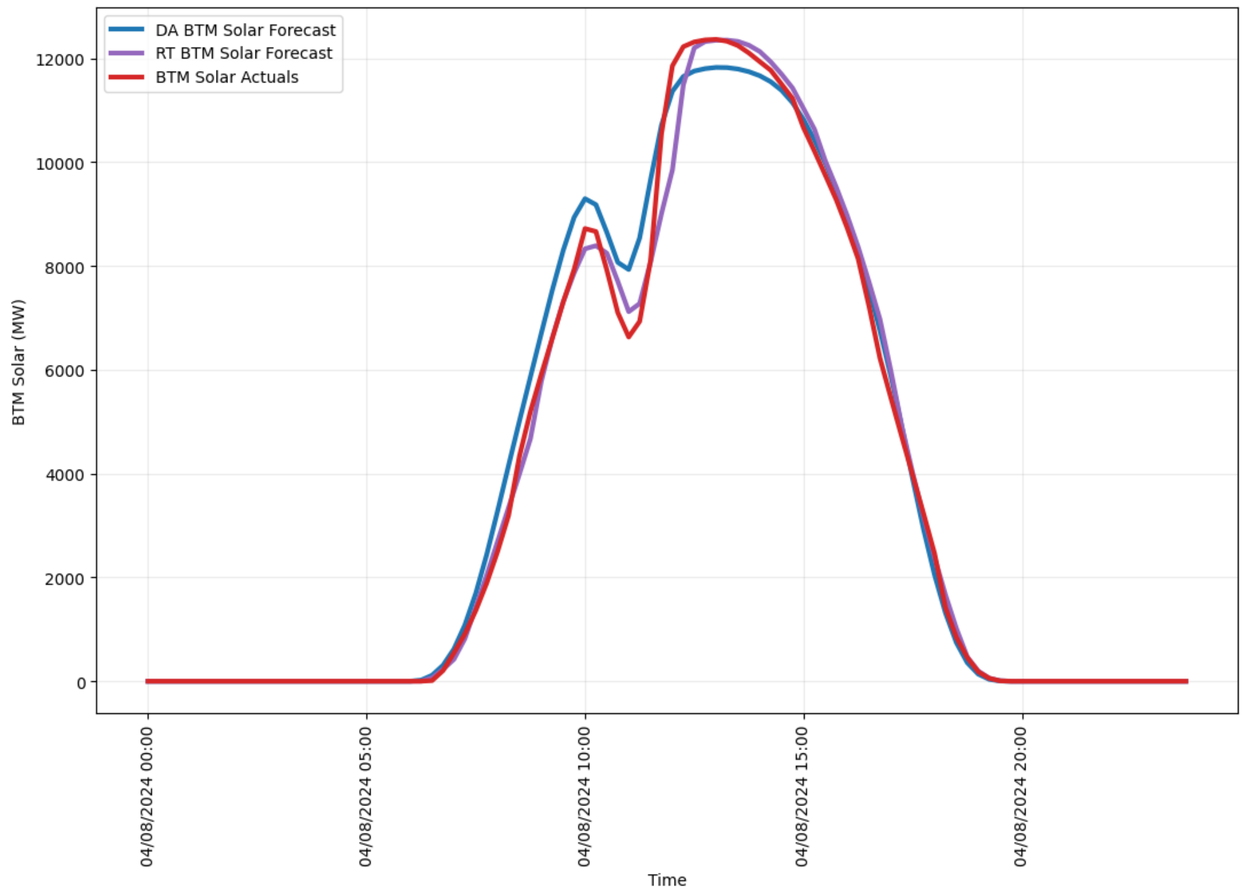


Figure 9 below shows CAISO-wide BTM solar forecasts and actuals throughout the eclipse day. The DA BTM Solar Forecast shows a forecast born on April 7, 2024 for the entire eclipse day. The RT BTM Solar Forecast shows a BTM forecast born 1-hour prior to the actual timeframe.

Figure 9: CAISO BTM solar forecasts and actuals throughout eclipse day

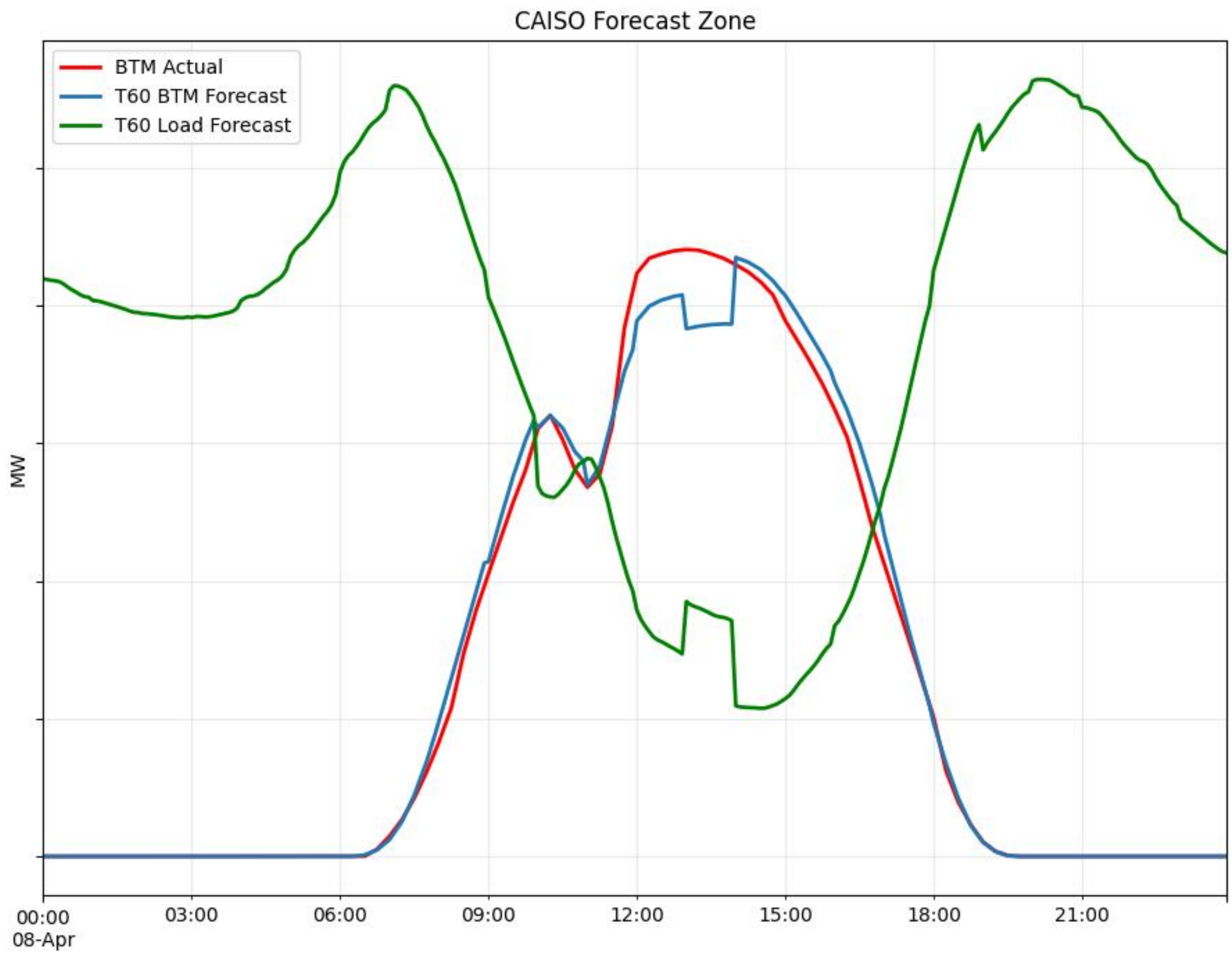


CAISO T-60 BTM Forecast and impact to T-60 Load Forecast

Real-time models generally captured the timing and magnitude of the eclipse; however, a large T-60 forecast jump occurred during the hours following the eclipse as seen in Figure 8. This was due the model reacting to the T-60 BTM solar forecast containing an anomalously low dip in the hours following the eclipse. Many CAISO entities were utilizing BTM solar reconstituted models, which enforce a one-to-one relationship between BTM solar forecasts and load. As such, this dip in BTM solar forecast caused load forecasts to move upward by an identical amount during this timeframe. When the BTM solar forecast moved back towards a more regular shape, load forecasts returned to accurate levels. A representative WEIM entity was selected to highlight the relationship between BTM solar forecast and load forecast for the T-60 timeframe in Figure 17 below.

CAISO relies on an external vendor to provide BTM solar forecasts. The CAISO will work with the vendor to further understand the cause of the drop and what can be done to protect load forecast accuracy from anomalous changes in BTM solar forecasts in the future. As the root cause of this BTM solar forecast is investigated, Short Term Forecasting will evaluate methods to ensure forecast quality remains intact, potentially including upstream meter validations to limit the likelihood of similar events.

Figure 10: CAISO forecast zone's T-60 BTM solar forecasts and impact to T-60 load forecast



Net Load

Figure 10 highlights net load fluctuation on April 8 during the eclipse period, and Table 4 reports the key net-load ramping data. From 10:15 a.m. to 11:10 a.m., net load increased by 4,553 MW. During the ramp-up period, net load increased by approximately 82.8 MW per minute on average, with a max ramp rate of +185.7 MW per minute. As the eclipse began to wane, net load dropped by 9,319 MW from 11:10 a.m. to 12:10 p.m. During the ramp-down period, net load decreased by approximately 155.3 MW per minute on average with a maximum down-ramp of -238.4 MW per minute.

Table 4: CAISO eclipse net load ramping data

	Start	End	Load Start	Load End	Total Ramp (MW)	Average Ramp (MW/min)	Max Ramp (MW/min)	Typical Ramp (MW/min)
Ramp Up	10:15	11:10	3,610	8,163	4,553	82.8	185.7	-30
Ramp Down	11:10	12:10	8,163	-1,156	-9,319	-155.3	-238.4	-7.8

	Start	End	Load Start	Load End	Total Ramp (%)	Average 5 Min Ramp (%)	Max 5 Min Ramp (%)	Typical 5 Min Ramp (%)
Ramp Up	10:15	11:10	3,610	8,163	126.1 %	11.5 %	25.8 %	-13.7
Ramp Down	11:10	12:10	8,163	-1,156	-114.2 %	-9.51 %	-14.6 %	-2.1

Figure 10: CAISO net load impact from eclipse during ramping period

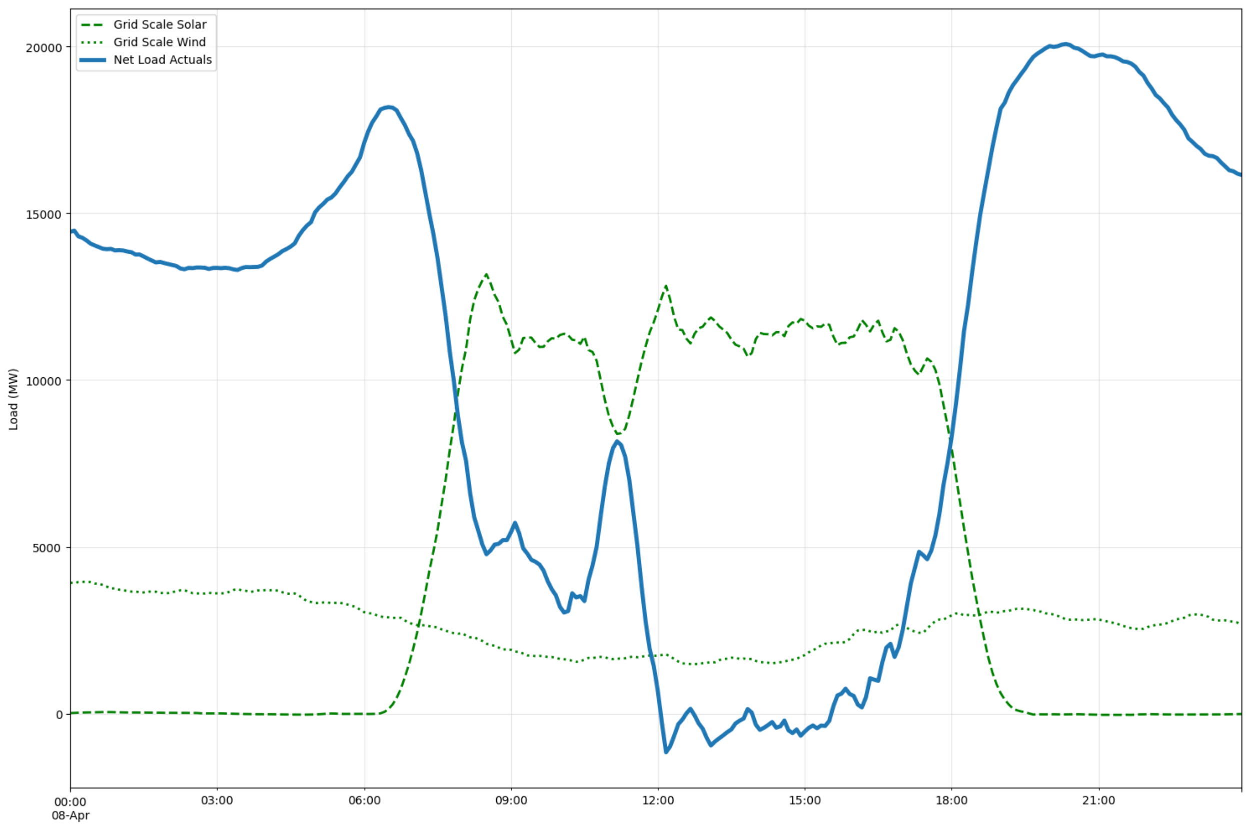
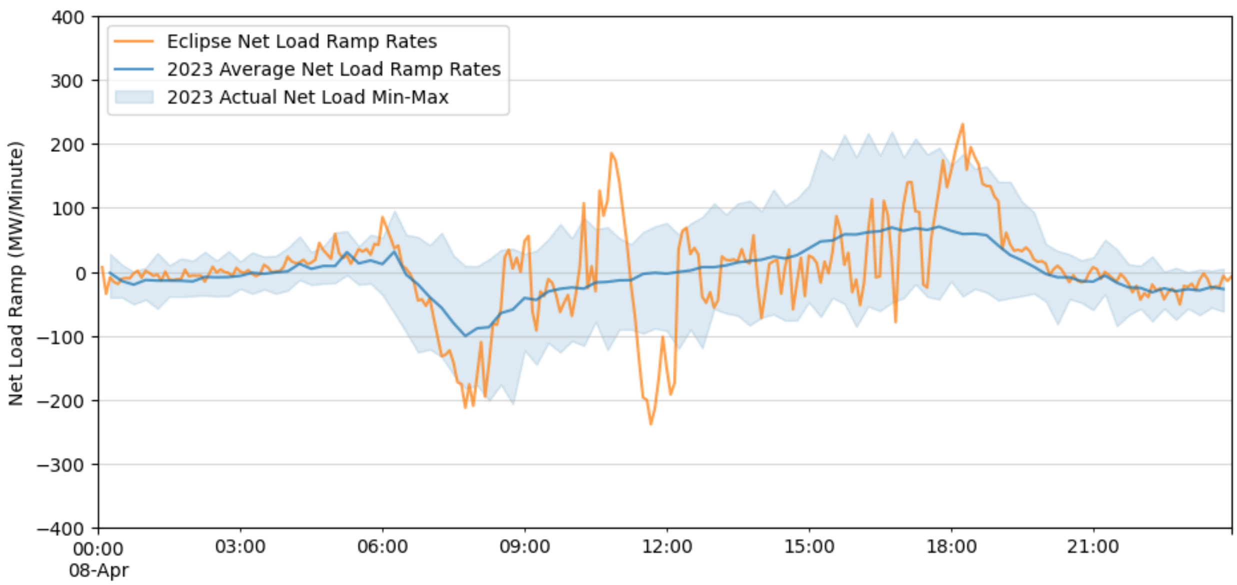


Figure 11 illustrates the eclipse ramping requirements relative to actual ramping data for 2023[7]. Ramp rates for the eclipse ramp-up period are higher than those typically experienced in the morning but are in line with the steeper ramps experienced during 2023 evening peaks. Ramp rates in the ramp-down period are steeper than those experienced in the late morning but are in line with the steeper ramps experienced

[7] Includes 15-min net load data from February 12th 2023 – February 11th 2024. October 2023 eclipse day excluded.

during 2023 morning peaks. The minimum ramp rate during the ramp-down period of -238.4 MW per minute exceeds the minimum late morning rate in 2023 by approximately 100 MW per minute.

Figure 11: Eclipse net load ramp rates compared to 2023 actual ramp rates



Impacts to WEIM Load and Renewables

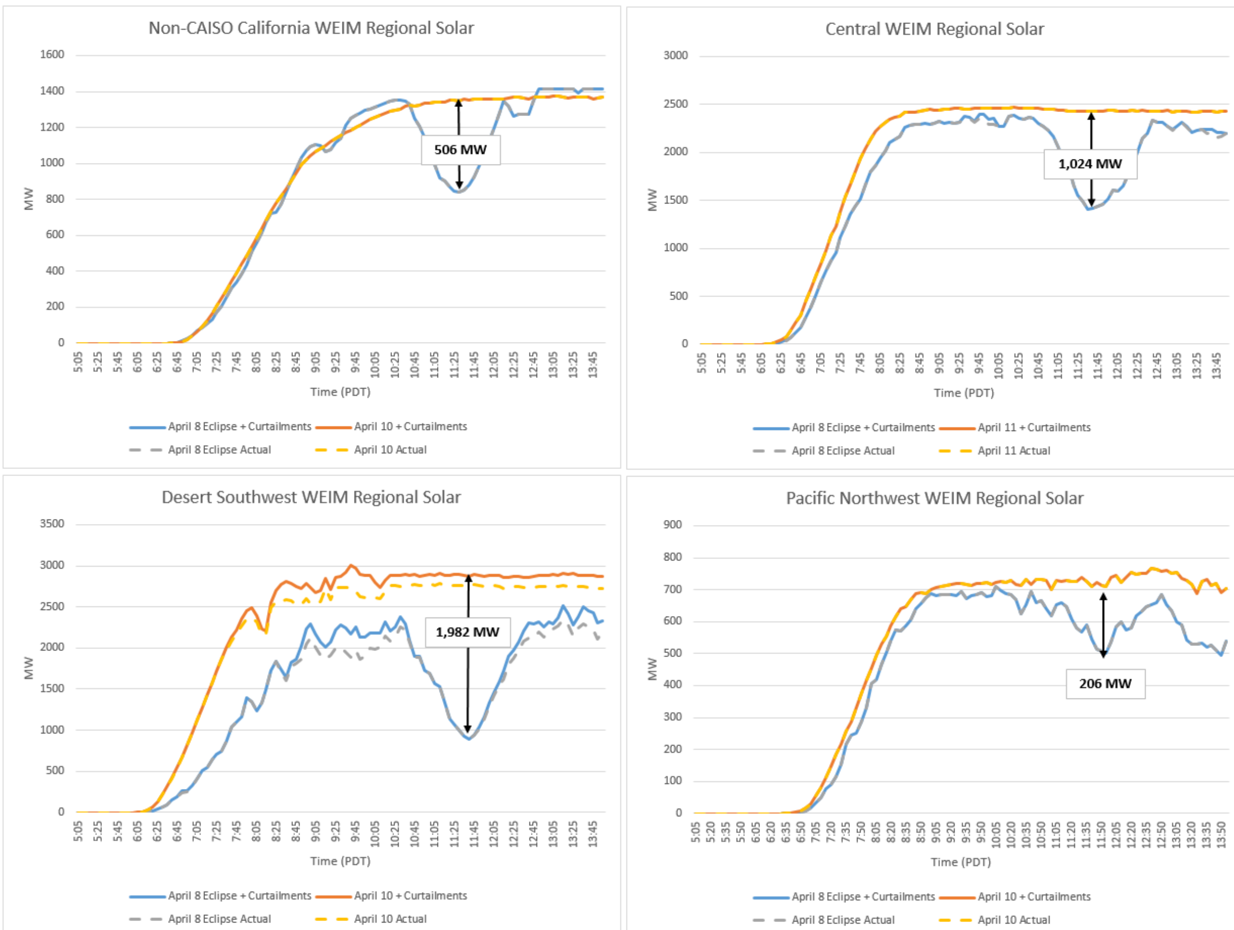
WEIM Grid Connected and Rooftop Solar

The WEIM footprint includes 22 participants and 21 balancing authority areas. Most WEIM participants submit forecasts for their renewables generation through their own forecast service providers (FSPs), but utilize the CAISO persistence methodology for their real-time dispatch (RTD) forecast. The persistence methodology is run in the real-time market for solar and wind resources and utilizes a the current telemetry data from the individual resources to create the RTD forecast out 10 minutes. Each WEIM with regional solar capacity that utilizes the solar persistence methodology for RTD was given the option of leaving the persistence methodology on or turning it off during the eclipse period. For those who elected to turn it off, this was done at 10 p.m. on April 7 to ensure all advisory and binding RTD forecasts would include the eclipse impacts. The time to resume the persistence methodology was also selected by each entity, which varied depending on the time the eclipse ended for their service area. Wind persistence remained on during the entire eclipse period.

The CAISO serves as the real-time load forecast service provider for most WEIM entities. The CAISO receives estimates of installed rooftop BTM solar for load-serving WEIM entities. WEIM BTM capacity estimates are provided to a third-party vendor, which generates a BTM solar forecast that the CAISO can incorporate into its load forecasting process.

Table 5 shows the approximate estimates of grid-connected and rooftop BTM solar for each WEIM entity. Also included is a mapping of each WEIM entity to a broader geographic WEIM region. The WEIM regions were impacted at various times as the eclipse passed through the West. Figure 13 shows the impact of each WEIM regional aggregate grid-connected solar for the eclipse day compared to a recent clear-sky day. Values indicate the difference in the eclipse day + curtailments to the non-eclipse day + curtailments. Cloudy skies across much of the Pacific Northwest and parts of the central and Desert Southwest regions contributed to lower output during the eclipse maximum and after the eclipse end.

Figure 12: The WEIM grid-connected solar impacts on the eclipse day compared to a recent clear sky day



The WEIM rooftop solar impacts, as well as the day-ahead and real-time forecasts, are shown in Figure 14. The DA BTM Solar Forecast shows a forecast born on April 7, 2024 for the entire eclipse day. The RT BTM Solar Forecast shows a BTM forecast created 1-hour prior to the actual timeframe.

Figure 13: WEIM regional BTM solar forecasts and BTM solar actuals

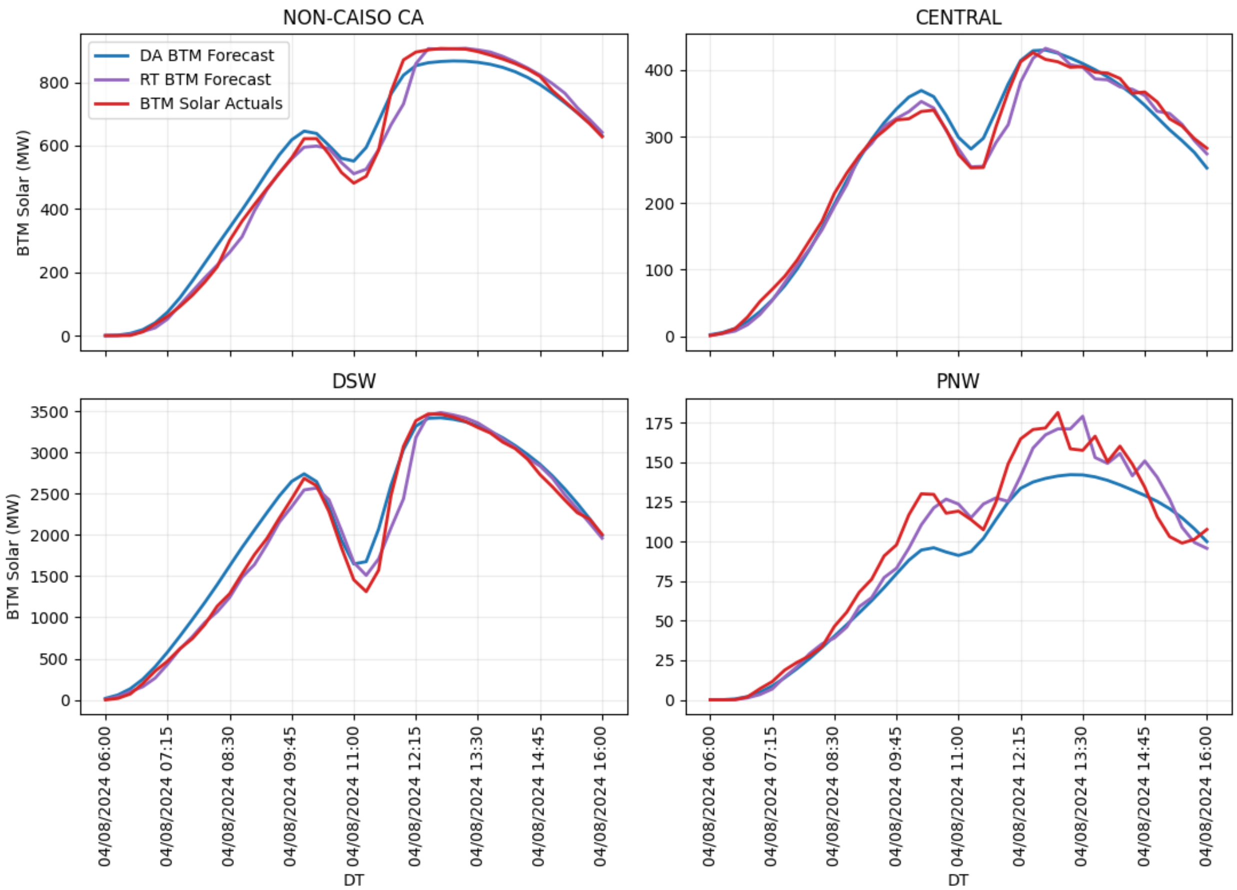


Table 5: WEIM grid connected and rooftop BTM solar capacity

WEIM Region	Approx. Grid Connected Solar (MW)	Approx. Rooftop BTM Solar (MW)
California	**1,561**	**1,016**
Balancing Area of Northern CA (BANC)	407	347
Los Angeles Department of Water and Power (LADWP)	1,154	597
Turlock Irrigation District (TID)		72
Central	**6,204**	**1,548**
Idaho Power Company (IPCO)	473	126
Northwestern Energy (NWMT)	179	50
NV Energy (NVEP)	3,311	884
PacifiCorp East (PACE)	2,240	488
Desert Southwest	**3,265**	**3,621**
Arizona Public Service (AZPS)	1,109	1,886
El Paso Electric Company (EPE)	285	181
Public Service Company of New Mexico (PNM)	1,040	340
Salt River Project (SRP)	436	534
Tucson Electric Power (TEPC)	428	550
WAPA Desert Southwest Region (WALC)	67	130
Pacific Northwest	**1,117**	**700**
Avangrid (AVRN)	522	
Avista (AVA)	20	21
Bonneville Power Authority (BPA)	139	88
PacifiCorp West (PACW)	436	188
Portland General Electric (PGE)		179
Puget Sound Energy (PSE)		165
Seattle City Light (SCL)		60
Tacoma Power (TPWR)		17
WEIM Totals	**12,150**	**6,903**

WEIM Load Forecast

Eclipse impacts on WEIM loads varied with proximity to the eclipse path and levels of installed BTM rooftop solar. Generally, eclipse impacts were more pronounced in regions with higher levels of BTM capacity relative to native load.

Eclipse impacts by region are shown in Table 6. The Desert Southwest region showed the greatest eclipse impacts with morning load increasing 1,297 MW (+15.1% relative to eclipse start load). The Central WEIM region showed a load increase of 236 MW (+2.0%), and the non-CAISO California WEIM region showed a load increase of 151 MW (+3.5%).

The Desert Southwest similarly showed the largest impact from eclipse maximum to post-eclipse minimum with load decreasing 1,851 MW (-18.7% relative to eclipse maximum load). The Central WEIM region showed load decreasing 689 MW (-5.6%), and non-CAISO California WEIM region showed load decreasing 431 MW (-9.7%).

Table 6: WEIM observed load and ramping data during eclipse hours

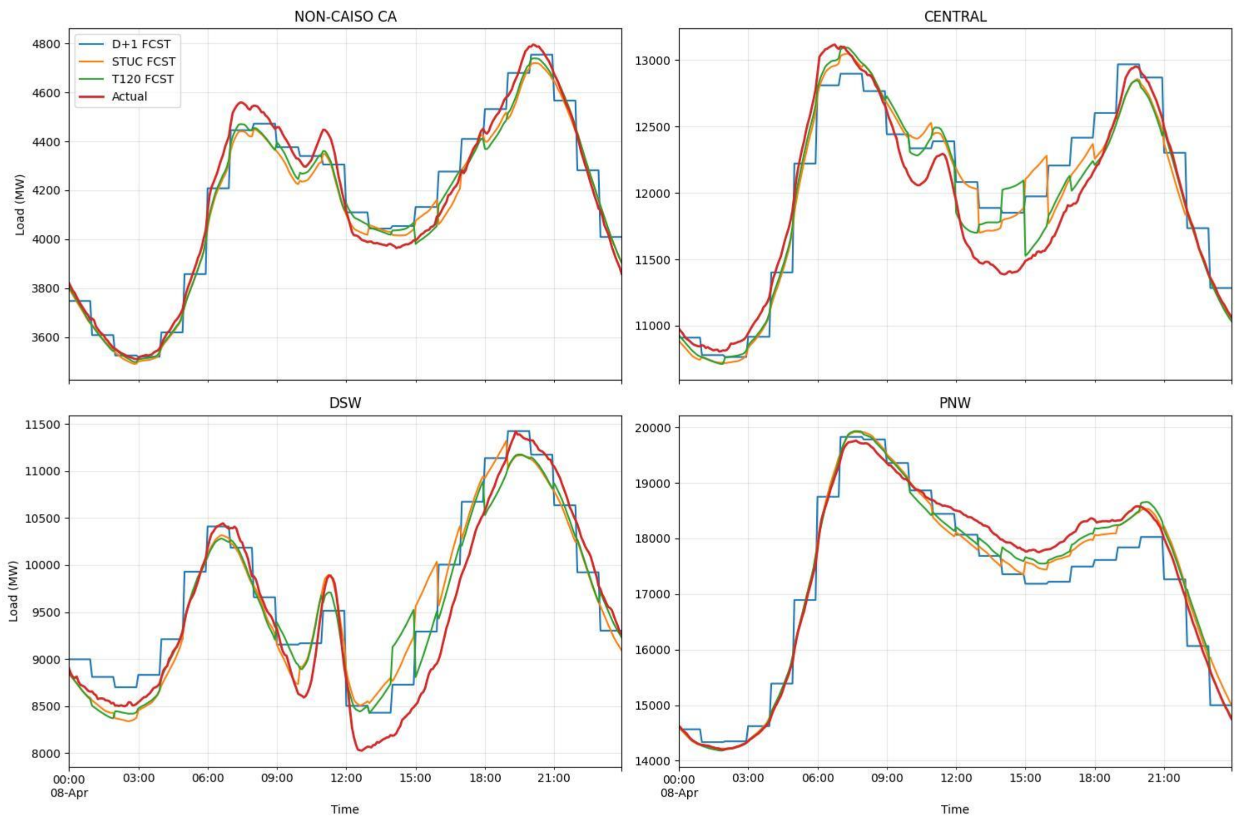
	WEIM Region	Start Time	Load Start (MW)	Maximum Time	Maximum Load (MW)	Total Up Ramp (MW)	Average Up Ramp (MW/min)	Max Up Ramp (MW/min)
Ramp Up	Non-CAISO California	10:15	4,296	11:00	4,447	151	3.4	4.5
	Pacific Northwest[8]	--	--	--	--	--	--	--
	Central	10:20	12,058	11:15	12,294	236	4.3	7.8
	Desert Southwest	10:10	8,593	11:15	9,890	1,297	20.0	33.6

	WEIM Region	Maximum Time	Load Max (MW)	End Time	End Load (MW)	Total Down Ramp (MW)	Average Down Ramp (MW/min)	Max Down Ramp (MW/min)
Ramp Down	Non-CAISO California	11:00	4,447	12:20	4,016	-431	-5.4	-9.7
	Pacific Northwest	--	--	--	--	--	--	--
	Central	11:15	12,294	12:30	11,605	-689	-9.2	-15.8
	Desert Southwest	11:15	9,890	12:30	8,039	-1,851	-24.7	-41.9

The D+1 through T-120 load forecasts can be seen in Figure 14 below. During the eclipse timeframe, forecasts remained slightly below eclipse maximum load values for the Non-CAISO California and Desert Southwest WEIM regions. Forecasts remained slightly higher than actuals during the eclipse maximum for the Central region. During the post-eclipse hours, forecasts generally remained elevated compared to load actuals for the D+1 through T-120 timeframes for all regions except Pacific Northwest.

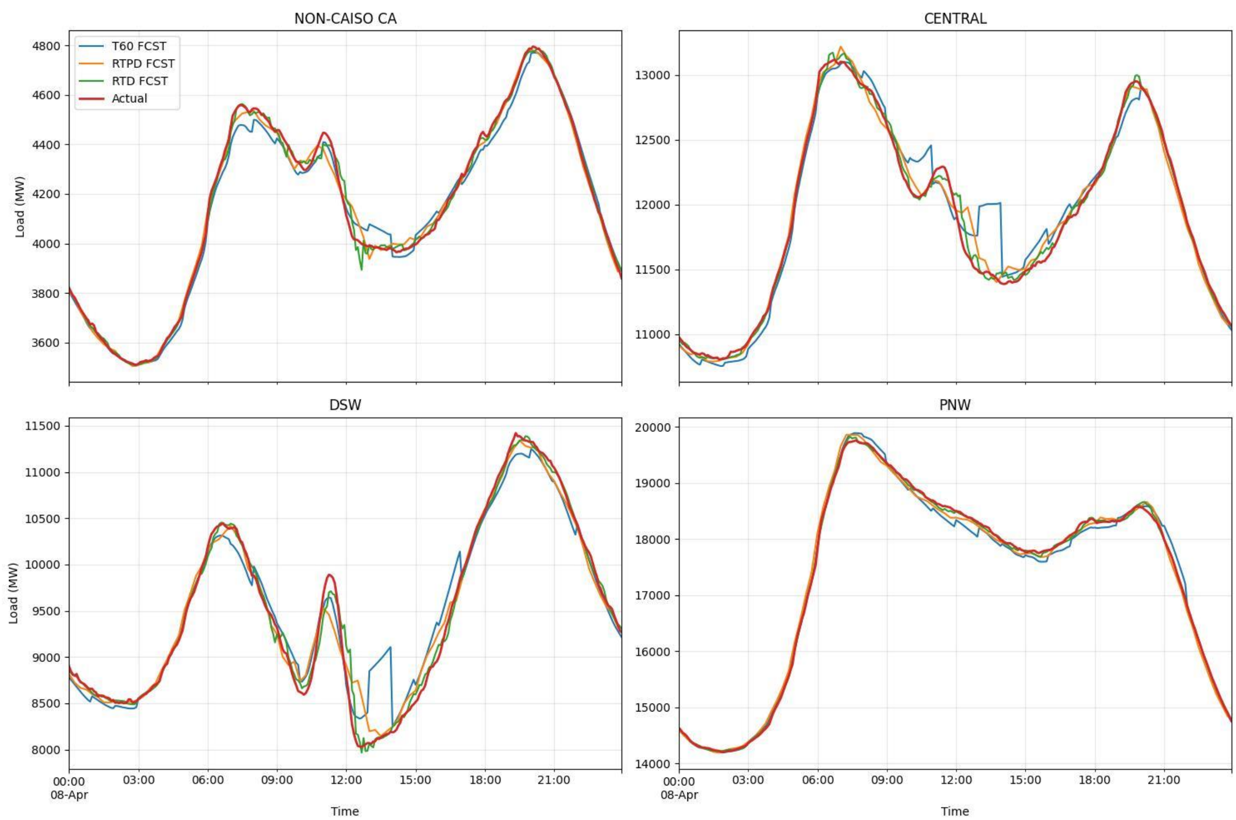
[8] The eclipse signal was not strong enough in the Pacific Northwest load profile to quantify impacts.

Figure 14: WEIM regional Day Ahead through T-120 forecast, and load actuals



The T-60 through RTD load forecasts can be seen in Figure 15 below. Load forecasts generally performed well at capturing the timing and magnitude of the eclipse, with forecasts generally coming in slightly below eclipse maximums for all regions. Minimal movement occurred in the eclipse maximum load value, with slight movements in the exact timing of the maximum over the T-60 to RTD timeframe. The T-60 upward movement exhibited in various WEIM Regions following the eclipse are discussed in *WEIM T-60 BTM Forecast and Impact to T-60 Load Forecast* section below.

Figure 15: WEIM regional T-60 through RTD forecasts and load actuals

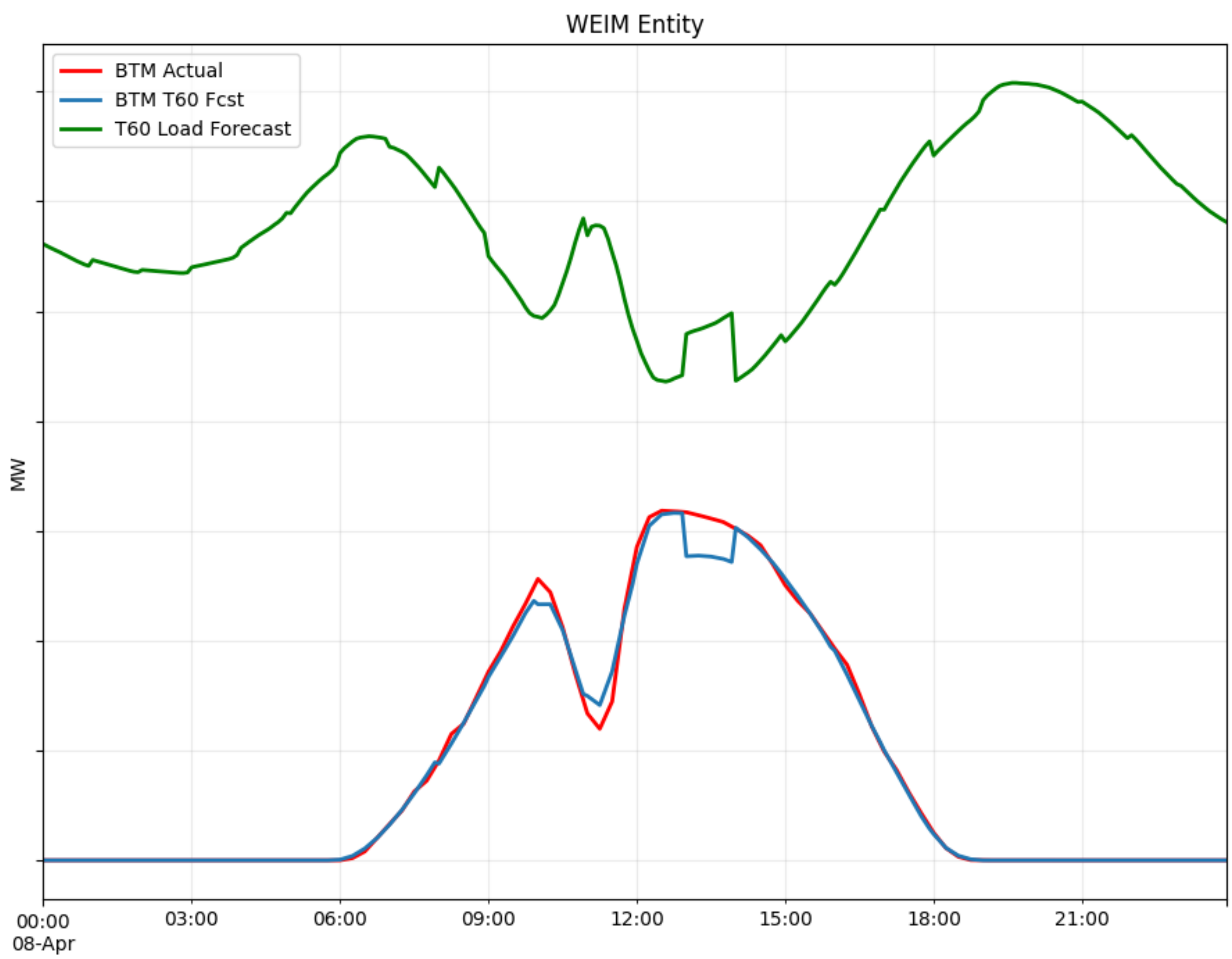


WEIM T-60 BTM Forecast and impacts to T-60 Load Forecast

Real-time models generally captured the timing and magnitude of the eclipse; however, a large T-60 forecast jump occurred during the hours following the eclipse as seen in Figure 16. This was due the model reacting to the T-60 BTM solar forecast containing an anomalously low dip in the hours following the eclipse. Many entities which were forecasted to experience substantial eclipse load impacts were utilizing BTM solar reconstituted models, which enforce a one-to-one relationship between BTM solar forecasts and load. As such, this dip in BTM solar forecast caused load forecasts to move upward by an identical amount during this timeframe. When the BTM solar forecast moved back towards a more regular shape, load forecasts returned to accurate levels. A representative WEIM entity was selected to highlight the relationship between BTM solar forecast and load forecast for the T-60 timeframe in Figure 17 below.

CAISO relies on an external vendor to provide BTM solar forecasts. The CAISO will work with the vendor to further understand the cause of the drop and what can be done to protect load forecast accuracy from anomalous changes in BTM solar forecasts in the future. As the root cause of this BTM solar forecast is investigated, the CAISO will evaluate methods to ensure forecast quality remains intact, potentially including upstream meter validations to limit the likelihood of similar events.

Figure 16: WEIM entity T-60 BTM forecast and impact on T-60 load forecast



Uncertainty Requirements

RUC Adjustments

Residual unit commitment (RUC) adjustments are used to ensure capacity is available to meet load forecasts and deviations between day ahead (DA) and real time (RT) market intervals. While RUC adjustments are ultimately made by operator discretion, the CAISO has trialed different methodologies to inform and guide adjustments. Since July 2023, quantile regression has been used to estimate the 97.5th percentile of uncertainty to inform RUC adjustments. Quantile regression is applied using an imbalance reserve-like approach, meaning regressions are trained on samples of historic load, solar, and wind forecasts, so that current load, solar, and wind forecasts can be used to estimate future uncertainty. Since December 2023, the percentile target became conditions-based with discrete targets at the 50th, 75th, and 97.5th percentile of historical uncertainty [9].

Weather forecasts indicated mostly clear skies in regions of high solar generation. In response to these expected conditions, initial RUC adjustment values were generated at the 50th percentile for the April 8 trade date. The additional input of five minute lowest confidence band values from renewable forecasts were considered, similar to the RUC review process used for the October 2023 eclipse. The upward adjustments to RUC reduced exceedance values, helping to mitigate maximum hourly differences between the hourly day-ahead forecast and the binding fifteen-minute market forecast.

Figure 17 shows RUC net-short values compared to realized uncertainty. In the RUC timeframe, uncertainty refers to the difference that arises between net load forecasts from day-ahead to fifteen minute market (FMM) binding. Interval-level uncertainty, the difference between the day-ahead hourly forecast and FMM fifteen-minute forecast, is shown as gray bars. Red shaded bars are used to capture the maximum uncertainty per hour interval. Percentiles of RUC uncertainty are trained using maximum hourly uncertainty values. Thus, while RUC net-short is a product to manage interval-level uncertainty, it is most properly evaluated against maximum hourly uncertainty values.

Mosaic requirement values are shown by the black stepped line and market-used values are shown in blue. Market-used values are discretionary adjustments that were made with respect to additive, rather than regression-based, uncertainty. Additive uncertainty is akin to a worst case scenario where minimum renewable supply and minimum BTM solar supply (reflected in the demand forecast) are coincident. Because RUC uncertainty percentiles are already trained on maximum hourly interval values, an average of the two methods was used so as not to exacerbate a conservative bias.

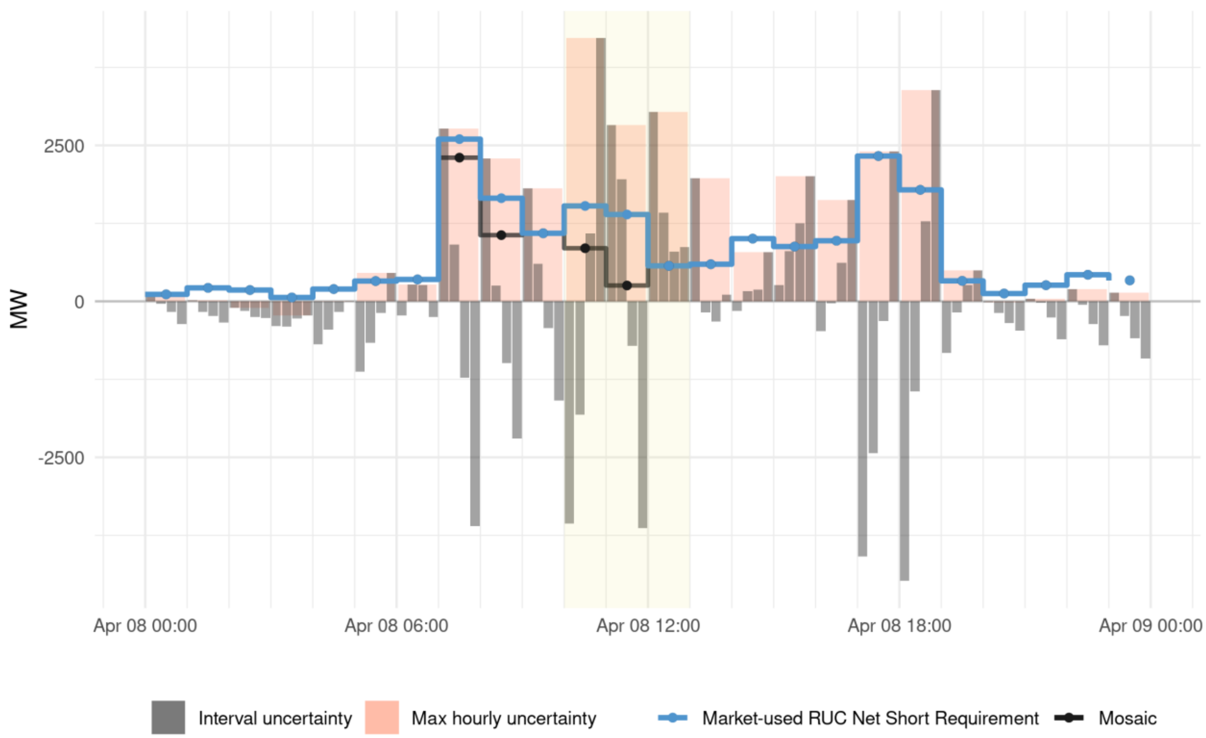
While uncertainty requirements are typically evaluated by observed coverage compared to target coverage, there is not necessarily a target coverage with RUC Net Short in an exceptional event. Adjustments to mosaic requirement values were made in the HE8 to HE12 period to ensure capacity was

[9] An update to specific percentile targets was made in May 2024. More details can be found here.

available rather than meet a particular coverage goal. The eclipse period is shaded in yellow (HE11 to HE13).

On April 8, exceedance was 553 MW compared to 665 MW for the mosaic requirement. For the October 2023 eclipse, the average requirement over the 24-hour period was 3,188 MW in comparison to 805 MW on April 8. Upward adjustments made to RUC helped mitigate uncertainty without being overly conservative.

Figure 17: RUC adjustments and realized uncertainty



Flex Ramp Product Requirements

The flexible ramping product (FRP) captures uncertainty arising between advisory net-demand forecasts and binding net-demand forecasts. More specifically, FRP in FMM covers the difference in net demand forecasts from FMM advisory to RTD binding and FRP in RTD covers the difference in net demand forecasts from RTD binding to RTD advisory.

Figure 18 shows the requirements held in FMM for CAISO and the EIM Area. Materialized uncertainty is shown by the gray bars. Flex ramp up (FRU) and flex ramp down (FRD) requirements are indicated by dark solid stepped lines in either the positive or negative direction, respectively. Figure 19 shows the same for requirements in RTD. The eclipse period, from HE11 to HE13, is shaded in pale yellow. As FMM to RTD is a longer time horizon than RTD advisory to binding, the uncertainty values are expectedly larger in the respective FMM plots compared to RTD plots.

Figure 18: FRP requirement and realized uncertainty for CAISO and EIM Area in FMM

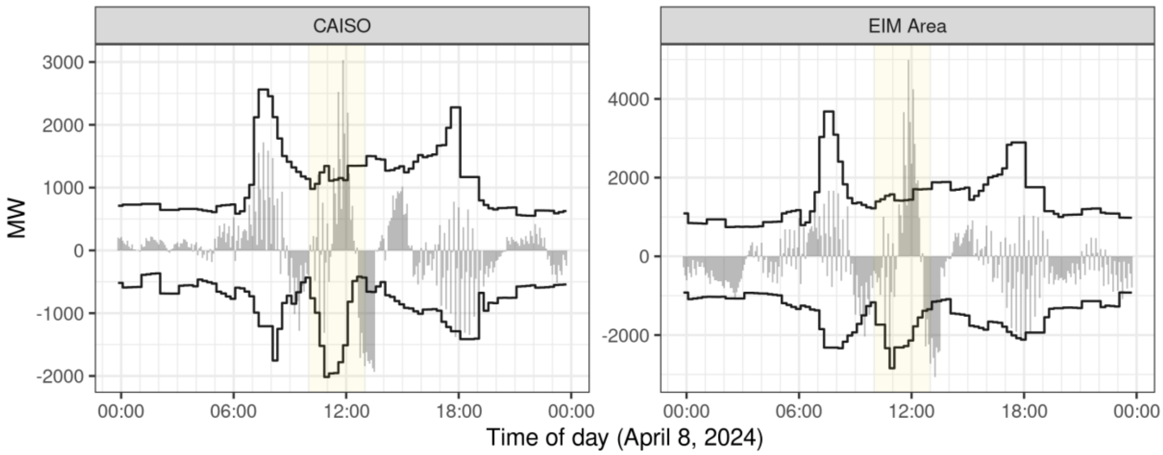


Figure 19: FRP requirement and realized uncertainty for CAISO and EIM Area in RTD

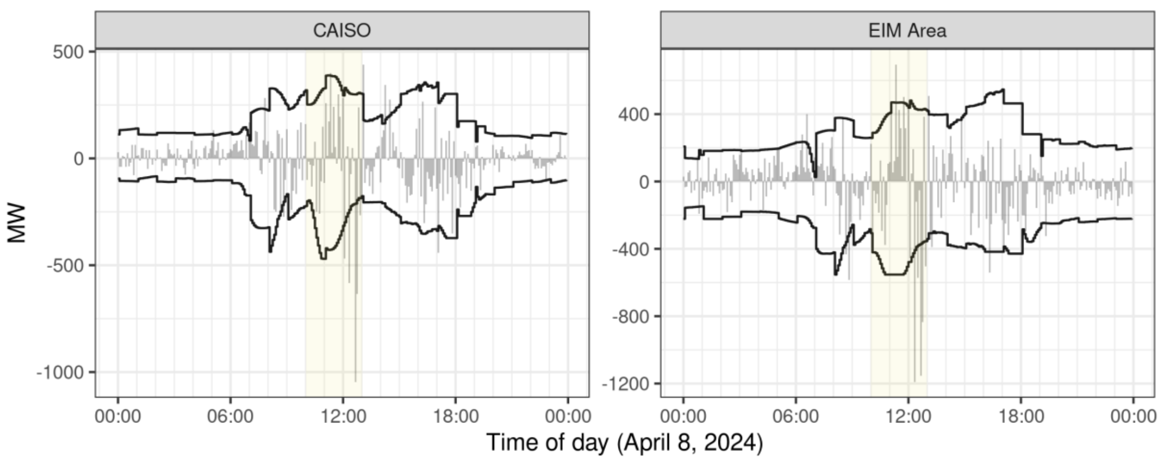


Table 7 gives coverage metrics for CAISO and the EIM Area BAA for the eclipse period and eclipse day, as well as the preceding and subsequent day as points of comparison. Coverage is given directionally, meaning the metric is evaluated separately FRU and FRD. For the positive direction, where the binding forecast is greater than the advisory forecast, FRU coverage is the fraction of intervals where the FRU requirement was greater than or equal to materialized uncertainty whether that uncertainty is positive or negative. FRU and FRD are evaluated at the 97.5th percentile and therefore have a target coverage of 0.975. Note that the meaningfulness of coverage scales with the size of the sample evaluated, as the granularity of percentiles breaks down in small samples (e.g. a 97.5th percentile is impossible to achieve precisely when evaluated over a sample size of 10).

Coverage during the eclipse slipped below target, especially in FRU in FMM in both CAISO and EIM Area. But compared to FRP coverage in the October 2023 eclipse, coverage stayed much nearer to target. No special adjustments were made to FRP in preparation for the eclipse. From a system-level scale, load and renewable forecasts provided enough signal for FRP to estimate uncertainty during the eclipse.

Because the solar eclipse is an exceptional event, the data from the eclipse period has been marked for removal from future uncertainty calculations so that information from this event does not inflate uncertainty estimations during normal conditions.

Table 7: FRP coverage metrics for realized uncertainty in FMM and RTD for April 7 through 9

Coverage		CAISO		EIM Area	
		FMM	RTD	FMM	RTD
FRU	Apr 7	1.00	0.98	1.00	0.98
	Apr 8 (HE11 - HE13)	0.81	0.97	0.76	0.92
	Apr 8	0.98	0.98	0.97	0.97
	Apr 9	0.98	0.95	0.98	0.98
		FMM	RTD	FMM	RTD
FRD	Apr 7	0.96	0.96	0.93	0.98
	Apr 8 (HE11 - HE13)	0.86	0.84	0.89	0.86
	Apr 8	0.93	0.97	0.95	0.95
	Apr 9	0.97	0.97	0.97	0.98

Market Performance

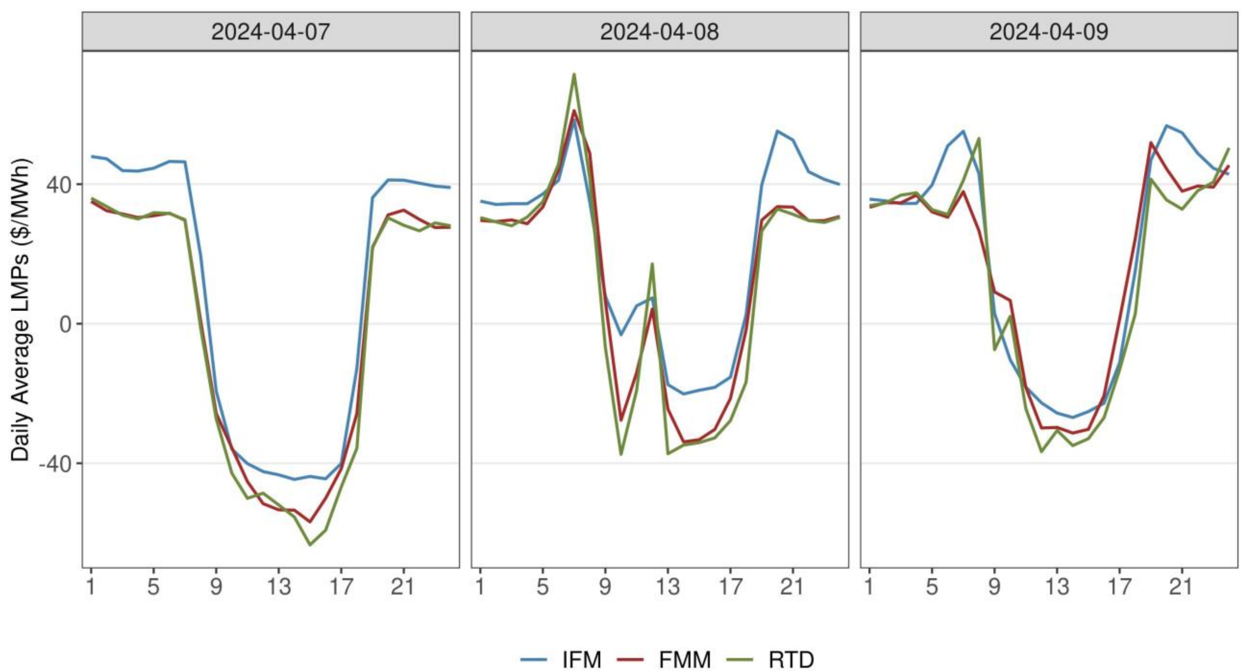
The first opportunity for the market to position the supply fleet for an eclipse is the day-ahead market, where the gross volume of energy is transacted. The day-ahead market is also the opportunity to commit long-start resources that otherwise cannot be committed in the real-time market. The real-time market is the last opportunity for the market to position resources in a shorter horizon. It can also procure additional imports and ancillary services as needed. The real-time dispatch determines optimal five-minute dispatches. Both markets rely on a forecast for solar and wind resources.

During the eclipse, when solar generation decreases, other types of supply need to be ramped up to offset the loss of generation. Conversely, when the solar generation comes back and ramps to full production, other types of supply need to be ramped down to balance the change. Which resources and how much to ramp down and up is determined by the least-cost market solution achieved through optimization, based on the economic bids of available resources and by the physical and market limitations of the resources and the system.

Market prices

Figure 20 shows a comparison of CAISO prices between markets for a three-day period around the eclipse event. [10] In this chart, the specific hours of the eclipse event are hours-ending 10 through 13. During the eclipse, CAISO market prices matched well with day-ahead integrated forward market (IFM) prices trending slightly higher than real time market prices before and after the event. The average real time prices were negative as low as -$38/MWh before and after the event. However, the average real time prices were positive at the peak of the event. The maximum average real time prices during the eclipse event were as high as $17/MWh.

Figure 20: Hourly average DLAP prices by market



On April 8, when solar production was about to ramp up, the increase in supply production combined with low load during the eclipse resulted in negative energy prices. In response, solar generation was reduced through economic curtailments. By hour ending 13, solar output had fully ramped up to its maximum production, and prices normalized afterwards. In addition, Figure 22 shows a similar trend for hourly averages for WEIM Load Aggregation Point (ELAP) prices aggregated by geographical region for the Real Time Dispatch (RTD) market.

Figure 21 and Figure 22 show hourly average ELAP prices for WEIM entities organized by geographic region for a three day period surrounding the eclipse event for fifteen-minute market prices and real-time dispatch prices respectively, with the specific hours of the eclipse event, hours-ending 10 through 13. During the eclipse event, prices for the Southwest region dipped below prices for the California, Pacific

The metrics presented here are based on an average of the Default Load Aggregation Point (DLAP) prices within the CAISO area.

Northwest and Central/Mountain regions, with Pacific Northwest prices remaining the highest. These prices eventually dropped below $0/MWh during the subsequent hours.

Figure 21: Hourly average WEIM ELAP prices by geographical region, FMM

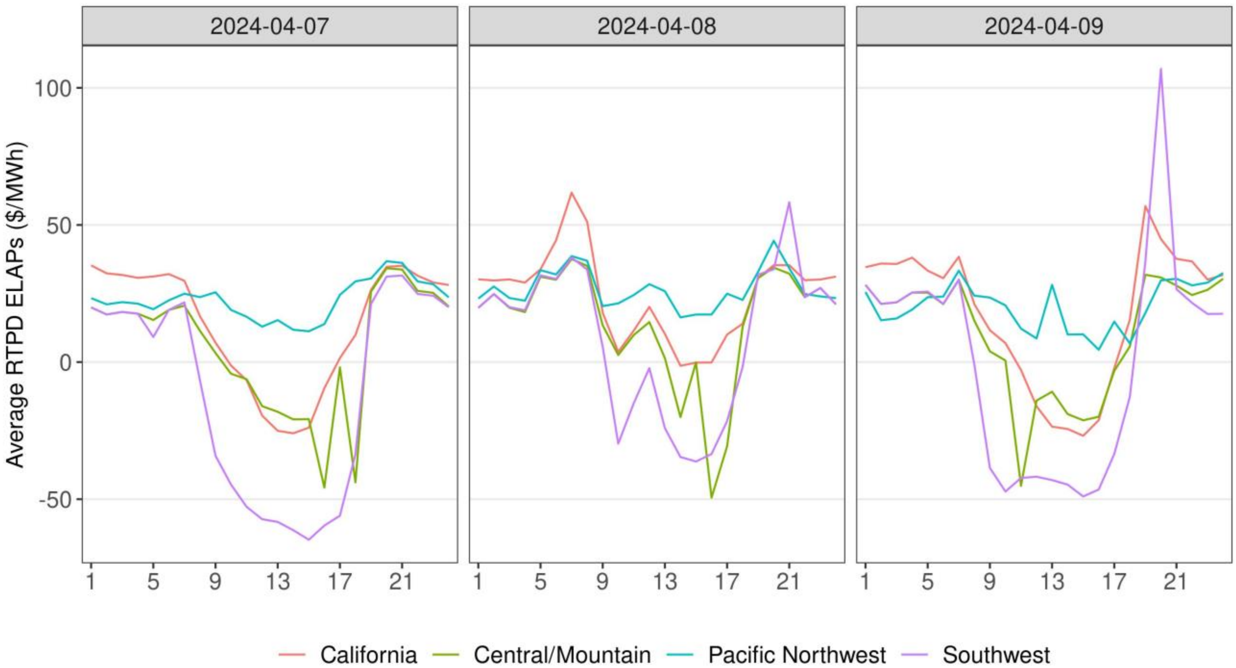
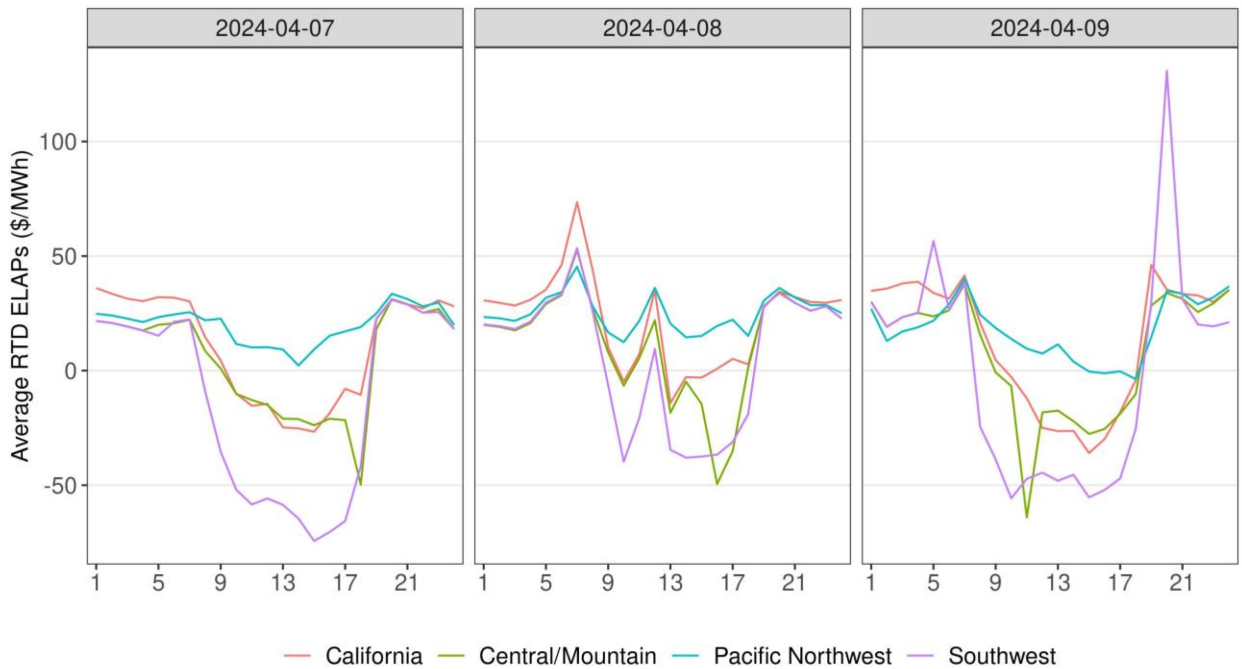


Figure 22: Hourly average WEIM ELAP prices by geographical region, RTD



Market costs

The CAISO's markets are settled based on awards and prices that have specific settlement charge codes; these include day-ahead and real-time energy and ancillary services charge codes. The majority of overall costs accrue on day-ahead settlements for CAISO.

Figure 23 shows the daily total settlement costs for the CAISO balancing area between March 1 and April 15, a longer time period leading up to and following the eclipse event. These cost figures do not include WEIM settlements. As demand or prices rise, the overall settlements are expected to increase. The dotted red line provides a reference of an average daily cost per MWh. The total daily cost over the period was $14.5 million on average, representing an average daily price of $30.6/MWh. The maximum daily cost of $22.2 million occurred on March 6, almost a month prior to the eclipse event. The daily cost on the day of the eclipse, April 8, was $16.1 million.

Figure 23: CAISO daily total and average market costs

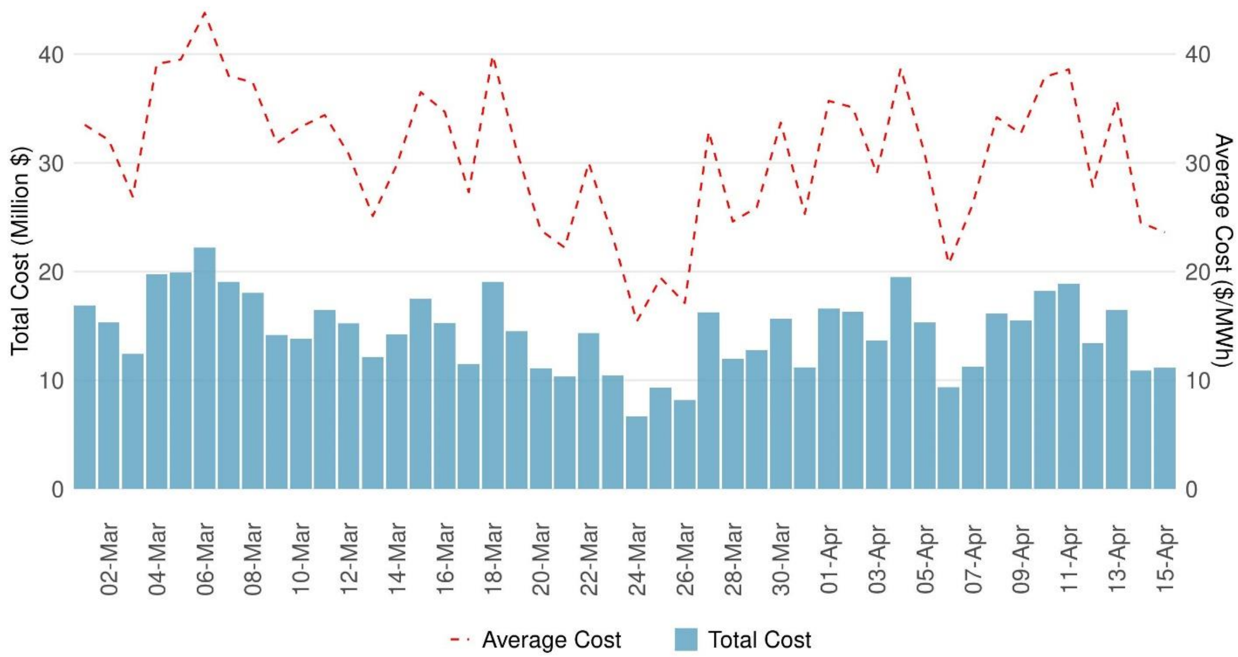


Figure 24 and Figure 25 show the real time offset costs for the CAISO and WEIM regions. On the day of the eclipse event, April 8, the CAISO-area real time congestion and real-time energy offsets were about $1.2 million and $0.96 million respectively. For the WEIM area, the real time congestion and real-time energy offsets were about $0.43 million and -$0.08 million, respectively.

Figure 24: Real-time energy and congestion offsets for CAISO

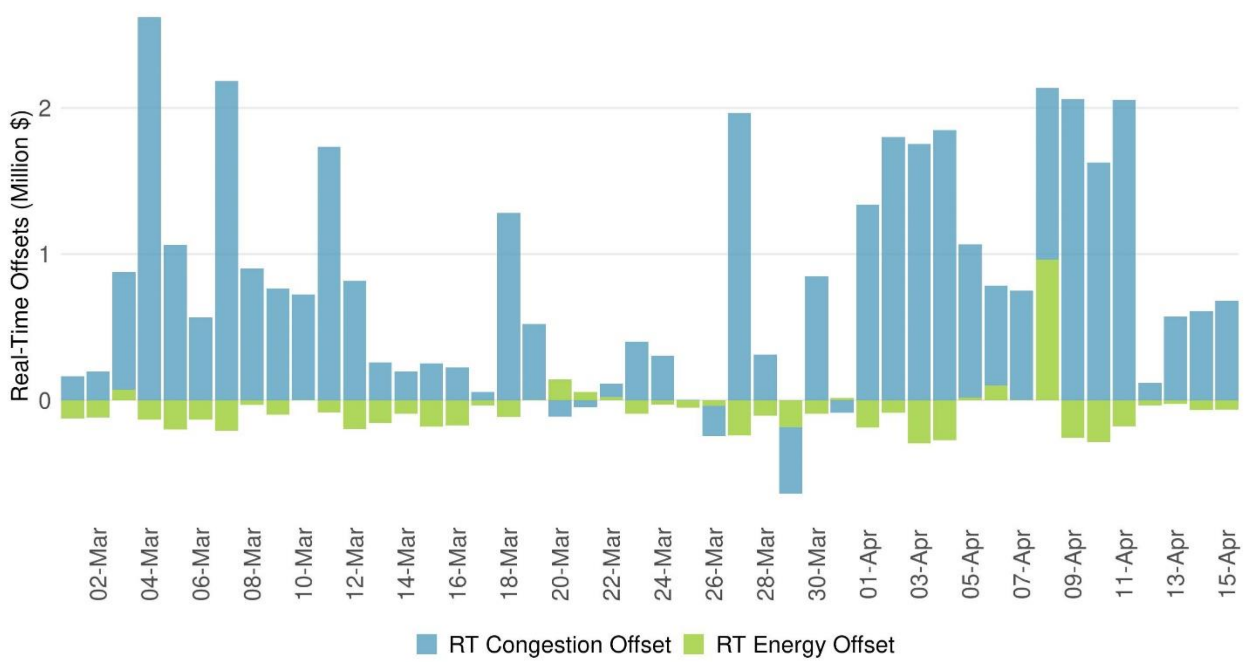
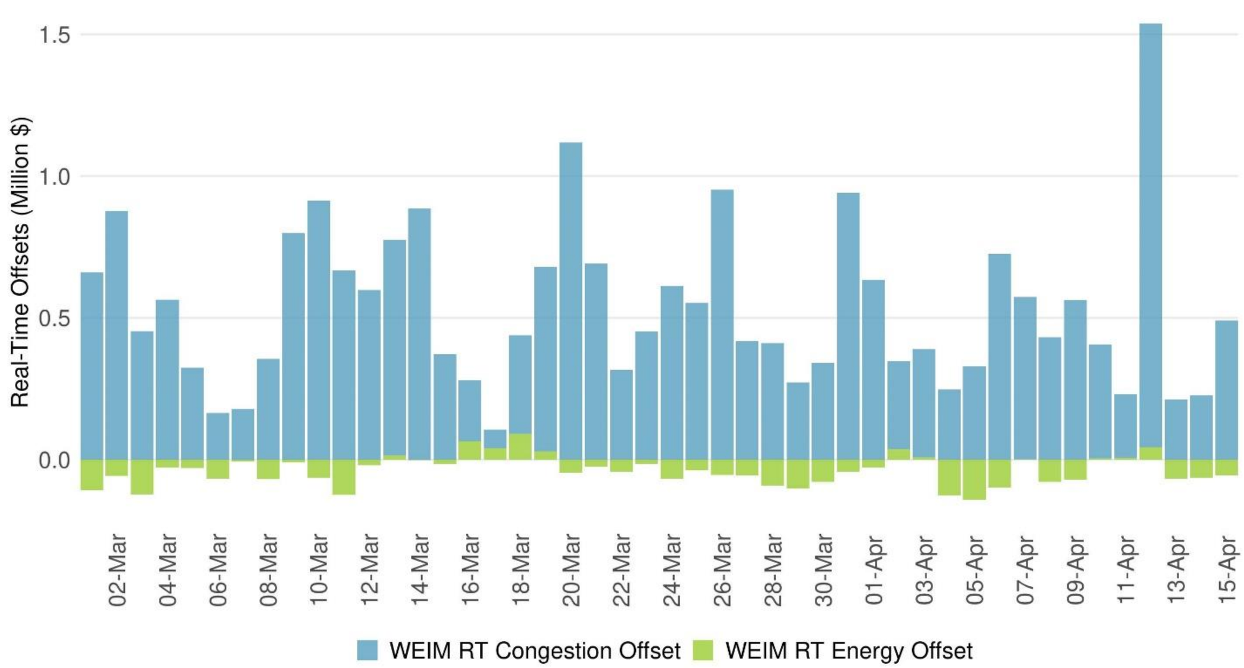


Figure 25: Real-time energy and congestion offsets for WEIM



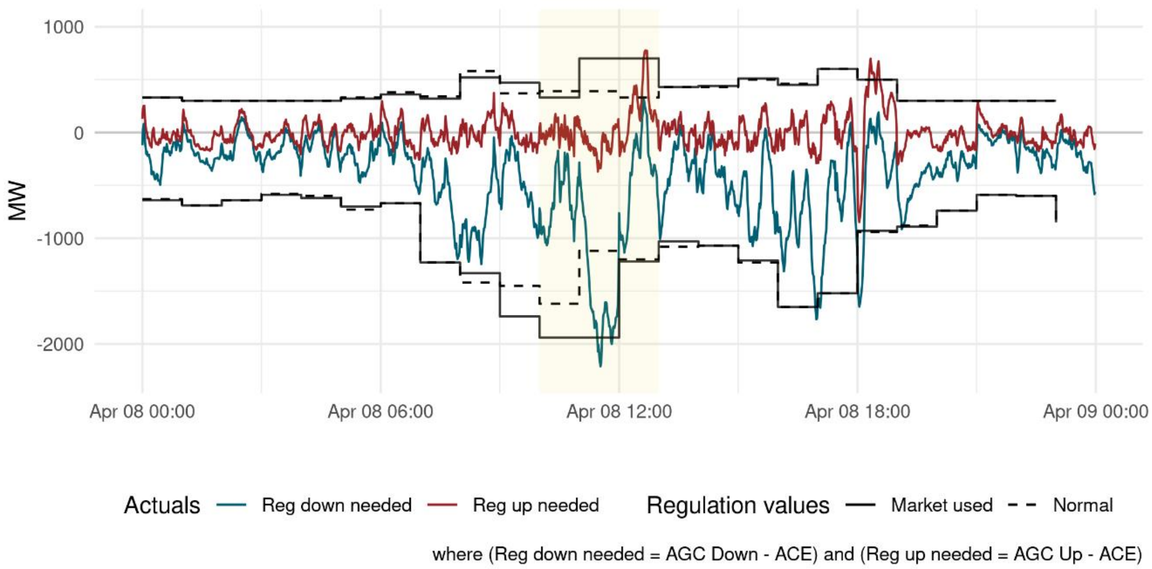
Regulation

Figure 26[11] shows hourly regulation values indicated by the stepped line plot for normal conditions in an April day (dashed line) versus those used by the market (solid line). The eclipse period is shaded in yellow. The Area Control Error (ACE)* variability high and ACE* variability low are used to assess regulation needed. For those familiar with ACE, these values are shown inverted for ease of comparison, since ACE* high would be met with regulation down and vice versa. Regulation values were adjusted in the HE11 to HE13 period[12].

Adjustments during the eclipse period helped procure needed capacity for frequency regulation and were well-timed. Review of the October 2023 eclipse showed greater need for regulation down moving into the eclipse then greater need for regulation up moving out of the eclipse. That pattern was observed again in the April 2024 eclipse. For October 2023, the largest regulation-up value was 2,000 MW in HE11 and the largest regulation-down value was 1,875 MW in HE9. In contrast, those values were 700 MW in HE12 and HE13 and 1,940 MW in HE11 and HE12 for regulation up and down, respectively. The adjusted regulation-up requirements were reduced in response to lessons learned from the October 2023 eclipse.

[11] The actuals of total regulation needed (regulation dispatched – ACE) are shown at 1-minute granularity by the red and blue lines, respectively, in Figure 26.
[12] The normal April values are generated in late March, whereas the reference regulation values, from which the eclipse regulation values adjusted, were generated about a week and a half before the eclipse in order to incorporate more recent data. Though it appears some regulation values were reduced from normal, this did not occur; all suggested adjustments led to increases in regulation, but used a slightly different reference point from the values listed as normal in Figure 26.

Figure 26: Comparison of regulation procured to regulation needed



During the eclipse, regulation requirements were adjusted to better position the system to absorb the rapid changes in the generation mix. The regulation up requirement was increased by as much as 700 MW in HE12 and HE13. Figure 27 presents the CAISO regulation-up requirement and prices in the day-ahead market (IFM). The regulation-up requirement during the day was noticeably higher on April 8, compared to April 7 and 9. Regulation-up requirements peaked in hours ending 12 and 13. With the higher regulation requirements, the day ahead market saw a slight increase in prices for regulation up to $5/MWh for the two hours.

Figure 27: Regulation up (Ru) requirement and prices in day-ahead (IFM)

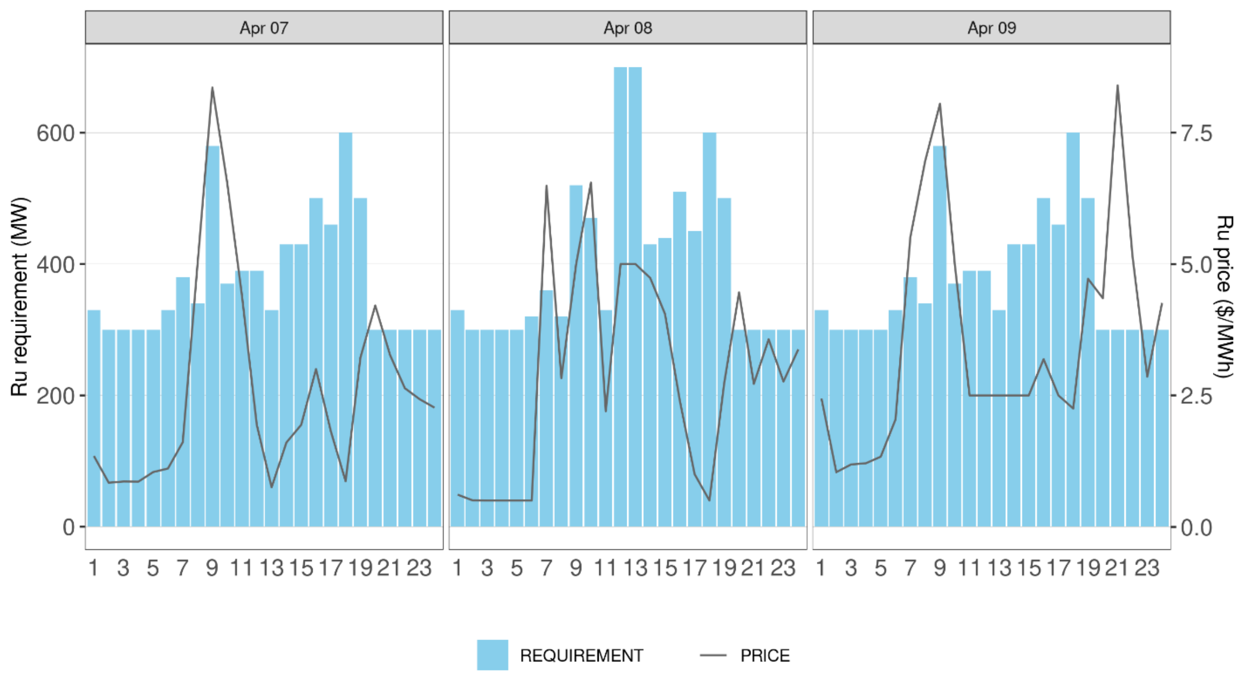
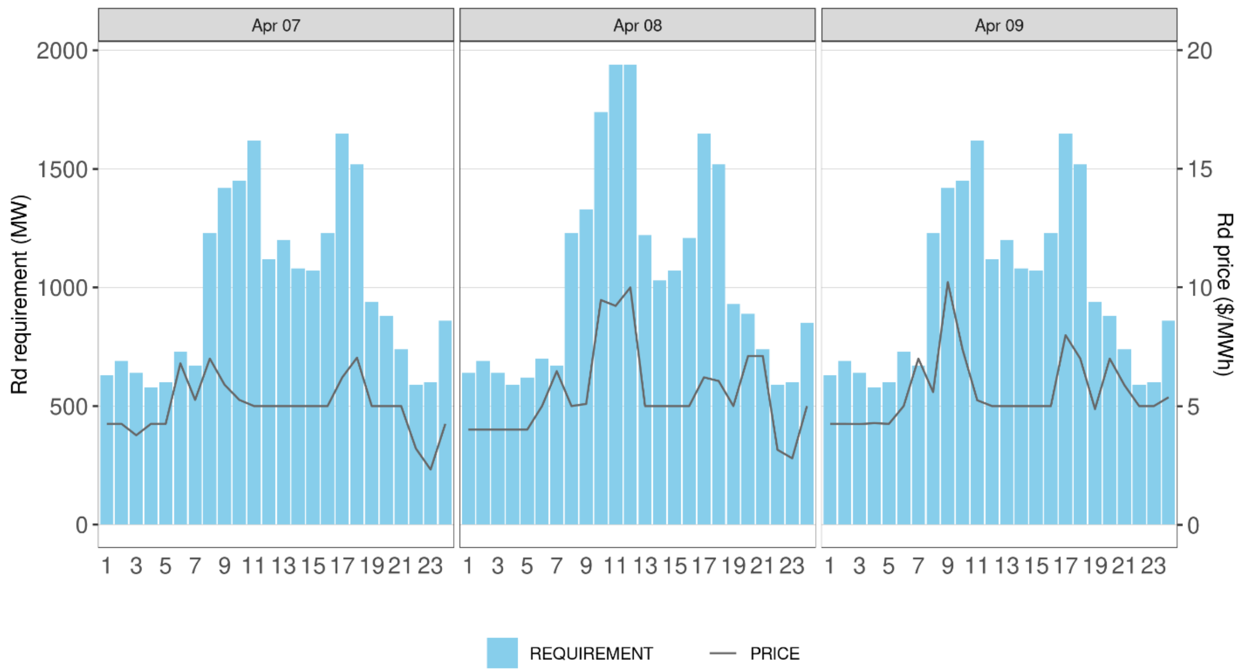


Figure 28 presents the CAISO regulation down requirement and prices in the day-ahead market. Regulation down requirements were increased to 1940 MW for hours ending 11 and 12, and prices from the same hours were up to $10/MWh, higher than a typical day.

Figure 28: Regulation down (Rd) requirement and prices in the day-ahead (IFM)



The objective is to procure all the regulation requirements through the day-ahead market. The real-time market can re-procure or procure incremental regulation. Figure 29 and Figure 30 show the regulation up and down requirements and prices in the FMM. On April 8, the regulation up and down prices remained low for both regulation up and down.

Figure 29: Regulation up (Ru) requirement and prices in real-time market (FMM)

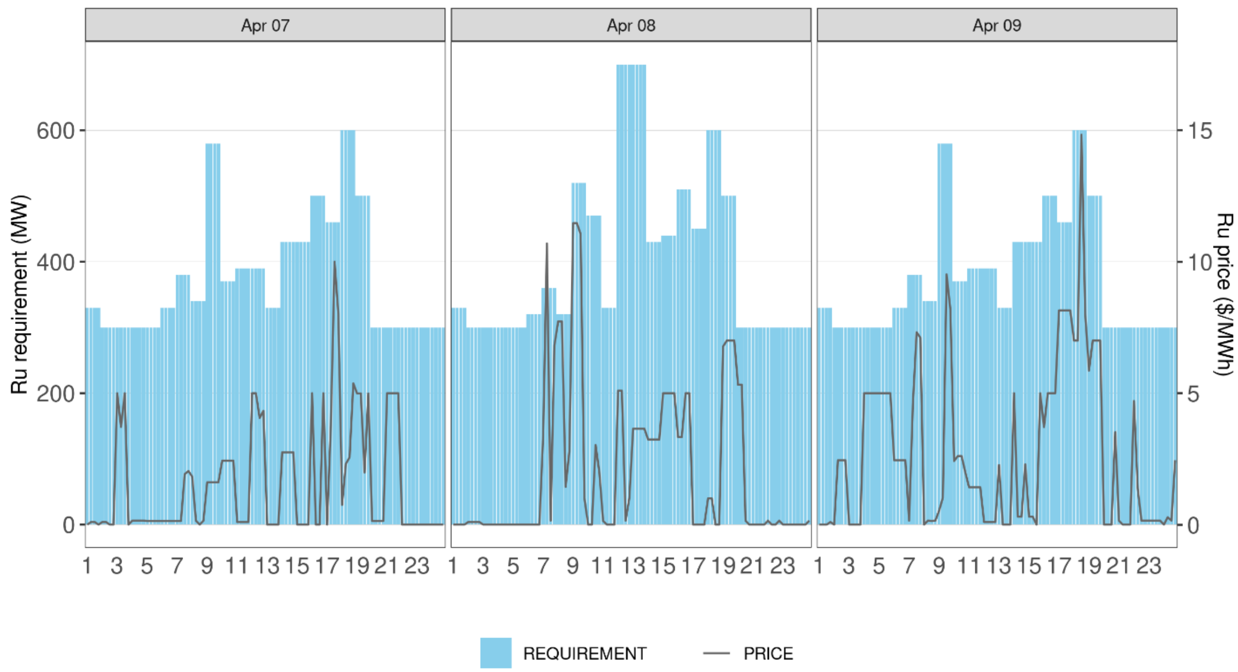


Figure 30: Regulation down (Rd) requirement and prices in real-time market (FMM)

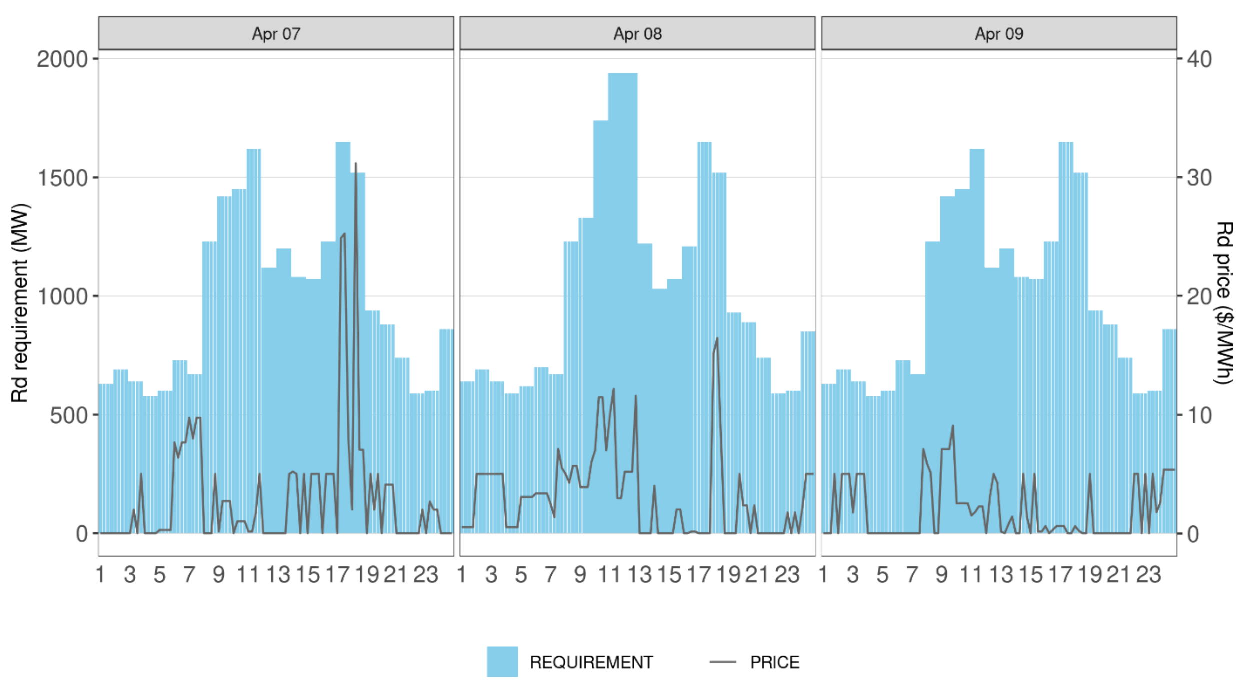


Figure 31 and Figure 32 below show the cost to procure regulation up and down in both the day-ahead and real-time markets for a longer time period leading up to and following the eclipse event. Both day-ahead and real-time regulation costs for the hours of the April 8 eclipse event were consistent with costs on April 7 and 9, with no significant price spikes around the time of the event.

Figure 31: Day-ahead regulation up and down costs

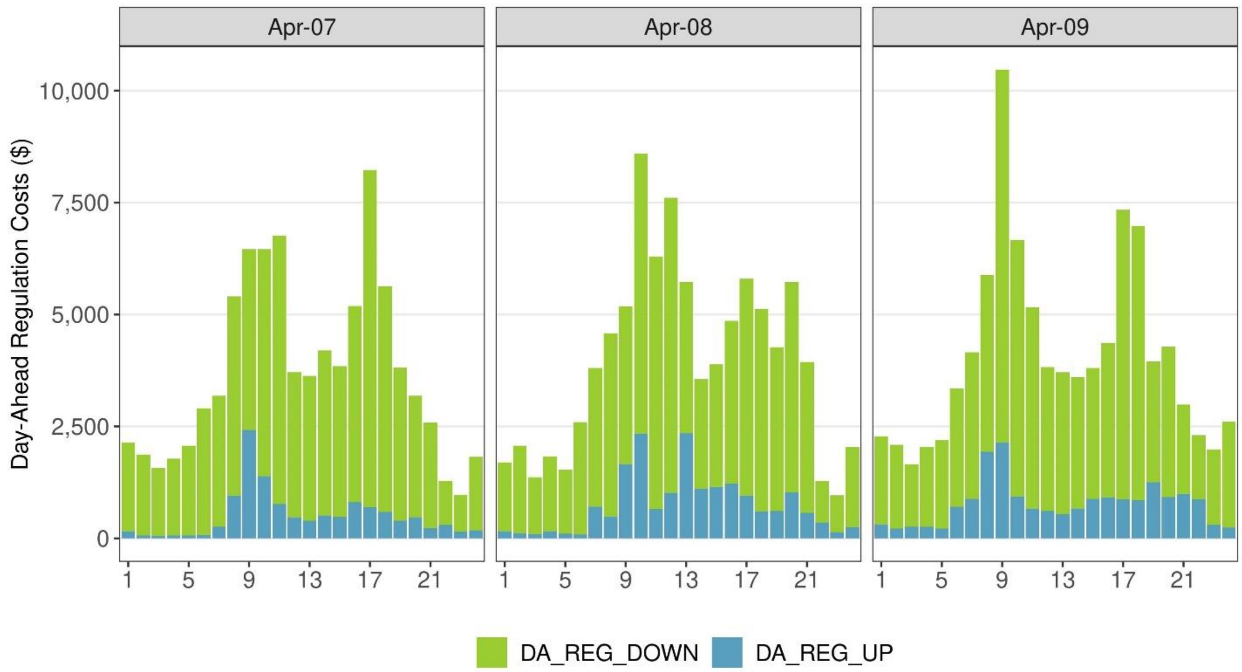
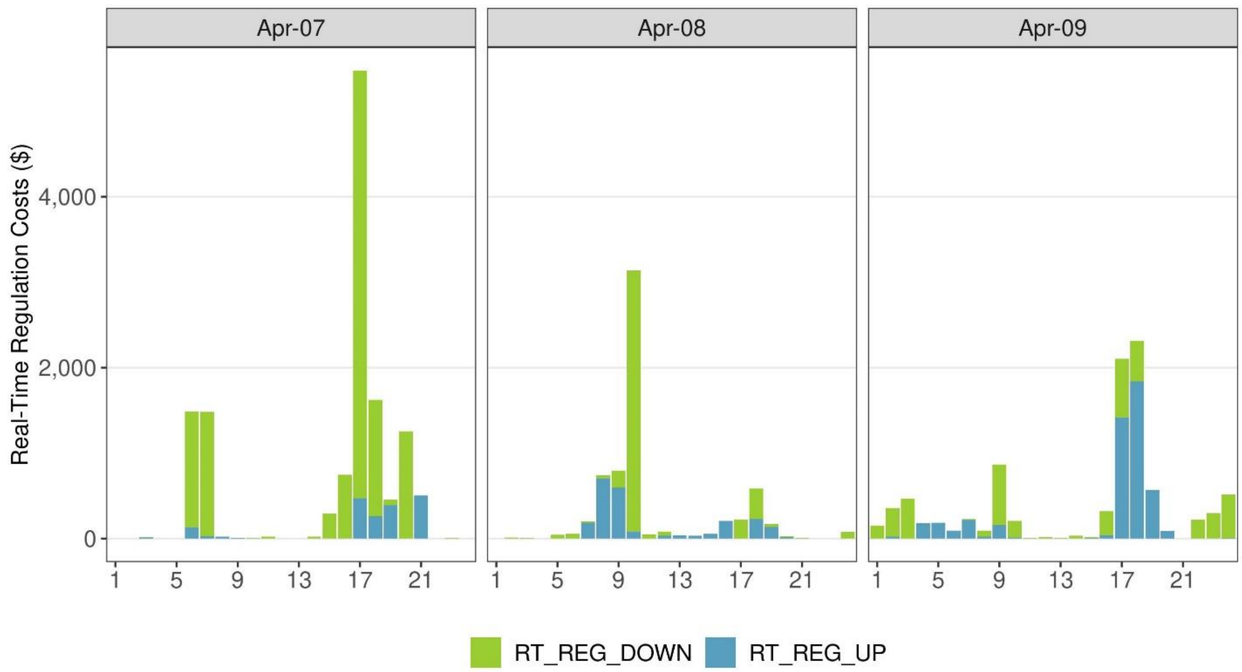


Figure 32: Real-time regulation up and down costs

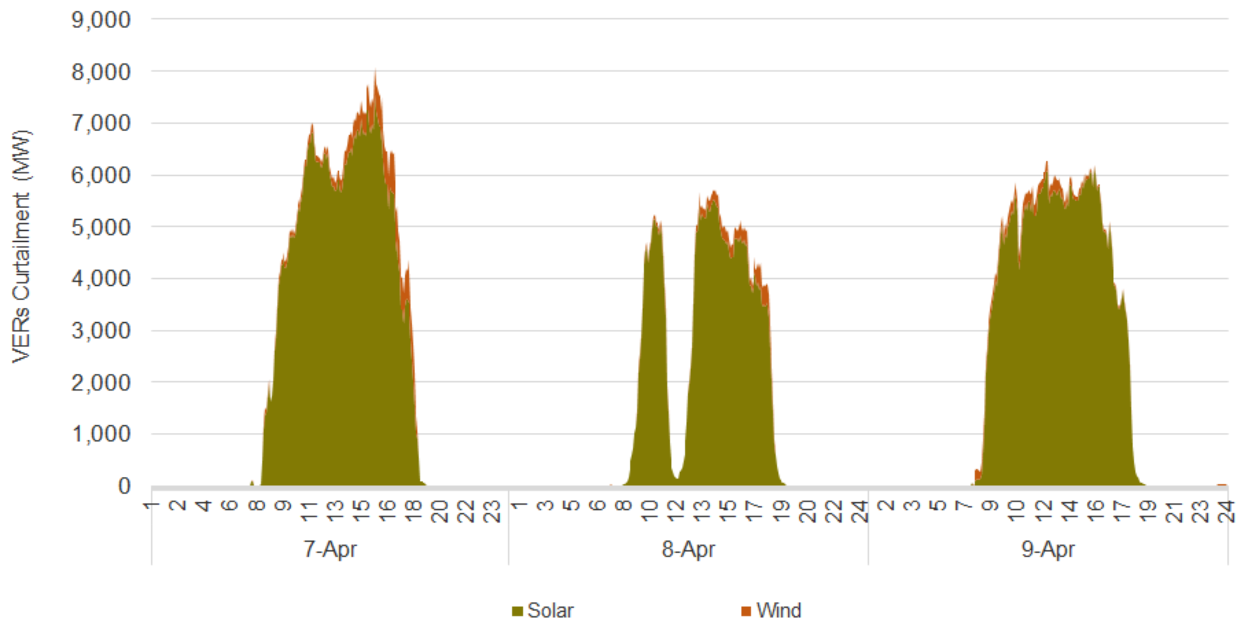


Curtailments

Under certain conditions, such as oversupply and congestion, the market solution may determine the need to curtail renewable dispatches below either the bid-in maximum output or forecasted value. The market will first reduce solar output based on the available economic bids, which reflect the willingness to reduce output. After all the economic bids are exhausted, the market will reduce the output of those resources that have self-scheduled their output to the level of their forecast. Sometimes the market will also reduce the output of those resources through exceptional dispatch. Curtailments are measured as the difference between a resource's dispatch upper limit and its RTD schedule when the resource has an economic bid.

Figure 33 below shows the VERs curtailment from April 7-9. The curtailment on these three days was mainly due to excess solar generation. On April 8, solar curtailment dropped sharply in HE 11 and HE 12 during the eclipse when solar production was low. In HE 13, solar curtailment started to rise when the solar eclipse waned, and the solar production ramped up at a faster rate than normal.

Figure 33: Hourly VERs curtailment compared over three days



Resource performance

The dispatch operating target (DOT) values are the instructions the CAISO market issues to resources. In order for the system to realize an optimal outcome, it is of paramount importance that resources follow the instructions. Requiring that all resources, including VERs such as wind and solar, follow the DOTs allows the market to optimize its overall solution and reduce the burden on regulation that may have occurred if VER resources deviated from the DOTs.

Figure 34 shows the solar DOT (RTD schedules) and actual generation (metered generation). During the solar eclipse event, the solar DOT and actual generation both declined initially and then fell further in HE 12, when the eclipse reached its peak. In hour ending 12, solar production decreased by about 1300 MW compared to hour ending 10. In hour ending 13, solar production started to recover, but it was still lower than the same period on April 9. Solar production declined gradually after HE 13 due to cloud cover. During the solar eclipse, actual generation was lower than the DOTs, especially in hour ending 11 and 12.

Figure 35 shows the profile for solar actual production and actual load compared to the profile of solar curtailments. During the intervals in hour ending 13, when solar generation was ramping back to full production and load was reaching a low point, the market reduced other types of supply. This led to a short period of oversupply in the market, which required solar curtailments of up to 5,600 MW in hour ending 13. Figure 36 shows the profile of solar and wind production compared to the load and net load for April 8. The solar and wind production does not include dynamic generation.

Figure 34: DOT vs actual production for solar production

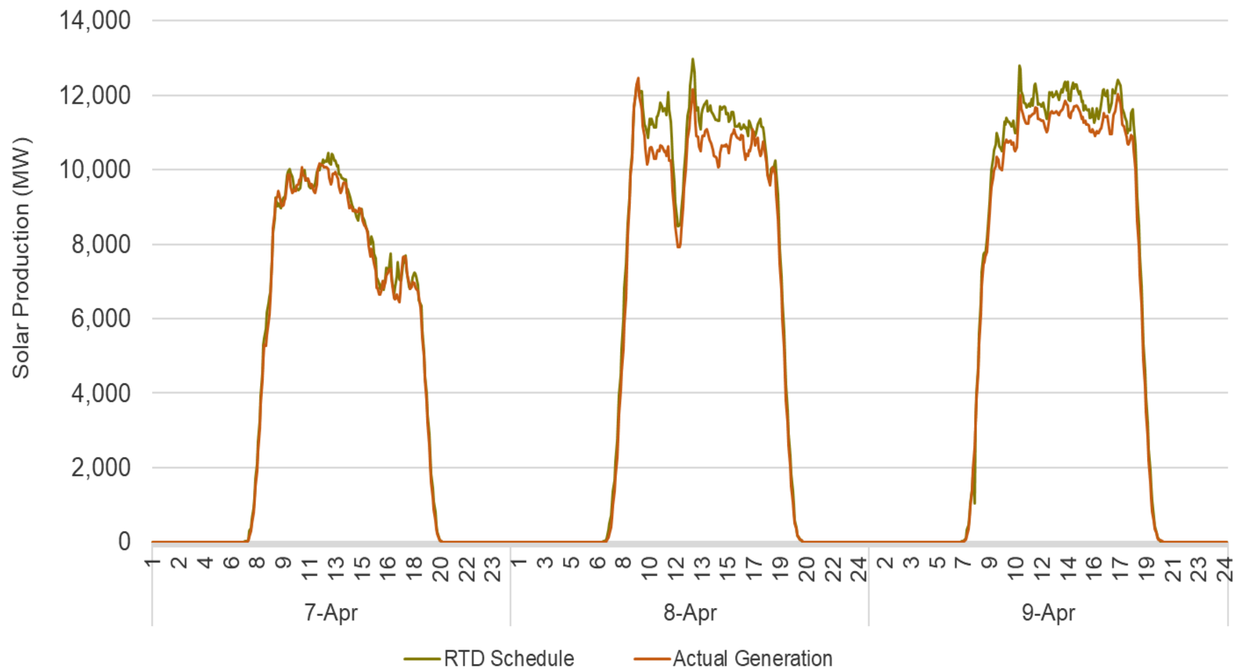


Figure 35: Solar production with curtailments vs load for April 8

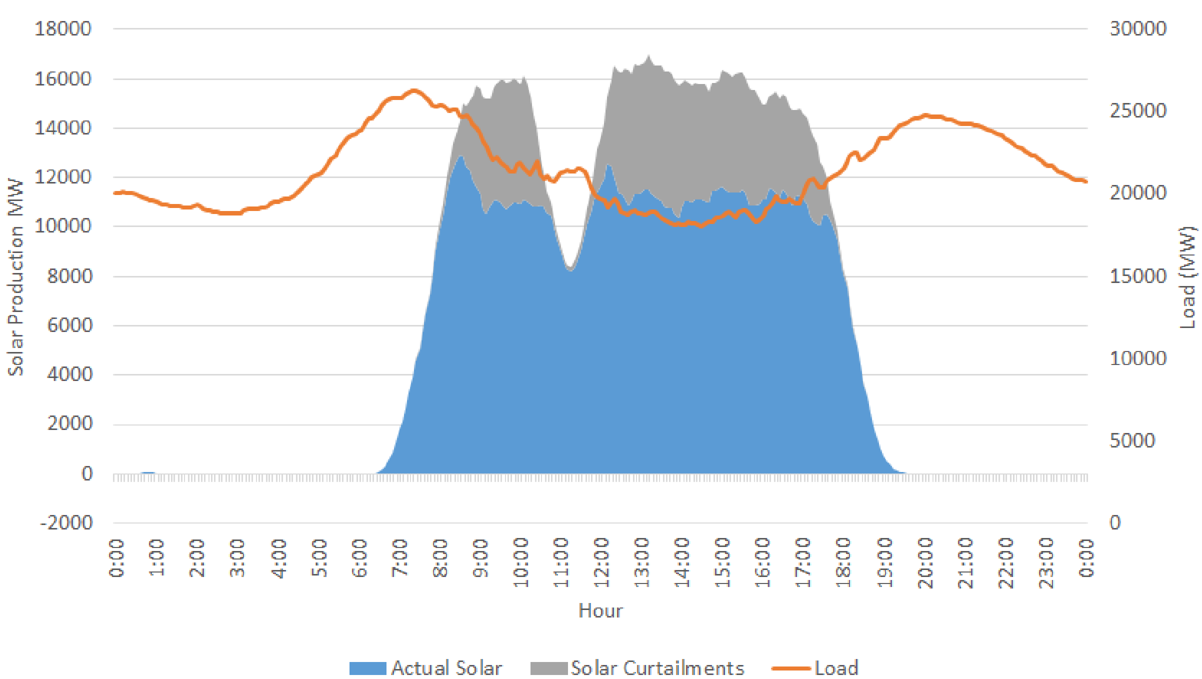
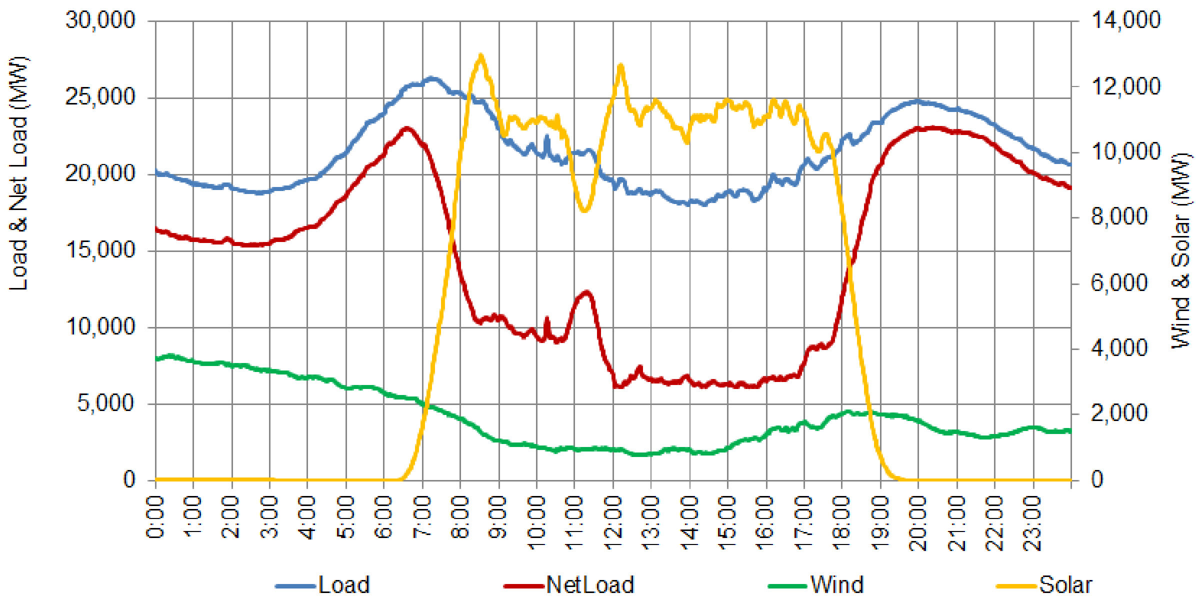


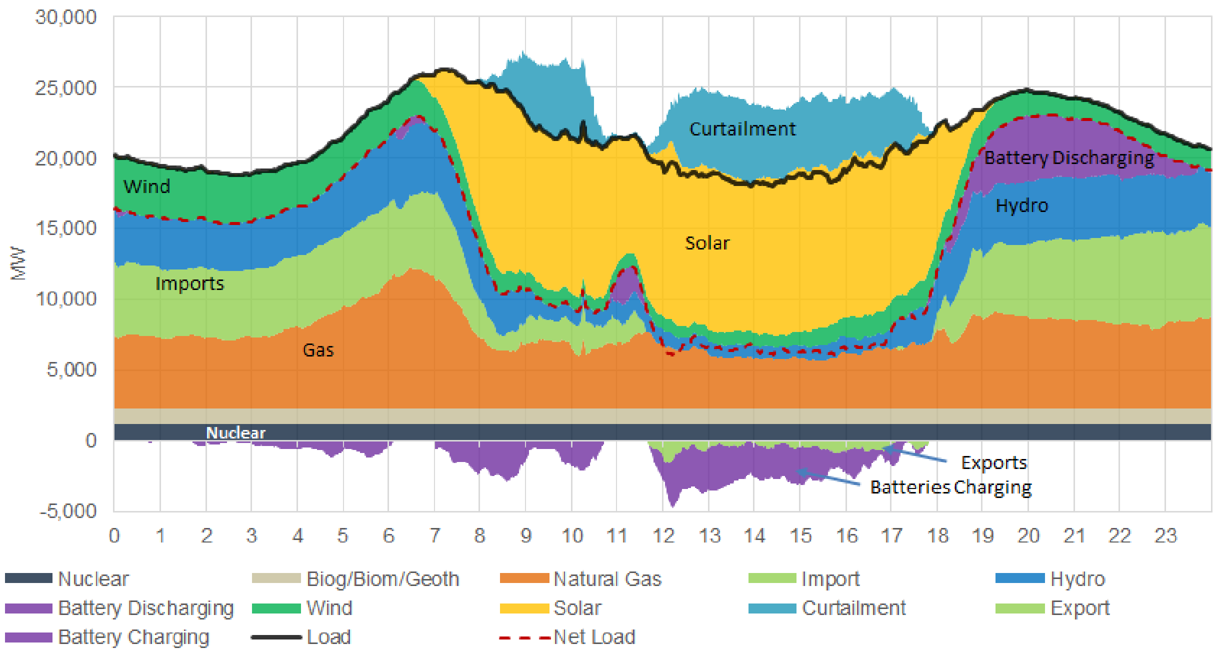
Figure 36: Comparison of Load, Net Load, Solar and Wind production for April 8



Generation Mix

Figure 37 shows the CAISO's resource breakdown on April 8, including the rapid changes in solar production during the eclipse hours that were compensated for by other generation types filling in. In hour ending 11 and 12, energy storage, gas and imports increased to replace the loss of solar production. In hour ending 13, as solar production began to increase, storage, gas and imports were dispatched downwards to compensate for the increased solar production. In the same time, there was a slight increase in exports. Batteries charged during the morning hours so that they were ready to discharge during the eclipse. Once the solar eclipse waned in hour ending 13, batteries returned to a charging state so that they would be ready to discharge during the evening peak.

Figure 37: Generation Mix of the energy produced



Storage Performance

On April 8, there were 111 storage resources actively participating in the CAISO markets. Most storage resources participated in both the energy and ancillary service markets. This section presents the performance of the energy storage resources on April 8.

Figure 38 presents the aggregate state of charge (SOC) of the storage resources in the day-ahead and real-time markets. It presents a comparison of the aggregate state of charge spanning three consecutive days. The overall state of charge pattern on April 8 was similar to the typical patterns observed for storage resources, with state of charge peaking in the afternoon hours between hours ending 16 to 19. State of charge was generally higher in the RTD compared to the day-ahead market. During the eclipse hours ending 11 to 13, a brief dip occurred in the trend, indicating the depletion of state of charge to compensate for the change in solar generation. The comparison of state of charge across the three days shows the market was aligning the storage resources in a way to be able to charge significantly during the morning so that they had enough state of charge to dispatch efficiently once solar generation was ramping down.

Figure 38: State of charge, DA vs. RTD

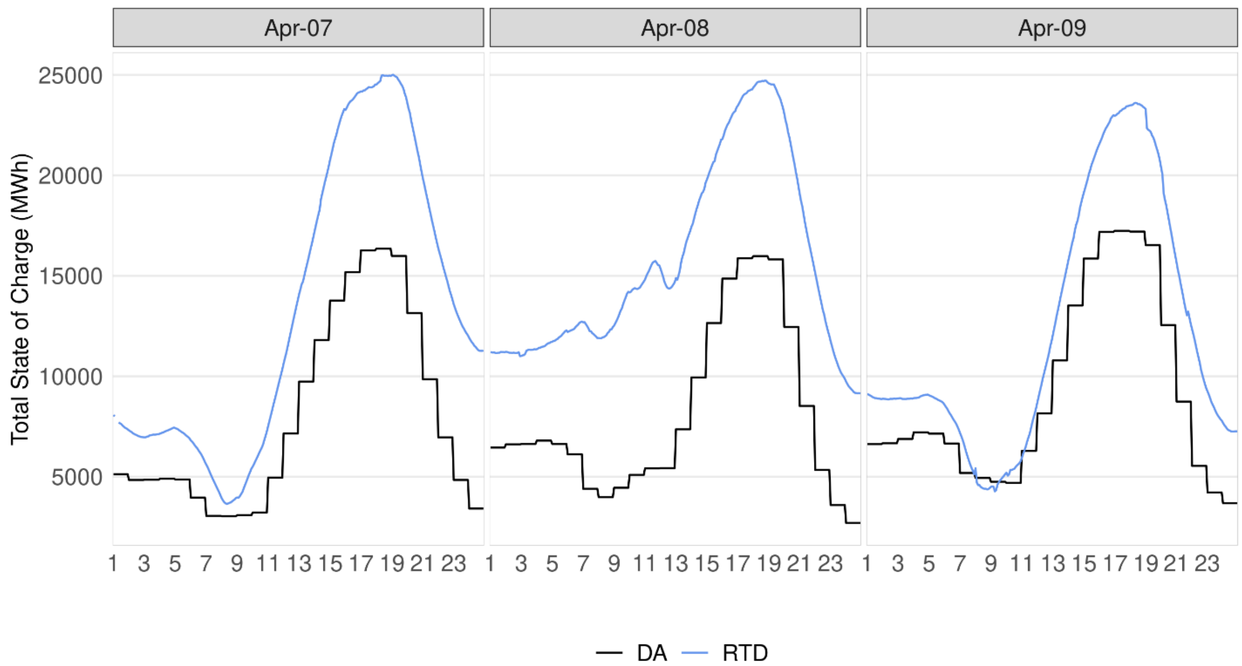


Figure 39 shows the bid-in capacity for storage resources in the day-ahead market. The negative area represents charging while the positive area represents discharging. The bid-in capacity is organized by $/MWh price ranges. There were consistent patterns of batteries bidding into the market over the observed period. Batteries were bidding to charge at negative prices most of the time. In the late morning to early afternoon hours before the evening peak, some batteries were willing to charge at positive prices. Batteries were almost always willing to discharge at higher prices.

Figure 39: Bid-in capacity for batteries in the day-ahead market (IFM)

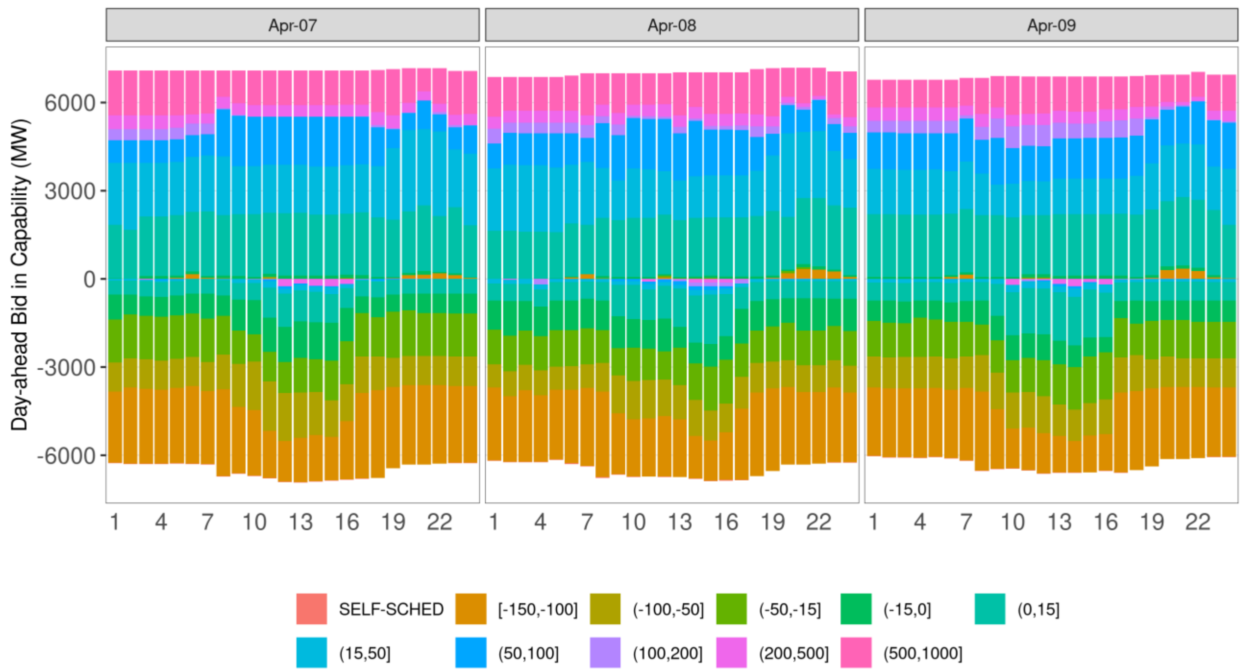


Figure 40 shows the bid-in capacity for the real-time market. Most batteries were willing to charge at prices $15/MWh or below, and to discharge at prices above $50/MWh. On April 8, in hours ending 11-13, battery storage resources bid to charge and discharge at slightly lower price ranges compared to April 7 and 9.

Figure 40: Bid-in capacity for batteries in the real-time market (FMM)

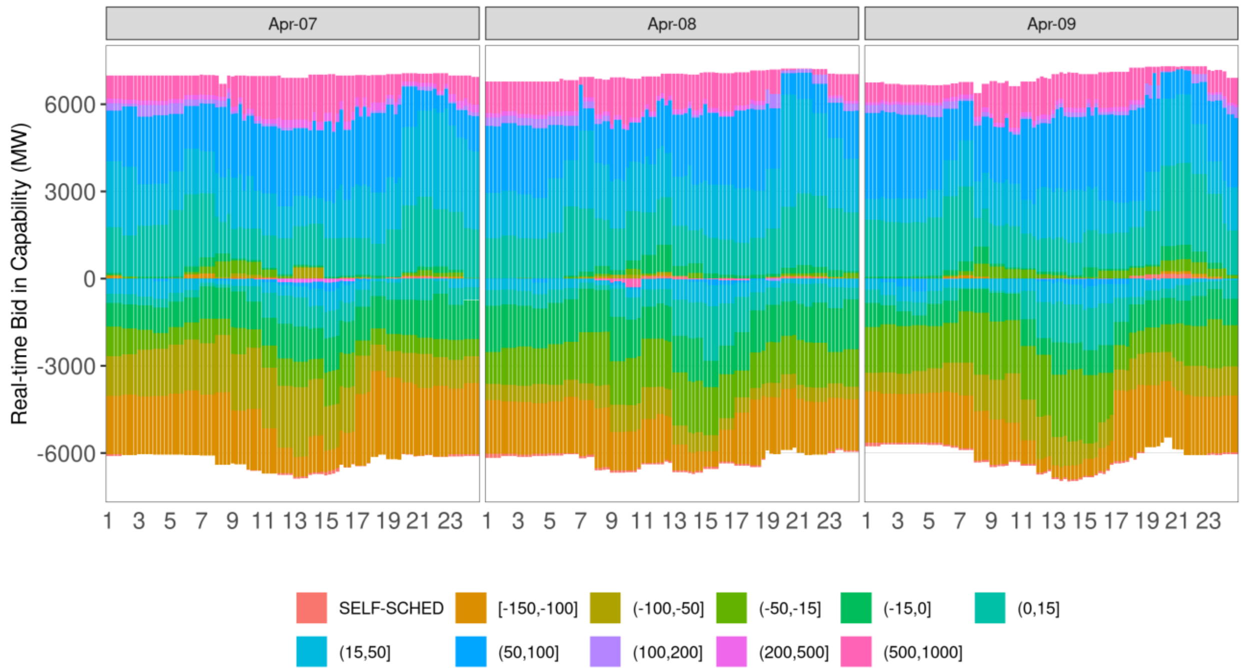


Figure 41 compares the aggregated energy schedules for storage resources in the DA and RTM. In both markets, the storage resources typically charged during peak solar hours of the day and discharged in the evening peak net-load hours. The figure presents the comparison of the total energy schedule spanning three consecutive days. On April 8, storage was charged in advance to prepare for the event, discharged up to 3428 MW in RTD during the eclipse hours, and subsequently recharged for later use.

Figure 41: Energy Schedules, DAM vs. RTM

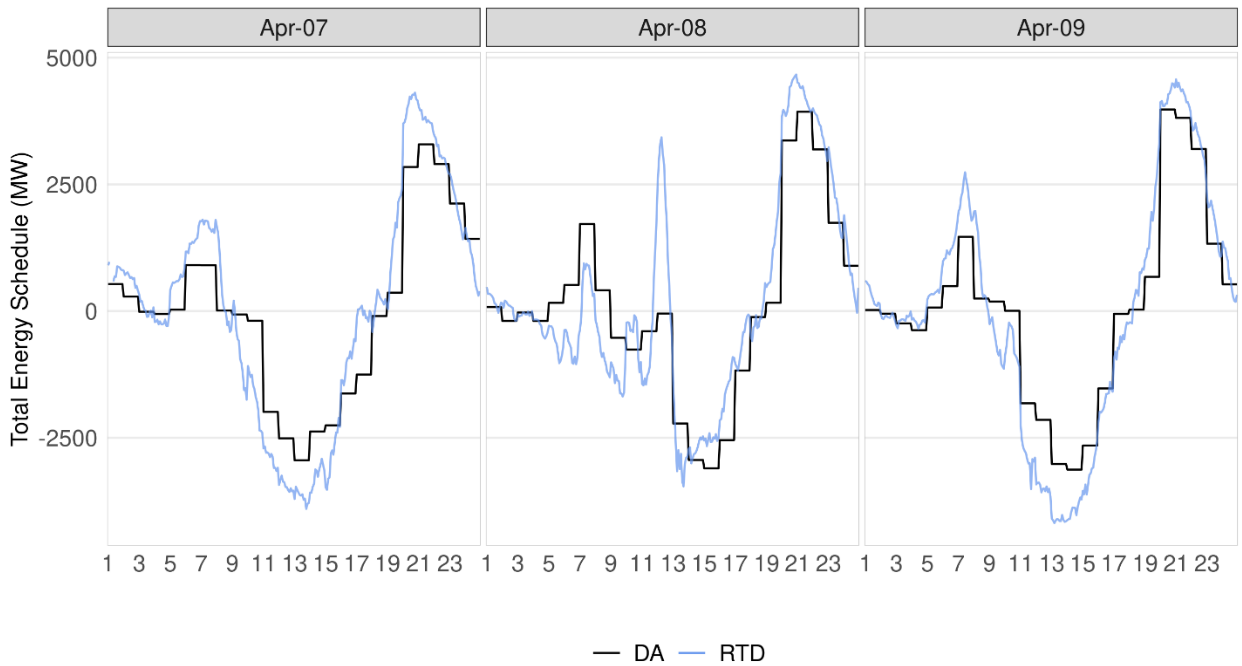


Figure 42 illustrates the energy awards for storage with prices in the RTD. The storage resources mostly charged through the morning peak hours, in anticipation of the eclipse event. During the eclipse hours, the storage resources discharged as prices reached the local peak, and charged in the midday hours after the event, when the real-time prices had turned negative.

Figure 42: RTD energy awards for storage resources and RTD SMEC

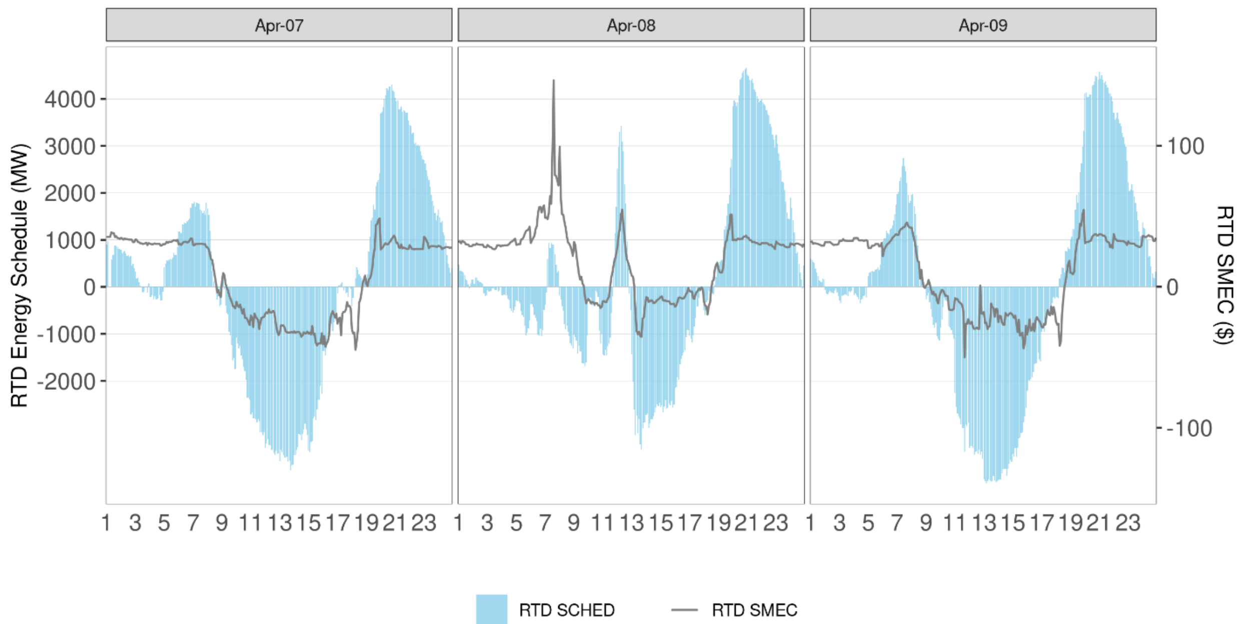
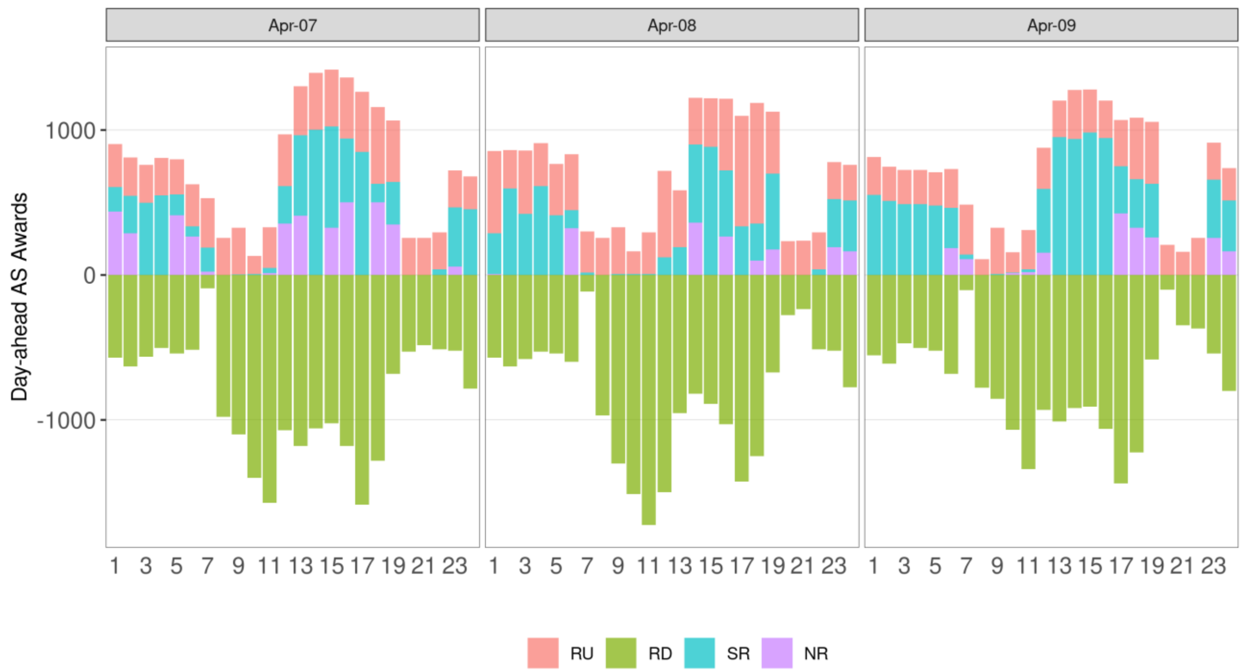


Figure 43 shows the hourly ancillary services (AS) awards for storage resources in the day-ahead market. Both upward AS (RU, SR, NR) and downward AS (RD) peaked during the eclipse hours. Storage resources contributed with a significant share of total regulation.

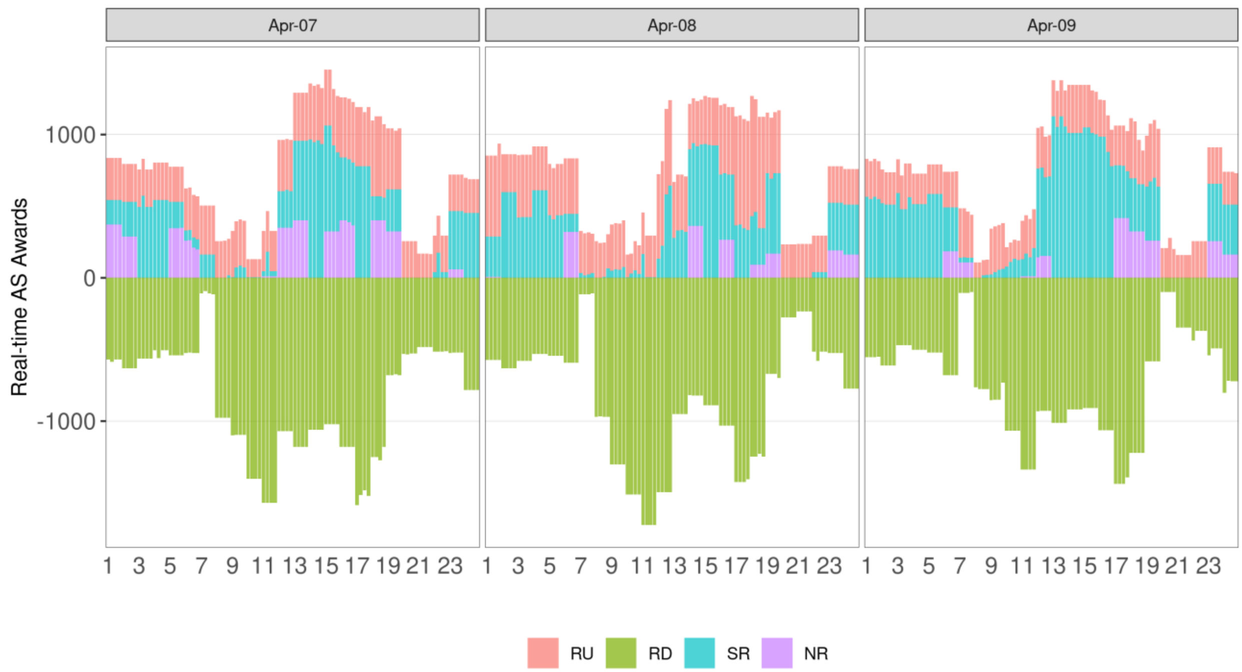
During the solar eclipse, the storage resources received the highest upward AS awards in hour ending 12, including 598 MW of regulation up and 643 MW of spinning reserves in the FMM. The downward AS awards for storage resource reached a peak of 1,724 MW in hour ending 11 for both the FMM and IFM markets.

Figure 43: Day-ahead (IFM) AS awards



The majority of the AS requirements are procured through the day-ahead market. Given the changing conditions to the real-time operation, the RTM is the last opportunity to re-procure or procure incremental AS. Figure 44 presents the total ancillary service awards in real-time for storage resources, showing a similar pattern to the day-ahead market.

Figure 44: Real Time (FMM) AS awards



The CAISO market provides two different participation models for mixed-fuel resources: a co-located model and a hybrid model. Figure 45 shows the aggregated energy schedules for hybrid resources in the DA and RTM, spanning three consecutive days. The schedules follow the solar ramp in the morning and have some small variations during midday, when the battery components charge using inexpensive solar power. During the eclipse hours, the hybrid resources reached a local peak of 1,129 MW in hour ending 12.

Figure 45: Hybrid Energy Schedule

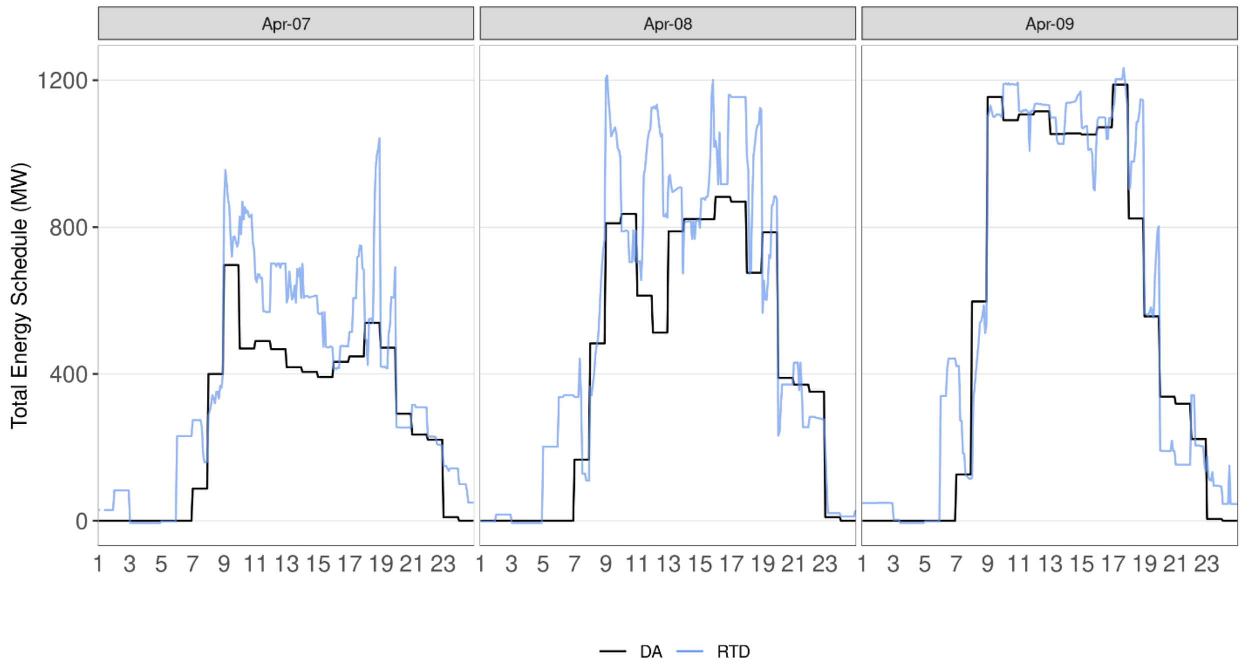
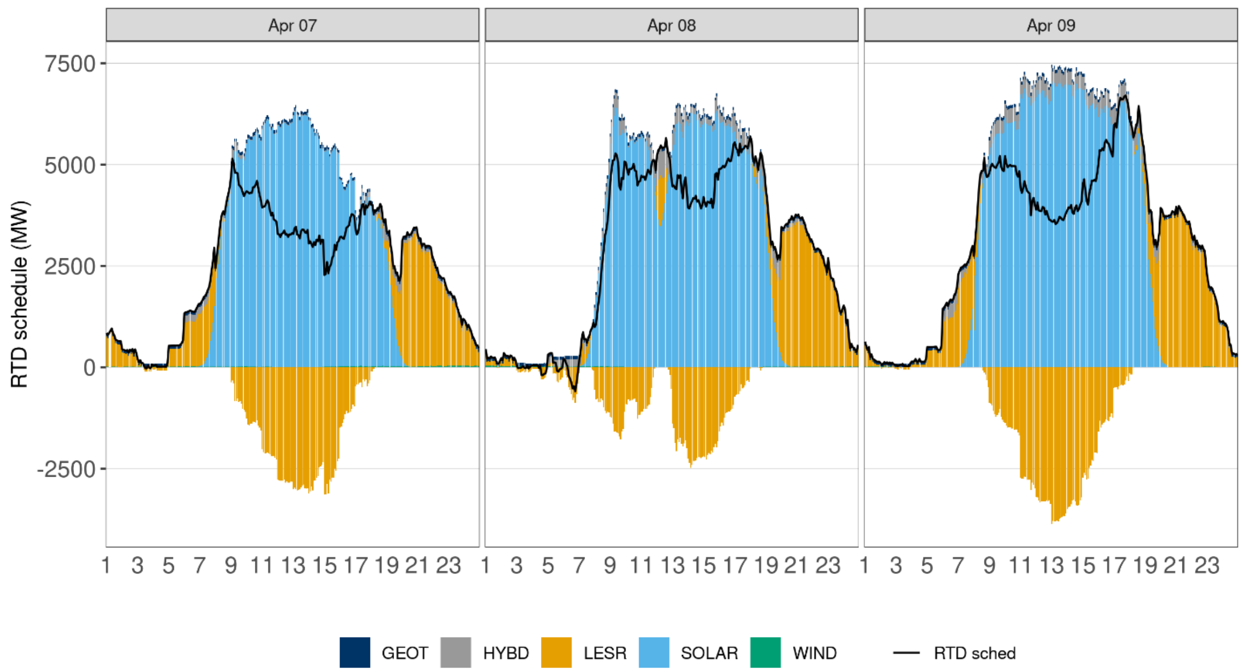


Figure 46 shows the RTD total energy schedule of co-located resources and schedule breakdown by resource types. Co-located resources may be a combination of different generation technologies behind a single point of interconnection. The major resource types using co-located models are solar and battery storage (LESR), with smaller volumes of geothermal, hybrid, and wind. On April 8, the performance of co-located resource followed the typical pattern. Co-located resources reached a combined local maximum of 5,474 MW in hour ending 12.

Figure 46: Co-located Energy Schedule



Flexible Ramping Product

A redesign of the CAISO's Flexible Ramping Product (FRP) was launched in February 2023. This section provides an overview of the FRP performance during the solar eclipse, which is relevant in situations when the system operates under tight supply conditions.

Figure 47 shows the FRU (Flexible Ramp Up) requirements versus procurements in the passing group in FMM. BAAs passing the capacity and flexible ramping tests collectively benefit from a passing group to procure FRP, leveraging BAA diversity. Those failing must individually fulfill their own requirements. The market will procure uncertainty requirements at that group level while respecting transmission and WEIM transfer constraints. On April 8, FRU requirements followed the typical pattern. During the solar eclipse hours, all WEIM BAAs passed the tests in the upward direction. The FRU group requirements were fulfilled for all intervals over the three days.

Figure 47: FRU passing group requirement vs. procurement

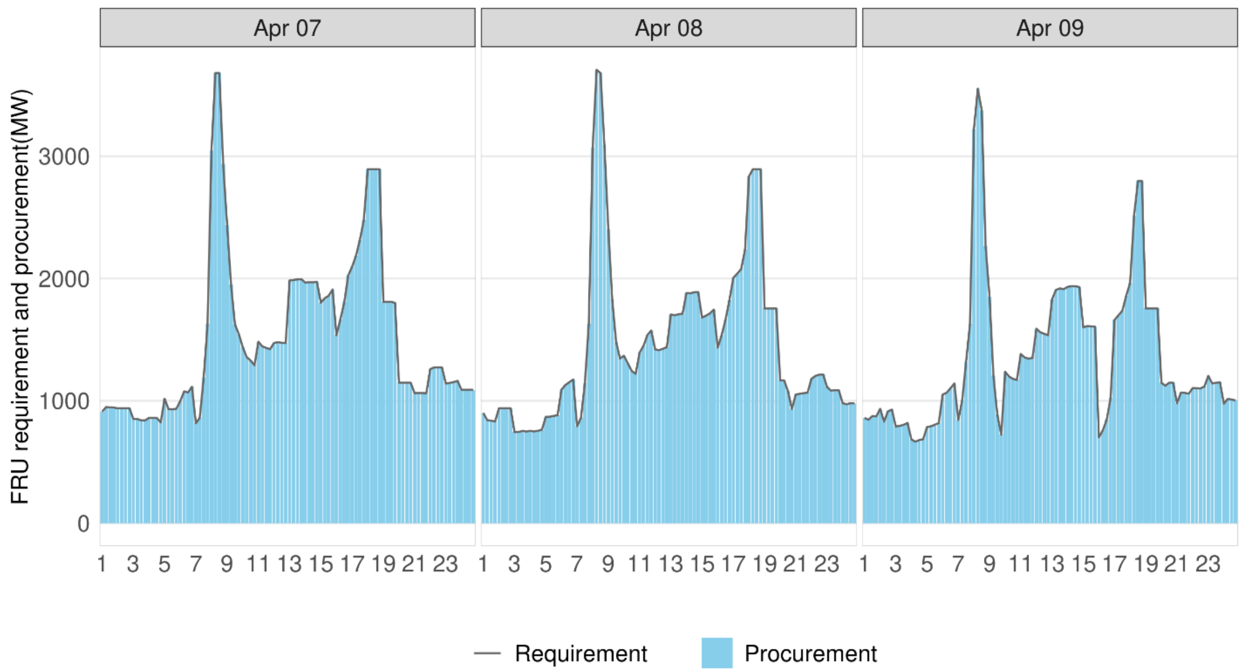


Figure 48 and Figure 49 presents the FRU procurement across the WEIM-wide area in the passing group. By region, FRU procurement primarily sourced from Pacific Northwest, California, and Southwest throughout the day. By resource type, generic non-generating resources (GNRC), hydro, solar, and battery storage (LESR) resources were the main resource types getting FRU awards.

Figure 48: FRU procurement by region

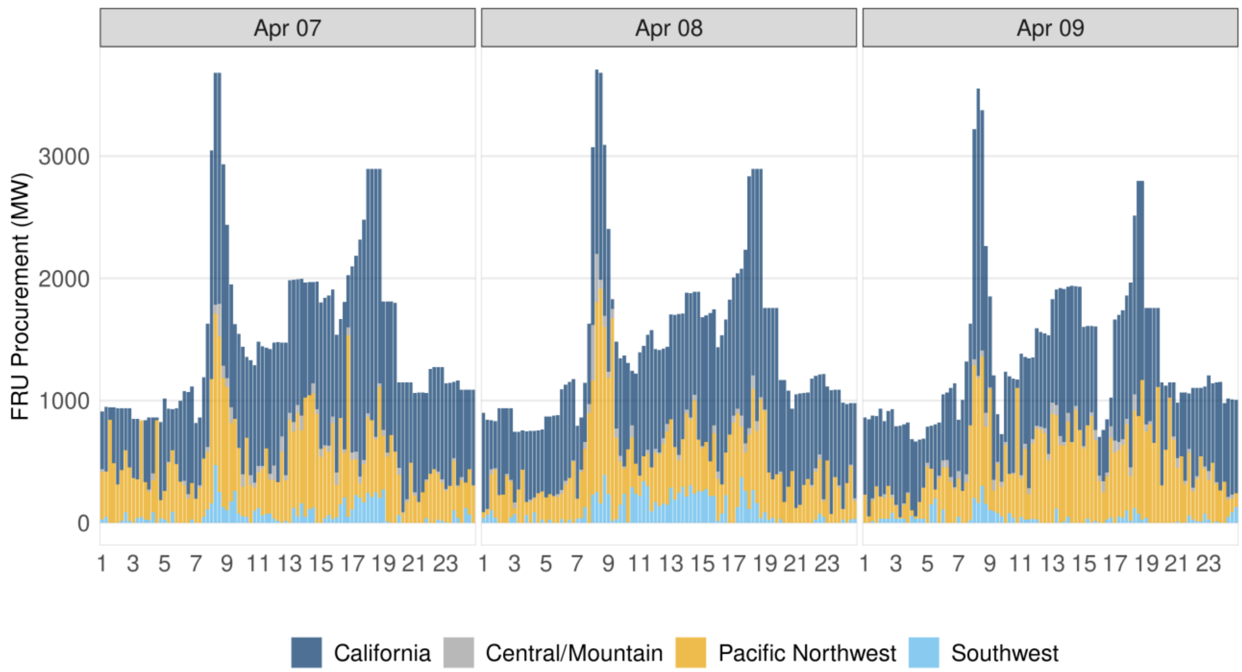


Figure 49: FRU procurement by resource type

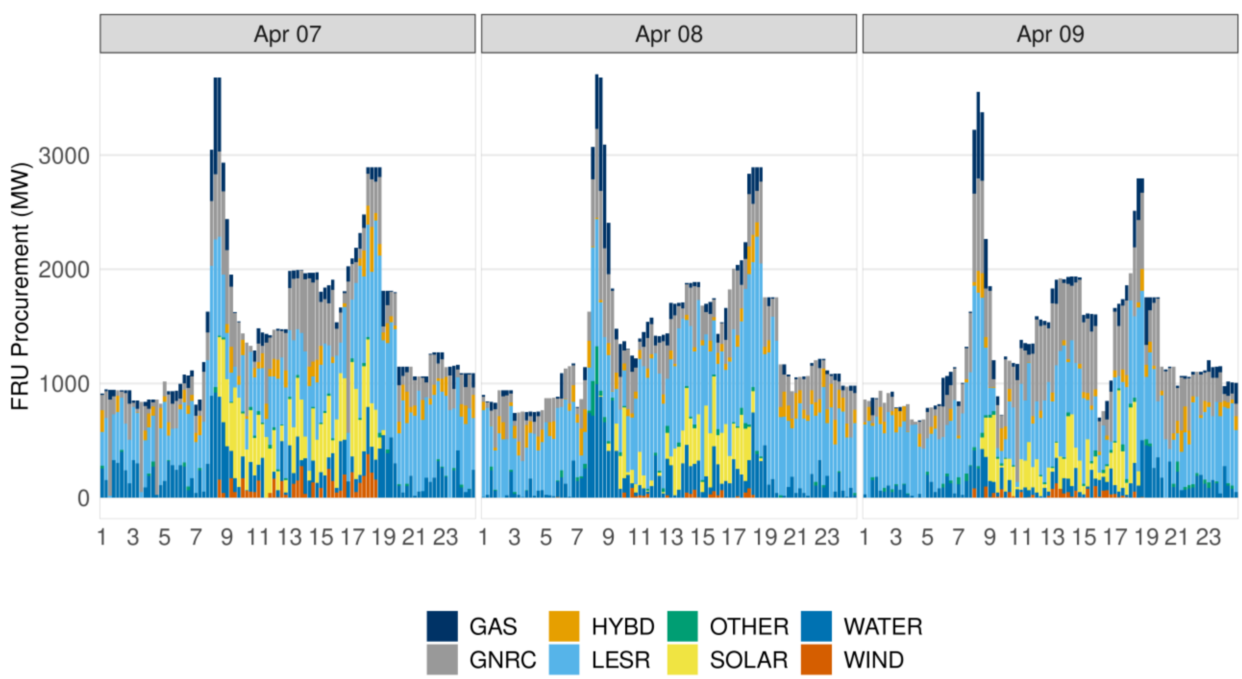


Figure 50 shows the FRD requirements versus procurements in the passing group in FMM. The FRD requirements were fulfilled for all intervals over the three days. During the eclipse hours, all but two WEIM

BAAs passed both tests in the downward direction. On April 8, the FRD requirement and procurement reached a peak of 2844 MW in hour ending 11.

Figure 50: FRD requirement vs. procurement

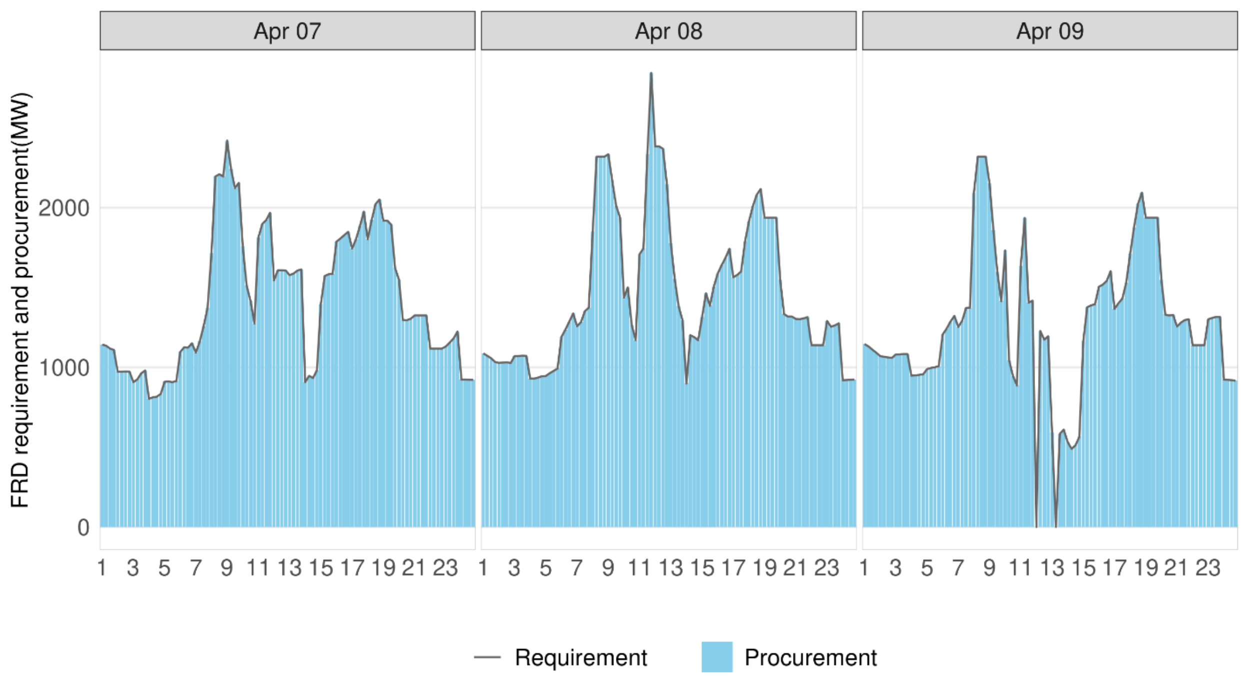


Figure 51 and Figure 52 present the FRD procurement breakdowns in the passing group. By region, FRD was procured across all regions. By resource type, solar was the main contributor for the midday hours, while wind, hydro, and storage (LESR) resources were the main sources for the remaining hours.

Figure 51: FRD procurement by region

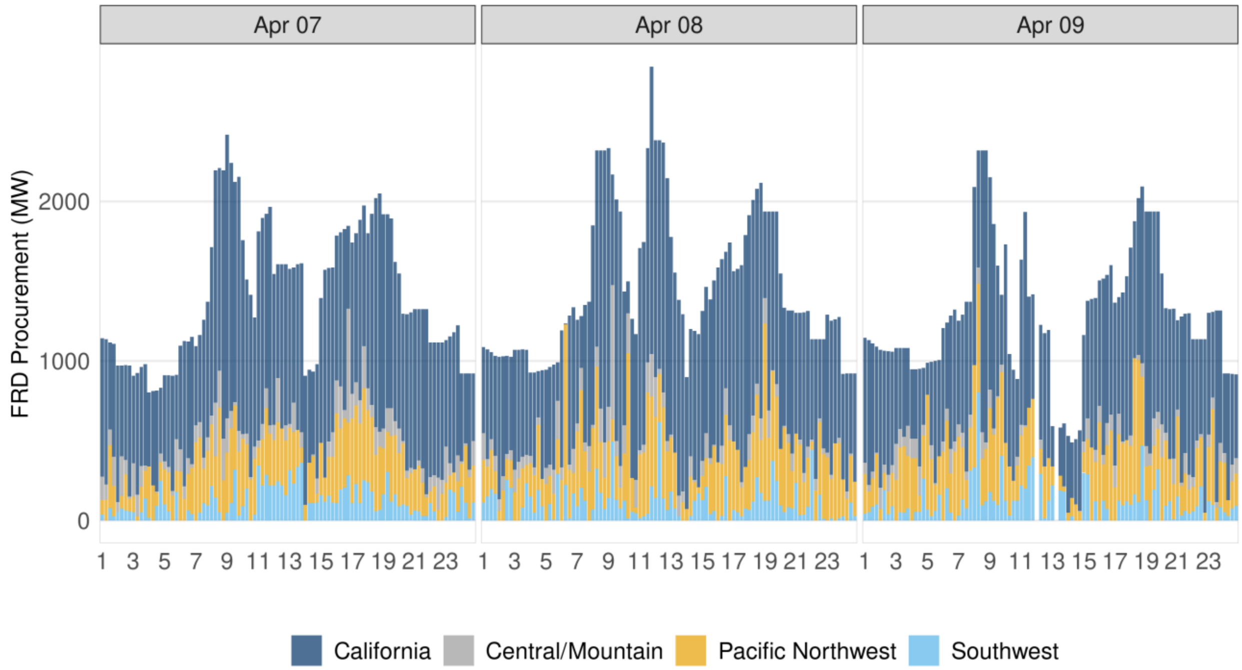
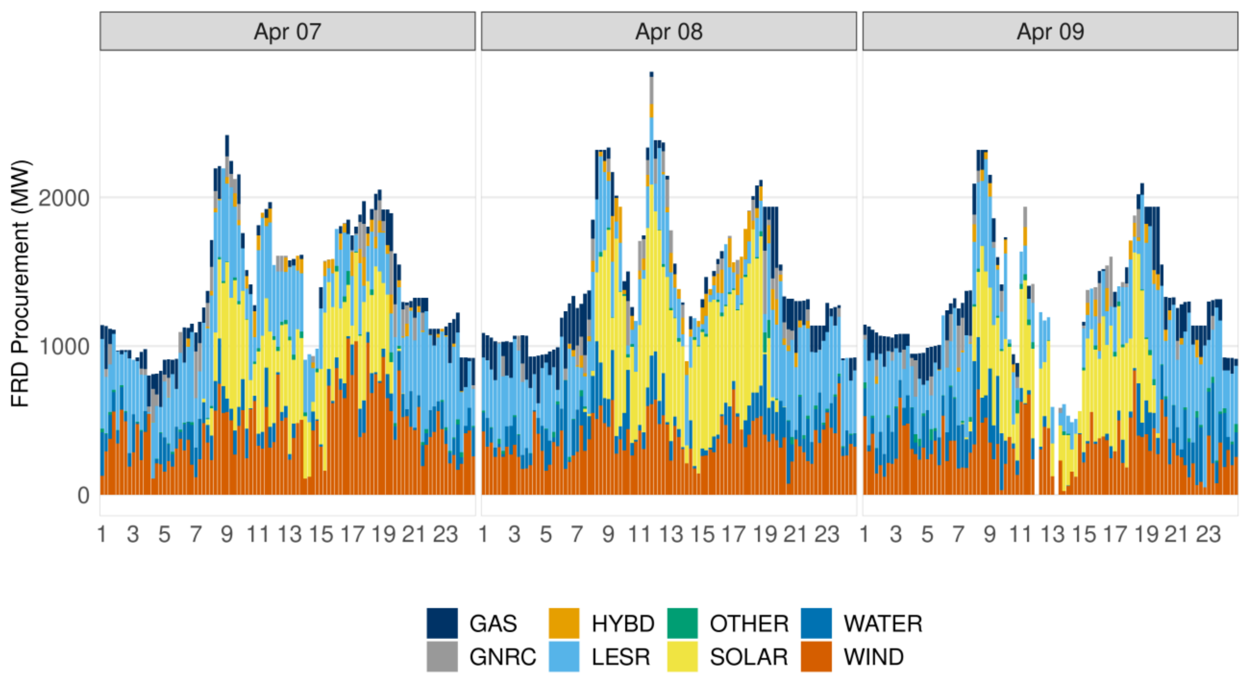


Figure 52: FRD procurement by resource type



Net Schedule Interchange

A pivotal aspect of the supply and demand mix within the CAISO system is intertie transactions, encompassing static non-resource-specific imports, dynamic schedules on the supply side, and exports on the demand side. The net outcome of these three components yields the net schedule interchange.

Net schedule interchange (NSI) is the net import or export (i.e. gross imports minus gross exports) into or out of the CAISO BAA.

Figure 53 shows the NSI trend for April 8 across three markets: IFM, FMM, and RTD. The overall patterns across the three markets are relatively consistent, particularly around the time of the eclipse. The most noticeable difference is that the IFM matched well with the FMM and RTD prior to the beginning of the eclipse and during the eclipse — except during HE 11-12, when the RTD and FMM schedules dropped. This was due to several large imports being awarded in FMM and RTD that were not awarded in the IFM.

Figure 53: Net schedule interchange by market for April 8

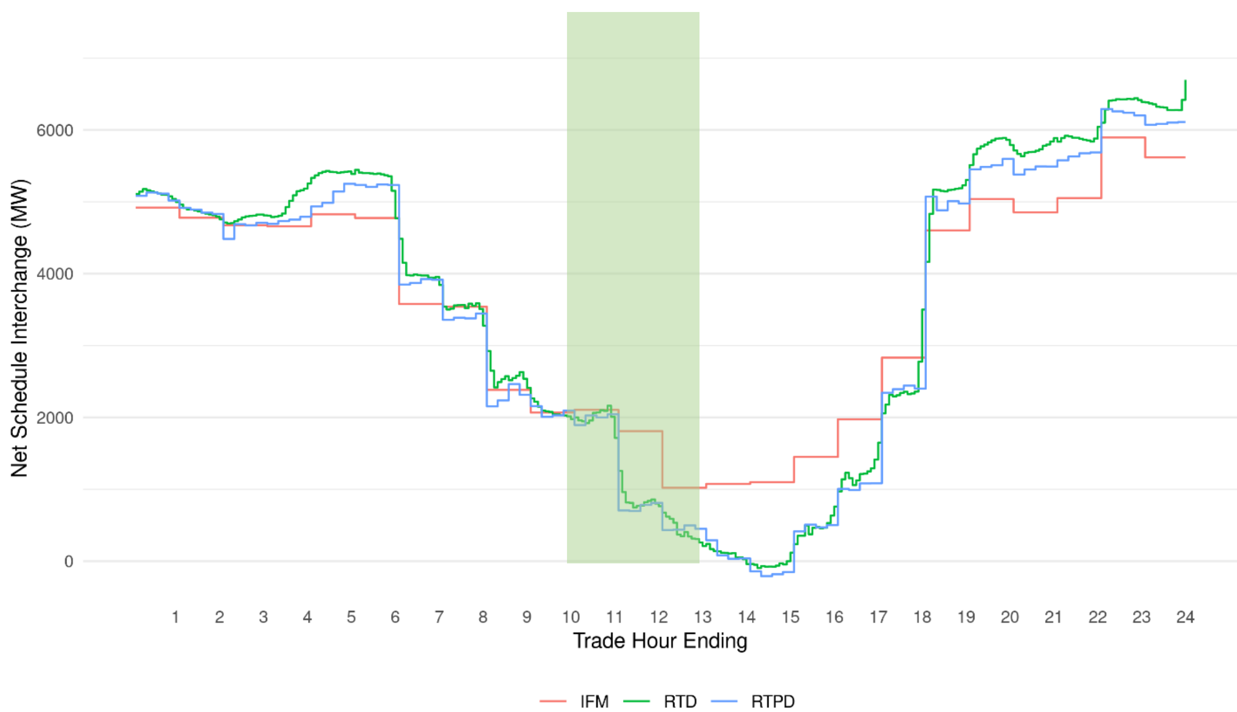
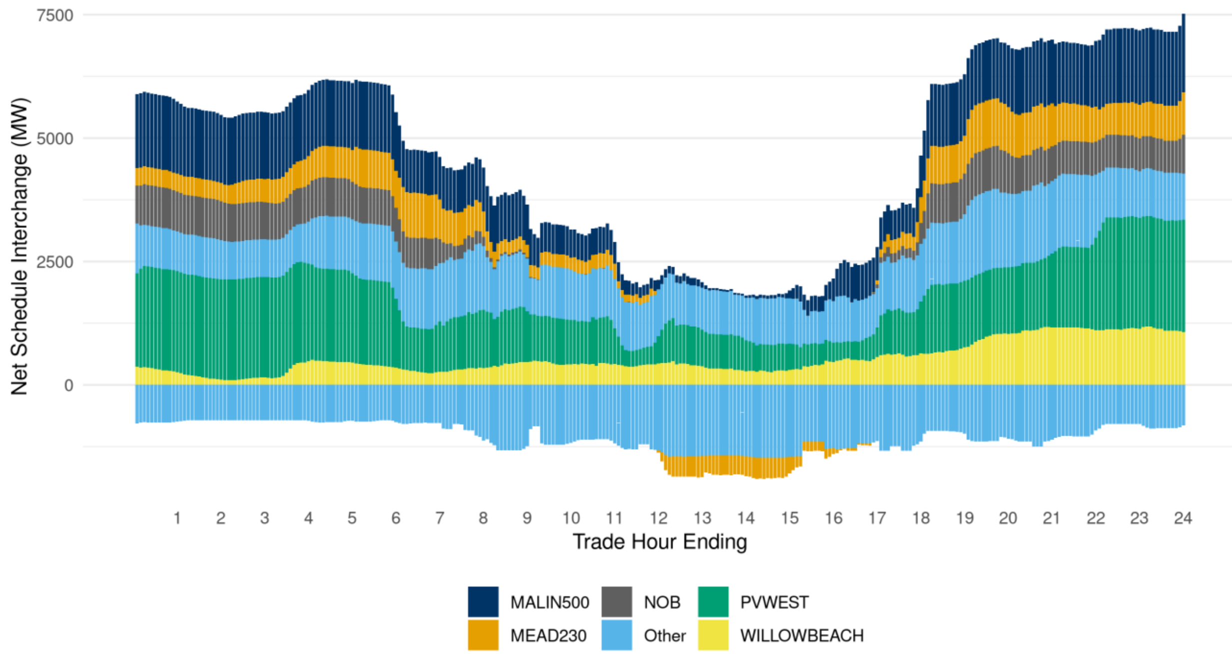


Figure 54 shows NSI on April 8 for RTD by major intertie point. The approximate time period of the eclipse is shown in light green. While there is no single intertie that drove the pattern of increased NSI during the time of the eclipse, PVWEST was the largest contributor.

Figure 54: Net schedule interchange in RTD by major intertie for April 8



WEIM Transfers

The centralized clearing process of the Western Energy Imbalance Market allows the market to attain an optimal solution across all balancing areas leveraging economical transfers among areas.

Figure 55 below shows the volume of WEIM transfers in RTD for the CAISO BAA for the day of the eclipse, April 8, and the day before and after. Negative values indicate net imports, while positive values indicate net exports.

CAISO WEIM transfers on April 8 experienced more volatility than the days before or after. Transfers spiked in the import direction more than on April 7 and 9. Transfers reached a net import maximum of 2,921 MW in hour ending 8. Another import spike occurred in hour ending 12 on April 8, with transfers reaching 1,567 MW of imports.

Figure 55: WEIM Transfers in RTD for CAISO from April 7 to 9

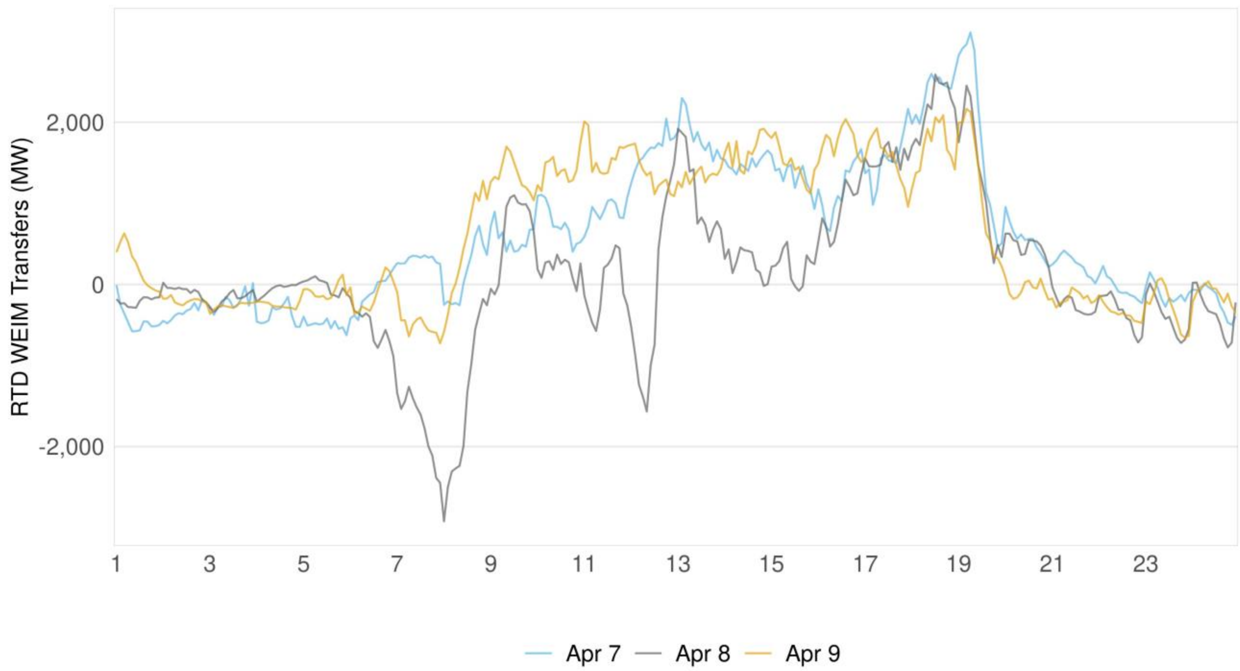
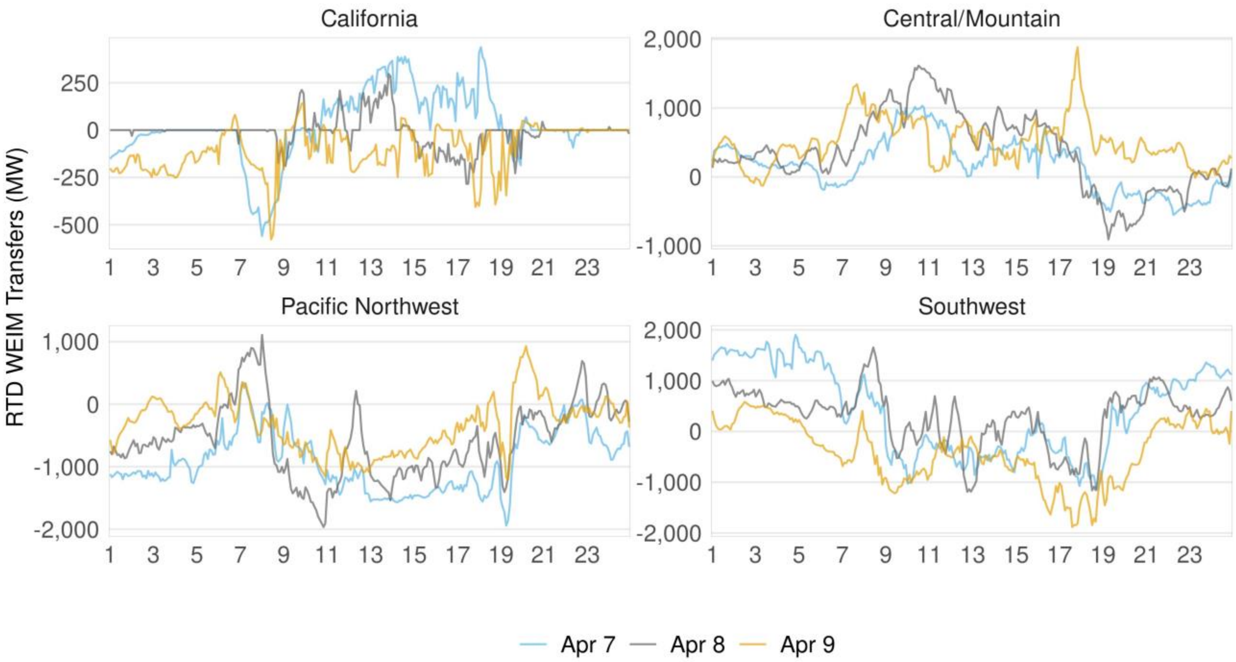


Figure 56 below shows the volume of WEIM transfers in RTD for all WEIM participants grouped by region. The California region does not include CAISO transfers. Negative values indicate net imports; positive values indicate net exports.

On April 8 transfers from non-CAISO California entities to other regions were zero for the early morning hours and late night hours. In hour ending 12, the Pacific Northwest saw a rise in net exports and the Central/Mountain region was also a net exporter. In the same hour, the CAISO BAA and Southwest regions saw higher imports than normal, reaching 1,567 MW and 1,188 MW of imports, respectively. The eclipse mainly impacted the CAISO BAA and Southwest region transfers, which saw greater than normal volatility in WEIM transfers from hour ending 11 to 13. Net exports from Pacific Northwest and Southwest regions spiked in hour ending 8, corresponding with the net import spike seen in CAISO.

Figure 56: WEIM Transfers in RTD by Region from April 7 to 9



Exceptional Dispatches

On the day of the eclipse, the CAISO issued exceptional dispatches for two main reasons: to ensure that battery resources had sufficient state of charge (SOC) to provide ramping capacity and meet energy needs and to position more traditional generating resources to provide ramping capacity. Both were needed to make up for the rapid decrease in solar generation during the onset of the eclipse.

Figure 57 shows the volume of exceptional dispatches by hour on April 8. A substantial volume of state-of-charge exceptional dispatches were issued prior to the beginning of the eclipse event. These exceptional dispatches served to ensure batteries had sufficient SOC to discharge as the solar generation decreased during the eclipse event. A smaller quantity of more traditional generation capacity was exceptionally dispatched to provide voltage support prior to, and following, the eclipse.

Figure 57: Exceptional Dispatch volumes by hour on April 8

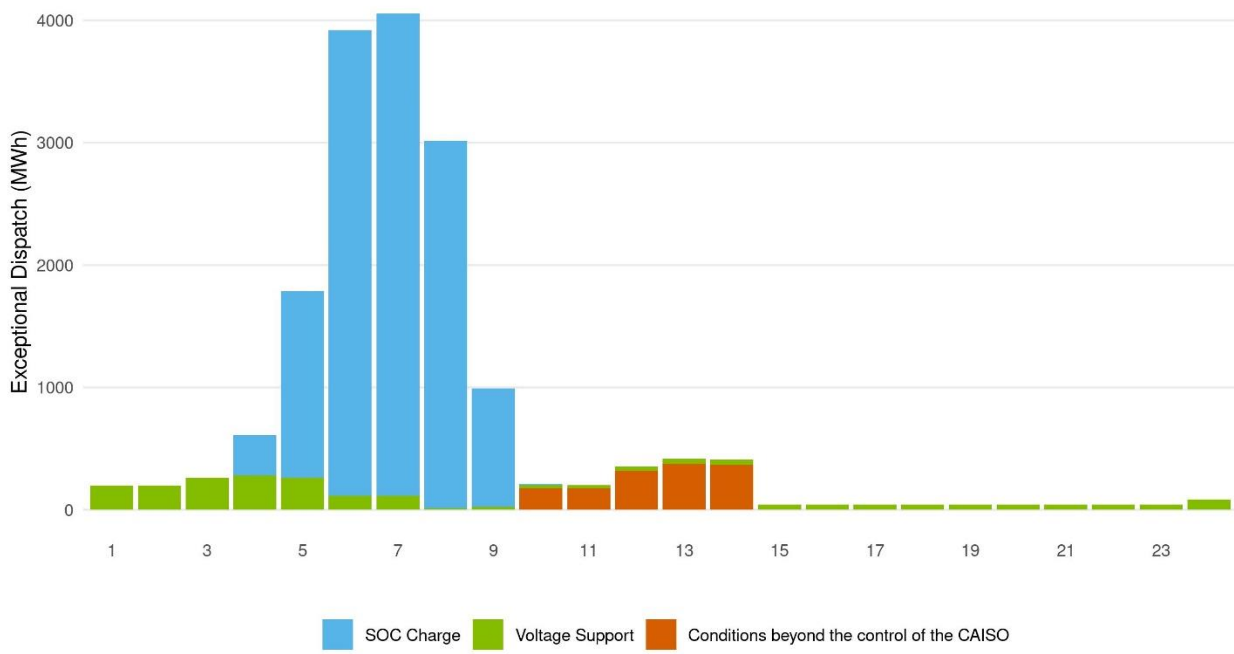
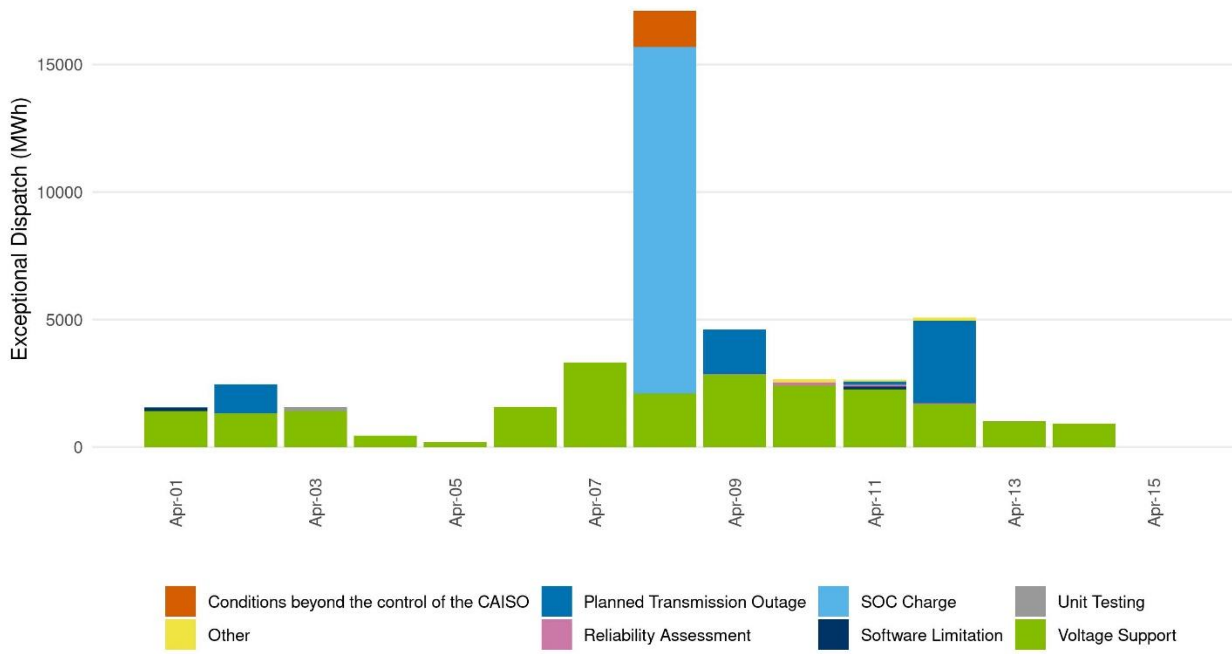


Figure 58 shows the volume of exceptional dispatches by day for a two week period around the eclipse event. By looking at this longer period of time, it is clear that the exceptional dispatch volumes on April 8 were higher than usual, primarily driven by the SOC exceptional dispatch volume.

Figure 58: Exceptional Dispatch volume from Apr 1 - 15



Operational Performance

To account for uncertainty in balancing supply and demand, the CAISO committed additional resources and procured additional ancillary services to ensure the operators had adequate flexible resources available for dispatch during the eclipse. This action allowed the operators to manage ACE between -231 MW and +400 MW in spite of the fluctuation in solar production. Also, the CAISO ensured that solar resources followed their dispatch operating targets to minimize net load variability.

Overall, the CAISO performed well based on NERC's Control Performance Standard (CPS1) measure during and after the eclipse, achieving an overall CPS1 score of 144% for the day. Operationally, the CAISO was able to meet the demand plus export energy to neighboring BAAs during the eclipse. Figure 59 shows the system frequency (solid green curve) of the WECC interconnection during the eclipse. As shown, system frequency declined below 60 Hz as solar production began to decrease and exceeded the lower frequency dead band (dashed green line) below 60 Hz just prior to maximum solar obfuscation. As solar production began to increase after 11:25 a.m., system frequency began to increase and exceeded the upper frequency dead band (dashed green line) above 60 Hz.

Figure 59: Solar Production vs. Frequency

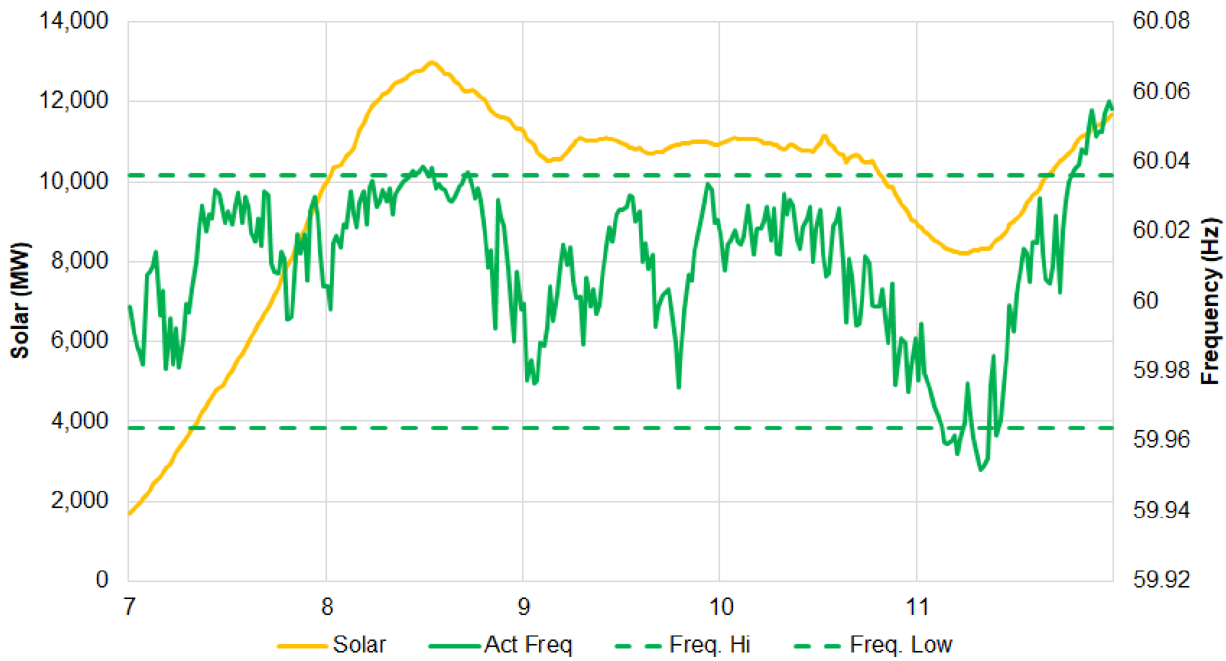
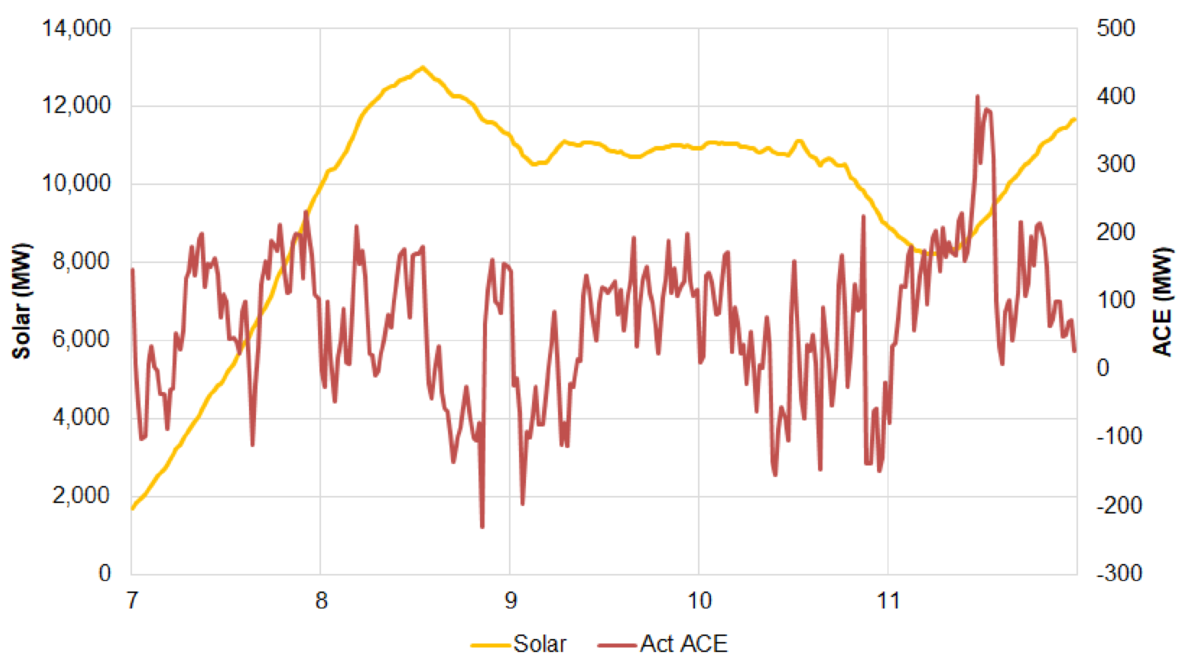
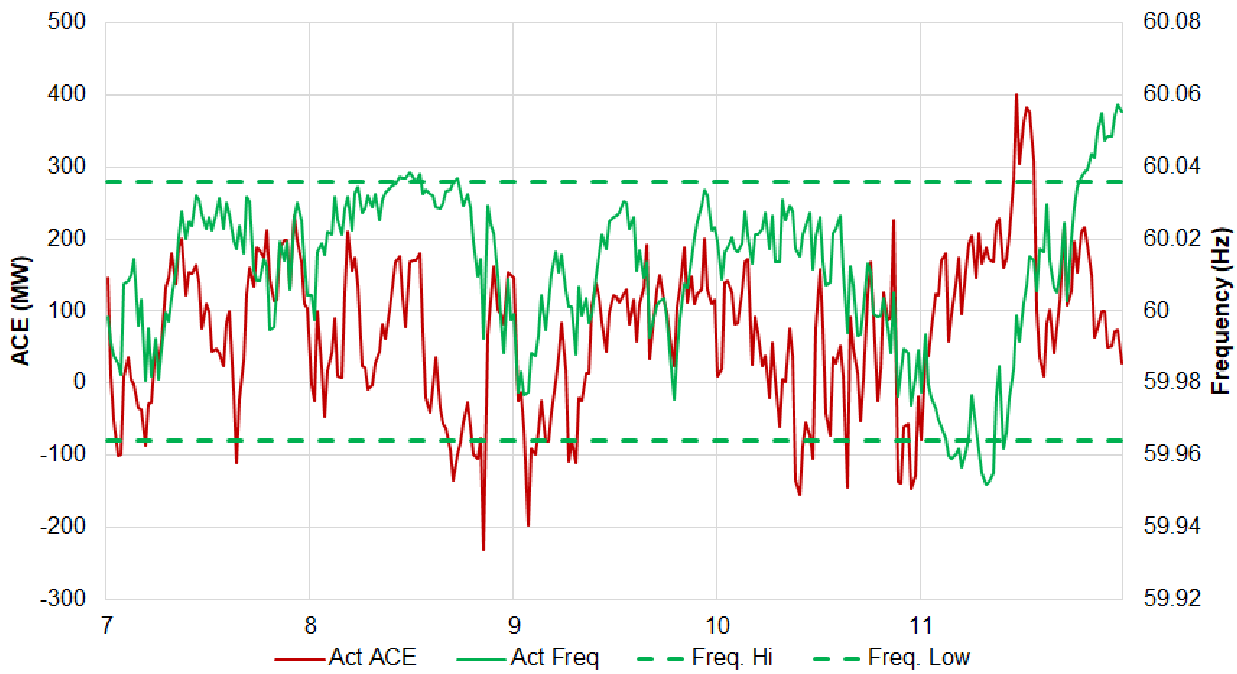


Figure 60: Solar Production vs. ACE



As shown in Figure 60, the CAISO's ACE hovered between -231 MW and +400 MW during the eclipse, indicating that the CAISO was able to maintain a very close balance between supply and demand.

Figure 61: ACE vs. Frequency



As shown in Figure 61, ACE hovered between -177 MW and +207 MW while system frequency hovered between 59.93 Hz and 60.05 Hz. The CAISO was able to effectively dispatch resources on regulation to minimize ACE deviations outside the ± 150 MW band. This translated into an overall control performance measure of an average ACE * Delta Frequency of 1.1 MW-Hz between the hours of 8:00 a.m. and 11:00 a.m. This is another indication that the CAISO supported the interconnection frequency during the eclipse.