Day-Ahead Market Enhancements Analysis

Guillermo Bautista Alderete, Ph.D
Kun Zhao, Ph.D.

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1 Introduction

In 2019, as part of the price performance analysis, the CAISO provided quantitative analysis of imbalances across markets. One of the findings was that the largest imbalances occur between the day-ahead and fifteen-minute market. These imbalances between the day-ahead and real-time market occur due to load and variable-energy resource forecast errors. Based on most recent trends, imbalances continue to exist in the CAISO's markets and are as significant as originally assessed back in 2019. This continues to be a particular area of interest as the CAISO explores the Day-Ahead Market Enhancement (DAME) initiative.

This report provides updated metrics and analysis with a focus on day-ahead imbalances. It shows historical imbalances but also estimated imbalance reserves (IR) using the proposed *quantile methodology* previously introduced in the initiative. Given the ongoing interest in the impact of operator actions to adjust the load forecast used in the day-ahead market, this report also provides analysis and metrics regarding these adjustments, as well as the upper confidence band that since recently serves as an input to guide the adjustments. The last part of the report analyses the outcomes of the Reliability Unit Commitment (RUC) process.

This analysis is exploratory in nature and is intended to provide data that can help guide the ongoing discussion of the DAME initiative.

2 Day-Ahead Imbalance

The imbalance ε is calculated as the difference between the net load from day-ahead market (DAM) and the net load from the fifteen minute market (FMM),

$$\varepsilon = NL^r - NL^d \tag{1}$$
$$= (LF^r - S^r - W^r) - (LF^d - S^d - W^d) \tag{2}$$

where NL^r and NL^d stand for the net load of the real-time and day-ahead markets, respectively. The net loads are derived by subtracting the wind $()S)$ and solar (W) forecast from the load forecast (LF). A positive imbalance reflects a higher net load in real-time than in day-ahead and this in turn will require more supply in real-time with respect to what was positioned in the day-ahead market.

Figure 1 one captures all the distributions by month of the imbalance reserves over the last three years. The imbalances are shown with distribution plots where the inner part of the plot shows a box with the summary statistics such as the media, as well as the outliers with the dots at the ends of the tail. Additionally, the external plot effectively illustrates the variation (density) of the imbalances. A wider section of each plot illustrates a higher probability of the imbalance taking on the given value. A thinner the portion of the plots represents lower probability.

There are several trends to describe from this figure.

First, historical imbalances materializes in both upward $(RT > DA)$ and downward $(RT < DA)$ direction. With the day-ahead market being farther in the horizon, it is expected that the real-time will be closer to actual conditions. Thus, the imbalance reserves direction simply reflects whether the DAM net load is over or under forecasted relative to real-time (FMM).

Second, the distributions consistently have the higher probabilities (wider portion of the distribution) around 0MW, which indicates that a high number of imbalances are relative smaller.

Third, the imbalances are in a relatively similar range for either direction, with historical values as high as 4,000MW in either upward or downward direction. Indeed, the highest upward imbalance was observed on July 2019 while the highest downward imbalance was observed on September 2020 due to extreme changes in weather conditions that resulted in a much lower load in real-time than that projected in the day-ahead time-frame. They exceed 6,000MW.

Fourth, using the last three years, there is no marked seasonal trend to observe as the imbalance remains quite consistent within $\pm 4,000MW$. The downward imbalance was higher in more recent months, which may be attributed in part to the growing penetration of variable energy resources VER.

Figure 2 provides an hourly profile of the historical imbalance but organized by month with box plots. This covers the same historical period of Figure 1. The largest imbalances accrued on August and September.

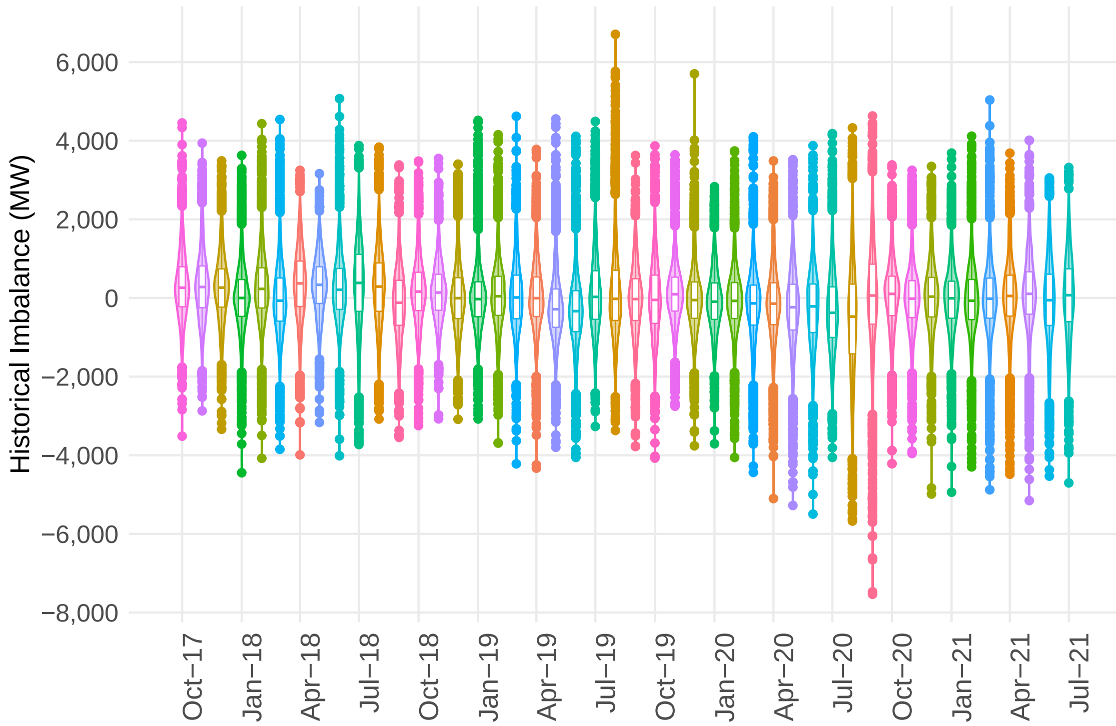

Figure 1: Monthly trend of historical day-ahead imbalance.

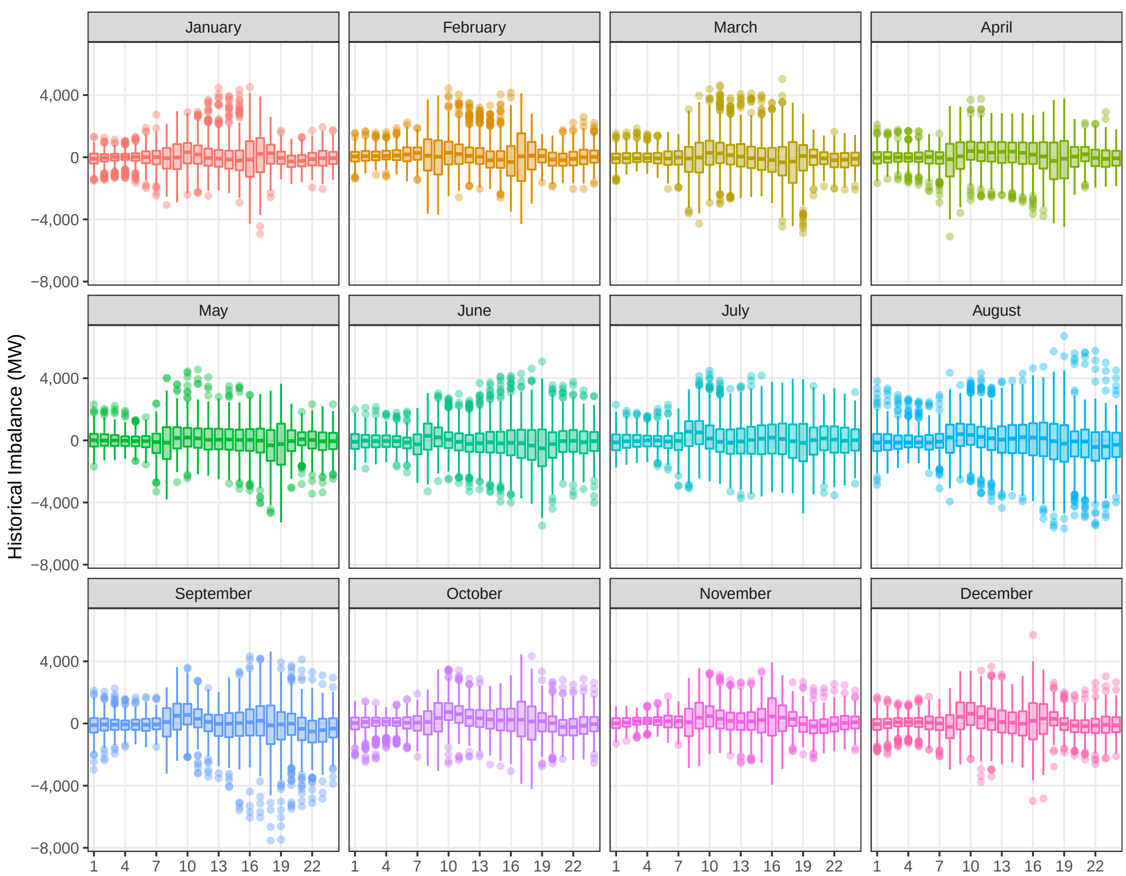

Figure 2: Hourly trend of Day-Ahead Imbalance Reserve.

3 Day-Ahead Imbalance Reserves

As discussed through previous efforts of the day-ahead market enhancements (DAME) initiative, CAISO has proposed to use a *quantile regression* to estimate the requirements to meet the needs for imbalances known as *Imbalance Reserves (IR)*. This is to some extent similar to the methodology proposed for the flexible ramp requirements estimated for real time as part of the flexible ramping product enhancements. Currently, CAISO uses a histogram approach to estimate flexible ramping requirements for the real-time market. This histogram approach largely relies on historical information of net load uncertainty in real-time. The drawback is that it does not consider the current net load conditions. The quantile approach is more sophisticated by using additionally the load and variable energy resources (VER) forecasts, including wind and solar, to estimate the requirements. This allows to estimate IR requirements taking into account historical conditions but also existing conditions (current forecasts). Figures 3 and 4 show the IR requirements estimated using the quantile methodology.

The upward IR is denoted with positive values while the downward IR is denoted with negative values to keep the same relative reference of historical imbalances. The minimum value for IR is $0MW$ and can be as high as $5,400MW$ for upward and $4,600MW$ for downward direction. The median for the upward IR shows a seasonal trend with higher values in the late summer months and lower values in the winter months; this seems to correlate to some extent with the increasing demand and VER production in summer and decreasing levels in winter.

Figure 5 illustrates in more detail the distributions of the upward IR for three sample months of August 2020, January 2021 and May 2021. These months were chosen since they represent different seasonal conditions and exhibit fairly different distributions. The month of May is a transition month from spring to summer and shows two peak distributions around an IR of $1,000MW$ and $2,000$MW. January is a winter month with expectation of VER uncertainty, while the month of August is a summer month with high production of VERs and high loads and exhibits a more typical normal distribution around $1,600MW$. The dotted lines represent the 2.5^{th}, 50 and 97.5^{th} percentiles of the distribution for each month. The lighter blue areas represent the tails of the distributions.

Figure 6 shows a more granular data for the period of July 8 through 10, 2021 when the system experienced tight supply conditions. The blue lines represent the upward and downward IR while the green bars represent the imbalances that actually materialized during this period. For all intervals but one, the imbalance reserves were sufficient to cover the materialized imbalance. Figure 7 shows the same information for a three-day period in December 2020 when upward IR requirements were relatively large, and the materialized uncertainty was within the requirements range for most of the time.

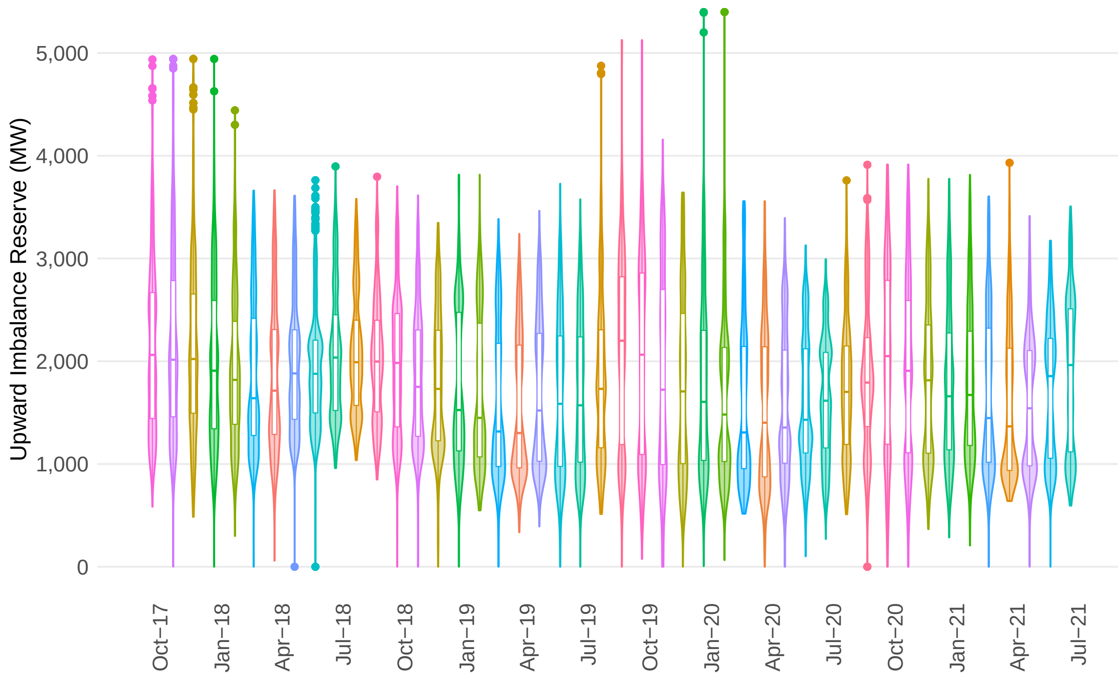

Figure 3: Monthly trend of calculated requirement for upward imbalance reserve.

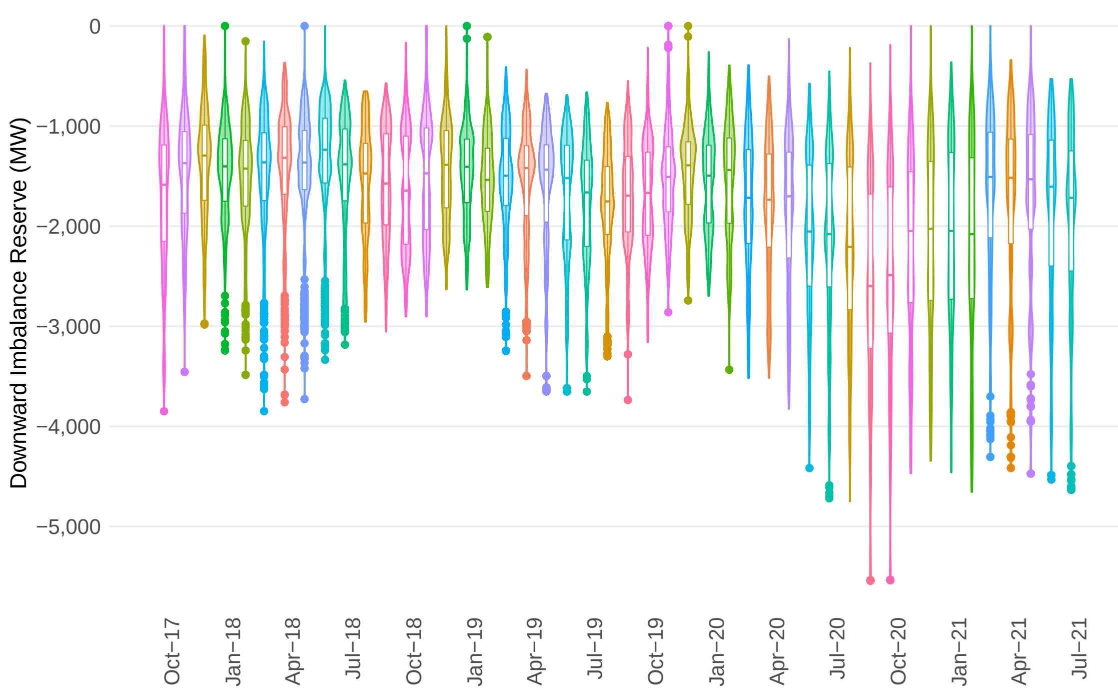

Figure 4: Monthly trend of calculated requirement for downward imbalance reserve.

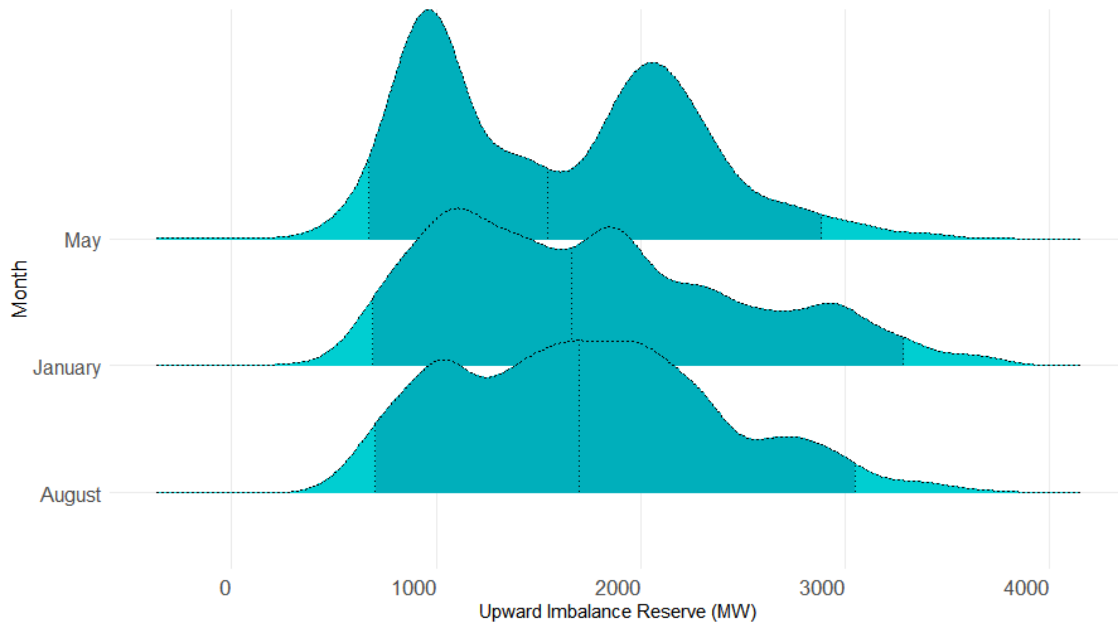

Figure 5: IR distributions for sample months.

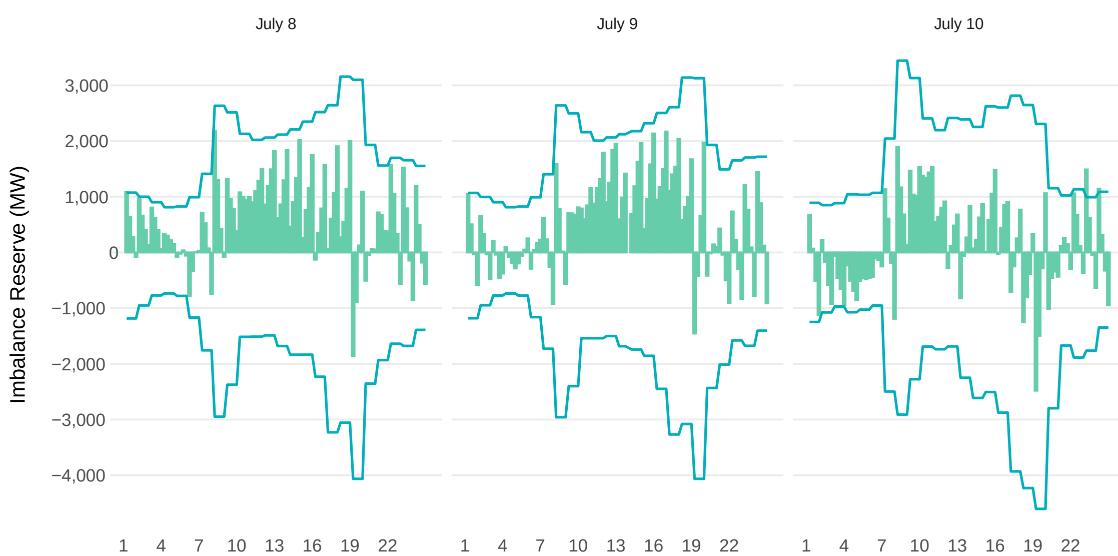

Figure 6: Materialized Imbalance versus IR requirements. July 8-10, 2021.

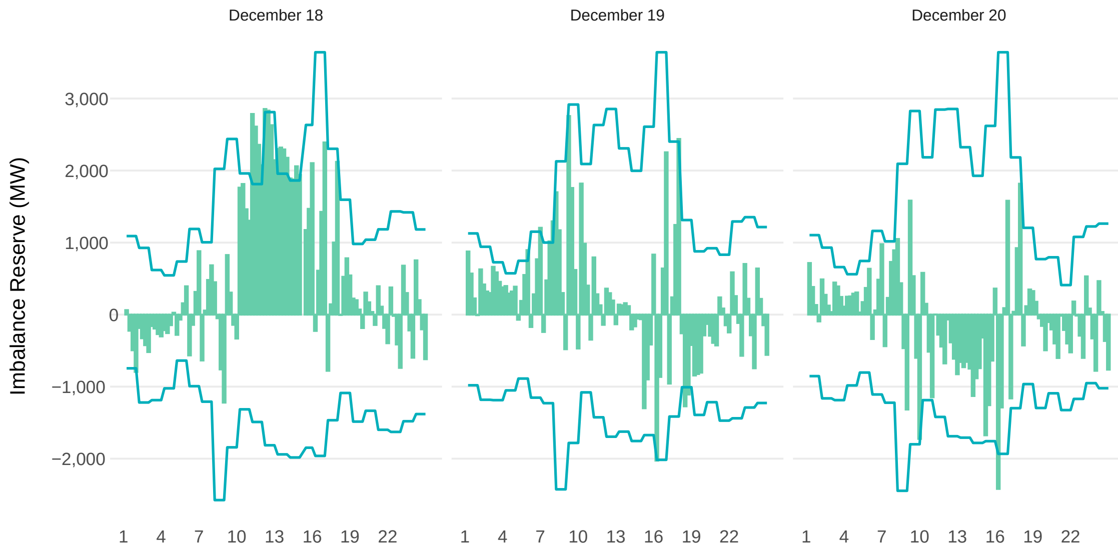

Figure 7: Materialized Imbalance versus IR requirements. December 18-20, 2020.

4 DAM Load Forecast Adjustments

The reliability unit commitment (RUC) process clears supply against the day-ahead load forecast for CAISO area. In order to factor in uncertainties between the day-ahead and real time, including load uncertainties, operators have the flexibility to apply adjustments to the day-ahead load forecast in either upward or downward direction; this is known as the RUC adjustments. This is a practice that has been in place for several years but overtime the logic to determine the magnitude of the adjustments has been enhanced. Historically, RUC adjustments have applied mainly to peak hours during summer months, when the system faces higher demands and there are tighter supply conditions while weather variations can lead to significant variations.

Figure 8 shows the historical trend of RUC adjustments for the last five years with a box plot. This trends highlights several conditions:

1. The magnitude of RUC adjustments has increased over the years; in 2017 the highest value was under 2,000MW and reached maximum levels of about 7,000MW in August 2020.

2. The frequency of RUC adjustments has increased over the years, going from a handful of hours in 2017 to effectively all hours during peak hours in summer 2021.

3. RUC adjustments are clustered in summer months and there are no adjustments used in shoulder and winter months

Figure 9 shows an hourly granularity for RUC adjustments, with one hourly subplot per year. This shows that RUC adjustments are mostly concentrated in peak hours. The maximum level of RUC adjustments is observed in afternoon ramp-hours prior to the gross and net load peak times.

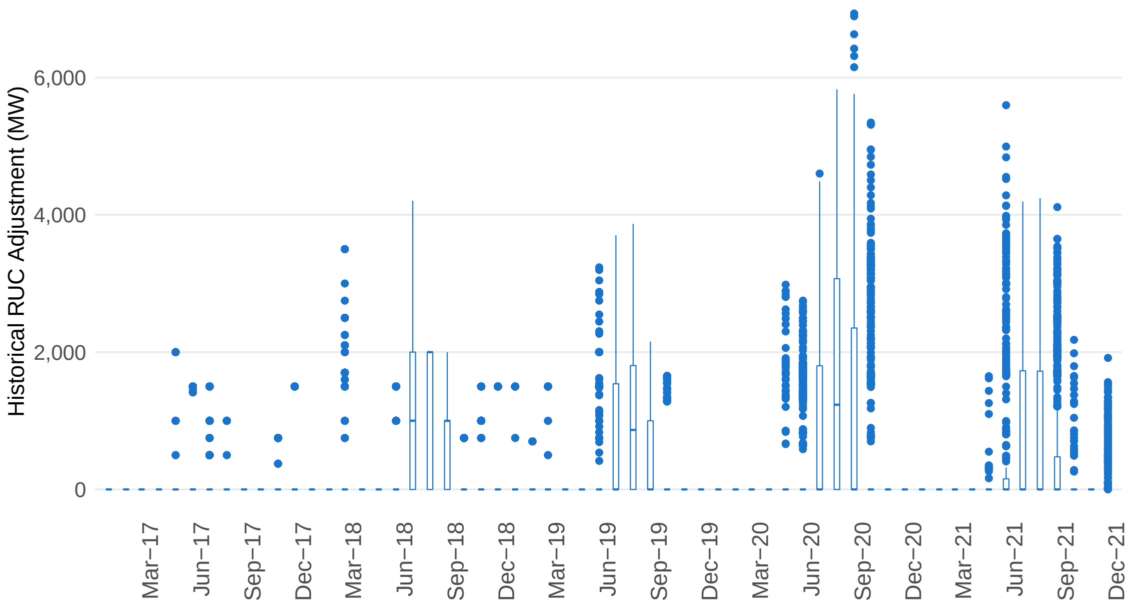

Figure 8: Monthly distribution of RUC adjustments.

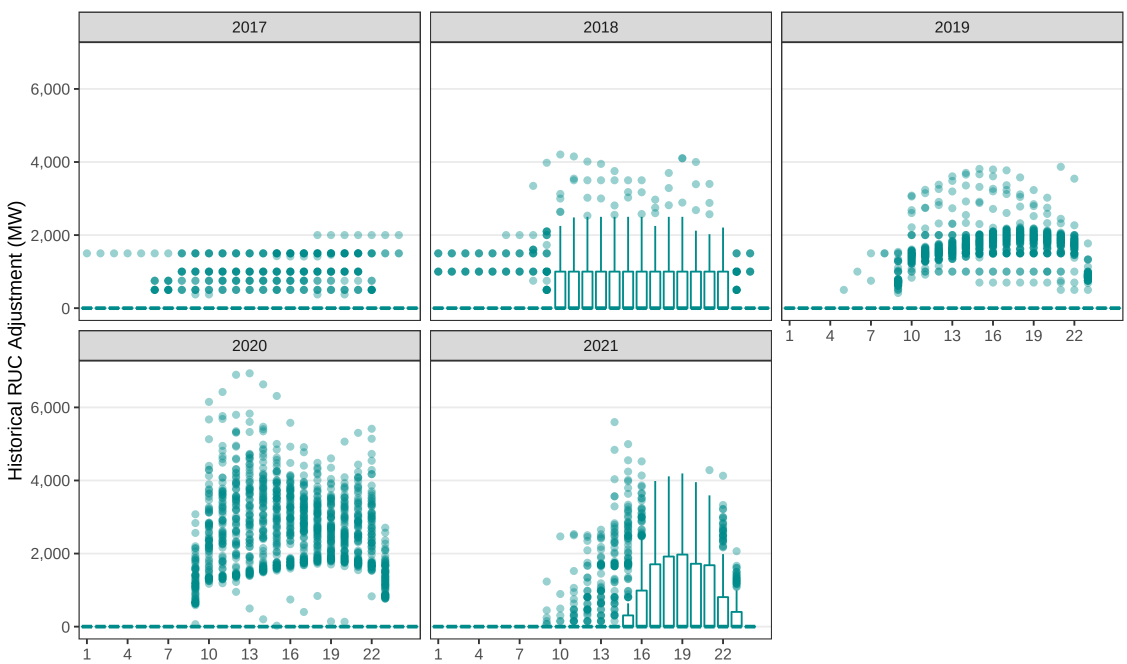

Figure 9: Hourly distribution of RUC adjustments.

5 Upper Confidence Band and RUC Adjustments

As the logic to assess the RUC adjustments evolved over time, more recently they have been guided by an upper confidence band for the day-ahead forecast. This confidence band is a proxy that uses historical days to assess the maximum load forecast that could be exhibited under similar weather conditions. Operators may consider this upper confidence bound plus other operational conditions, such as risk of fires, to determine the final RUC adjustments.

Figure 10 shows a monthly trend of the upper confidence band for the day-ahead forecast over the last two years. The data sample may be too small to expose longer trends but to some extent it shows that the upper confidence is greater in summer months when load levels are higher, while it reaches lowest levels during the winter months when load levels are the lowest. In some cases, the upper confidence can exceed the 6,000MW. Figures 49 in the Appendix shows additional hourly distributions organized by month for 2021.

Figure 11 shows a comparison of the upper confidence band against the final RUC adjustment utilized in the market. If the RUC adjustment were only reflecting the upper confidence band, all the dots would be clustered in a 45 degree line. About 16% of the RUC adjustments match the upper confidence band. There is about 29% of the RUC adjustment that are higher than the upper confidence band, while about 55% of RUC adjustments are lower than the upper confidence band and they exhibit lower correlation. This correlation is also illustrated based on the load level as denoted with the color of the dots; the blue dots represent instances of lower levels of demand while purple dots represents higher demand levels.

Figure 12 shows the trend of the delta between the RUC adjustments and the upper confidence band for 2020 and 2021. A positive difference represents instances when the upper confidence value is higher than the RUC adjustment. This trend shows that in general the upper confidence is higher than the RUC adjustment, while during high-load conditions, typically in the summer months, there are instances wiht RUC adjustments higher than the upper confidence value.

Another interesting comparison is the level of the upper confidence band covering for RUC adjustments, relative to the demand level. Figure 13 illustrates that the majority of RUC adjustments are lower than the upper confidence band.

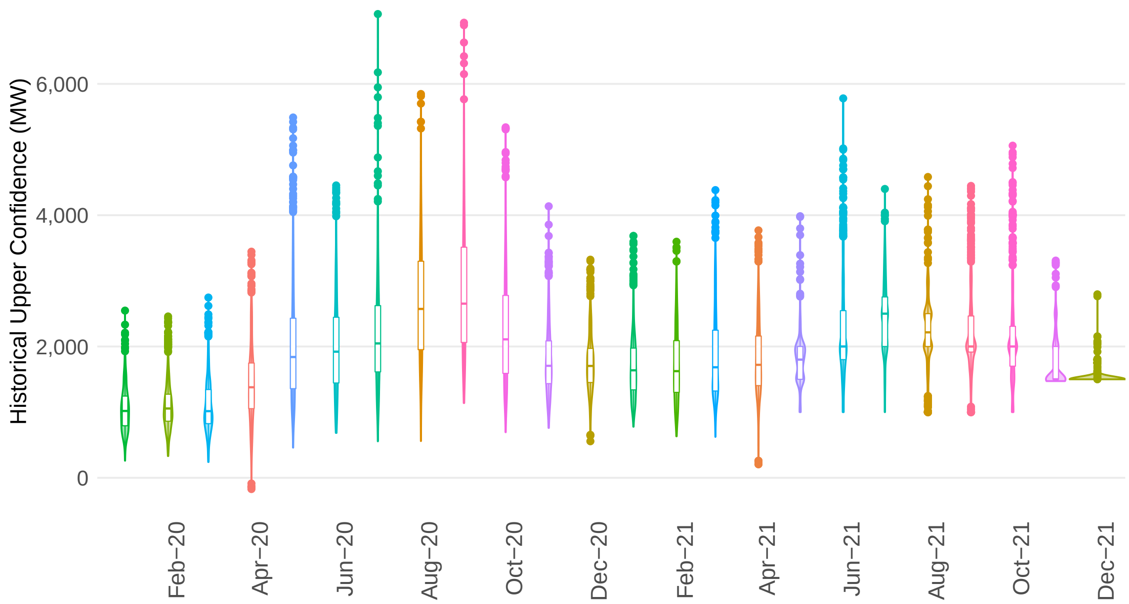

Figure 10: Monthly trend of upper confidence band for day-ahead load forecast.

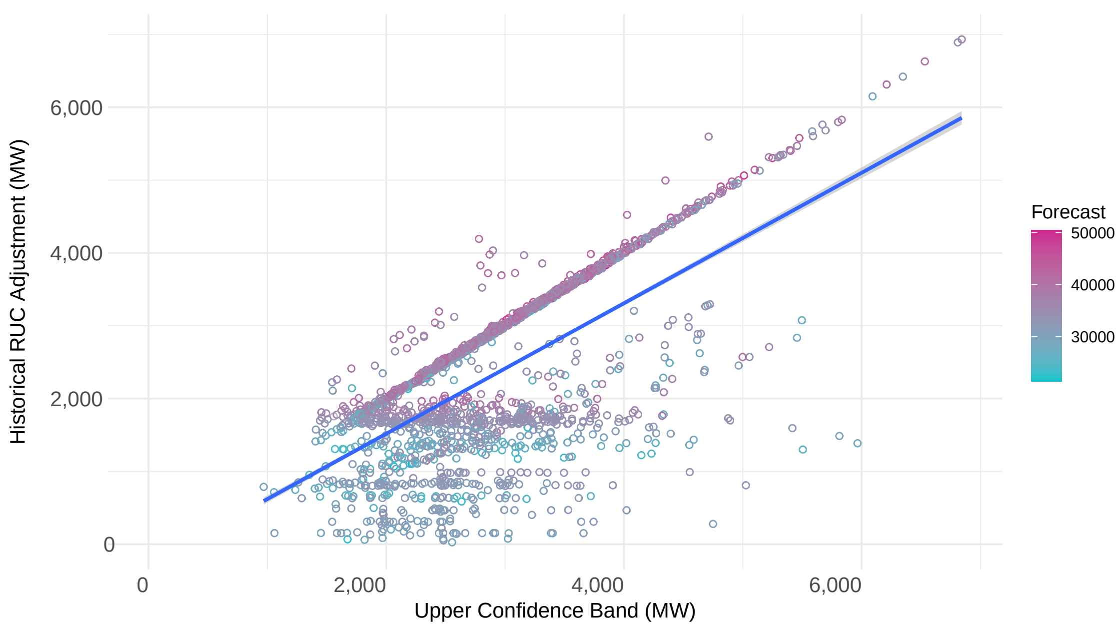

Figure 11: Comparison of upper confidence and RUC adjustments t> 0.

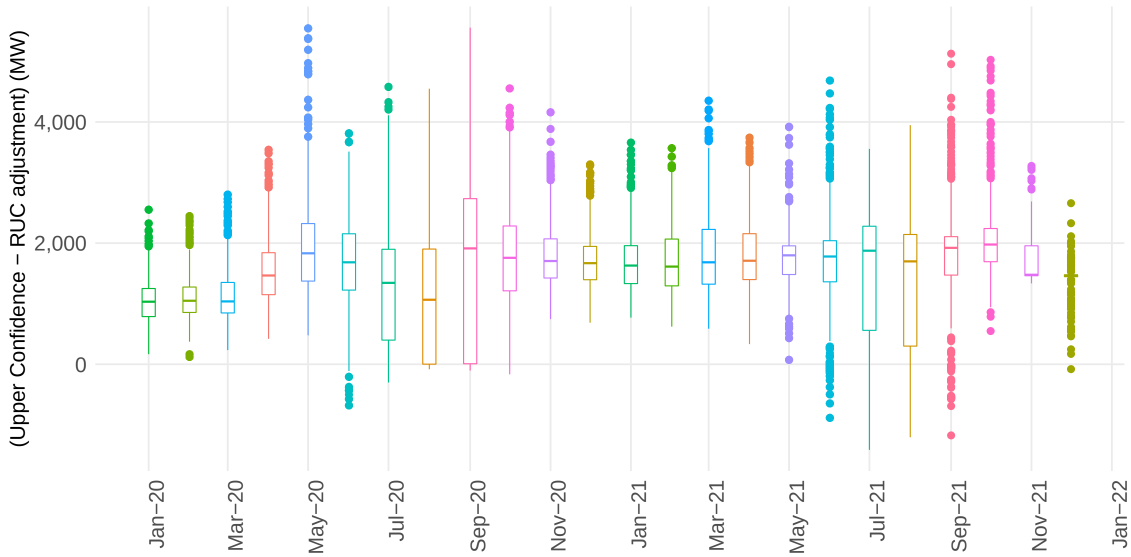

Figure 12: Comparison of upper confidence and RUC adjustments t> 0.

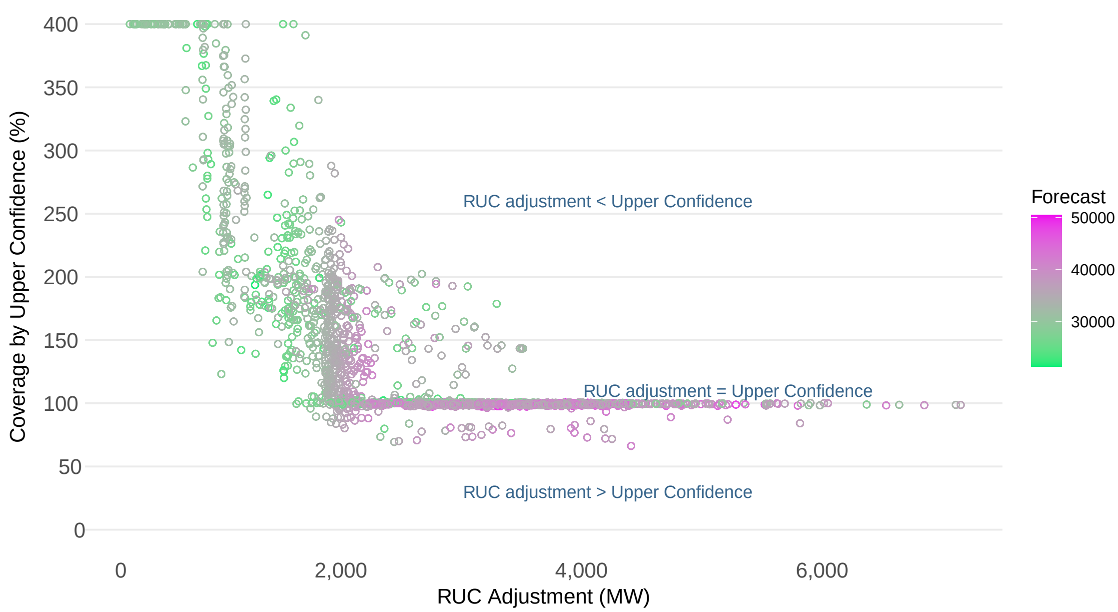

Figure 13: Coverage of RUC adjustment> 0 provided by upper confidence.

6 RUC Adjustments and Imbalance Reserves

Figure 14 compares the historical RUC adjustments with the estimated IR requirement from the quantile approach. The IR captures the load, wind and solar uncertainty from day-ahead to real-time plus the granularity differences (from day ahead hourly to real time 15 minutes), while RUC adjustments consider extreme load uncertainty plus other operational concerns. Therefore, this comparison aims at assessing how closely these two factors track to each other. This figures depicts all data points for the period under analysis, even those in which there is no RUC adjustments, like in the winter time frame, and it shows that there is no significant correlation between the two conditions. The data sample is organized by year so that it show a potential evolution over time. The only marked trend is that in the first years of the sample, when RUC adjustments were sporadic, values of RUC adjustments were basically flat values at discrete magnitudes of 2,000, 1,500MW or 1,000MW. As the logic to estimate the RUC adjustments evolved, the RUC values become more diverse.

Figure 15 has the same construct of that of 14 with the caveat that it only accounts for data points in which the RUC adjustment is nonzero. This effectively disregards all the0 dots for the Y axis. The subset of data points still exhibit very low correlation. The blue line represents a linear regression to visualize the level of correlation. This comparison also shows the level of load, with darker blue dots representing lower demand levels while darker purple dots represents higher demand levels. This allows to visualize any if the correlation between these two conditions follows any with the demand level. The darker purple dots are in the range of higher RUC adjustments but more spread for the values of imbalance reserves, which is expected since higher demand levels will command higher RUC adjustments. The low correlation is present at all demand levels.

The intent of the RUC adjustment is to cover for the load uncertainty and other operational uncertainties between the day-ahead and real-time frames while the IR is a more scientific method to factor in the uncertainties related to load, wind and solar forecast from day-ahead to real-time. It does not factor in any other operational conditions. Thus, it's expected that the IR captures to some extent the load uncertainty that RUC adjustment are intended to cover. Figure 16 shows a trend of the coverage that the IR can provide for RUC adjustments; i.e., what portion of the RUC adjustment is covered by the IR. Thus the RUC adjustments covered by IR can be defined as

$$Cov_{RUC} = \frac{IR}{RUC Adjustment} \tag{3}$$

A value $> 100\%$ means the IR is high enough to fully cover all the RUC adjustments. The points falling below 100% (orange region) represent hours in which the RUC adjustments could not be fully covered by the IR. Overall IR covered about 90%, 83%, 78%, 40% and 60% of the RUC adjustments from 2017 through 2021, respectively. The color of the data points represent the level of the demand, with darker green representing lower demand and darker blue representing higher levels of demand. This shows that many of the instances where the IR covers the RUC adjustment happens at low levels of demand.

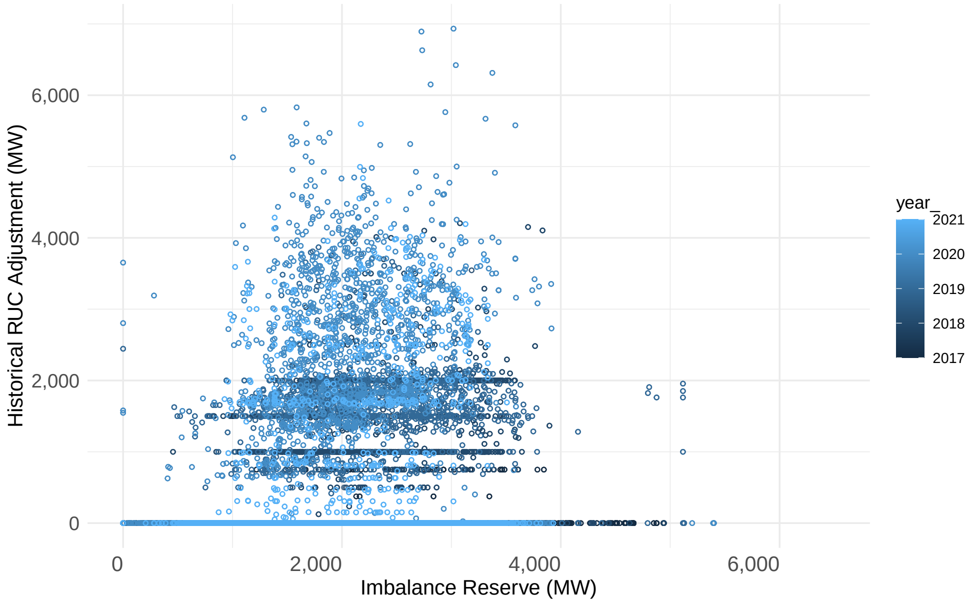

Figure 14: Correlation between RUC adjustments and imbalance reserve requirements.

Figure 15: Correlation between RUC adjustments> 0 and imbalance reserve requirements.

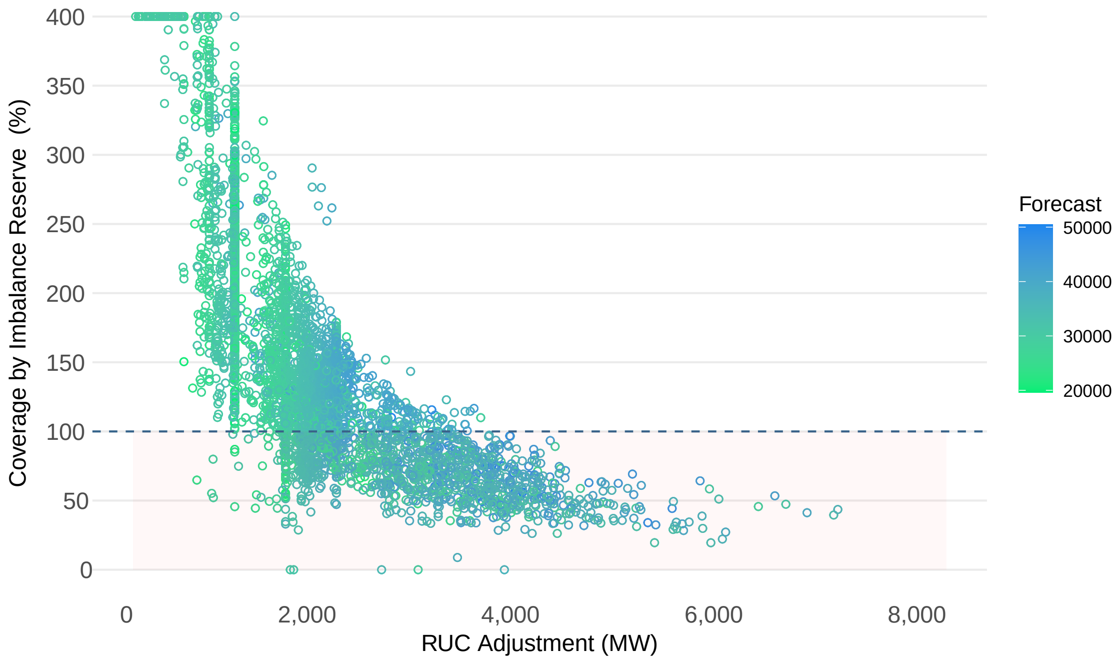

Figure 16: Coverage of RUC adjustments by imbalance reserve requirement.

7 Upper Confidence and Imbalance Reserves

In order to assess the level of coverage that IR provides for the upper confidence band, Figure 17 shows the cumulative distribution of the coverage

$$Cov_{UCB} = \frac{IR}{Upper\, Confidence\, Band} \tag{4}$$

In 2020, about 20%t of the time the IR was high enough to cover the upper confidence band (represented with the vertical blue dotted line), or in about 80% of the time, the upper confidence band was higher than the estimated IR. For 2021, that coverage increase to above 25%. The vertical line points out the coverage at the 50^{th} percentile. In 2020, for about a half of the hours the IR provided a coverage no greater than 70% , while in 2021 it was about 80%.

A different way to visualize this coverage is by a correlation plot between IR and the upper confidence band, as illustrated in Figure 18 and associating that with the level of demand. The color of the dots represents the load levels.

Figure 19 shows a comparison of ppper confidence value with RUC adjustment and estimated Imbalance reserve for the period of July 8 through 10 when the system experienced tight supply conditions. On July 8 and 9 the imbalance reserve was comparable to the levels of RUC adjustments and upper confidence. For the peak hours, the RUC adjustment level was set fully by the upper confidence value, which shows by the two lines overlapping.

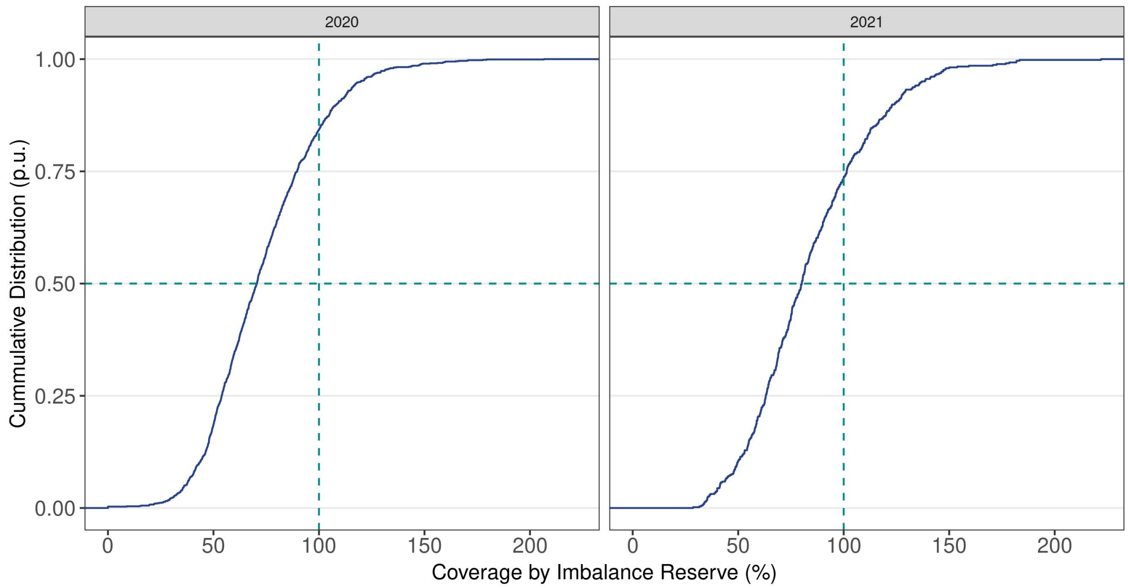

Figure 17: Cumulative distribution of IR coverage.

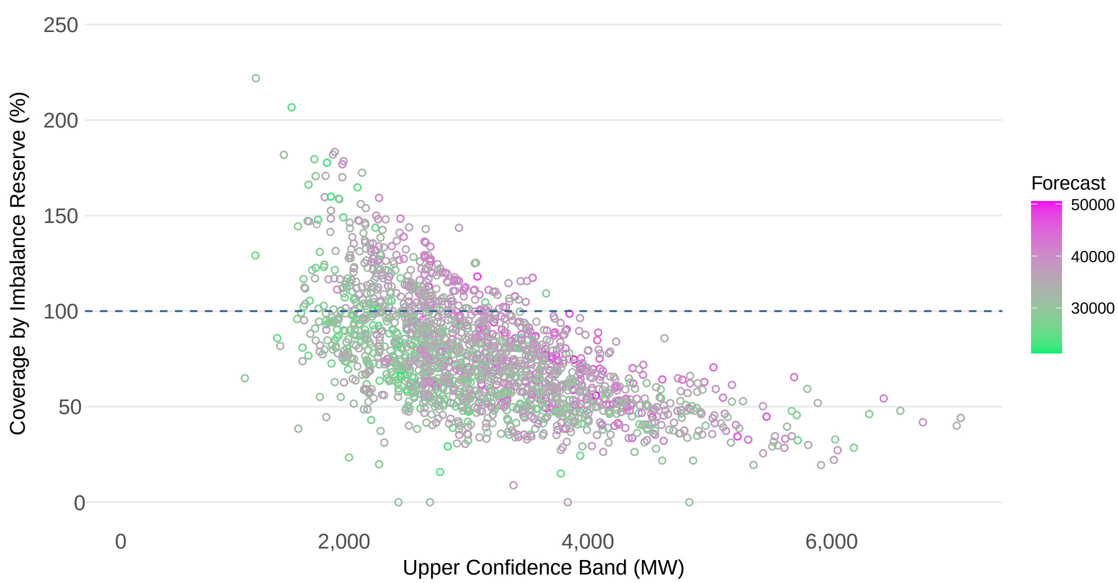

Figure 18: Coverage of upper confidence by imbalance reserves.

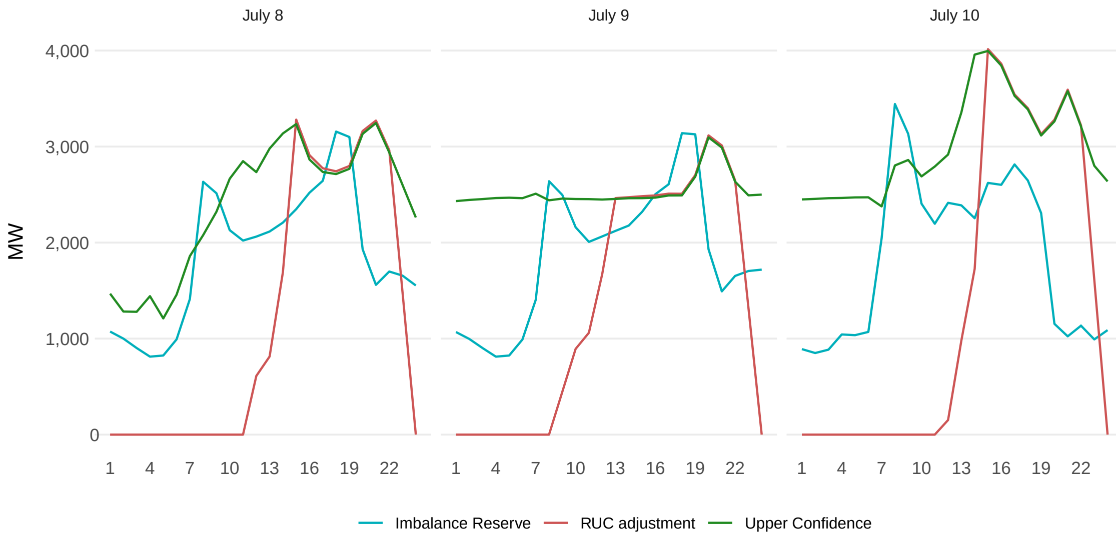

Figure 19: Comparison between confidence band, IR and demand levels. July 2021.

8 Day-Ahead Supply and Load Obligation

CAISO tracks whether RA capacity available in the CAISO's markets could be sufficient to meet the needs of both load and operating reserves. To assess this condition, all supply capacity is classified accordingly relative to its monthly RA value. For any wind or solar resource that has any RA capacity assigned in the month, the entire supply available in the market from that resource is considered RA. For instance, if a solar or wind resource has a supply available in the day-ahead market for 100 MW in a given hour and its RA capacity is 30 MW, the full 100 MW are considered RA capacity. For any other type of resource such as gas, hydro or imports, RA capacity is determined up to the RA monthly value; any capacity above the RA value is considered or above RA.

Figure 20 shows the breakdown of the day-ahead supply capacity as RA capacity and above RA capacity. The purple line represents the day-ahead load forecast plus the capacity required to meet operating reserves (OR), which is typically about 6 percent of the load value. The blue line represents the adjusted load forecast which is obtained by adding the RUC adjustments plus OR. The yellow dotted line represents the load forecast plus OR plus IR estimated with a quantile approach. These trends allow one to compare the overall load obligation to be met with all available supply. In particular, the comparison of the load obligation with RUC adjustments compared to the load obligation can show how closely the obligation with RUC adjustments or IR tracked to available supply.

Figure 21 and 22 show a more granular trends for July 8 through 10 when CAISO experienced tight supply conditions; it is shown for both the gross load obligation and net load obligation. Figure 21 has the same capacity breakdown but the comparison is relative to the net load (gross load minus VER forecast). Since this figure represents net load, the supply side is also reduced by subtracting all VER contributions. Tracking the available capacity for the net load peak hour is as important as tracking available capacity for the gross peak hour.

Overall, these granular trends show that in these particular days the obligation set by the RUC adjustments or IR tracked closed one to another. In this context, the use of IR could have created similar burden on the supply pool.

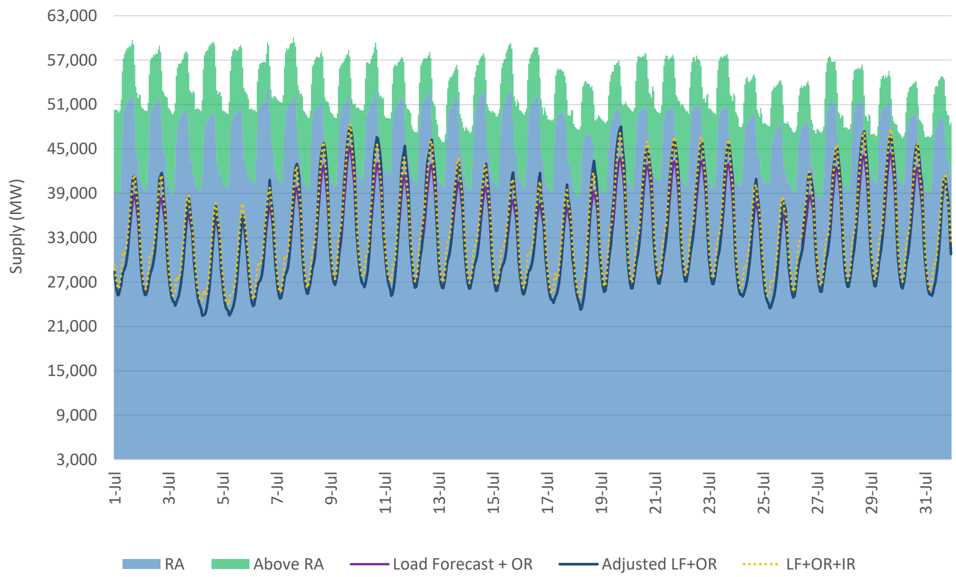

Figure 20: Supply capacity available relative to load obligation in the day-ahead market

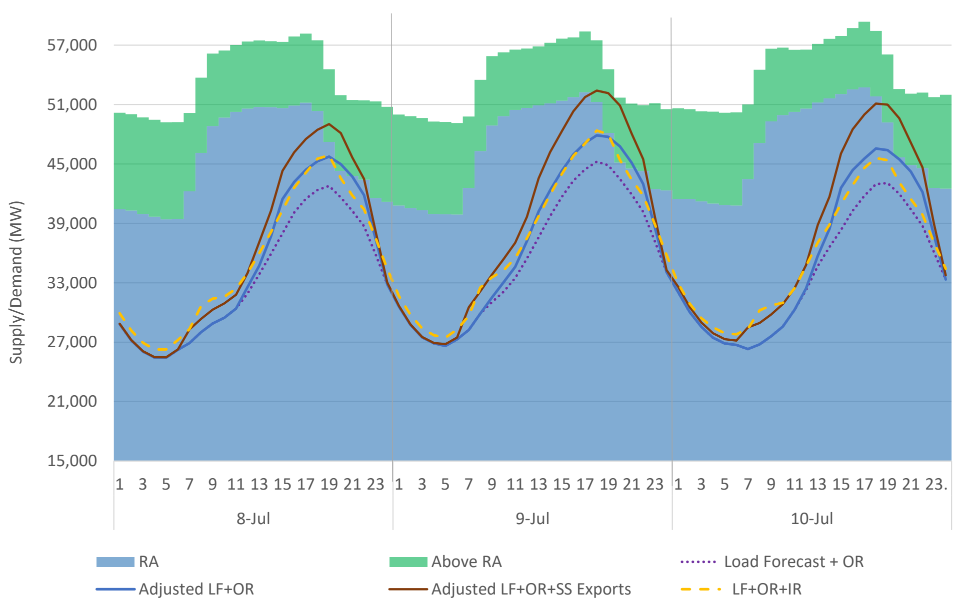

Figure 21: Supply capacity available and gross load obligation for July 8-10

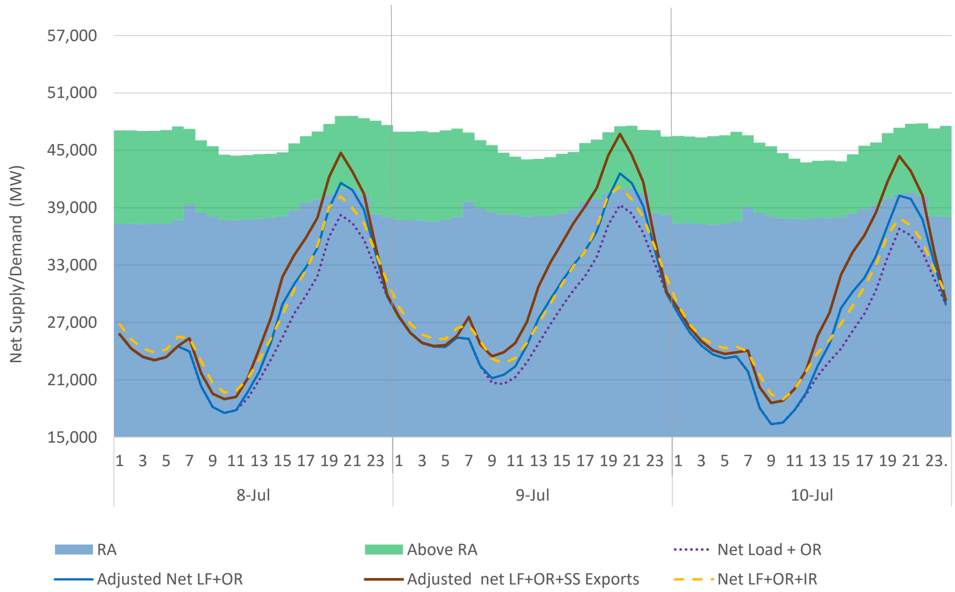

Figure 22: Net supply capacity available and net load obligation for July 8-10

9 RUC Capacity

9.1 Incremental capacity and commitments

The integrated forward market (IFM) clears the market supply against bid-in demand, while RUC clears physical resources against the day-ahead adjusted load forecast. Starting from the IFM solutions, the RUC pass will procure extra or reduce excess supply where necessary, resulting in a potential schedule difference between the two markets. RUC capacity is defined as the supply increase in RUC from IFM. Subsequent figures show the RUC capacity organized by different grups.

Each data point is the net delta $()RUC - IFM)$ per trade date, hour, by the corresponding grouping type. Typically the deltas will be positive indicating RUC needed to secure more capacity, leading to the positive RUC capacity volumes in the figures below. The highest values of incremental RUC capacity occurred in summer months. In some cases, RUC cleared over 4,000MW additional supply.

Figure 23 and 24 show the monthly and hourly distributions of the total incremental RUC capacity grouped by the time of dispatch between IFM and RUC. Since the metric is intended for analyzing supply patterns, exports are excluded. For resources already committed in IFM, RUC capacity is simply an incremental dispatch as it is a matter of utilizing their unloaded capacity. This is referred as *Incremental* and represents the total delta schedule from the IFM committed resources. These values can be both positive and negative. RUC can also commit additional resources. These are label as *Commitment* in the figures below. Since RUC should not de-commit resources, incremental RUC from RUC commitments are expected to be non-negative [1].

Distribution of type incremental capacity had higher median values thane commitment capacity for almost all months. Under stressed conditions, when RUC needed to increase the supply extensively

[1] The negative values shown for trade date 05/10/2021 were due to a missing data point

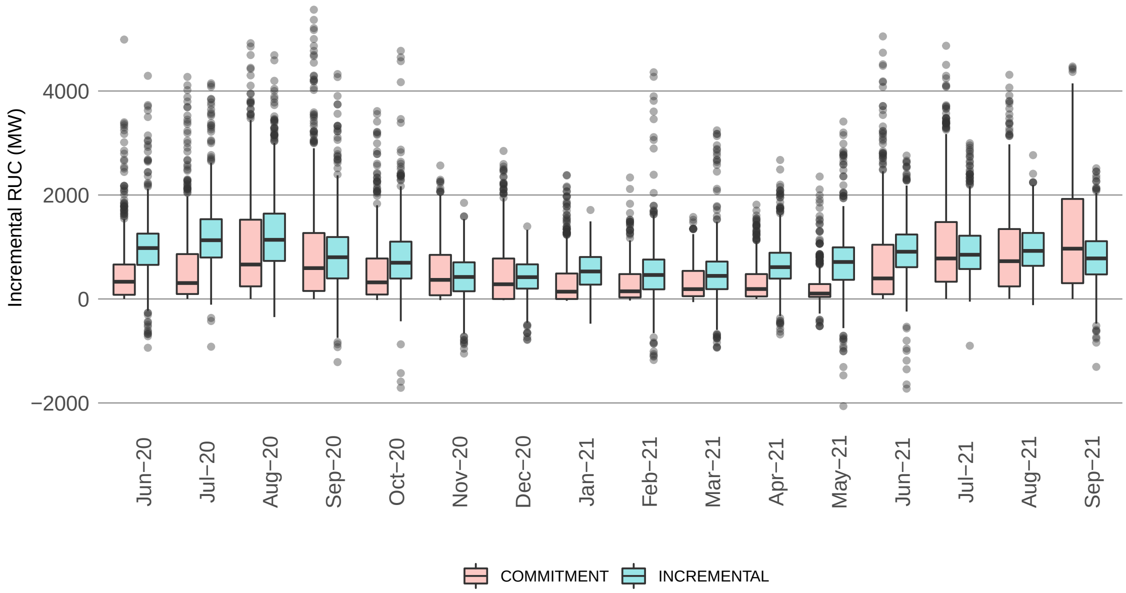

Figure 23: Monthly RUC capacity organized by incremental and commitment capacity.

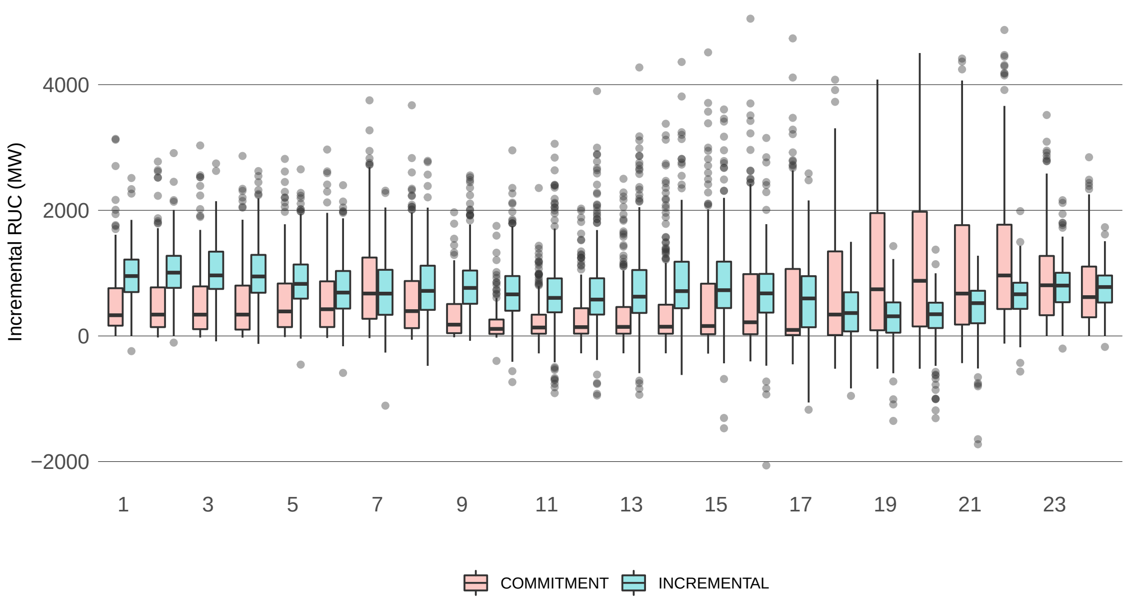

Figure 24: Hourly RUC capacity organized by incremental and commitment capacity

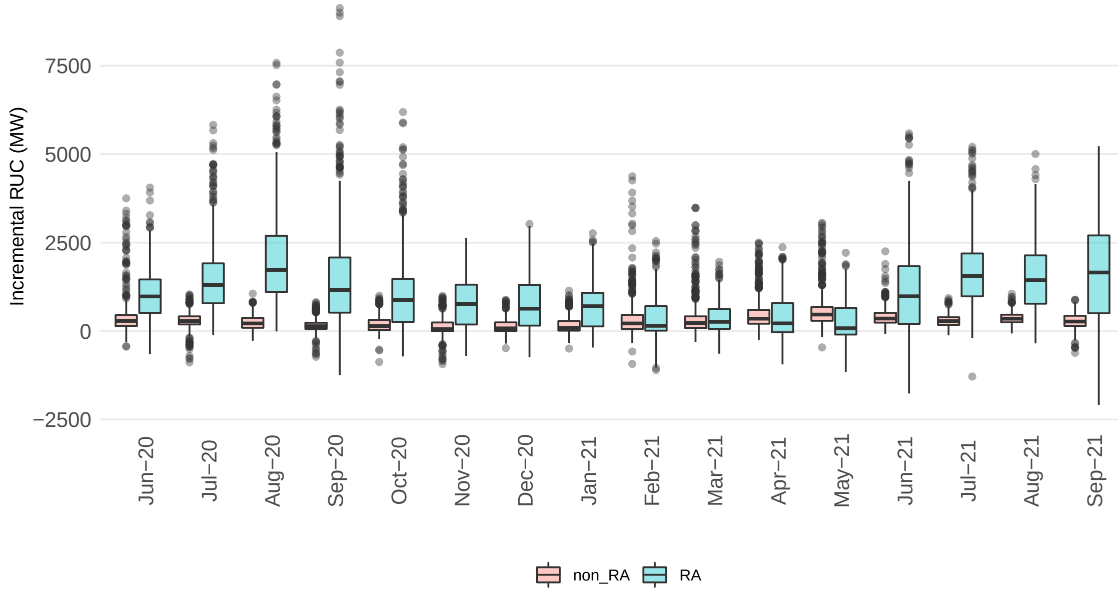

Figure 25: Monthly RUC capacity organized by RA and above RA.

on the local or large-scale, RUC capacity was mostly supported through RUC commitments. Capacity from commitment had higher median and wider spreads than incremental capacity from hour ending 19 through 22.

Figure 50 in Appendix provides a more granular of the monthly trends. It displays the distribution of hourly RUC capacity, organized by month, for Q1 through Q3 of 2021. From January through May, the RUC capacity was around or below 2,000MW. Going into summer from June to September, hour ending 18 through 22, the volume of RUC capacity increased rapidly to more than double and peaked around hour ending 20 to 21.

9.2 RA capacity and above RA capacity

Figure 25 and 26 display the same RUC capacity volumes broken down by resource adequacy (RA) and non-RA. The RA portion is the additional RUC procurement supported by RA resources with a must offer obligation, and the non-RA portion is the additional RUC capacity above RA. As shown in the figures, the overall RUC capacity was met largely by RA capacity. From February through May, total RUC capacity was mostly contributed by non-RA capacity for hour ending 10 through 17. For summer months June through September, RUC relied on RA to procure additional capacity. Figure 51 in Appendix provides a breakdown by hour and month.

9.3 RUC capacity organized by fuel type

Figure 27 and 28 partitions the RUC capacity by fuel types. To align with the direction of increasing market supply, RUC reduction for exports was counted as the incremental RUC capacity. Gas and solar made up over 50% of incremental RUC capacity across all months. Together with wind and hydro, they made up over 90% of the supply increase in RUC.

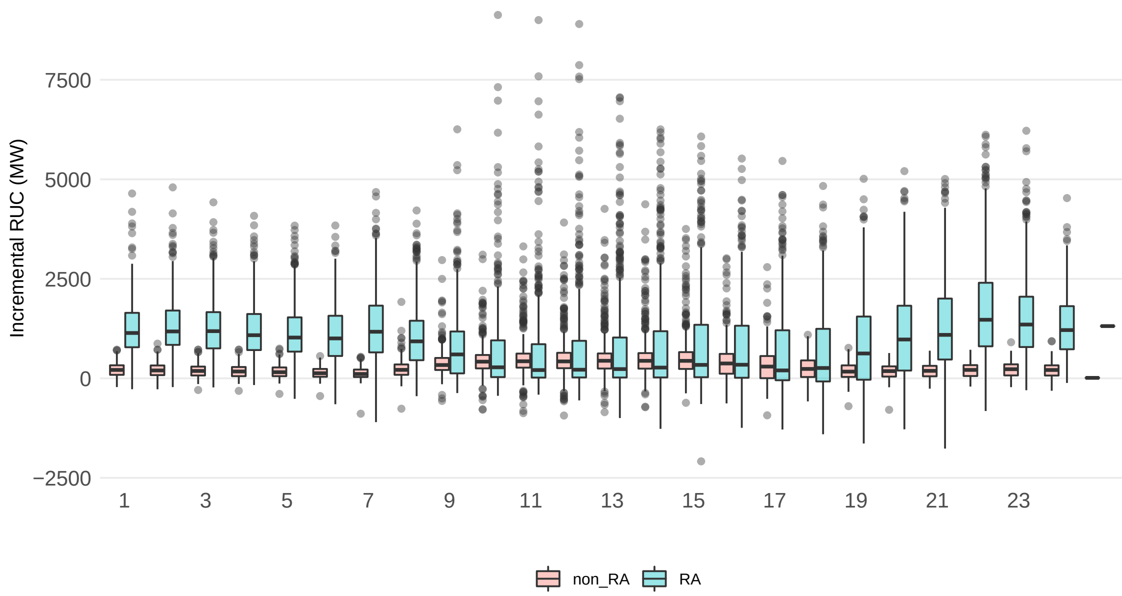

Figure 26: Hourly RUC capacity organized by RA and above RA.

Figure 27: Monthly RUC capacity by fuel type.

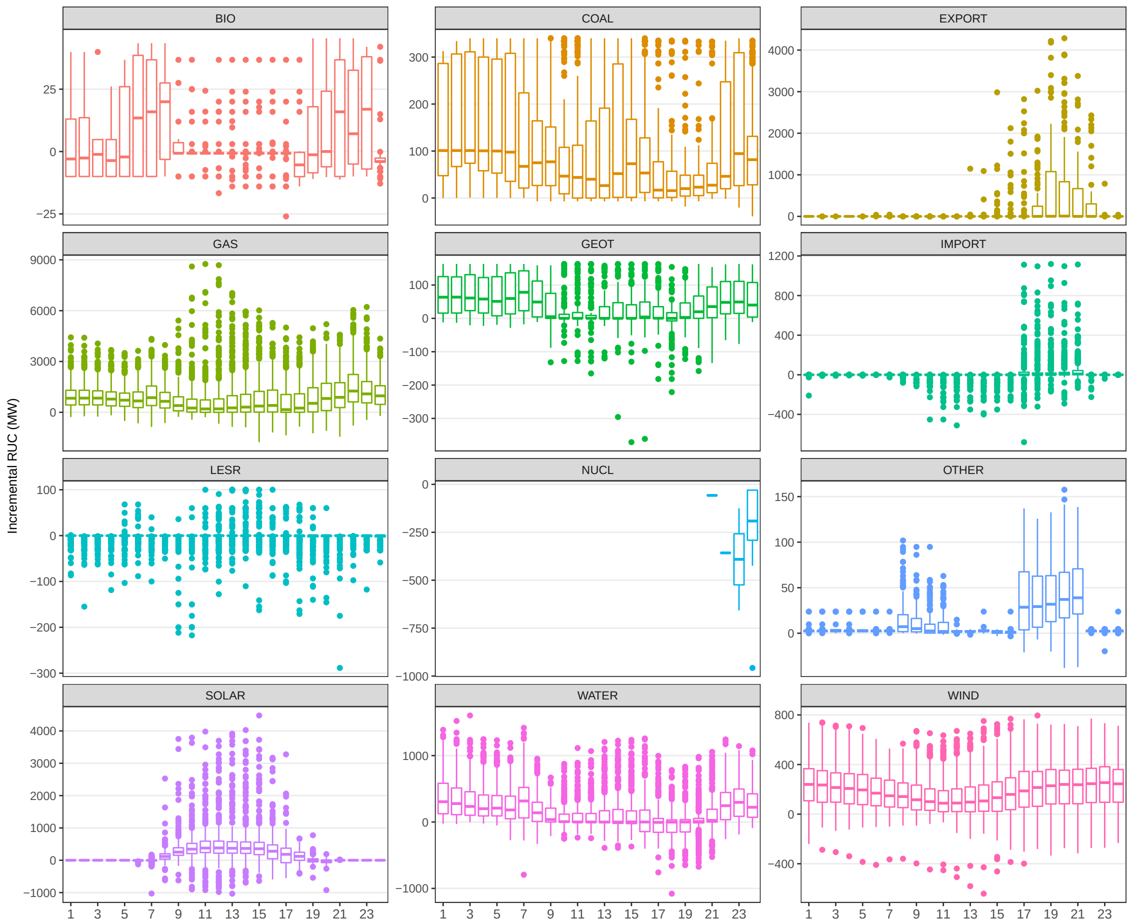

Figure 28: Hourly RUC capacity by fuel type.

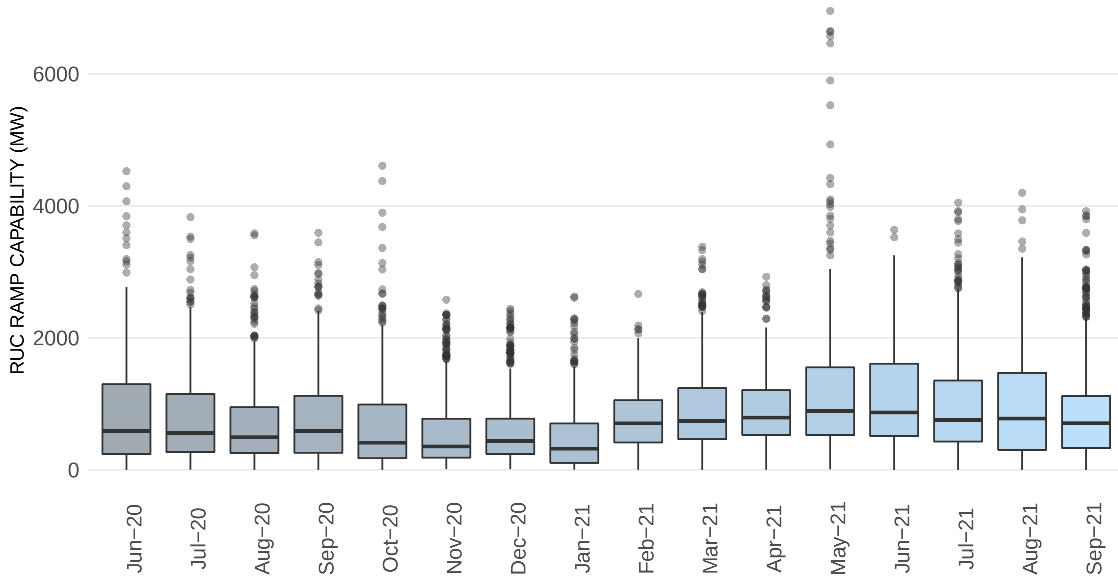

Figure 29: Monthly RUC ramp capability.

9.4 RUC ramp capability

RUC ramp capability is additional headroom available (unloaded) supply from the resources dispatched in RUC, taking into consideration the resource limitations such as bid max, ramp rates, and outages. The aggregated ramp capability indicates the extra flexibility of the supply. This can serve as an upper bound on the ramp capability in RUC; however, when analyzing the data, there may be other factors that could prevent that capacity from being fully utilized, such as congestion forcing certain resources to have lower dispatches and unable to be dispatched upward.

Monthly and hourly distribution of the ramp capability in RUC from June 2020 to September 2021 are presented below in Figures 29 and 30. From the monthly view, June through September 2021 had relatively higher ramp capability than the corresponding months in 2020. On the hourly view in 30, hour ending 9 to 14 had the highest hourly ramp capability of the day.

Figure 31 and 32 show the breakdown by fuel types. The total ramp capability was primarily contributed by gas and hydro. As solar supply reduced in the late afternoon, other resources provide supply to offset the drop and to serve the evening peak. The afternoon ramp capability was largely utilized in this period, resulting in the diminishing availability in ramp capability from hour ending 17 to 22.

This ramp capability can also be seen by the speed of resources to provide the ramp, which is based on the ramp rate. As a sample, Figure 33 and 34 show the breakdown of ramp capability for gas resources organized by month and hour.

9.5 July 7 – 13 and September 4 – 10, 2021

Figures 35 through 38 show the hourly incremental RUC capacity during tight system conditions over the last summer, July 7 – 13 and September 4 – 10, 2021. Within the two weeks, generally RUC needed to schedule additional capacity of up to 3,000MW. The highest RUC capacity was over 5000mw (hour ending 22 on July 10th, hour ending 22 on September 8th, hour ending 22 on Sep 10th). in SOme sinatnces, RUC capacity can be negative. FOr instance, on September 7th, RUC capacity was negative

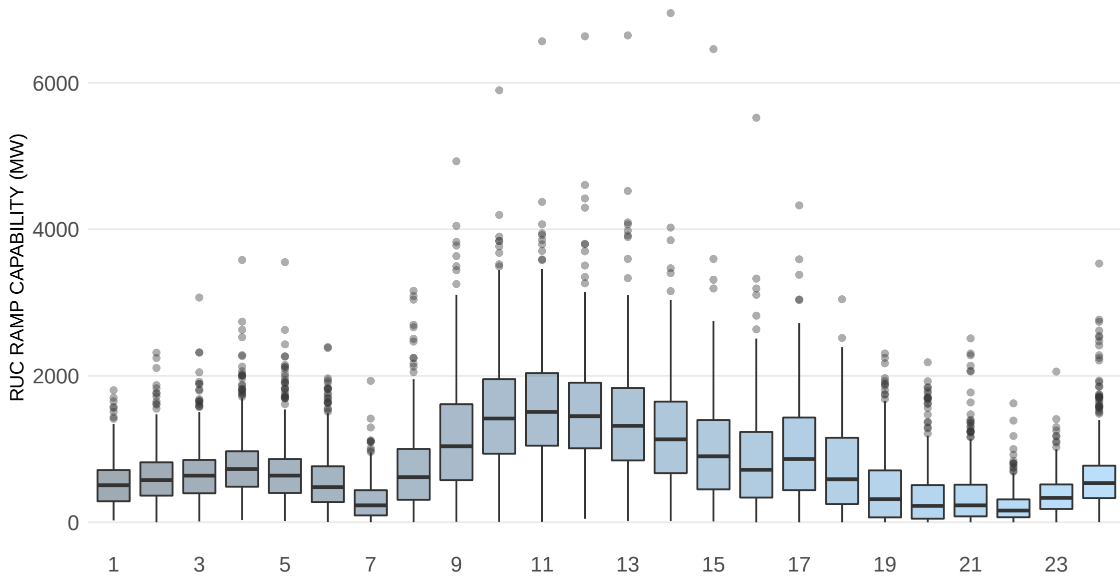

Figure 30: Hourly RUC ramp capability .

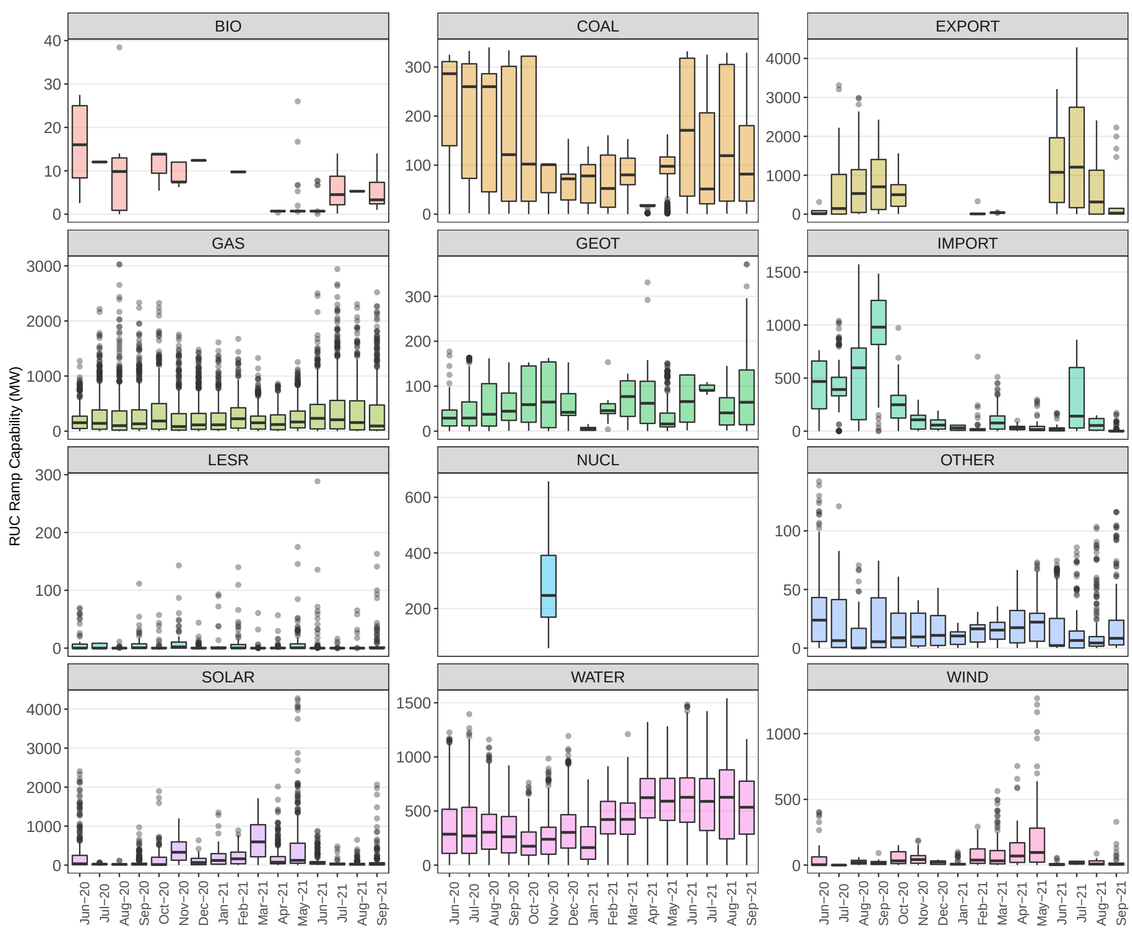

Figure 31: Monthly RUC ramp capability organized by fuel type.

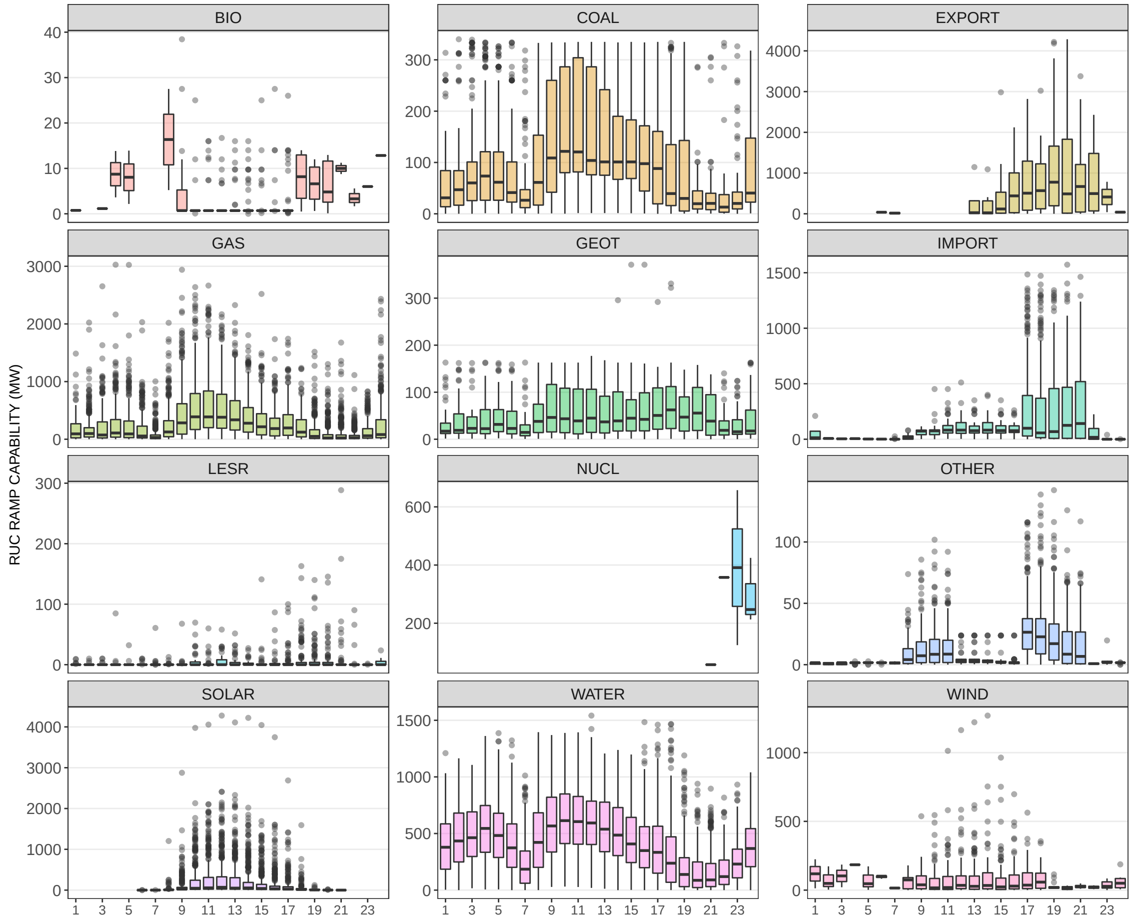

Figure 32: Hourly RUC ramp capability organized by fuel type.

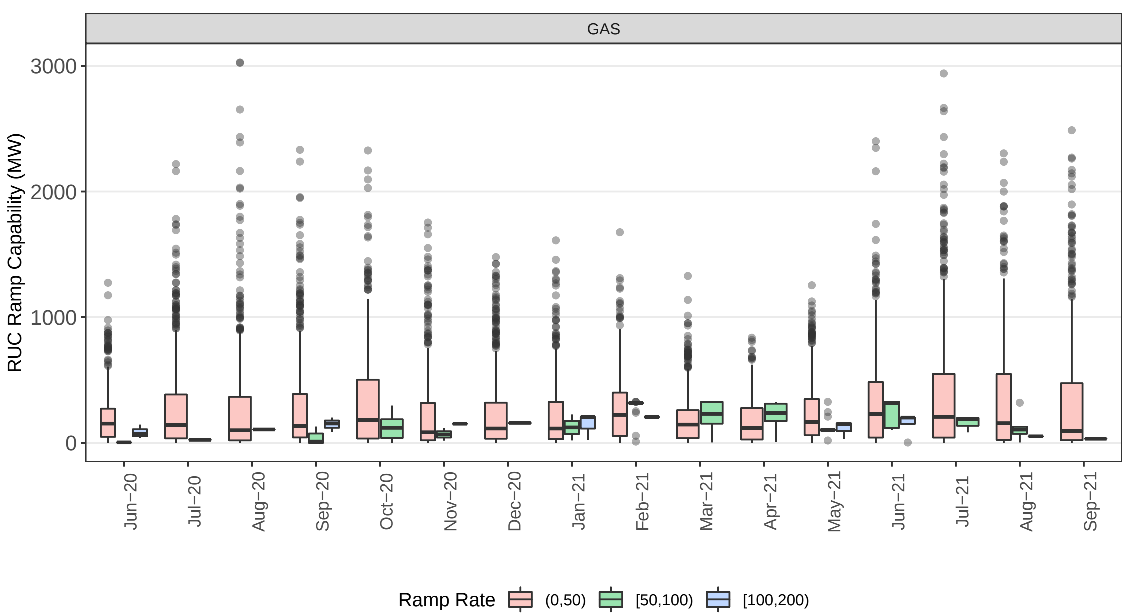

Figure 33: Monthly RUC ramp capability for gas resources.

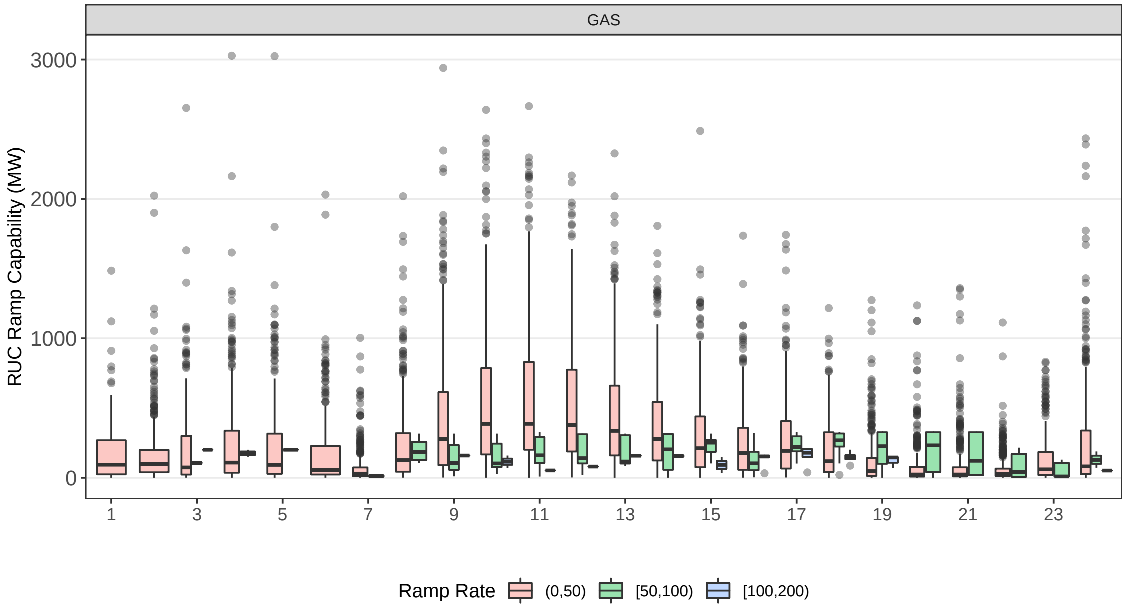

Figure 34: Hourly RUC ramp capability for gas resources.

from hour ending 13 to 15, due to the system over-gen. This happened when RUC had to reduce supply to match forecasted demand through adjusting the schedule from IFM dispatch downward.

From Figures and , RUC capacity was largely supported by gas resources followed by hydro and wind. In some critical hours, RUC capacity was gained by reducing exports, which in some cases exceeded 1,000MW. Instances of these reductions are hour ending 20 on July 8, hour ending 18-22 on July 9, hour ending 19-21 on July 10 – 12, and hour ending 19 on September 8 – 9.

Figure 41 and 42 show the hourly RUC capacity for the same period. The availability of RUC ramp capability on the supply side approximately complemented the level of the incremental RUC capacity. When RUC scheduled more supply, the available ramp capability was utilized, so the unloaded capacity reduced. For hour ending 19 to 22, RUC ramp capability was low or close to zero when incremental RUC capacity was high. The highest ramp capability was about 2000MW or higher in hour ending 9 to 12. Gas and hydro were the two main sources of ramp capability.

Figure 43 and 44 display the breakdown by ramp rate. Most RUC ramp capability are from resources at the ramp rate below 50MW/min.

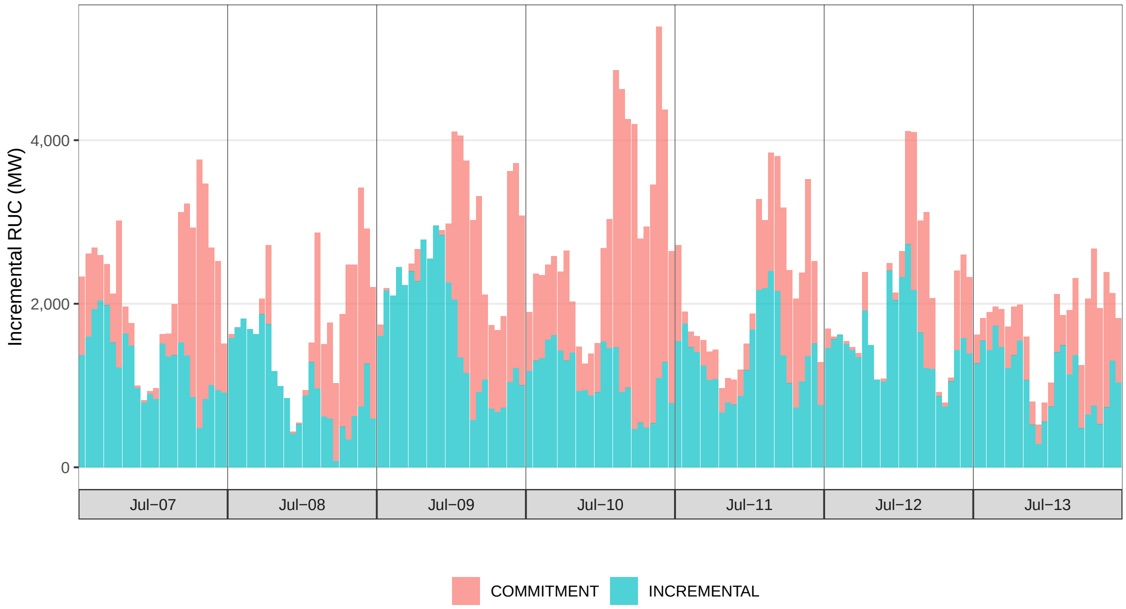

Figure 35: Hourly RUC capacity, commitment vs. incremental. July 7-13.

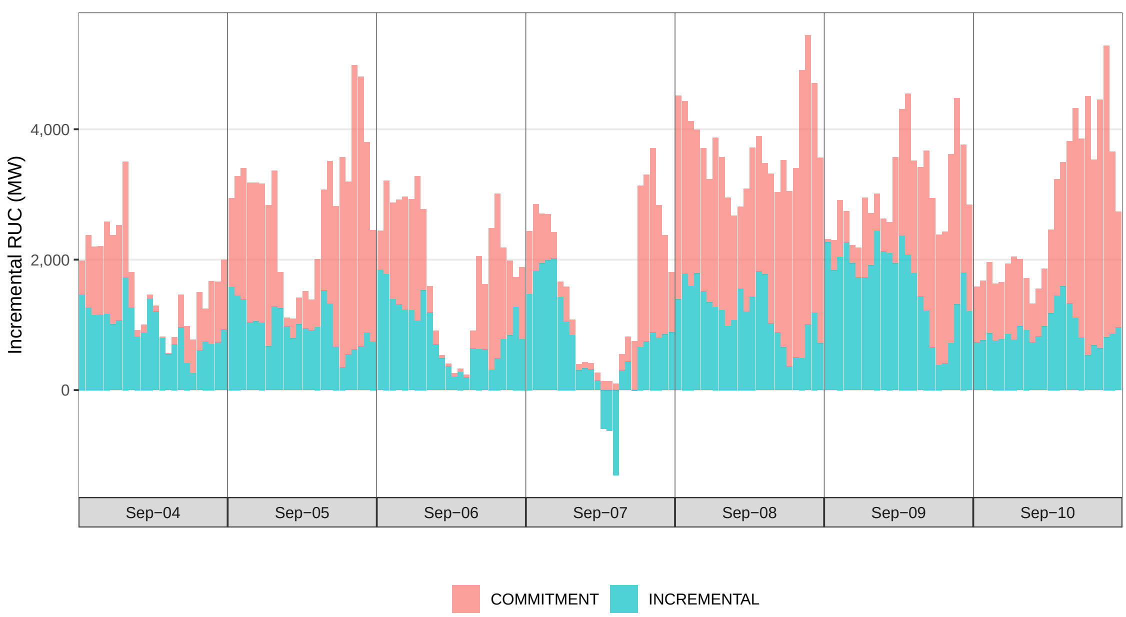

Figure 36: Hourly RUC capacity, commitment vs. incremental. September 4-10.

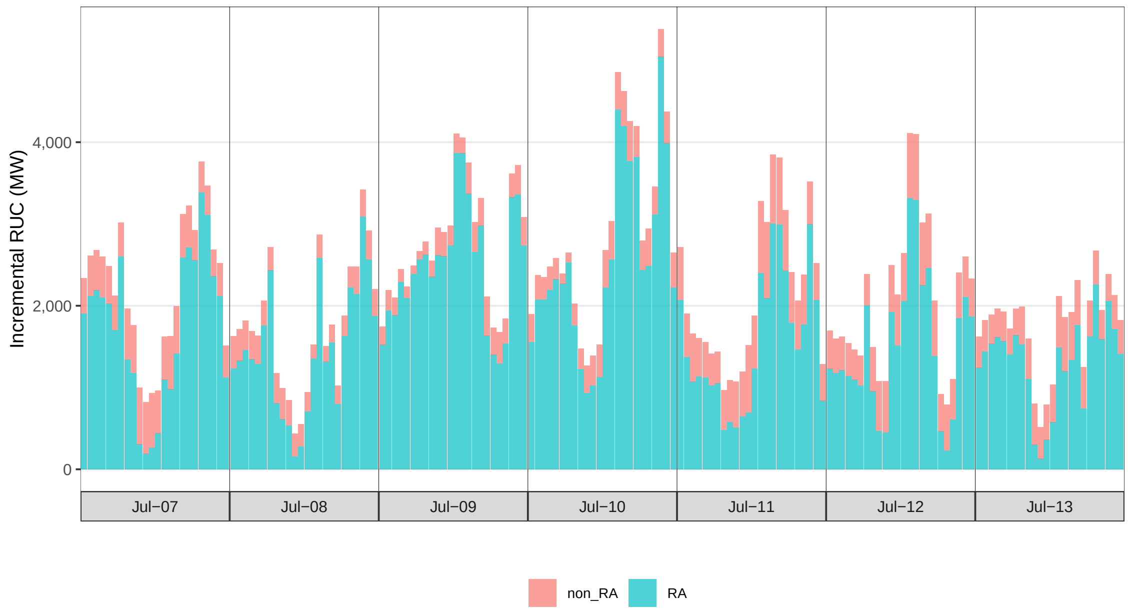

Figure 37: Hourly RUC capacity, RA vs. Above RA. July 7-13.

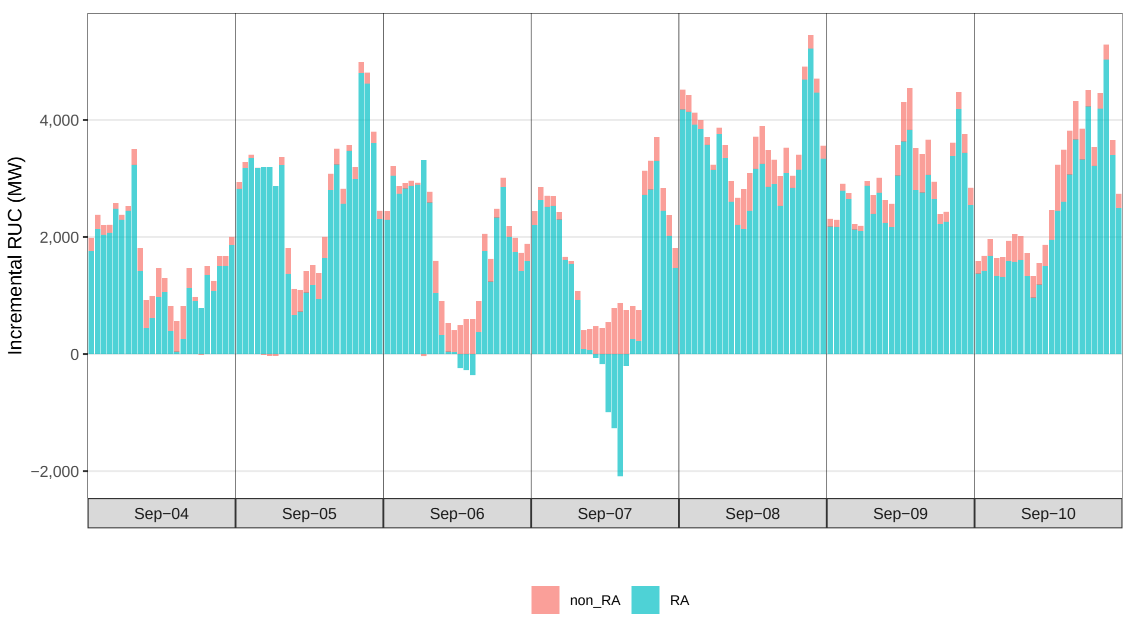

Figure 38: Hourly RUC capacity, RA vs. Above RA. September 4-10.

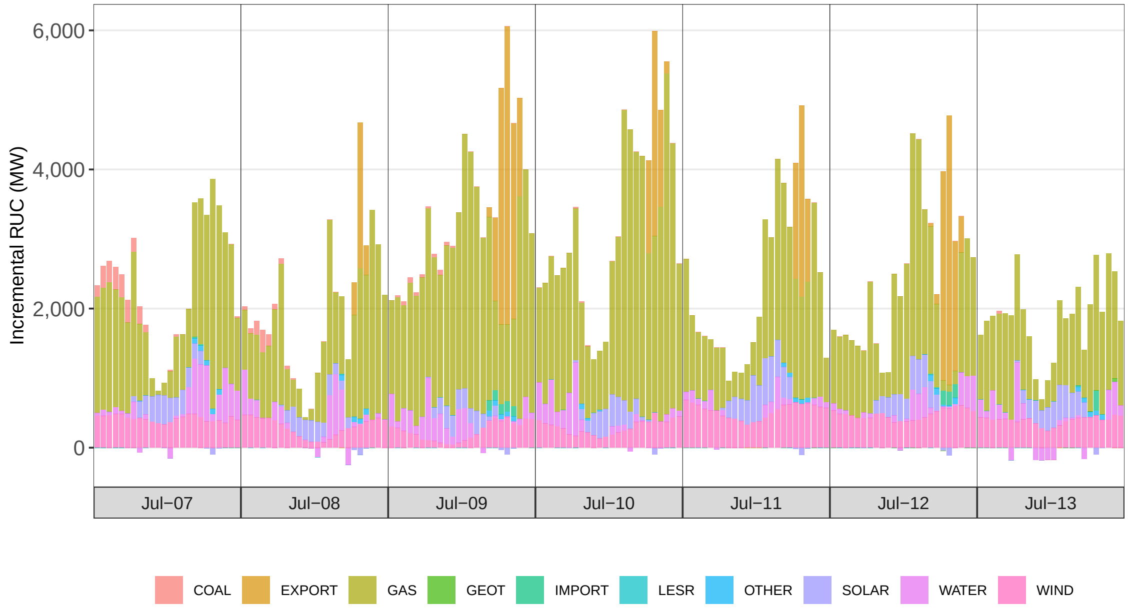

Figure 39: Hourly RUC capacity, RA vs. Above RA. July 7-13.

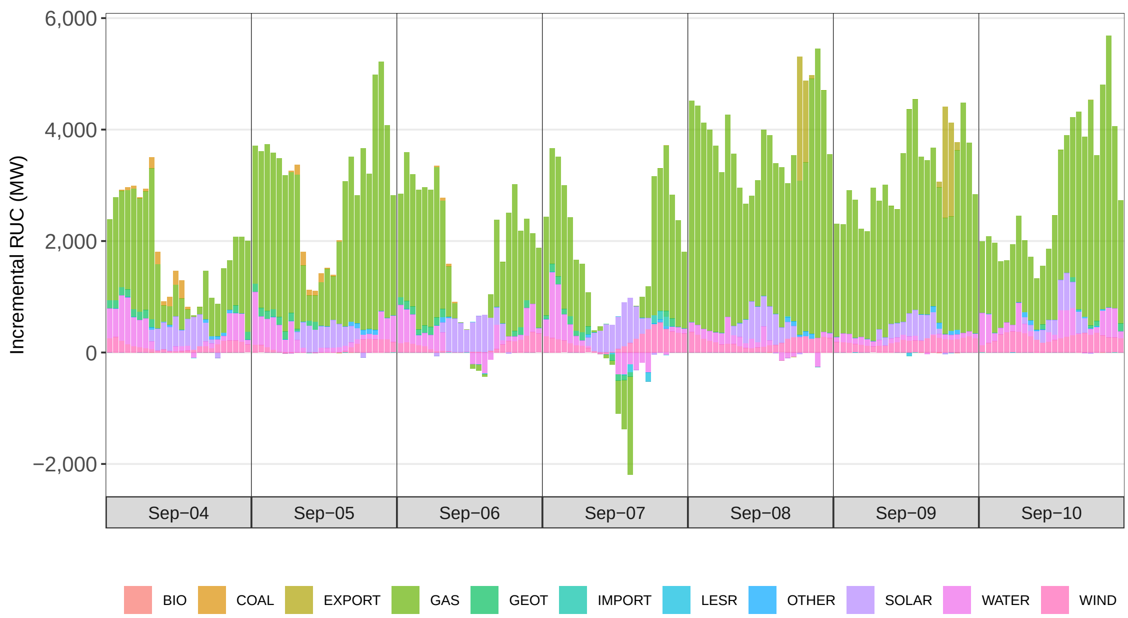

Figure 40: Hourly RUC capacity, RA vs. Above RA. September 4-10.

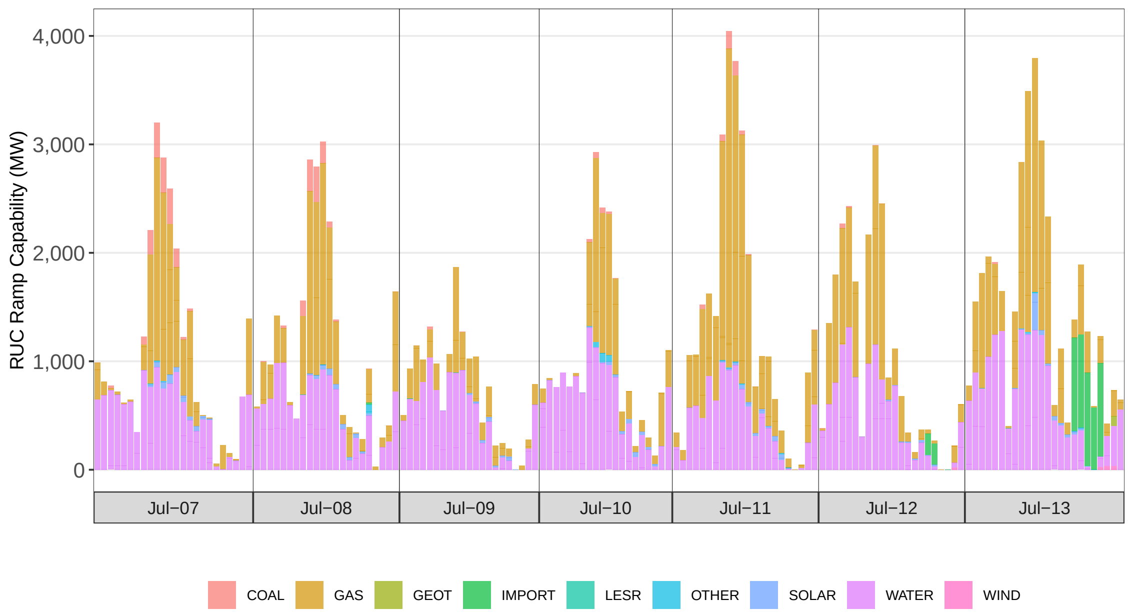

Figure 41: Hourly RUC ramp capability, by fuel type July 7-13.

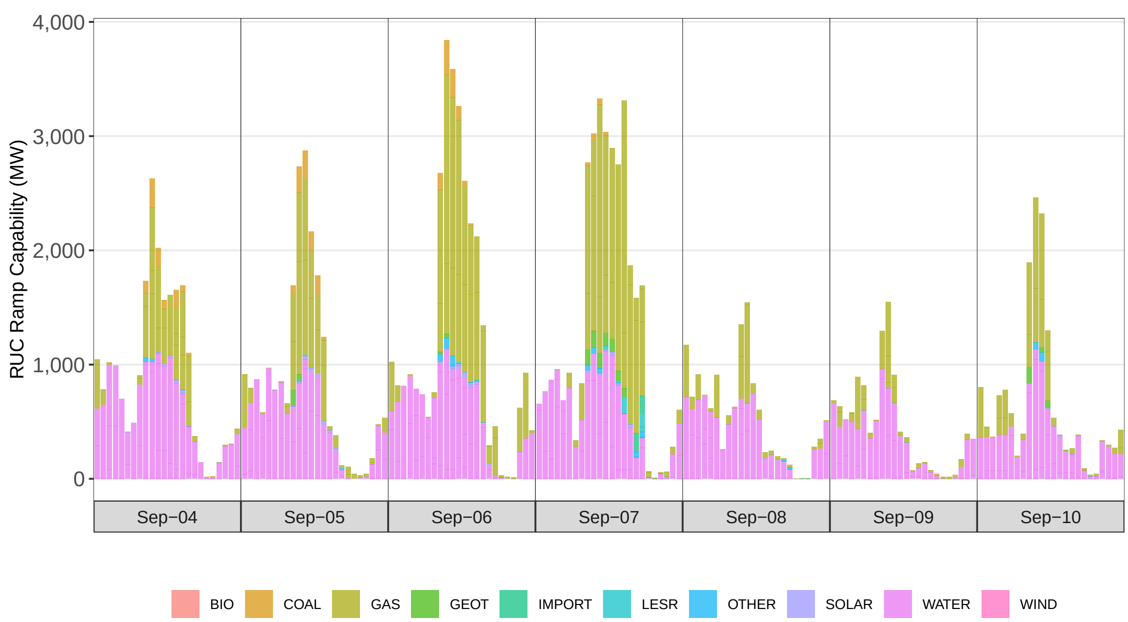

Figure 42: Hourly RUC ramp capability, by fuel type September 4-10.

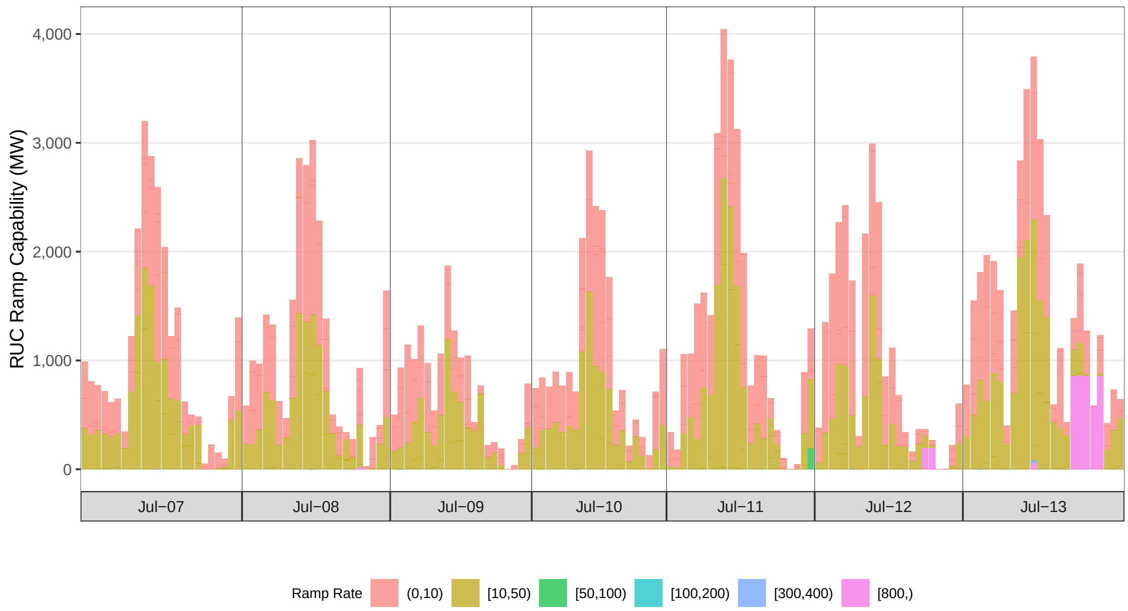

Figure 43: Hourly RUC ramp capability, by ramp rate July 7-13.

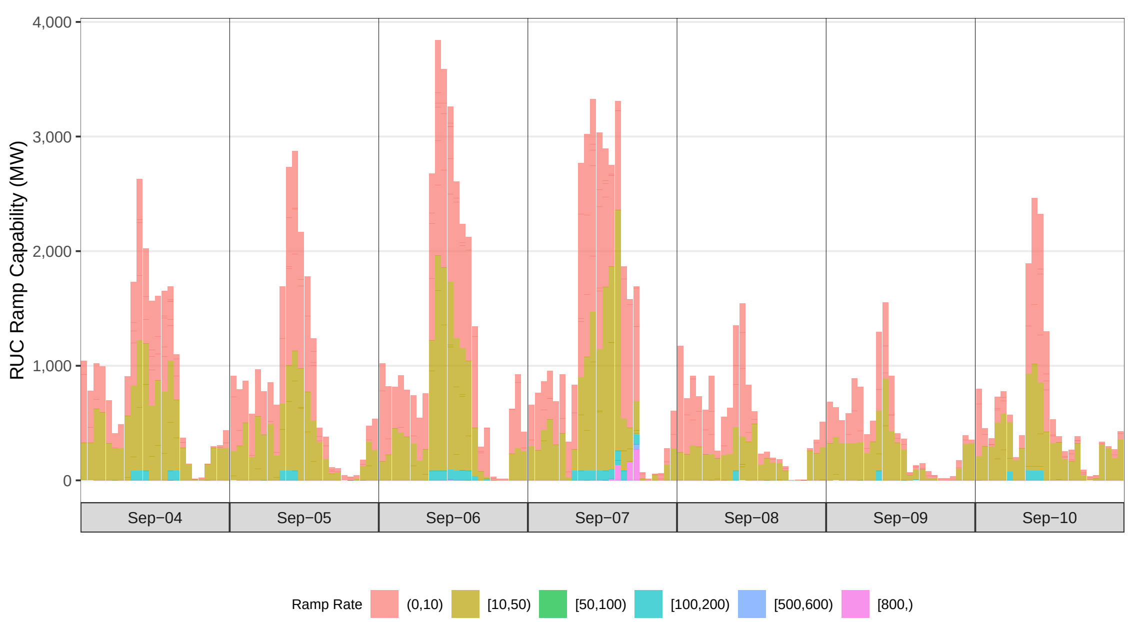

Figure 44: Hourly RUC ramp capability, by ramp rate. September 4-10.

10 Appendix

This appendix provides additional metrics with more granular trends of the different areas analyzed in this report.

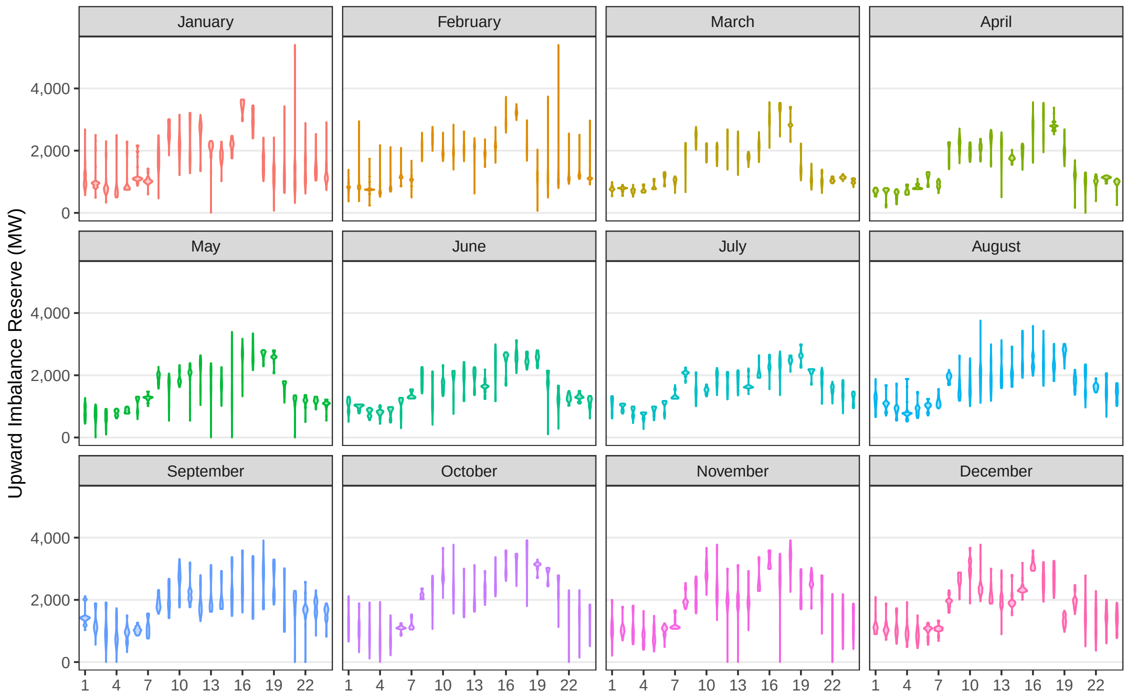

Figure 45: Monthly trend for upward IR in 2020.

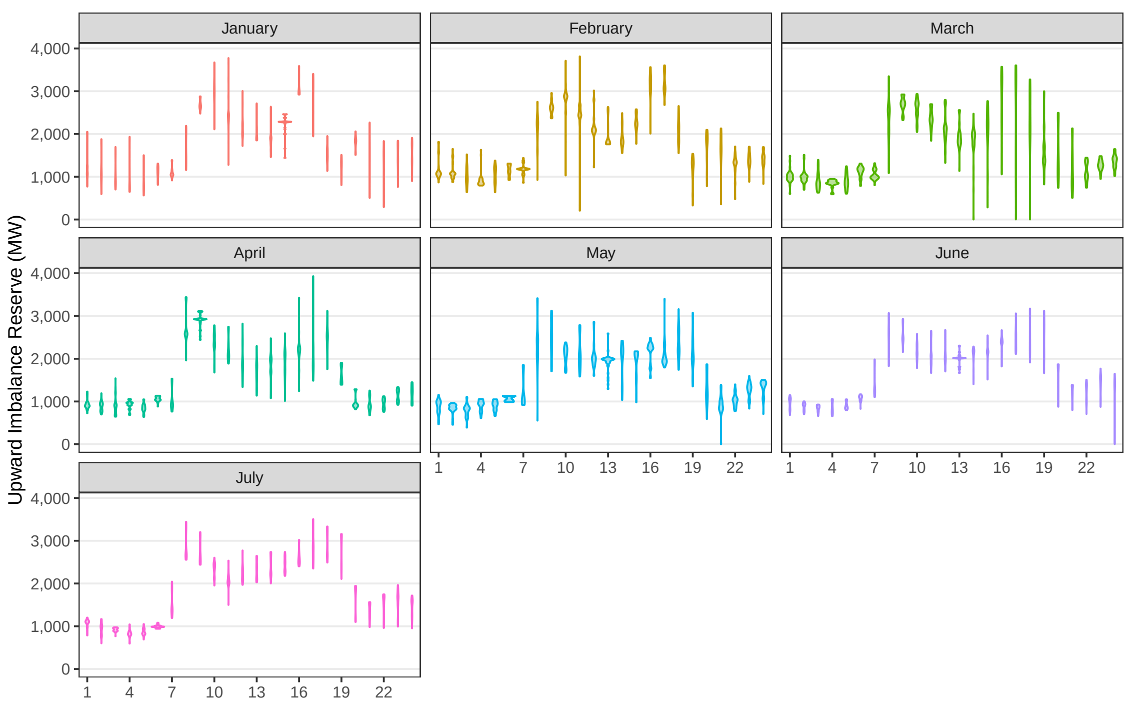

Figure 46: Monthly trend for upward IR in 2021.

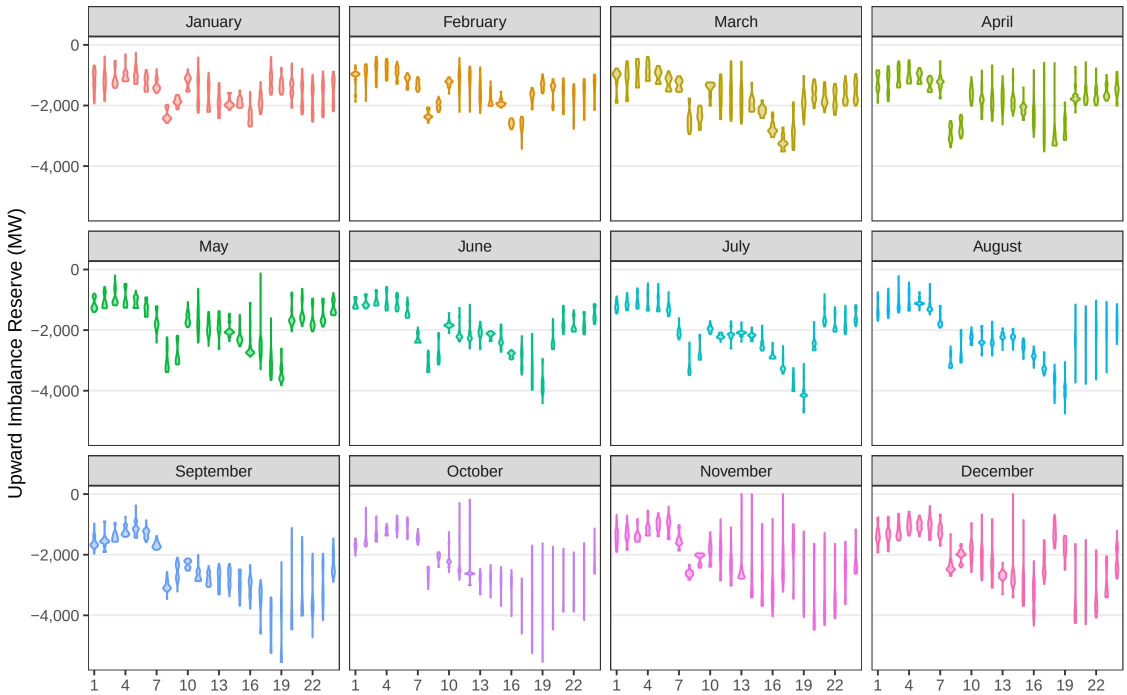

Figure 47: Monthly trend for downward IR in 2020.

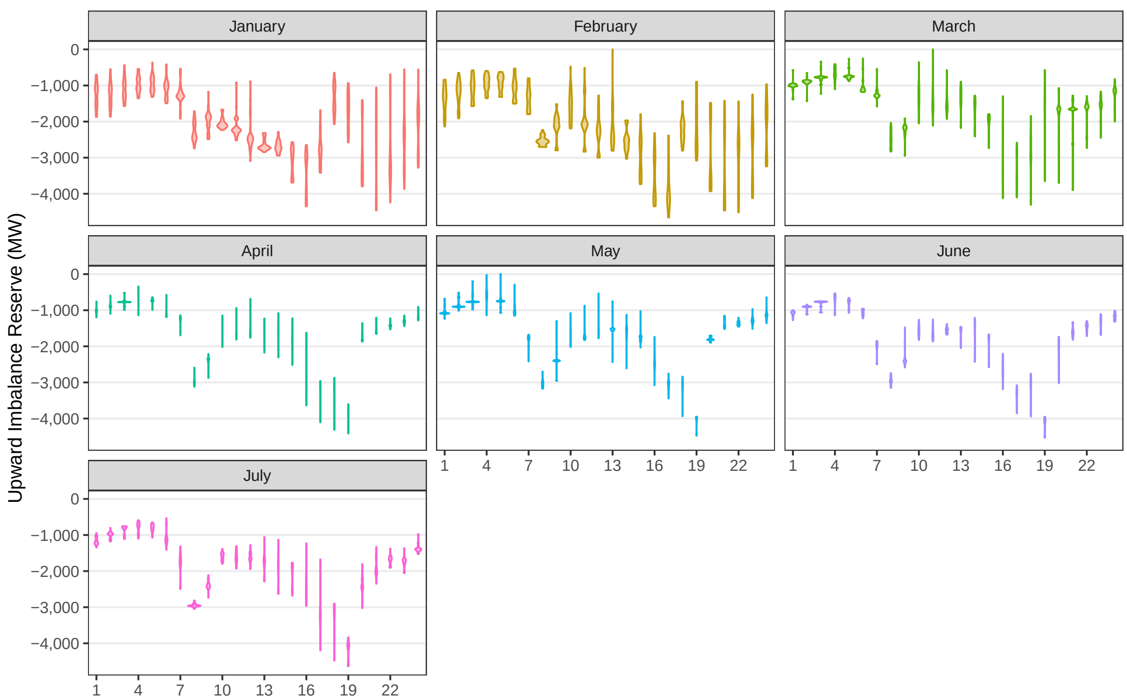

Figure 48: Monthly trend for downward IR in 2021.

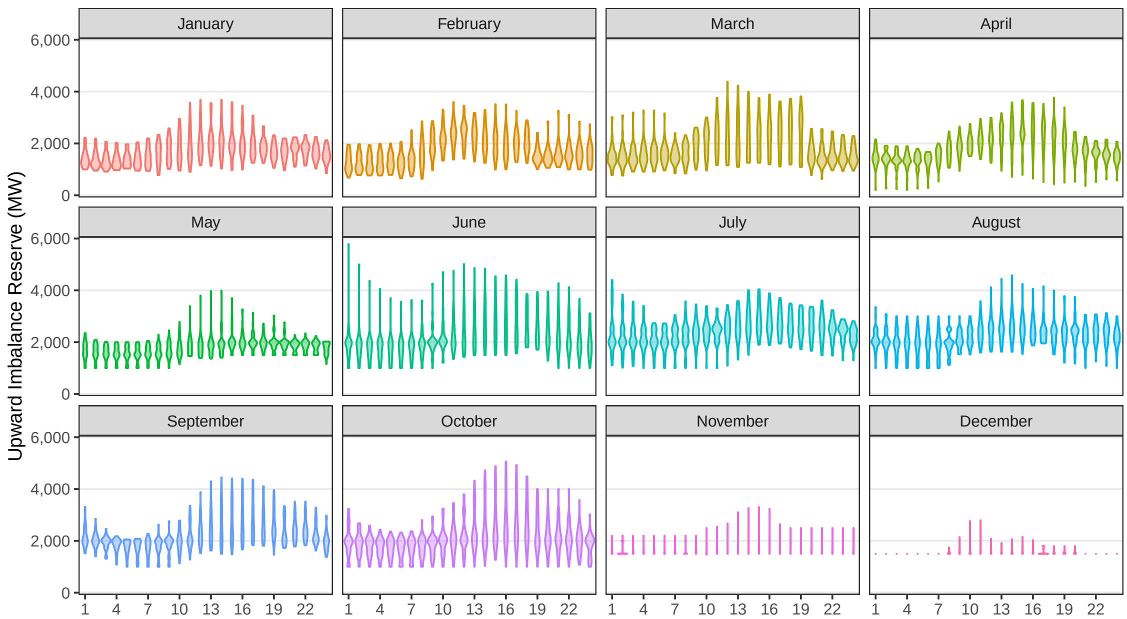

Figure 49: Hourly distribution of upper confidence values in 2021.

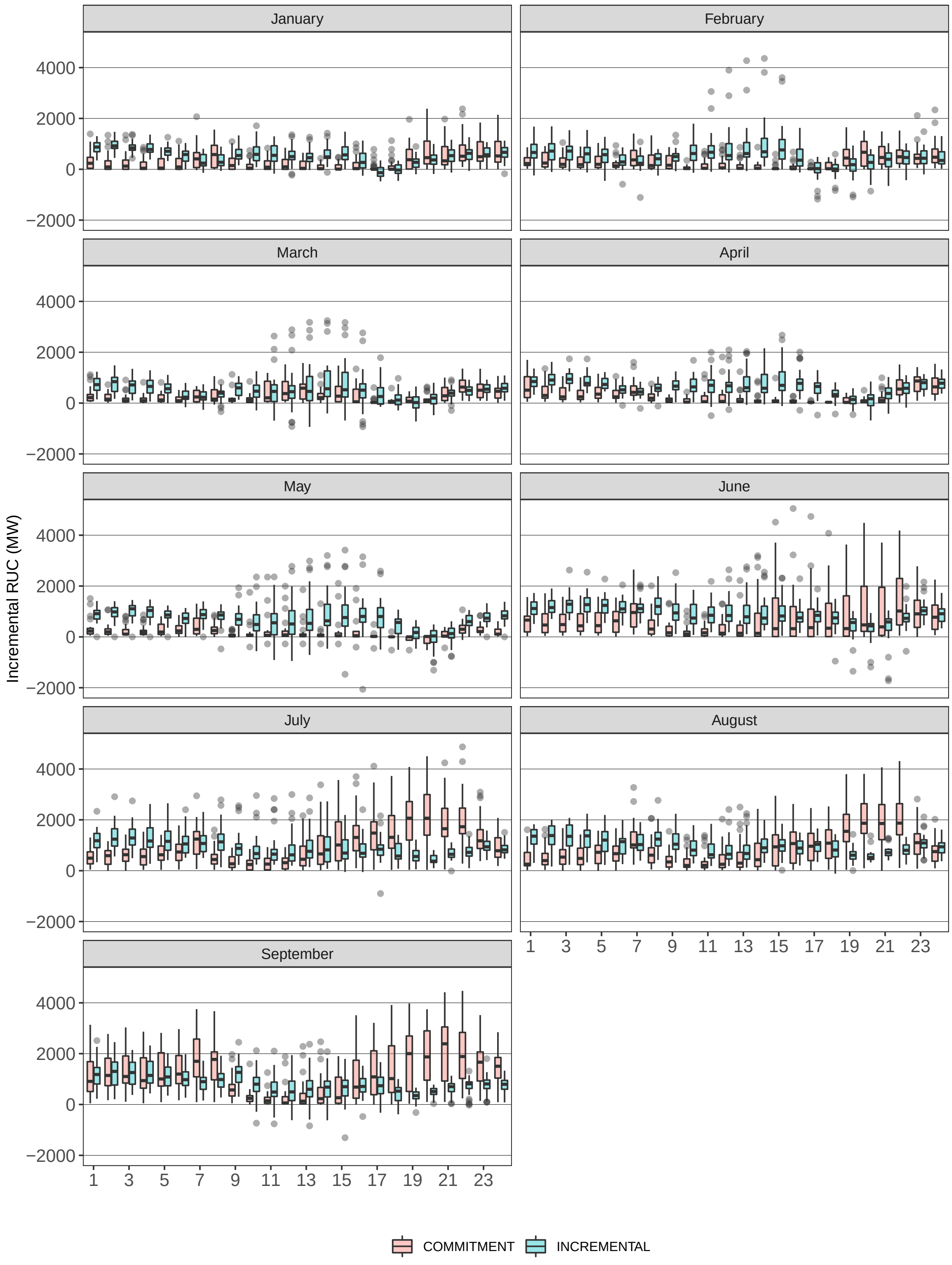

Figure 50: Hourly incremental RUC capacity, commitment vs incremental (Q1-Q3, 2021).

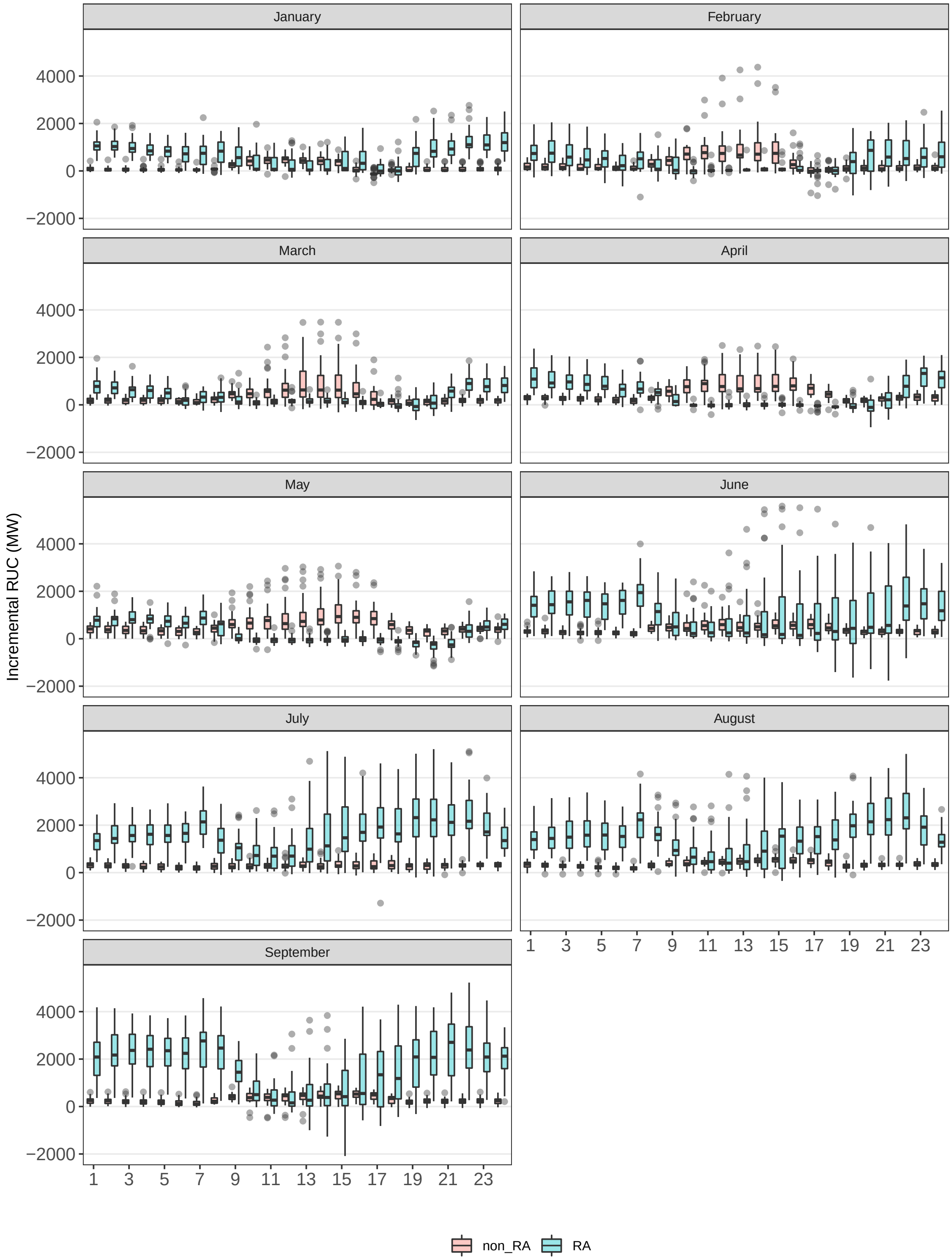

Figure 51: Hourly incremental RUC capacity, RA vs non-RA (Q1-Q3, 2021).