MARKET MONITORING UNIT

STATE OF THE MARKET

SUMMER 2022

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1 MARKET HIGHLIGHTS

This report covers market performance and highlights during the summer quarter of 2022 (June through August). Annual figures shown on the charts in this report represent only this three-month period for each year, unless labelled otherwise. Highlights of this summer period are as follows:

- The average gas price at the Panhandle Eastern hub remains high with an average of $7.31/MMBtu in summer 2022, up 114 percent from $3.42/MMBtu in 2021. The gas price hit a new all-time high (outside of February 2021) for the Integrated Marketplace at $8.03/MMBtu in August 2022.
- Day-ahead prices increased from an average of $33.30/MWh in summer 2021 to $74.63/MWh in 2022, an increase of 124 percent. Real-time prices increased from an average of $30.68/MWh in summer 2021 to $69.65/MWh in 2022, an increase of 127 percent.
- Total day-ahead make-whole payments were up from $15.5 million in summer 2021 to $38.4 million in 2022. Day-ahead make-whole payments to all resource types were up from 2021 to 2022. Much of the increase in day-ahead make-whole payments can be attributed to higher gas prices.
- Total reliability unit commitment make-whole payments were up from $45.4 million in summer 2021 to $120.6 million in 2022. The increase can mostly be attributed the increase in natural gas prices, along with out-of-market commitments during periods of high load.
- Total revenue neutrality uplift for summer 2022 was $109 million, up from $39 million in 2021 and $11 million in 2020. The increase can mostly be attributed to higher levels of congestion costs. After peaking in the spring, revenue neutrality uplift has abated somewhat in the summer, but still remains higher than previous years.

- Average hourly load for the 2022 summer season was six percent above 2021, with all months showing an increase. The increased load was primarily driven by increased temperature impacts.
- Coal generation was the primary fuel type in terms of generation during the summer 2022 quarter accounting for 40 percent of total generation, a decrease from 42 percent in 2021. Wind generation was up from 24 percent of total generation in summer 2021 to 26 percent in 2022. Gas, combined-cycle generation was down slightly from summer 2021 to 2022, while gas, simple-cycle generation was up slightly during the same period.
- Net virtual profits before fees for summer 2022 averaged $21 million per month, while net virtual profits after fees averaged a loss of $3 million per month. Net virtual profits before fees were up a monthly average of $12 million in summer 2021, while net virtual profits were down from an average monthly profit of $3 million in summer 2021.
- During the summer season, the most congested flowgate was in central Oklahoma (Cimarron transformer 345/1kV [OKGE]), with six of the top ten located in Oklahoma.
- Day-ahead congestion was dramatically higher quarter over quarter from $281 million in summer 2021 to $707 in summer 2022. The increase is driven largely by the increase in gas prices over the prior period.
- Total TCR funding for summer 2022 was 92 percent, up from 87 percent in summer 2021. The improvement in TCR funding can be attributed to improved alignment between the congestion hedging model and the day-ahead market model.
- Auction revenue right funding percentages decreased slightly quarter over quarter. Additionally, the auction revenue right surplus increased from $18 million in summer 2021 to $48 million in summer 2022.
- A special issues section, with an initial review of the recently implemented ramp capability product, is included at the end of this quarter's report.

2 LOAD AND RESOURCES

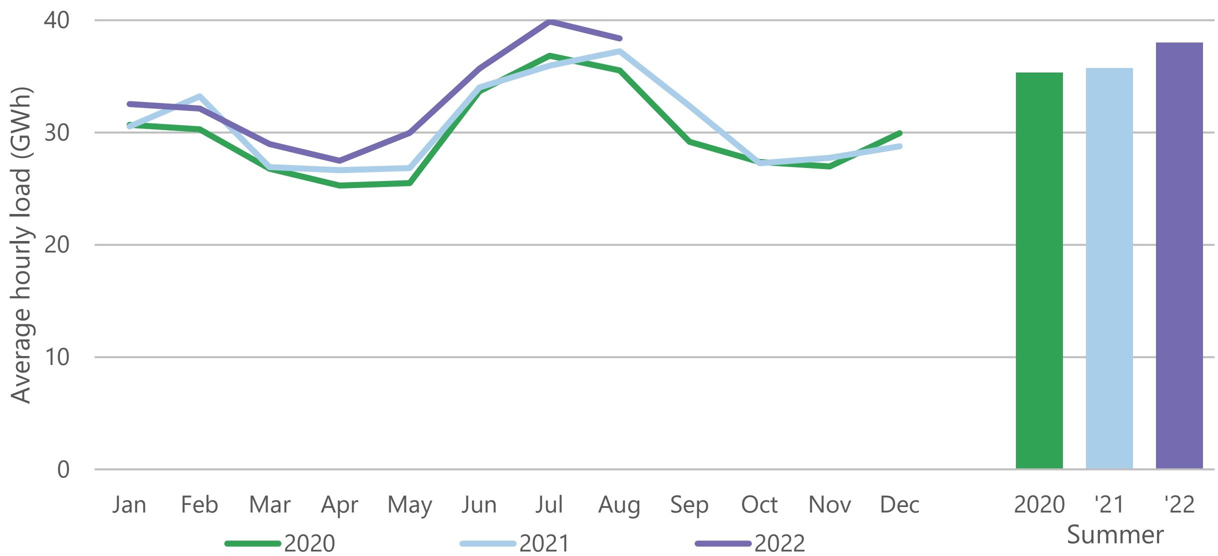
This chapter reviews load and resources in the SPP market for the summer 2022 period. Key points from this chapter include:

- Average hourly load for the 2022 summer season was six percent above 2021, with all months showing an increase. The increased load was primarily driven by increased temperature impacts.
- Coal generation was the primary fuel type in terms of generation during the summer 2022 quarter accounting for 40 percent of total generation, a decrease from 42 percent in 2021. Wind generation was up from 24 percent of total generation in summer 2021 to 26 percent in 2022. Gas, combined-cycle generation was down slightly from summer 2021 to 2022, while gas, simple-cycle generation was up slightly during the same period.
- Wind generation nameplate capacity at the end of August 2022 was 31,673 MW. This is an increase of nearly 2,000 MW from the prior year.
- For market-to-market payments during the summer period, nearly $27 million was paid from MISO to SPP, and $12 million from SPP to MISO, for a net of $15 million paid from MISO to SPP. This up just slightly from a net of $14 million from MISO to SPP in summer 2021.
- For the summer period, total cleared virtual transactions as a percent of load were 21 percent in 2022, up from 20 percent in 2021.
- Net virtual profits before fees for summer 2022 averaged $21 million per month, while net virtual profits after fees averaged a loss of $3 million per month. Net virtual profits before fees were up a monthly average of $12 million in summer 2021, while net virtual profits were down from an average monthly profit of $3 million in summer 2021.

2.1 LOAD

The average hourly load for each month is shown in Figure 2–1 below.

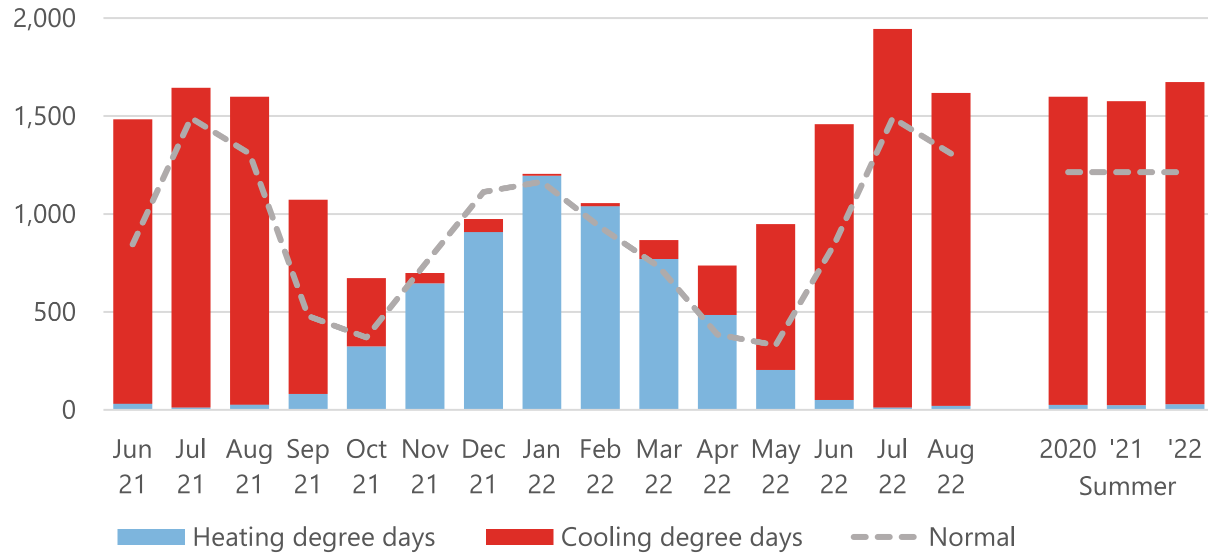
Figure 2-1 Average hourly load



Average hourly load for the 2022 summer season was six percent above 2021, with monthly average load peaking at just under 40 GWh in July. Loads were higher in all three months of the summer season in 2022 in comparison to the two prior years.

Heating and cooling degree days are used to estimate the impact of actual weather conditions on energy consumption as shown in Figure 2–2. Regression analysis has shown that a cooling degree has about 4.2 times the impact of a heating degree on load, so cooling degree days are multiplied by 4.2 in the chart below.

Figure 2-2 Degree days, SPP footprint

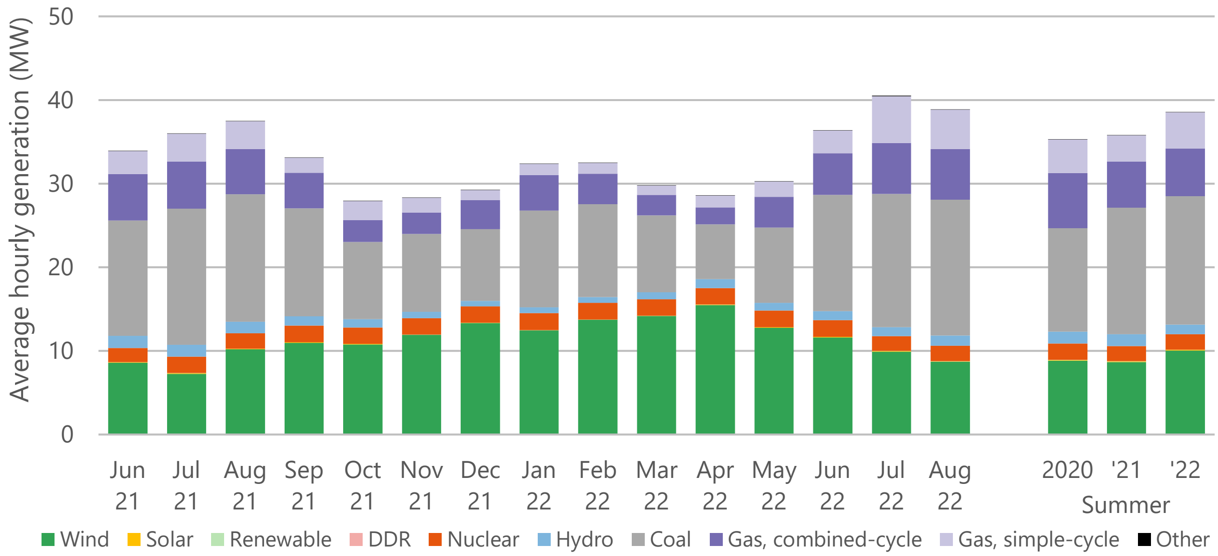


Degree day impact for the 2022 summer season was six percent above 2021. Degree day impact for June 2022 was two percent below 2021, July was 18 percent above 2021, and August was one percent above 2021. The increased degree day impact correlates well to the increase in load during the summer season.

2.2 RESOURCES

Average hourly generation, broken down by technology type of resource, is shown below in Figure 2–3. The “renewable” category includes biomass and other renewable resources (not including wind, solar, and hydro resources), while the “other” category includes fuel oil and miscellaneous resources.

Figure 2-3 Generation by technology type, real-time

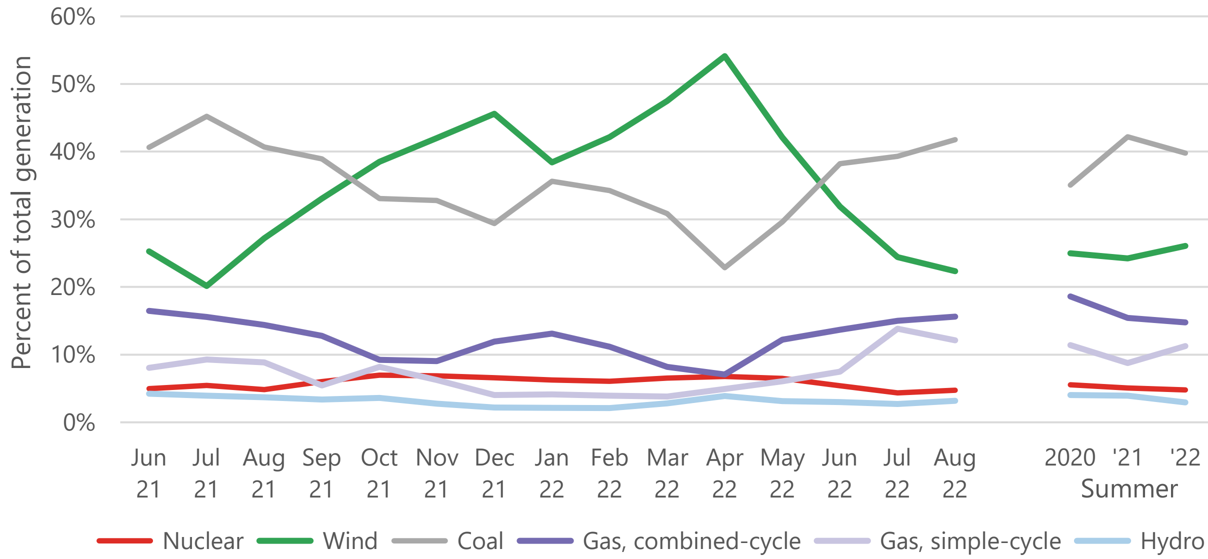


Overall average hourly generation was up nearly eight percent from summer 2021 to 2022. Hydro generation was down nearly 20 percent from summer 2021 to 2022. All other major fuel types were up from summer 2021 to 2022, with gas, simple-cycle generation up 39 percent and wind generation up 16 percent.

Figure 2–4 below shows the percentage of total generation attributed to each technology type.[1]

[1] Only the most prevalent technology types are shown in this figure. This chart does not include solar, renewable, dispatchable demand response, and "other" resources.

Figure 2-4 Generation by technology type, real-time by percent

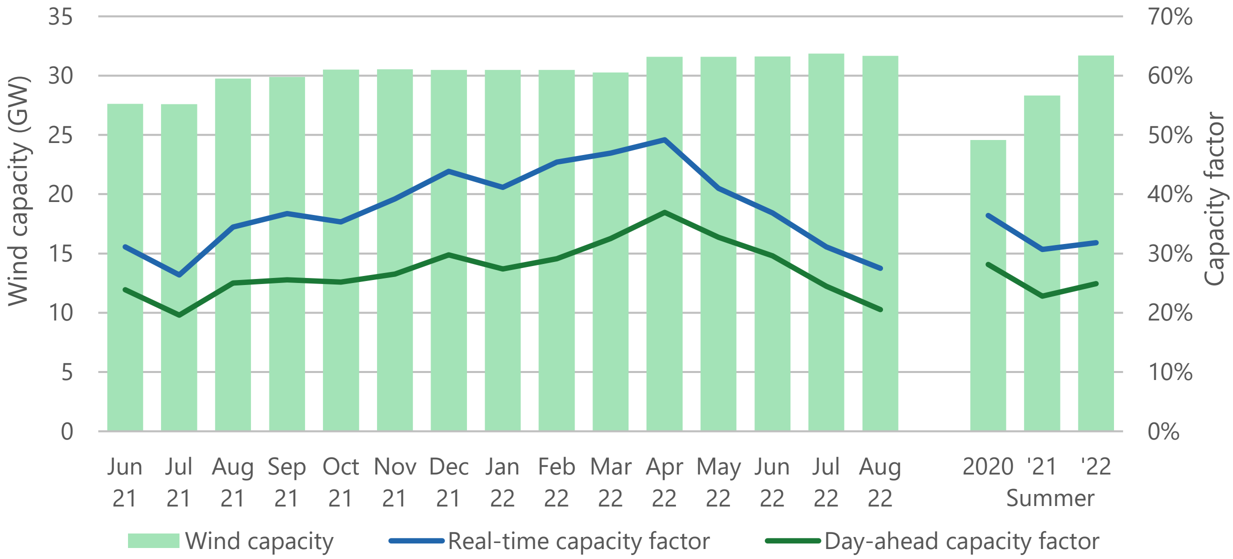


Coal generation was the primary fuel type in terms of generation during the summer 2022 quarter, accounting for 40 percent of total generation, a decrease from 42 percent in 2021. Hydro generation was down from four percent of total generation in summer 2021 to 2022, and gas, combined-cycle was down about half of a percentage point from summer 2021 to 2022. Wind generation increased from providing 24 percent of total generation in summer 2021 to 26 percent in 2022. The decrease in gas, combined-cycle generation can primarily be attributed to higher natural gas prices in summer 2022, while the increase in gas, simple-cycle generation can primarily be attributed to higher loads.

Figure 2–5 shows wind capacity (nameplate in megawatts) along with the wind capacity factor. Note that the wind capacity figure is reported as of month-end, while the capacity factor is reported for the entire month.[2]

[2] Wind resources may be considered in-service, but not yet in commercial operation. In this situation, the capacity will be counted but the resource may not be providing any generation to the market.

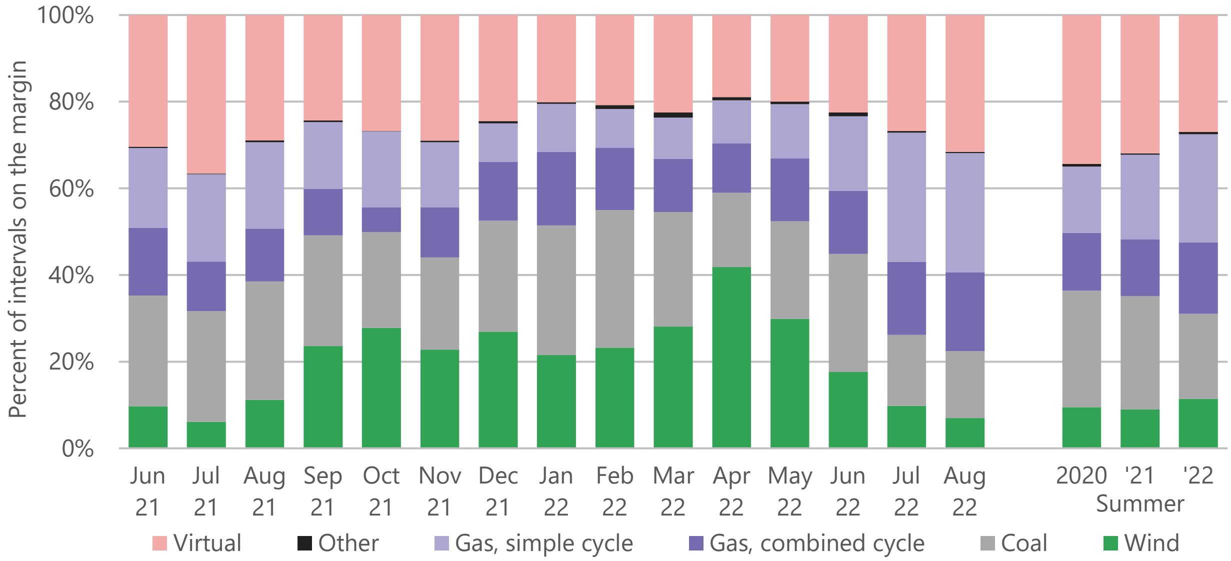
Figure 2-5 Wind capacity and capacity factor



At the end of August 2022, nameplate wind capacity was 31,673 MW. The wind capacity factor in the real-time market for summer 2022 was nearly 32 percent, while capacity factor for the day-ahead market was 25 percent. Over time, the spread between the capacity factor in the real-time market has averaged about 10 percentage points higher than that in the day-ahead market.

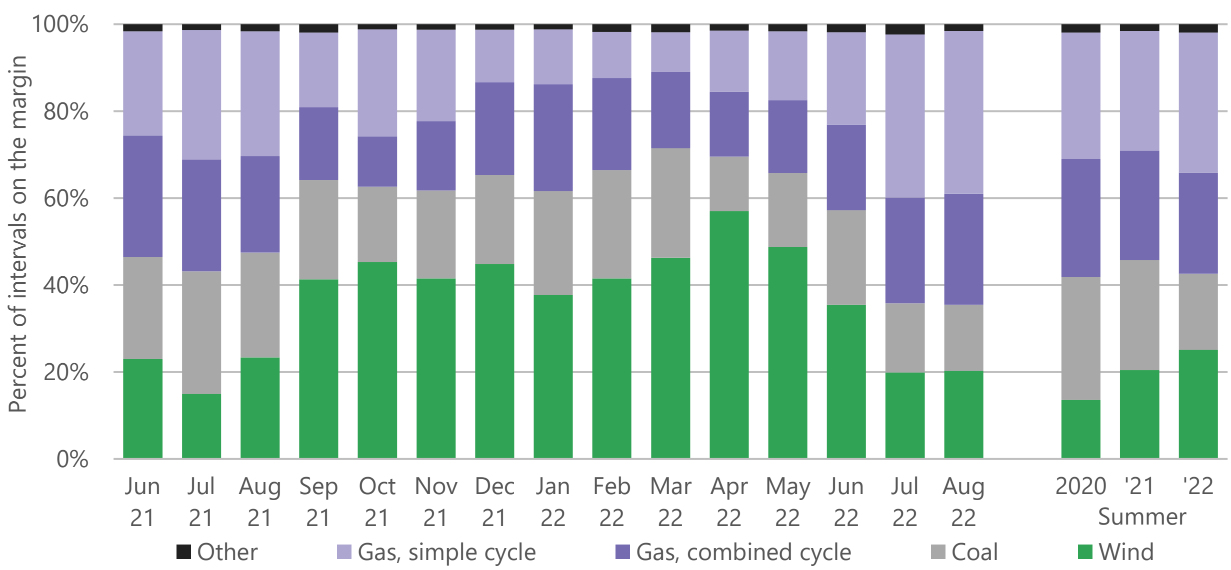
Figure 2–6 and Figure 2–7 show the technology types of marginal units in both the real-time and day-ahead markets. Marginal units set the locational marginal price in each hour in the day-ahead market and each five-minute interval in the real-time market. One important distinction is that virtual transactions can be marginal in the day-ahead market, but are not included in the real-time market and, thus, cannot set the real-time price. During congested periods, the market is effectively segmented into several sub-areas, each with its own marginal resource(s). During non-congested periods, one resource sets the price for the entire market, thus that resource is marginal for the interval. When there is congestion, there can be more than one marginal unit during an interval within a particular sub-area.

Figure 2-6 Technology on the margin, day-ahead



In the day-ahead market, virtual transactions set prices in 27 percent of intervals in summer 2022, down from 32 percent in 2021. Gas, combined-cycle resources set prices in 17 percent of all intervals in summer 2022, up from 13 percent in 2021, while gas, simple-cycle resources set prices in 25 percent of all intervals in summer 2022, up from 20 percent in 2021. Coal resources set prices in 20 percent of all intervals in summer 2022, down from 25 percent in 2021. Wind resources setting prices was up slightly from summer 2021 to 2022.

Figure 2-7 Technology on the margin, real-time



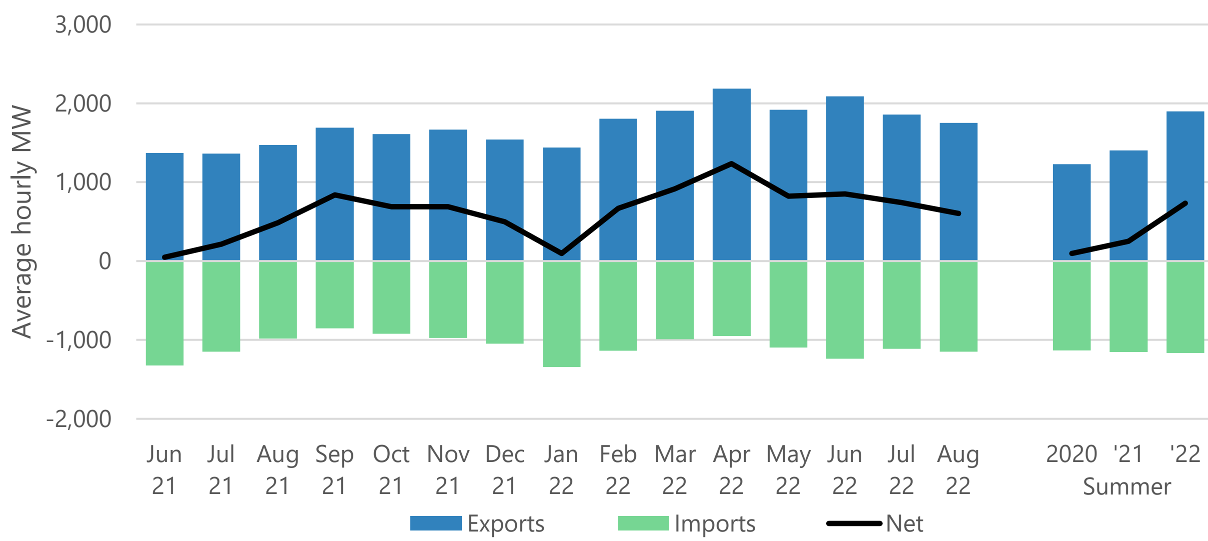
In the real-time market, the percentage of intervals where gas, combined-cycle, gas, simple-cycle, and wind resources were all up from between three and five percentage points. Conversely, coal resources set prices in 18 percent of all intervals in summer 2022, down from 25 percent in 2021.

2.3 EXTERNAL TRANSACTIONS

The SPP Integrated Marketplace has more than 6,000 MW of AC interties with MISO to the east, 810 MW of DC ties to ERCOT to the south, and over 1,000 MW of DC ties to the Western interconnection to the west. Additionally, SPP has over 1,500 MW of interties with the Southwestern Power Administration (SPA) in Arkansas, Missouri, and Oklahoma, and over 5,000 MW of AC interties with the Associated Electric Cooperative (AECI) in Oklahoma and Missouri.

Figure 2–8 shows average hourly imports and exports across the SPP system.

Figure 2-8 Exports and imports, SPP system



Net hourly imports/exports for the summer in the SPP market climbed from an hourly average of 250 MW net export in 2021 to 733 MW net export in 2022. All months of the summer season increased in gross exports from summer 2021 to 2022, while gross imports were steady. Much of the increase in exports can be attributed to increased wind generation during the summer.

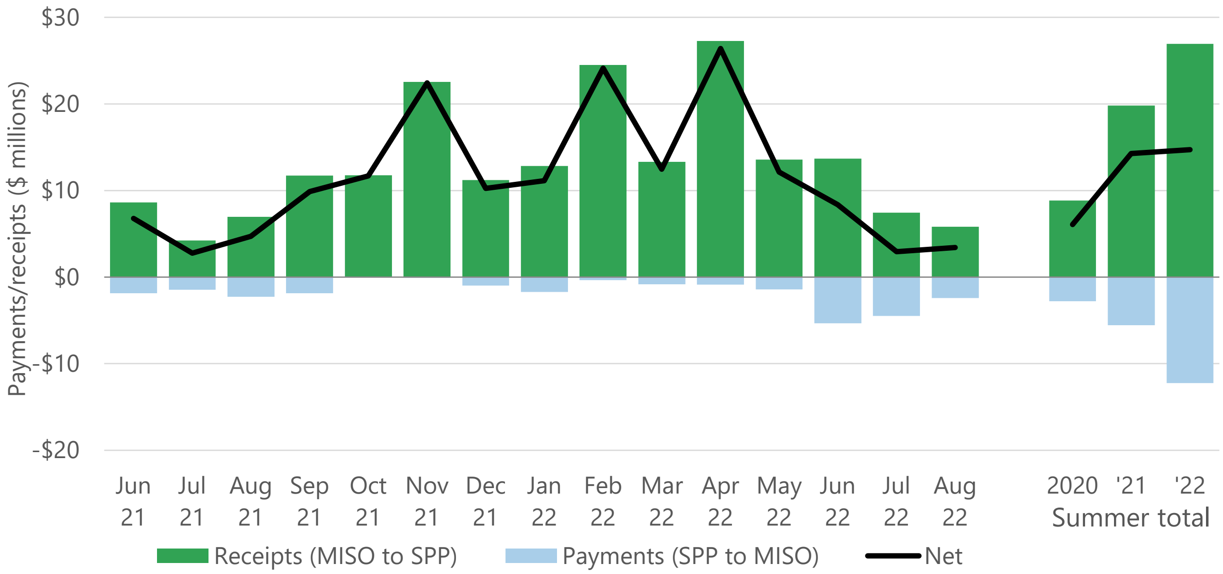
SPP began the market-to-market (M2M) process with MISO in March 2015. The market-to-market process under the joint operating agreement allows the monitoring and non-monitoring RTOs[3] to efficiently manage market-to-market constraints by exchanging information (shadow prices, relief request, control indicators, etc.) and using the RTO with the more economic redispatch to address flows.

Each RTO is allocated property rights on market-to-market constraints. These are known as firm flow entitlements (FFE), and each RTO calculates its real-time usage, known as market flow. RTOs exchange money (market-to-market settlements) for redispatch based on the non-monitoring RTO's market flow in relation to its firm flow entitlement. The non-monitoring RTO receives money from the monitoring RTO if its market flow is below its firm flow entitlement. The non-monitoring RTO pays the monitoring RTO if its market flow is above its firm flow entitlement.

The total monthly market-to-market payments are shown in Figure 2–9, while the market-to-market payments by flowgate (with payments more than $1 million from MISO to SPP and more than $500,000 from SPP to MISO) for the summer period are shown in Figure 2–10.

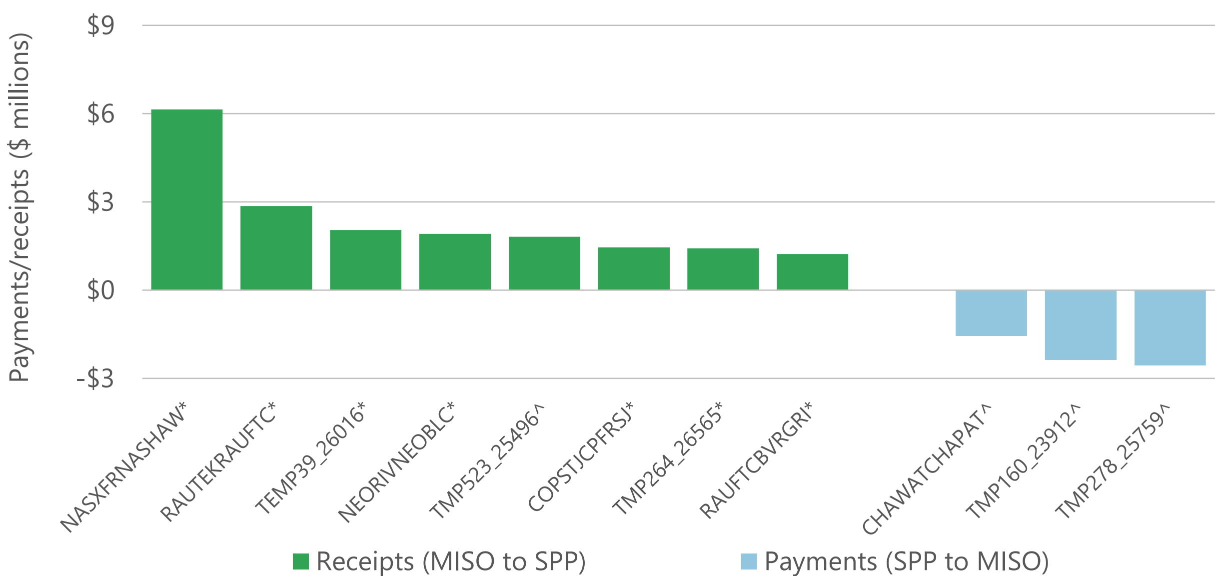
[3] The RTO which manages the most limiting element of the constraint is the monitoring RTO. In most cases, the monitoring RTO has most of the impact and resources that provided the most effective relief of a congested constraint.

Figure 2-9 Market-to-market, monthly



Historically, on a monthly basis, net payments are predominantly from MISO to SPP. The amount of market-to-market payments from MISO to SPP continues to grow. However, that growth is offset by growth, albeit at a slower pace, of market-to-market payments from SPP to MISO. Summer 2022 net receipts from MISO to SPP were at $14.7 million, up from $14.3 million in 2021 and $6.1 million in 2020.

Figure 2-10 Market to market, by flowgate



NASXFRNASHAW* Nashua Xfmr 345/1kV (KCPL) ftlo Nashua-Hawthorn 345kV (KCPL)
RAUTEKRAUFTC* Raun-Tekamah 161kV ftlo Raun-Fort Calhoun 345kV (OPPD-MEC)
TEMP39_26016* Tekamah-Sub 1226 161kV (OPPD) ftlo Fort Calhoun-Raun 345kV (MEC-OPPD), Fort Calhoun-Fort Calhoun 345kV (OPPD)

NEORIVNEOBLC* Neosho-Riverton 161kV (EDE-WR) ftlo Neosho-Blackberry 345kV (AECI-WR)
TMP523_25496^ Ellendale-Aberdeen Junction 115kV (WAUE-MDU) ftlo Twin Brooks-Big Stone South 345kV (OTP)
COPSTJCPFRSJ* Cooper-St. Joe 345kV (NPPD-MPS) ftlo Fairport Xfmr 345/161kV (AECI-AECI), St. Joe-Fairport 345kV (MPS-AECI), Cooper-Fairport 345kV (NPPD-AECI)
TMP264_26565* Blairsburg-Granite Falls 230kV (WAUE) ftlo Hawken Lake-Lyon County 345kV (NSP)
RAUFTCBVRGRI* Raun-Fort Calhoun 345kV (MEC-OPPD) ftlo Grimes-Beaver Creek 345kV (MEC)
CHAWATCHAPAT^ Charlie Creek-Watford City 230kV (WAUE) ftlo Charlie Creek-Patent G 345kV (WAUE)
TMP160_23912^ Prairie Island-North Rochester 345kV (NSP) ftlo Hampton Corner-North Rochester 345kV (NSP)
TMP278_25759^ Overton Xfmr 345/161kV (AMRN) ftlo Overton-McCredie Switch Sta. 345kV (AMRN-AECI)

** SPP market-to-market flowgate*
^ MISO market-to-market flowgate

During summer 2022, the flowgate with the highest payments from MISO to SPP of just over $6 million was NASXFRNASHAW [Nashua transformer 345/1kV (KCPL) for the loss of Nashua-Hawthorn 345kV (KCPL)], which is located in the Kansas City area. For payments from SPP to MISO, the top flowgate in summer 2022 was a MISO flowgate, TMP278_25759 [Overton transformer 345/161kV (AMRN) for the loss of Overton-McCredie Switch Sta. 345kV (AMRN-AECI)], located in mid-Missouri with just over $2.5 million in payments.

2.4 VIRTUAL TRADING

Virtual trading in the day-ahead market aims to facilitate convergence between the day-ahead and real-time prices, while helping to improve the efficiency of the day-ahead market and moderate market power. Virtual transactions scheduled in the day-ahead market are settled in the real-time market.

Virtual demand bids are profitable when the real-time energy price is higher than the day-ahead price. Virtual supply offers are profitable when the day-ahead energy price is higher than the real-time price.

The following figures show both cleared and uncleared virtual demand bids (Figure 2–11) and supply offers (Figure 2–12).

Figure 2-11 Virtual demand bids

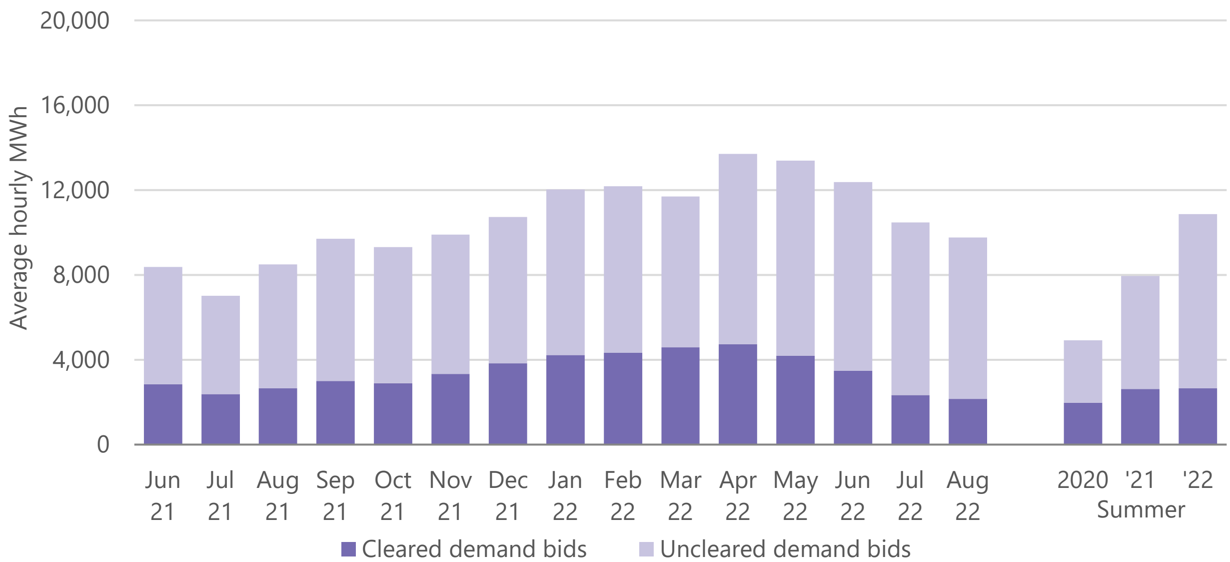
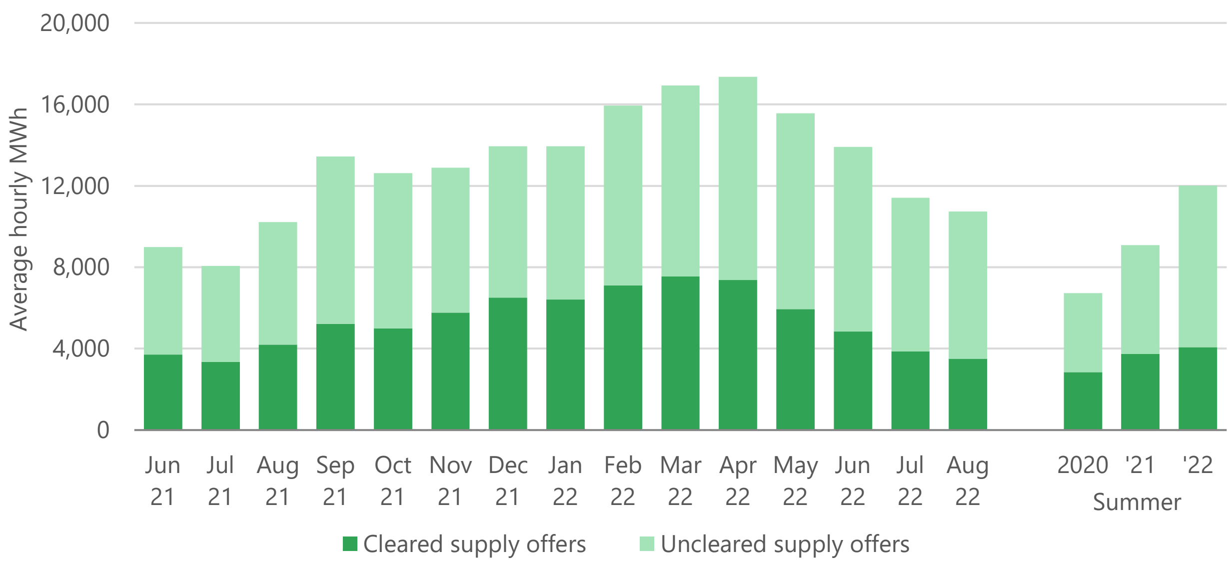


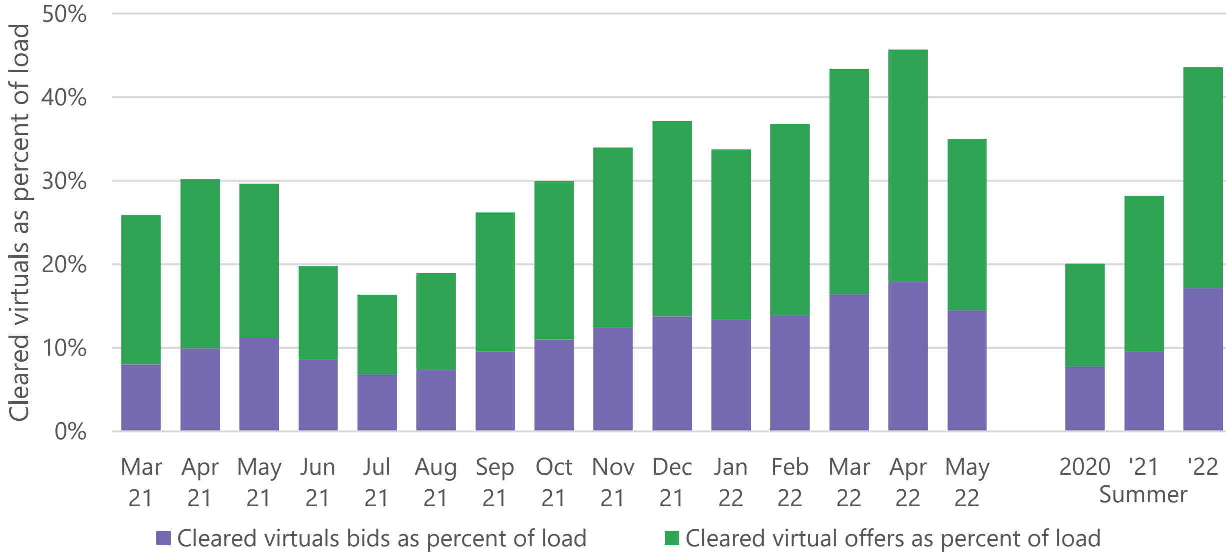
Figure 2-12 Virtual supply offers



As these figures show, both cleared and uncleared demand bids and supply offers continue to grow from summer 2021 to 2022, although the growth in cleared demand bids and supply offers has slowed.

Cleared virtual transactions as a percent of load are shown in Figure 2–13.

Figure 2-13 Cleared virtual transactions as a percent of load



For the summer period, total cleared virtual transactions as a percent of load were 21 percent in 2022, up slightly from 20 percent in 2021.

Generally, market participants with physical assets (resources and/or load) place virtual transactions in order to hedge physical obligations. In contrast, financial-only market participants generally place virtual transactions to arbitrage prices.

Figure 2–14 and Figure 2–15 show virtual transactions by participant type, either financial-only entities, or entities with resources and/or load. These figures show that financial-only market participants place the vast majority of virtual transactions.

Figure 2-14 Virtual demand bids by participant type

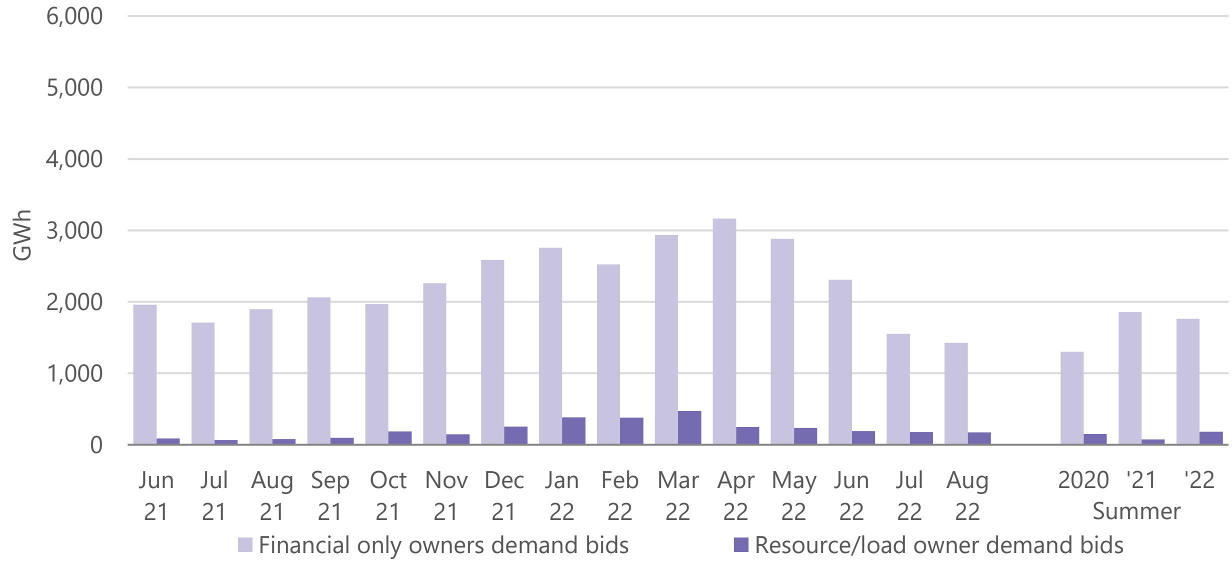
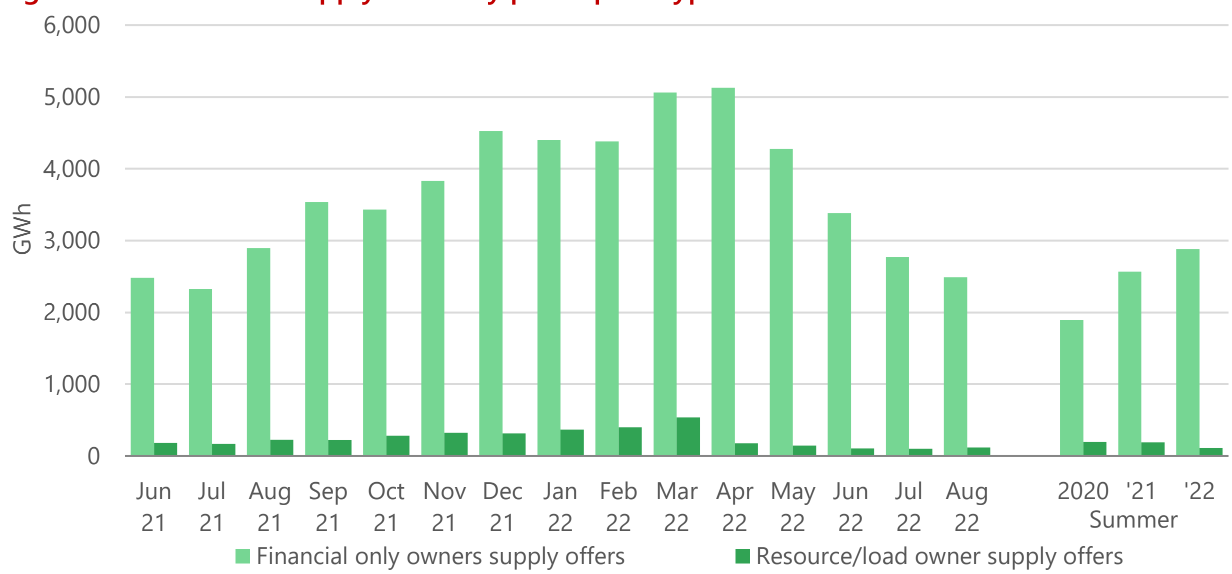


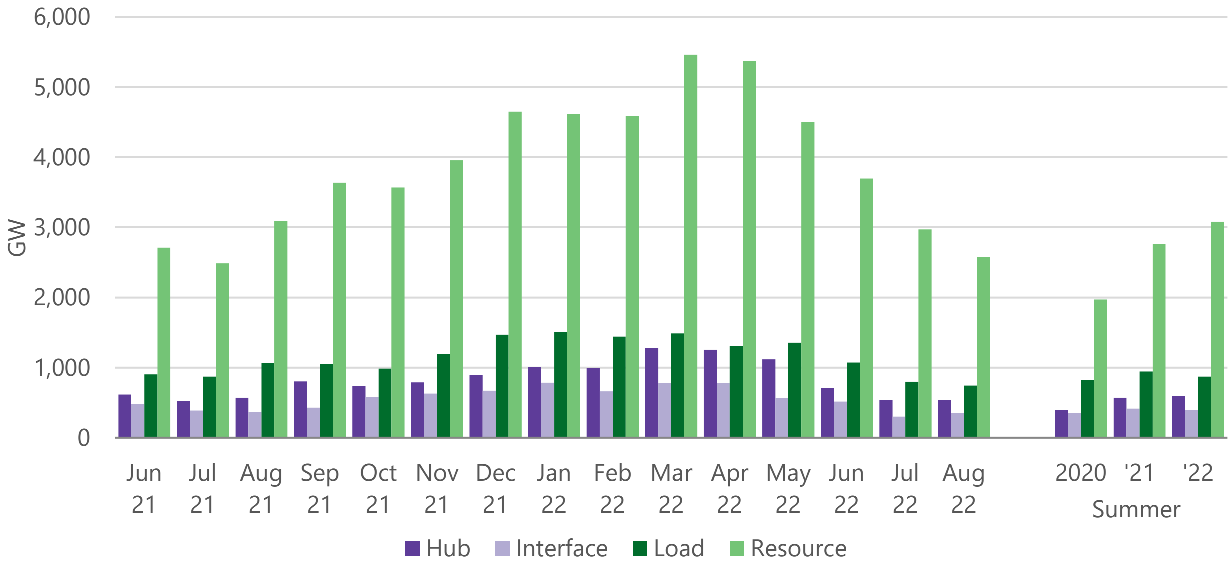
Figure 2-15 Virtual supply offers by participant type



Virtual demand bids by financial-only participants for the summer season fell from 1,860 GWh in summer 2021 to 1,760 GWh in 2022, while virtual demand bids from physical asset owners increased, albeit at much lower levels, from 77 GWh in summer 2021 to 182 GWh in 2022. Virtual supply offers by financial-only participants continues to increase steadily, from 2,600 GWh in summer 2021 to 2,900 GWh in 2022, while virtual supply offers from physical asset owners dropped from 192 GWh in summer 2021to 110 GWh in 2022.

Virtual transactions can be made at hubs, interfaces, loads, and resources, as shown in Figure 2–16.

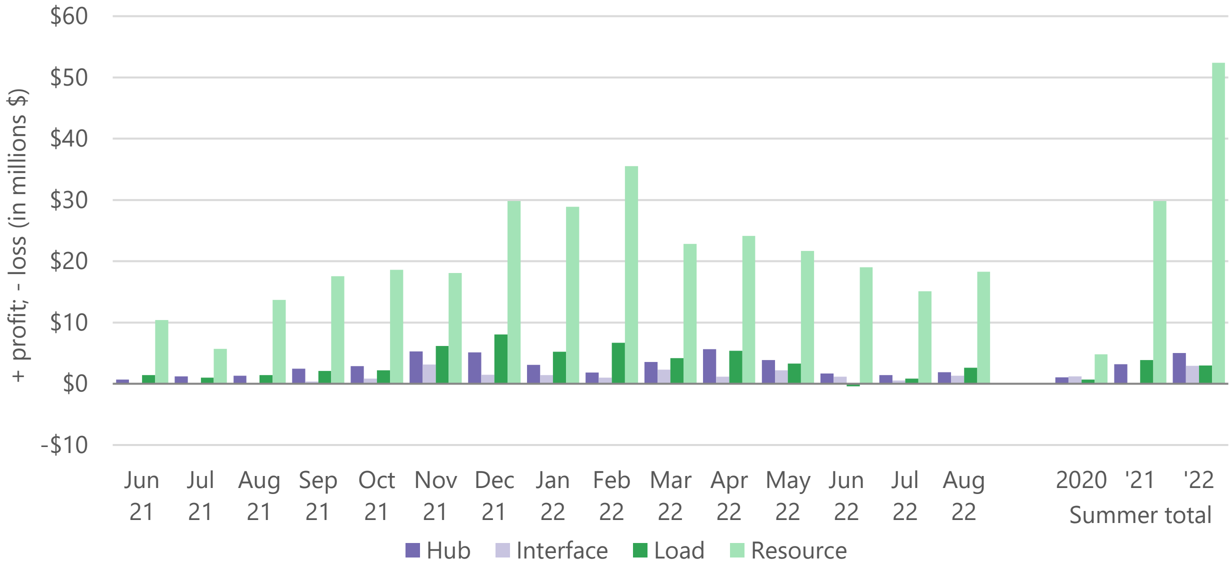
Figure 2-16 Virtual transactions by location type, volume



The great majority of virtual transactions are made at resources (primarily wind resources), with an average of 3,100 GW in summer 2022, compared to 2,800 GW in 2021. Virtual transactions at hubs grew slightly from summer 2021 to 2022, while interfaces and loads decreased slightly from 2021 to 2022. Historically, participants have placed the fewest virtual transactions at external interfaces and hubs.

As with the volume of virtual transactions, the majority of the profits (before fees), shown in Figure 2–17, from virtual transactions are derived from resource locations.

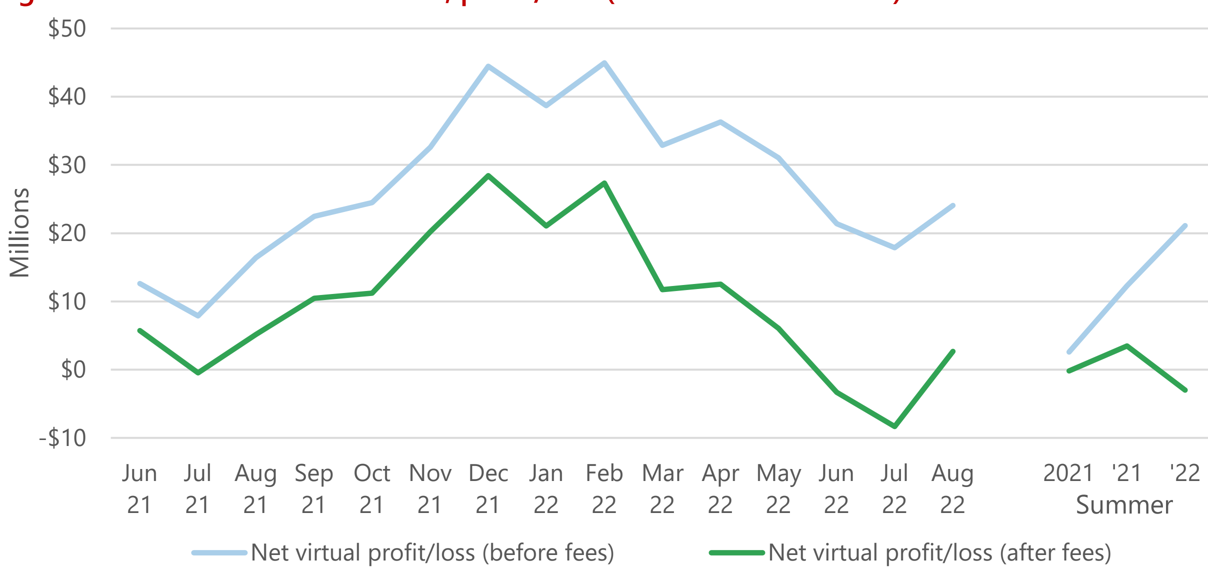
Figure 2-17 Virtual transactions by location type, profit/loss before fees



The total profit for virtual transactions at all different location types was up in summer 2022 compared to 2021. Virtual transactions at resource locations saw a total profit for summer 2022 of $52 million, up from $30 million in 2021.

Overall profit and loss from virtual transactions, both before and after fees, is shown in Figure 2–18.

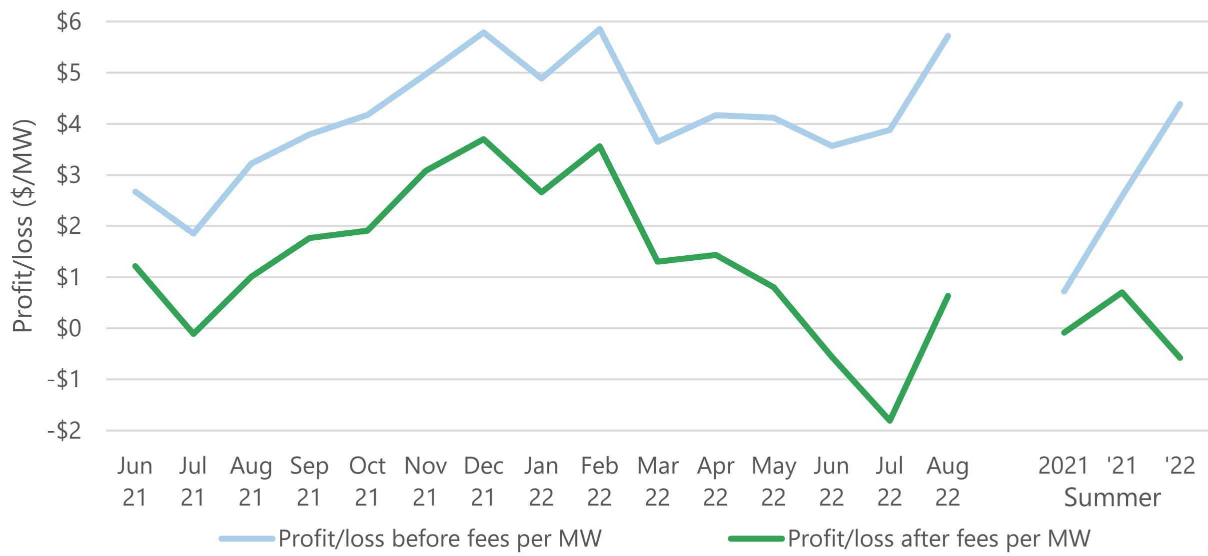
Figure 2-18 Virtual transactions, profit/loss (before and after fees)



Net virtual profits before fees for summer 2022 averaged $21 million per month, while net virtual profits after fees for the same period was a $3 million loss. Summer 2022 fees were significantly higher due to higher revenue neutrality uplift and real-time make-whole payment charges for the summer season. The increased revenue neutrality uplift and make-whole payments are discussed more fully in Section 4.4.

Applying the profit and loss from virtual transactions on a per megawatt basis is shown in Figure 2-19.

Figure 2-19 Virtual transactions, profit/loss per MW (before and after fees)



On a per megawatt basis, profit before fees from virtual transactions for summer 2022 was $4.39/MW, compared to $2.58/MW in 2021. Profit after fees for virtual transactions for summer 2022 was -$0.58/MW, down from $0.70/MW in 2021. As stated above, the decrease in profit per MW after fees can be attributed to higher revenue neutrality uplift and real-time make-whole payment charges.

3 UNIT COMMITMENT AND DISPATCH

This chapter reviews unit commitment and dispatch processes in the SPP market for the summer 2022 period. Key points from this chapter include:

- Use of market commitment status had been on a slow, but steady rise, leveling off back in summer 2021 at around 79 percent and staying in that range through summer 2022.
- Summer 2022 saw 72 percent of megawatts produced due to market commitment status, which is exactly the same as 2021, but up from 70 percent in 2020.
- In the real-time market, summer 2022 saw a monthly average of 161 regulation-up scarcity intervals, up from 80 in 2021. Contingency reserve scarcity intervals were up from a monthly average of six in summer 2021 to 20 in 2022, while regulation-down scarcity intervals were up from a monthly average of 13 in summer 2021 to 17 in 2022.
- For real-time scarcity, the average amount of megawatts short per interval have decreased for regulation-up and regulation-down scarcity from summer 2021 to 2022, while megawatts short per interval increased for contingency reserve scarcity during the same period.
- Summer 2022 saw four hours of scarcity in the day-ahead market – three in June and one in July. All of these scarcity hours occurred during the morning ramp-up period, when load was sharply increasing.
- The summer season saw a drop in generation outages and derates from nearly 27,600 GWh in summer 2021 to 25,700 GWh in 2022, a decrease of seven percent. Gas, combined-cycle units had the largest drop in outages and derates between summer 2021 and 2022 at 27 percent.

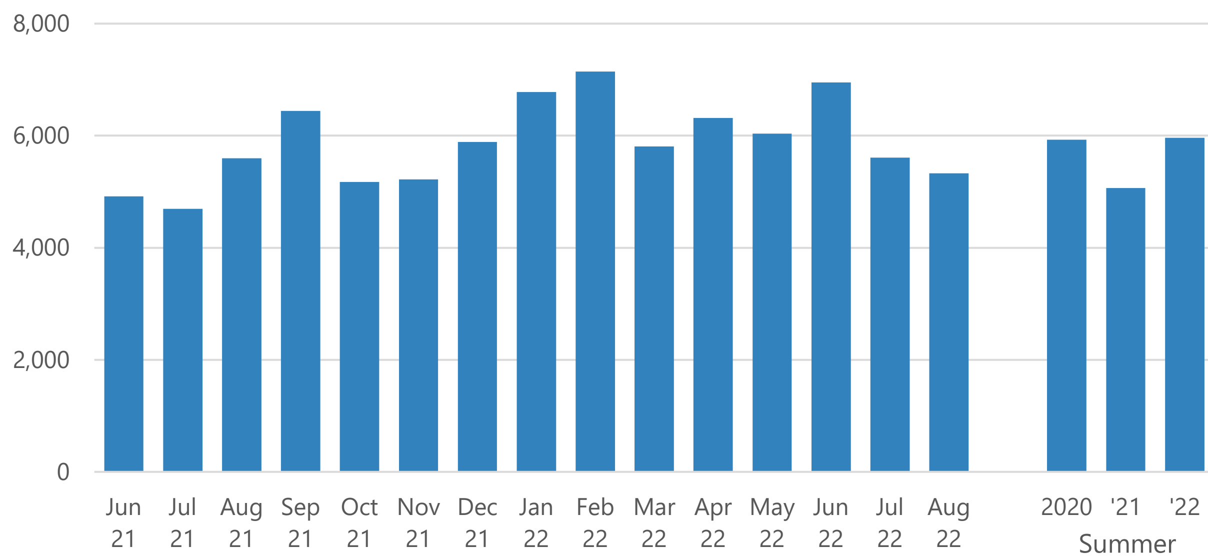
3.1 UNIT COMMITMENT

The day-ahead market provides market participants with the ability to submit offers to sell energy, regulation-up service, regulation-down service, spinning reserves, and supplemental reserves, and/or to submit bids to purchase energy. The day-ahead market co-optimizes the clearing of energy and operating reserve products out of the available capacity. All day-ahead market products are traded and settled on an hourly basis.

Participation in the day-ahead market tends to be robust for both generation and load in the market. Load procures over 98 percent of its requirements in the day-ahead market. Load-serving entities consistently offered generation into the day-ahead market at levels in excess of the requirements of the limited day-ahead must-offer obligation. Participation by merchant generation—for which no such obligation exists—was comparable to that of the load-serving entities.

Figure 3–1 shows the real-time average peak hour capacity overage. SPP calculates the amount of capacity overage required for the operating day to ensure that unit commitment is sufficient to reliably serve load in real time while maintaining the operating reserve requirements.

Figure 3-1 Peak hour capacity overage, real-time average



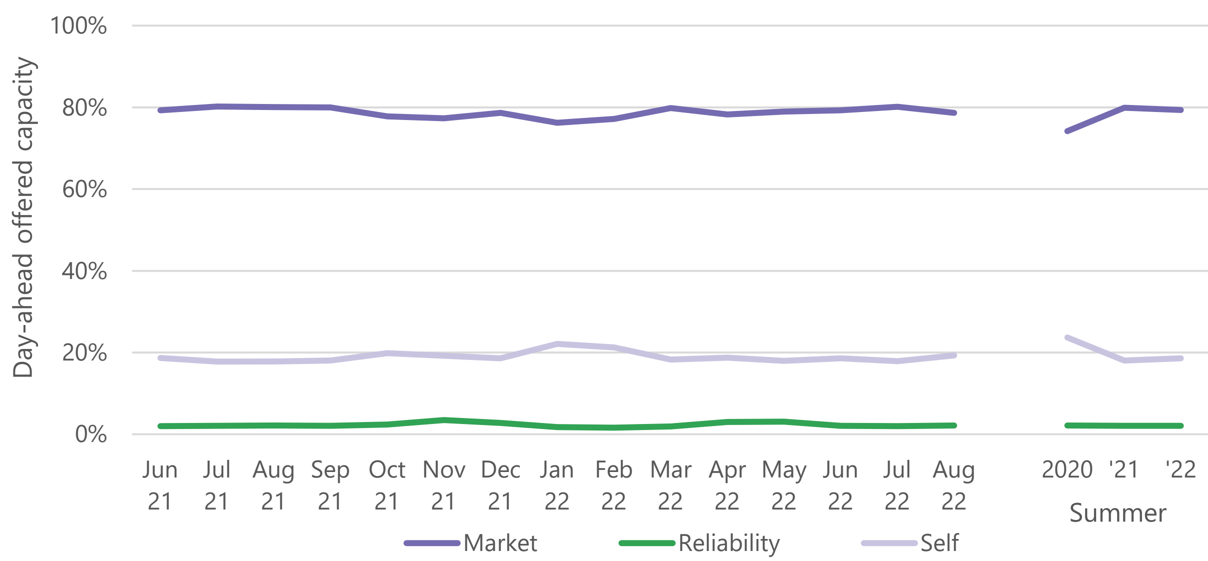
The average peak hour overage[4] for summer 2022 was just under 6,000 MW, up from 5,000 MW in 2021. Much of this overage is used to manage resource and load uncertainty. SPP designed

[4] The calculation for real-time average peak hour capacity overage is: economic maximum – load – net scheduled interchange – (regulation up + spinning reserves + supplemental reserves). All capacity from

the uncertainty product to better manage this overage and to compensate resources for addressing uncertainty needs and improving reliability. The uncertainty product, which was recommended in the 2018 Annual State of the Market report and updated in the 2019 and 2020 Annual State of the Market report,[5] was approved at the July 2021 MOPC meeting. The uncertainty product was approved by FERC in August. SPP intends to implement this product in 2023.

Figure 3–2 shows the status, by percent, of the physical resources offered in the day-ahead market.[6] This metric replaces a previous metric that used nameplate capacity and included capacity on outage and not-participating status. The new metric gives a better view of resources available in market status, and those offered by self-commitment as well as reliability status, as it includes only resources that could be committed by the RTO.

Figure 3-2 Day-ahead physical resources offered by status



Use of market commitment status had been on a steady rise since early 2018, but has recently leveled off at around 80 percent. In summer 2022, use of market commitment status was 79.3 percent, down slightly from 79.9 percent in 2021.

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wind generation is not included in the economic maximum. Only capacity from traditional fuel resources is included in this calculation.

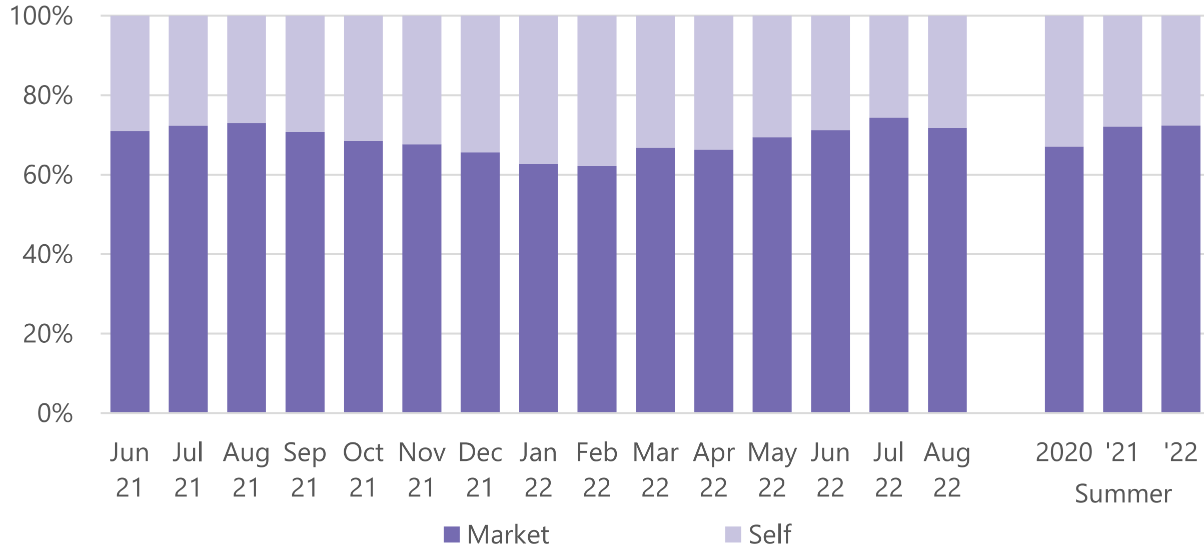
[5] Annual State of the Market reports

[6] All resources offered use their economic maximum for this capacity calculation.

We continue to encourage market participants and the RTO to find ways to enhance market efficiencies and reduce self-commitment.[7]

Figure 3–3 shows the percentage of dispatch megawatts by commitment status in the day-ahead market. All output from a self-committed unit is counted as self.

Figure 3-3 Percentage of megawatts dispatched by commitment status



The volume of market-committed[8] megawatts has set a new peak at 74 percent of megawatts in July 2022. From the summer 2022 season, 72 percent of megawatts produced were market-committed, which is exactly the same as 2021, but up from 67 percent in 2020. Generation dispatched in self-commitment status indicates that the energy produced was from a resource that was not economically selected by the day-ahead market's centralized unit commitment process.

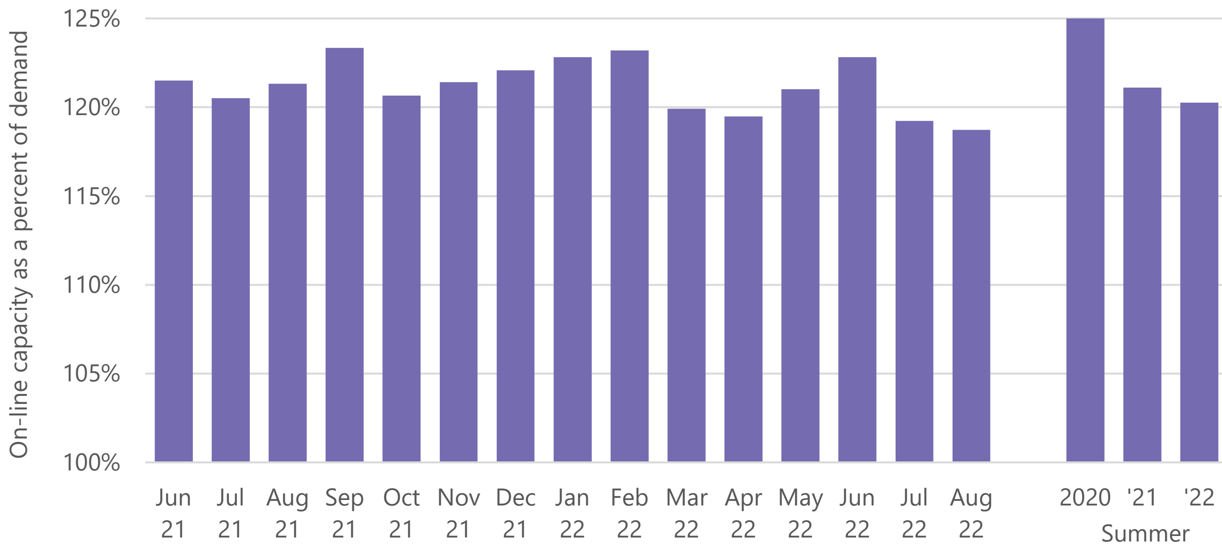
[7] See the MMU's whitepaper on self-commitment, Self-committing in SPP markets: Overview, impacts, and recommendations.

[8] Reliability unit commitments that continued to run in the day-ahead market were considered a market commitment.

Self-commitment shifts the merit order of the supply curve by treating the self-committed generators as price insensitive at their minimum, which shifts the supply curve to the right. The expected result of a rightward shift in supply is a decline in the marginal price of energy.

Figure 3–4 shows on-line capacity commitment as a percent of demand.

Figure 3-4 On-line capacity as a percent of demand



The capacity commitment as a percent of average monthly demand for summer 2022 was 120 percent, down slightly from 121 percent in 2021. The uncertainty product will help manage the relationship of on-line capacity relative to demand.

3.2 SCARCITY

A scarcity price is a price that reflects the value of a product when there is not enough of the product to meet the demand. SPP's market uses marginal cost pricing, which prices a product by the cost to produce the next increment. When a product is scarce, there may not be an additional supplier, so price cannot be determined by the next increment. In this case, a scarcity price is used to set marginal price. The Integrated Marketplace uses demand curves to set graduated scarcity prices so that small scarcities are priced lower than large scarcities. Scarcity prices inform market participants that the product was short and incentivize future provision of that product, and should provide representation of the reliability risk of not having a product.

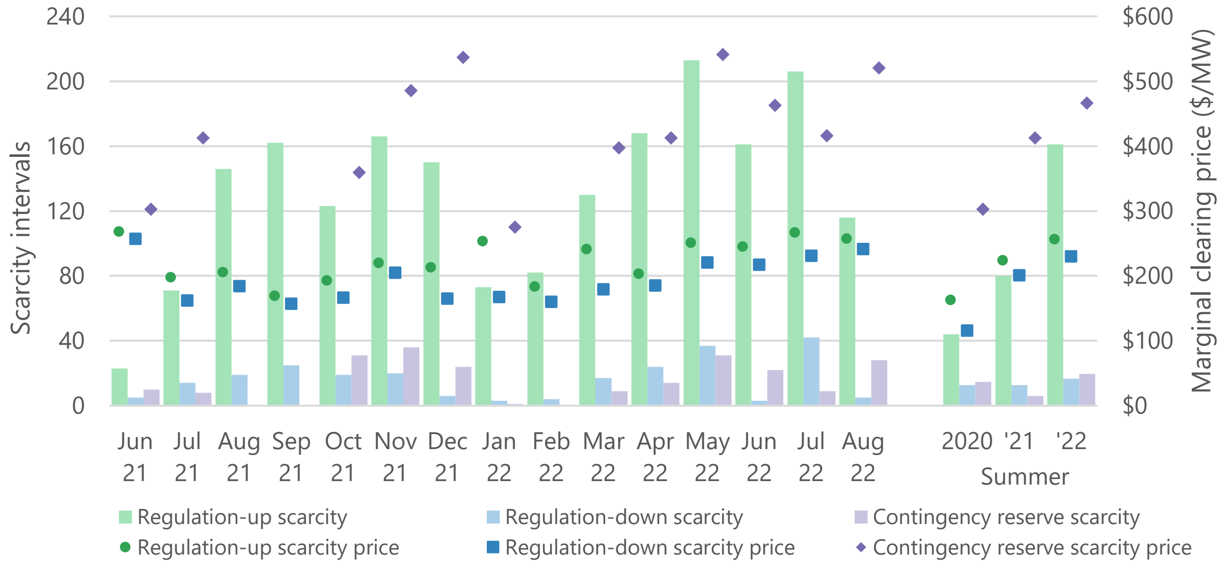
When an insufficient amount of regulation-up service, regulation-down service, or contingency reserve is cleared, a scarcity price is set by a demand curve. The scarcity of these products can be caused by a lack of capacity or a lack of ramp. Scarcities are due to capacity when there are insufficient resources at maximum output available to meet demand. Scarcities are due to ramp when sufficient capacity is available, but ramp rate limitations do not allow access to the full capacity. When multiple products compete for the same, limited capability of resources, the scarcity of one product can also raise the price of other products.

Regulation and operating reserve scarcities are priced by demand curves. The regulation demand curves, for both up and down, consist of six steps with a maximum of $600/MW. The operating reserve demand curve consists of three steps with a maximum of $1,100/MW.

The clearing engine does not record the reason for the scarcity, (i.e., capacity or ramp.) The MMU suggest that SPP capture the appropriate information so that the reason for the scarcity will be transparent.

Figure 3–5 displays the number of real-time scarcity intervals and prices by month, along with a seasonal comparison of monthly averages. Typically, more regulation-down is available than regulation-up. First, variable energy resources provide regulation-down and not regulation-up. Second, the market dispatches energy from a resource’s minimum until it is no longer profitable or until the resource is limited by a parameter, such as ramp rate up or a maximum operating limit. Consequently, many resources are operating closer to their maximum than their minimum which provides more downward capability than upward capability.

Figure 3-5 Scarcity intervals and marginal energy cost, real-time

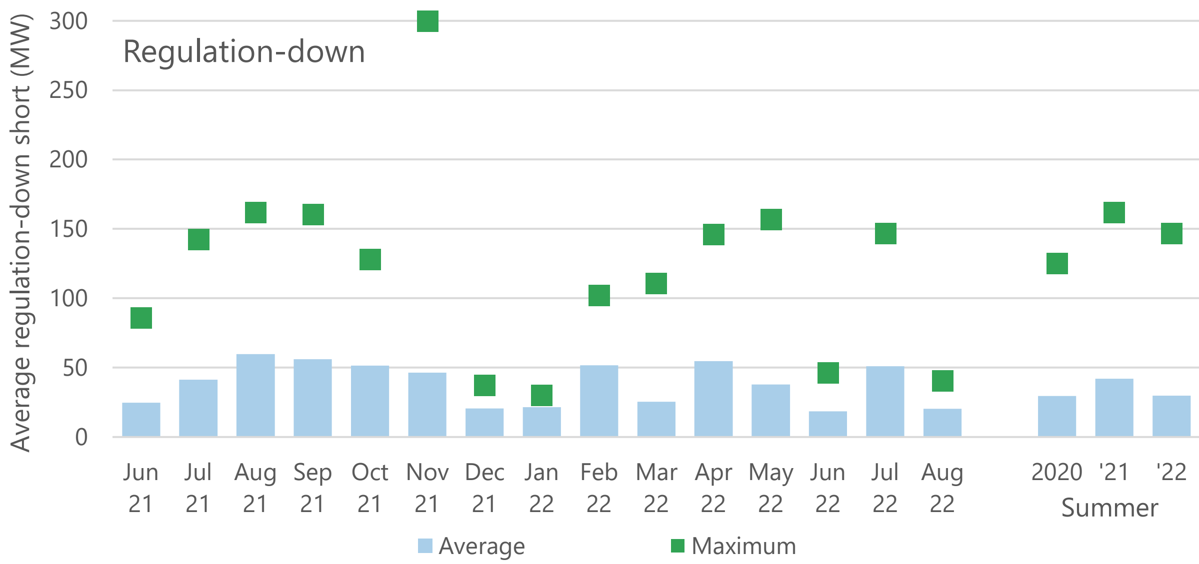


Historically, more scarcity intervals typically occur during the shoulder spring and fall seasons, as these months typically have high wind production, low load, and more generator outages. Summer 2022 saw an increase in all types of real-time scarcity. Regulation-up scarcity doubled from a monthly average of 80 intervals in summer 2021 to 161 in 2022; regulation-down scarcity increased from a monthly average of 13 intervals in summer 2021 to 17 intervals in 2022, and contingency reserve scarcity increased from a monthly average of 6 intervals in summer 2021 to 20 intervals in 2022.

The average monthly scarcity price was also up for all types of scarcity. Average contingency reserve price increased from $413/MW in summer 2021 to $466/MW in 2022, average regulation-up price increased from $224/MW in summer 2021 to $257/MW in 2022, and average regulation-down scarcity price was up from $201/MW in summer 2021 to $230/MW in 2022.

In addition to the number and price of scarcity events, also of interest is the number of megawatts short in scarcity events. Increasing shortage levels can be an indication that the resource mix is being stretched more thinly, more often. Figure 3-6 shows the average and maximum number of megawatts short for regulation-down scarcity.

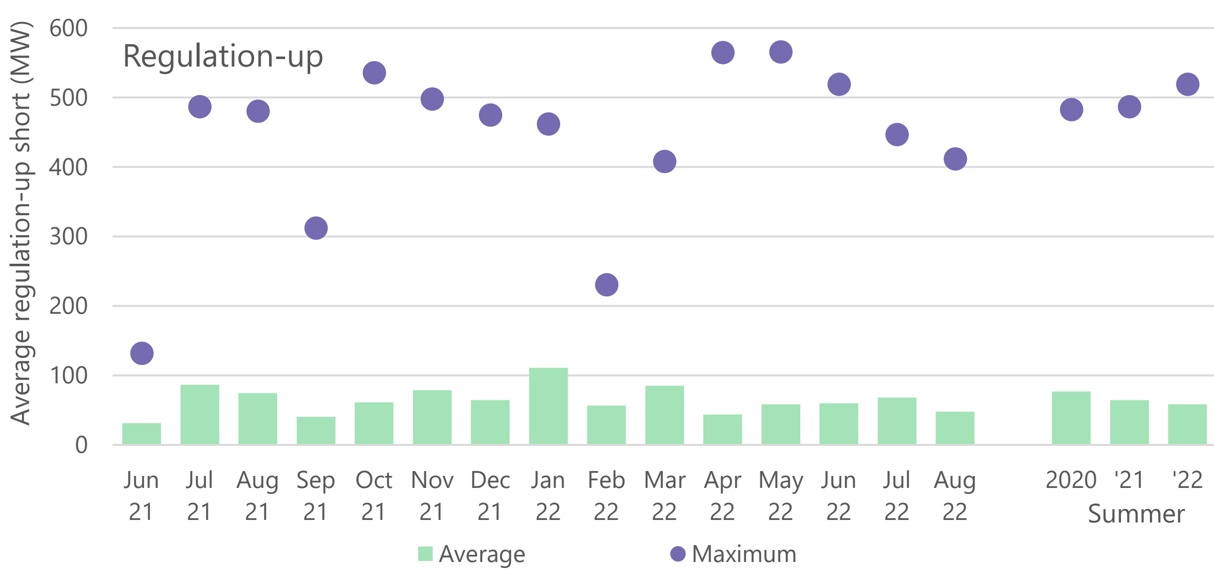
Figure 3-6 Regulation-down scarcity MW short, real-time



As shown above, the average number of megawatts short for regulation-down scarcity intervals in the summer season has decreased from 42 MW in summer 2021 to 31 MW in 2022.

Figure 3-7 shows the average and maximum number of megawatts short for regulation-up scarcity.

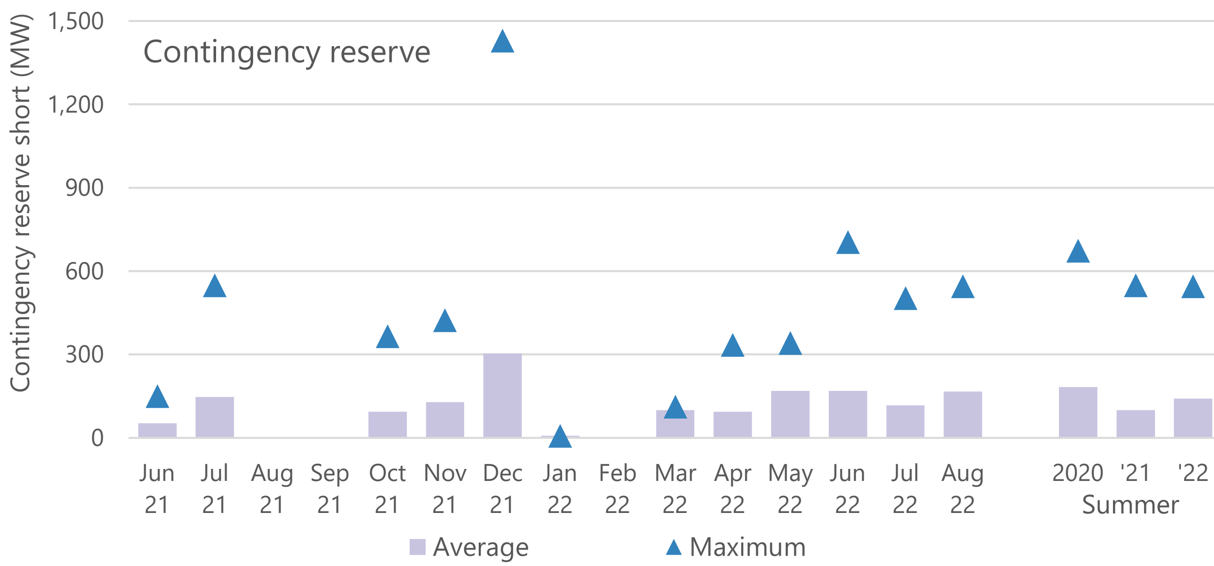
Figure 3-7 Regulation-up scarcity MW short, real-time



Like regulation-down, the average number of megawatts short for regulation-up scarcity intervals in the summer season has decreased from 64 MW in summer 2021 to 59 MW in 2022. However, the maximum megawatts short did increase from summer 2021 to 2022.

Figure 3-8 shows the average and maximum number of megawatts short for contingency reserve scarcity.

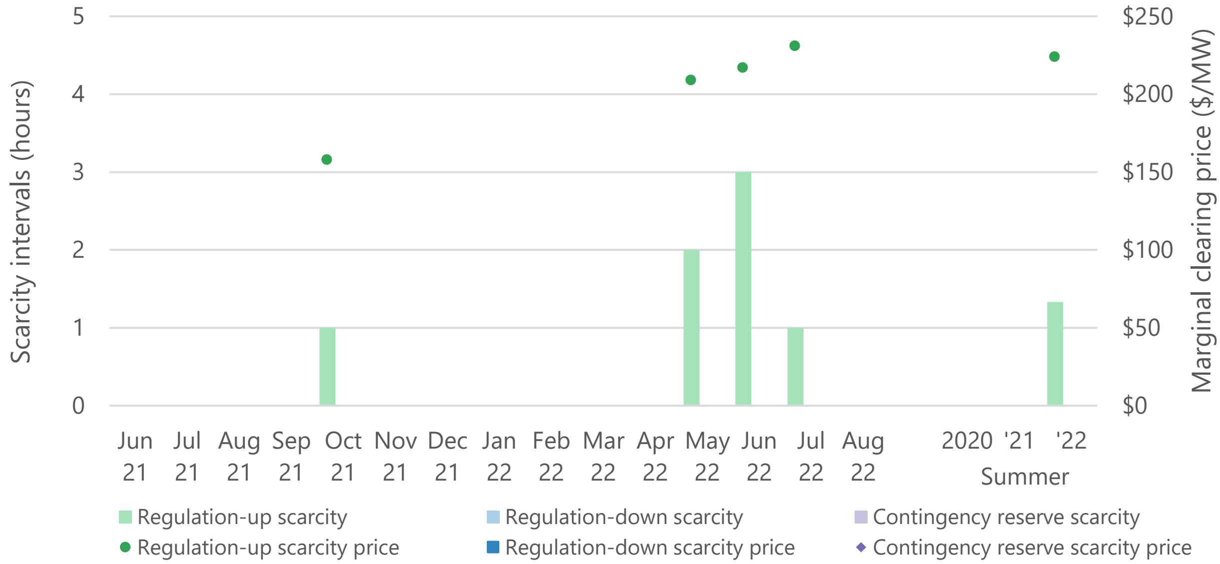
Figure 3-8 Contingency reserve scarcity MW short, real-time



The average number of megawatts short for contingency reserve scarcity intervals has increased from 100 MW in summer 2021 to 142 MW in 2022, while the maximum has stayed essentially flat.

Figure 3-9 displays the number of day-ahead scarcity intervals and prices for scarcity by month, along with a seasonal comparison of monthly averages

Figure 3-9 Scarcity intervals and marginal energy cost, day-ahead

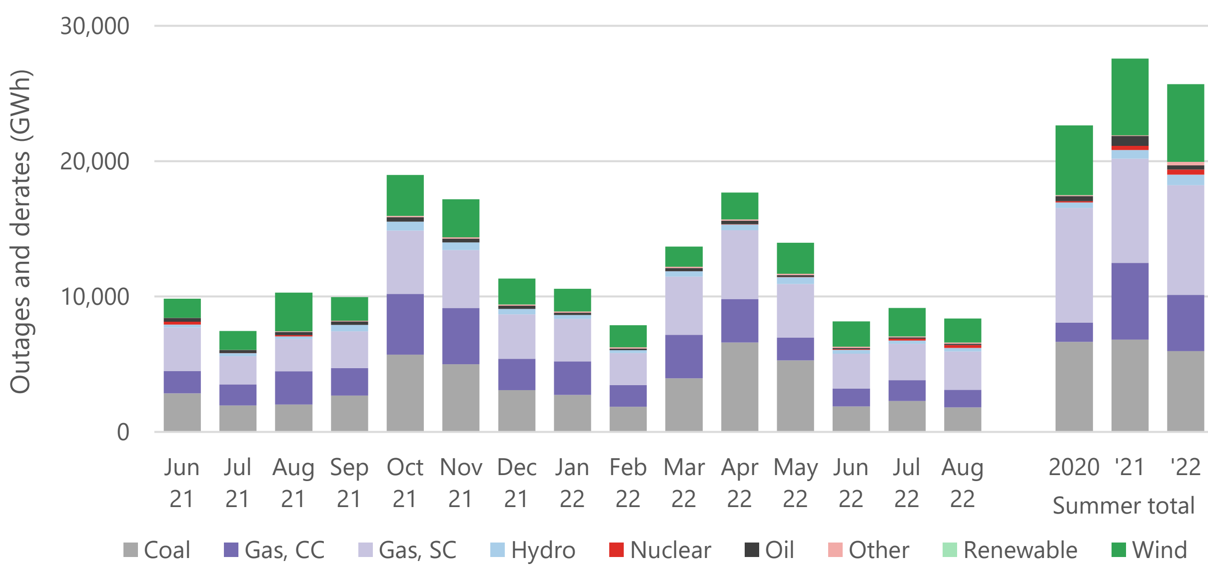


Summer 2022 saw four hours scarcity in the day-ahead market – three in June and one in July. All of these scarcity hours occurred during the morning ramp-up period, when load was sharply increasing. The amount of scarcity for these four hours ranged from 1.5 MW to 19.7 MW.

3.3 GENERATION OUTAGES AND DERATES

Generation outages and derates by fuel type of resource are shown in Figure 3-7. This metric shows the total gigawatt-hours of resources on outage and derated for each fuel type.

Figure 3-10 Generation outages and derates, by fuel type



Summer 2022 saw a drop in generation outages and derates from 27,600 GWh in summer 2021 to 25,700 GWh in summer 2022, a decrease of seven percent. Gas, combined-cycle resources, down 27 percent from summer 2021 to 2022, accounted for the majority of the decrease, while coal resources were also down, whereas gas, simple-cycle resources were up slightly.

4 MARKET PRICES AND COSTS

This chapter reviews prices in the SPP market for the summer 2022 period. Key points from this chapter include:

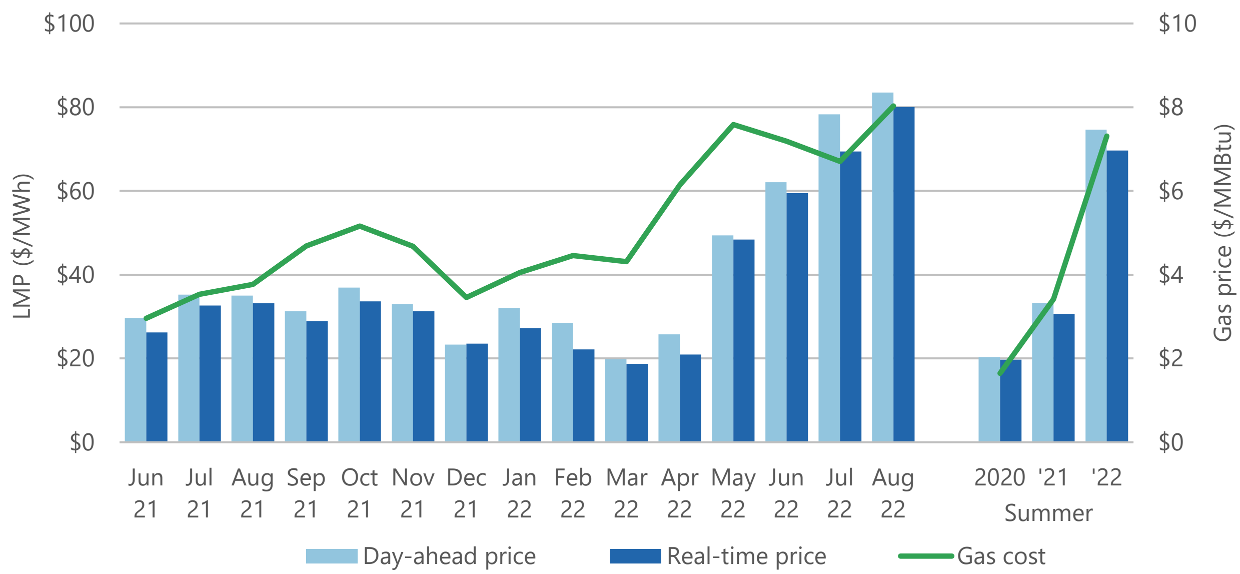
- The average gas price at the Panhandle Eastern hub remains high with an average of $7.31/MMBtu in summer 2022, up 114 percent from $3.42/MMBtu in 2021. The gas price hit a new all-time high (outside of February 2021) for the Integrated Marketplace at $8.03/MMBtu in August 2022.
- Day-ahead prices increased from an average of $33.30/MWh in summer 2021 to $74.63/MWh in 2022, an increase of 124 percent. Real-time prices increased from an average of $30.68/MWh in summer 2021 to $69.65/MWh in 2022, an increase of 127 percent.
- The highest prices, both on-peak and off-peak, were found in the southeast portion of the SPP footprint – central and eastern Oklahoma, western Missouri and northwest Arkansas, and northeast Texas; on the Texas-New Mexico border; and in the northwest corner of North Dakota.
- Summer is typically when the lowest incidence of negative prices occurs, and summer 2022 was no exception. In summer 2022, nearly 1.2 percent of settlement location intervals in the day-ahead market had prices below zero. This is down just slightly from 1.4 percent in 2021. In the real-time market, 4.4 percent of all settlement location intervals had negative prices, compared to 4.8 percent in summer 2021. The decrease in real-time negative prices can be attributed, in part, to higher load during summer 2022.
- Total day-ahead make-whole payments were up from $15.5 million in summer 2021 to $38.4 million in 2022. Day-ahead make-whole payments to all resource types were up from 2021 to 2022. Much of the increase in day-ahead make-whole payments can be attributed to higher gas prices.

- Total reliability unit commitment make-whole payments were up from $45.4 million in summer 2021 to $120.6 million in 2022. The increase can mostly be attributed the increase in natural gas prices, along with out-of-market commitments during periods of high load.
- Total revenue neutrality uplift for summer 2022 was $109 million, up from $39 million in 2021 and $11 million in 2020. The increase can mostly be attributed to higher levels of congestion costs. After peaking in the spring, revenue neutrality uplift has abated somewhat in the summer, but still remains higher than previous years.

4.1 MARKET PRICES

Historically, gas and electricity prices have been highly correlated in the SPP market. Workably competitive electricity markets are expected to see highly correlated gas costs and electricity prices in general.

Figure 4-1 Electricity and gas prices

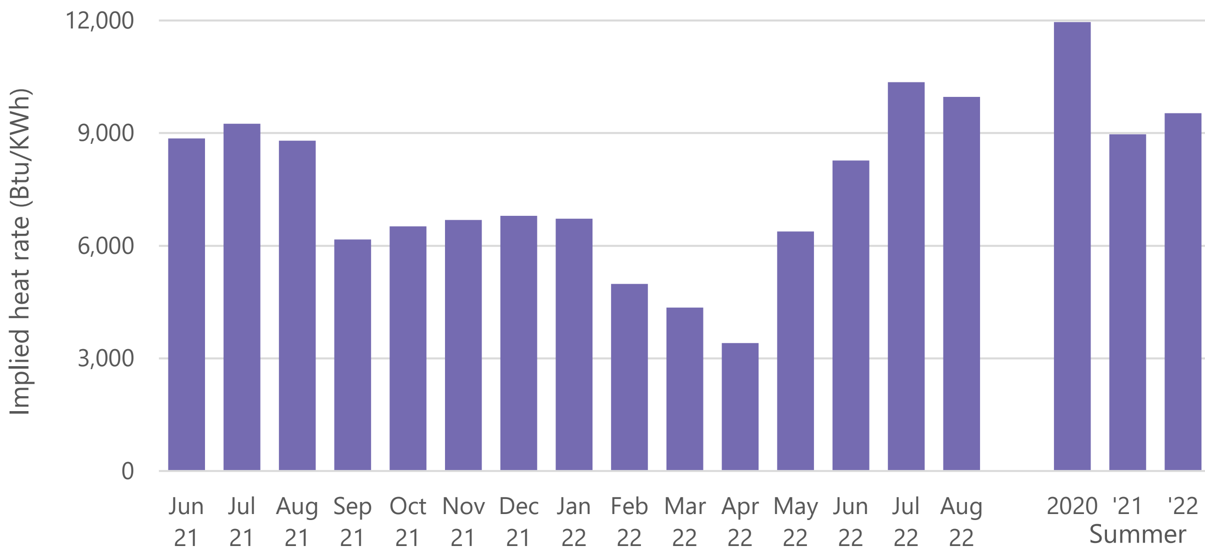


The average gas price at the Panhandle Eastern hub continues to increase with an average of $7.31/MMBtu in summer 2022, up over double (114 percent) from $3.42/MMBtu in summer 2021. Outside of February 2021, the highest average monthly gas price since the start of the market was in August 2022 at $8.03/MMBtu.

Day-ahead prices over doubled from an average of $33.30/MWh in summer 2021 to $74.63/MWh in summer 2022, an increase of 124 percent. Real-time prices increased from an average of $30.68/MWh in summer 2021 to $69.65/MWh in 2022, an increase of 127 percent. This increase is in prices is driven predominantly by the increase in gas costs, along with higher loads.

Implied heat rate shows the relative efficiency of generation required to cover the variable costs of production, given system prices. Figure 4–2 shows the implied heat rate for the past three years.

Figure 4-2 Implied heat rate

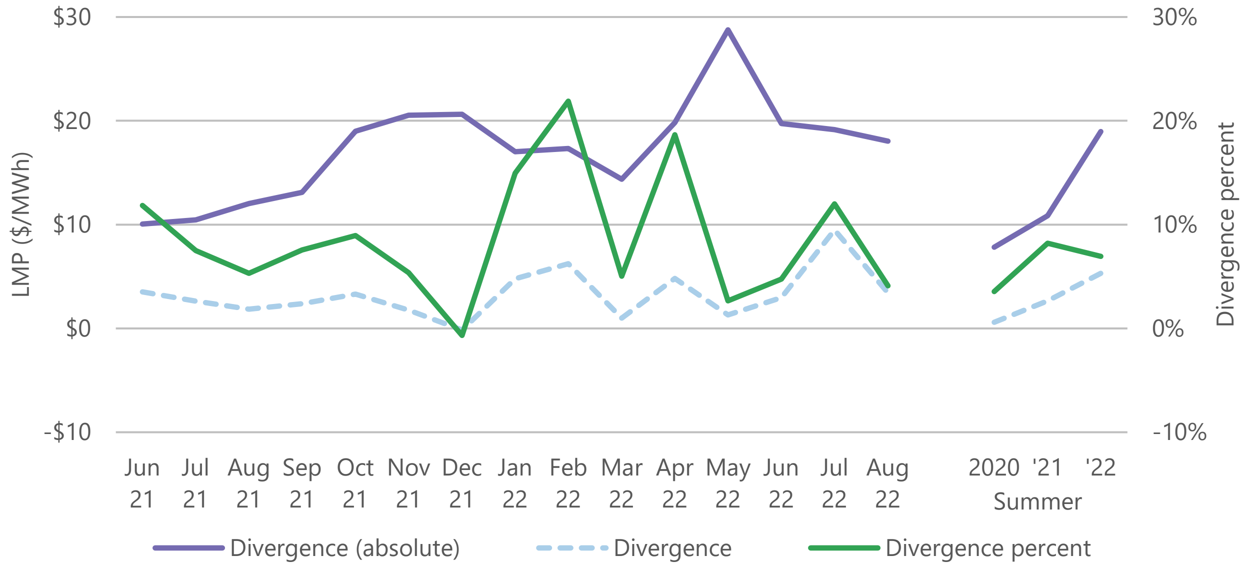


As the figure above shows, the implied heat rate has risen from 9,000 Btu/KWh in summer 2021 to 9,500 Btu/KWh in 2022. Typically, the implied heat rate is lowest in the shoulder months (spring and fall), primarily due to lower loads as well as increased wind generation, and highest in the summer period due to higher loads coupled with generally lower levels of wind generation.

Figure 4–3 shows the day-ahead to real-time price divergence at the SPP system level. Price divergence is calculated as the difference between day-ahead and real-time prices, using system prices for each five-minute (real-time) or hour (day-ahead) interval. Price divergence percent is calculated as the day-ahead price minus the real-time price, divided by the day-ahead price.

The absolute divergence is calculated by taking the absolute value of the divergence for each interval.

Figure 4-3 Price divergence, day-ahead and real-time



Absolute divergence is the best measurement of divergence, as this method eliminates the "softening" of averages when positive and negative values are encountered.[9] Continued price convergence is generally one indicator of an effectively and efficiently operating market. Absolute divergence for summer 2022 was $18.98/MWh, up from $10.85/MWh in 2021. As gas prices have continued to rise, divergence has increased during that same period. The MMU is evaluating the implementation of the ramping capability product in early 2022, to determine its effectiveness in address ramping limitations that cause price volatility, and intends to report on this in an upcoming quarterly report.[10]

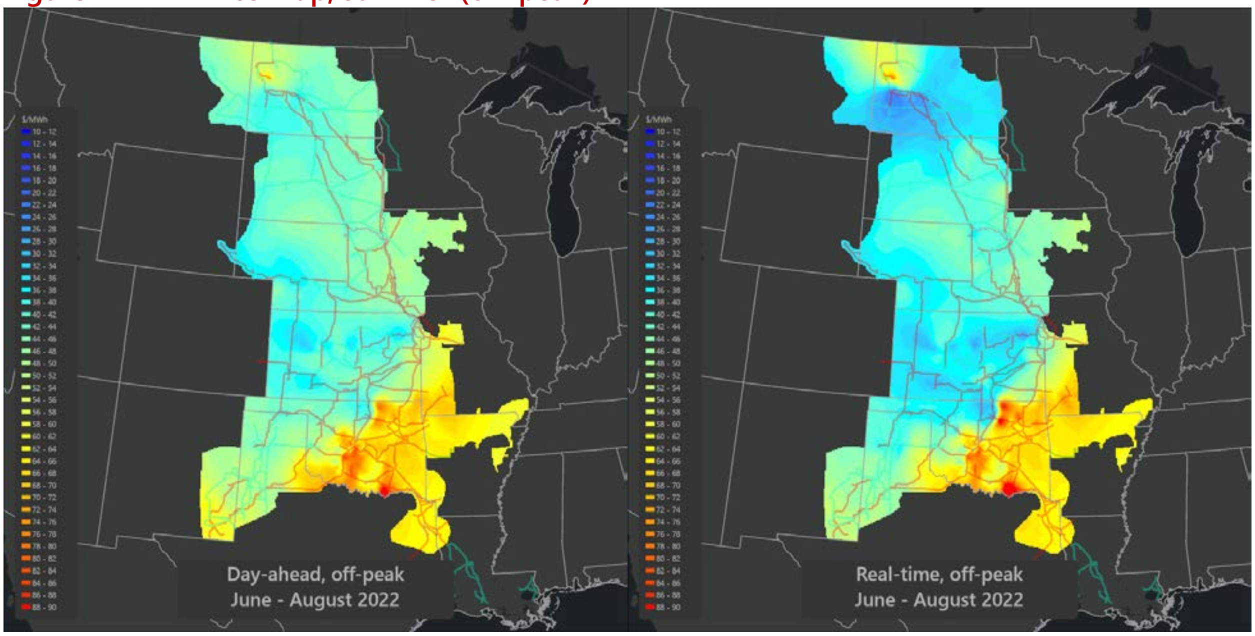
Overall price patterns between the day-ahead and real-time markets are similar, as shown on the price contour maps below in Figure 4–4 and Figure 4-5. Blue represents lower prices, while

[9] For example, if one hour had a price divergence of +$10/MWh and the next hour had a price divergence of −$10/MWh, the average divergence for those two hours would be zero. By using the absolute divergence, the absolute average divergence would be $10/MWh.

[10] The design for a ramping product was approved by FERC on July 16, 2020. [Tariff Revisions to Add Ramp Capability, Docket No. ER20-1617](#).

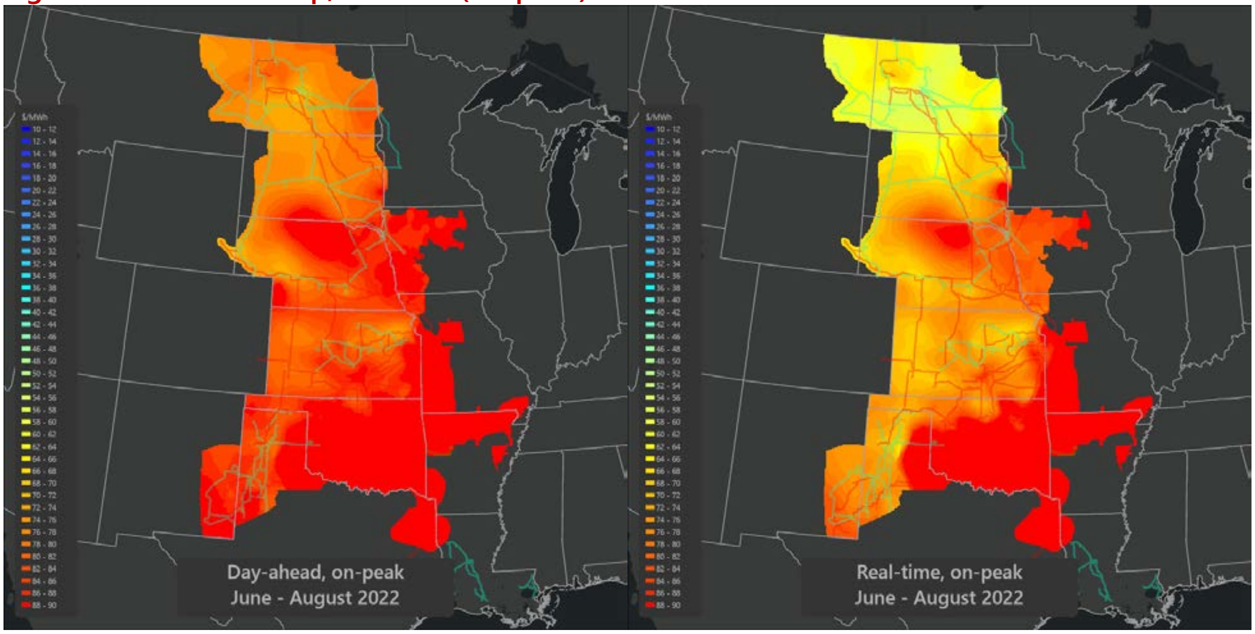
yellow and red represent higher prices. Significant color changes across the map signify constraints that limit the transmission of electricity from one area to another.

Figure 4-4 Price map, summer (off-peak)



Typically, lower prices are more prevalent in the west-central part of the footprint due to abundant low-cost wind generation in that area. However, this can change because of localized congestion and outages. The highest off-peak prices were found in the southeast portion of the SPP footprint – central and eastern Oklahoma, western Missouri and northwest Arkansas, and northeast Texas; on the Texas-New Mexico border; and in the northwest corner of North Dakota.

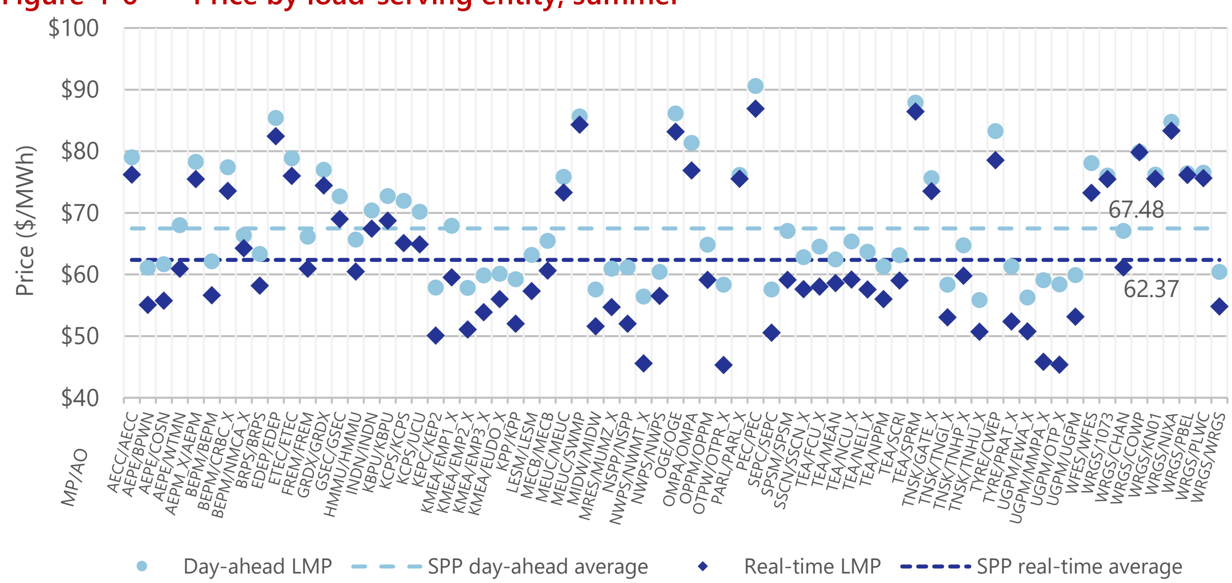
Figure 4-5 Price map, summer (on-peak)



As discussed below, on-peak prices historically average around $10/MWh higher than off-peak prices. The same areas seeing the highest prices in the off-peak hours remain for the on-peak hours.

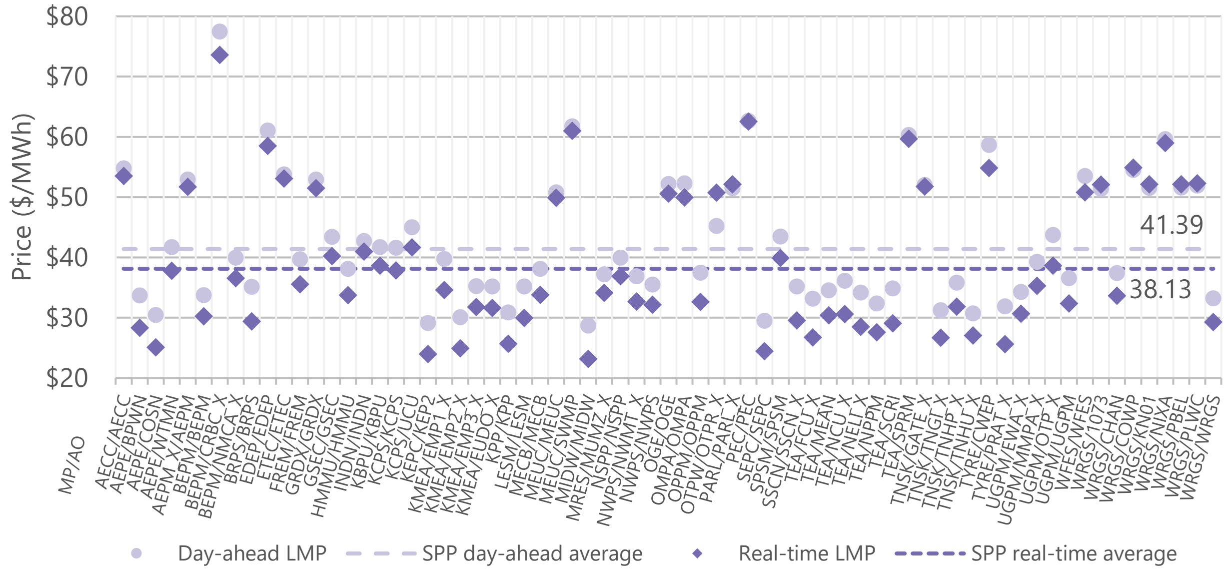
Figure 4-6 and Figure 4-7 display average prices paid by load-serving entity for the summer period and the last 12 months.

Figure 4-6 Price by load-serving entity, summer



Average prices for the summer period were the highest in entities around southwest Missouri and portions of Oklahoma, and lowest in western Kansas, Nebraska, and the Integrated System.

Figure 4-7 Price by load-serving entity, rolling 12 month[11]

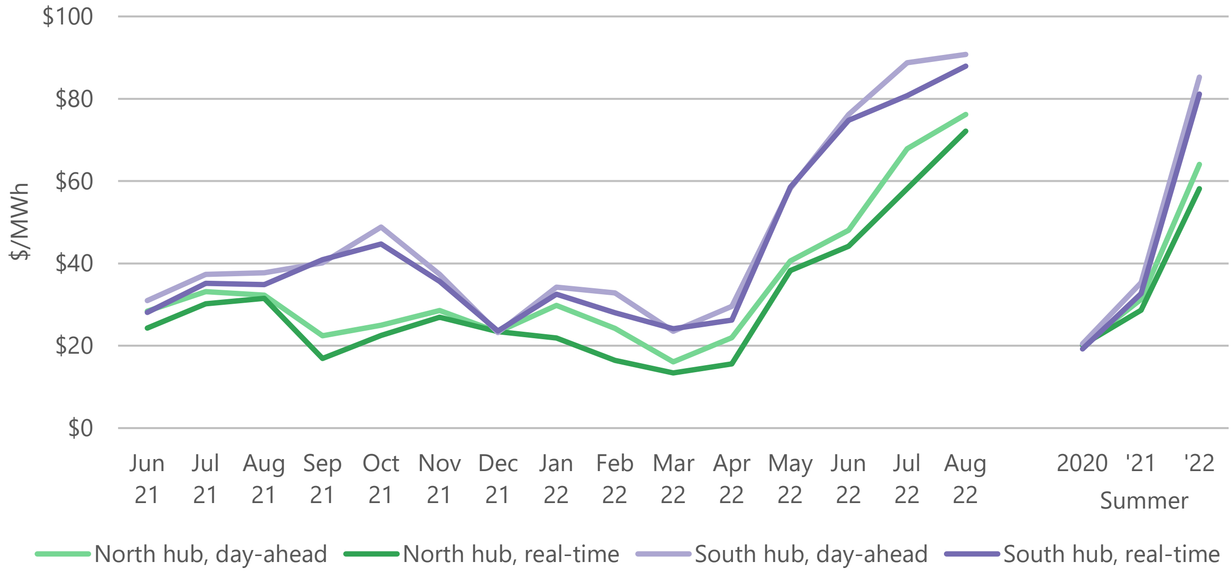


Average prices over the past 12 months had the same pattern as summer 2022 prices. Entities around southwest Missouri, and portions of Oklahoma had the highest prices, while the lowest prices were in western Kansas and Nebraska. Western Kansas has abundant low-cost generation, primarily wind, while the northwest portion of the footprint has primarily low-cost coal and hydro generation. Typically, entities in those portions of the SPP footprint see some of the lowest prices overall.

Figure 4-8 shows monthly average day-ahead and real-time prices for the SPP North and SPP South trading hubs. A trading hub is a settlement location consisting of an aggregation of price nodes for financial and trading purposes.

[11] Market participant/asset owner BEPM/CRBC_X just joined the market at the beginning of August 2022, so their figures only represent one month of data.

Figure 4-8 Trading hub prices



Because of an abundance of lower-cost generation in the northern part of the SPP footprint, historically prices at the North hub have typically been lower than the South hub. For summer 2022, average real-time prices were $81.15/MWh at the South hub and $58.16/MWh at the North hub. In the day-ahead market, the average price for summer was $85.23/MWh at the South hub and $64.03/MWh at the North hub.

Historically, the spread between North and South hub prices have been in the $3/MWh to $5/MWh range. However, beginning in September 2021 the spreads between the two hubs increased to about $20/MWh, with a decrease in November and December, before increasing again in the first five months of 2022. This larger spread can be mostly attributed to a preponderance of gas-fired resources in the southern portion of the SPP footprint compared to the northern portion, as well as congestion. With the high gas prices, these resources generally experience higher prices during these months.

In addition, hub prices can be broken down into on-peak and off-peak prices, as shown in Figure 4-9 and Figure 4-10.

Figure 4-9 North hub prices, on-peak and off-peak

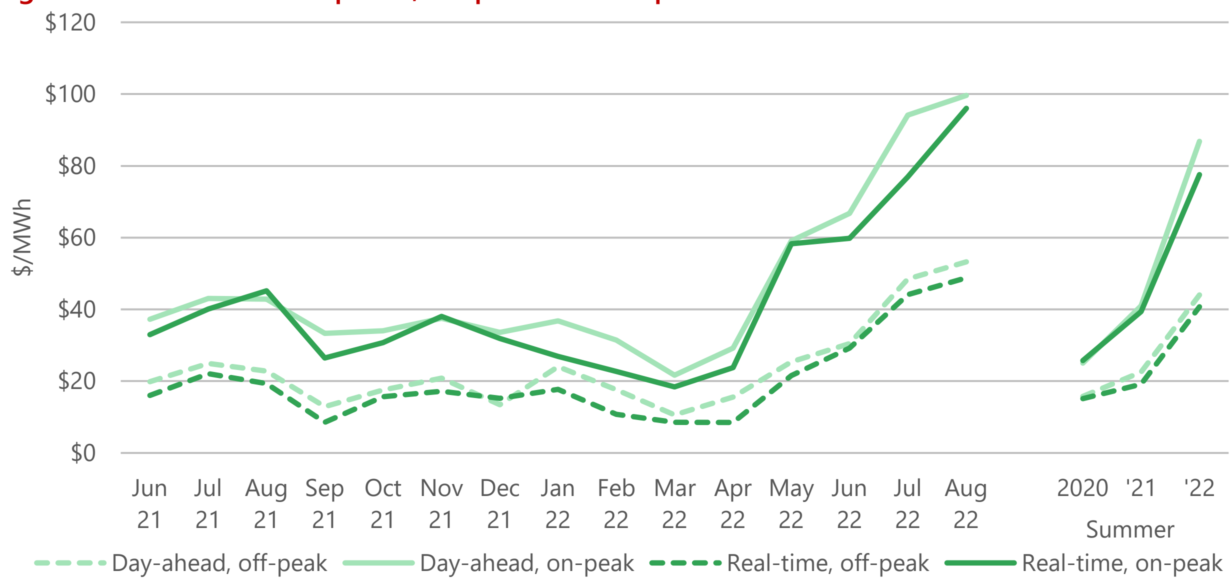
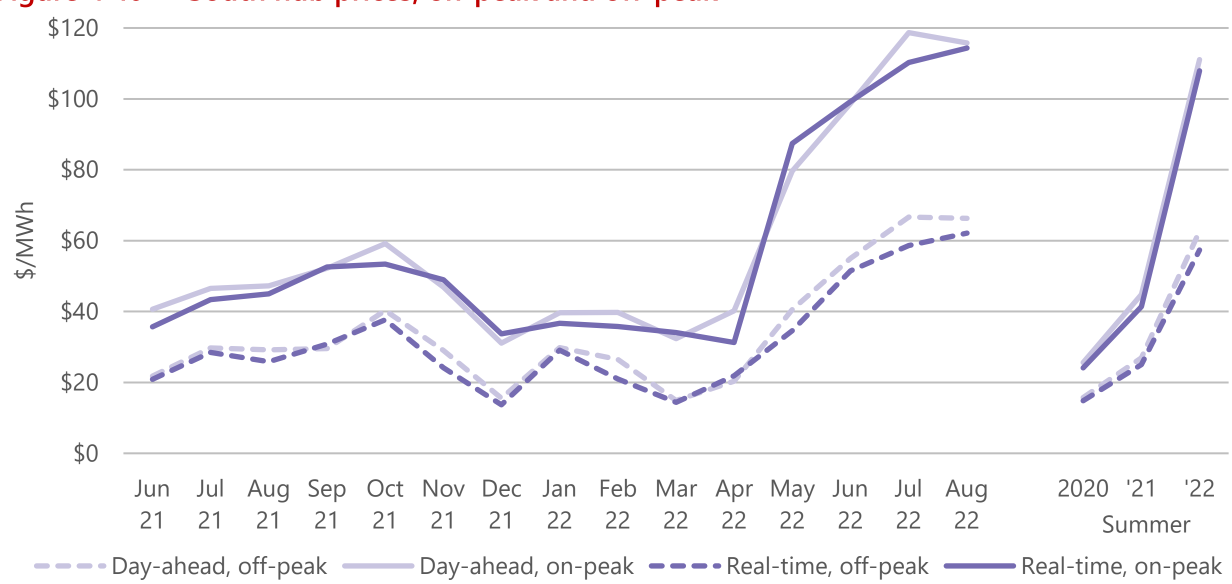


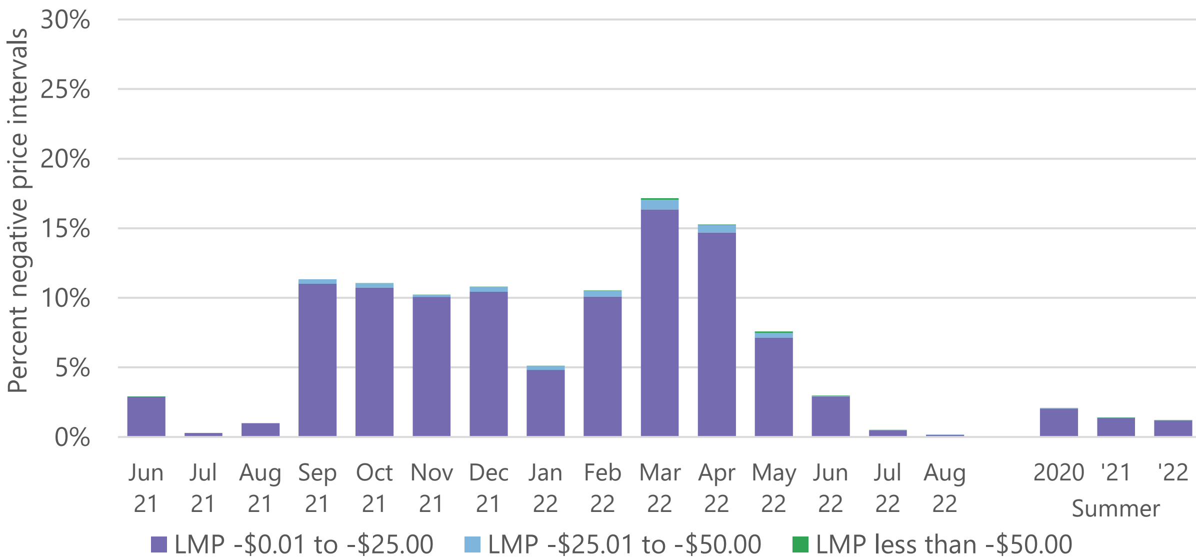
Figure 4-10 South hub prices, on-peak and off-peak



Historically, there has been a price spread between on- and off-peak prices at both hubs around $10/MWh. On average, while there are monthly variations, the spread between on-peak and off-peak prices has remained fairly consistent over the past several years. Beginning in summer 2021, that spread has increased to about $20/MWh, and then starting in May 2022 increasing again into the $50/MWh range. This increase is primarily due to higher gas prices and more gas resources setting prices during on-peak hours during periods of high loads than in off-peak hours.

While negative prices are a legitimate market outcome, they can make it difficult for generators to earn revenue. Negative price intervals can be caused by many different factors including high amounts of wind generation, self-commitment of resources in the day-ahead market, negative natural gas prices, and external impacts. Negative price intervals for the day-ahead market are shown in Figure 4-11.

Figure 4-11 Negative price intervals, day-ahead

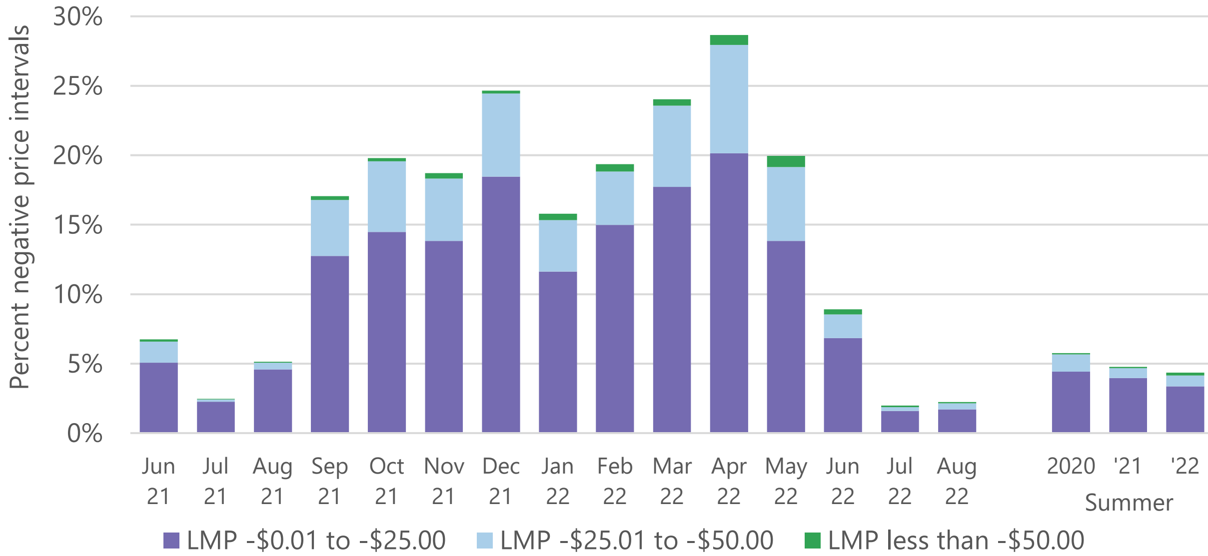


In summer 2022, 1.2 percent of settlement location intervals[12] in the day-ahead market had prices below zero. This is down just slightly from 1.4 percent in 2021.

Typically, the frequency of negative price intervals in the real-time market is about two to three times that of the day-ahead market as shown in Figure 4-12.

[12] Settlement location intervals are calculated as the number of settlement locations serving load that are active in an interval. For example, if there 100 settlement locations active in one five minute interval throughout an entire 30 day month, the total asset owner intervals would be 864,000 for the month (100 settlement locations * 288 intervals per day * 30 days).

Figure 4-12 Negative price intervals, real-time



Summer 2022 had nearly 4.4 percent of all settlement location intervals in the real-time market with negative prices, compared to 4.8 percent in summer 2021. The decrease in real-time negative prices can be attributed, in part, to higher load during the summer season.

During SPP's Holistic Integrated Tariff Team process, the MMU discussed potential concerns with unduly low offers on price. The Holistic Integrated Tariff Team ultimately adopted a recommendation to review the effects of these offers and potentially develop automatic mitigation to ensure that prices are only negative when market fundamentals dictate it.[13] After study and completion of a white paper,[14] the MMU identified specific problems with the recommendation: load prices are on average $5/MWh lower, generator prices are less negative, and breached transmission lines are reduced by 25 percent when offers of -$500/MWh are replaced by -$100/MWh offers. As such, an adjustment to the market floor is recommended for addition to SPP's Market Roadmap. The MMU will continue to evaluate the market to identify if further changes are warranted.

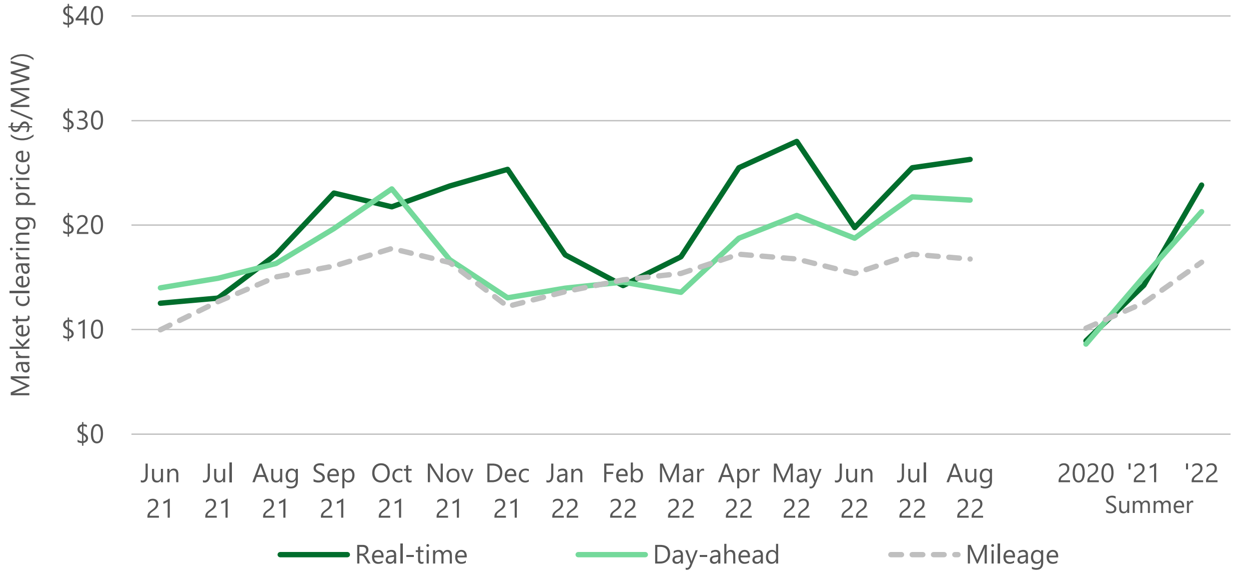
[13] SPP Holistic Integrated Tariff Team report, page 25.

[14] SPP MMU Study of Unduly Low Offers white paper.

4.2 OPERATING RESERVE MARKET

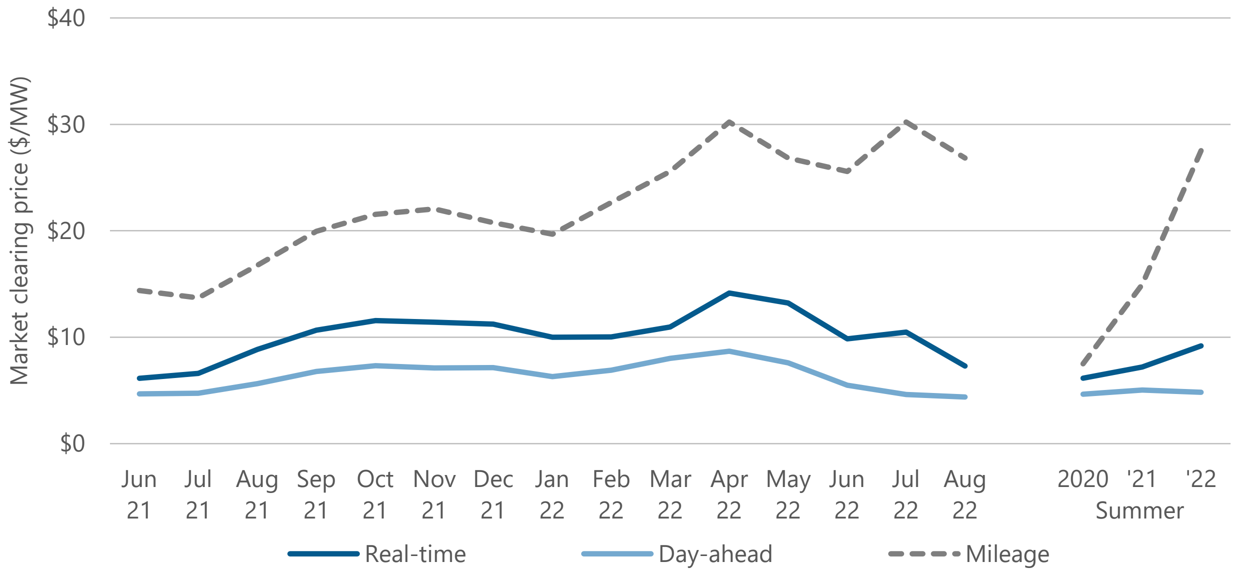
The following figures (Figure 4-13 through Figure 4-16) show marginal clearing prices for the four operating reserve products: (1) regulation-up, (2) regulation-down, (3) spinning reserve, and (4) supplemental reserve. The regulation products are used to ensure the amount of generation matches load on a subinterval basis. Generators respond to regulation instructions in seconds. Spinning and supplemental products are reserved for contingency situations and respond to instructions within ten minutes.

Figure 4-13 Regulation-up prices



For summer 2022, the average real-time regulation-up price was $21/MW, up from $15/MW in 2021; and day-ahead regulation-up price was $24/MW in summer 2022, up from $14/MW in 2021. Regulation-up mileage was nearly $16/MW in summer 2022, up from $13/MW in 2021. Higher demand for increased generation generally results in the higher regulation-up prices. Units incur higher opportunity costs to provide ancillary services. Higher natural gas prices also influence higher regulation-up prices.

Figure 4-14 Regulation-down prices



Regulation-down prices were up in the real-time market, from $7/MW in summer 2021 to $9/MW in 2022. Day-ahead regulation-down was down slightly from $5.02/MW in summer 2021 to $4.83/MW in 2022. Regulation-down mileage has been on a sharp, steady increase from summer 2020 at $7.50/MW to 2022 at $27.54/MW. The MMU has identified that the price increase is related, in part, to issues related to an outstanding MMU recommendation related to regulation mileage.[15] The MMU continues to recommend addressing these regulation mileage concerns.

[15] SPP MMU 2021 Annual State of the Market report, page 273.

Figure 4-15 Spinning reserve prices

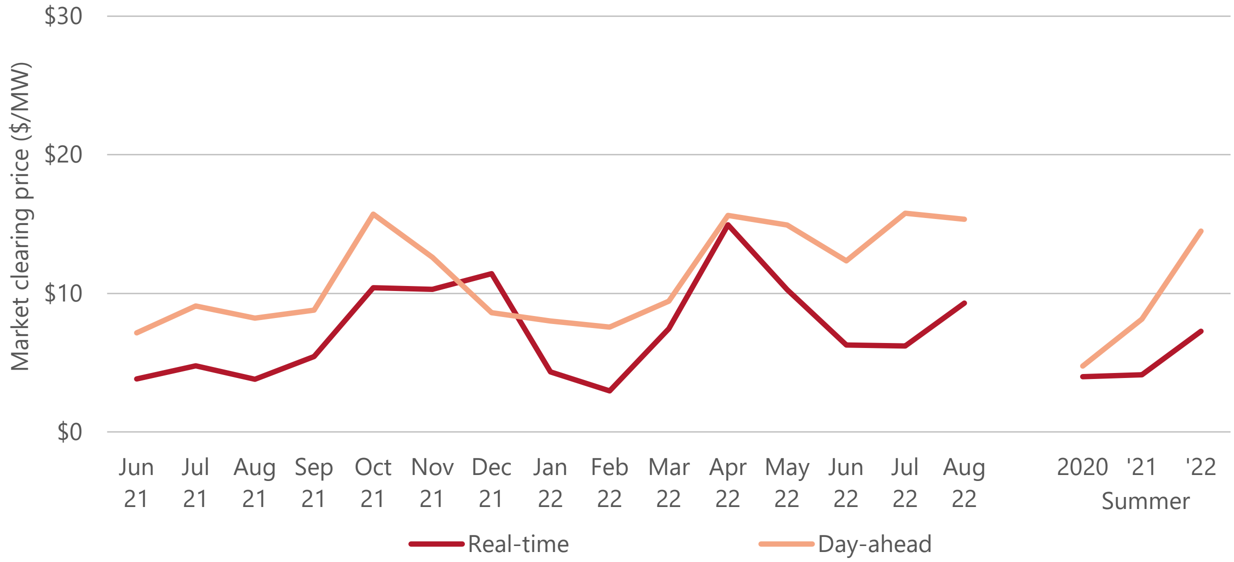
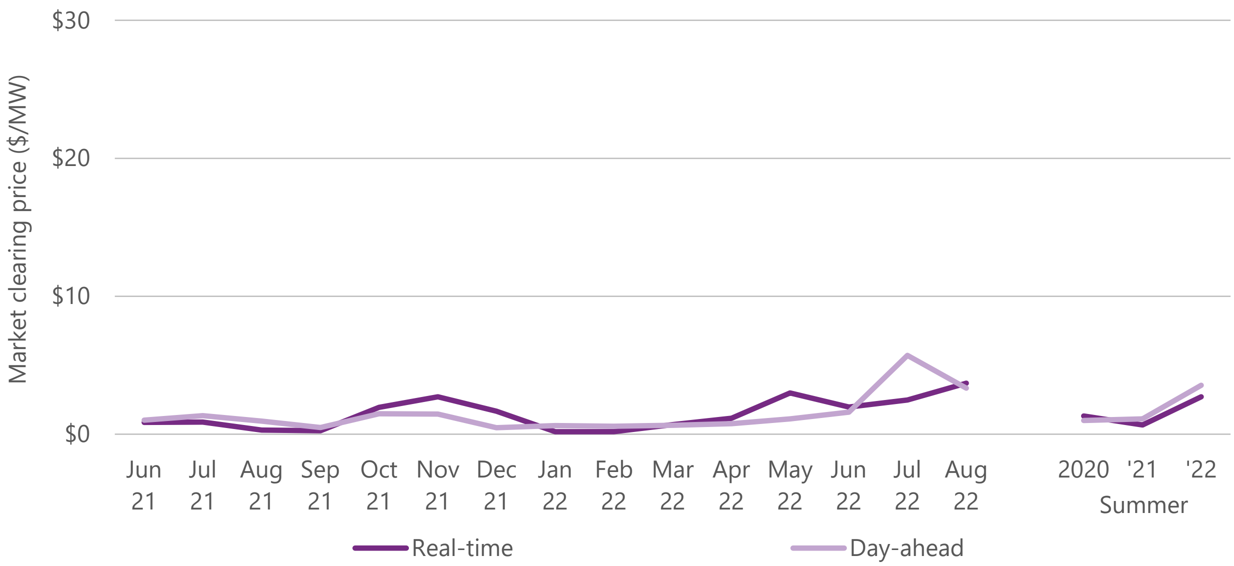


Figure 4-16 Supplemental reserve prices

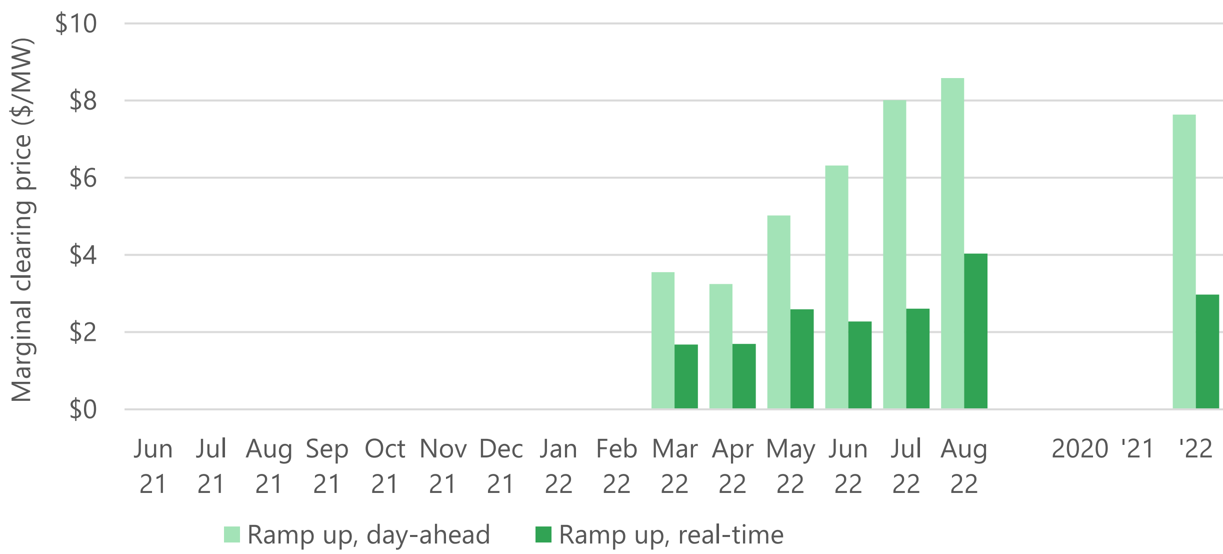


Spinning reserve prices were up in the day-ahead market from $8/MW in summer 2021 to $14/MW in 2022 and in the real-time market up from $4/MW in summer 2021 to $7/MW in 2022. Supplemental reserve prices were up from summer 2021 to 2022 in both the day-ahead and real-time markets.

Historically, reserve prices have generally been low. Correspondingly, SPP operators remain concerned about wind forecast errors and often manually commit resources for capacity. These concerns do not appear to be addressed with the supplemental reserve product, because of its short time frame. However, the uncertainty product under development by SPP should help compensate generators that are specifically needed to mitigate the risk associated with wind forecast error.[16] The uncertainty product received FERC approval in mid-August and is awaiting implementation by SPP in 2023.

The SPP ramping capability product was implemented on March 1, 2022. The maximum price per interval was $35/MW. This price occurred in 151 real-time intervals and 8 day-ahead intervals. Average ramp-up capability product prices were just under $7/MW in day-ahead and $3/MW in real-time for the summer quarter. There have been no ramp down product prices since implementation on March 1.

Figure 4-17 Ramp product prices



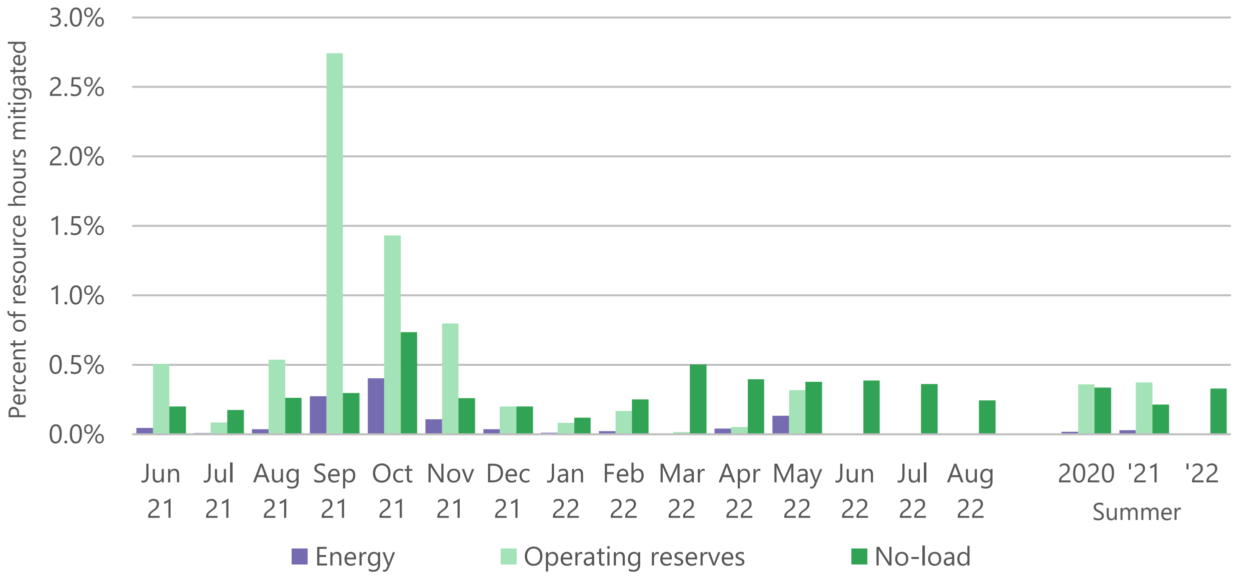
4.3 MITIGATION

SPP uses an automated conduct and impact mitigation approach to address potential market power abuse. SPP resources' incremental energy, start-up, no-load, and operating reserve offers are subject to mitigation for economic withholding.

[16] SPP Holistic Integrated Tariff Team report, page 18.

Mitigation frequency varies across products in the SPP market. Figure 4-18 shows the frequency of mitigation of incremental energy, operating reserves, and no-load costs in the day-ahead market.

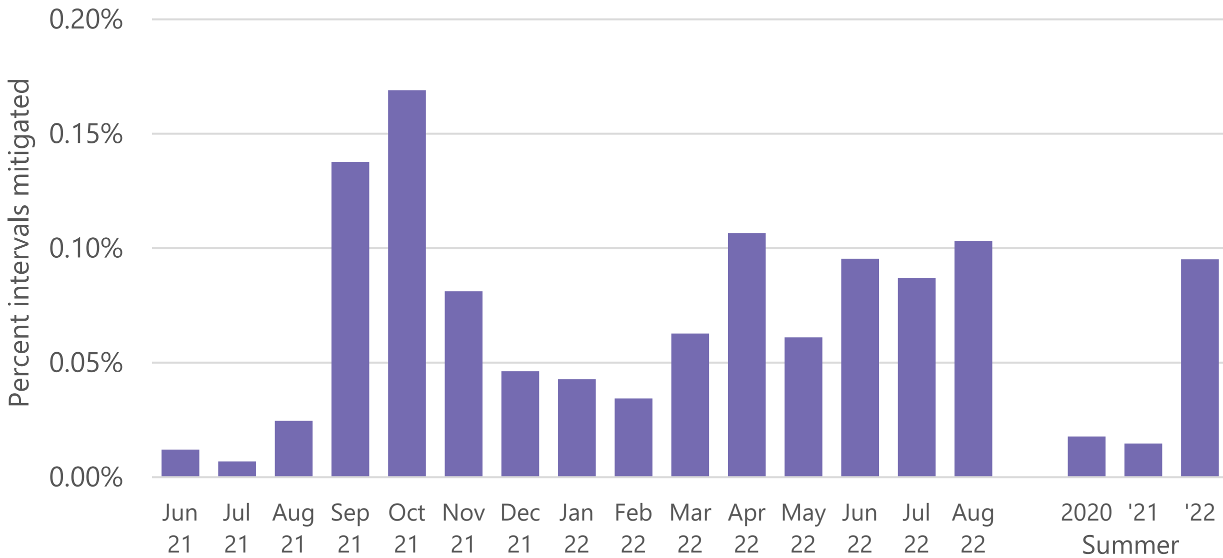
Figure 4-18 Mitigation frequency, day-ahead market



Mitigation frequency in energy, operating reserves, and no-load in the day-ahead market remains low. Overall, energy and operating reserve day-ahead mitigation types are down from summer 2021 to 2022, while no-load mitigation is up slightly. Generally speaking, as wind increases, congestion increases which increases instances of local market power, which increases potential candidates for mitigation.

For the real-time market, the mitigation of incremental energy is shown in Figure 4-19.

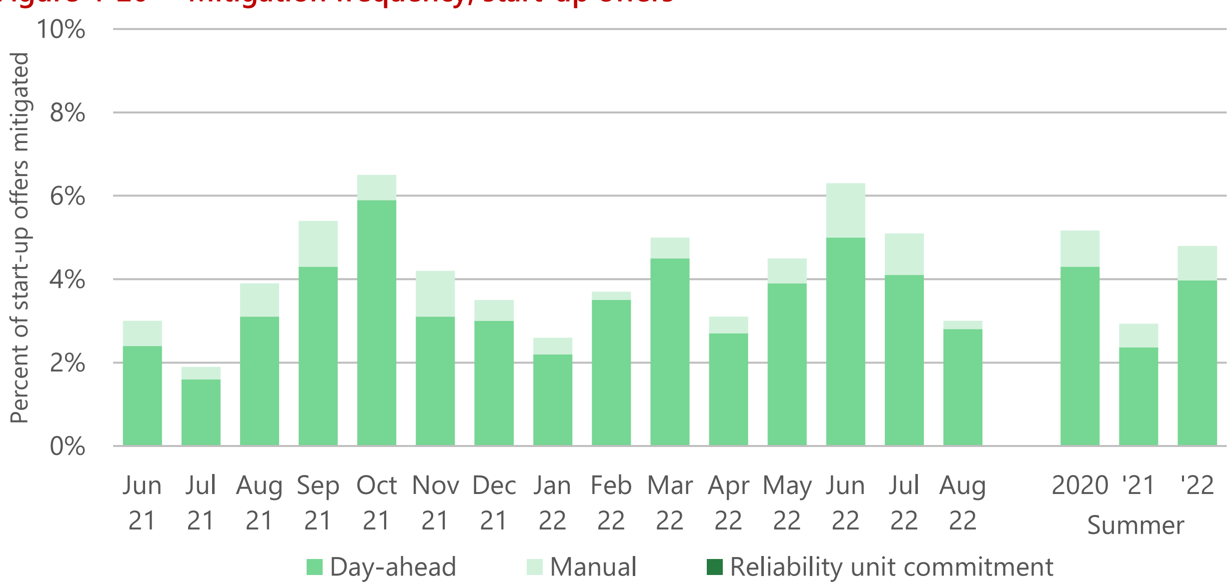
Figure 4-19 Mitigation frequency, real-time market



Mitigation frequency in the real-time market has remained at very low levels, with less than 0.11 percent of resource intervals mitigated in real-time in all except for two months. After a spike in fall 2021 where three large resources were frequently running near their economic maximum while affecting binding constraints, real-time mitigation frequency returned to historical levels in spring 2022, but increased again in the summer. Overall, real-time market mitigation increased from 0.015 percent in summer 2021 to 0.095 percent in 2022.

Figure 4-20 shows the mitigation of start-up offers for different commitment types.

Figure 4-20 Mitigation frequency, start-up offers

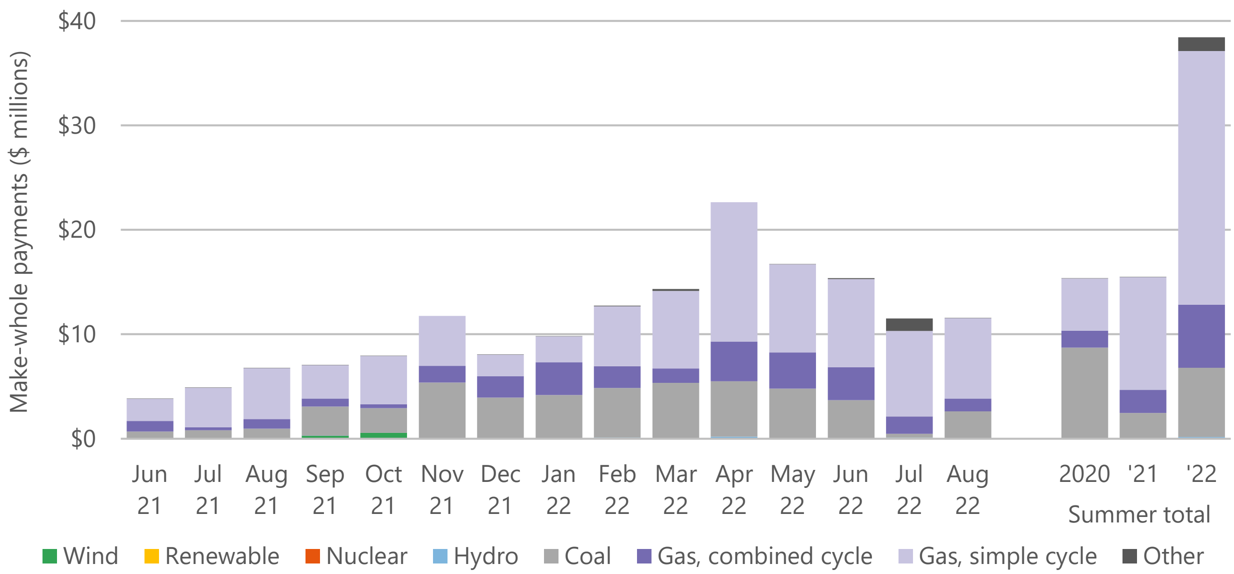


The overall level for mitigation of day-ahead start-up offers has increased from 2.9 percent to 4.8 percent from summer 2021 to 2022. Overall, the frequency of start-up offer mitigation remains low.

4.4 UPLIFT

A make-whole payment (uplift) is paid to a generator when the market commits a generator with offered costs exceeding the realized market revenue from providing energy and ancillary services for the commitment period. The day-ahead make-whole payment (Figure 4-21) applies to commitments from the day-ahead market. Day-ahead make-whole payments are typically less frequent and smaller in magnitude than those in the real-time market.

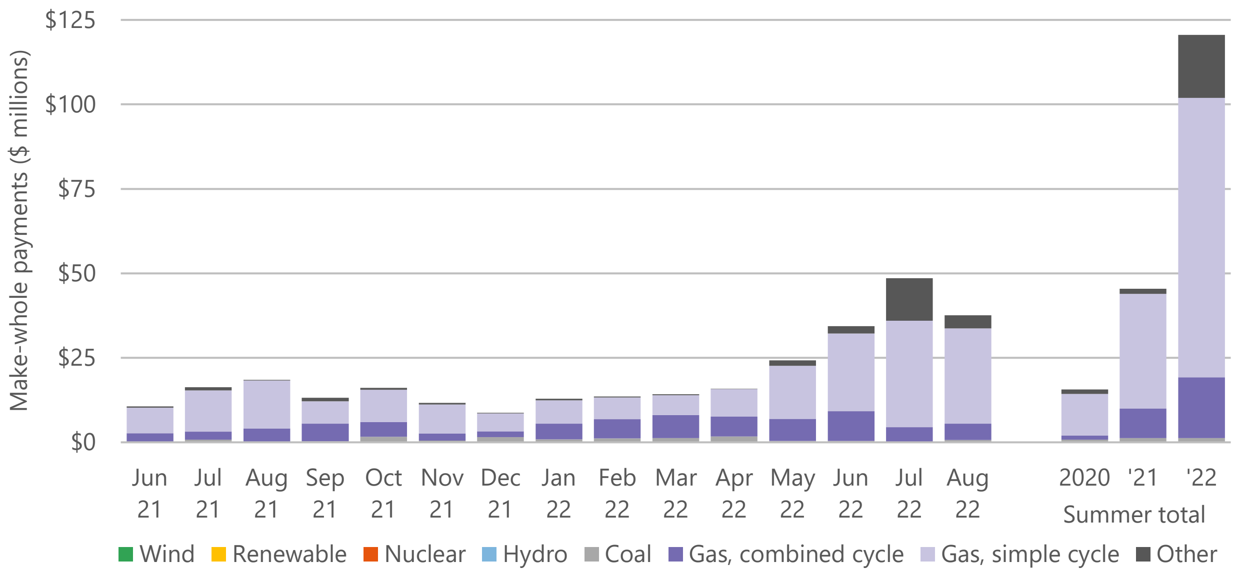
Figure 4-21 Make-whole payments, day-ahead



Typically, most day-ahead make-whole payments are attributed to coal and gas resources. Total day-ahead make-whole payments were up from $15 million in summer 2021 to $38 million in 2022. Day-ahead make-whole payments to coal and gas resources all increased from summer 2021 to 2022. Much of the increase in day-ahead make-whole payments can be attributed to higher gas prices, higher loads, and wind forecast uncertainty.

The reliability unit commitment (RUC) make-whole payment (Figure 4-22) applies to commitments made in the day-ahead RUC, intra-day RUC processes, short-term RUC, and manual commitments. The majority of the reliability unit commitment make-whole payments are paid to gas resources, and more specifically gas simple-cycle resources.

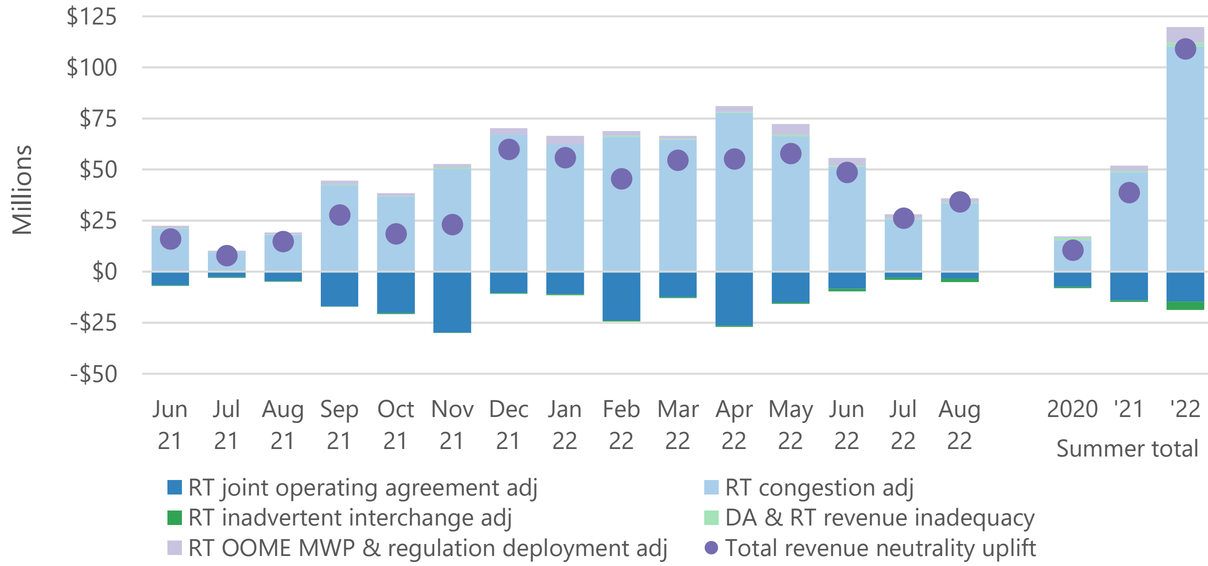
Figure 4-22 Make-whole payments, reliability unit commitment



Total reliability unit commitment make-whole payments were up from $45 million in summer 2021 to $121 million in 2022. The increase can mostly be attributed the increase in natural gas prices, with gas resources accounting for the majority of the increase. Additionally, many of the gas resources receiving make-whole payments are committed to address uncertainty. Summer 2022 also saw commitments of oil resources as an outcome of conservative operations experienced in July, this accounts for the increase in the 'other' category. The addition of the uncertainty product should help to alleviate some of these commitments as well as provide additional payments for resources that are committed for uncertainty.

Revenue neutrality uplift (RNU), shown in Figure 4-23, ensures settlement payments/receipts for each hourly settlement interval equal zero. Positive revenue neutrality uplift indicates that SPP receives insufficient revenue and collects from market participants. Negative revenue-neutrality uplift indicates where SPP receives excess revenue, which must be credited back to market participants.

Figure 4-23 Revenue neutrality uplift



Total revenue neutrality uplift for summer 2022 was $109 million, up from $39 million in 2021 and $11 million in 2020. The increase can mostly be attributed to higher levels of congestion costs during the summer months. Since November 2021 congestion costs have been over $50 million on a monthly basis, but dropped to $26 million and $34 million for July and August 2022, respectively. The MMU, along with the SPP RTO, are currently studying the increase in congestion costs, and the MMU will report more in future reports.

5 CONGESTION AND TRANSMISSION CONGESTION RIGHTS MARKET

This chapter reviews congestion and transmission congestion rights in the SPP market for the summer 2022 period. Key points from this chapter include:

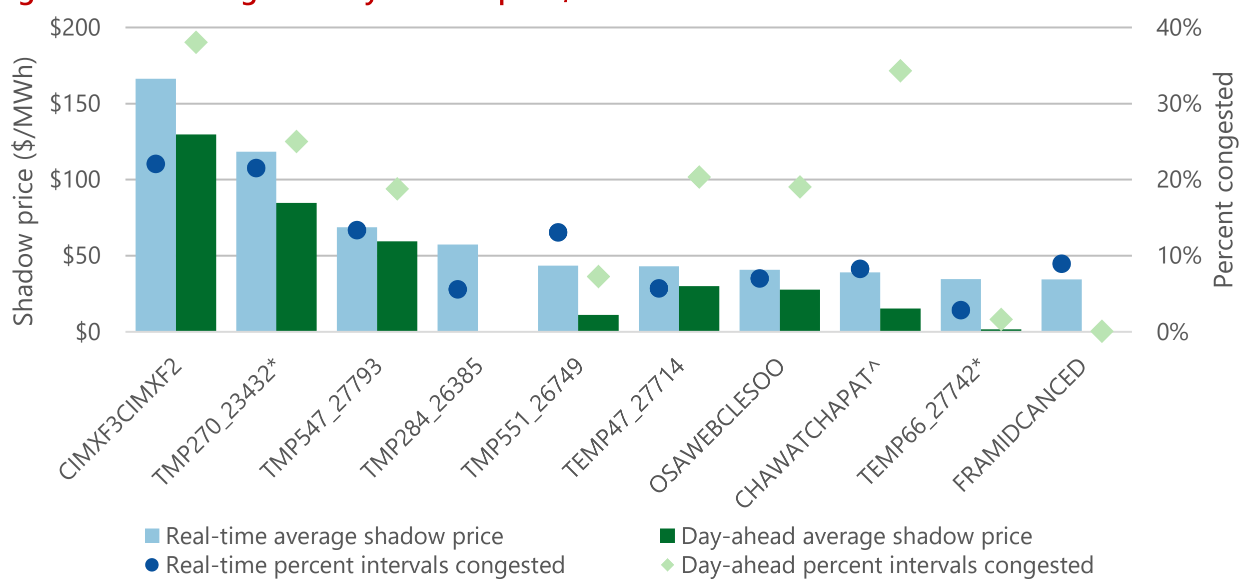
- During the summer season, the most congested flowgate was in central Oklahoma (Cimarron transformer 345/1kV [OKGE]), with six of the top ten located in Oklahoma
- Overall, real-time market congestion for summer in terms of intervals with breached flowgates increased to 72 percent of all intervals. This is up from 63 percent in summer 2021 and 43 percent in 2020.
- Analysis shows that over the last three summer seasons, when excluding market-to-market flowgates, the percentage of intervals with breached flowgates was 51 percent in summer 2022, 34 percent in 2021, and 14 percent in 2020.
- Day-ahead congestion was dramatically higher quarter over quarter from $281 million in summer 2021 to $707 in summer 2022. The increase is driven largely by the increase in gas prices over the prior period.
- The surplus between the congestion payments and the total congestion cost shows that overall for the quarter, load-serving entities fully covered their congestion cost through the congestion hedging market.
- Total TCR funding for summer 2022 was 92 percent, up from 87 percent in summer 2021. The improvement in TCR funding can be attributed to improved alignment between the congestion hedging model and the day-ahead market model.
- Sixty percent of participants received positive net congestion revenues, while 40 percent of participants held hedges that did not cover their total congestion costs. The bottom five participants collectively paid $70 million more in congestion costs than was offset by their auction revenue right and transmission congestion right positions.

- Auction revenue right funding percentages decreased slightly quarter over quarter. Additionally, the auction revenue right surplus increased from $18 million in summer 2021 to $48 million in summer 2022.

5.1 CONGESTION

The impact of a constraint on the market is represented by its shadow price, which reflects the magnitude of congestion on the path represented by the flowgate. The shadow price indicates the marginal value of an additional increment of relief on a congested constraint in reducing the total production costs. This is the marginal congestion component of the energy price. Congestion by shadow price for the summer period is shown in Figure 5–1, while congestion by shadow price for the rolling 12-month period ending May 2022 is shown in Figure 5–2. Areas of the footprint experience varying congestion, which is caused by many factors, including transmission bottlenecks, transmission and generation outages and derates (planned or unplanned), weather events, and external impacts.

Figure 5-1 Congestion by shadow price, summer

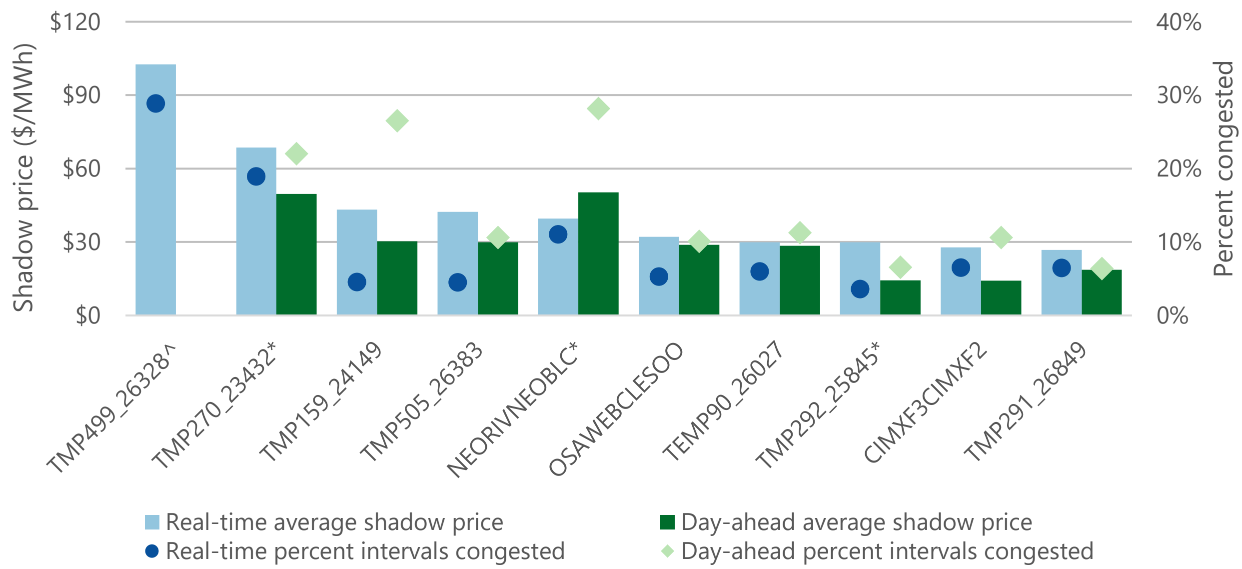


CIMXF3CIMXF2 Cimarron Xfmr 345/1 kV fto 3 contingent elements of Cimarron Xfmr (OKGE)
TMP270_23432* Cleveland-Cleveland AECI 138 kV (AECI-GRDA) ftlo Cleveland-Tulsa North 345 kV (CSWS-GRDA)
TMP547_27793 Arcadia transformer 345/kV (OKGE) ftlo Arcadia transformer 1/138kV, 1/13.8kV (OKGE)
TMP284_26385 Tupelo-South Brown 138kV (WFEC) ftlo Johnston County transformer (OKGE)
TMP551_26749 Conway-Kirby Sw. Station 115kV (SPS) ftlo Nichols-Grapevine 230kV (SPS)

TEMP47_27714 Neosho-Riverton 161kV (WR-EDE) ftlo UN STL4391 - STL4391 13.8 kV (EDE), XF STL4391 13.8/161 kV (EDE)
OSAWEBCLESOO Osage-Webb Tap 138 kV (CSWS-OKGE) ftlo Sooner-Cleveland 345 kV (GRDA-OKGE)
CHAWATCHAPAT^ Charlie Creek-Waterford City 230kV (WAUE) ftlo Charlie Creek-Patentgate 345kV (WAUE)
TEMP66_27742* Brookings-Aurora 115kV (WAUE) ftlo White-Split Rock 345kV (WAUE)
FRAMIDCANCED Franklin-Midwest 138kV (OKGE) ftlo Canadian-Cedar Lane 138kV (WFEC-OKGE)
** SPP market-to-market flowgate*
^ MISO market-to-market flowgate

During the summer season, the most congested flowgate was in central Oklahoma (Cimarron transformer 345/1kV [OKGE]), with six of the top ten located in Oklahoma, and the remaining four located in southwest Missouri/southeast Kansas, the Amarillo area, western North Dakota, and eastern South Dakota. Most of the congestion can be attributed to transmission outages across the SPP footprint and external parallel flows.

Figure 5-2 Congestion by shadow price, rolling 12 month



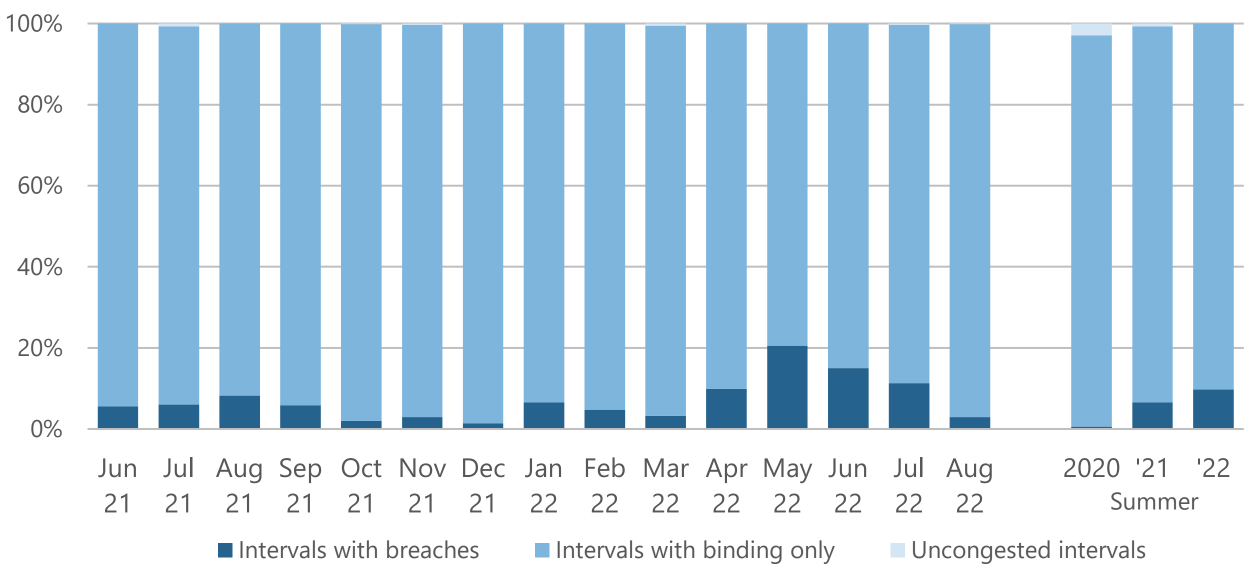
TMP499_26328^ Forman Xfmr 230/1 kV ftlo Hankinson-Wahpeton 230kV (OTP)
TMP270_23432* Cleveland-Cleveland AECI 138 kV (AECI-GRDA) ftlo Cleveland-Tulsa North 345 kV (CSWS-GRDA)
CIMXF3CIMXF2 Cimarron Xfmr 345/1 kV fto 3 contingent elements of Cimarron Xfmr (OKGE)
TMP159_24149 Russett-South Brown 138kV (WFEC) ftlo Little City-Brown Tap 138kV (OKGE)
OSAWEBCLESOO Osage-Webb Tap 138 kV (CSWS-OKG) ftlo Sooner-Cleveland 345 kV (GRDA-OKGE)
NEORIVNEOBLC* Neosho-Riverton 161 kV (EDE-WR) ftlo Neosho-Blackberry 345kV (AECI-WR)
TEMP90_26027 Monett-Aurora 161kV (EDE) ftlo Blackberry-Jasper 345kV (AECI)
TMP278_25759^ Overton Xfmr 345/161 kV (AMRN) ftlo Overton-McCredie 345 kV (AECI-AMRN)
TEMP89_22229 Gracemont-Anadarko 138kV (WFEC-OGE) ftlo Washita-Southwestern 138kV (CSWS-WFEC)
TMP291_26849 Southard-Roman Nose 138kV ftlo Red Dirt Wind Project-Matthewson 345kV (OKGE)
** SPP market-to-market flowgate*
^ MISO market-to-market flowgate

Nine of the top ten most congested flowgates for the last 12 months are located in Oklahoma (6) and western Missouri (3), with the remaining one located in eastern North Dakota. The most congested flowgate over the past 12 months continues to be TMP499_26328 (Forman transformer 230/1 kV for the loss of Hankinson-Wahpeton 230kV [OTP]). As with the three-month summer period, most of the congestion in the past twelve months can be attributed to increased transmission outages across the footprint along with external parallel flows.

One way to analyze transmission congestion is to study the total incidence of intervals in which a flowgate was either breached or binding. A breached condition is one in which the load on the flowgate exceeds the effective limit. A binding flowgate is one in which flow over the element has reached but not exceeded its effective limit.

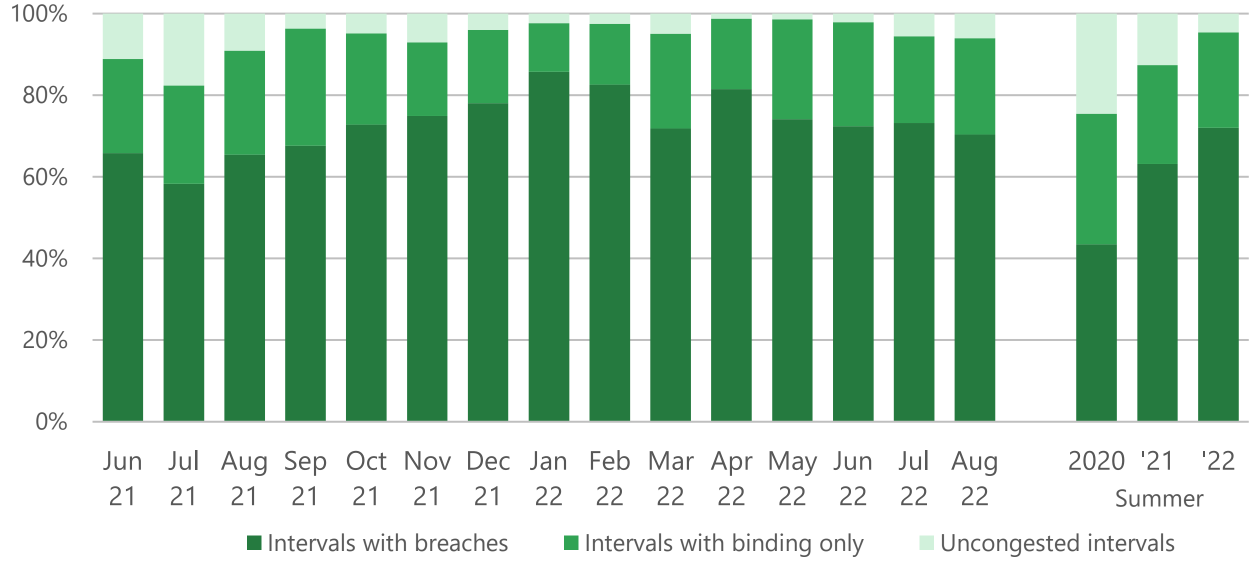
The figures below show the percent of intervals by month that had at least one breach, had only binding flowgates (but no breaches), or had no flowgates that were breached or binding (uncongested) in both the day-ahead (Figure 5–3) and real-time (Figure 5–4) markets.

Figure 5-3 Congestion by interval, day-ahead



Through May 2021, in the day-ahead market typically over 99 percent of all intervals have had only binding constraints, with uncongested intervals and intervals with a breach making up just a fraction of all intervals. Beginning in June 2021, breached intervals began to increase in the day-ahead market. Summer 2022 saw 10 percent of all intervals breached, which was up from seven percent in 2021 and one percent in 2020.

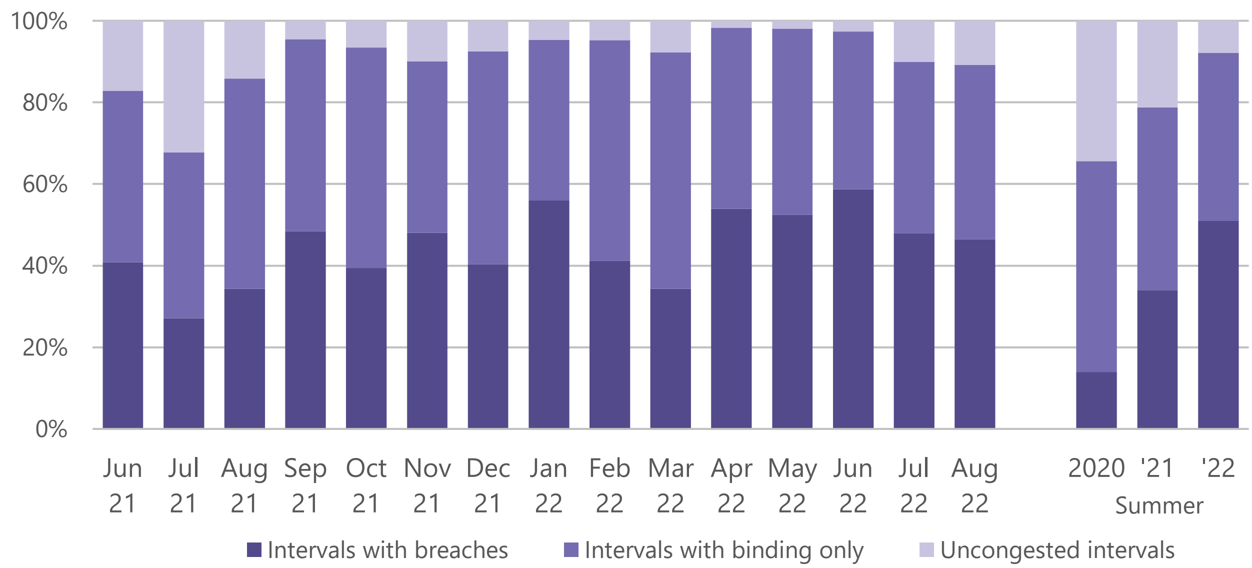
Figure 5-4 Congestion by interval, real-time



Overall, real-time market congestion for summer 2022 in terms of intervals with breached flowgates increased to 72 percent of all intervals, compared to 63 percent in 2021 and 43 percent in 2020. Transmission and generation outages, along with higher levels of imports and external parallel flows, are the most likely causes of this increased congestion.

Market-to-market flowgates are a leading factor in the increase in breaches. Figure 5-5 shows congestion by interval, but with market-to-market flowgates excluded.

Figure 5-5 Congestion by interval, real-time (no market-to-market)



As shown above, when excluding market-to-market flowgates, the summer 2022 total for intervals with a breach drops to 51 percent of all intervals, from 72 percent when including all flowgates, as shown in Figure 5-4. Looking at the trend when excluding market-to-market flowgates, there has been a steady increase in breached intervals from summer 2020 to 2022. The MMU will continue to evaluate breaches and provide additional insight in future reports.

5.2 TRANSMISSION CONGESTION RIGHTS MARKET

The transmission congestion right and auction revenue right net payments paid to entities in SPP are shown in Figure 5-6.

Figure 5-6 Total congestion payments, summer

(in $ millions)	Load-serving entities			Non-load-serving and financial only entities		
	Summer 2020	Summer 2021	Summer 2022	Summer 2020	Summer 2021	Summer 2022
DA congestion	96.3	205.1	532.4	31.4	76.3	175.3
RT congestion	(5.8)	(12.1)	(52.2)	(9.8)	(37.0)	(59.9)
Net congestion	90.5	193.0	480.2	21.6	39.3	115.4
TCR charges	38.0	72.1	260.3	33.1	51.2	142.0
TCR payments	(90.4)	(189.3)	(537.1)	(63.2)	(135.8)	(234.6)
TCR uplift	13.4	22.1	41.1	14.3	26.3	29.7
TCR surplus *	(0.9)	(2.2)	(3.7)	(1.0)	(2.4)	(3.1)
ARR payments	(54.2)	(99.1)	(333.2)	(6.1)	(6.5)	(21.3)
ARR surplus	(9.9)	(16.1)	(43.9)	(0.9)	(1.6)	(4.0)
Net TCR/ARR	(104.0)	(212.6)	(616.5)	(23.7)	(68.8)	(91.2)

* remaining at year end

During summer 2022, load-serving entities earned $617 million in congestion payments. These payments exceed their day-ahead congestion cost of $532 million. Real-time congestion costs aided load-serving entities, and decreased the total congestion cost to $480 million. When compared to summer 2021, the 2022 difference between congestion payments and total congestion costs increased from a surplus of $20 million to a surplus of $136 million.

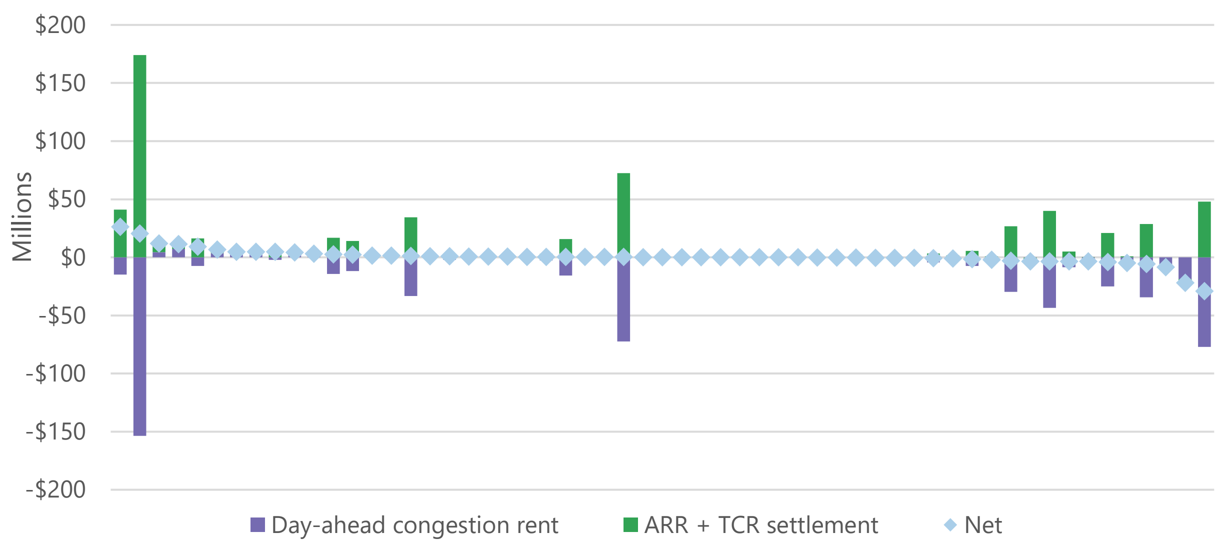
The surplus between the congestion payments and the total congestion cost shows that overall, for the quarter, load-serving entities fully covered their congestion costs in aggregate through the congestion hedging market.

Additionally, non-load-serving and financial-only entities received congestion payments of $91 million. These payments did not exceed their $175 million in day-ahead congestion costs. Real-time congestion costs aided non-load-serving and financial-only entities and decreased their total congestion cost by $60 million to $115 million. This shows the $91 million in payments to non-load-serving, and financial-only entities did not fully cover their total congestion cost through the transmission congestion rights market.

Moreover, day-ahead congestion costs increased 160 percent for load-serving entities and 130 percent for non-load-serving and financial-only entities when compared to summer 2021.

Figure 5-7 shows, by market participant,[17] the day-ahead congestion exposure along with the value of all congestion hedges, as well as the net overall position.

Figure 5-7 Net congestion revenue by market participant



** does not include Auction Revenue Rights closeout*

Figure 5-7 highlights that 60 percent of participants received positive net revenues, while 40 percent of participants held hedges that did not cover their day-ahead congestion costs. The bottom five participants collectively paid $70 million more in congestion costs than was offset by their auction revenue right and transmission congestion right positions. This is a material

[17] Figure 5-6 and Figure 5-7 reference market participants who hold ARR entitlements.

increase in the related figure in summer 2021 where the bottom five participants collectively lost $26 million. The increase is driven largely by the increase in day-ahead congestion.

Figure 5-8 shows, by market participant, the day-ahead and real-time congestion exposure along with the value of all congestion hedges, as well as the net overall position.

Figure 5-8 Net congestion revenue by market participant

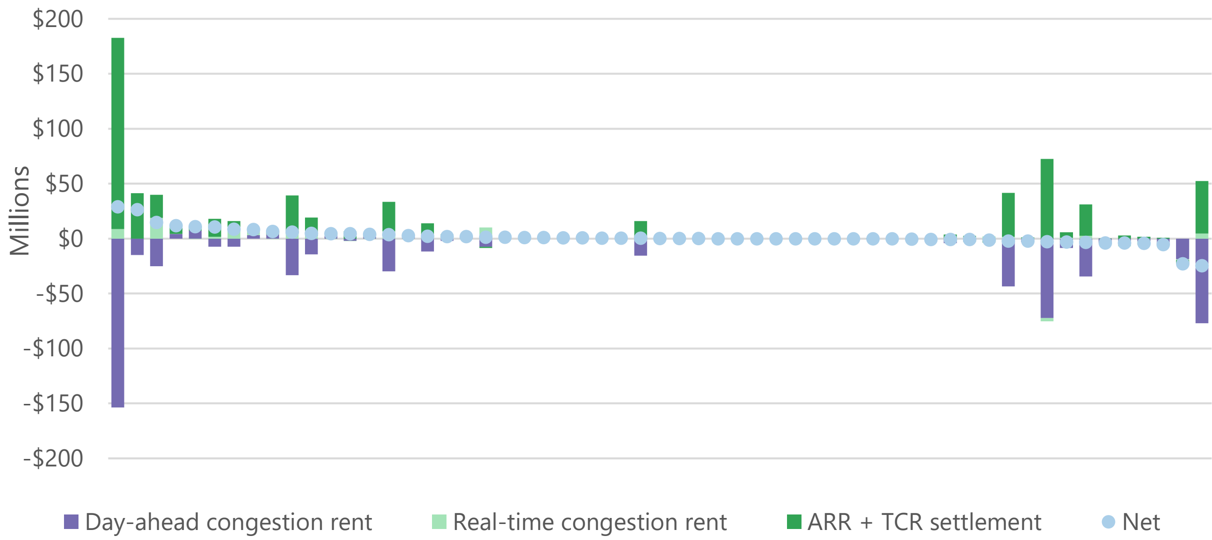


Figure 5-8 highlights that 67 percent of participants received positive net revenues, while 33 percent of participants held hedges that did not cover their total congestion costs. The bottom five participants collectively paid $91 million more in congestion costs than was offset by their auction revenue right and transmission congestion right positions. This is also a significant increase over and above summer 2021 figure of $25 million.

Figure 5-9 Transmission congestion right funding

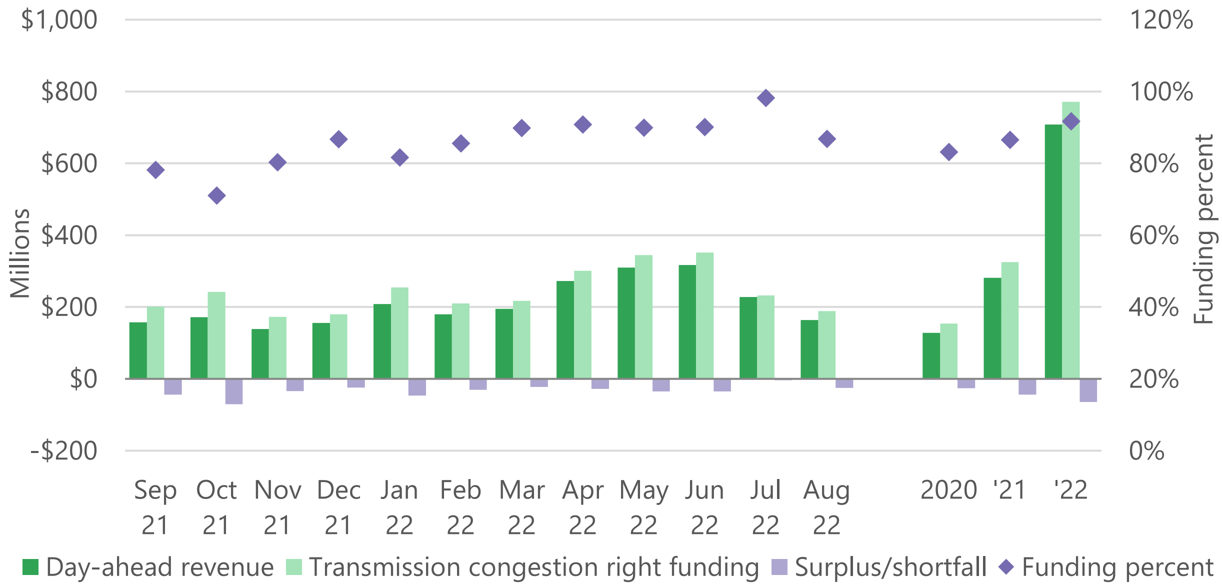
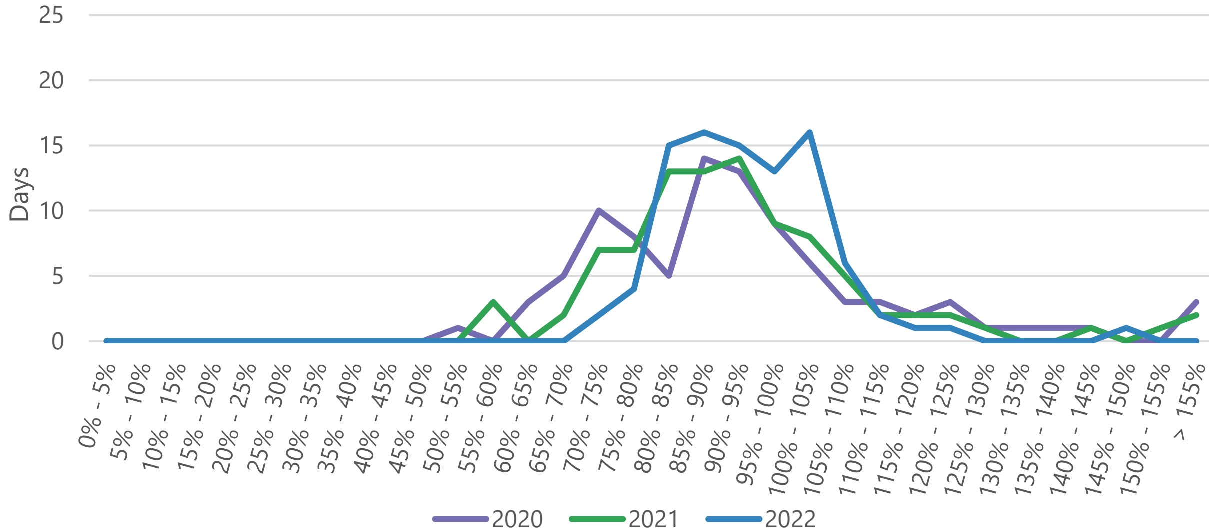


Figure 5-9 above shows transmission congestion right funding, day-ahead revenue, net surplus/shortfall, and transmission congestion right funding percent by month and quarter. Outside of October, monthly TCR funding was relatively stable over the preceding 12 months, ranging between 71 and 98 percent. July 2022 is the outlier, with roughly 98 percent funding. The values observed in July stem from significant alignment between the congestion hedging model and the day-ahead market model.

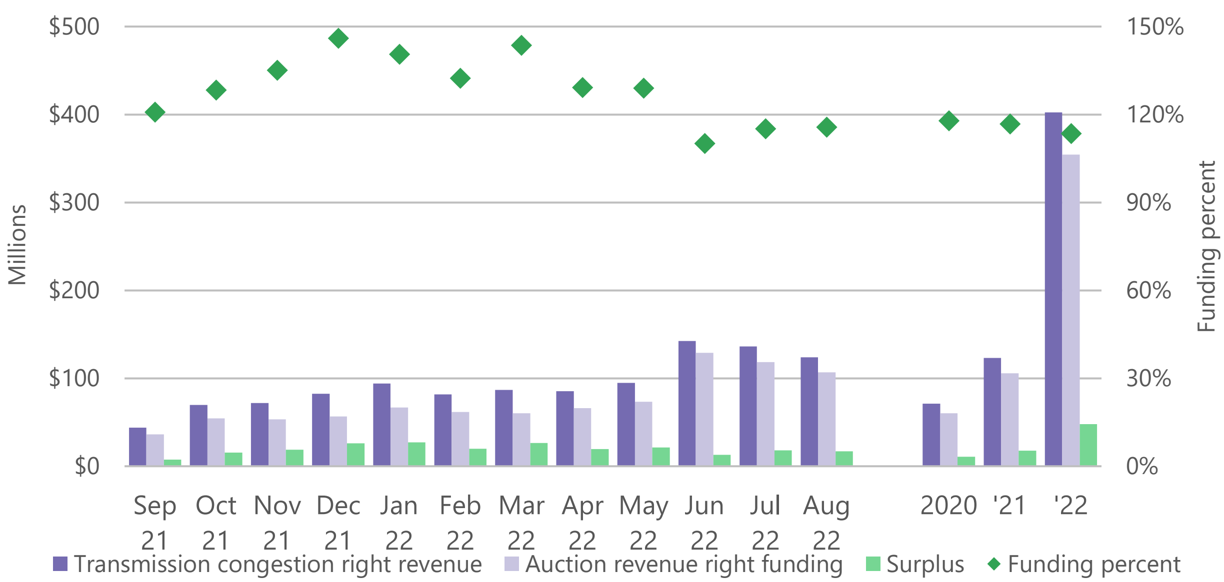
Daily observations of transmission congestion right funding for the 2020, 2021, and 2022 summer periods are shown in Figure 5-10.

Figure 5-10 Transmission congestion right funding



Slightly more than ninety-one percent of the daily observations of transmission congestion right funding fell between 80 percent and 120 percent over the 2022 summer quarter. The funding distribution continued to shift noticeably toward higher percentages. In summer 2021, twenty-one percent of the funding events for the quarter fell between 45 percent and 79 percent funded. The summer 2022 figure materially improved to only seven percent.

Figure 5-11 Auction revenue right funding



Auction revenue right funding percentages decreased in June – the start of the new TCR year. From September 2021 through May 2022 auction revenue right funding percentages were relatively stable. The auction revenue right funding decreased quarter over quarter from 117 percent to 114 percent.

6 SPECIAL ISSUES

RAMP CAPABILITY PRODUCT

Introduction

SPP implemented a ramp capability product on March 1, 2022. This product is used to provision rampable up and down capacity for uncertainty events in net load forecasts across a 10-minute future time horizon. Historically, SPP operators procured ramp through out-of-market mechanisms, often resulting in uplift payments. The ramp capability product is a market-based approach for ramp management that leverages existing operational experiences to:

- pre-position resources to manage net load variations and uncertainties, and
- provide transparent price signals in order to incentivize flexibility.

The ramp capability product was designed to allow for more economical and transparent management of the intermittent aspects of the system. Its function was to procure ramp-up and ramp-down to meet historical net load forecast needs up to the historical 95th percentile of error.

This new product allows a systematic way to hold back resources that have ramp capability for future intervals in which ramp may be needed. SPP calculates the ramp-up and ramp-down capability product requirements based on two components:

1) the forecasted net load changes from interval to interval, and
2) the historical net load forecast error.

A resource that clears ramp capability is dispatched uneconomically for the current interval so that it will be capable of ramping during the next 10 minutes.[18] The day-ahead market, reliability unit commitment (RUC), and real-time studies include the ramp capability requirements as inputs.

The purpose of this review is to report the SPP MMU's preliminary assessment of the ramp capability product's effectiveness to date in three areas:

1) increasing transparency into the market's ramp needs, both through effective pricing and the reduction of make-whole payments,
2) cost effectively redispatching resources to economically provision ramp for uncertainty needs, and
3) the effects of the ramp scarcity demand curves on market clearing.

Since the implementation of this product, the ramp-down capability has been priced at $0/MW, as there has not been any opportunity cost for the product. As such, the analysis for this report will concentrate on ramp-up capability.

Ramp capability demand curve

Scarcity is priced by a stepped demand curve with a maximum price based on the average cost of committing a fast-start resource to cure the ramp deficiency (calculated monthly). SPP uses a minimum scarcity price of $10/MWh for ramp-up capability and $0/MWh for ramp-down capability.[19]

[18] Resources that have available ramp, but are uneconomic for energy and ancillary services, will likely clear ramp without needing to be redispatched, as these resources have no opportunity cost to provide ramp.

[19] A $10/MWh floor was put on the ramp-up scarcity demand curve because studies showed that clearing resources to meet the ramp requirement frequently required make whole payments when prices were lower than this floor.

The demand curve contains six equal price increments depending on the severity of the shortage. SPP updates the demand curve every month based on the data from the last three months, similar to the demand curve for regulation.

Resources that are eligible to clear for ramp-up capability and ramp-down capability must be dispatchable for energy.

Cleared based on lost opportunity cost

Ramp-up capability and ramp-down capability are cleared and a market clearing price is set based on the lost opportunity cost with other products. If a resource's capacity is cleared for the ramp capability product, it cannot be used to clear other products.

Analysis

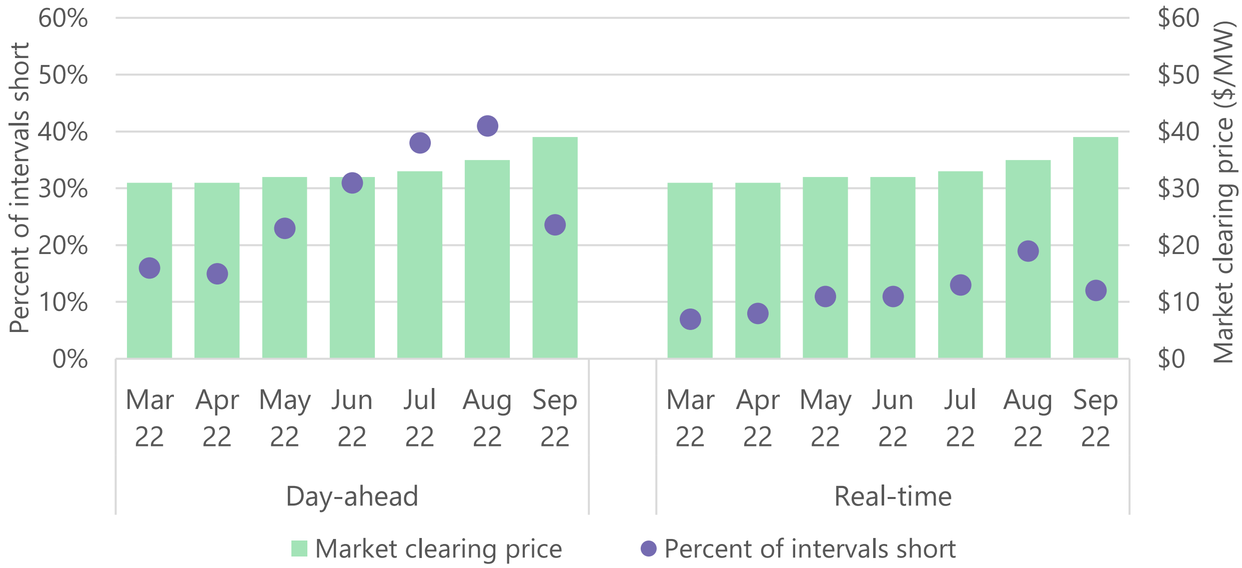
The table below shows the number and percent of intervals short, along with the average and maximum megawatts short, and the market clearing price for ramp-up in the day-ahead and real-time markets.

Figure 6-1 Ramp-up capability product statistics

Month	Day-ahead					Real-time				
	Intervals short	Percent of total intervals	Maximum MW short	Average MW short	Market clearing price	Intervals short	Percent of total intervals	Maximum MW short	Average MW short	Market clearing price
March	119	16%	518	16	$31	640	7%	1,059	10	$31
April	108	15%	551	15	$31	657	8%	848	13	$31
May	174	23%	456	28	$32	972	11%	960	11	$32
June	227	31%	589	43	$32	908	11%	782	8	$32
July	280	38%	728	55	$33	1,165	13%	1,231	18	$33
August	303	41%	472	49	$35	1,601	19%	801	24	$35
September	170	24%	233	19	$39	1,041	12%	804	17	$39

The figure below plots the percent of intervals short and the market clearing price for the first seven months of the ramp capability product.

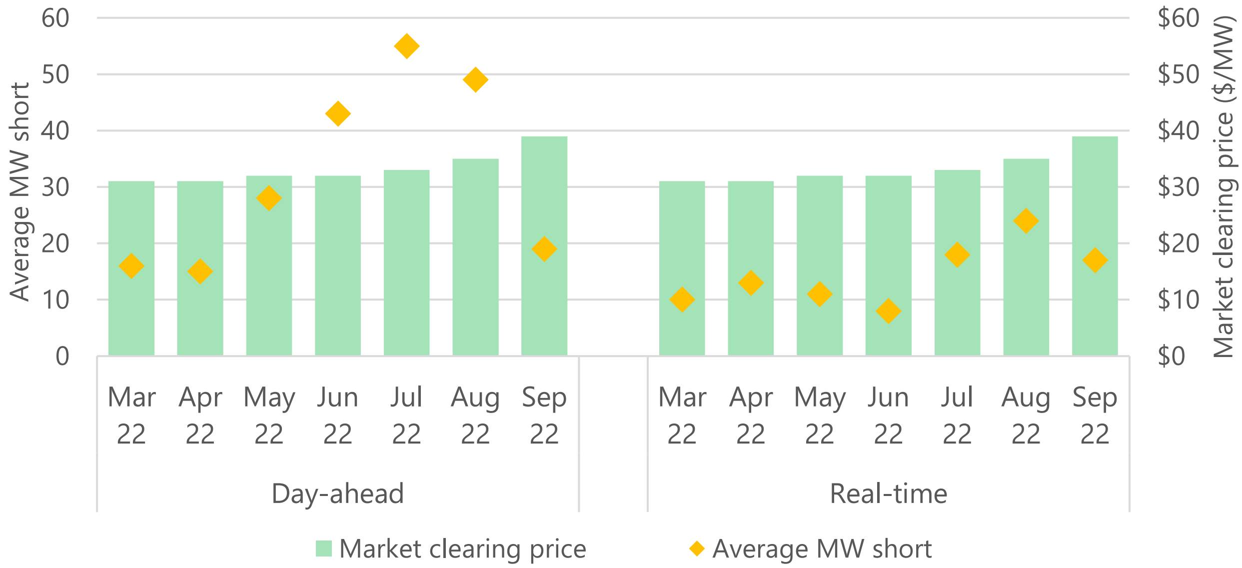
Figure 6-2 Ramp-up, percent of intervals short and market clearing price



As shown above, the percent of intervals short in the day-ahead market increased by 156 percent from March to August 2022, while the market clearing price increased by just 13 percent for the same period. A similar trend was observed in the real-time market, with the percent of intervals short increased by 171 percent from March to August 2022, while the market clearing price increased by 13 percent (which was the same as the day-ahead market).

The figure below plots the monthly average megawatts short, along with the market clearing price.

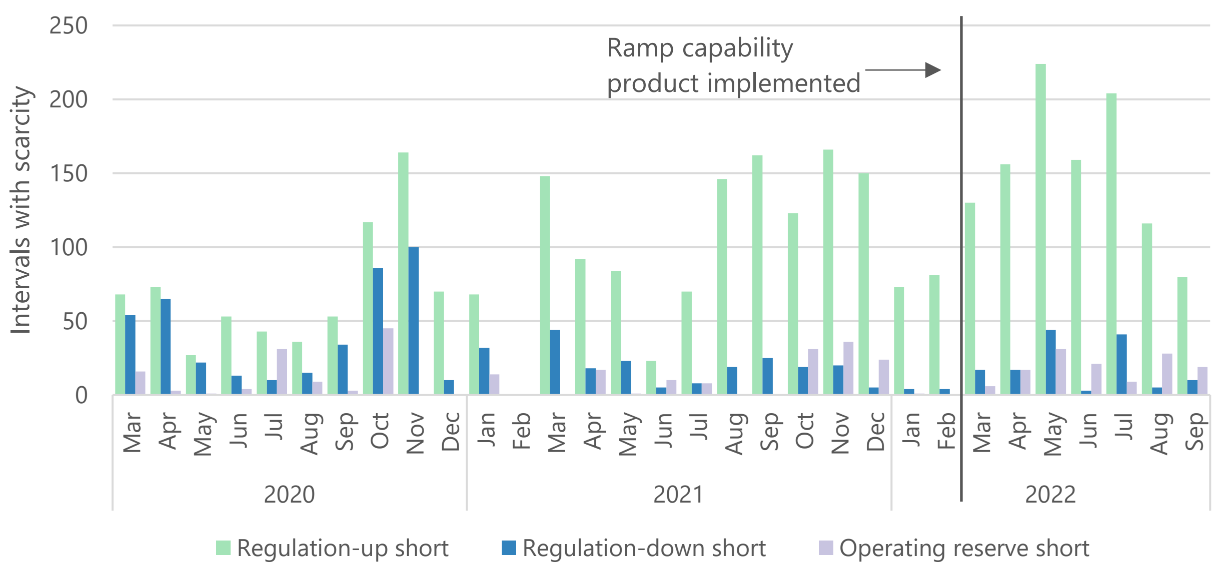
Figure 6-3 Ramp-up, average megawatts short and market clearing price



Similar to the previous chart, day-ahead average megawatts short increased by 206 percent from March to August 2022, real-time average megawatts short increased by 140 percent, while the market clearing price increased just 13 percent in both the day-ahead and real-time markets for the same period.

Ramp shortages are the primary driver for ancillary services shortages. The chart below illustrates the count of ancillary service shortages each month.

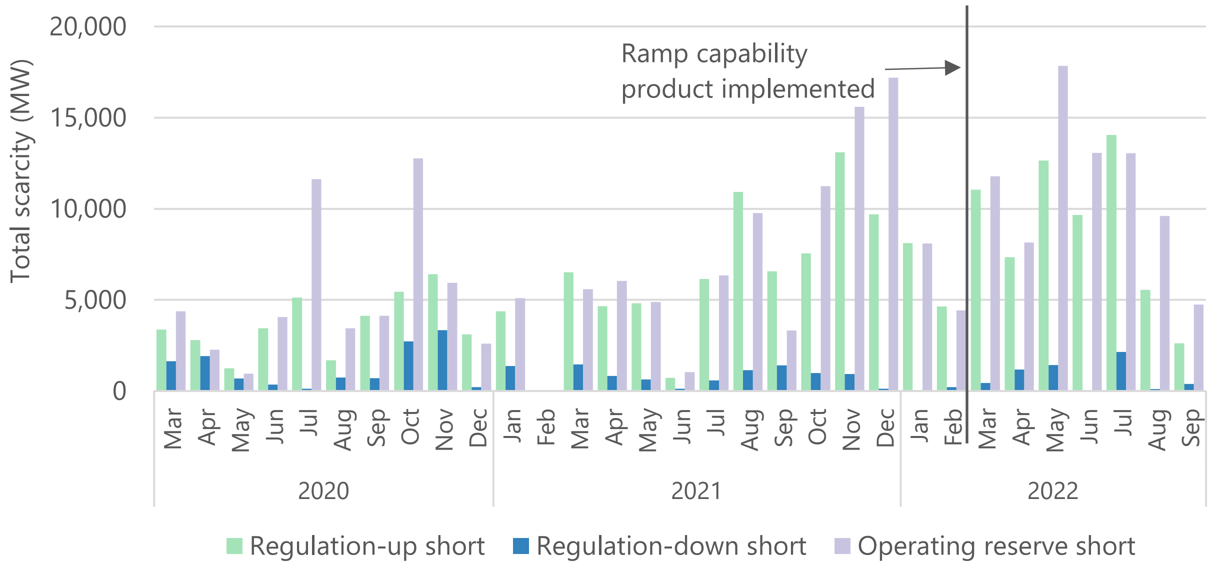
Figure 6-4 Ramp-up, average megawatts short and market clearing price



As shown in the chart, there was not a discernable difference in regulation-down and operating reserve scarcity events, but there was an uptick in regulation-up scarcity events and a slight increase in regulation-down scarcity events after implementation of the ramp capability product in March.

The chart below shows the total megawatts scarce by product.

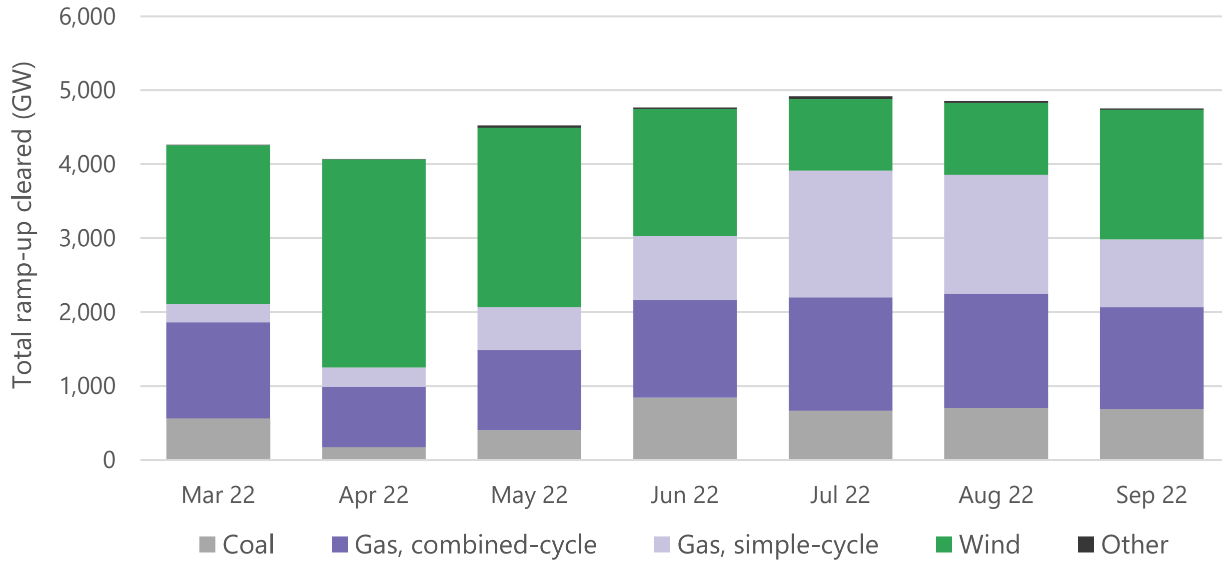
Figure 6-5 Megawatts short, by product, real-time



As shown in the chart, there was not a discernable difference pre- and post-implementation. March through July seem to have more scarcity events after the ramp capability product was implemented compared to prior years. However, August and September have slightly fewer scarcity events. The SPP MMU plans to perform more detailed analysis using market reruns. These reruns will work to better pinpoint the effects of the ramp capability product, as other differences – like increasing natural gas prices, load, or wind generation – may be the primary cause of the increase in scarcity.

The chart below shows the amount of ramp-up cleared in the real-time market.

Figure 6-6 Ramp-up cleared by resource type, real-time

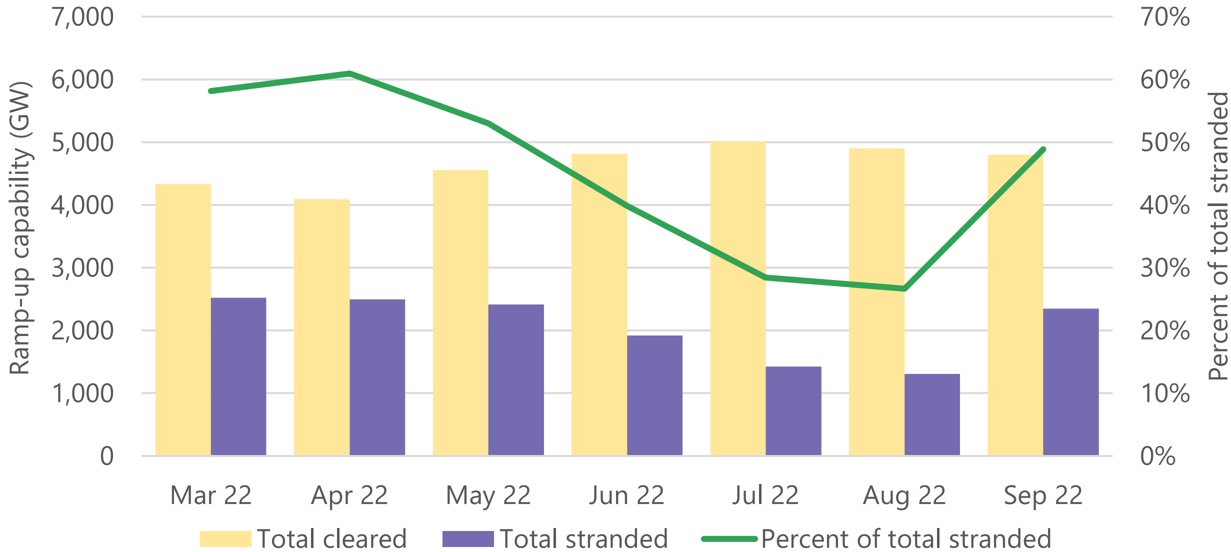


Ramp-up cleared megawatts from wind resources has been a large contributor to the ramp capability product, providing around 40 percent of total ramp-up cleared on average. Gas, combined-cycle contributes 28 percent, gas, simple-cycle provides 19 percent, and coal resources provide 12 percent of ramp-up cleared.

In order to clear the ramp product, a resource must be dispatchable and qualified to provide energy, this includes wind-powered resources registered as dispatchable variable energy resources (DVERs). However, dispatchable variable energy resources are not allowed to provide any other upward operating reserve product (regulation-up, spinning, or supplemental reserves). With such a large amount of ramp up being provided by dispatchable variable energy resources, it is probable that operating reserve shortages remain unaffected by the ramp product as the additional ramp procured is largely cleared on resources that cannot provide the upward operating reserve products.

The ramp capability product was intended to reduce other operating reserve product shortages. However, the ramp cleared cannot be used as energy and delivered when there is congestion. The next graph shows the amount of ramp-up capability cleared along with ramp-up capability that is stranded behind congestion.

Figure 6-7 Ramp-up cleared and stranded, real-time



The chart shows that about 50 percent of the generation cleared for the ramp product up was on resources that are pivotal to congested flowgates. Much of this stranded generation is from wind resources.

The chart below shows the average cleared ramp product up megawatts by shift factor.

Figure 6-8 Average ramp product up cleared, real-time

The graph shows that more ramp up product is cleared on the loading side (those intervals with a positive shift factor) of the constraint. When resources are on the loading side of a constraint, the ability to deliver the ramp is limited and thus the ramp is stranded.

Conclusion

While the ramp capability product has been active in the market for seven months, there may not be enough data at this time to make a full assessment of its impact on the Integrated Marketplace. Moreover, the system is still experiencing large swings in load and variable generation that may not be included in the load and variable generation forecast at this time.

Even so, the MMU's preliminary findings raise the following concerns with performance of the ramp capability product:

1) much of the ramp up capability is provided by dispatchable variable energy resources, which can only provide regulation-down and energy;
2) much of the ramp capability is procured behind congestion, which is thus unable to be dispatched to meet ramping needs;
3) the market clearing price is too low, thus not providing meaningful incentives to provide more ramp, especially given the increase in natural gas prices over the past several months; and
4) there is more physical ramp that is available for ramp, but it is not being procured because the ramp scarcity demand curve is clearing prices. Instead, if the market clearing price was set by the resources and not opportunity costs, the price would be higher and would likely encourage more participation in this product.