Southwest Power Pool
Market Monitoring Unit

State of the Market
Fall 2018

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Southwest Power Pool, Inc.
Market Monitoring Unit

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1. MARKET HIGHLIGHTS

This report covers market performance and highlights during the fall quarter of 2018 (September through November). Annual figures shown on the charts in this report represent only this three-month period for each year, unless labelled otherwise. Highlights of this fall period are as follows:

- The hourly average load for fall 2018 was up around four percent from fall 2017. September and October loads were similar to prior years, however, load in November 2018 was just over eight percent higher than 2017.
- Average monthly real-time generation increased by about five percent from fall 2017 to fall 2018. The percent of total generation provided by coal-powered resources continued to fall, accounting for only 42 percent of energy produced in the fall 2018 period. This is down from 50 percent in fall 2016, and from 45 percent in fall 2017. During this same period, wind resources accounted for 23 percent of total generation, which is up from 20 percent in fall 2016, but down from fall 2017 when wind resources accounted for 26 percent of total generation.
- During fall 2018, the average day-ahead price was $27/MWh, an increase of 35 percent from fall 2017, and an increase of 11 percent over fall 2016. The average real-time prices mirrored the trend of day-ahead prices, with nearly identical prices. Higher loads, increasing natural gas prices, and lower wind output were factors in increasing prices during this period compared to previous years.
- The average monthly gas price at the Panhandle Eastern hub averaged $2.86/MMBtu for fall 2018, up from $2.58/MMBtu in fall 2017, an 11 percent increase.
- The trend of declining occurrences of negative price intervals continued in the fall period. Prices were negative in just over 2.7 percent of real-time intervals in fall 2018, down from 10.4 percent in fall 2017, and down from 3.7 percent in fall 2016. Day-ahead intervals with negative prices remained negligible.
- The areas with the highest congestion in the fall 2018 period were around Tulsa, in North Dakota, and in northwest Kansas (near Hays).

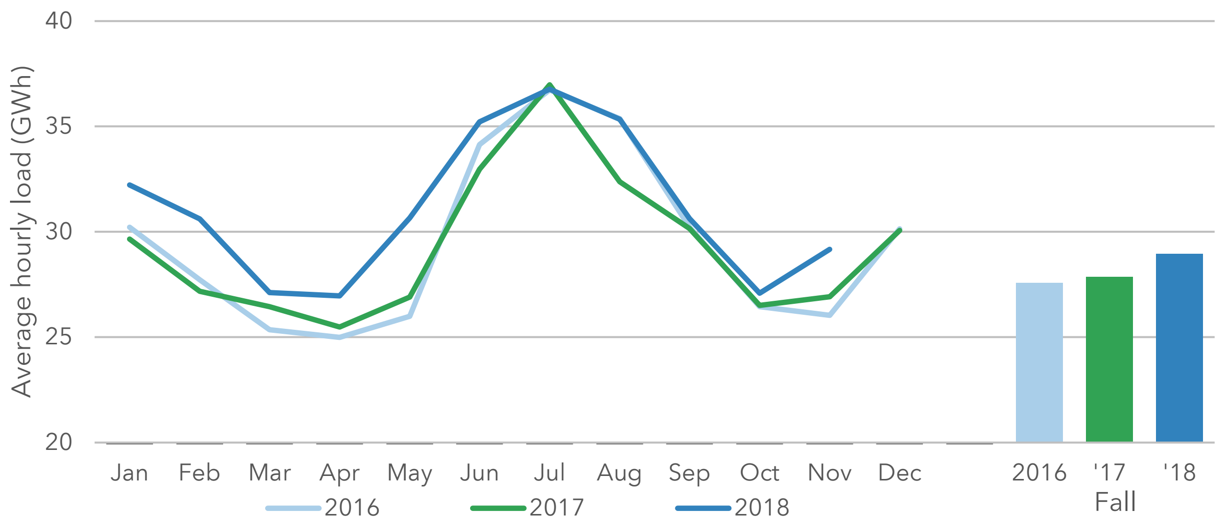
- The area with the highest congestion for the past 12 months is now the Vine to North Hays constraint in northwest Kansas, replacing the Neosho to Riverton constraint in southwest Missouri/southeast Kansas.
- Overall congestion the SPP market footprint has declined. Intervals with breaches in the real-time market decreased from nearly 44 percent in fall 2016, down to 27 percent of intervals in fall 2018. Additionally, intervals with no congestion increased from two percent in fall 2016 to 17 percent in fall 2018.
- October and November 2018 had higher than usual levels of scarcity pricing, which increased the number of price spikes, both in the energy and ancillary service markets. These scarcity events contributed to an overall increase in market prices. This increase in scarcity events can primarily be attributed to higher volatility in wind output, along with unplanned generator outages or derates.
- The frequently constrained area process has improved to implement changes in frequently constrained areas in a more timely manner when indicated by the MMU's analysis.

2. LOAD AND RESOURCES

2.1 LOAD

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

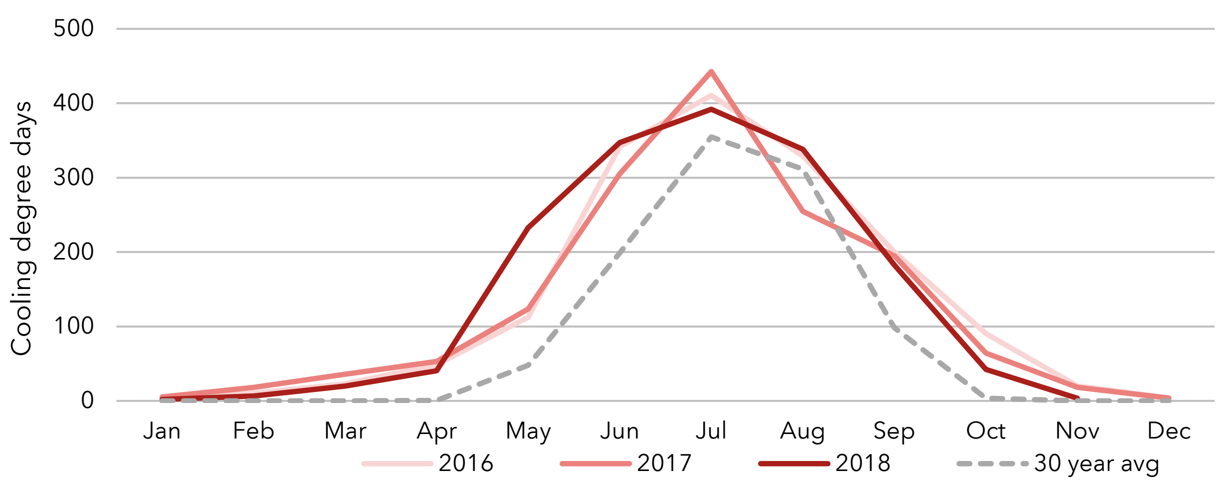
Figure 2–1 Average hourly load



Overall, the hourly average load for fall 2018 was nearly 29,000 megawatts, which was up about four percent from fall 2017. Each month of the fall 2018 season had a higher average hourly load than both fall 2016 and fall 2017.

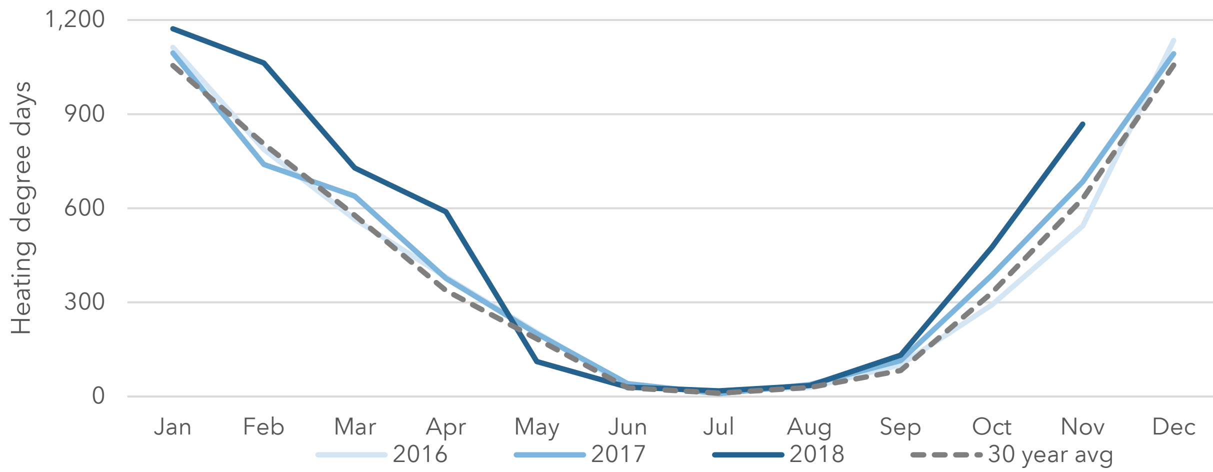
Heating and cooling degree days are used to estimate the impact of actual weather conditions on energy consumption as shown in Figure 2–2 and Figure 2–3 .

Figure 2–2 Cooling degree days, SPP footprint



Due to lower temperatures in the fall, cooling degree days decreased sharply from September to October, then become negligible by November.

Figure 2–3 Heating degree days, SPP footprint

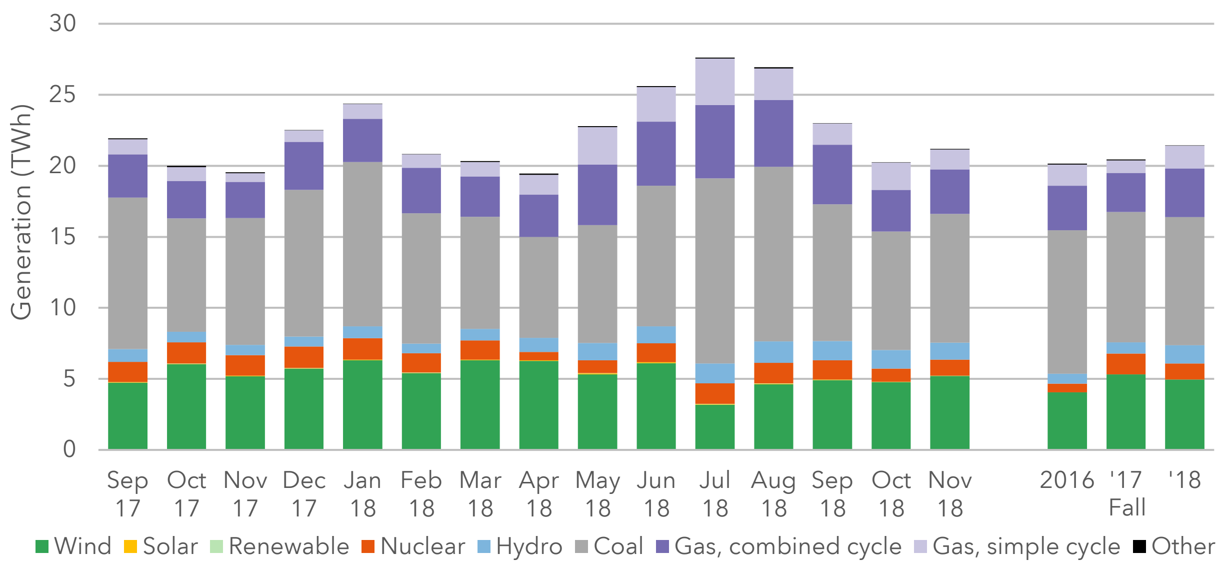


While heating degree days for September 2018 were near prior years and the 30 year average, October and November saw much colder temperatures compared to prior years and the 30 year average. This weather pattern for the fall months is a larger driver for the increased load in fall 2018, as shown in Figure 2–1.

2.2 RESOURCES

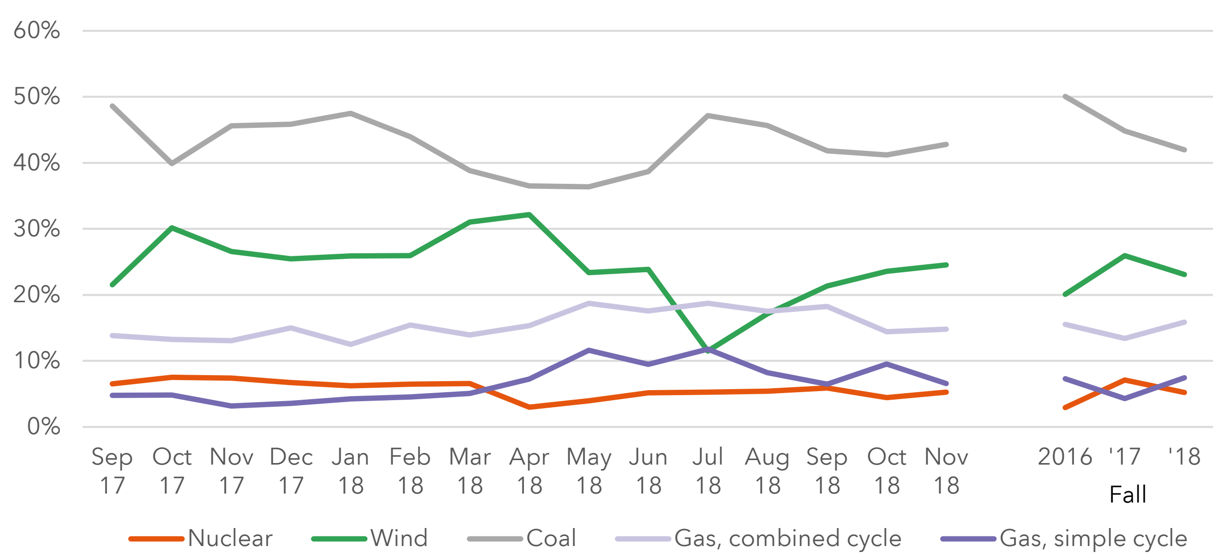
Total monthly generation, broken down by technology type of resources, is shown below in Figure 2–4. The "renewable" category includes biomass and other renewable resources (not including wind, solar, and hydro resources), while the "other" category includes fuel oil and miscellaneous resources.

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



Overall generation levels increased about nearly five percent from fall 2017 to fall 2018, which matched the increase in load during that same period, as shown in Figure 2–1. Figure 2–5 below shows the percentage of total generation attributed to each technology type.[1]

Figure 2–5 Generation by technology type, real-time by percent



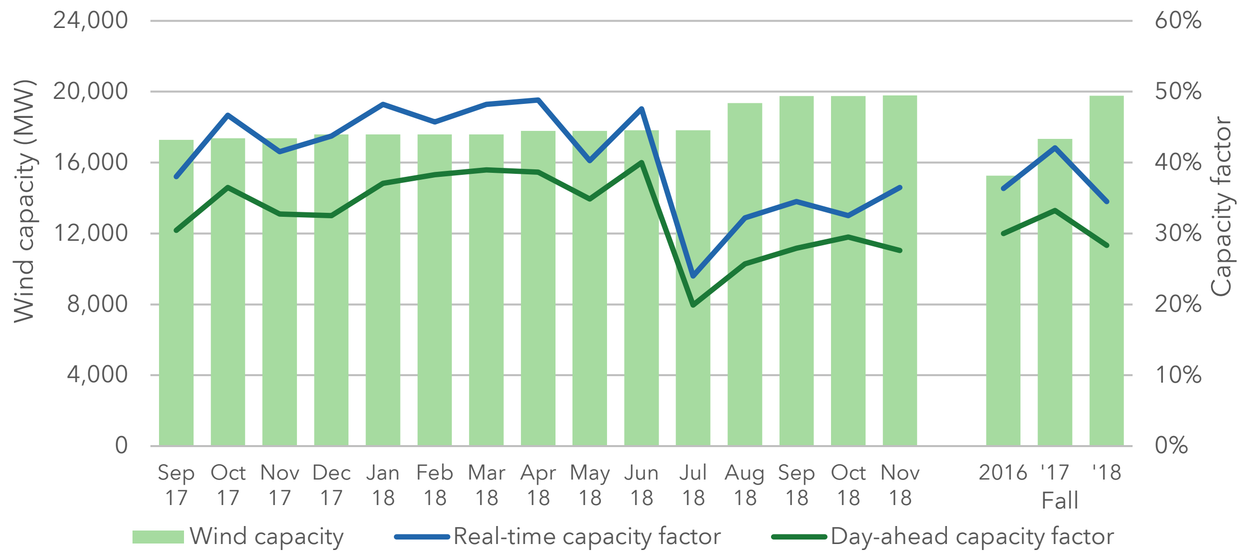
Generation by coal resources as a percentage of total generation continues to decrease, dropping from 50 percent in fall 2016, to 42 percent in fall 2018. While wind generation

[1] Only the most prevalent technology types are shown in this figure. Solar, renewable, hydro, and other resources are not shown.

spiked in fall 2017, overall wind generation continues to climb, up from 20 percent in fall 2017 to 23 percent in fall 2018. The percentage of total generation provided by both combined-cycle and simple-cycle natural gas resources have remained consistent from 2016 to 2018. Due to the spike in wind generation and nuclear generation in fall 2017, the increased generation from these resources tended to offset generation by gas resources.

Figure 2–6 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]

Figure 2–6 Wind capacity and capacity factor



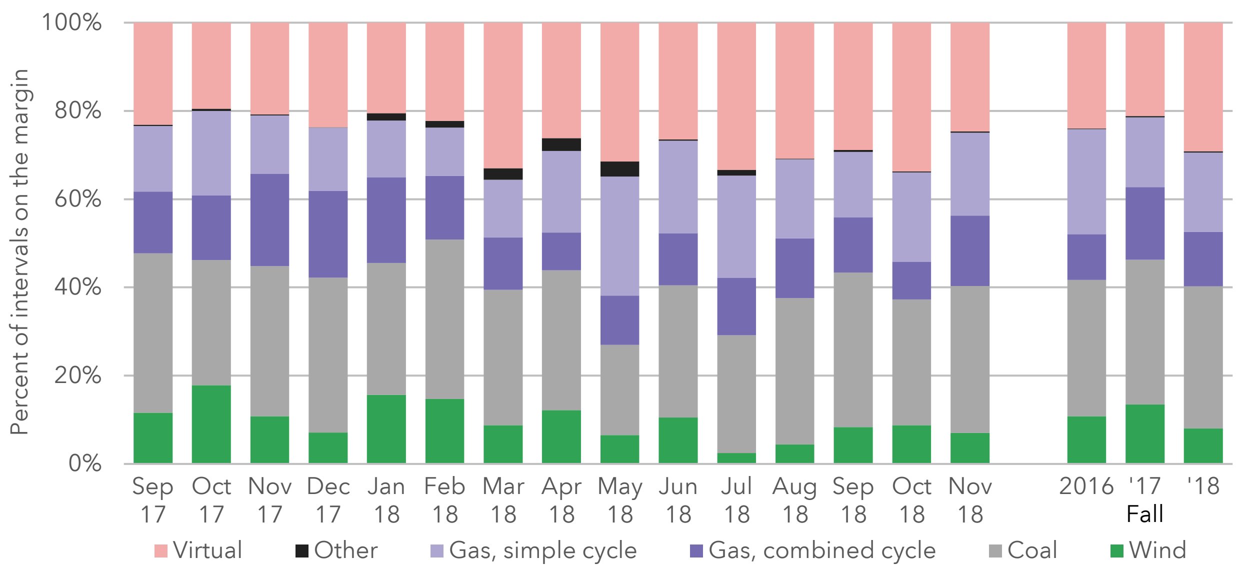
Wind capacity in the footprint continues to grow steadily, with nameplate wind capacity increasing from 15,200 MW at the end of November 2016, to just under 20,000 MW at the end of November 2018.

The wind capacity factor in the real-time market dropped from 42 percent in fall 2017 to 35 percent in fall 2018, while the day-ahead wind capacity factor dropped from 33 percent to 28 percent during the same period. Lower wind generation totals, coupled with increased wind capacity, drove this drop in capacity factor. The spread between the real-time and the day-ahead wind capacity indicates a disconnect in the amount of wind in the real-time market, compared to the forecasted wind in the day-ahead market.

[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.

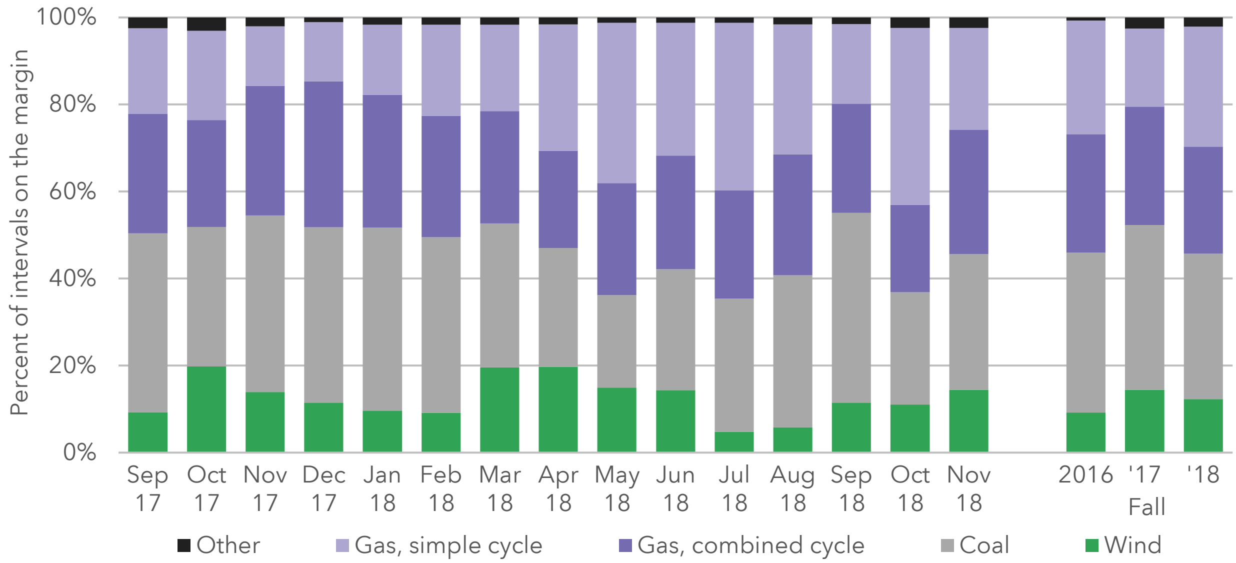
Figure 2–7 and Figure 2–8 show the technology types of marginal units in both the real-time and day-ahead markets. Marginal units set the locational marginal price in each hour in the day-ahead market and each five-minute interval in the real-time market. One important distinction is that virtual transactions 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 2–7 Technology on the margin, day-ahead



In the day-ahead market, coal resources and virtual transactions were each the marginal technology type in about 30 percent of intervals in fall 2018. Gas simple-cycle resources set prices in 18 percent of intervals, while gas combined-cycle resources set prices in 12 percent of intervals in this same period. In comparison to other technology types, wind resources, at eight percent, still represent a small portion of intervals in which they set day-ahead prices.

Figure 2–8 Technology on the margin, real-time



In the real-time market, coal resources were the highest marginal technology, at 33 percent of all intervals. Gas simple-cycle was next at 28 percent, and gas combined-cycle resources were at 25 percent for fall 2018. Although down from the high levels in fall 2017, wind resources still set prices 12 percent of all real-time intervals.

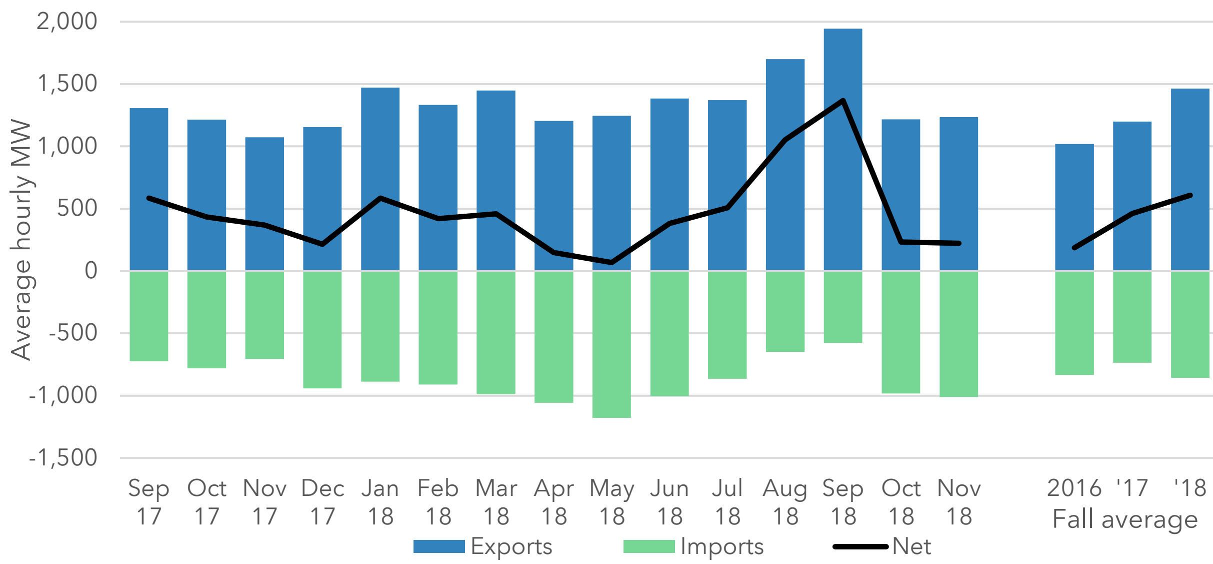
The decline in wind on the margin in both the day-ahead and real-time markets correlates with the decline in the frequency of negative prices in fall 2018, which is discussed in Section 4.1.

2.3 EXTERNAL TRANSACTIONS

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

Figure 2–9 shows average hourly imports and exports across the SPP system.

Figure 2–9 Exports and imports, SPP system



SPP is typically a net exporter in real time. Net exports continue to rise for the fall period, with an average hourly net export of 186 MW in fall 2016 increasing to 608 MW in fall 2018. This increase in net exports matches increases in wind production, shown in Figure 2–5.

Generally, SPP exports follow the wind production curve for the day. Typically, as wind generation increases, exports increase. The same pattern of exports following wind is also evident on a month-to-month basis, as the highest wind generation months in the spring and the fall tend to see the highest exports.

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.

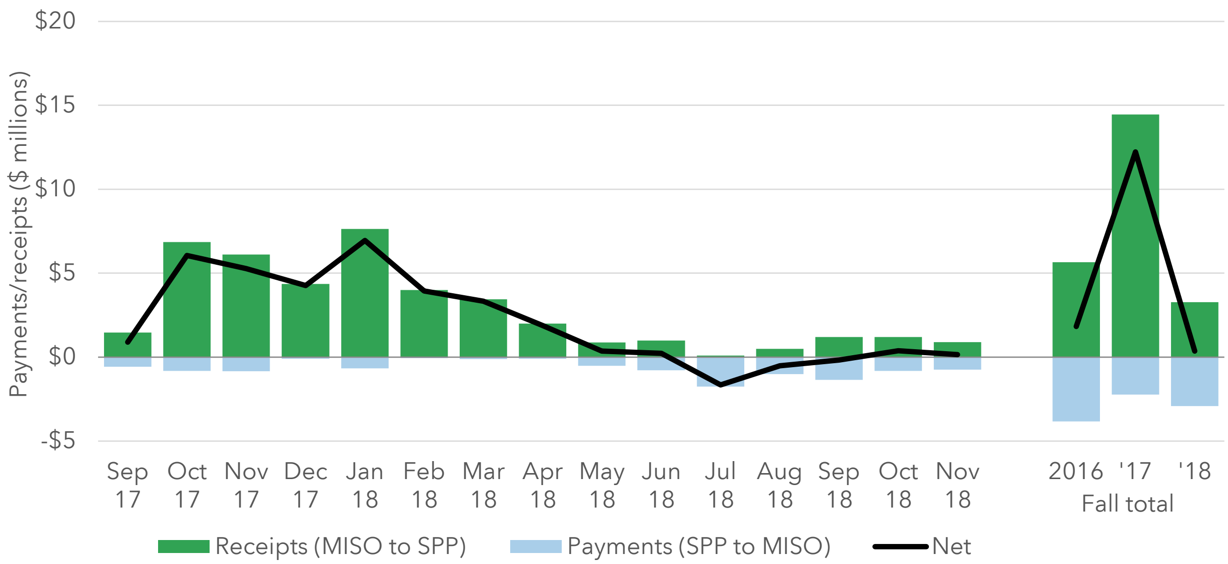
Each RTO is allocated property rights on market-to-market constraints. These are known as firm flow entitlements (FFE), and each RTO calculates its real-time usage, known as market flow. RTOs exchange money (market-to-market settlements) for redispatch based on the non-monitoring RTO's market flow in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

[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.

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 2–10, while the market-to-market payments by flowgate for the summer period are shown in Figure 2–11.

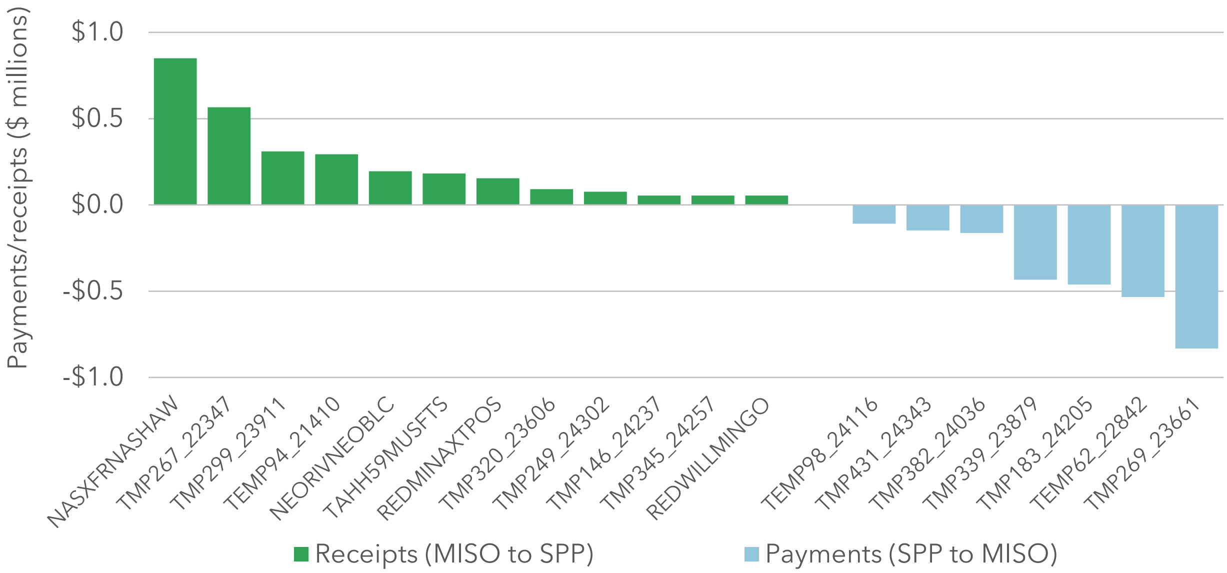
Figure 2–10 Market-to-market, monthly



Payments are predominantly from MISO to SPP for most of year, with the exception of the summer. In summer 2018, payments from SPP to MISO increased to almost $2 million, which was up from $1.7 million in summer 2017, and $600,000 in summer 2016.

For the fall period, market-to-market payments were nearly even between SPP and MISO at a total of $363,000 paid to SPP. Total payments from MISO to SPP were $3.2 million, while payments from SPP to MISO were $2.9 million. This is down significantly from fall 2017, when total payments from MISO to SPP were nearly $15 million, primarily due to high levels of congestion on the Neosho-Riverton for the loss of Neosho-Blackberry constraint. This constraint has been less congested over the last several months.

Figure 2–11 Market to market, by flowgate



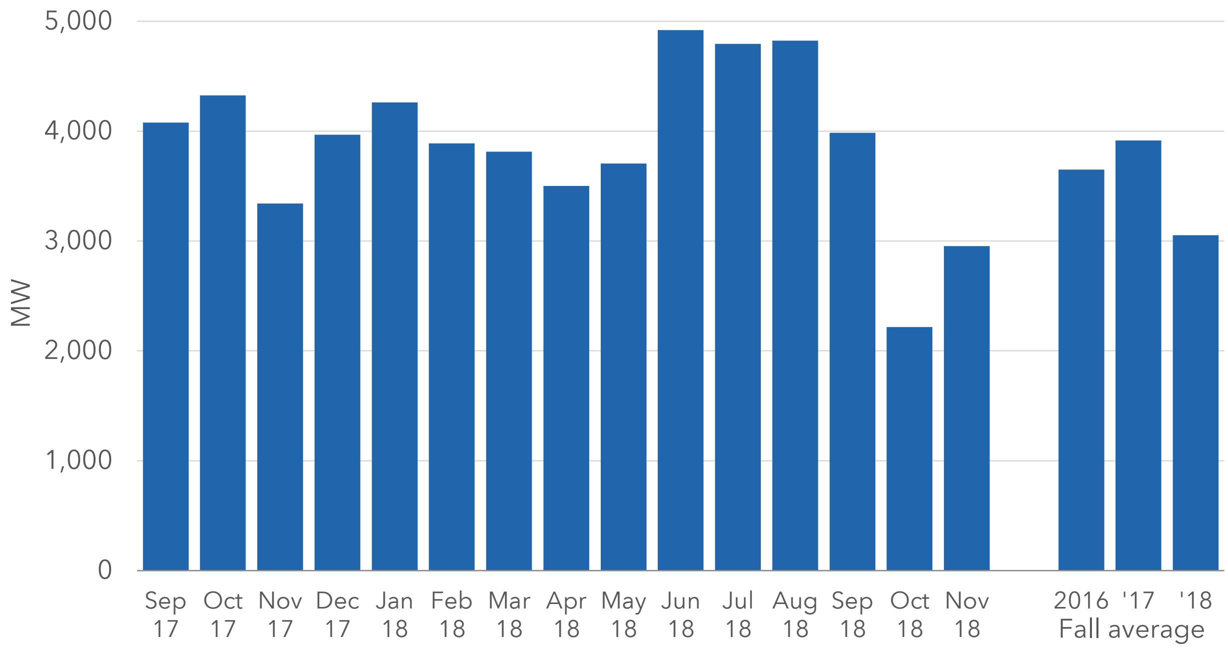
Market-to-market payments on individual flowgates have returned to levels that are more typical after peaking during the period from October 2017 through January 2018. During that period, high levels of congestion on the Neosho-Riverton for the loss of Neosho-Blackberry flowgate were the main driver for the high market-to-market payments, as mentioned above.

3. UNIT COMMITMENT AND DISPATCH PROCESSES

3.1 UNIT COMMITMENT

Figure 3–1 shows the real-time average peak hour capacity overage.[4] 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 for fall 2018 was just over 3,000 MW, down from nearly 4,000 MW in fall 2017, and from 3,600 MW in fall 2016.

3.2 GENERATION SCHEDULING

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

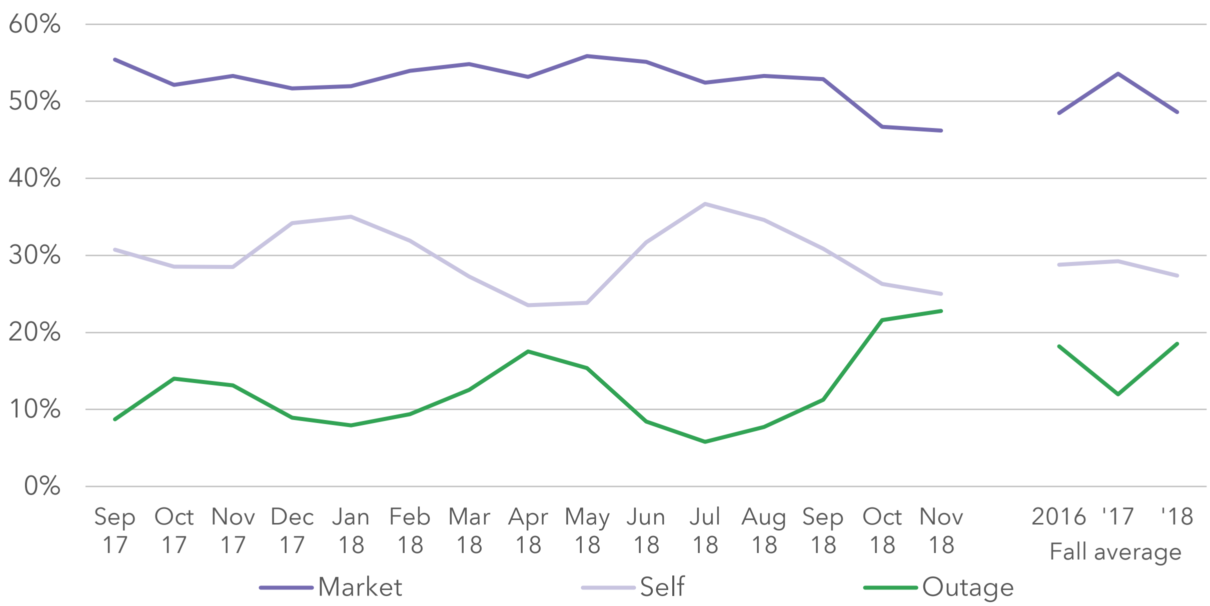
[4] The calculation for real-time average peak hour capacity overage is: economic maximum – load – net scheduled interchange – (regulation up + spinning reserves + supplemental reserves). Capacity from wind generation is not included in the economic maximum. Only capacity from traditional fuel resources is included in this calculation.

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-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 3–2 shows the percentage of generation participation offers in the day-ahead market for the "market," "self," and "outage" commitment statuses. "Reliability" and "not participating" are other statuses that are available, but the total of those statuses typically average around five to six percent on a monthly basis.

Figure 3–2 Day-ahead comparison of commitment status

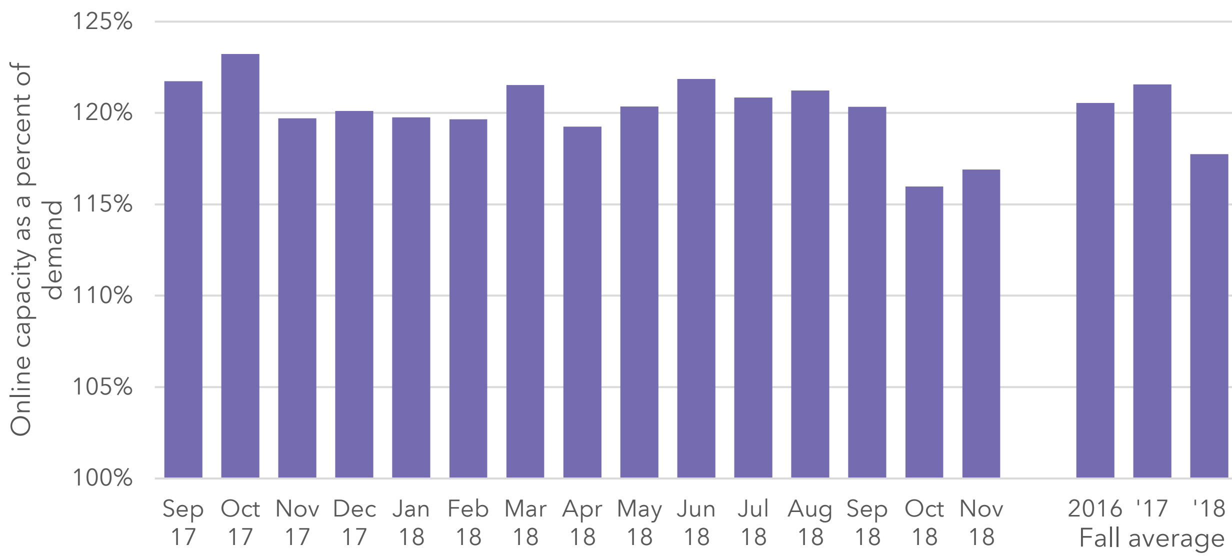


"Market" commitment status in both fall 2016 and 2018 was right at 49 percent. Fall 2017 saw higher market commitment status at nearly 54 percent. Fall 2017 saw much lower levels of "outage" status at about 12 percent, which accounted for the increase in market status during that period. Offered capacity in "self" commitment status is on a downward trend with approximately 29 percent of commitments with this status in fall 2016 and 2017. This has decreased to 27 percent in fall 2018.

While we view the reduction of self-committed offers as a positive trend, which may have also helped contribute to a reduction in the frequency of negative prices, we continue to encourage market participants and the RTO to find ways to enhance market efficiencies and reduce self-commitment.

Figure 3–3 shows online capacity commitment as a percent of demand.

Figure 3–3 Online capacity as a percent of demand



The capacity commitment as a percent of demand for the past three fall seasons has ranged around 120 percent, with 2018 at the low end of 117 percent. Some factors that contribute to lower levels of online capacity are fewer self-committed coal plants and the continued growth of wind capacity and generation. Lower online capacity levels may be a result of market participants and market operators adjusting to changes in market conditions.

3.3 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 3–4) and supply offers (Figure 3–5).

Figure 3–4 Virtual demand bids

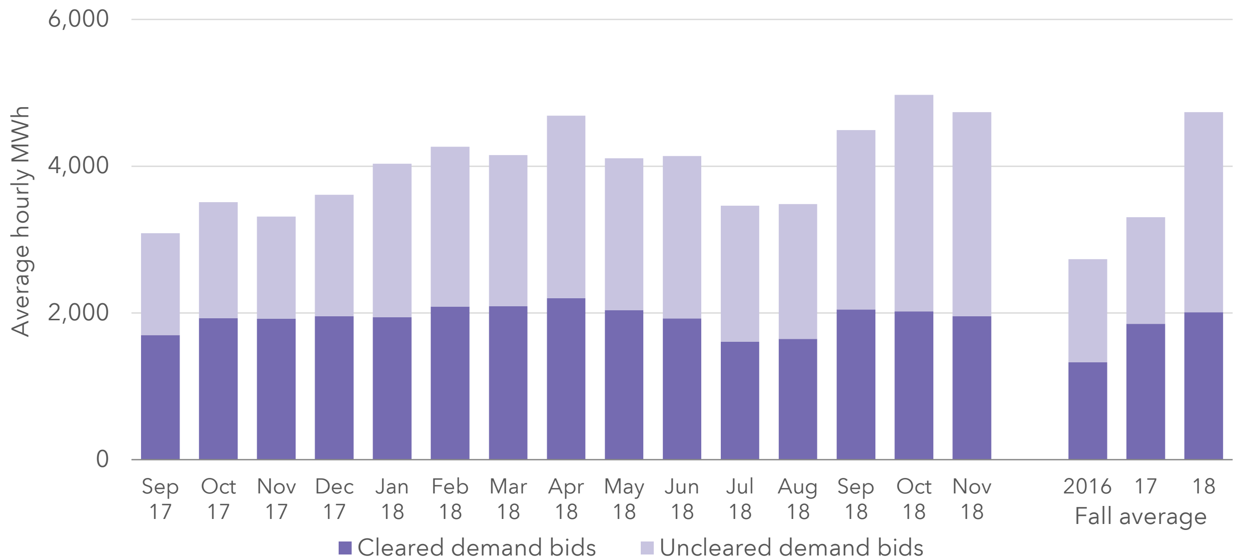
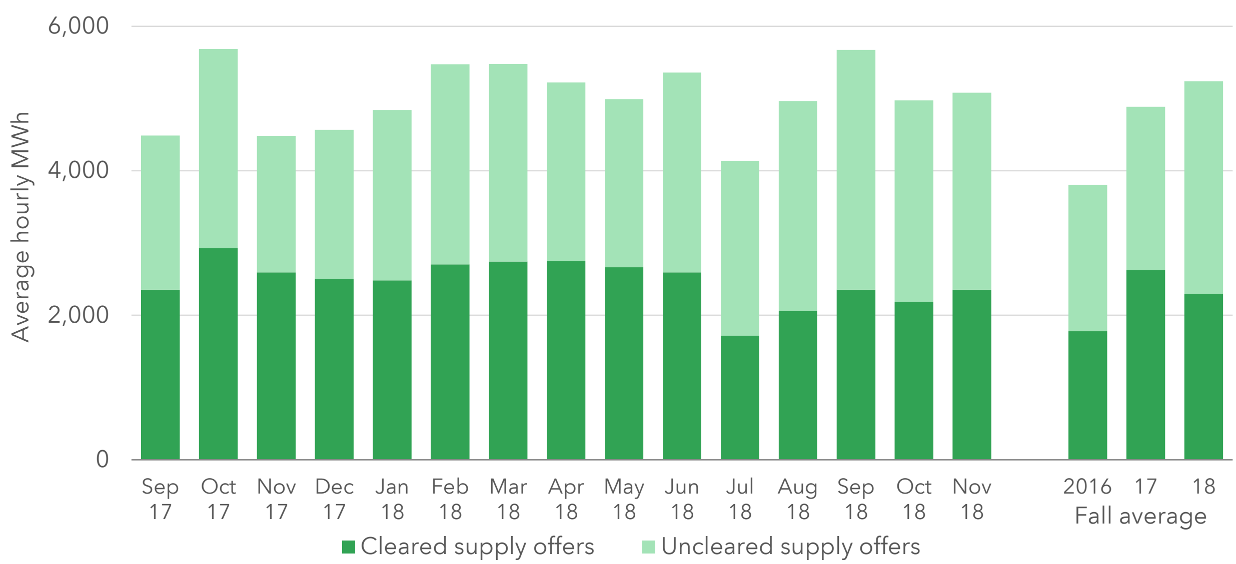


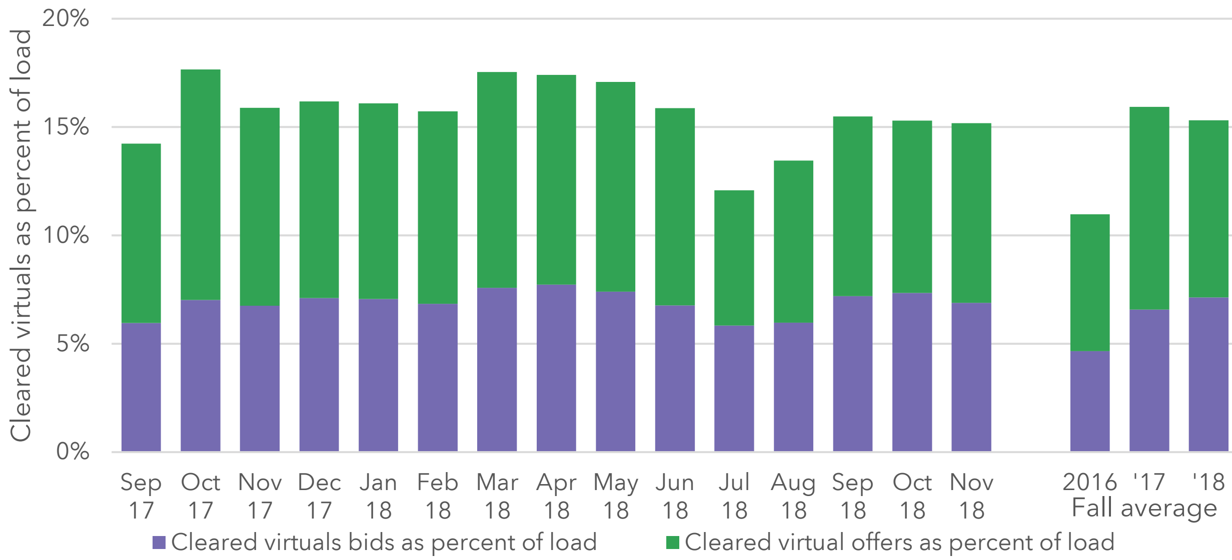
Figure 3–5 Virtual supply offers



As these figures show, both virtual demand bids and virtual supply offers continue to steadily increase.

Cleared virtual transactions as a percent of load are shown in Figure 3–6.

Figure 3–6 Cleared virtual transactions as a percent of load



For the fall period, virtual transactions as a percent of load were around 15 percent in 2017 and 2018, up from 11percent in 2016.

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 3–7 and Figure 3–8 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 3–7 Virtual demand bids by participant type

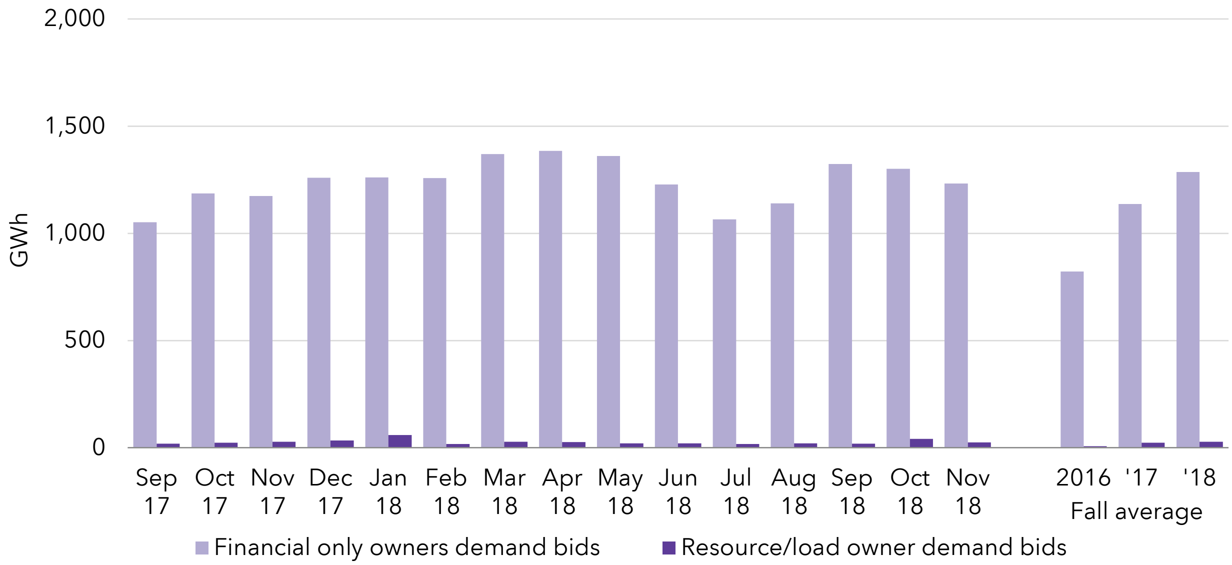
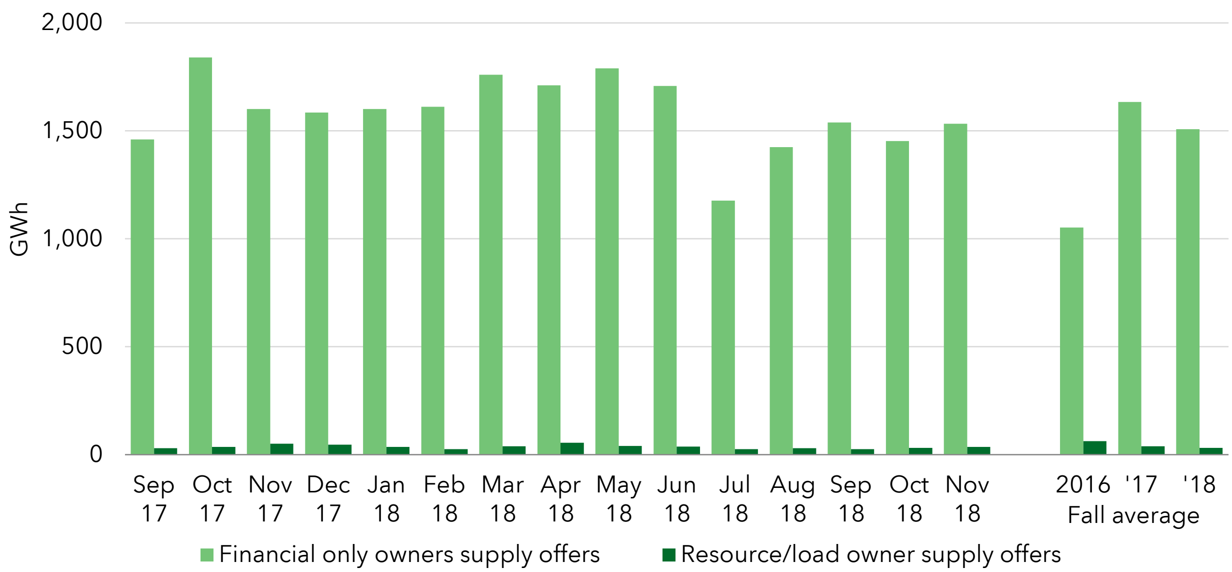


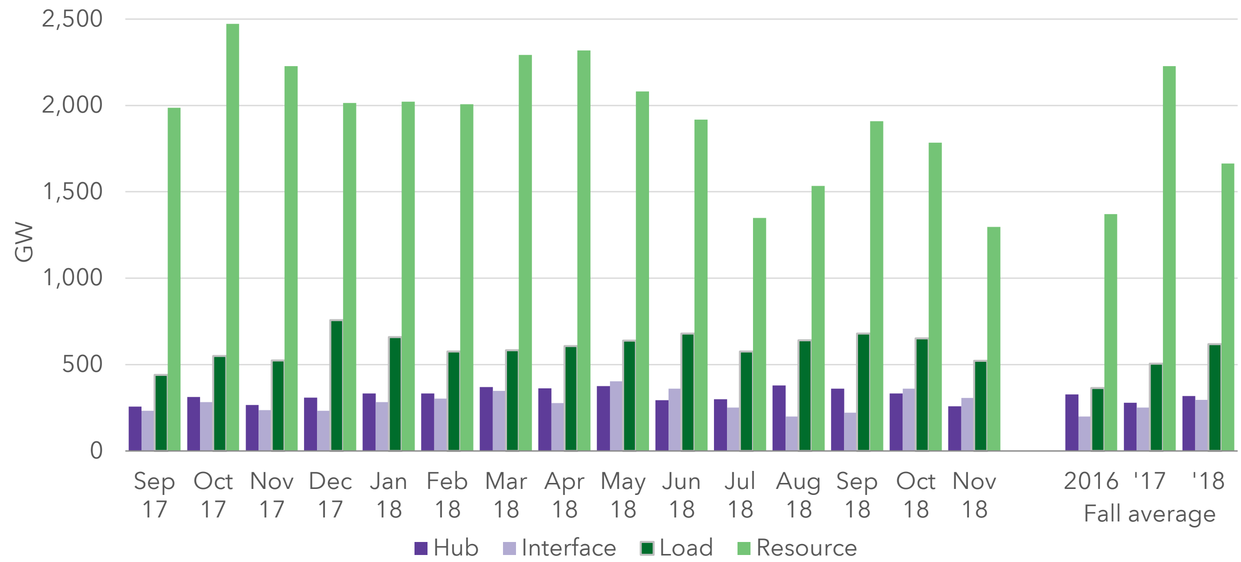
Figure 3–8 Virtual supply offers by participant type



While the number of virtual demand bids and supply offers by resource/load owners has remained negligible over time, both demand bids and supply offers by financial-only participants have increased from 2016 to 2018. This has contributed to the overall increase in virtual transactions.

Virtual transactions can be made at hubs, interfaces, loads and resources, as shown in Figure 3–9.

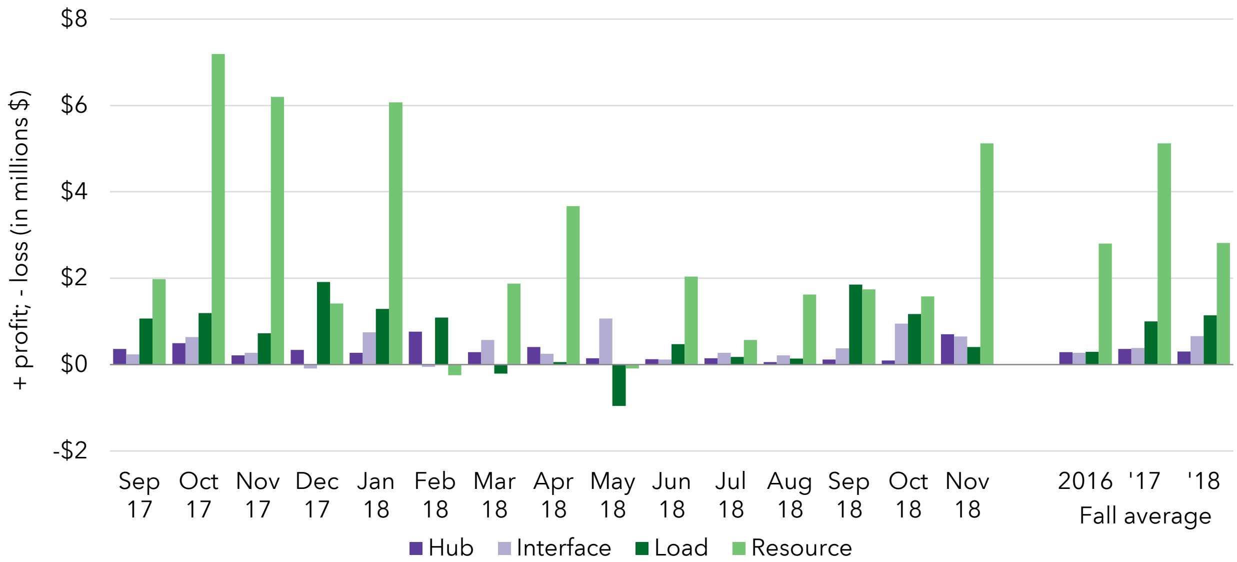
Figure 3–9 Virtual transactions by location type, megawatts



The great majority of virtual transactions are made at resources (primarily wind resources), even though there was a decline in virtual transactions at resource locations in fall 2018 compared to fall 2017. Historically participants have placed the fewest virtual transactions at external interfaces and hubs. Virtual transactions at load locations overall are still much lower than virtuals at resources, but have also been increasing, nearly doubling in volume from fall 2016 to fall 2018.

As with the volume of virtual transactions, the majority of the profits, shown in Figure 3–10, from virtual transactions are derived from resource locations.

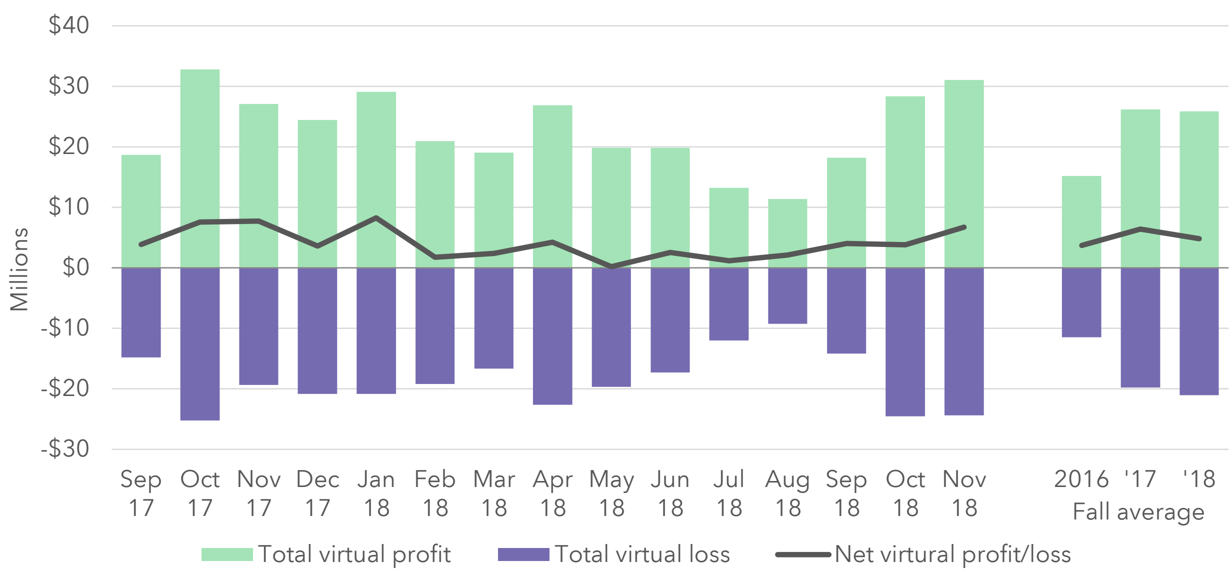
Figure 3–10 Virtual transactions by location type, profit/loss



Overall profit from virtual transactions was at similar levels in fall 2016 and 2018 at the resource level, but increased for interfaces and loads. Fall 2017 saw much higher profits due to increased levels of congestion and a higher number of cleared virtual transactions.

Overall profit and loss from virtual transactions is shown in Figure 3–11.

Figure 3–11 Virtual transactions, profit/loss



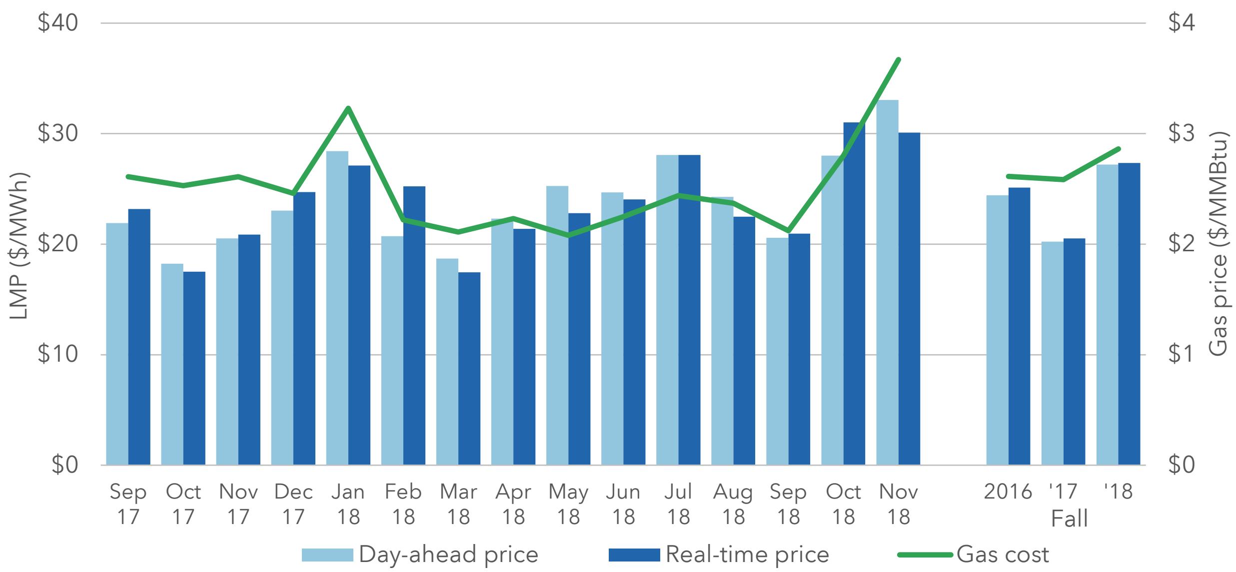
Gross virtual profits for fall 2018 averaged nearly $26 million, while gross virtual losses averaged nearly $21 million, for an average net profit of around $5 million. This was slightly lower than the average profit in fall 2017, but above fall 2016.

4. PRICES

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. Although this correlation is generally observed over time, some periods exhibit divergence.

Figure 4–1 Electricity and gas prices



Following an extended period of gas prices averaging between $2/MMBtu and $3/MMBtu, the November 2018 average gas price at the Panhandle Eastern hub climbed to $3.67/MMBtu. This is the highest gas price at the Panhandle Eastern hub since November 2014. The fall 2018 average gas price of $2.86/MMBtu represents an 11 percent increase over the fall 2017 price.

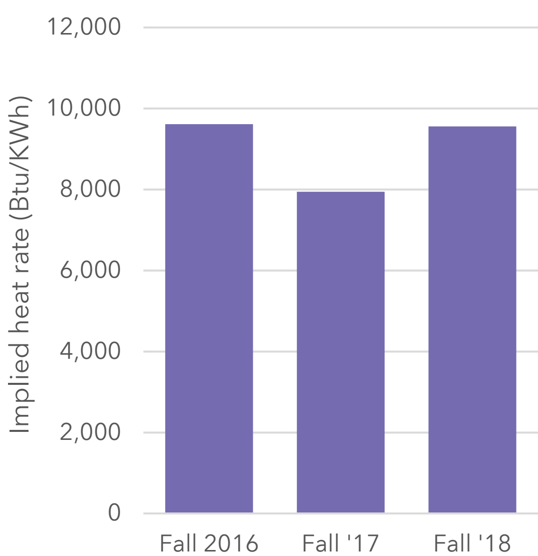
During fall 2018 the average day-ahead energy price was $27.22/MWh, and the average real-time price was $27.36/MWh, as shown in Figure 4–1. These prices represent a 35 percent increase for the day-ahead market, and a 33 percent increase for the real-time market over the fall 2017 energy prices.

The increase in energy prices from fall 2017 to fall 2018 of 33 and 35 percent, outweigh the 11 percent increase in gas prices during that same period. Thus, there are additional factors causing prices to increase including higher loads, a decline in wind generation, and a reduction in the frequency of negative prices.

When looking at the increase in energy prices from fall 2017 to fall 2018 of 33 and 35 percent, compared to an increase in gas prices during that same period of 11 percent, there appears to be a disconnect.

These additional factors are reflected in the implied heat rate. 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 fall period for the past three years.

Figure 4–2 Implied heat rate



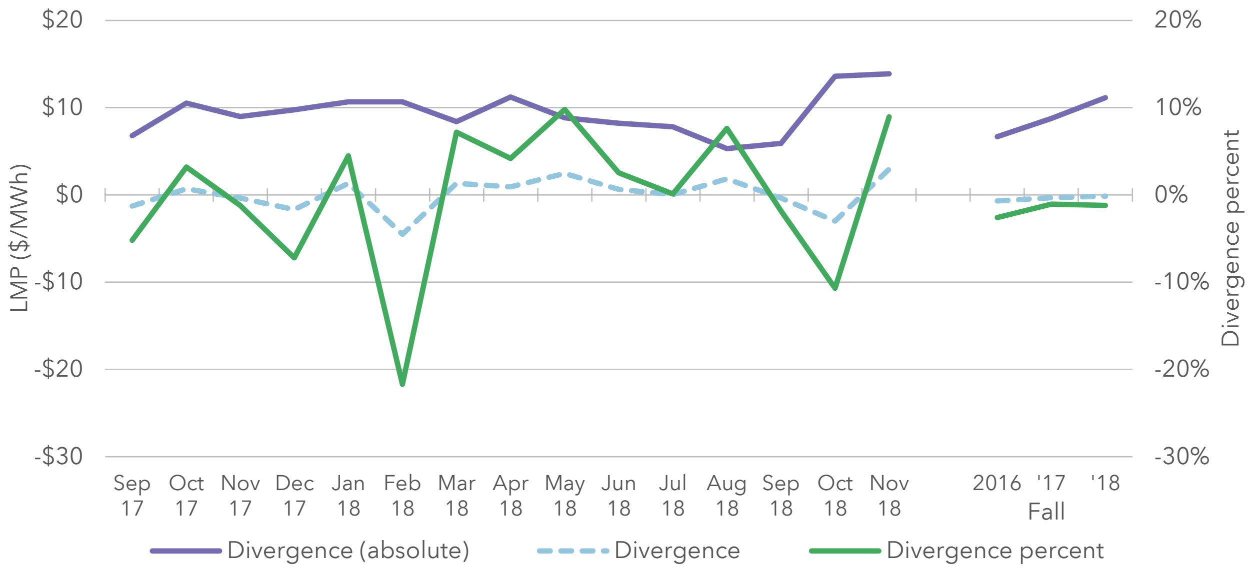
As the figure above shows, the implied heat rates for fall 2016 and fall 2018 where nearly identical. Fall 2017 had a much lower implied heat rate, primarily due to high levels of wind generation, as was shown in Figure 2–5, and a corresponding increase in negative prices, discussed below, during that period.

Figure 4–3 shows the day-ahead to real-time price divergence at the SPP system level. Price divergence[5] is calculated as the difference between day-ahead and real-time prices, using

[5] Price divergence percent is calculated as the day-ahead price minus the real-time price, divided by the day-ahead price.

system prices for each five-minute (real-time) or hour (day-ahead) interval. The absolute divergence is calculated by taking the absolute value of the divergence for each interval.

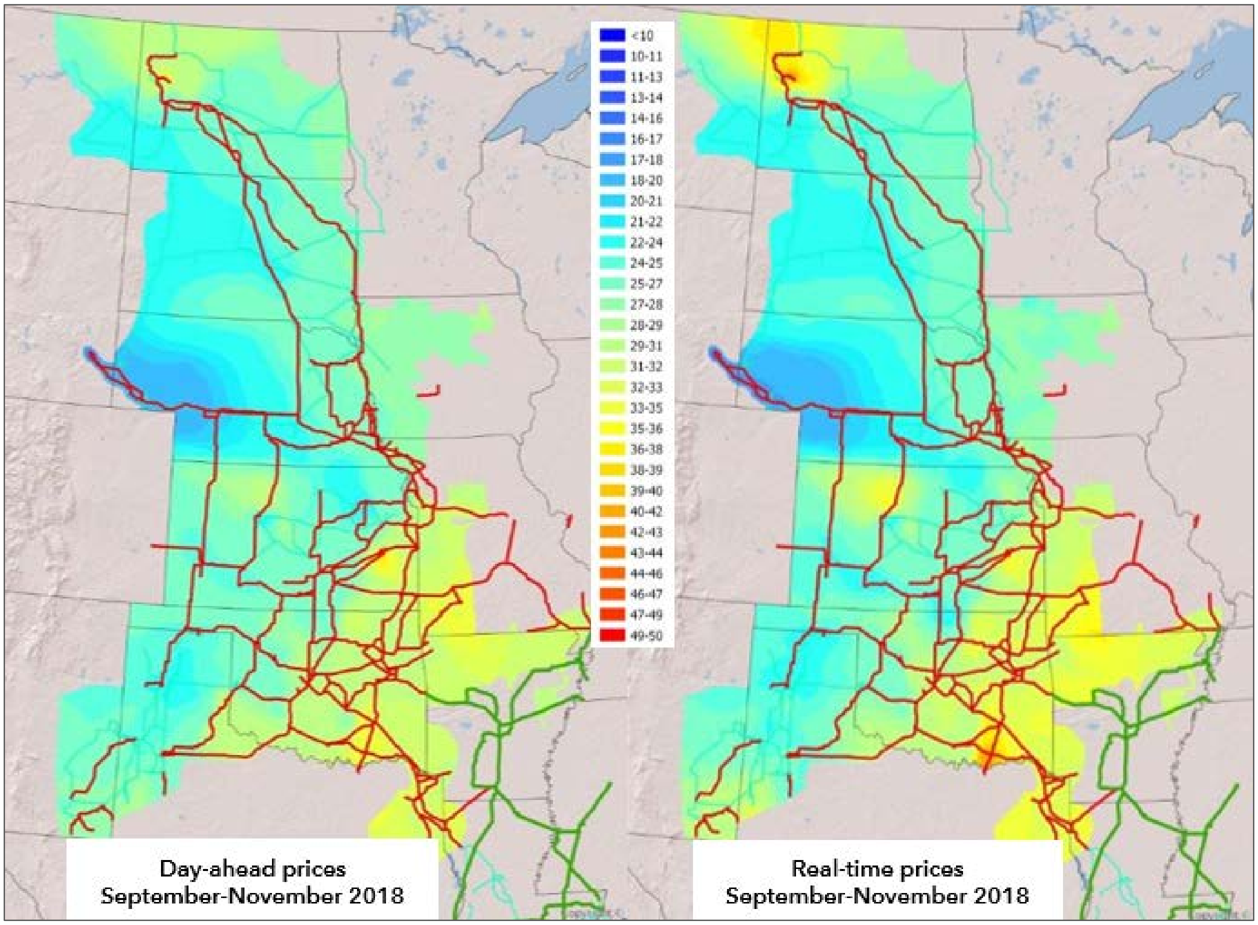
Figure 4–3 Price divergence, day-ahead and real-time



While the divergence percent (green line) and average divergence (dashed blue line) remained flat from fall 2017 to fall 2018, absolute divergence (dark purple line) climbed from $9/MWh to $11/MWh. While there have been sporadic months with an absolute divergence above $10/MWh, the October and November 2018 absolute divergence figures are the highest experienced since the first three months of the Integrated Marketplace. Some of this volatility can be attributed to the increase in scarcity events, which is discussed in Chapter 6 (special issues) of this report.

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

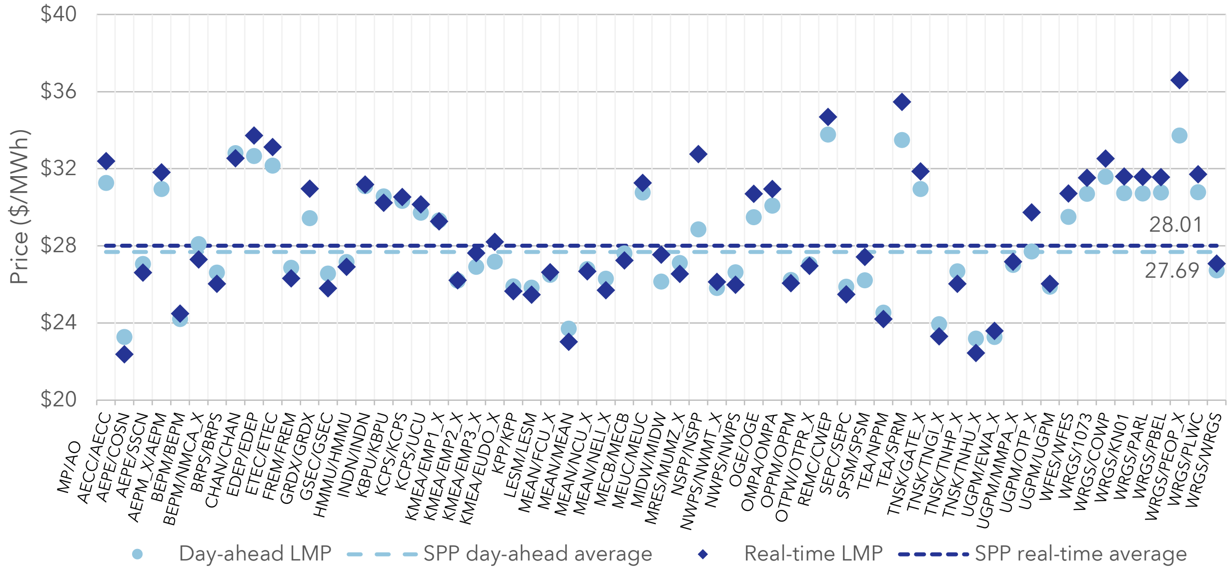
Figure 4–4 Price map, fall (all hours)



Lower prices are typically more prevalent in the north due to less expensive generation in the area, and in the west-central part of the footprint due to abundant low-cost wind generation in that area. The areas with highest prices in the footprint for the fall are concentrated in three areas – the southeast corner of the SPP footprint, northwest North Dakota, and northwest Kansas. The lowest prices in the footprint for the fall were found in western Nebraska. Congestion in these areas contributing to the high and low prices is discussed in Chapter 5 of this report.

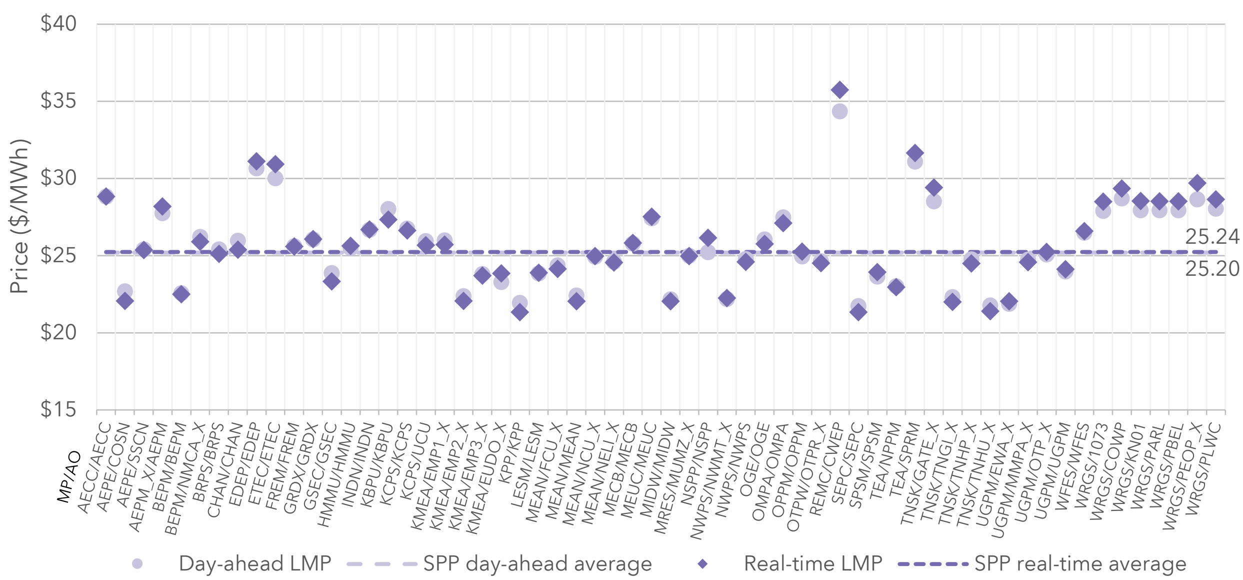
Figure 4–5 and Figure 4–6 display average prices paid by load-serving entity for the fall period and the last twelve months.

Figure 4–5 Price by load-serving entity, fall



Fall period average prices were the highest in eastern Oklahoma and southwest Missouri (City of Springfield and Carthage Water and Electric). This can primarily be attributed to the congestion mentioned above in the southwest Missouri/southeast Kansas area. Average prices were lowest for entities located in the northern portion of the SPP footprint.

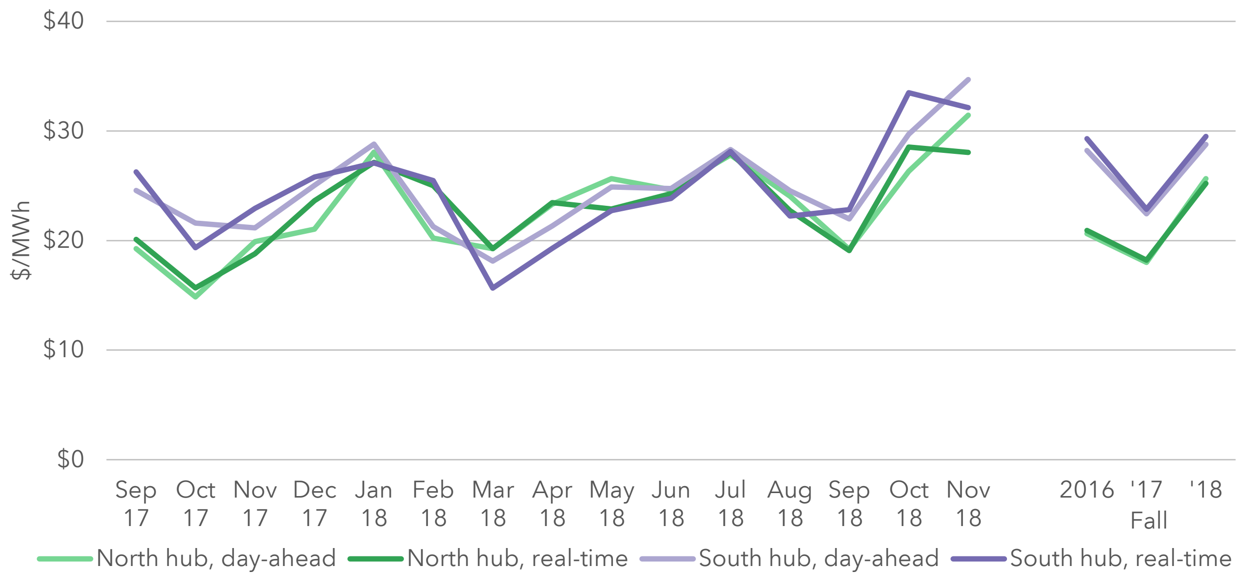
Figure 4–6 Price by load-serving entity, rolling 12 month



Over the past 12 months, overall prices in the day-ahead and real-time markets were almost identical. For this period, entities in the southwest Missouri/southeast Kansas area still saw the highest prices overall, while entities in western Kansas saw the lowest prices overall. As with the fall period, high prices for the past year in southwest Missouri/southeast Kansas can be mostly attributed to congestion in the area, along with some external impacts. Western Kansas has abundant low-cost generation, primarily wind, typically entities in that portion of the SPP footprint see some of the lowest prices overall.

Figure 4–7 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.

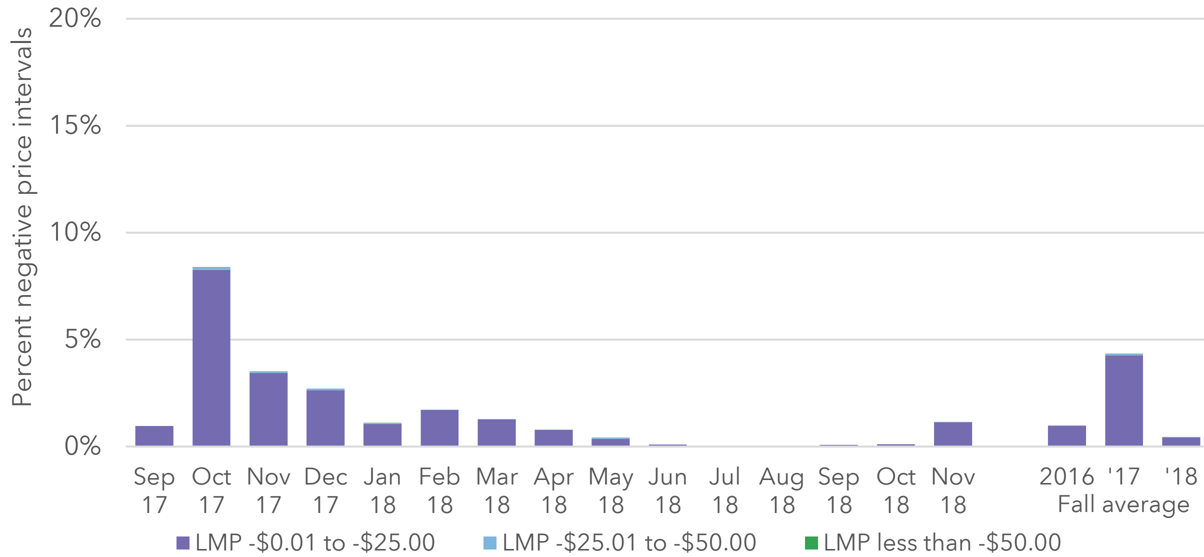
Figure 4–7 Trading hub prices



Because of an abundance of lower-cost generation in the northern part of the SPP footprint, prices at the North hub are typically lower than the South hub. The spread between the hub prices continues to narrow, with about an $8/MWh difference in fall 2016, decreasing to about $4/MWh difference in fall 2018. This convergence is likely attributable to transmission additions over the last few years that have decreased congestion and increased the ability of power to flows throughout the SPP footprint.

While negative prices are a legitimate market outcome, 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, and external impacts. After a steady growth of intervals with negative prices, fall 2018 saw a decrease in negative price intervals as shown in Figure 4–8.

Figure 4–8 Negative price intervals, day-ahead

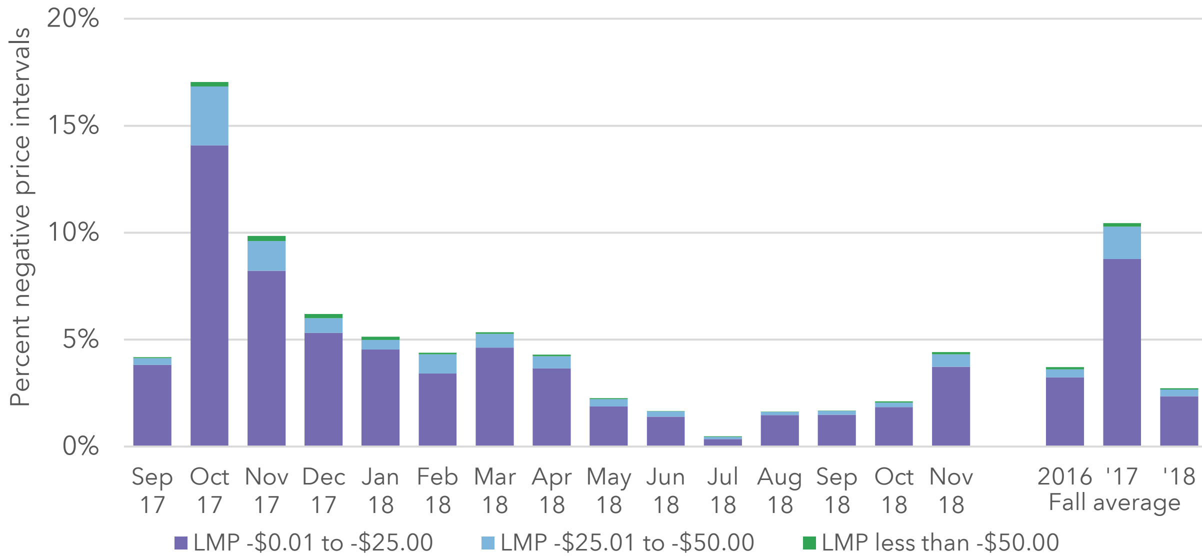


In fall 2018, less than one percent of asset owner intervals[6] in the day-ahead market had prices below zero. This is more similar to fall 2016, when negative price intervals were just above one percent. With the higher levels of wind, and lower load, in fall 2017, negative price intervals in the day-ahead market were nearly five percent.

Typically, the frequency of negative price intervals in the real-time market is about three times that of the day-ahead market, see Figure 4–9.

[6] Asset owner intervals are calculated as the number of asset owners serving load that are active in an interval. For example, if there 60 asset owners active in one five minute interval throughout an entire 30 day month, the total asset owner intervals would be 518,400 for the month (60 asset owners * 288 intervals per day * 30 days).

Figure 4–9 Negative price intervals, real-time



Fall 2018 had nearly three percent of all asset owner intervals in the real-time market with negative prices, compared to just over 10 percent fall 2017. The fall season has historically seen the most intervals with negative prices.

Factors causing the frequency of negative prices to fall include a key transmission expansion earlier this year, along with higher loads and less wind output overall in fall 2018 compared to fall 2017.

4.2 OPERATING RESERVE MARKET

The following figures (Figure 4–10 through Figure 4–13) 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 4–10 Regulation-up prices

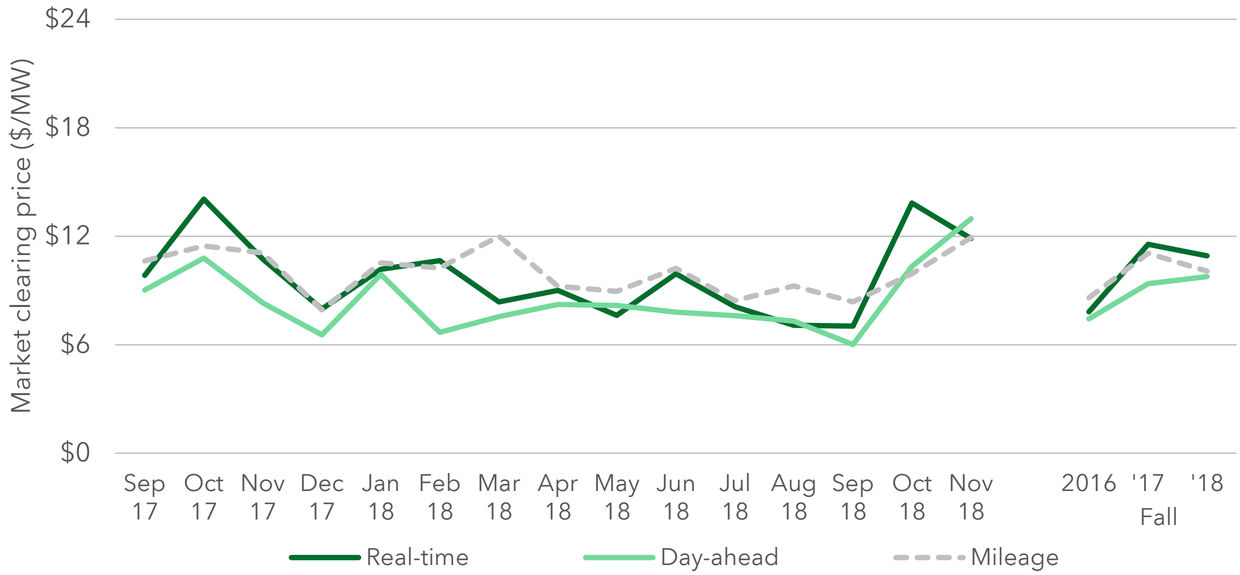
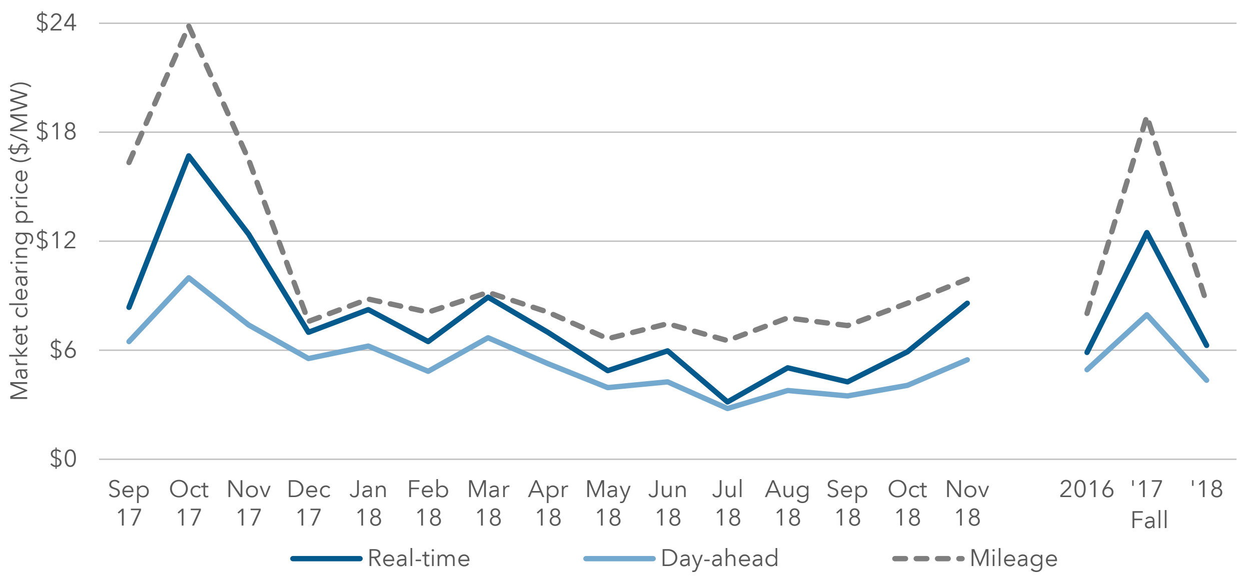


Figure 4–11 Regulation-down prices



Regulation-up in real-time and mileage each dropped slightly from fall 2017, while remaining above fall 2016 levels. Regulation-up marginal clearing prices continue to climb in the day-ahead market to just over $10/MW. Market clearing prices for regulation-down products in fall 2018 were nearly identical to fall 2016. October 2017 saw unusually high regulation-down prices, which significantly raised the averages for fall 2017.

Figure 4–12 Spinning reserve prices

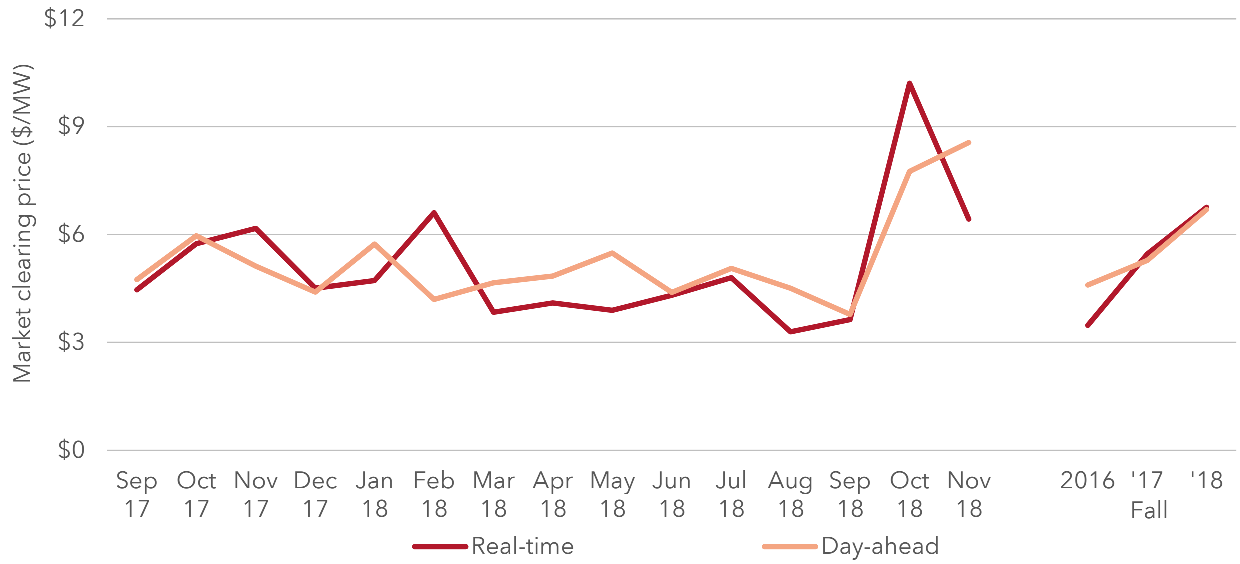
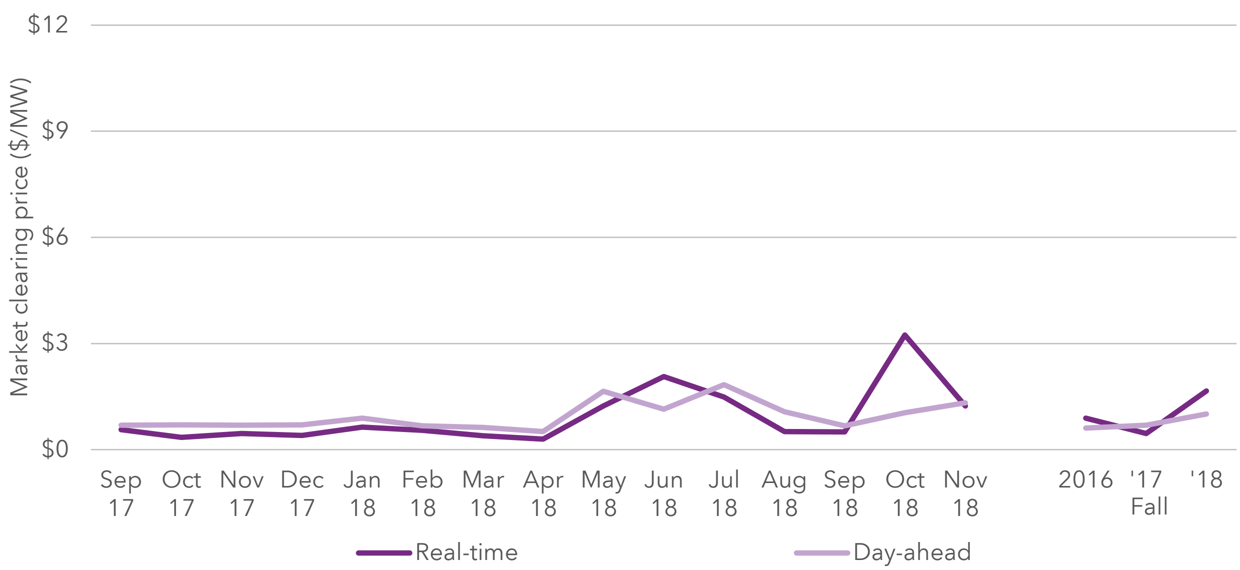


Figure 4–13 Supplemental reserve prices



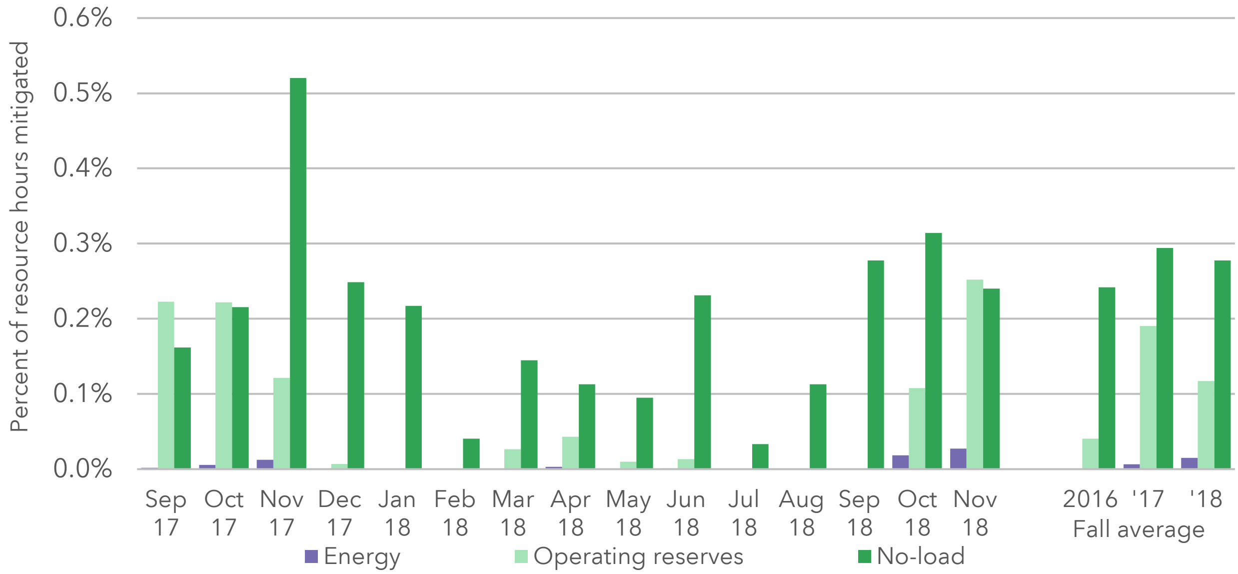
Marginal clearing prices for spinning reserves have steadily increased from fall 2016 to 2018. Prices for real-time supplemental reserves spiked above $3/MW in October 2018. This was the highest price for real-time supplemental reserves since May 2014.

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.

Mitigation frequency varies across products in the SPP market. Figure 4–14 shows the frequency of mitigation of incremental energy, operating reserves, and no-load costs in the day-ahead market.

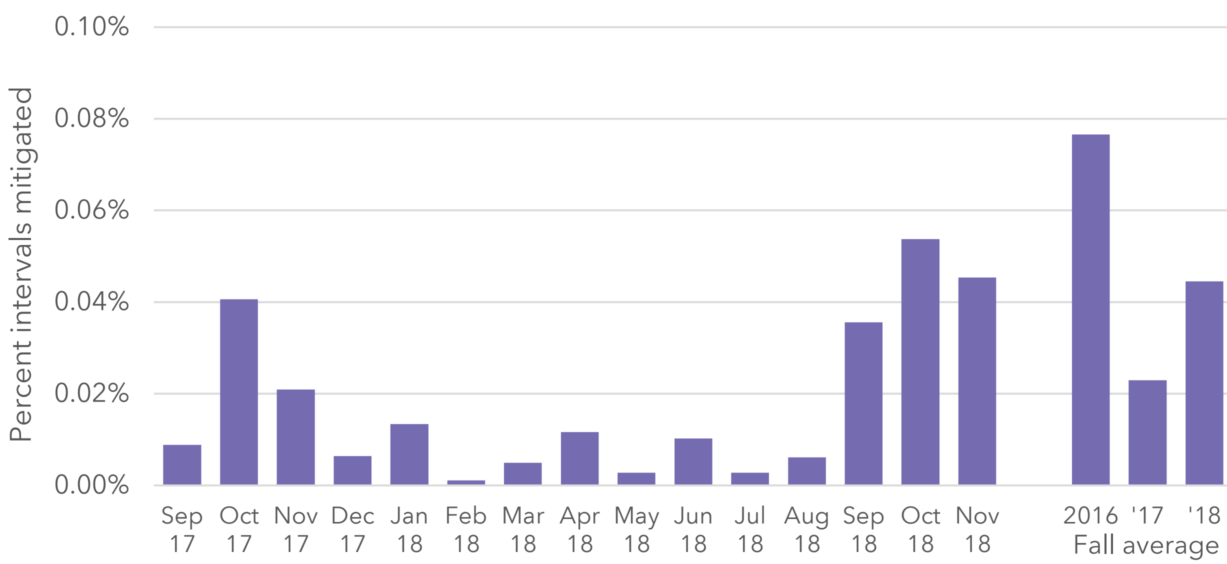
Figure 4–14 Mitigation frequency, day-ahead market



Mitigation frequency in energy, operating reserves, and no-load in the day-ahead market remains low, totaling less than 0.5 percent of resource hours mitigated in fall 2018.

For the real-time market, the mitigation of incremental energy is shown in Figure 4–15.

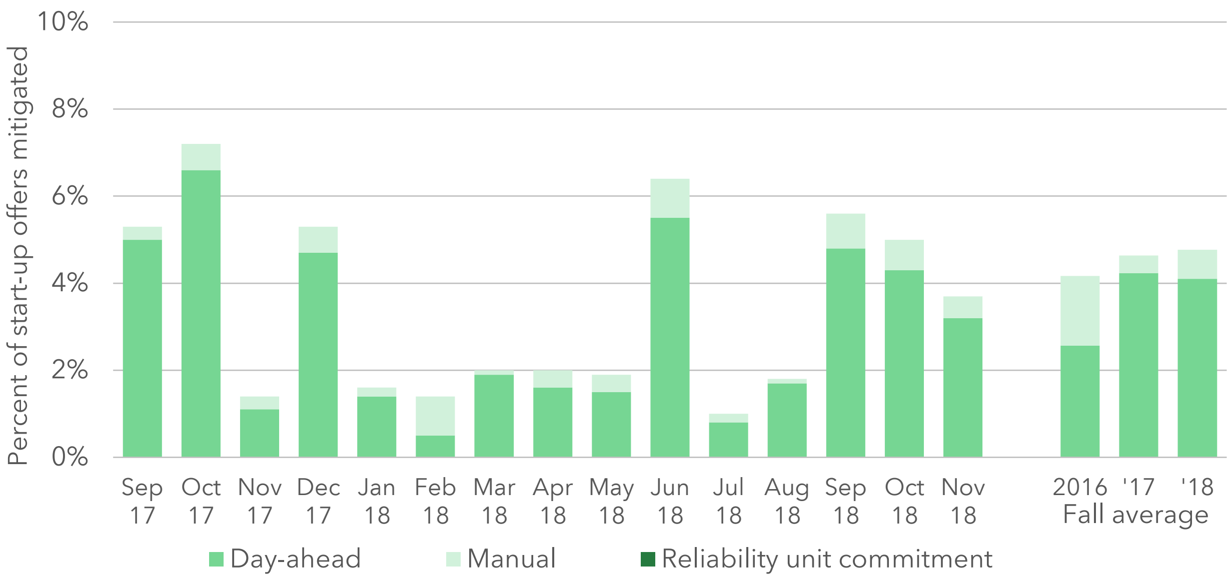
Figure 4–15 Mitigation frequency, real-time market



Mitigation frequency in the real-time market remains at very low levels as well, with less than 0.05 percent of resource hours mitigated in real-time.

Figure 4–16 shows the mitigation of start-up offers for different commitment types.

Figure 4–16 Mitigation frequency, start-up offers

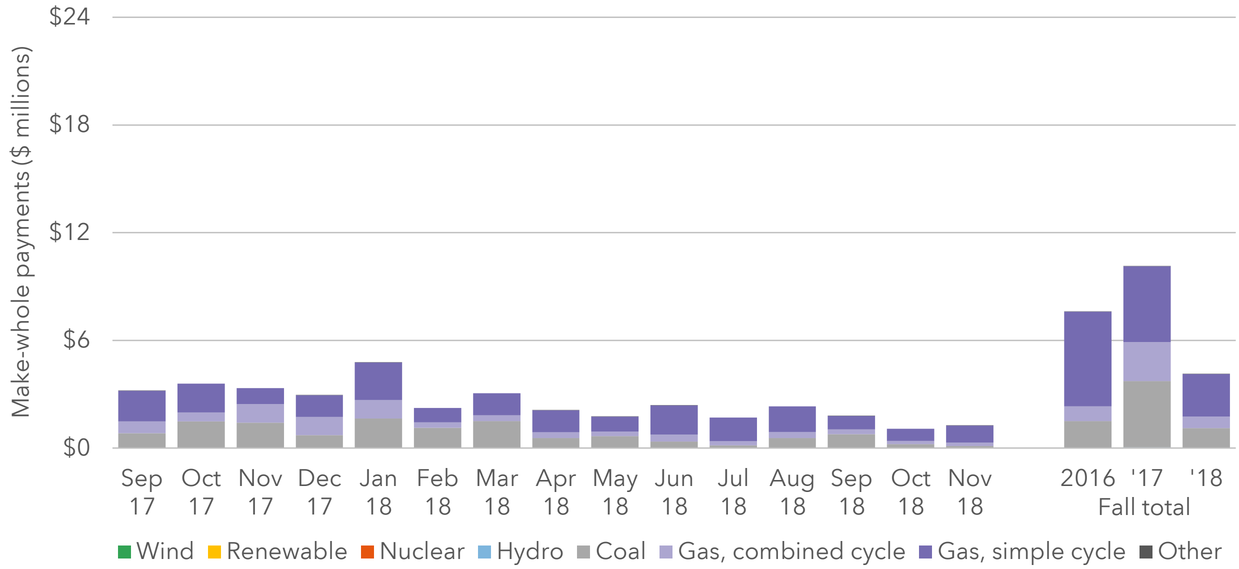


The overall level for mitigation of start-up offers has averaged around four percent for the past three fall periods.

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 4–17) 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.

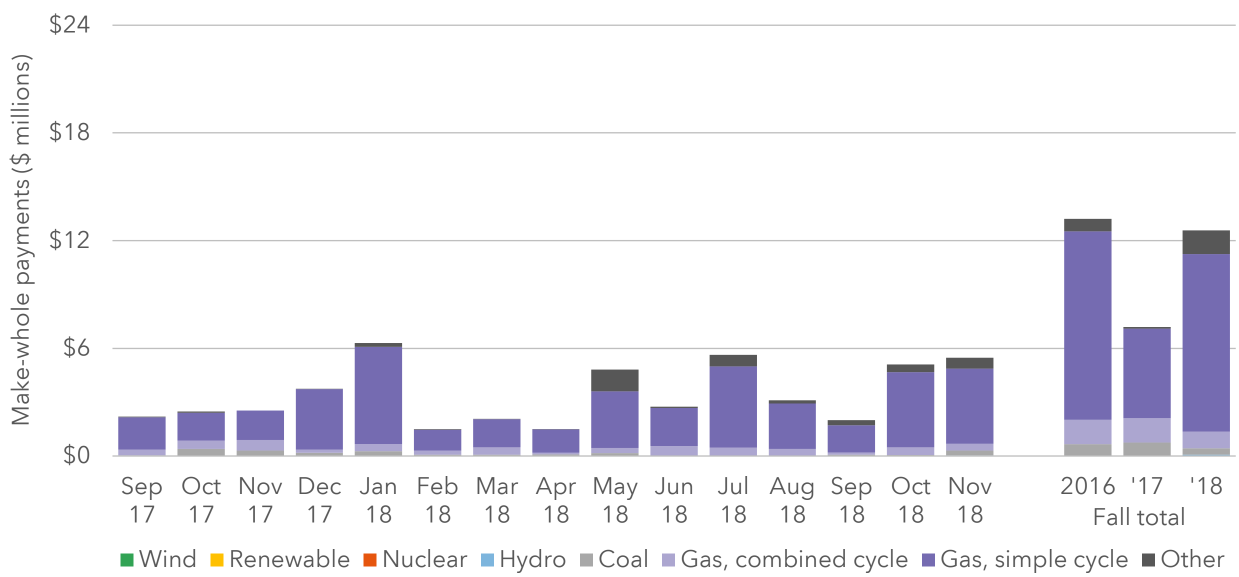
Figure 4–17 Make whole payments, day-ahead



Typically, most day-ahead make-whole payments are attributed to coal and gas resources. Compared to the previous years, fall 2018 day-ahead make-whole payments were about 50 percent lower, at around $4 million.

The reliability unit commitment (RUC) make-whole payment (Figure 4–18) applies to commitments made in the day-ahead RUC and intra-day RUC processes. The majority of the reliability unit commitment make-whole payments are paid to gas resources, and more specifically gas simple-cycle resources.

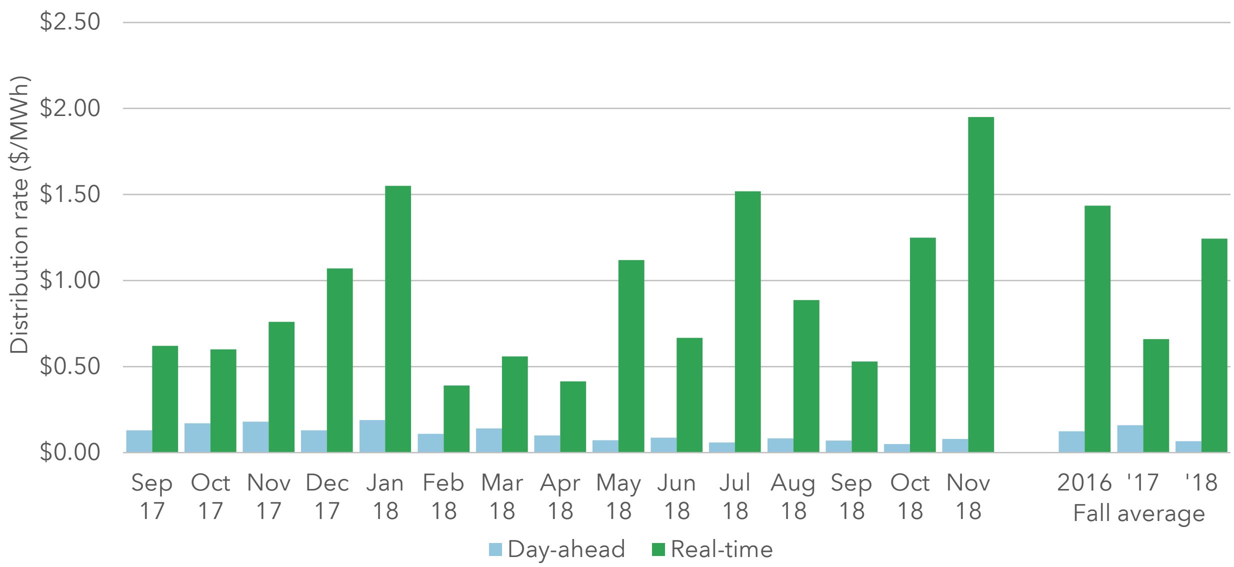
Figure 4–18 Make whole payments, reliability unit commitment



Fall 2018 monthly real-time make-whole payments totaled just over $12 million, which was similar to the level in fall 2016.

The make-whole payment distribution charge, as shown in Figure 4–19, is applied to asset owners that receive benefits from units committed in the day-ahead and real-time markets. The day-ahead make-whole payment distribution amount is an hourly charge or credit based on a daily allocation. The total of all make-whole payments paid to generation resources is spread among all load according to the ratio of the withdrawals relative to a specific market. For the day-ahead market, the distribution rate is the sum of all day-ahead market make-whole payments for the day, divided by the total day-ahead market withdrawals. For the real-time market, the distribution rate is the sum of real-time make-whole payments for the day divided by the total real-time market deviation from day-ahead schedules.

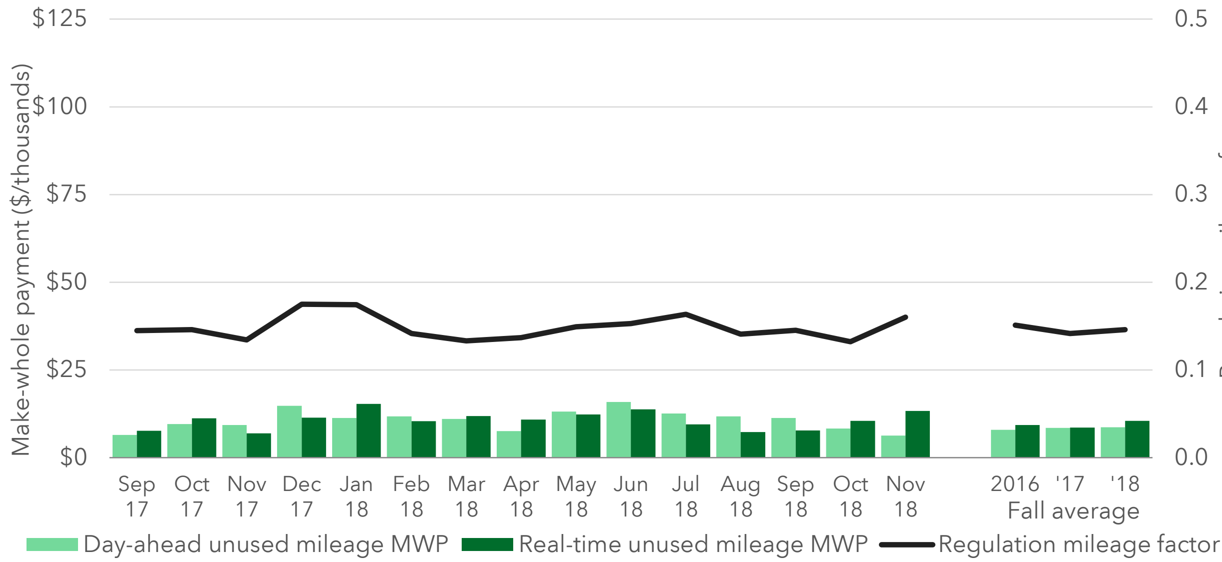
Figure 4–19 Make whole payment distribution rate



Although the real-time distribution rate in fall 2018 was nearly double that of fall 2017, the 2018 was lower than the fall 2016 rate. The day-ahead distribution rate remains steady in the past three fall seasons, averaging around $0.10/MWh.

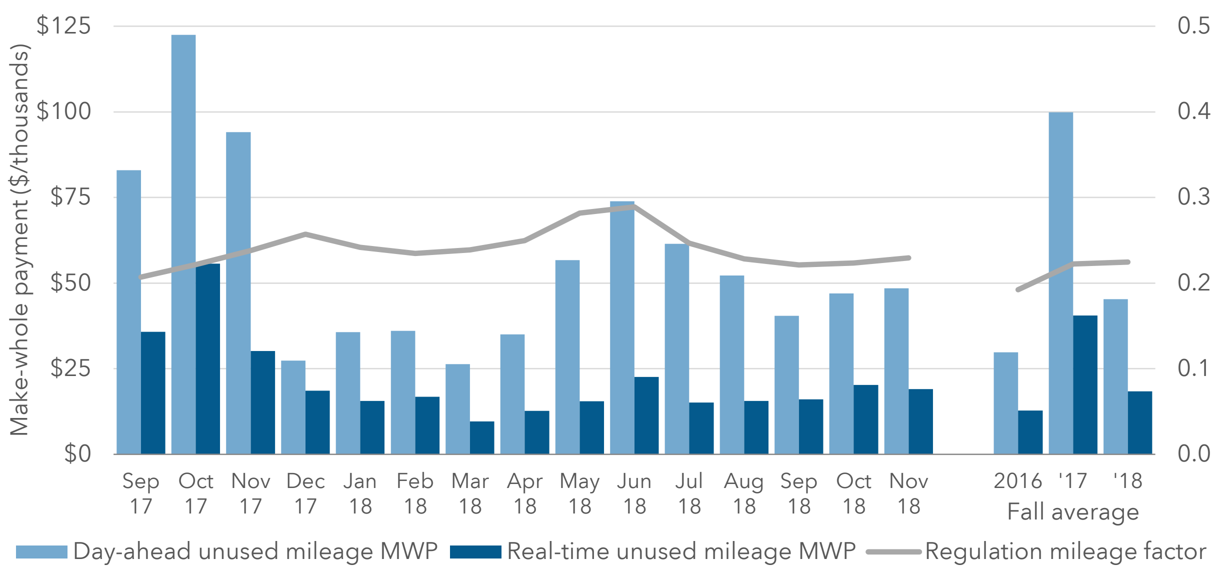
Regulation compensation includes payment to market participants, which are shown in Figure 4–20 and Figure 4–21, based on changes in energy output for regulation deployment.

Figure 4–20 Regulation-up mileage make whole payments



Regulation-up mileage make-whole payments remained steady in both the day-ahead and real-time markets. The regulation-up mileage factor continues to average around 0.15 in the past three fall periods.

Figure 4–21 Regulation-down mileage make whole payments

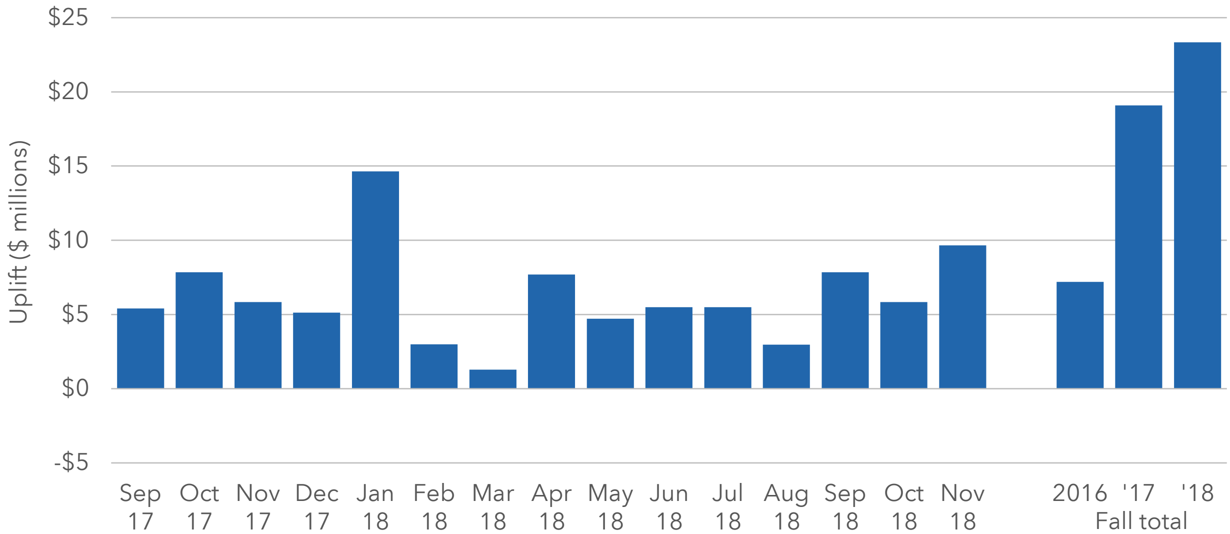


Just as regulation-down marginal clearing prices spiked in October 2017, regulation-down mileage make-whole payments also spiked in that same period, increasing the fall 2017 averages.

Revenue neutrality uplift (RNU), shown in Figure 4–22, 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 4–22 Revenue neutrality uplift



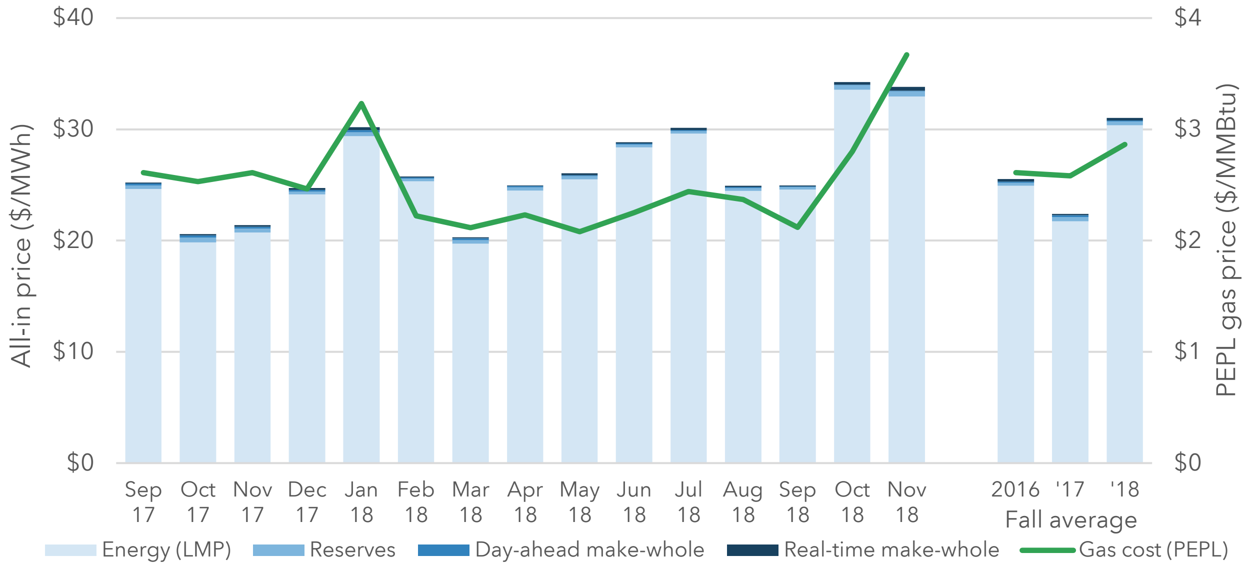
amounts shown are from the latest available settlement data and are subject to change due to resettlements

Total revenue neutrality uplift for fall 2018 was just over $23 million, an increase from $19 million in fall 2017. On a monthly basis, revenue neutrality uplift typically averages around $5 million per month, with variations primarily driven by seasonality and congestion levels.

The all-in cost, shown in Figure 4–23 includes the cost of energy, day-ahead and real-time reliability make-whole payments (uplift), operating reserves costs, reserve sharing group costs, and payment to demand response resources.[7] The cost of energy includes all of the shortage pricing components.

[7] Reserve sharing group costs and demand response costs are included in the all-in price, however costs for both of those items are zero.

Figure 4–23 All-in cost



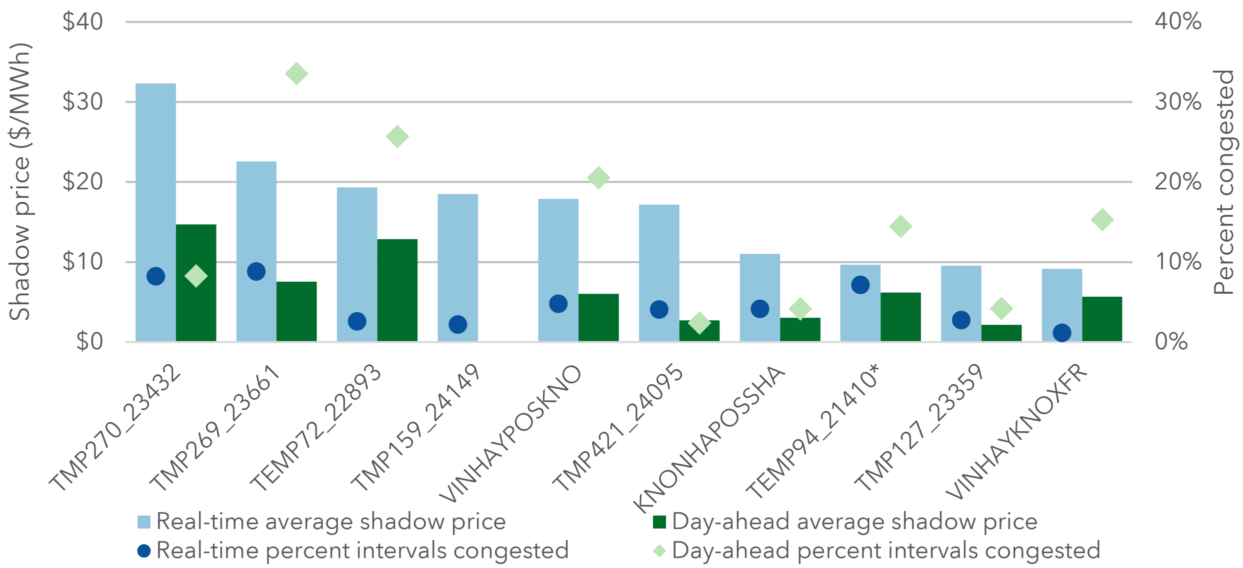
Generally, the energy cost in the SPP market constitutes around 98 percent of the all-in cost, showing that uplift makes up a very small portion of the total cost incurred by market participants. Since all-in cost primarily consists of energy, the seasonal pattern mirrors that of the SPP energy cost shown in Figure 4–1. The increase in all-in costs were driven by multiple factors including higher gas prices, higher loads, less wind generation, and fewer negative prices.

5. CONGESTION AND TRANSMISSION CONGESTION RIGHTS MARKET

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 fall period is shown in Figure 5–1, while congestion by shadow price for the rolling 12-month period ending November 2018 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 (planned or unplanned), weather events, and external impacts.

Figure 5–1 Congestion by shadow price, fall

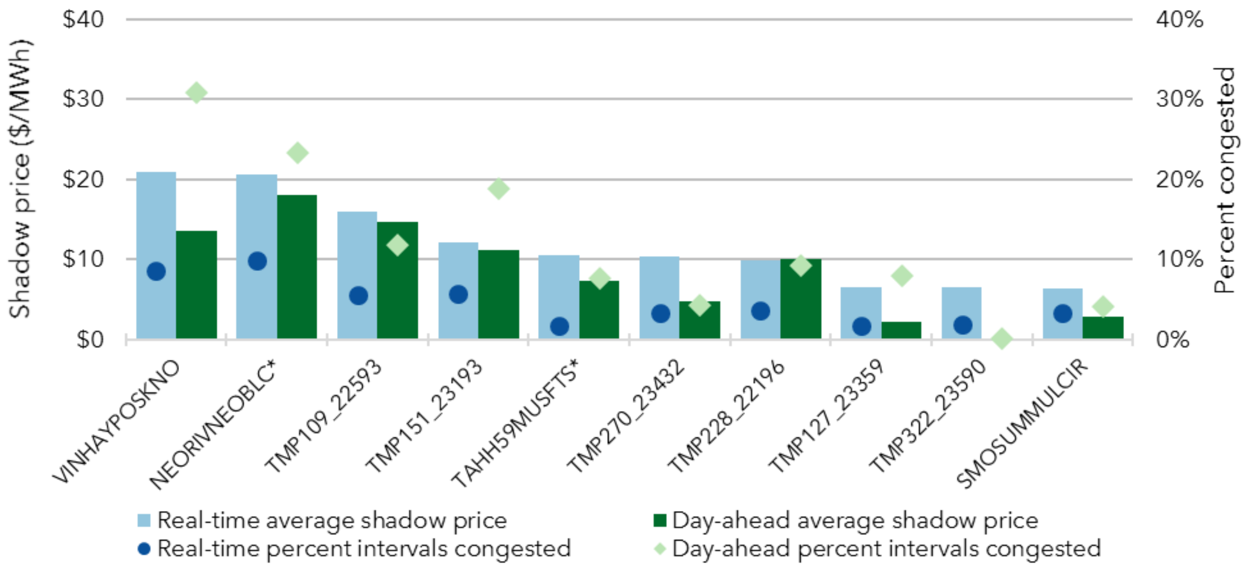


TMP270_23432 Cleveland-Cleveland AECI 138kV (GRDA-AECI) ftlo Cleveland-Tulsa North 345kV (GRDA-CSWS)
TMP269_23661 Charlie Creek-Watford 230kV ftlo Charlie Creek-Patentgate 345kV (WAUE)
TEMP72_22893 Wolf Creek Xfmr 345kV/1 ftlo Wolf Creek-Waverly 345kV (WR)
TMP159_24149 Russett-South Brown 138kV (WFEC) ftlo Brown Tap-Little City 138kV (OKGE)
VINHAYPOSKNO Vine Tap-North Hays 115kV ftlo Post Rock-Knoll 230kV (MIDW)
TMP421_24095 Cimarron Xfmr A 345/138kV ftlo Cimarron Xfmr B 345/138kV (OKGE)
KNONHAPOSSHA Knoll-North Hays 115kV ftlo Post Rock-South Hays 230kV (MIDW)
TEMP94_21410* South Hays-Mullergren 230kV ftlo Post Rock-Spearville 345kV (MIDW)
TMP127_23359 Scotsbluff-Victory Hill 115kV (NPPD) ftlo Stegall Xfmr 345kV/1 (WAUE)
VINHAYKNOXFR Vine Tap-North Hays 115kV ftlo Knoll Xfmr 230/115kV (MIDW)

** SPP market-to-market flowgate*

During the fall season, the most congested flowgate was found in the Tulsa area – TMP270_23432 (Cleveland-Cleveland AECI 138kV (GRDA-AECI) for the loss of Cleveland-Tulsa North 345kV (GRDA-CSWS). The next most congested flowgate was found in North Dakota – TMP269_23661 (Charlie Creek-Watford 230kV ftlo Charlie Creek-Patentgate 345kV (WAUE). In addition, three of the top ten most congested flowgates were near Hays, Kansas.

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



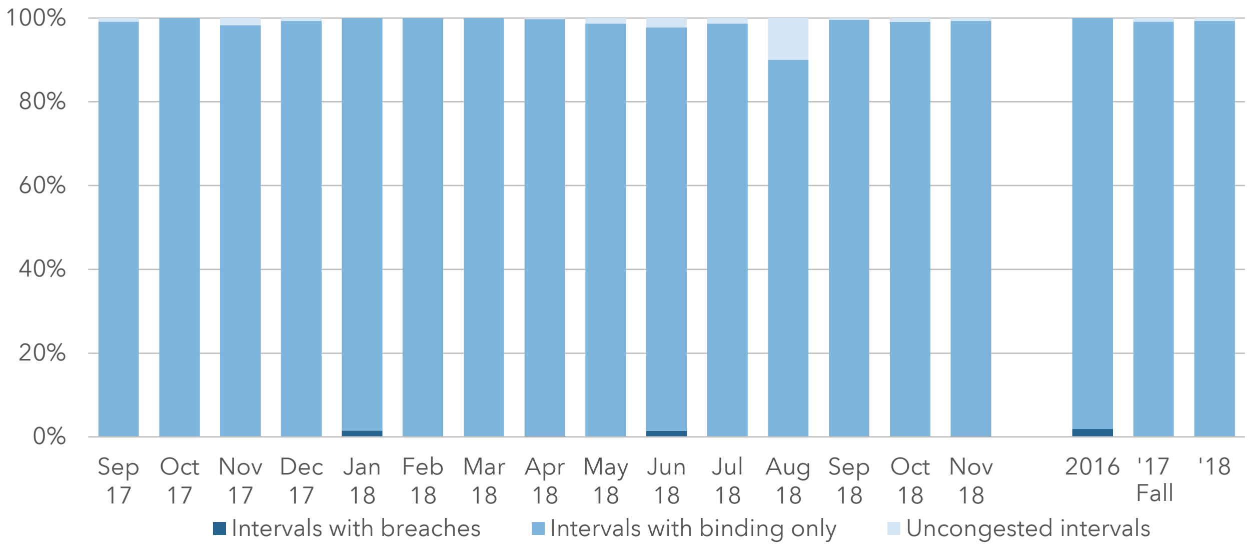
VINHAYPOSKNO Vine Tap-North Hays 115kV ftlo Post Rock-Knoll 230kV (MIDW)
NEORIVNEOBLC* Neosho-Riverton 161kV (WR-EDE) ftlo Neosho-Blackberry 345kV (WR-AECI)
TMP109_22593* Stonewall Tap-Tupelo Tap 138kV (WFEC) ftlo Seminole-Pittsburg 345kV (CSWS-OKGE)
TMP151_23193 Oakland East Switch-Joplin Atlas Junction 161kV ftlo Asbury Plant-Purcell Southwest 161kV (EDE)
TAHH59MUSFTS* Tahlequah-Highway 59 161kV ftlo Muskogee-Fort Smith 345kV (GRDA-OKGE)
TMP270_23432 Cleveland-Cleveland AECI 138kV (GRDA-AECI) ftlo Cleveland-Tulsa North 345kV (GRDA-CSWS)
TMP228_22196 Hale County-Tuco 115kV ftlo Swisher County-Tuco 230kV (SPS)
TMP127_23359 Scotsbluff-Victory Hill 115kV (NPPD) ftlo Stegall Xfmr 345kV/1 (WAUE)
TMP322_23590 Stonewall Tap-Tupelo Tap 138kV (WFEC) ftlo Sunnyside-Terry 345kV (CSWS-OKGE)
SMOSUMMULCIR Smokey Hills-Summit 230kV (WR) ftlo Mullergren-Circle 230kV (WR-SECI)
** SPP market-to-market flowgate*

The most congested flowgate over the past 12 months has been Vine Tap-North Hays 115kv for the loss of Post Rock-Knoll 230kV, displacing the Neosho-Riverton 161 kV for the loss of Neosho-Blackberry 345 kV constraint. The Vine Tap-North Hays 115kV flowgate (VINHAYPOSKNO) has been highly congested up through November 2018, but an upgrade was energized in this area in early December. Vine Tap-North Hays 115kV continues to appear with congestion after the upgrade, but now appears on the Knoll 230/115kV transformer (VINHAYKNOXFR) constraint.

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.

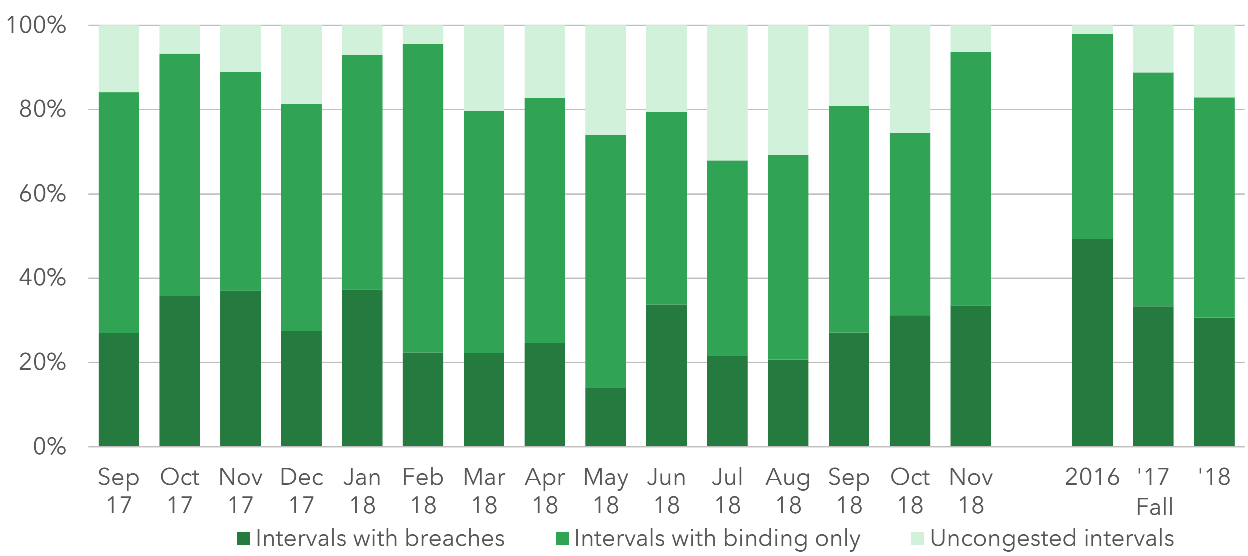
The figures below show the percent of intervals by month that had at least one breach, had only binding flowgates (but no breaches), or had no flowgates that were breached or binding (uncongested) in both the day-ahead (Figure 5–3) and real-time (Figure 5–4) markets.

Figure 5–3 Congestion by interval, day-ahead



Typically, in the day-ahead market over 99 percent of all intervals have only binding constraints, with uncongested intervals and intervals with a breach making up just a fraction of all intervals.

Figure 5–4 Congestion by interval, real-time



Overall, real-time market congestion decreased from the last fall period, with nearly 20 percent of intervals having no congestion in fall 2018, up from 16 percent in fall 2017, and two percent of all intervals in fall 2016. Intervals with a breach in the real-time market remained fairly consistent from fall 2017 to 2018 with around 15 percent of all intervals having breaches. These figures are down from fall 2016, when nearly 50 percent of all real-time intervals had at least one breached flowgate. The Woodward – Tatonga – Matthewson 345kV project, which was completed in February 2018, has helped reduce congestion in the western portion of the footprint. Another reason for a reduction in breaches compared to earlier periods could be the change to violation relaxation limits in March 2017 which allowed the market to solve at a higher shadow price before relaxing a constraint limit.

5.2 TRANSMISSION CONGESTION RIGHTS MARKET

During the fall 2018 quarter, the MMU observed the following highlights in the transmission congestion rights market:

- Financial only and non-load-serving market participants hedged more effectively than load-serving market participants. However, the hedging effectiveness of load-serving market participants did improve over their fall 2017 position by nearly $23 million.

- Among the market participants who own auction revenue right (ARR) entitlements, roughly 60 percent did not fully offset their congestion cost. Within this group, the bottom five participants collectively paid $18 million more in congestion than they offset through SPP's congestion hedging markets.

- The transmission congestion right (TCR) shortfall improved, decreasing 24 percent, against fall 2017. Additionally, the TCR funding percentage was unchanged when compared to the previous fall quarter.

- The daily observations of TCR funding greater than 150 percent increased from zero to three. The magnitude of the overfunding associated with these events is almost 4 times the average overfunding event from the quarter.

- ARRs remain overfunded; however, the overfunding has decreased from $30 million in fall 2017 to $28 million in fall 2018.

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

Figure 5–5 Total congestion payments, fall

(in $ millions)	Load-serving entities			Non-load-serving and financial only entities		
	2016 Fall	2017 Fall	2018 Fall	2016 Fall	2017 Fall	2018 Fall
DA congestion	103.5	111.9	102.9	30.8	72.7	41.7
RT congestion	4.1	13.3	(3.3)	(27.5)	(56.5)	(25.6)
Net congestion	107.6	125.2	99.6	3.3	16.1	16.2
TCR charges	9.9	49.6	64.1	19.8	43.5	43.4
TCR payments	(82.1)	(104.9)	(95.7)	(60.8)	(102.8)	(66.6)
TCR uplift	7.0	10.7	9.5	6.0	13.8	10.6
TCR surplus *	(2.0)	(0.6)	(1.1)	(2.1)	(0.8)	(1.3)
ARR payments	(16.3)	(58.0)	(75.2)	(1.4)	(5.2)	(4.8)
ARR surplus	11.2	27.4	25.4	0.8	1.6	2.1
Net TCR/ARR	(72.3)	(75.8)	(73.0)	(37.7)	(49.9)	(16.6)

* *remaining at period end*

During fall 2018, load-serving entities earned $73 million in congestion payments. These payments did not exceed their day-ahead congestion cost of $103 million. Real-time congestion costs aided load-serving entities, reducing the total congestion cost to $100 million. When compared to fall 2017, the 2018 shortfall between congestion payments and total congestion costs decreased by 46 percent, from nearly $50 million to $27 million.

The shortfall between the congestion payments and the day-ahead congestion cost shows that overall, for the quarter, load-serving entities did not fully hedge congestion through the congestion hedging market. However, the effectiveness of the positions will ultimately be evaluated over the full course of the 2018 TCR year. Moreover, day-ahead congestion costs for load-serving entities decreased 8 percent when compared to fall 2017.

Additionally, non-load-serving and financial-only entities collected congestion payments of $17 million. These payments did not exceed their $42 million in day-ahead congestion costs. However, real-time congestion costs aided non-load-serving and financial-only entities, reducing their total congestion cost to $16 million. This shows that overall, non-load-serving, and financial-only entities were relatively effective at hedging congestion through the transmission congestion right market, but that they collectively did not gain compared to previous periods.

Figure 5–6 shows, by market participant,[8] the day-ahead congestion exposure along with the value of all congestion hedges, as well as the net overall position.

Figure 5–6 Net congestion revenue by market participant, fall

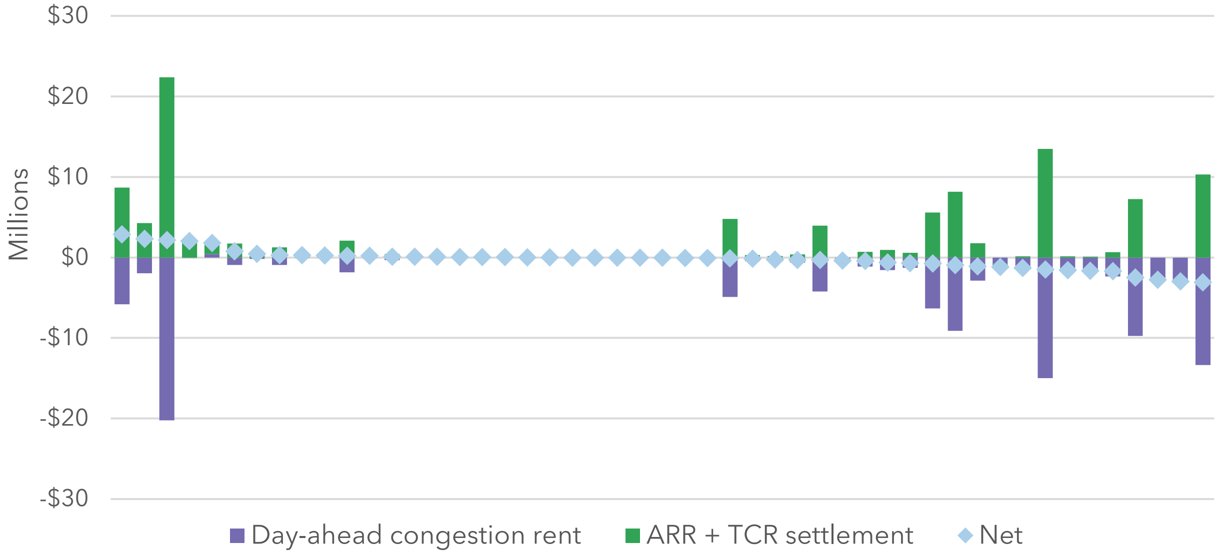


Figure 5–6 highlights that 43 percent of participants received positive net revenues, while 57 percent of participants held hedges that did not cover their day-ahead congestion costs. The bottom five participants collectively paid $13 million more in congestion costs than was offset by their auction revenue right and transmission congestion right positions.

Figure 5–7 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.

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

Figure 5–7 Net congestion revenue by market participant, fall

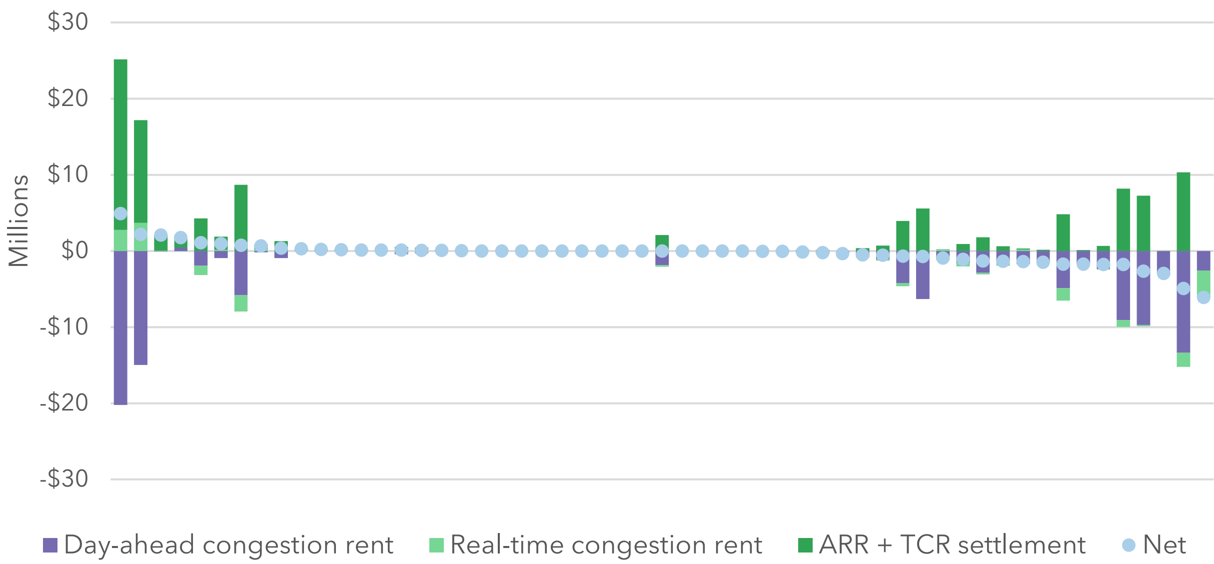
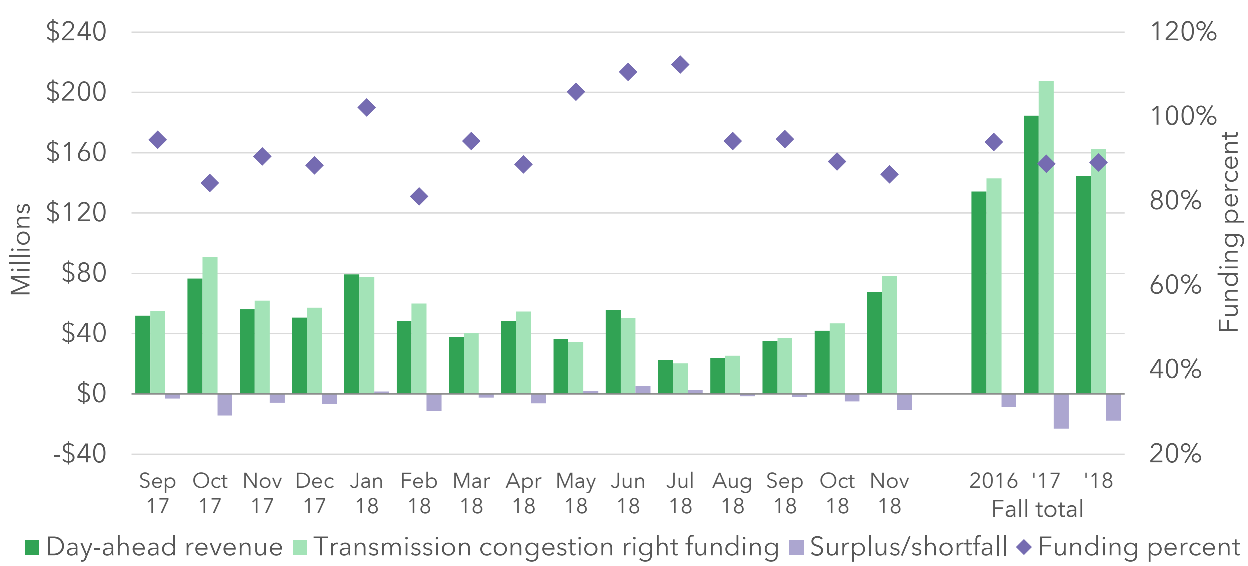


Figure 5–7 highlights that 41 percent of participants received positive net revenues, while 59 percent of participants held hedges that did not cover their total congestion costs. The bottom five participants collectively paid $18 million more in congestion costs than was offset by their auction revenue right and transmission congestion right positions.

Figure 5–8 below shows transmission congestion right funding, day-ahead revenue, net surplus/shortfall, and transmission congestion right funding percent.

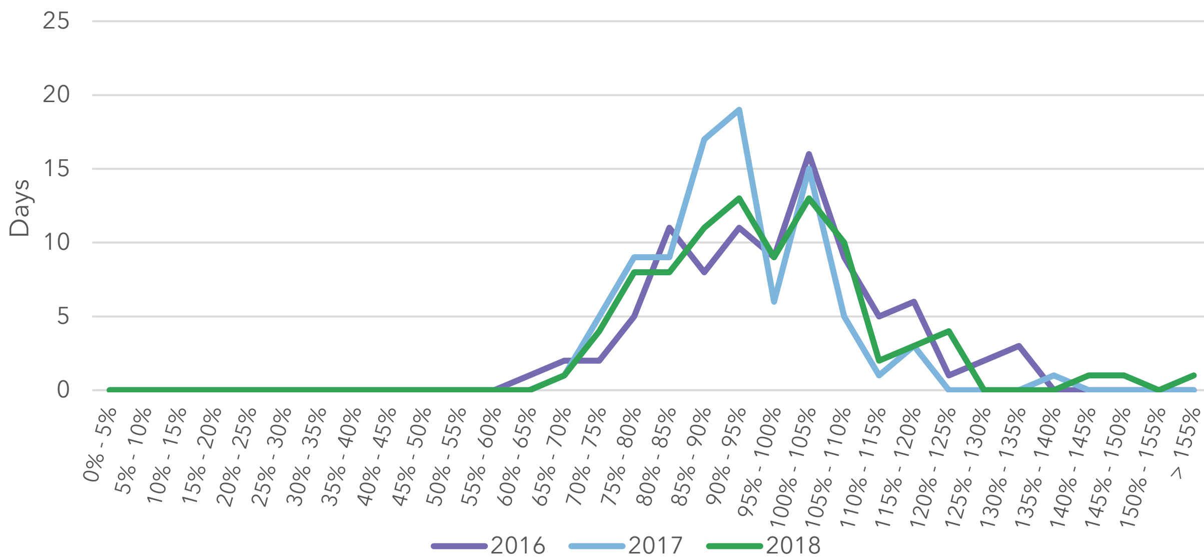
Figure 5–8 Transmission congestion right funding



Transmission congestion right funding levels fell short of the target range[9] in two of the quarter's three months. Overall, the fall 2018 monthly funding of 89 percent is similar to fall 2017 results. Furthermore, the fall 2018 funding deficit decreased 24 percent from 2017 levels and stands at negative $18 million for the quarter.

Daily observations of transmission congestion right funding for the 2016, 2017, and 2018 fall periods are shown in Figure 5–9.

Figure 5–9 Transmission congestion right funding, fall



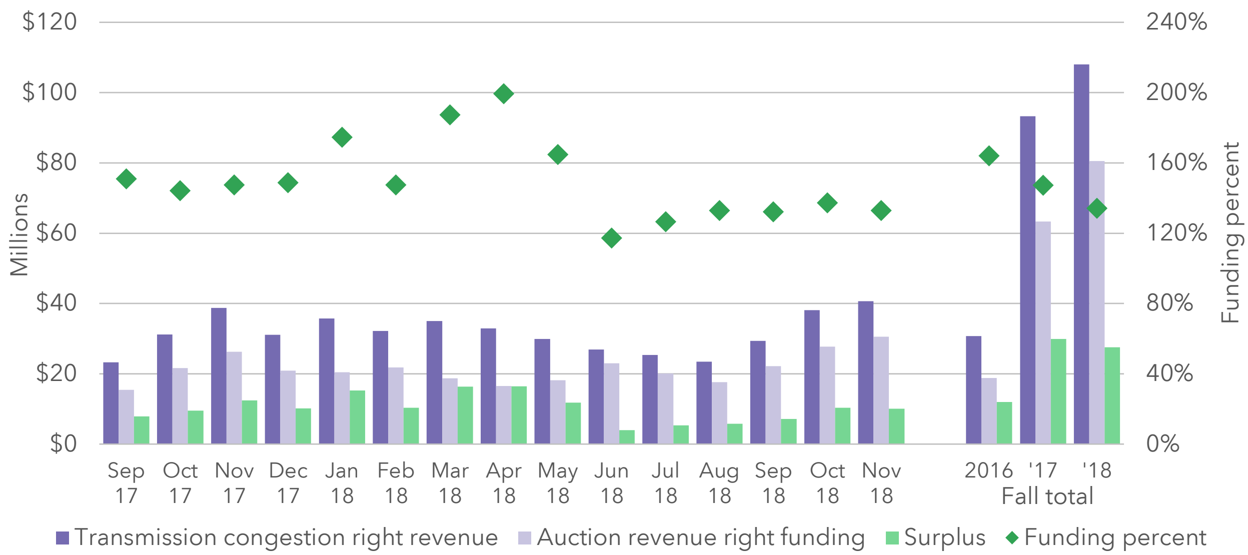
Most daily observations of transmission congestion right funding fall between 80 percent and 120 percent over the 2018 fall quarter.[10] However, the funding distributions have shifted noticeably toward higher percentages over the last two fall quarters. In fall 2018 we observed an increase in significant over-funding events. The number of events where funding exceeded 150 percent increased from zero to three. Furthermore, the magnitude of the overfunding associated with these events is roughly four times the average. While these cases are extreme, the fact that the majority of funding falls within or near the target range indicates that the overall process is generally effective.

Figure 5–10 shows transmission congestion right revenue, auction revenue right funding, net surplus, and auction revenue right funding percent.

[9] Target range is implied in the Protocols section 5.3.3. "In the event the cumulative funding is at or below 90% or above 100%, MWG may approve an additional adjustment…"

[10] Seventy-six percent of the fall 2018 funding observations fell within this range.

Figure 5–10 Auction revenue right funding



Auction revenue right funding percentages remained stable over the fall 2018 quarter, but decreased when compared to the related period in 2017. However, the magnitude of the auction revenue right surplus correlates and trends strongly with the fall 2017 surplus.

The fall 2018 quarterly funding percentage decreased from 147 percent to 134 percent. The related surplus dollars have also decreased from $30 million to $28 million. The fall 2018 funding percentage is also down relative to the fall 2016 quarter where funding exceeded 164 percent. Even though the funding percentage has fallen over the last few years, the fall 2018 surplus more than doubled relative to the 2016 surplus. The increase in the current surplus over the fall 2016 surplus is largely due to the growth in funding dollars between the two periods.

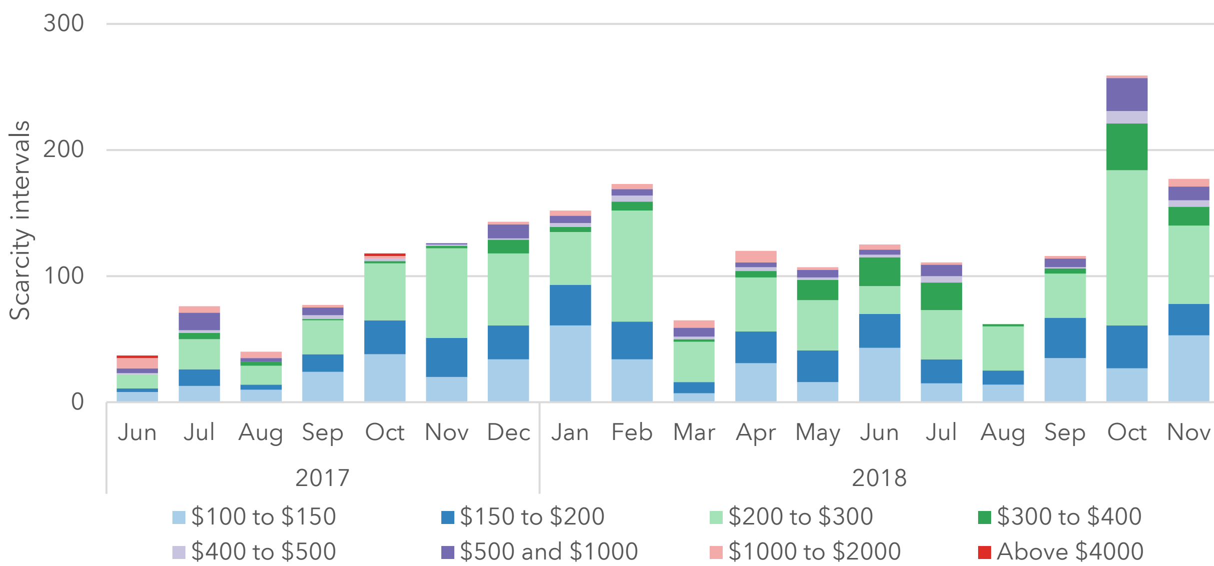
6. SPECIAL ISSUES

Scarcity

October and November 2018 had a large increase in the number of price spikes, both in the energy and ancillary service markets, contributing to an overall increase in market prices. The increase in price spikes due to scarcity can primarily be attributed to higher volatility in wind output, along with unplanned generator outages or derates.

Figure 6–1 below shows the marginal energy component of interval prices above $100/MWh and counts the number of price spikes in each group.

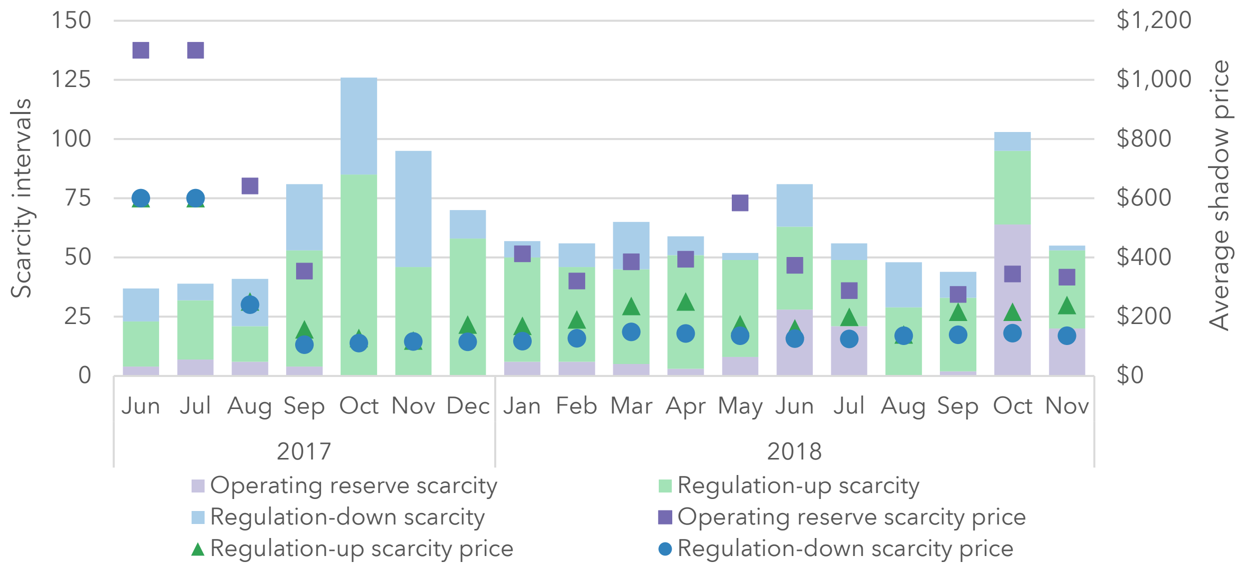
Figure 6–1 Marginal energy component price spikes (count of intervals)



This chart begins in June 2017, as this was the first full month after SPP started pricing ramp scarcity events. As shown in the chart, October and November 2018 had a large increase in price spikes, particularly in the $200 to $400 range. October also had 26 price spikes in the $500 to $1,000 range. This was over three times the historical monthly average for that price range.

Figure 2 below shows the count of scarcity intervals for each month for the three scarcity types – operating reserve, regulation-up, and regulation-down.

Figure 6–2 Scarcity events and shadow prices



As shown on the chart, October is usually a high month for scarcity events, particularly for regulation up and down. However, October 2018 had an unprecedented number of operating reserve scarcity events. The chart shows that regulation-up and regulation-down scarcity events for this quarter were slightly less than the last quarter of 2017. However, there were 64 intervals with operating reserve scarcity in October 2018, which is six times the prior month's average of 10 intervals of operating reserve scarcity. The October 2018 operating reserve scarcity events intervals had an average shadow price of $345.

Regulation-up and regulation-down scarcity events in October 2018 decreased by more than half when compared to October 2017. However, those events have smaller impacts on ancillary service and energy prices than the operating reserve scarcity events. For instance, regulation-up and regulation-down products have six separate price points and operating reserves only have three price points. In October 2018, the lowest scarcity price for both regulation products was $144 and the highest was $600. These were much lower than the October operating reserve prices that started at $275 and went to $1,100. These higher shadow prices directly affect both energy and ancillary service prices when scarcity events occur.

Typically, scarcity intervals are driven by ramp shortages among the various energy and reserve products. For example, assume the market needs 30 megawatts of additional regulation-up for an interval ten minutes in the future. Now assume that the resources online have an additional 80 megawatts of available capacity for regulation-up. With just these two assumptions in place, there would be no scarcity event, as there is adequate capacity to meet the requirement. However, the units' ramp constraints must be taken into consideration. If the two units with available regulation-up only have ramp rates of one megawatt per minute, the market will be short ten megawatts.[11]

SPP uses violation relaxation limits (VRL) for energy ramp scarcity events and spinning reserve scarcity events. The VRL limit for spinning reserve redispatch is capped at a cost of $200 and ramp shortages for energy are capped at $5,000. These caps are used to put a ceiling on the redispatch cost associated for procuring products. For example, if the market has a requirement of 600 megawatts of spinning reserve, the market clearing engine will attempt to redispatch the system until it either meets the requirement or the redispatch cost reaches $200. If the redispatch cost reaches $200 and the market could only provide 550 megawatts, then the original requirement is relaxed from 600 megawatts down to 550 megawatts. The market clearing engine then resolves using the new relaxed requirement that it is able to meet within the associated cost limit.

Ramp shortages for energy are rare because SPP allows for energy to borrow ramp from the reserve products. In fact, SPP has only had 11 energy ramp scarcity events since the market started pricing ramp shortages. However, four of those events happened in the month of October 2018 and one happened in November 2018.

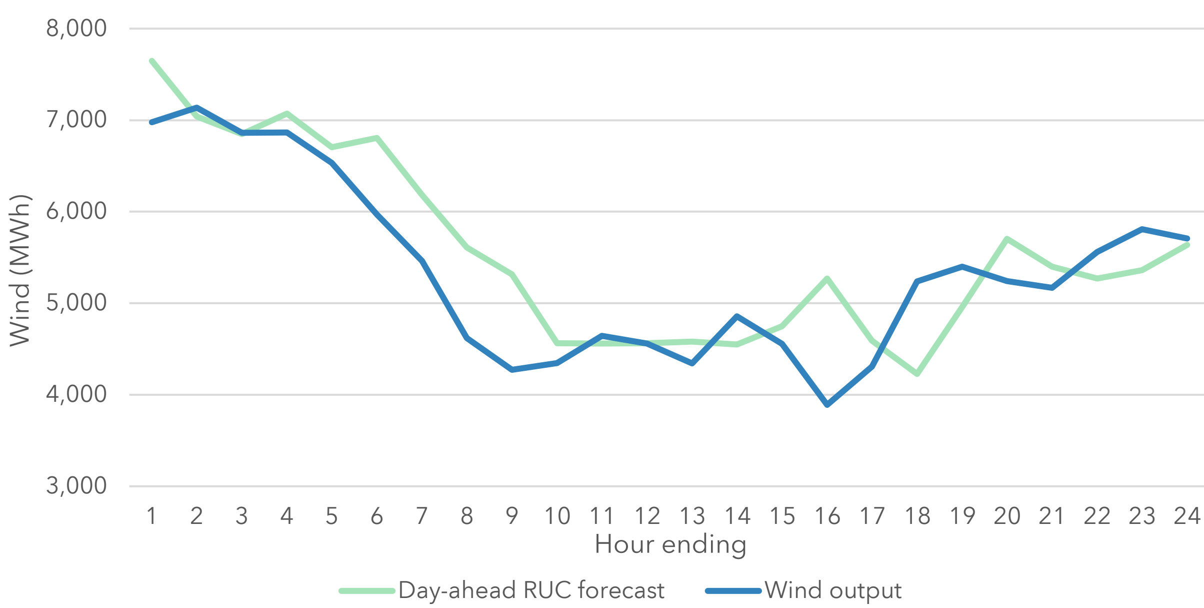
The causes for the uptick in price spikes and scarcity events appear to be a combination of multiple factors. One of the main causes appears to be an increase in mid-term and long-term wind forecast errors. When large wind dips are not accurately forecasted the market will often be short ramp-able capacity, causing SPP operators to take manual action to get more capacity online. The long-term wind forecast is used for forecasting wind output for the day-ahead reliability unit commitment process. This forecast had an average error rate of 7.8 percent in 2018, which is 87 percent higher than the 2016 average of 4.3 percent. The mid-term load forecast is used four hours ahead of the intra-day reliability unit commitment processes. This forecast had an average wind forecast error of 4.5 percent in 2018, which was 28 percent higher than the 2016 average of 3.5 percent.

[11] (1MW/min*10min*2 units) – (30 megawatt need) = –10 megawatt (shortage)

In addition to the wind forecast errors, there was a large jump in natural gas spot prices. The spot index price for natural gas at the Panhandle hub increased 72 percent between September and October from $2.13/MMBtu to $3.67/MMBtu. The gas price increase can increase the amount of the scarcity events because redispatch costs go up quicker with the more expensive fuel until scarcity occurs. Since the scarcity caps are priced-based they are reached more frequently due to increased gas prices.

The highest energy price in the fourth quarter happened on September 3 at 2:40 PM central time. During this interval, the real-time marginal energy price was $1,575/MWh. The reason for the scarcity event on this day appears to be a large dip in wind, coupled with the unplanned derate of a large generator. Figure 6–3 compares the wind forecast used for the day-ahead reliability unit commitment process to the actual wind output.

Figure 6–3 Wind output versus day-ahead RUC wind forecast, September 3



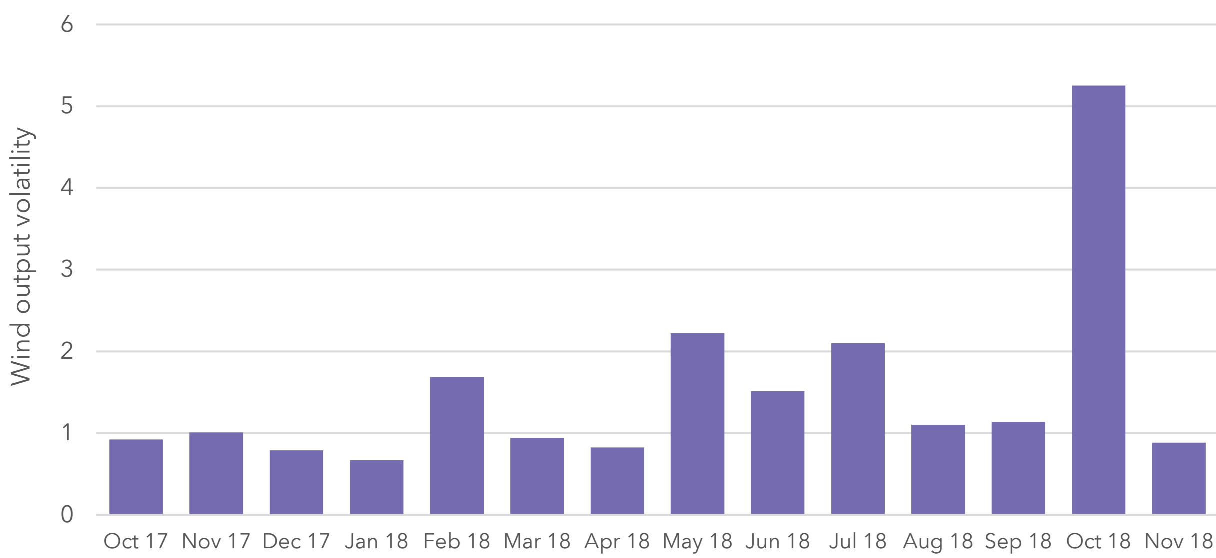
In the latter half of hour ending 14, the wind took a sudden drop that was not forecasted. This unanticipated wind drop appears to be the main driver for the scarcity event in the intervals to follow. The operators took corrective action by adjusting the load offset and manually committing quick start units. Prices began quickly dipping but took three more intervals to get back below $100.

These sudden wind dips are typical drivers of scarcity events. However, the MMU has observed that it typically takes more than a single wind dip to cause a ramp scarcity event.

Other factors are often at play when these ramp scarcity events occur. One common scenario is the combination of a large unit trip or derate along with a sudden drop in wind output.

A major reason for the wind errors in October had do with the volatility of wind output during that month as shown in Figure 6–4. This chart shows the coefficient of variation (standard deviation divided by average) of the change in hour-to-hour wind output.

Figure 6–4 Volatility of wind output



This metric can be used to illustrate how much the wind is shifting from hour to hour each month, thus making it harder to forecast. October 2018 was by far the most volatile month, with more than double the next highest month's volatility during the last 14-month period.

While there is no current answer for better forecasting the fluctuating nature of wind, having a ramp product could help abate these price spikes. By reserving ramp for unexpected conditions, such as wind drops or unit trips, the market will be better positioned when these events occur. SPP is currently designing a ramp product with its stakeholders. The MMU is in agreement with these efforts and fully anticipates it will help reduce the frequency and impacts of these price spikes.

Frequently Constrained Area Process

The frequently constrained area process has improved to implement changes in frequently constrained areas in a more timely manner when indicated by the MMU's analysis. Stakeholders approved revision request 304 (Accelerate Frequently Constrained Area Process) and this was accepted by FERC on December 20, 2018.[12]

The MMU's analysis uses historical real-time data to identify areas with frequent congestion and recommends changes to stakeholders. The previous process required these changes proceed through the stakeholder process, including Board approval, followed by a Tariff filing with FERC because these frequently constrained area designations were specifically listed in the SPP tariff.

This process could delay the removal or addition of areas identified in this analysis, creating situations where resources could be subject to a tighter conduct threshold for energy offers after initially being proposed for removal. Conversely, resources in newly identified areas are not subject to this tighter threshold during the approval process, which would typically take five to six months.

Under the improved process, the MMU will apply the same concepts stated in Section 3.1.1 of Attachment AF[13] in its analysis. Following this analysis, the MMU will notify market participants of identified changes, allowing them to have 14 days to respond with questions or concerns regarding the proposed changes. This improvement will accelerate the implementation time after the analysis from five or more months to about two weeks, thus applying the appropriate mitigation thresholds in a timely manner.

[12] http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20181220-3042

[13] Tariff Attachment AF, Section 3.1.1 states that a frequently constrained area is "expected to be binding for at least five-hundred (500) hours during a given twelve (12)-month period and within which one (1) or more suppliers are pivotal."