Southwest Power Pool
Market Monitoring Unit

State of the Market
Winter 2018

published
May 1, 2018

TABLE OF CONTENTS

LIST OF FIGURES

1. MARKET PERFORMANCE HIGHLIGHTS

This report covers market performance during the winter quarter of 2018 (December 2017 through February 2018). The annual figures shown on the charts in this report represent only this three-month period for each year, unless labelled otherwise. Highlights of this winter period are as follows:

- During winter 2018, the average day-ahead and real-time prices were $24.07/MWh and $25.69/MWh, respectively. The day-ahead price for winter 2018 was only ten cents lower than winter 2017, while the winter 2018 real-time price was about five percent higher than winter 2017.
- Average monthly gas cost at the Panhandle Eastern hub averaged $2.64/MMBtu for winter 2018, down from $3.08/MMBtu in winter 2017, a 14 percent decrease. In January 2018, the gas cost spiked to $3.23/MMBtu, but then declined to $2.22/MMBtu in February.
- Occurrences of negative price intervals continues to increase, with winter 2018 levels higher than previous years.
- The hourly average load for winter 2018 was up nearly seven percent from winter 2017. While December 2017 was at a very similar level to the prior year, January and February 2018 average loads were nearly 11 percent higher than the previous year. This increase is primarily driven by lower than normal temperatures during January and February.
- Average monthly real-time generation increased by seven percent from winter 2017 to winter 2018. Generation by coal-powered resources continued the downward trend, accounting for only 46 percent of energy produced in the winter 2018 period. During this same period, wind resources accounted for 26 percent of total generation.
- During winter 2018, the day-ahead wind capacity factor was 36 percent. This increased to 46 percent in the real-time market. The disparity between day-ahead and real-time capacity factors contributes to the increase in negative price intervals.

- High levels of congestion continue on the Neosho – Riverton constraint in southwest Missouri/southwest Kansas, which is a market-to-market flowgate that is impacted by SPP and MISO wind, as well as flows from neighboring non-market areas.

- Virtual transactions as a percent of load continue to increase, nearly doubling from winter 2016 to winter 2018.

- Several notable events occurred during the winter 2018 period. These are discussed in more detail in the special issues section of this report.

    - A new wind peak of 15,690 MW of wind production was set on December 16, 2017.

    - High natural gas prices (around $65/MMBtu) occurred at the Ventura pipeline during December 27-29, 2017.

    - SPP set a new winter peak on January 17, 2018, with load peaking at nearly 43,000 MW during hour ending 0700.

    - Wind turbines experience icing conditions during February 19-21, 2018, causing large errors in wind forecasts.

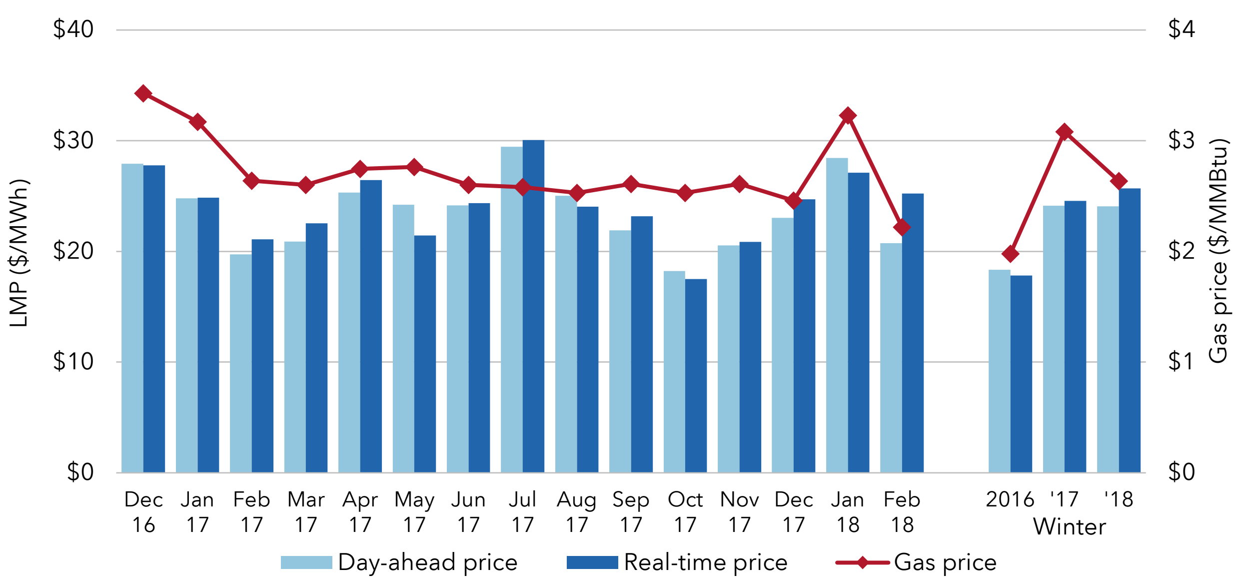
2. PRICES AND MARKET COSTS

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. Average gas prices had been relatively stable with average monthly prices at the Panhandle Eastern hub ranging between $2.50 and $2.80/MMBtu since February 2017. In January 2018, gas prices rose to $3.23/MMBtu, a 30 percent increase from December 2017. The gas price dropped by 30 percent from January to February 2018. For the winter period, gas prices dropped by 14 percent overall, from $3.08/MMBtu in 2017 to $2.64/MMBtu in 2018.

During winter 2018 the average day-ahead price was $24.07/MWh, and the average real-time price was $25.69/MWh, as shown in Figure 2–1. The winter 2018 day-ahead price of was nearly identical to the $24.14/MWh in 2017. The real-time price for winter 2018 was $25.69/MWh, about five percent higher than winter 2017.

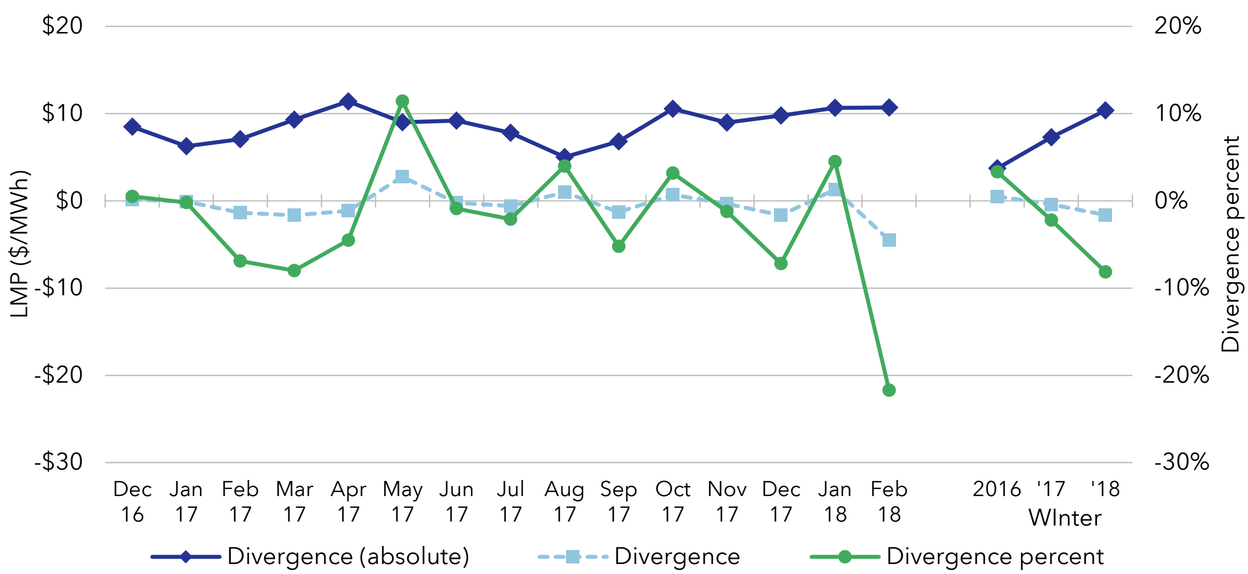
Figure 2–1 Electricity and gas prices



As mentioned earlier, periods of divergence will occur between electricity and gas prices. This was true when comparing winter 2017 and 2018 results, as gas prices decreased by 14 percent, day-ahead electricity prices were virtually unchanged, and real-time electricity prices rose by five percent. The major driver in the divergence was higher gas prices in December 2016, which were nearly $1/MMBtu above December 2017 levels.

Figure 2–2 shows the day-ahead to real-time price divergence at the SPP system level. Price divergence[1] 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. The absolute divergence is calculated by taking the absolute value of the divergence for each interval.

Figure 2–2 Price divergence, day-ahead and real-time

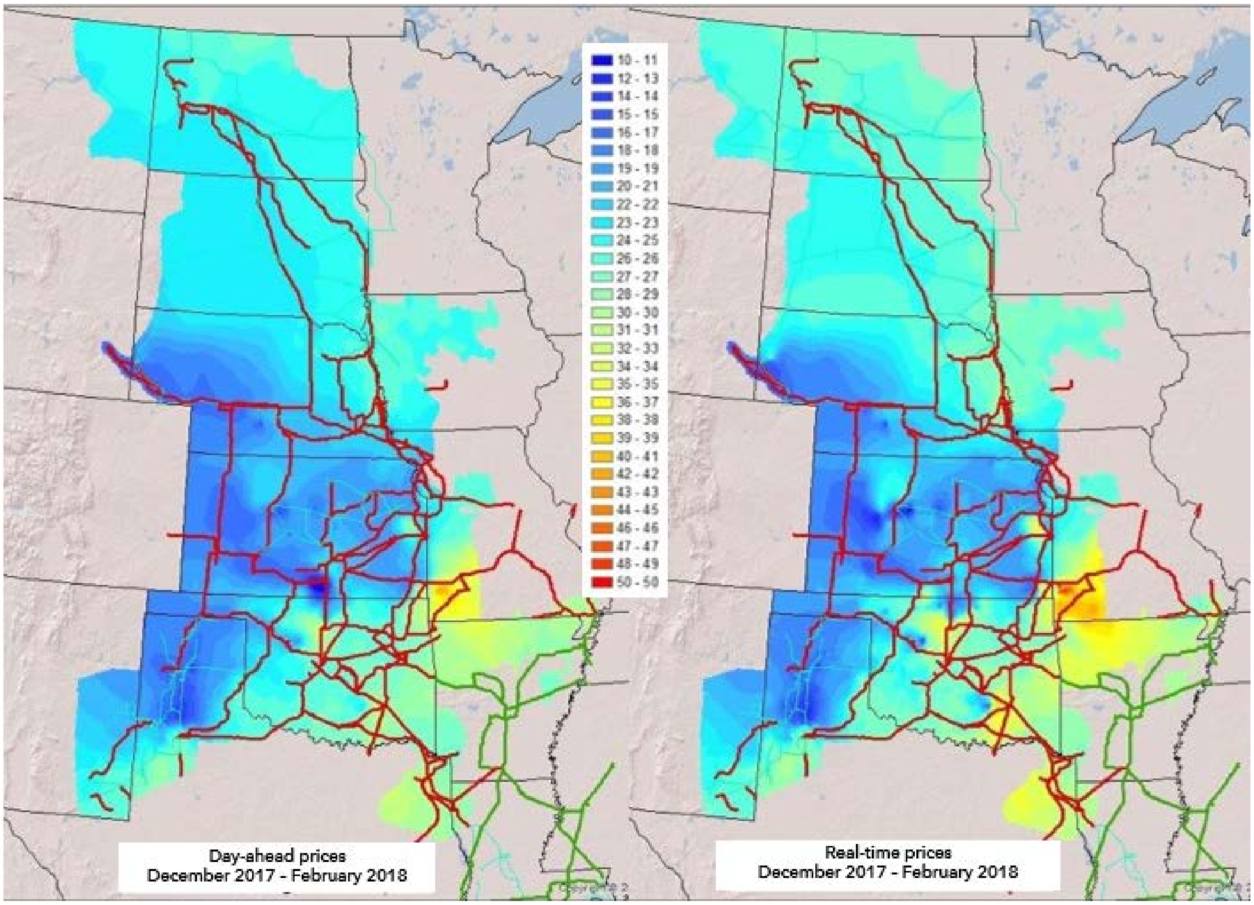


While divergence and divergence percent fell on a year-to-year basis, absolute divergence has been climbing, indicating increasing levels of volatility in prices. At nearly 22 percent, the percent of price divergence for February 2018 is the highest ever experienced in the market.

Even with the large price divergence, the overall price patterns between the day-ahead and real-time markets are similar, as shown on the price contour map below in Figure 2–3. Blue represents lower prices and red represents higher prices. Significant color changes across the map signify constraints that limit the transmission of electricity from one area to another.

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

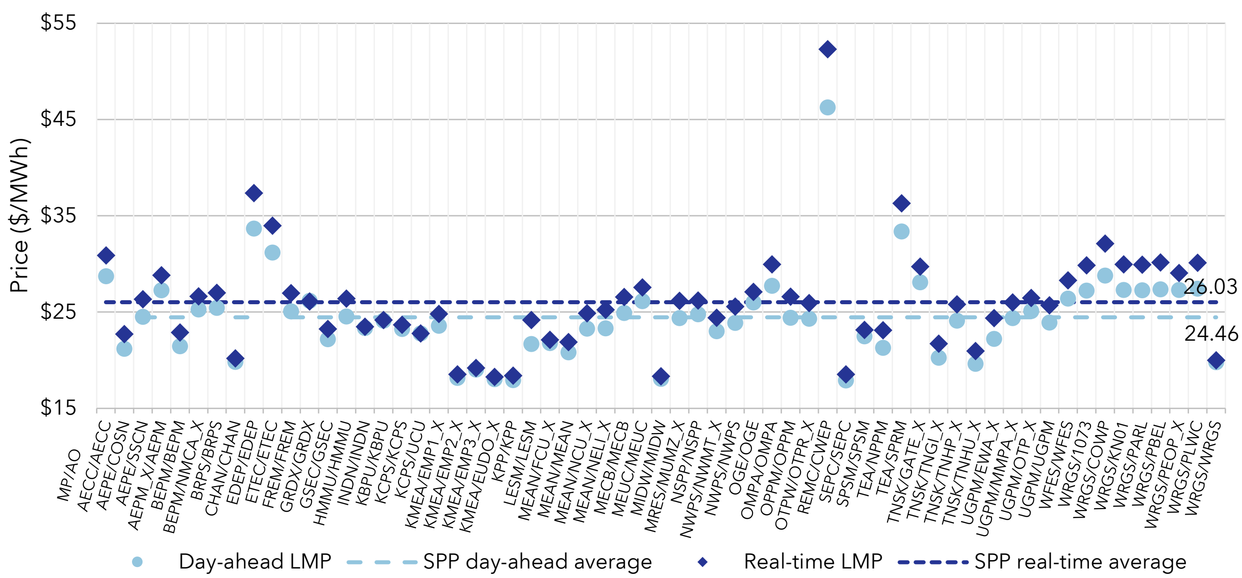
Figure 2–3 Price map, winter (all hours)



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. Historically, the areas seeing the highest congestion and thus the highest average prices, include the area south of the Texas panhandle, northwest Oklahoma near Woodward, and northwest Kansas near Hays. Lately, the areas with highest congestion have shifted to the southwest Missouri/southeast Kansas region, central Oklahoma, and the Ark-La-Tex region (southwest Arkansas, northwest Louisiana, and northeast Texas). Factors that can influence congestion and resulting prices are transmission bottlenecks, generator and transmission outages, weather events, differences in fuel prices and cost of generation, and differences in temperatures across the footprint.

Figure 2–4 and Figure 2–5 display average prices paid by load serving entity for the winter period and the last twelve months. Unlike other periods, nearly all load-serving entities had higher real-time prices than day-ahead prices. This was primarily driven by higher real-time prices in January and February due to extensive use of the market-to-market MISO/SPP mechanism for congestion control during those months. In addition, a few days of real-time temperatures being colder than day-ahead expected temperatures in mid-January and mid-February, along with a wind event in late February contributed to the higher real-time prices. Weather events will be discussed more in chapter 6.

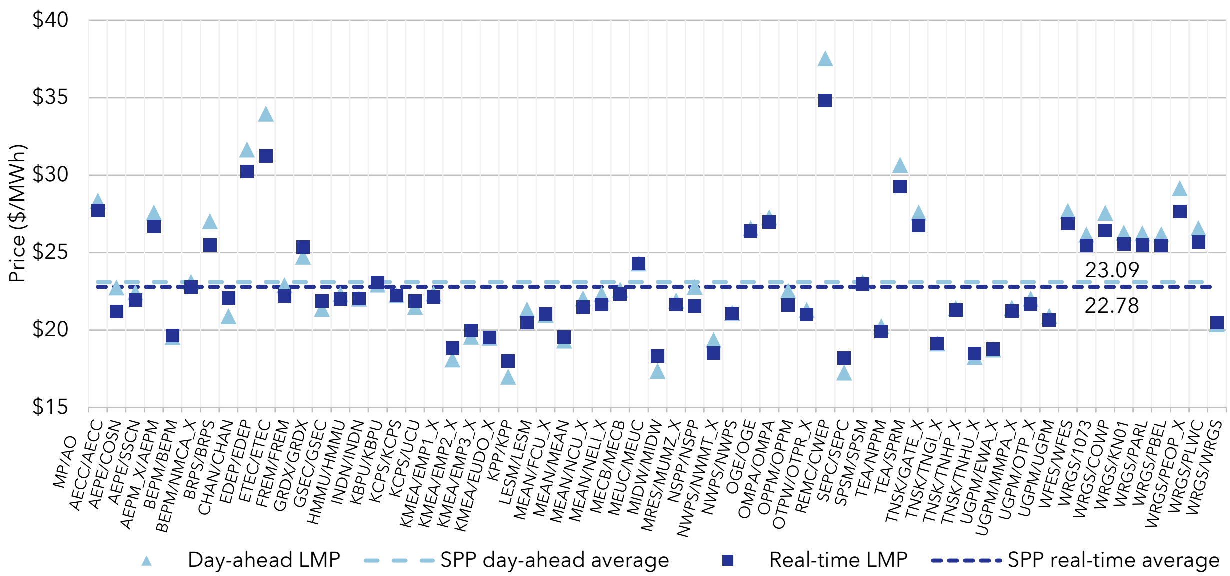
Figure 2–4 Price by load-serving entity, winter



Winter period average prices are the highest for City of Carthage, City of Springfield, and Empire District, all located in the tristate area discussed above. Average winter prices are lowest for Sunflower Electric, Kansas Power Pool, Midwest Energy, and portions of Kansas Municipal Energy Agency located in western Kansas.

High prices in the Missouri/Kansas/Oklahoma area can primarily be attributed to congestion on the NEORIVNEOBLC (Neosho-Riverton for the loss of Neosho-Blackberry) flowgate. Some reasons for congestion in this area are high levels of internal and external wind generation, and external north to south flow. Additionally, prices in this area rose when market to market congestion management with MISO was in effect.

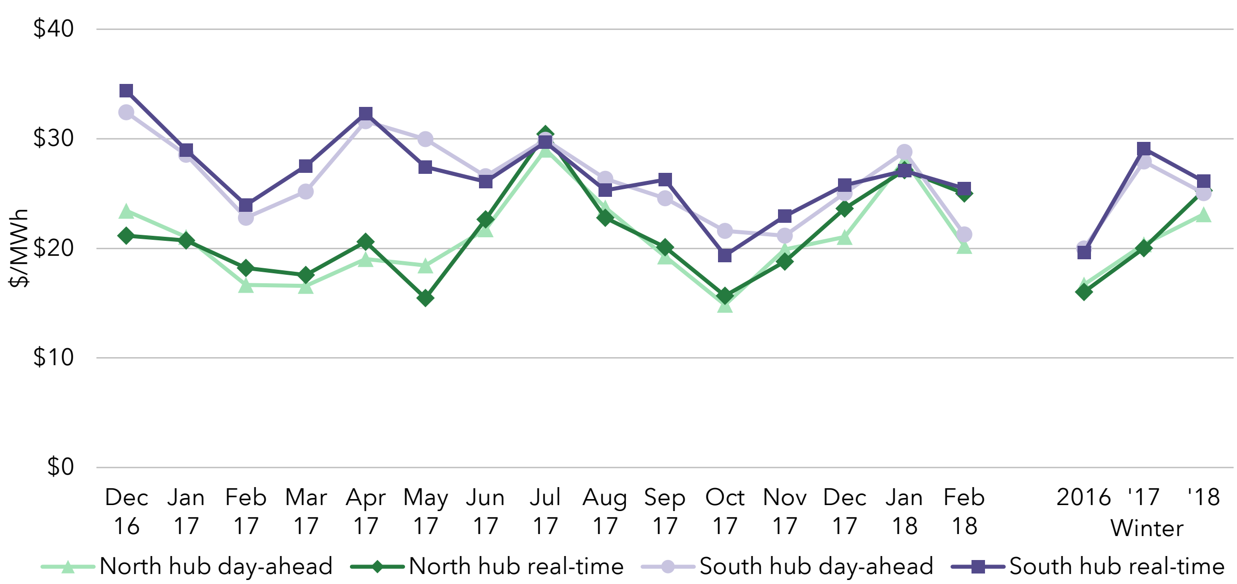
Figure 2–5 Price by load-serving entity, rolling 12 month



Average prices for the 12 month period have the more typical relationship between day-ahead and real-time prices, with day-ahead prices higher than real-time prices as shown in Figure 2–5.

Figure 2–6 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 2–6 Trading hub prices

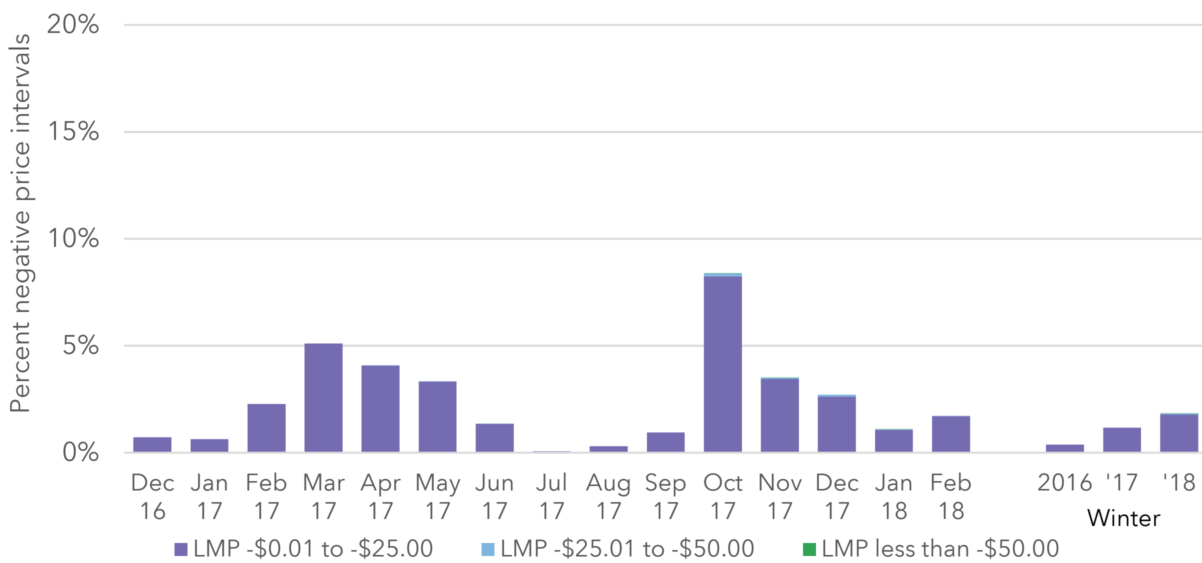


Because of an abundance of lower-cost generation in the northern part of the SPP footprint, prices at the North hub are typically lower than the South hub. As shown above, North hub prices were at similar levels as South hub prices in both July 2017 and January 2018. In winter 2017, the spread between the North and South hubs averaged around $8/MWh, and in winter 2018 that spread was just over $1/MWh.

Negative prices

With the continued growth of wind generation in the SPP market, the number of intervals with negative prices continues to increase as shown in Figure 2–7.

Figure 2–7 Negative price intervals, day-ahead, monthly

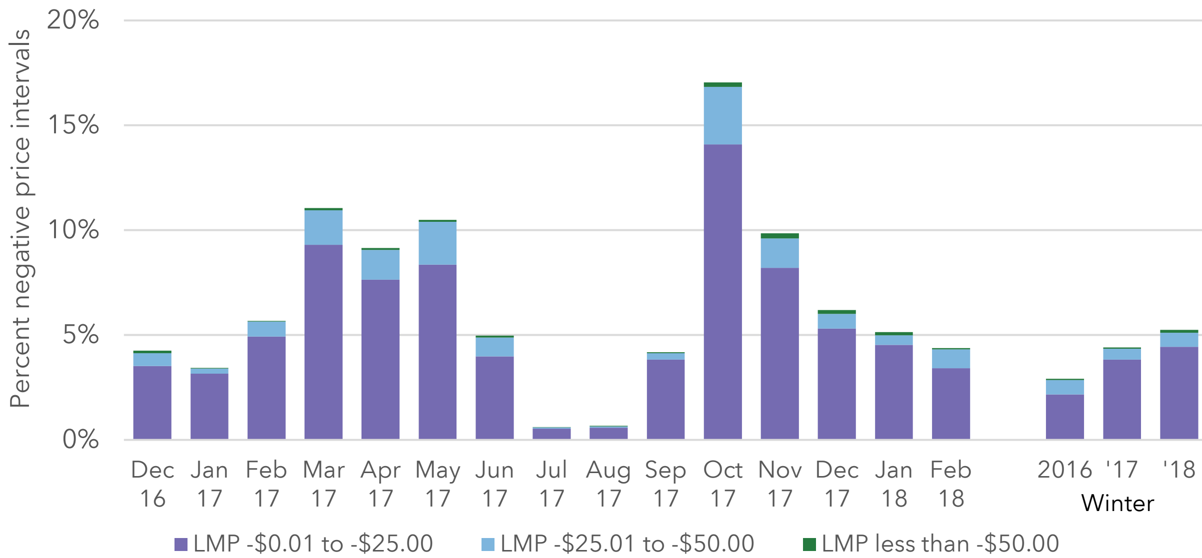


In winter 2018, 1.8 percent of all asset owner intervals[2] in the day-ahead market had prices below zero. This has grown from 0.4 percent of asset owner intervals in winter 2016, and 1.2 percent of asset owner intervals in winter 2017.

[2] 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).

While the same pattern holds in the real-time market (see Figure 2–8), the frequency of negative price intervals in the real-time market is nearly three times that of the day-ahead market.

Figure 2–8 Negative price intervals, real-time, monthly

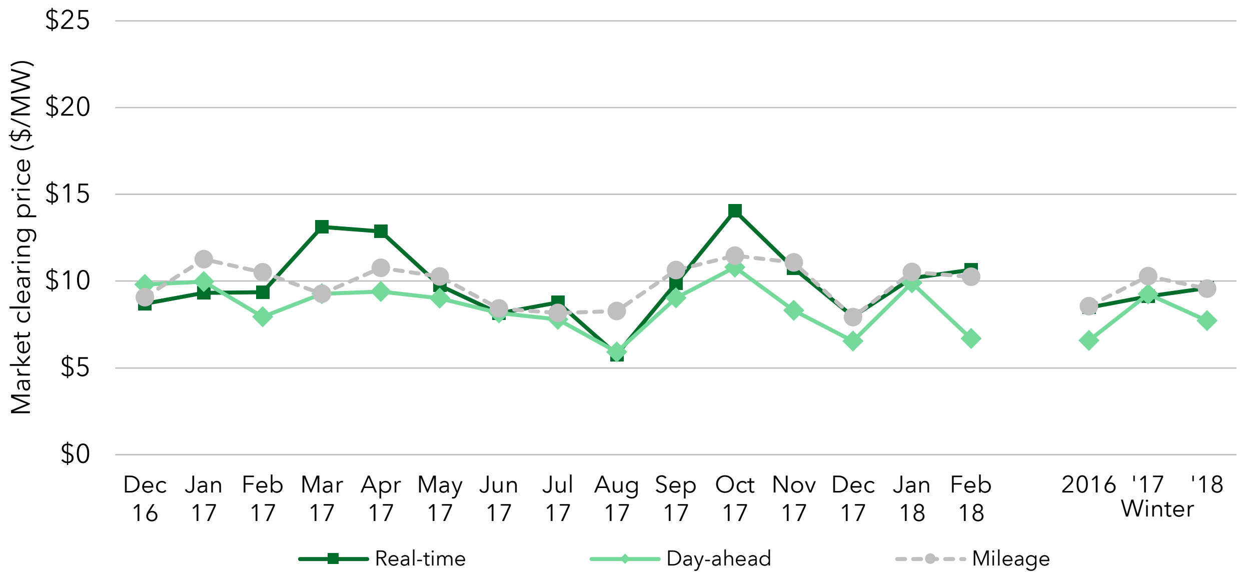


Winter 2018 had 5.3 percent of all asset owner intervals with negative prices, compared to 1.8 percent in the day-ahead market. Note that negative prices in the day-ahead market are almost exclusively between -$0.01/MWh and -$25/MWh, where in the real-time market a sizable number of intervals have prices lower than -$25/MWh.

Operating reserve market

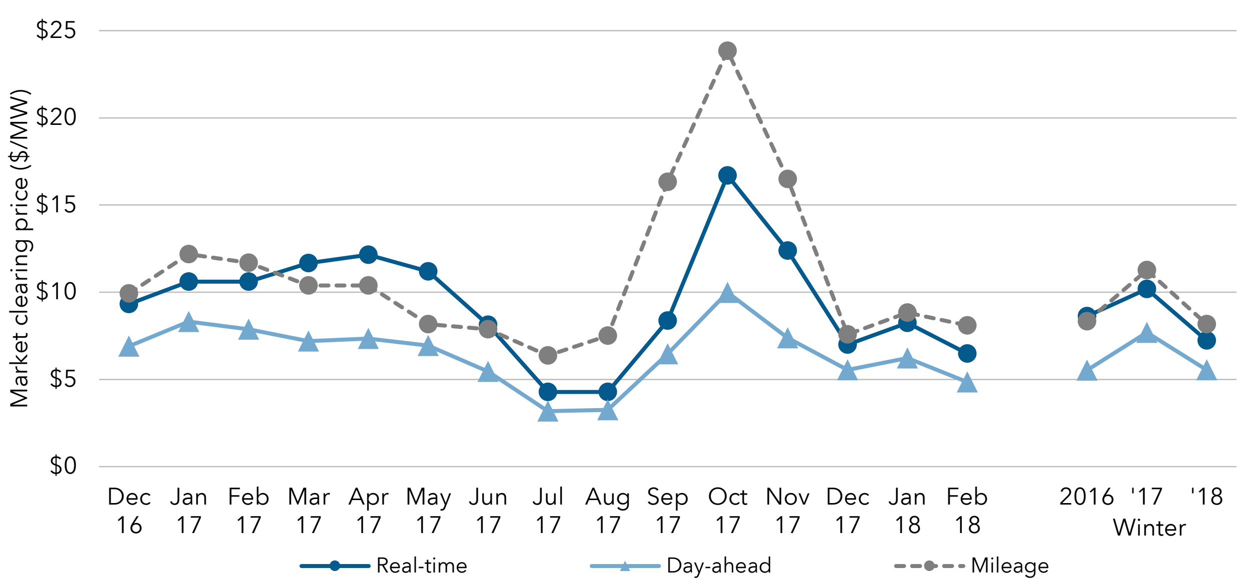
The following figures (Figure 2–9 through Figure 2–12) show marginal clearing prices for the four operating reserve products: (1) regulation-up, (2) regulation-down, (3) spinning reserve, and (4) supplemental reserve. The regulation products are used to ensure the amount of generation matches load on 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 2–9 Regulation-up prices



Regulation-up prices remain near levels observed in earlier periods, with real-time prices higher than day-ahead prices in winter 2018. December 2016 and January 2017 saw higher day-ahead regulation-up prices, compared to real-time regulation-up prices. This caused the average winter 2017 day-ahead regulation-up price to be slightly higher than the real-time price.

Figure 2–10 Regulation-down prices



After spiking in October 2017, regulation-down prices returned to more typical levels in winter 2018, averaging around $5.50/MW in the day-ahead market and about $7.25/MW in the real-time market.

Figure 2–11 Spinning reserve prices

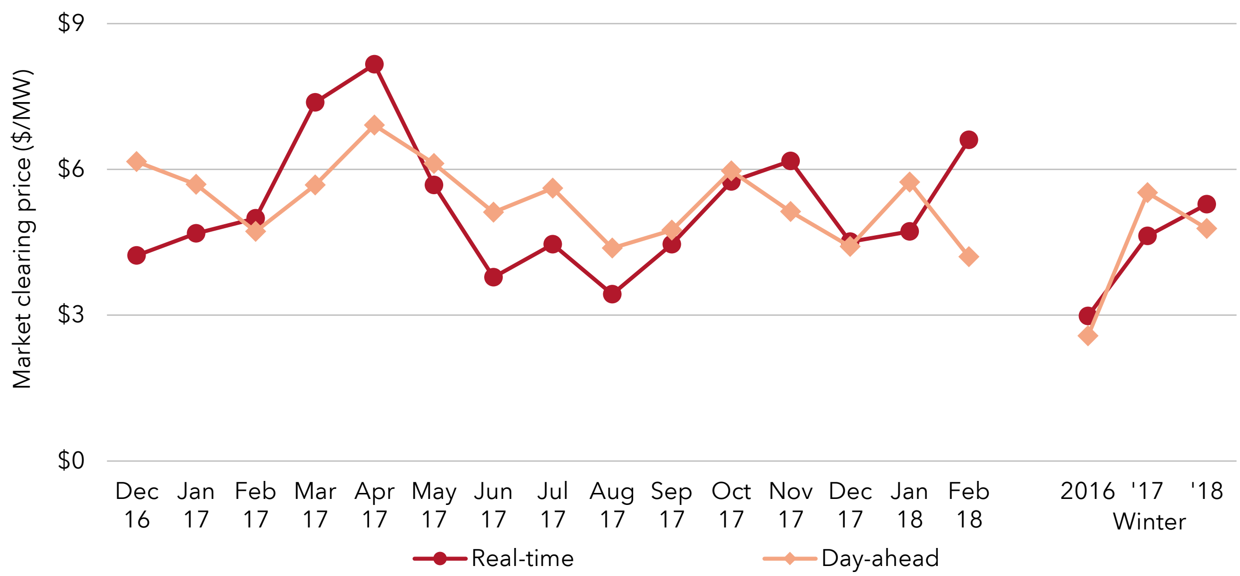
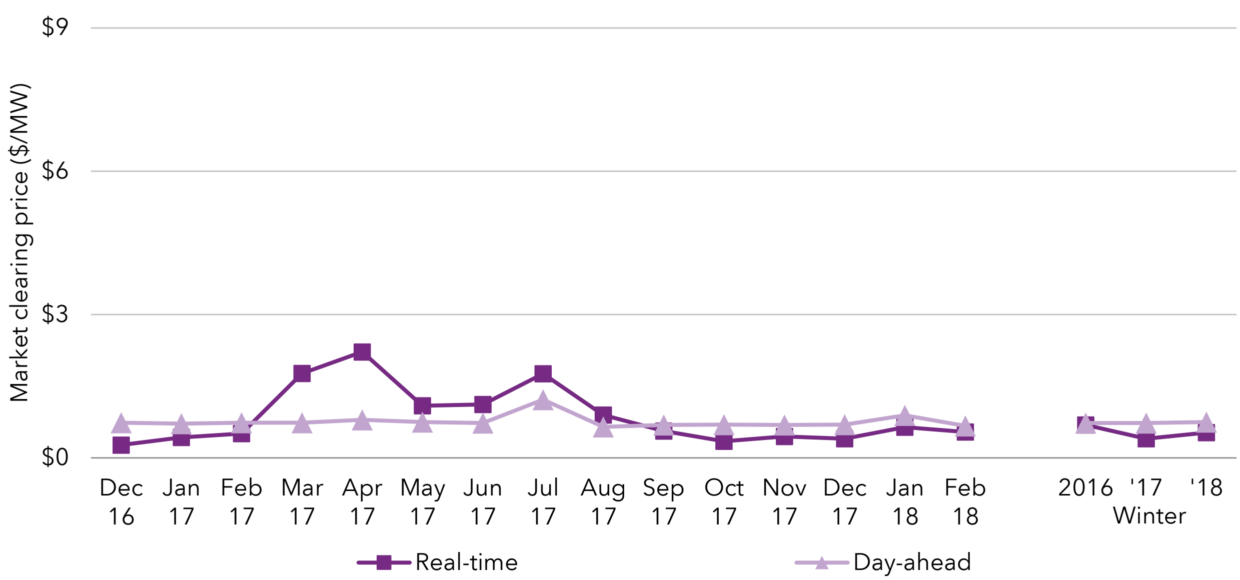


Figure 2–12 Supplemental reserve prices



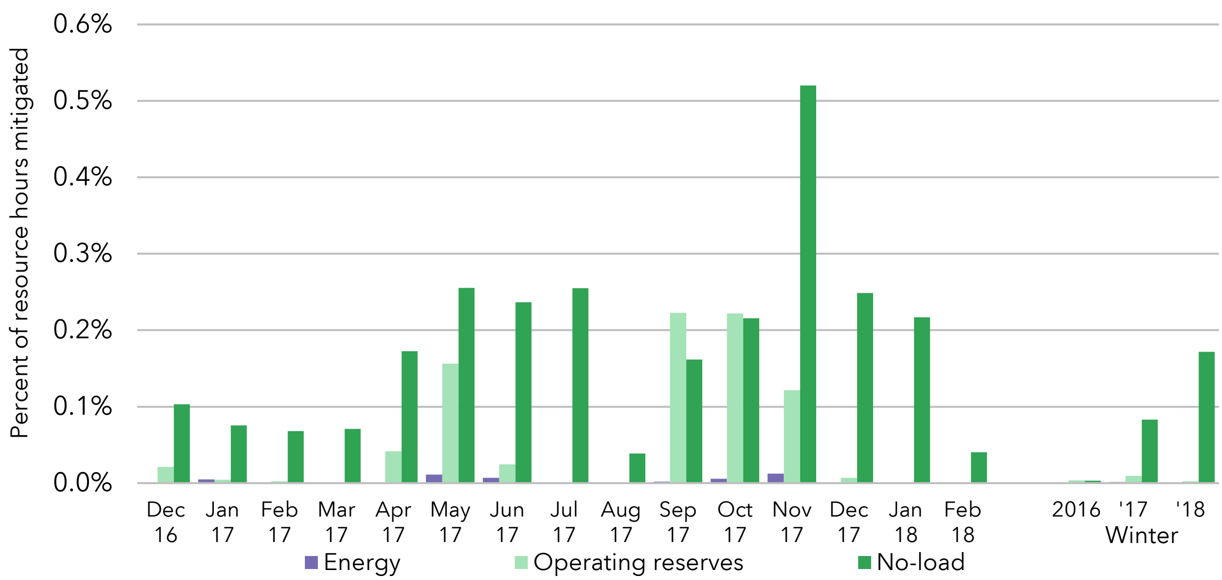
Spinning reserves were around $5/MW, and supplemental reserves were below $0.75/MW, which was consistent with prior periods.

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 2–14 shows the frequency of mitigation of incremental energy, operating reserves, and no-load costs in the day-ahead market.

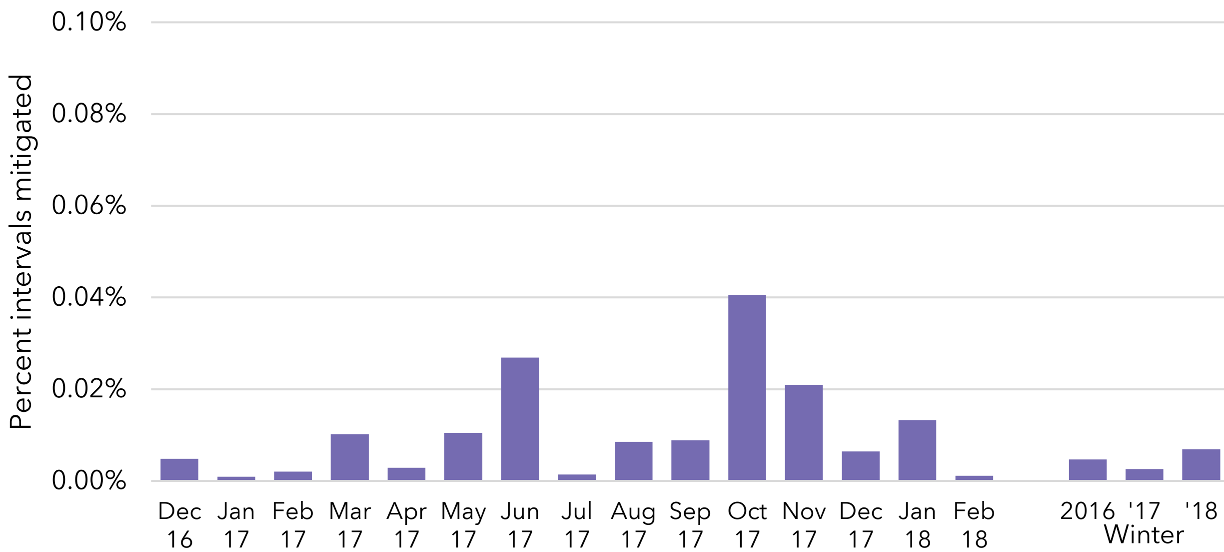
Figure 2–13 Mitigation frequency, day-ahead market



Winter 2018 had an average of just less than 0.2 percent of total resource hours mitigated for all products, increasing from just under 0.1 percent of resource hours in winter 2017.

For the real-time market, the mitigation of incremental energy is shown in Figure 2–15.

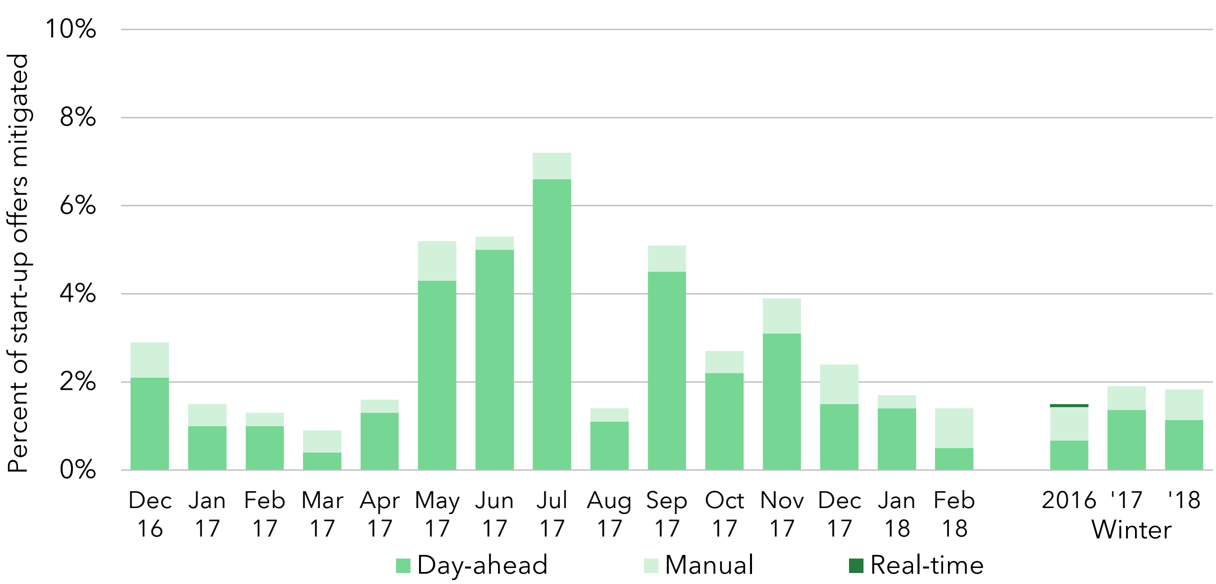
Figure 2–14 Mitigation frequency, real-time market



Mitigation frequency in the real-time market remains at very low levels. Mitigation frequency for the past three winter seasons has averaged less than 0.01 percent.

Figure 2–15 shows the mitigation of start-up offers for different commitment types.

Figure 2–15 Mitigation frequency, start-up offers

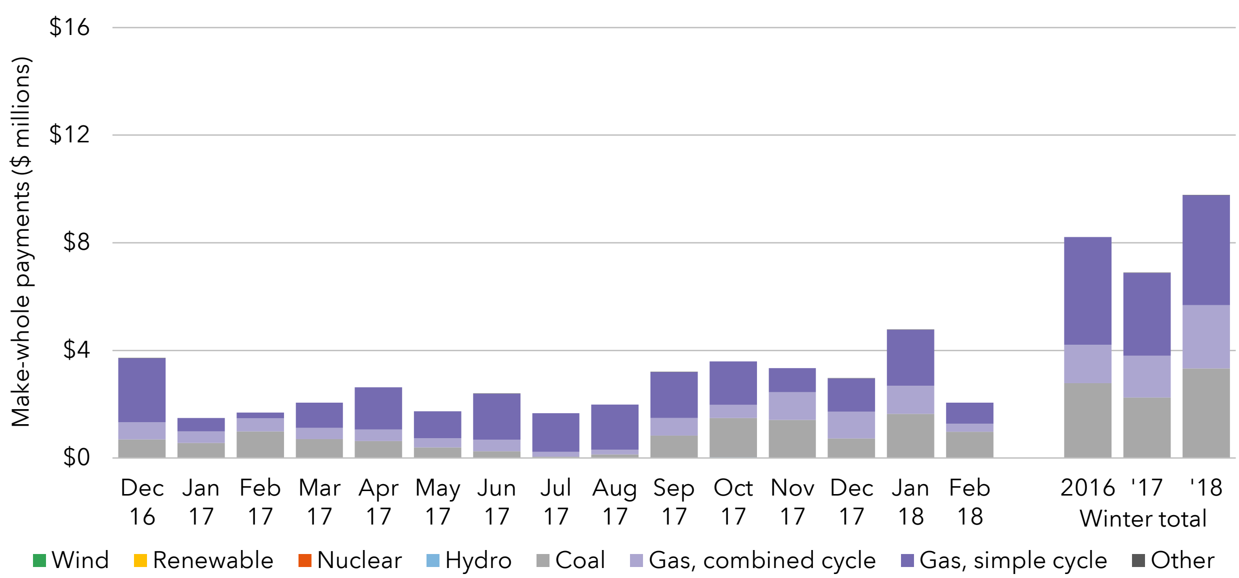


The overall level for mitigation of start-up offers is typically low during the winter months, peaking in the summer and fall. Over the past three winter seasons, mitigation of start-up offers has been less than two percent.

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 2–16) 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.

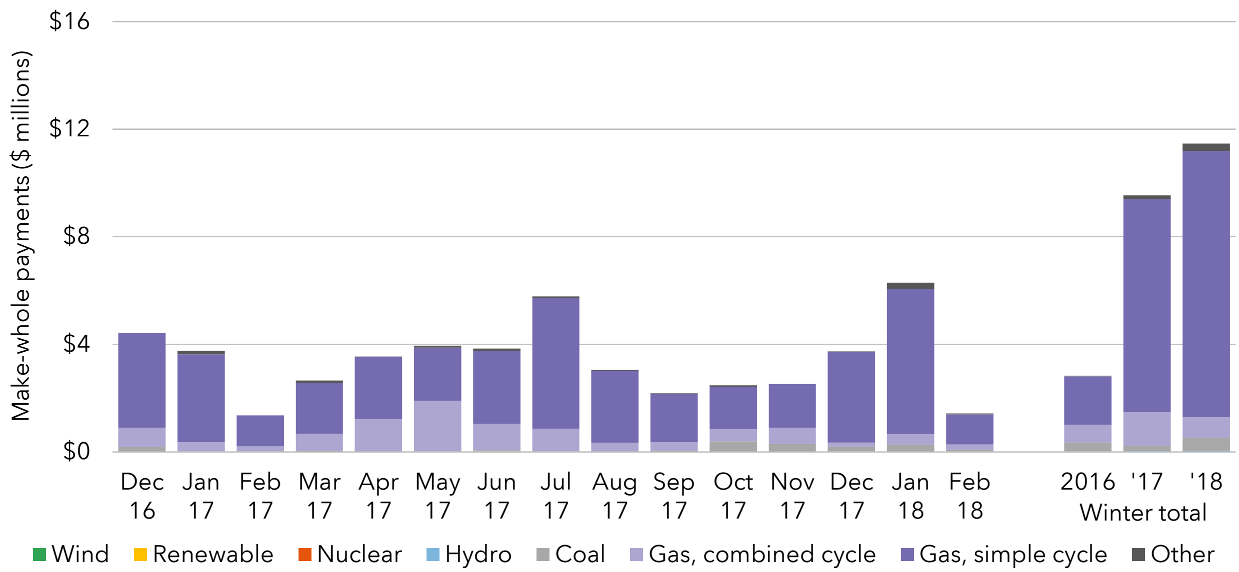
Figure 2–16 Make whole payments, day-ahead



Typically most day-ahead make-whole payments are attributed to coal and gas resources. Compared to the previous year, winter 2018 day-ahead make-whole payments were up around 40 percent. Specifically, January 2018 saw nearly $4.8 million in day-ahead make-whole payments. This can primarily be attributed to colder temperatures and higher winter peak loads, which caused some oil-fired units and units with high gas prices to be committed for transmission constraints, even though this reliability need was not reflected in prices.

The reliability unit commitment (RUC) make-whole payment (Figure 2–17) 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.

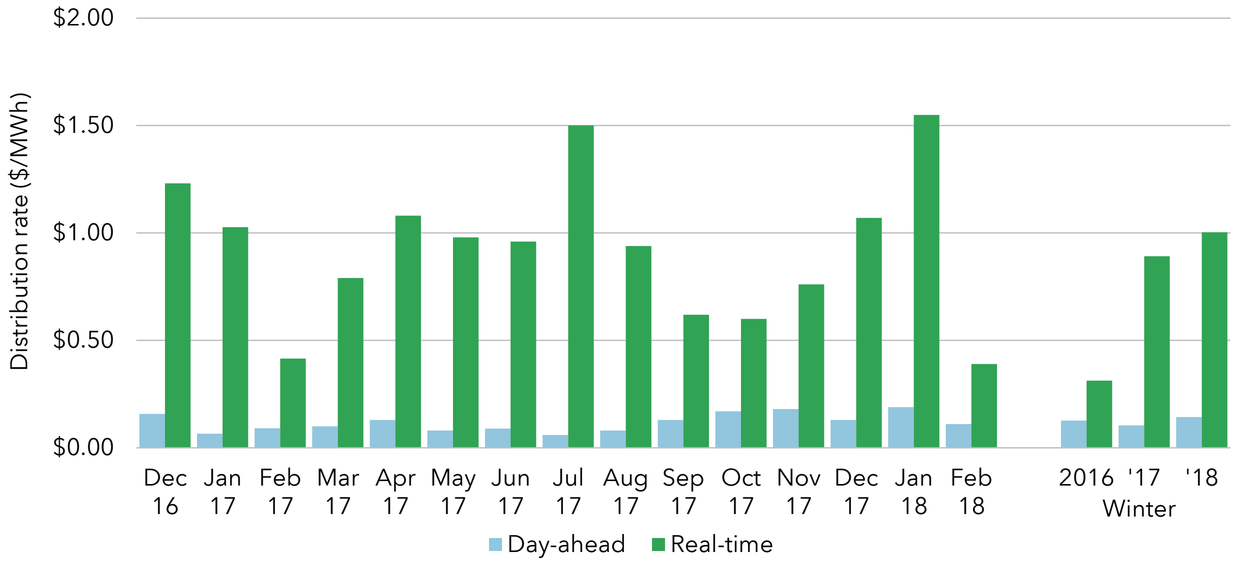
Figure 2–17 Make whole payments, reliability unit commitment



Winter 2018 monthly real-time make-whole payments totaled nearly $12 million, about 20 percent higher than winter 2017. Similar to the day-ahead make-whole payments, January 2018 saw high real-time make-whole payments.

The make-whole payment distribution charge, as shown in Figure 2–18, 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.

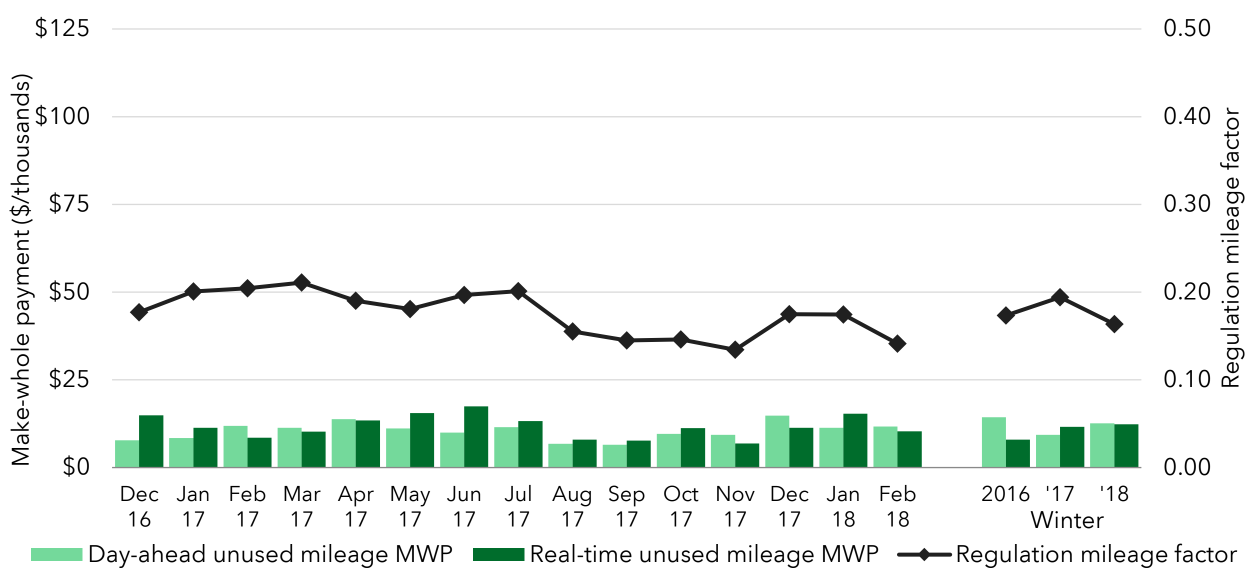
Figure 2–18 Make whole payment distribution rate



The day-ahead distribution rate remains fairly steady in all months, averaging around $0.12/MWh. The real-time distribution rate for winter 2018 was right at $1.00/MWh, which was just slightly higher than winter 2017, and nearly triple the rate in winter 2016.

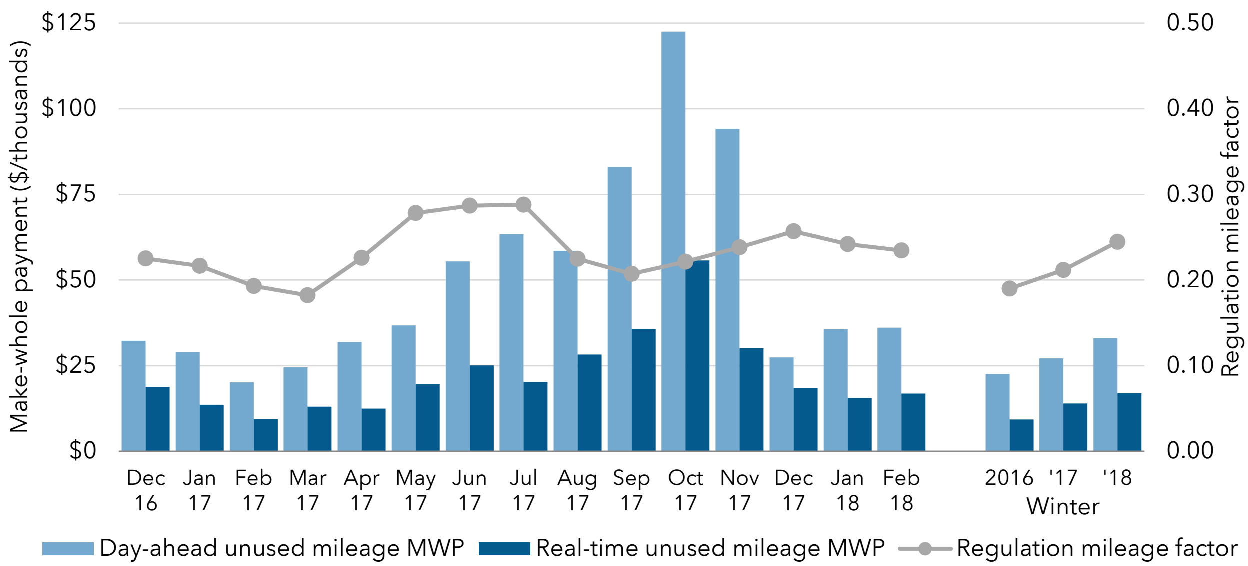
Regulation compensation includes payment to market participants, which are shown in Figure 2–19 and Figure 2–20, based on changes in energy output for regulation deployment.

Figure 2–19 Regulation-up mileage make whole payments



Regulation-up mileage make-whole payments remained steady in both day-ahead and real-time during the past three winter seasons. The regulation-up mileage factor decreased from 0.19 in winter 2017 to 0.16 in 2018.

Figure 2–20 Regulation-down mileage make whole payments



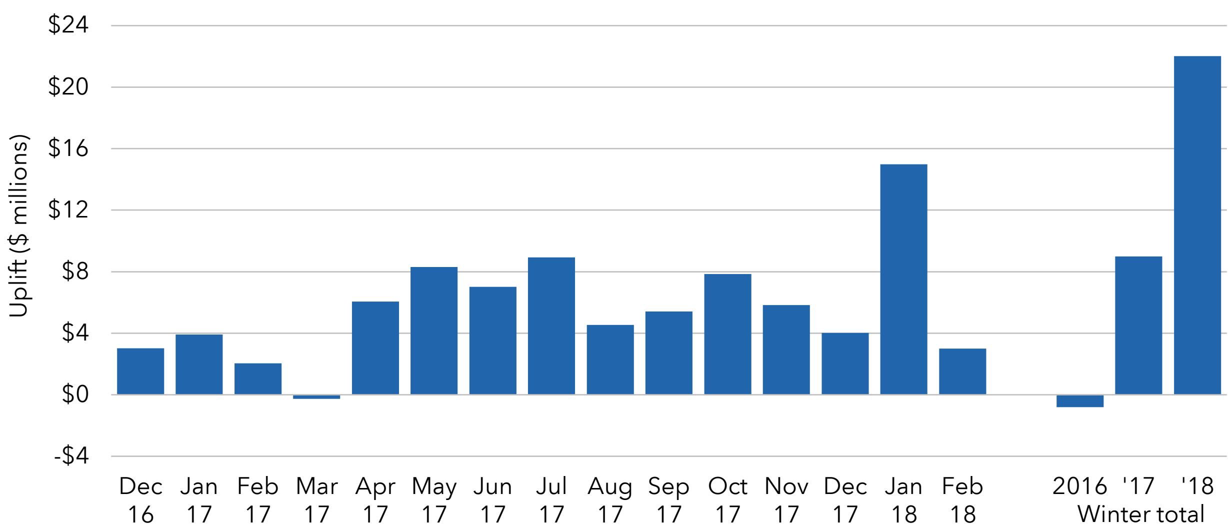
Regulation-down mileage make-whole payments, as well as the regulation-down mileage factor, for both the day-ahead and real-time markets have steadily increased over the past three winter seasons. Generally, as the wind output increases, regulation-down deployment increases, which increases the mileage factor. Additionally, many thermal units cannot regulate on their economic minimum so the market pays the opportunity cost to move them to the regulation minimum increasing the regulation down prices.

Revenue neutrality uplift (RNU), shown in Figure 2–21, 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.

Revenue neutrality uplift is comprised by the following components:

- day-ahead revenue inadequacy
- real-time revenue inadequacy
- real-time out-of-merit energy (OOME) make-whole payment
- real-time regulation deployment adjustment
- real-time joint operating agreement adjustment
- real-time inadvertent interchange adjustment
- real-time congestion adjustment

Figure 2–21 Revenue neutrality uplift



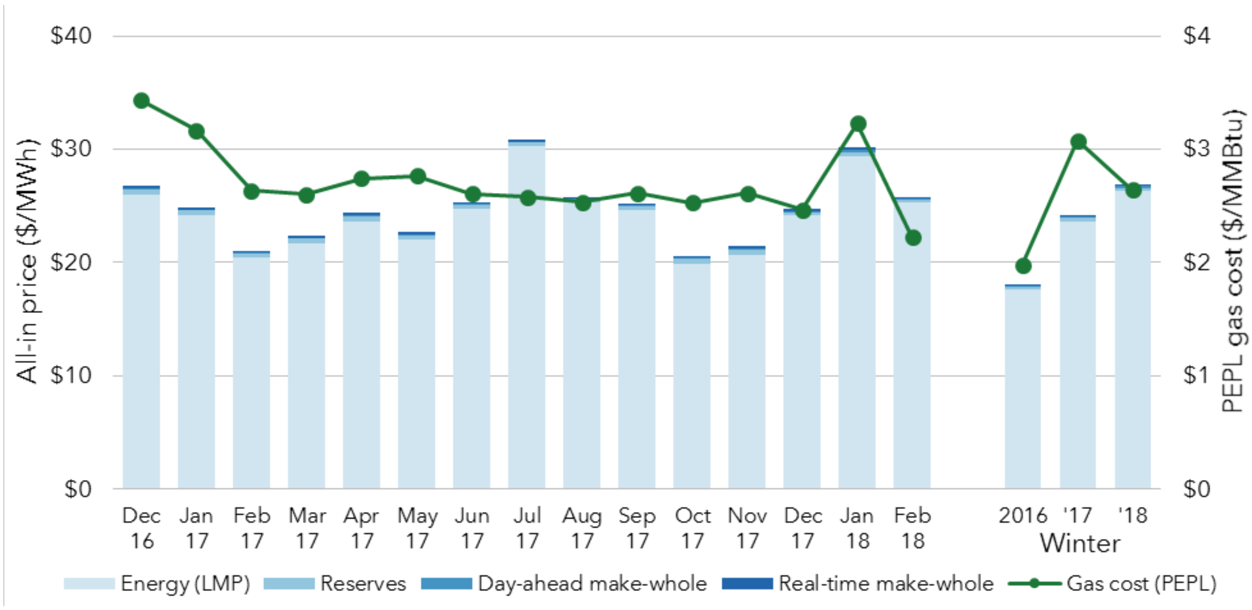
amounts shown are from the latest available settlement data and are subject to change due to resettlements

January 2018 saw total revenue neutrality uplift of nearly $15 million. This monthly total is the highest since the beginning of the Integrated Marketplace in March 2014. Prior to January the highest month had just under $9 million in revenue neutrality uplift. The high uplift in January can primarily be attributed to high levels of real-time and day-ahead congestion from January 16 to 18. During this period SPP set new winter peak loads, and the Midcontinent ISO (MISO) used almost 4,400 MW of north-to-south flow.[3]

[3] These conditions are discussed more in Chapter 6.

The all-in cost, shown in Figure 2–22 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.[4] The cost of energy includes all of the shortage pricing components.

Figure 2–22 All-in cost



Generally, the energy cost in the SPP market constitutes around 97.5 percent of the all-in price, showing that uplift makes up a very small portion of the total price incurred by market participants. All-in cost in winter 2018 was $26.28/MWh indicating an 11 percent increase compared to the winter 2017 level of $23.56/MWh. The increase in the all-in cost was primarily driven by increased costs in January, which were the result of both higher gas prices and higher loads.

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-

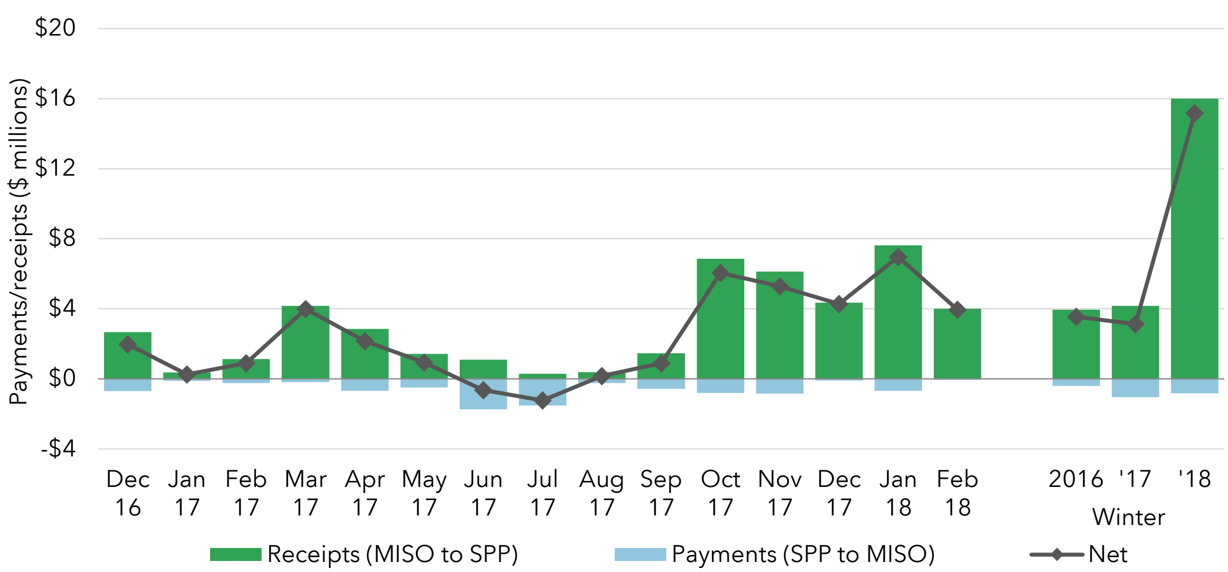
[4] Reserve sharing group costs and demand response costs are included in the all-in price, however costs for both of those items are zero.

monitoring RTOs[5] 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.

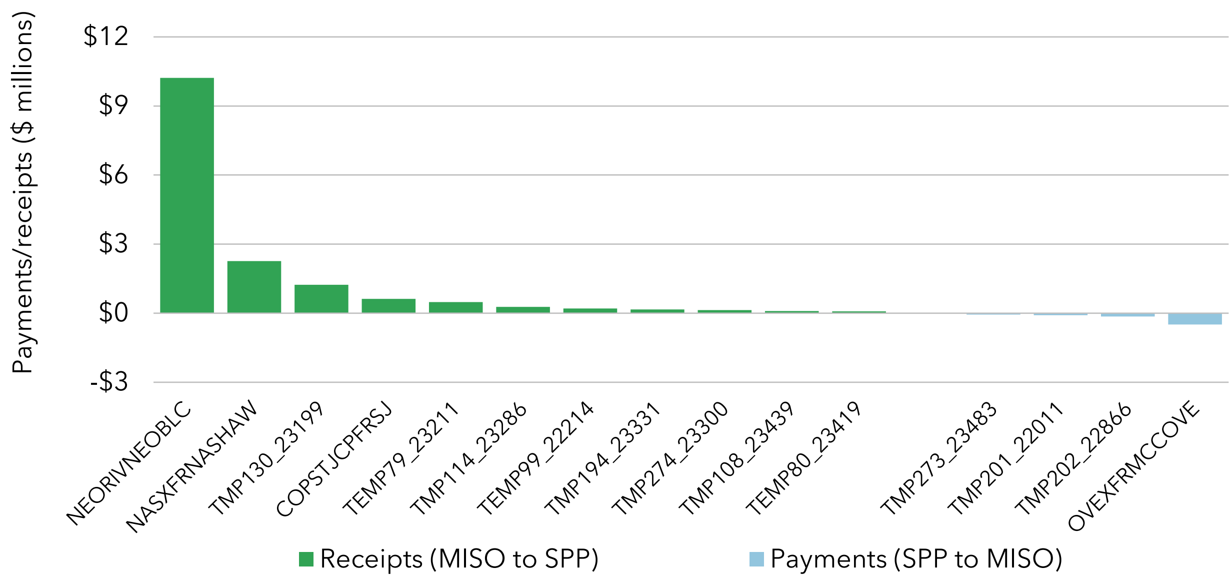
The total monthly market-to-market payments are shown in Figure 2–23, while the market-to-market payments by flowgate for the winter period are shown in Figure 2–24.

Figure 2–23 Market-to-market, monthly



[5] 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 2–24 Market to market, by flowgate



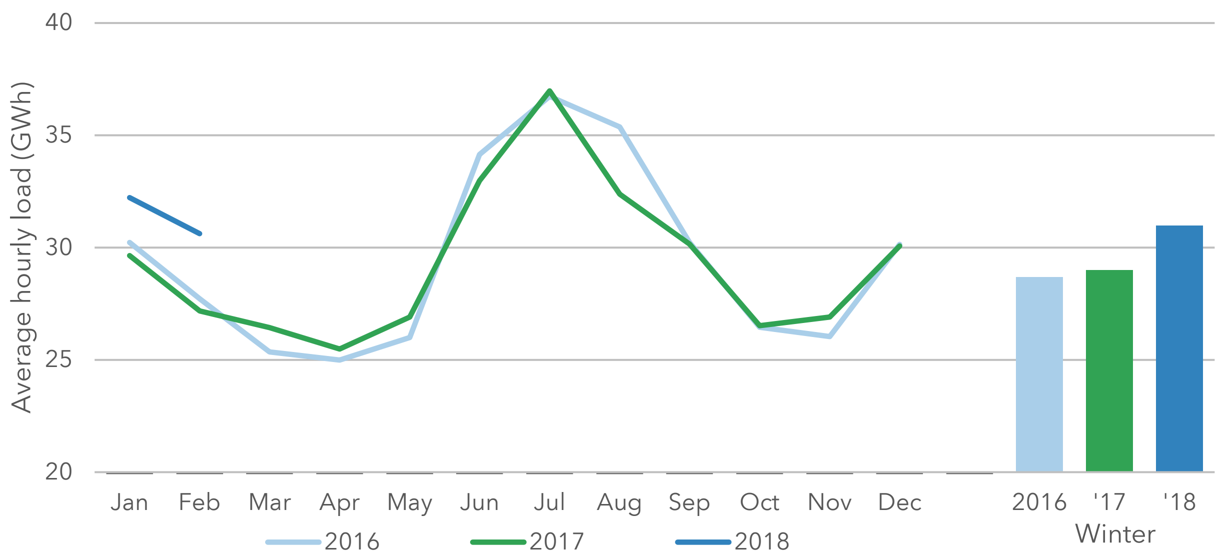
The sharp increase in total market-to-market payments in since October 2017 is almost exclusively due to the NEORIVNEOBLC (Neosho-Riverton for the loss of Neosho-Blackberry) flowgate. The flowgate was highly congested during these months, resulting in increased payments from MISO to SPP during this time.

3. DEMAND, GENERATION AND UNIT COMMITMENT

Demand

The average hourly load for each month is shown in Figure 3–1 below.

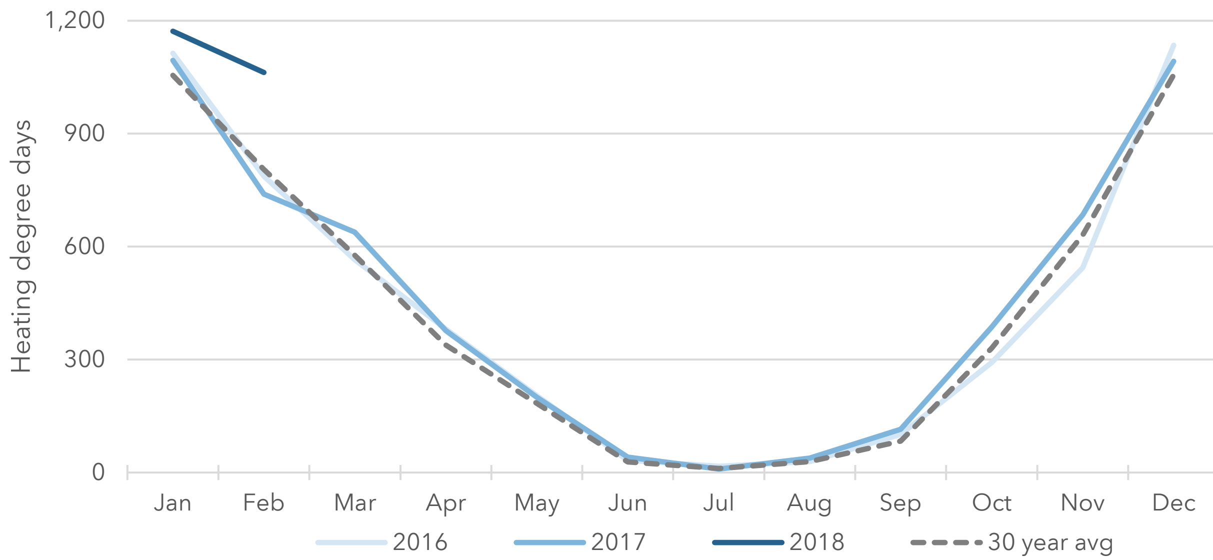
Figure 3–1 Average hourly load



Overall the hourly average load for winter 2018 was just under 31,000 megawatts, which was up nearly seven percent from winter 2017. While December 2017 was at a very similar level to the prior year, January and February 2018 average loads were nearly 11 percent higher than the previous year. This increase is primarily weather-driven as shown in Figure 3–2 below. Load continues to follow the typical pattern which has a secondary peak during the winter season.

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

Figure 3–2 Heating degree days, SPP footprint

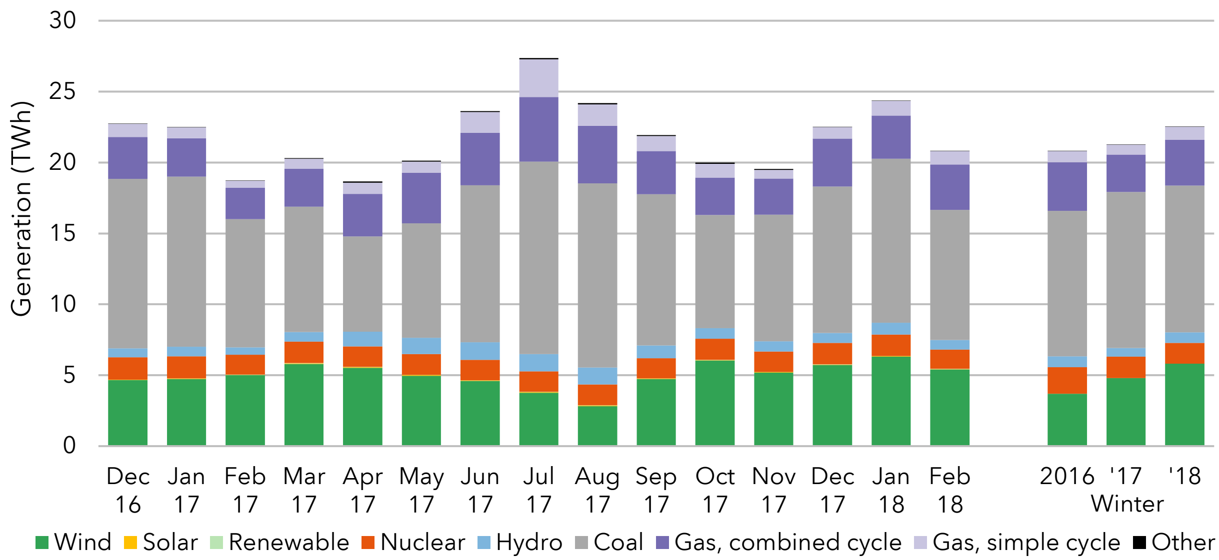


While December 2017 had near normal heating degree days, January and February 2018 were both well above normal as compared to prior years. These higher heating degree days in January and February, driven by lower temperatures, were the key driver to the increased load during those months as shown in Figure 3–1.

Generation

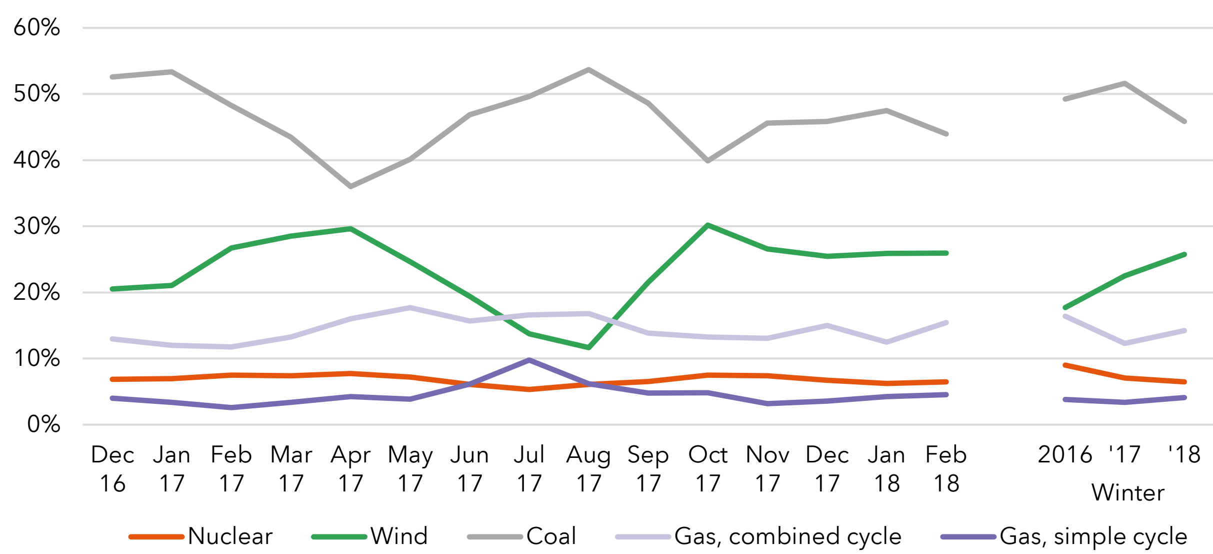
Total monthly generation, broken down by technology type of resources, is shown below in Figure 3–3. The "renewable" category includes biomass and other renewable resources (not including wind, solar, and hydro resources), while the "other" category includes fuel oil and miscellaneous resources.

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



Overall generation levels continue to increase slightly from year-to-year in the winter period, with winter 2018 average load six percent higher than winter 2017. Figure 3–4 below shows the percentage of total generation attributed to each technology type.[6]

Figure 3–4 Generation by technology type, real-time by percent

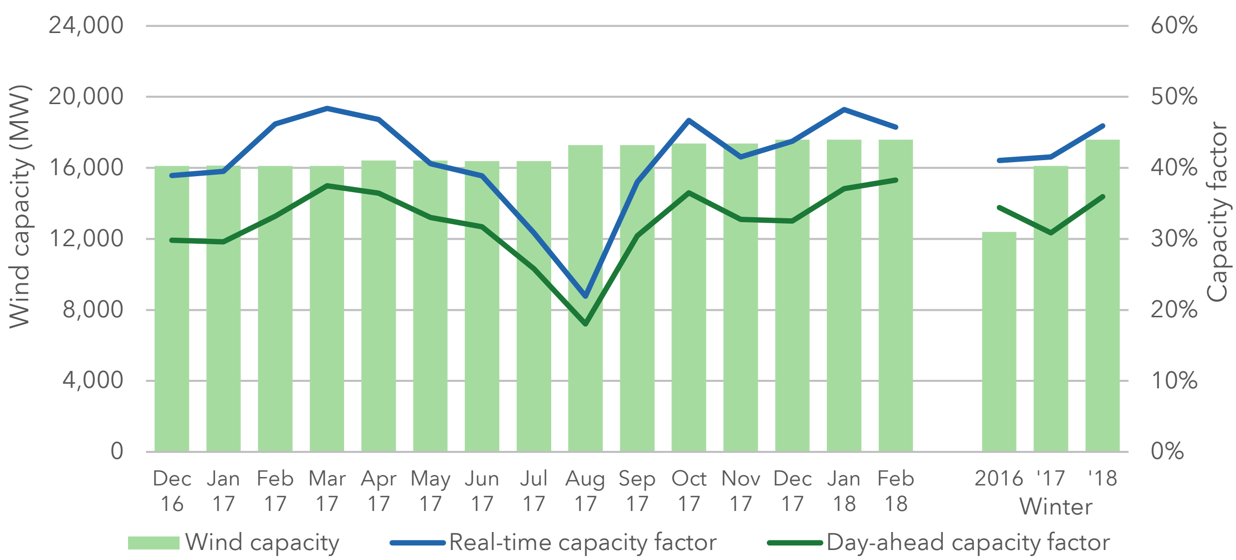


[6] Only the prevalent technology types are shown in this figure. Solar, renewable, nuclear, hydro, and other resources are not shown.

The percentage of total generation by provided by coal resources went from 49 percent in winter 2016, to 52 percent in winter 2017, and then dropped to 46 percent in winter 2018. This decline has been primarily offset by increases in wind generation, which is up from 16 percent in winter 2016, to 23 percent in winter 2017, and to 26 percent in winter 2018. Natural gas generation also increased in winter 2018.

Figure 3–5 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.[7]

Figure 3–5 Wind capacity and capacity factor



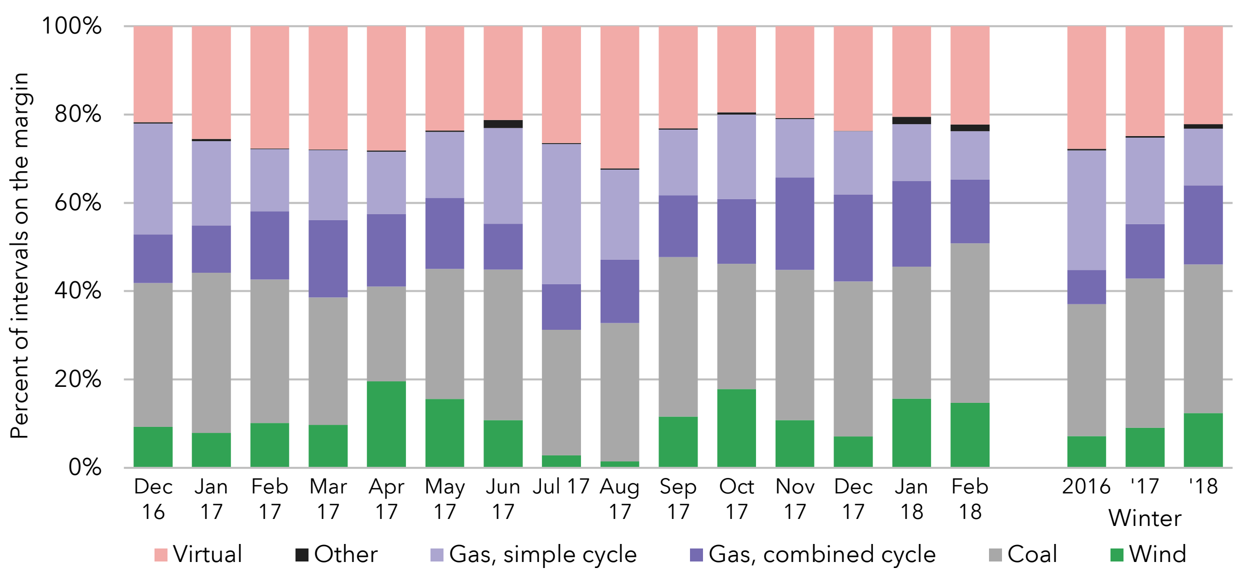
Wind capacity in the footprint continues to steadily grow, with wind capacity increasing from 12,400 MW at the end of February 2016, to 17,600 MW at the end of February 2018.

The wind capacity factor in both the day-ahead and real-time markets both climbed nearly five percent from winter 2017 to 2018. The wind capacity for January 2018 in real time was 48.2 percent, which is very similar to the high wind capacity factors typically seen during the spring months.

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

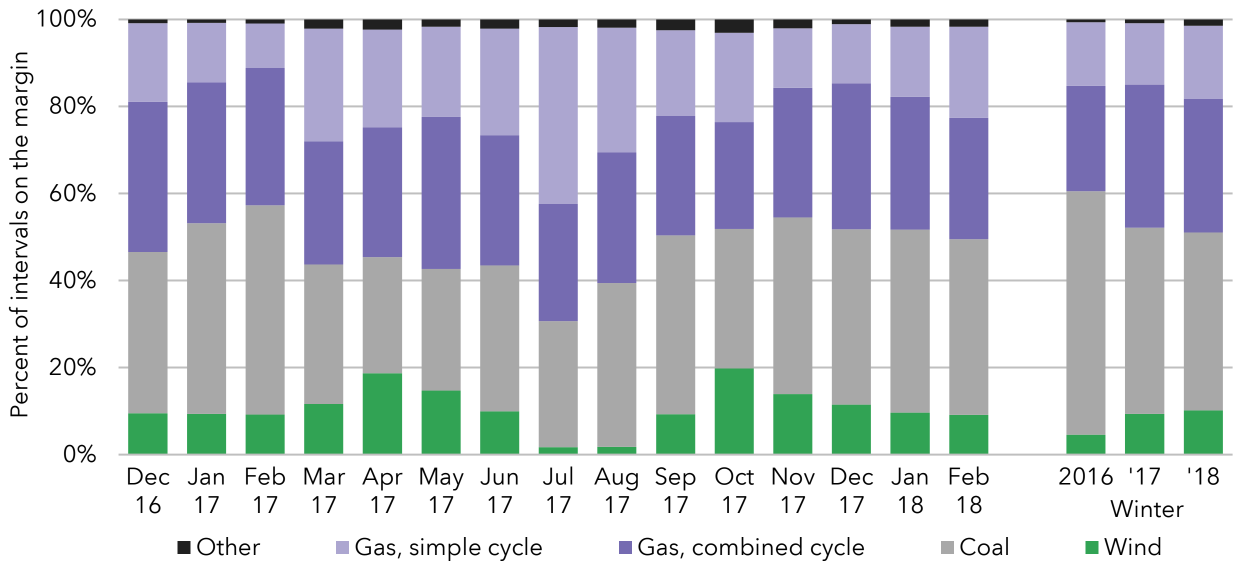
Figure 3–6 and Figure 3–7 show the technology types of marginal units in both the real-time and day-ahead markets. Marginal units set the locational marginal price in each hour in the day-ahead market and each five-minute interval in the real-time market. One important distinction is that virtual transactions can be marginal in the day-ahead market, but are not included in the real-time market and, thus, cannot set 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 3–6 Technology on the margin, day-ahead



In the day-ahead market, gas resources were marginal 31 percent of all intervals in both winter 2017 and 2018. However, in winter 2018 combined cycle resources accounted for two-thirds of gas units on the margin, and simple cycle resources accounted for one-third of gas units on the margin. This ratio was almost exactly the opposite in 2017, with simple cycle units representing two-thirds of gas units on the margin, and combined cycle representing one-third of the gas units. Coal resources continue to set prices in approximately 30 percent of intervals during winter 2016 through winter 2018. Wind resources on the margin in the day-ahead market are slowing climbing from year-to-year, while virtual transactions on the margin have been slowly declining over the past three years.

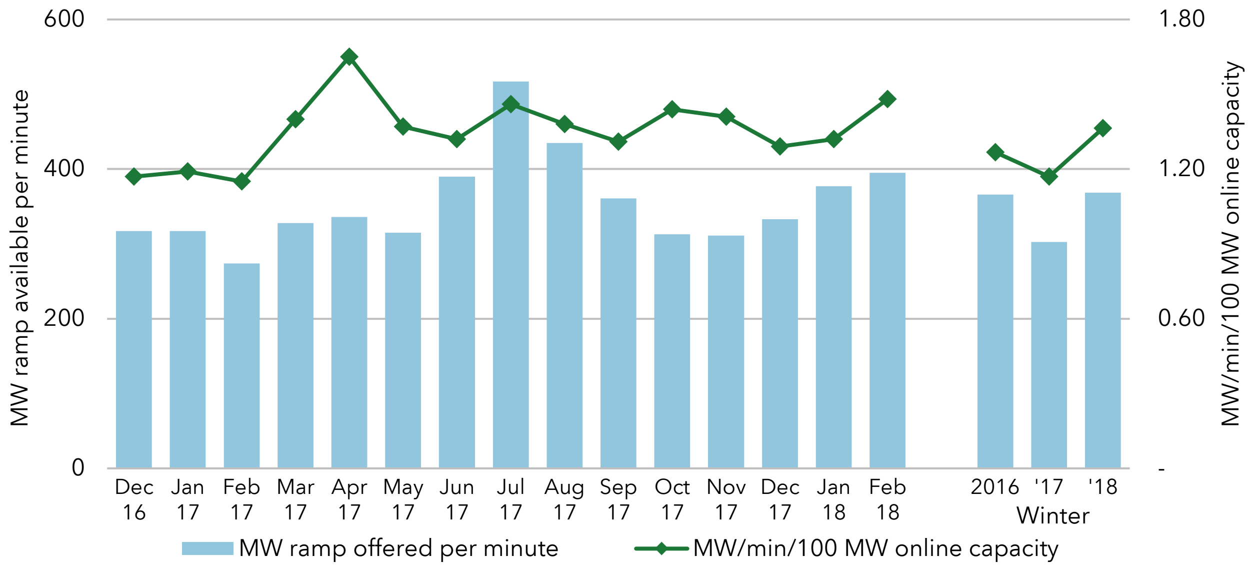
Figure 3–7 Technology on the margin, real-time



In the real-time market coal resources were marginal in about 42 percent of all intervals in winter 2017 and 2018, compared to being marginal in nearly 56 percent of all intervals in winter 2016. This decline mirrors the decline in coal generation as a percent of all generation during this same period, which is shown in Figure 3–6 above. The decline was primarily offset with increases in gas combined cycle (24 percent in winter 2016, and 32 percent in winter 2017 and 2018), and wind resources (5 percent in winter 2016, 9 percent in 2017, and 10 percent in 2017) on the margin.

Ramp available to the system as standardized by available capacity, compared to the average on-line capacity is shown in Figure 3–8. Ramp rates play a key role in market operations because they place limits on how quickly a unit can respond to changes in load conditions and the need for redispatch to manage congestion.

Figure 3–8 Ramp rate offered

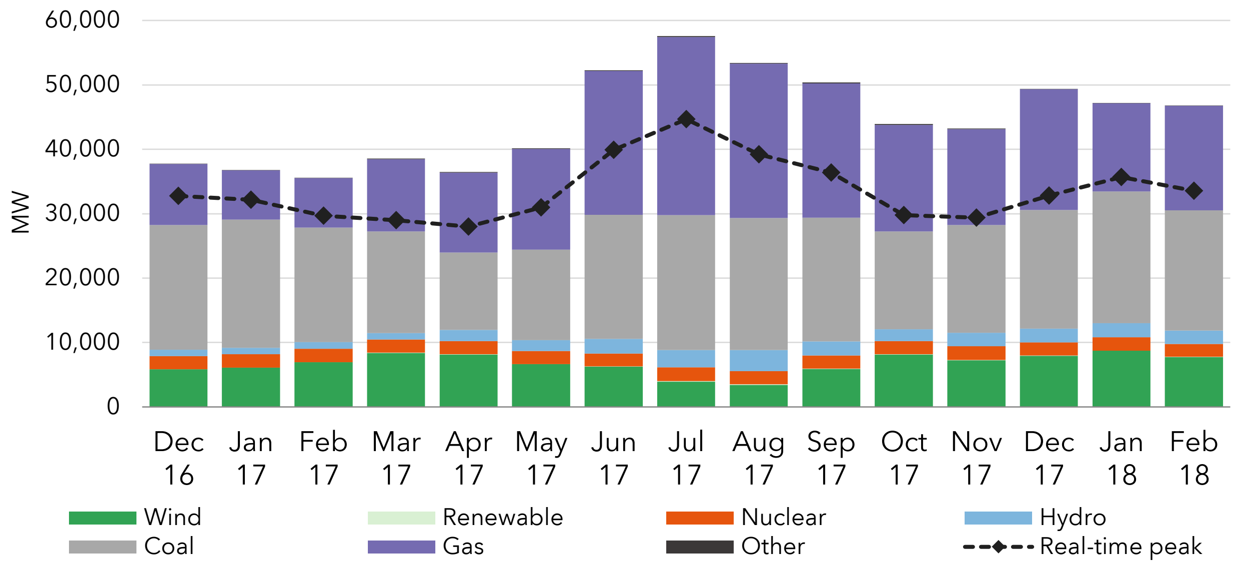


Ramp rate offered per minute for winter 2018 was nearly equal to the rate for winter 2016. Winter 2017 saw lower amounts of ramp offered per minute.

Unit commitment

The real-time average hourly offered capacity for the peak hour, along with the real-time peak load obligation for that hour is shown in Figure 3–9. Capacity above the line indicates that there is generally sufficient available capacity to meet peak load obligations.

Figure 3–9 Hourly offered capacity, real-time average

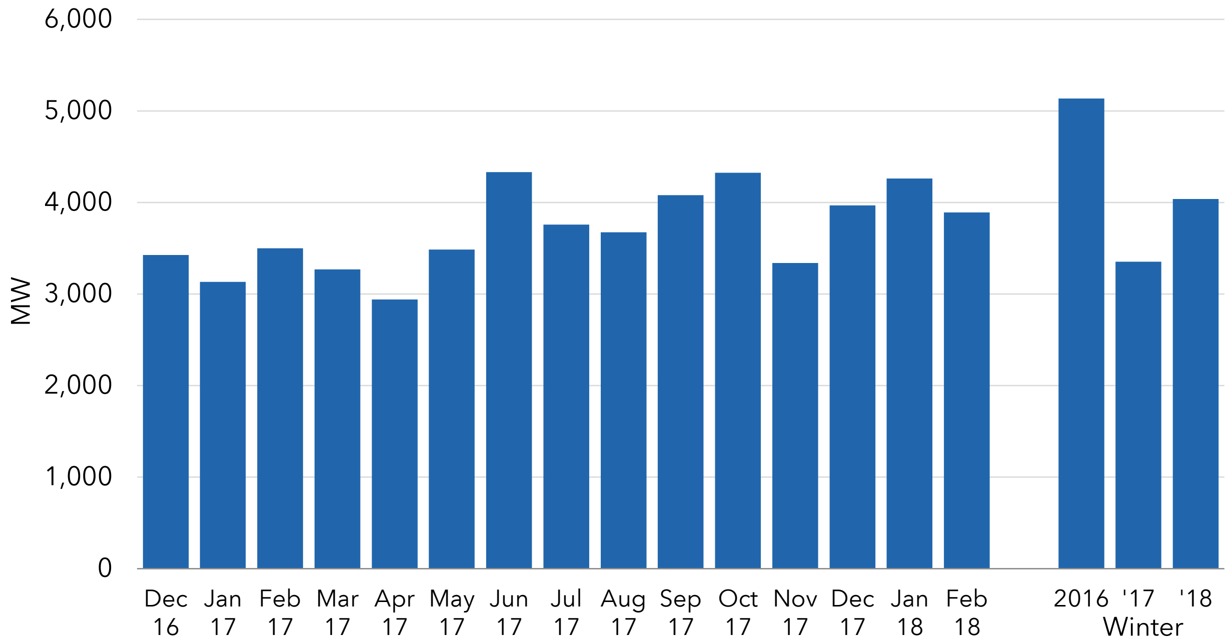


Although levels fluctuate from month-to-month, coal and gas resources typically account for 75 to 85 percent of offered capacity during peak hours. With the continued growth in wind capacity, the percent of wind capacity during the winter season typically ranged from 15 to 20 percent in winter 2017 and 2018, up from around 10 percent in the previous winter seasons. As can be seen from Figure 3–10, the load could be met on average during winter 2018 even without any wind generation.

Figure 3–10 shows the real-time average peak hour capacity overage.[8] 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.

[8] 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.

Figure 3–10 Peak hour capacity overage, real-time average



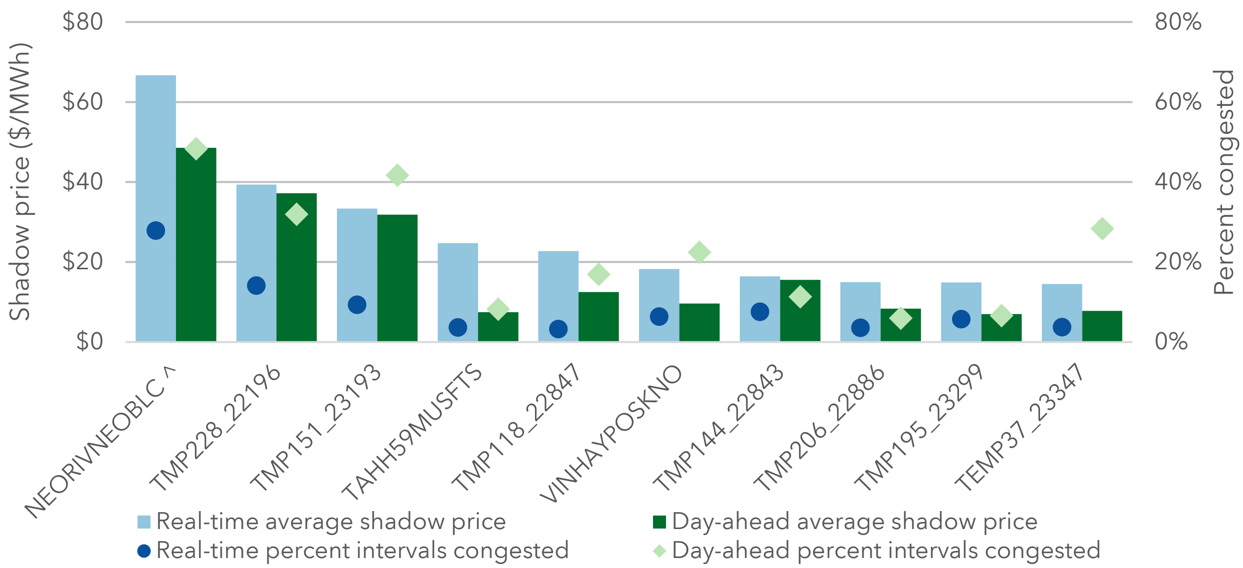
The average peak hour overage for winter 2018 was around 4,000 MW, compared to 3,300 MW in winter 2017, and 5,100 MW in winter 2016.

4. CONGESTION AND TRANSMISSION CONGESTION RIGHTS MARKET

Congestion

The impact of a constraint on the market can be illustrated 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 megawatt of relief on a congested constraint in reducing the total production costs. The shadow price is also a key determinant of the marginal congestion component (MCC) of the locational marginal price for each pricing point. Congestion by shadow price for the winter period is shown in Figure 4–1, while congestion by shadow price for the rolling 12-month period ending February 2018 is shown in Figure 4–2.

Figure 4–1 Congestion by shadow price, winter

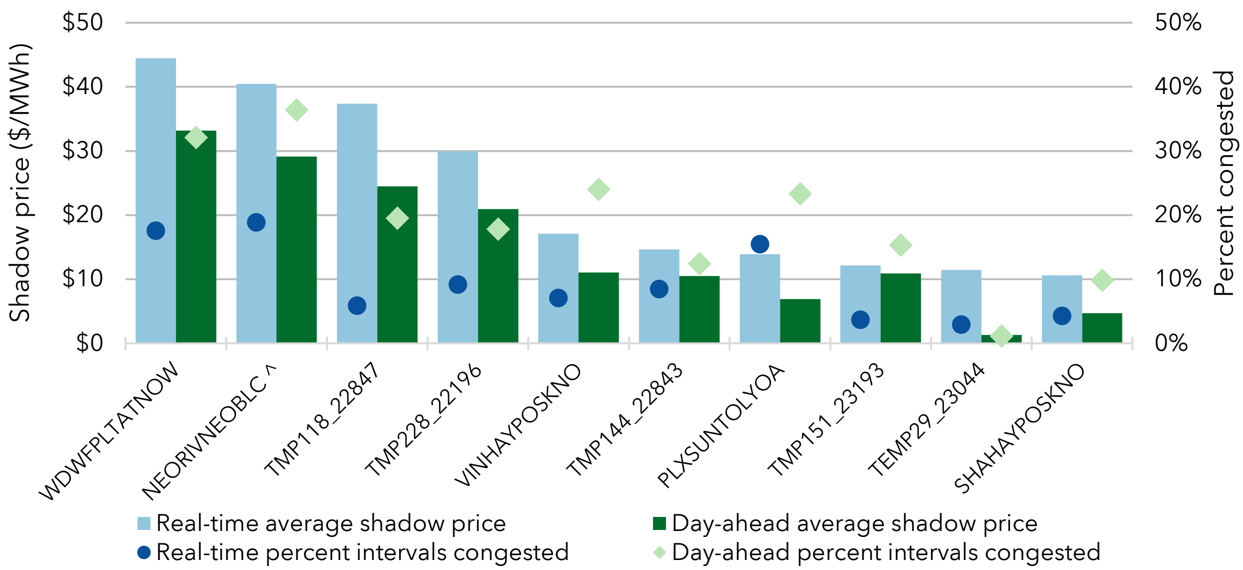


NEORIVNEOBLC ^ Neosho-Riverton 161kV (WR-EDE) ftlo Neosho-Blackberry 345kV (WR-AECI)
TMP228_22196 Hale County-Tuco 115kV ftlo Swisher County-Tuco 230kV (SPS)
TMP151_23193 Oakland East Switch-Atlas Junction 161kV ftlo Asbury Plant-Purcell Southwest 161kV (EDE)
TAHH59MUSFTS Tahlequah-Highway 59 161kV ftlo Muskogee-Fort Smith 345kV (GRDA-OKGE)
TMP118_22847 Southard-Roman Nose 138kV ftlo Tatonga-Matthewson 345kV (OGE)
VINHAYPOSKNO Vine Tap-North Hays 115kV ftlo Post Rock-Knoll 230kV (MIDW)
TMP144_22843 Woodring Xfmr 345/138kV ftlo Woodring-Sooner 345kV (OGE)
TMP206_22886 Kress-Hale County 115kV ftlo Swisher County-Tuco 230kV (SPS)
TMP195_23299 Oakland East Switch-Joplin Atlas Junction 161kV (EDE) ftlo Tipton Ford-Neosho 161kV (EDE-SPA)
TEMP37_23347 Centennial-Paola 161kV ftlo West Gardner-Pleasant Valley 161kV (KCPL)

^ SPP market-to-market flowgate

The Neosho – Riverton 161kV constraint is a market-to-market flowgate that is impacted by SPP and MISO wind, as well as flows from neighboring non-market areas.[9] Congestion in this area dates back to prior to the start of the Integrated Marketplace. However, continued addition of wind in SPP and neighboring areas have contributed to the increased congestion. Since the upgrade to the Woodward area discussed below, this area has been one of the top congested constraints during high wind months.

Figure 4–2 Congestion by shadow price, rolling 12 month



WDWFPLTATNOW Woodward-FPL Switch 138kV ftlo Woodward EHV-Northwest 345kV (OGE)
NEORIVNEOBLC ^ Neosho-Riverton 161kV (WR-EDE) ftlo Neosho-Blackberry 345kV (WR-AECI)
TMP118_22847 Southard-Roman Nose 138kV ftlo Tatonga-Matthewson 345kV (OGE)
TMP228_22196 Hale County-Tuco 115kV ftlo Swisher County-Tuco 230kV (SPS)
VINHAYPOSKNO Vine Tap-North Hays 115kV ftlo Post Rock-Knoll 230kV (MIDW)
TMP144_22843 Woodring Xfmr 345/138kV ftlo Woodring-Sooner 345kV (OGE)
PLXSUNTOLYOA Plant X Sub-Sundown 230kV ftlo Tolk Sub-Yoakum 230kV (SPS)
TMP151_23193 Oakland East Switch-Joplin Atlas Junction 161kV ftlo Asbury Plant-Purcell Southwest 161kV (EDE)
TEMP29_23044 Tupelo Tap-Tupelo 138kV ftlo Pittsburg-Valliant 345kV (CSWS)
SHAHAYPOSKNO South Hays-Hays 115kV ftlo Post Rock-Knoll 230kV (MIDW)
^ SPP market-to-market flowgate

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. The Woodward flowgate

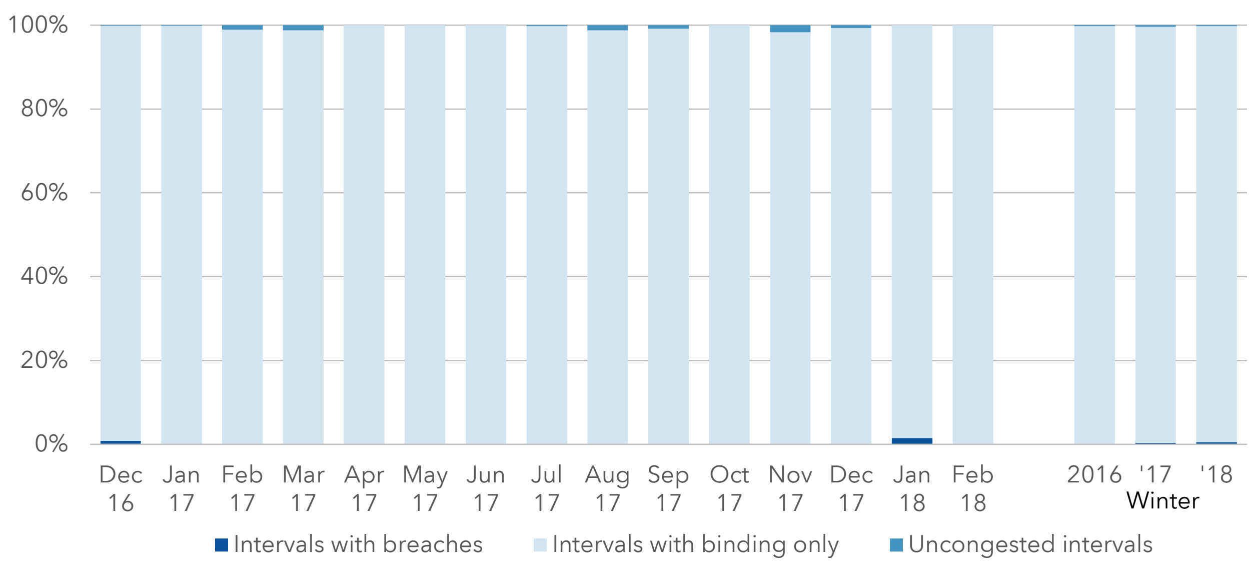
[9] Neighboring non-markets include; Tennessee Valley Authority, Associated Electric Cooperative Inc., and Southwestern Power Administration

(WDWFPLTATNOW) does not appear in the top ten congested flowgates for the winter (and did not appear in the fall), even though it still has the highest shadow price for the past 12 months. This decrease in congestion can primarily be attributed to the installation of an extra-high voltage phase-shifting transformer at Woodward in late May, which increased the amount of transfer capability in the area.

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.

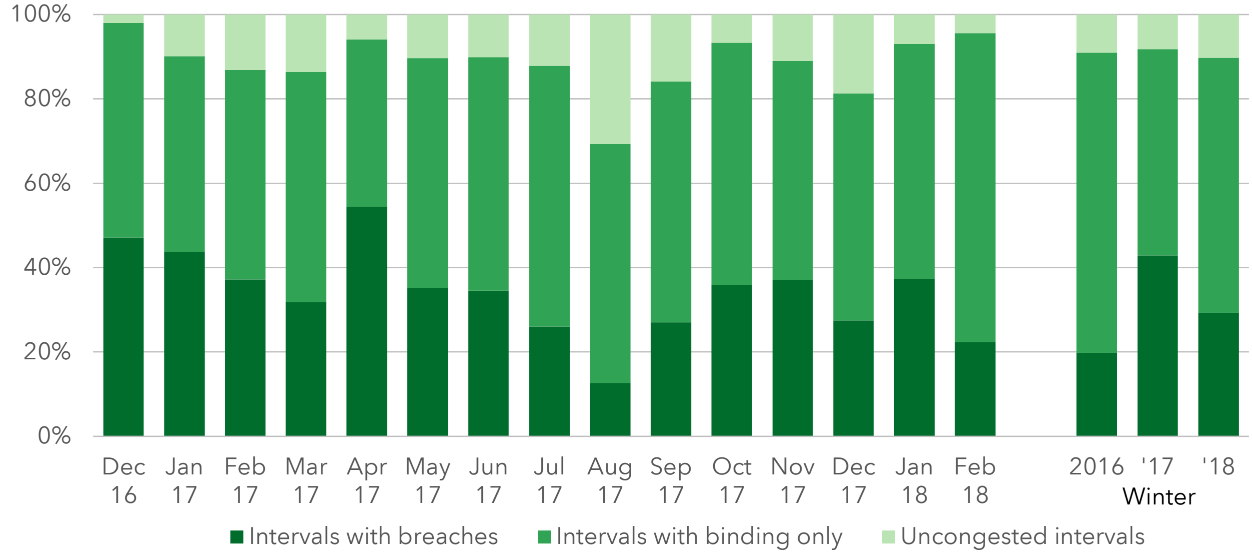
The figures below show the percent of intervals by month that had at least one breach, had only binding flowgates (but no breaches), or had no flowgates that were breached or binding (uncongested) in both the day-ahead (Figure 4–3) and real-time (Figure 4–4) markets.

Figure 4–3 Congestion by interval, day-ahead



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 4–4 Congestion by interval, real-time



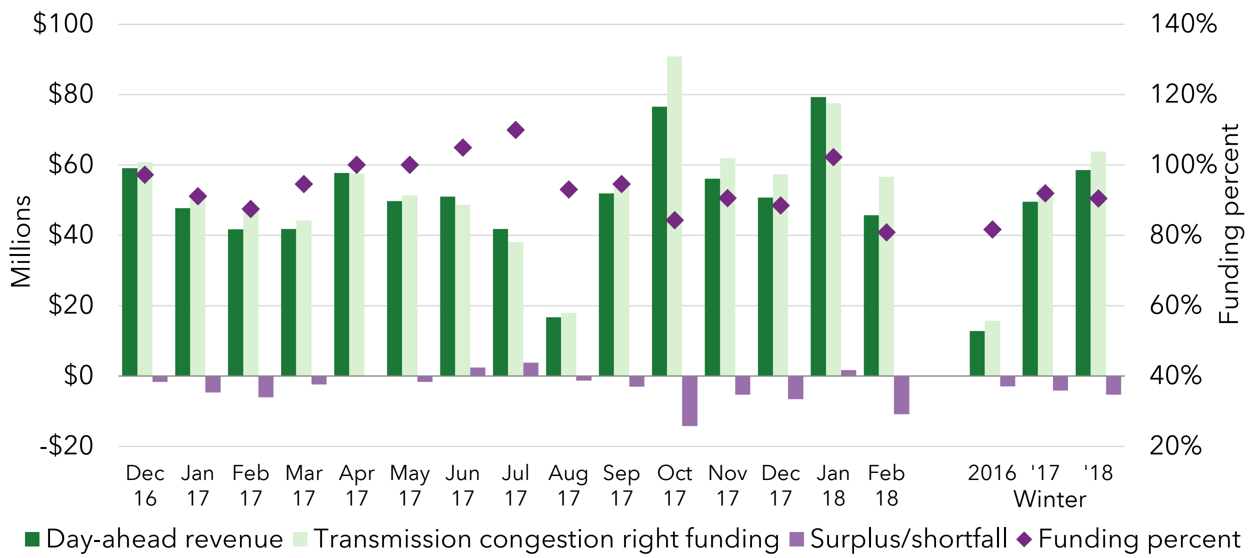
Overall, real-time market congestion decreased from the last winter period, with 29 percent of intervals with a breach in winter 2018, down from 43 percent of all intervals in winter 2017. Intervals without congestion in the winter season remains fairly steady, averaging between eight to 10 percent per year.

Transmission congestion rights market

In the Integrated Marketplace, the market generally charges load a higher price than it pays generation. Transmission services serve as the underpinning of the transmission congestion rights market, which provides day-ahead market payments to hedge the cost of congestion. Annual and monthly transmission congestion right auctions award the "rights" to shares of day-ahead market congestion revenue. SPP allocates auction revenue rights in annual and monthly processes based on transmission ownership, and auction revenue right holders receive payments from the transmission congestion rights auction and conversions of auction revenue rights into transmission congestion rights.

Figure 4–5 below shows transmission congestion right funding, day-ahead revenue, net surplus/shortfall, and transmission congestion right funding percent.

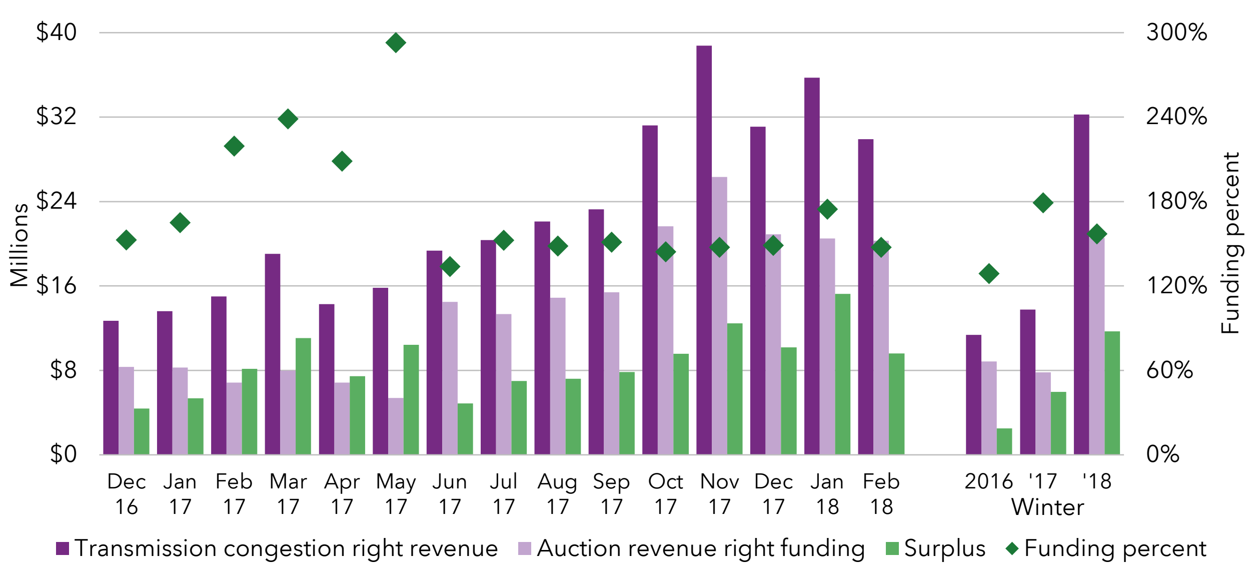
Figure 4–5 Transmission congestion right funding



Net transmission congestion right funding during winter 2017 and 2018 averaged right near 90 percent. This is up from 82 percent in winter 2016. This increase can primarily be attributed to an increase in the purchase of transmission congestion rights.

Figure 4–6 shows transmission congestion right revenue, auction revenue right funding, net surplus, and auction revenue right funding percent.

Figure 4–6 Auction revenue right funding



The auction revenue right funding percent has remained fairly consistent at around 140 to 150 percent since peaking in May 2017, though January 2018 was an outlier at around 175 percent. Auction revenue rights funding surplus (and funding percent) have remained at high levels primarily because market participants have likely been valuing transmission congestion rights at high levels in anticipation of higher congestion. Higher transmission congestion auction revenues in excess of the payment level are required to fund auction revenue rights payments which yield a funding surplus.

5. VIRTUAL TRANSACTIONS

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 cleared and uncleared virtual demand bids (Figure 5‒1) and supply offers (Figure 5‒2).

Figure 5‒1 Virtual demand bids

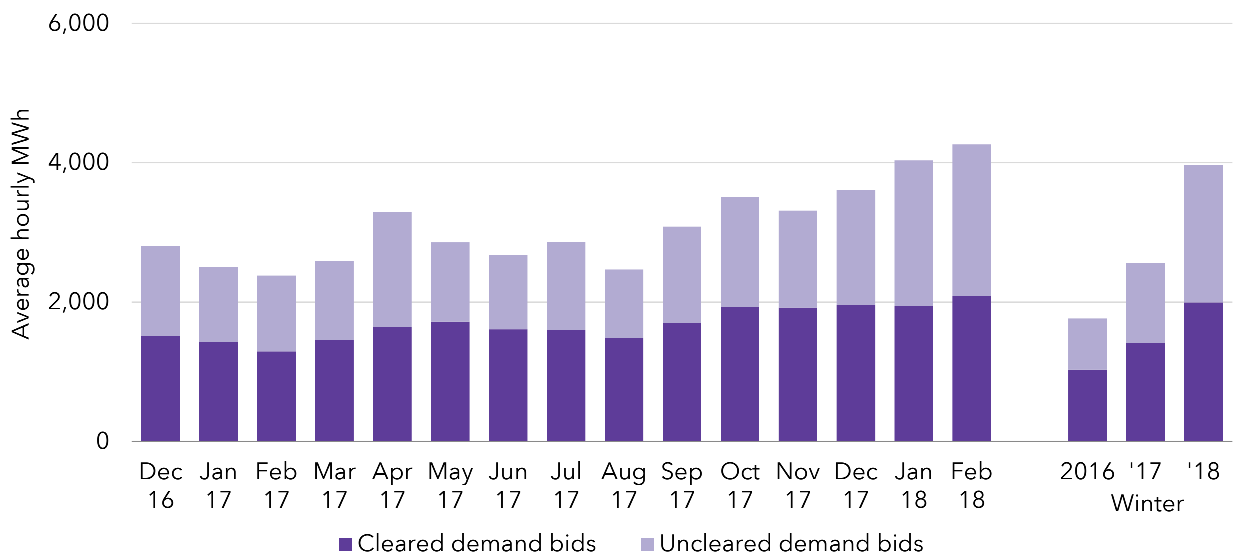
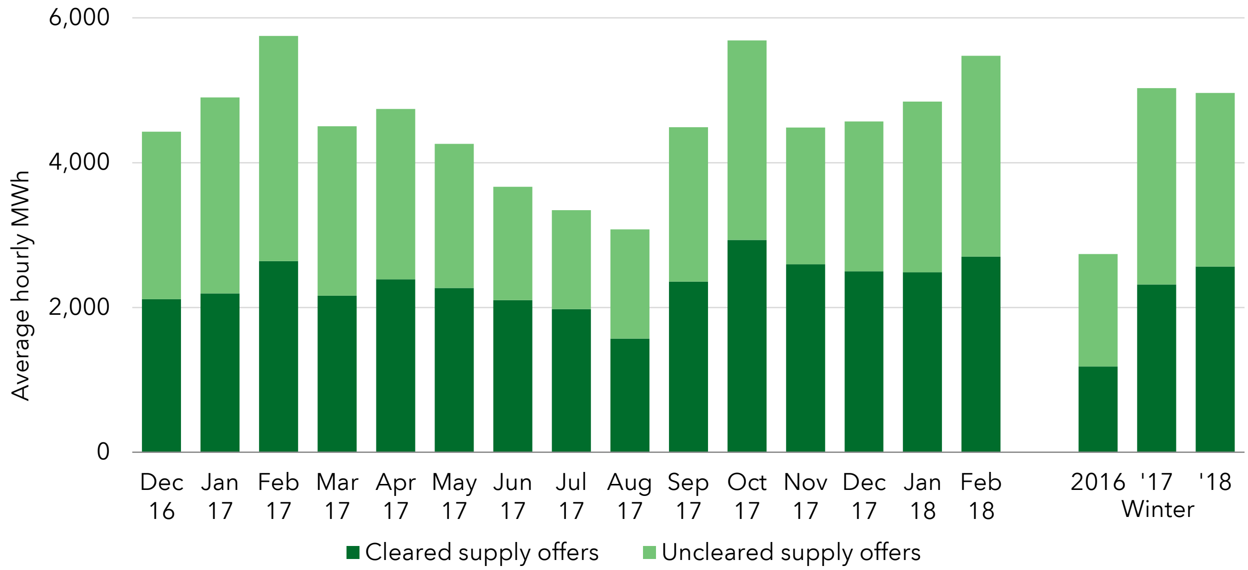


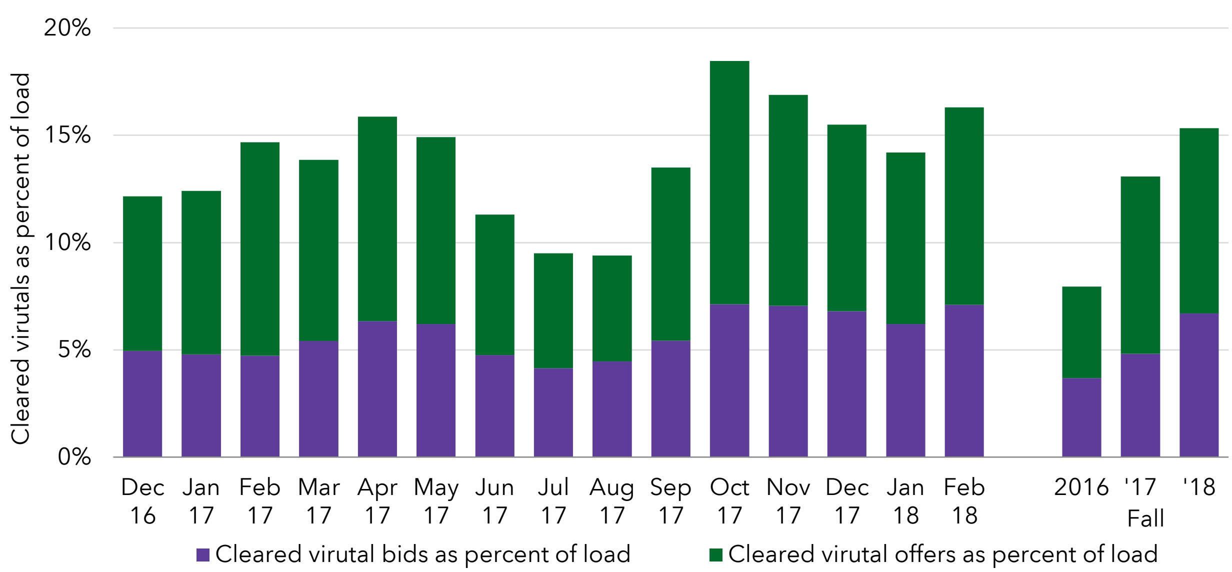
Figure 5–2 Virtual supply offers



As these figures, and other figures in this section show, virtual demand bids have steadily increased from year-to-year, while virtual supplier offers were basically level from winter 2017 to 2018.

Cleared virtual transactions as a percent of load are shown in Figure 5–3.

Figure 5–3 Cleared virtual transactions as a percent of load

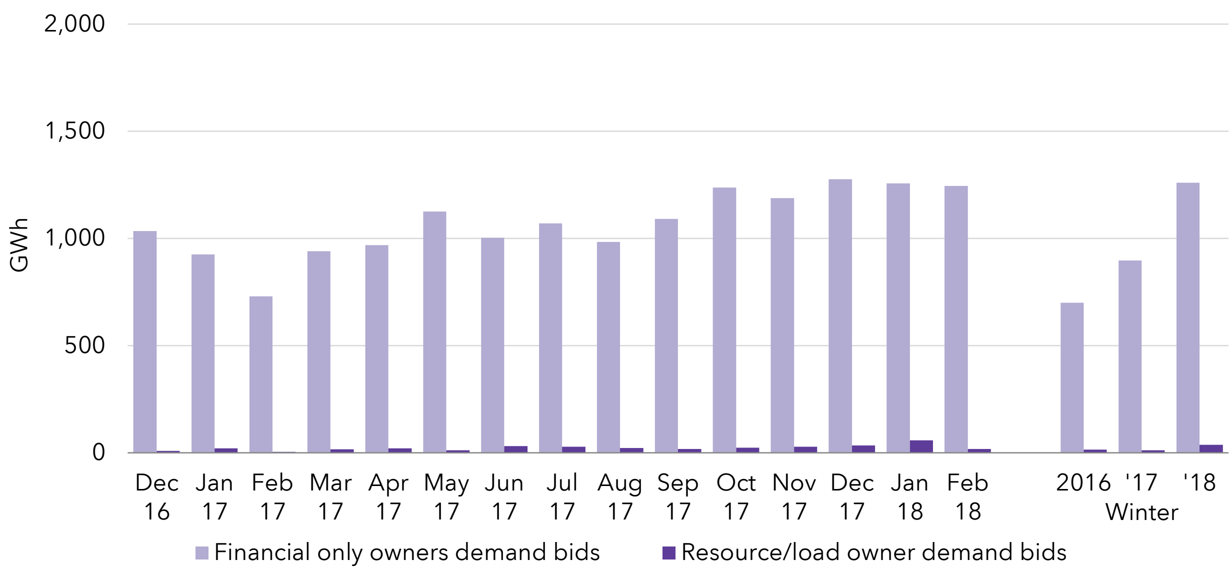


For the winter period, virtual transactions as a percent of load has increased from eight percent in 2016, to 13 percent in 2017, and to 15 percent in 2018.

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.

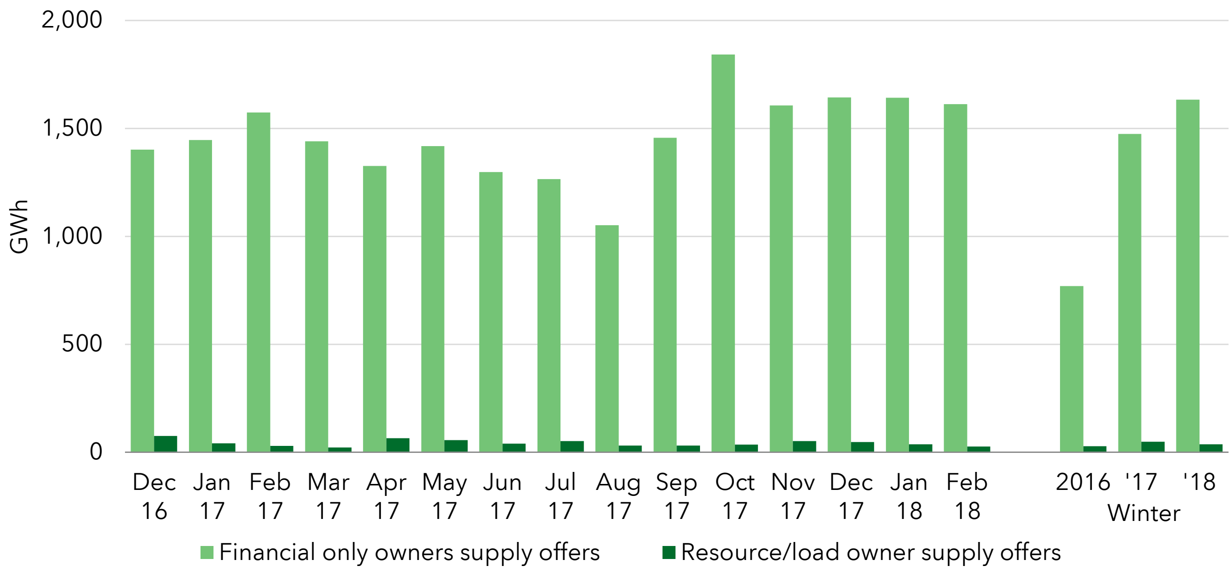
Figure 5–4 and Figure 5–5 show virtual transactions by participant type, either financial-only entities, or entities with resources and/or load. These figures show that the vast majority of virtual transactions are placed by financial-only market participants.

Figure 5–4 Virtual demand bids by participant type



While the number of virtual demand bids by resource/load owners has remained negligible, demand bids by financial-only participants have nearly doubled from winter 2016 to 2018.

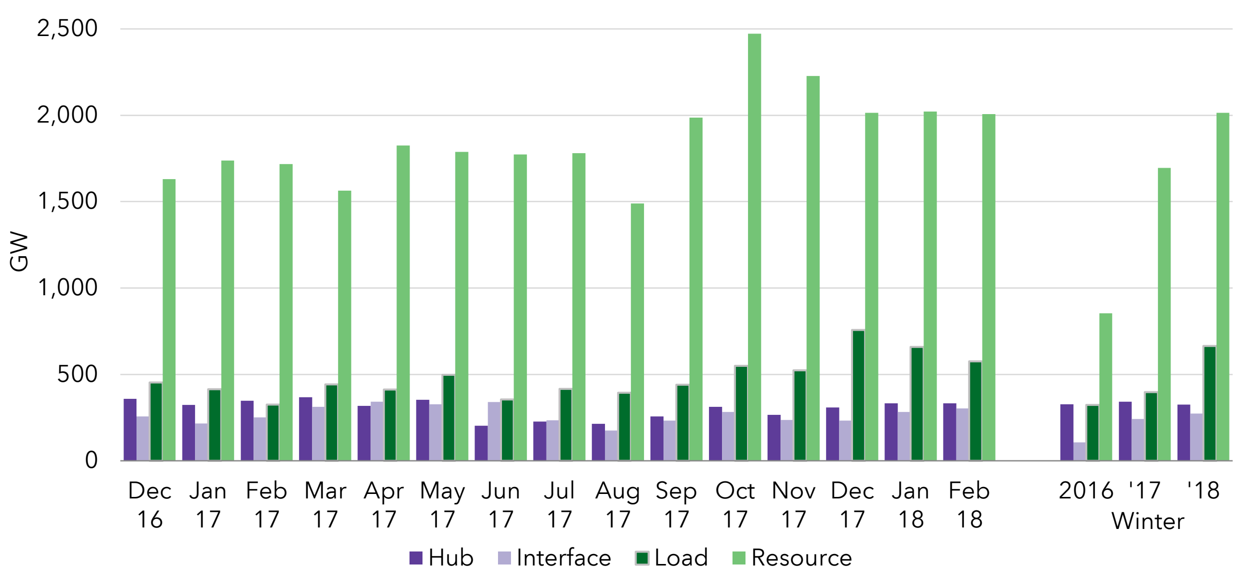
Figure 5–5 Virtual supply offers by participant type



Virtual supply offers by resource/load owners have been on a nearly flat trend from winter 2016 to winter 2018. However, those amounts have remained negligible while financial-only participants have doubled their virtual supply offers during that same period.

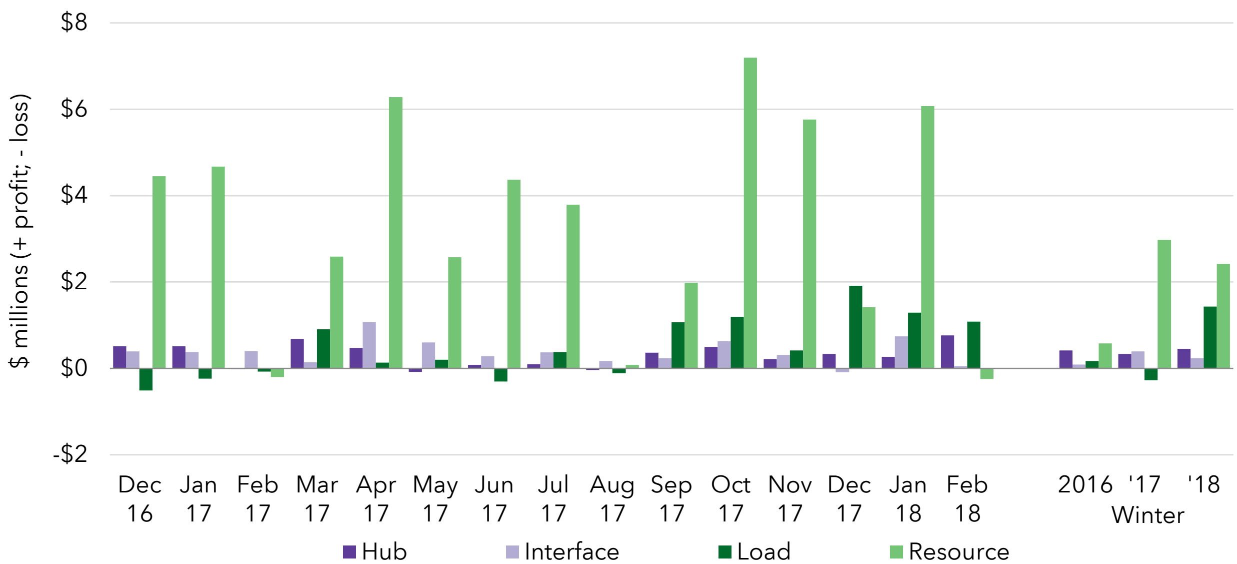
Virtual transactions can be made at hubs, interfaces, loads and resources, as shown in Figure 5–6.

Figure 5–6 Virtual transactions by location type, megawatts



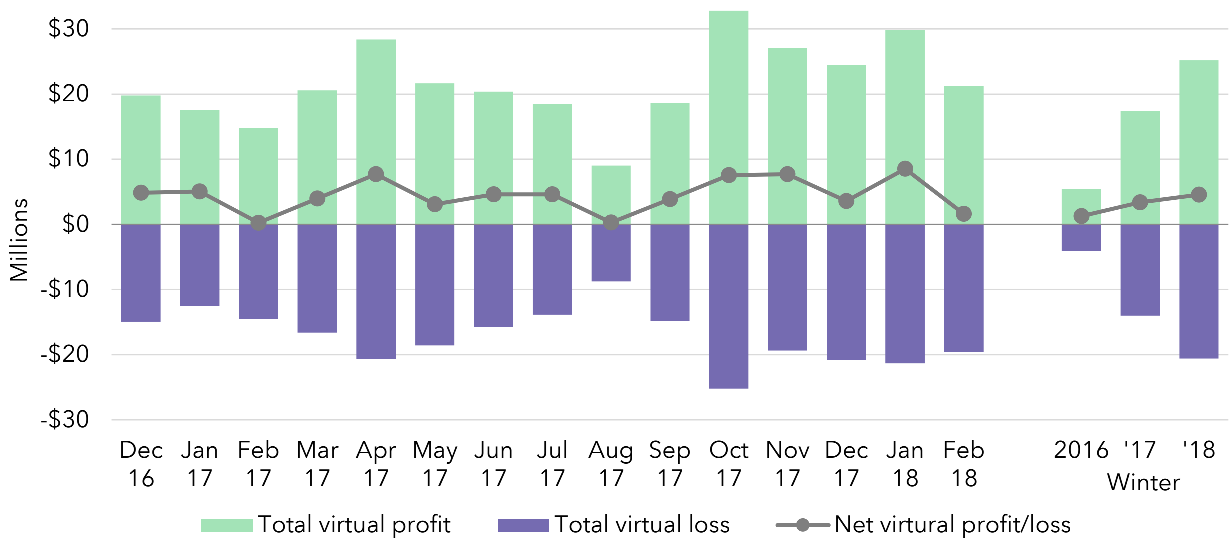
The great majority of virtual transactions are made at resources (primarily wind resources), and are steadily increasing from year-to-year, with the fewest transactions at external interfaces and hubs. Virtual transactions at load locations increased significantly during winter 2018.

Figure 5–7 Virtual transactions by location type, profit/loss



As with the volume of virtual transactions, the majority of the profits (shown in Figure 5–7) from virtual transactions are derived from resource locations. Comparing to winter 2017, the profits of virtual transactions from resource locations decreased about 20 percent in winter 2018. Meanwhile, the profits of virtual transactions from load locations was significantly increased in the winter of 2018, which could explain the increase in virtual transaction activity at these locations during this period.

Figure 5–8 Virtual transactions, profit/loss



Gross virtual profits for winter 2018, as shown in Figure 5–8, averaged just over $25 million, while gross virtual losses averaged nearly $21 million, for an average net profit of $4 million. In comparison, winter 2017 had average gross profits of just over $15 million and average gross losses of just over $12 million, for an average net profit close to $3 million. Gross virtual profits have steadily increased from winter 2016 to winter 2018.

6. SPECIAL ISSUES

Winter conditions

During winter peak periods, prices can be high as the power system competes with residential heating load for natural gas supply. This section of the report will review a few days that experienced peak conditions. Overall, the SPP market performed well, sending appropriate price signals during times where reliability conditions were more challenged.

New wind peak - December 16, 2017

SPP set a new wind peak of 15,690 MW of wind production on this day. During this day, SPP exported about 1,500 MW during each hour. Both the day-ahead and real-time markets saw negative overnight prices, but positive on-peak prices. In contrast with the normal market behavior, virtual transactions offered a larger quantity of virtual supply priced below $0/MW than the wind forecast error for that day. This followed several days where day-ahead wind plus virtuals was still under the actual wind production. On this day regulation-down and regulation-up were moderately priced, generally between $10/MW and $18/MW.

High natural gas price - December 27-29, 2017

During this period, the Ventura pipeline experienced very high natural gas prices with confirmed trades at around $65/MMBtu. Units that had fuel oil on-site were able to switch to a lower-priced fuel. As natural gas prices were much lower on other pipelines, the SPP market was able to provide lower cost generation from generators that did not face high natural gas prices. An SPP transmission commitment did result in a very large reliability make-whole payment for this period. On December 27, wind was approximately 3,000 MW below the reliability unit commitment forecast and 1,300 MW below the day-ahead scheduled amount. This contributed to over 27 intervals of regulation-up scarcity, primarily driven by a lack of spinning generation, which resulted in approximately $24 million in higher production costs in the real-time market. Overall, the day-ahead market reflected higher prices than normal, peaking at around $50/MWh at the SPP North Hub. Real-time prices were volatile on December 28 and 29, but the overall production costs were about the same between the two markets on December 28 and lower on December 29 in real time when compared to the day-ahead market.

SPP New Winter Peak - January 16-18, 2018

SPP set new winter peaks on January 16 at hour ending 1900 at around 41,000 MW, and hour ending 0700 at around 42,500 MW. Subsequently, a new winter peak was set on the next day (January 17) at hour ending 0700 of nearly 43,000 MW. During this time SPP experienced high prices, particularly in western Arkansas, east Texas, and southern Missouri, where prices routinely exceeded $400/MWh as oil-fired units set prices. Additionally, during this time, MISO South had an Energy Emergency Alert Level 2. Over 4,320 MW of MISO north-to-south flow occurred during hour ending 0700 on January 17. SPP and MISO did make extensive use of the market-to-market redispatch, resulting in SPP collecting $940,000 on January 16, $1.97 million on January 17, and $647,000 on January 18. Virtual market participants made $1.5 million in net profit on January 16, $2.4 million on January 17, and $2.1 million on January 18. SPP's forced outages were in line with normal levels. Gas prices in the SPP system exceeded $5/MMBtu in several locations, which did set prices at $50-$60/MWh when gas was marginal.

Wind turbine Icing - February 19-21, 2018

Very large errors in the wind and load forecasts occurred on these days. In particular, the load was approximately 1,500 MW higher during the afternoon of February 19 and 3,000 MW higher than forecast during the afternoon of February 20. Wind started dropping below forecast starting at hour ending 0900 on February 19 and reached 6,000 MW below forecast at hour ending 1500 on February 19, and remained below 6,000 MW until hour ending 1800 on February 20 when it was only 3,000MW below forecast. Wind returned to the forecast at about hour ending 0100 on the February 21. Temperatures dropped sooner and lower than expected, which led to higher load. Additionally, wind speeds dropped unexpectedly on February 19, based on wind data reviewed from wind farms. On February 20, wind generators had icing problems.

The large shortage of wind that day led to 39 five-minute intervals of regulation scarcity, approximately half of which were accompanied by spinning reserve shortages.[10] Additionally, numerous oil-fired units were brought online and frequently were price setting in the energy market. The real-time hourly average price ranged from $250/MWh to $400/MWh during hour ending 1400 on February 19. On February 20, there were 30 instances of regulation-up scarcity, often accompanied by a spinning reserve shortage. On February 21, while the wind performance was somewhat improved, 14 intervals of regulation-up scarcity accompanied by spin shortages occurred.

[10] Product substitution results in regulation-up being scarce first and results in the addition of a scarcity adder to the price. The MMU reviews the relationship between the spinning and regulation prices to determine the underlying cause of the shortage.

COMMON ACRONYMNS

AECC	Arkansas Electric Cooperative Corporation
AECI	Associated Electric Cooperative, Inc.
AEP/AEPM	American Electric Power
BEPM	Basin Electric Power Cooperative
CHAN	City of Chanute (Kan.)
EDE/EDEP	Empire District Electric Co.
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
GMOC/UCU	Greater Missouri Operations Company (KCPL)
GRDA/GRDX	Grand River Dam Authority
GSEC	Golden Spread Electric Cooperative, Inc.
HMMU	Harlan (Iowa) Municipal Utilities
INDN	City of Independence (Mo.)
IS	Integrated System
KBPU	Kansas City (Kan.) Board of Public Utilities
KCPL/KCPS	Kansas City Power & Light
KMEA	Kansas Municipal Energy Agency
KPP	Kansas Power Pool
LES/LESM	Lincoln (Nebr.) Electric System
MEAN	Municipal Energy Agency of Nebraska
MEC/MECB	MidAmerican Energy Company
MEUC	Missouri Joint Municipal Electric Utility Commission
MIDW	Midwest Energy Inc.
MISO	Midcontinent Independent Transmission System Operator
MRES	Missouri River Energy Services
NDVER	non-dispatchable variable energy resource
NERC	North American Electric Reliability Corporation
NOAA	National Oceanic and Atmospheric Administration
NPPD/NPPM	Nebraska Public Power District
NSP/NSPP	NSP Energy

NWPS	Northwestern Energy
OGE	Oklahoma Gas & Electric
OMPA	Oklahoma Municipal Power Authority
OPPD/OPPM	Omaha Public Power District
OTPW/OTPR	Otter Tail Power Company
PJM	Pennsylvania-New Jersey-Maryland Interconnection
PEPL	Panhandle Eastern Pipe Line
SECI/SEPC	Sunflower Electric Power Corporation
SPA	Southwestern Power Administration
SPP	Southwest Power Pool, Inc.
SPRM	City Utilities of Springfield (Mo.)
SPS	Southwestern Public Service Company
TEA	The Energy Authority
TNSK	Tenaska Power Service Company
UGPM	Western Area Power Administration, Upper Great Plains
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council
WFEC/WFES	Western Farmers Electric Cooperative
WR/WRGS	Westar Energy, Incorporated