SPP Southwest Power Pool
Market Monitoring Unit

STATE OF THE MARKET

2017

published
May 8, 2018

Acknowledgement

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Southwest Power Pool, Inc.
Market Monitoring Unit

State of the Market 2017

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1 EXECUTIVE SUMMARY

The Southwest Power Pool (SPP) Market Monitoring Unit's (MMU) Annual State of the Market report for 2017 presents an overview of market design and market outcomes, assesses market performance, and provides recommendations for improvement. The purpose of this report is to provide SPP market stakeholders with reliable and useful analysis and information to use in making market-related decisions. The MMU emphasizes that economics and reliability are inseparable and that an efficient wholesale electricity market provides the greatest benefit to the end user both presently and in the years to come.

1.1 MARKET HIGHLIGHTS

The following list identifies key observations in the SPP marketplace over the past year.

- SPP market results were workably competitive, with infrequent mitigation of offers and high resource participation levels.
- Total wholesale market costs—including energy, operating reserve, and uplift payments—averaged around $24/MWh in 2017, which was about seven percent higher than in 2016. This was primarily caused by increases in energy costs.
- As natural gas-fired resources set prices in the SPP market a majority of the time, changes in natural gas prices influences electricity prices. Natural gas prices increased about 14 percent in 2017 compared to 2016.
- When system prices are controlled for changes in fuel prices, they averaged about eight percent lower in 2017 compared to 2016.
- While day-ahead and real-time prices both averaged around $23/MWh for the year, real-time price volatility nearly doubled in 2017 compared to 2016. Much of this volatility was the result of short-term transient ramping related price spikes.
- The incidence of negative prices doubled in 2017 to around seven percent of all real-time intervals, up from about 3.5 percent of intervals in 2016.
- Day-ahead and real-time congestion costs totaled over $500 million in 2017, a 70 percent increase from almost $300 million in 2016. The increase in congestion is related to continued development of wind resources and transmission limitations in the SPP system.

- Wind generation peaked at 15.7 GW and peak wind penetration was almost 57 percent of load in December. Wind capacity increased to almost 17.6 GW in 2017, up about nine percent from 2016.

- Wind generation totaled 23 percent of all generation in 2017, up from 18 percent in 2016. Coal generation fell from 48 percent in 2016 to 46 percent in 2017.

- New capacity additions were almost 2,200 MW at nameplate capacity, with wind representing 70 percent of the new capacity. Retirements were low, at around 130 MW.

- The interconnection process includes almost 48 GW of additional resources, of which 93 percent are renewable.

- SPP continues to have significant excess capacity at peak loads. The MMU estimates that capacity at peak is 30 percent higher than the peak demand level in 2017.

- Market prices themselves do not signal new investment in generation. Furthermore, MMU analysis shows that market revenues do not support going forward costs for coal resources.

- Market uplifts were low at about $68 million in 2017, which was down slightly from 2016 levels.

- Combined operating reserve costs totaled $80 million last year, an increase of 28 percent over 2016. This was driven by a combination of factors including higher spinning reserve requirements and prices.

- Auction revenue rights were funded at almost 165 percent in 2017, up from just over 140 percent in 2016.

- Transmission congestion rights funding increased to 94 percent in 2017 from 92 percent in 2016.

- While many participants sufficiently hedged their congestion costs with auction revenue rights and transmission congestion rights in 2017, some participants did not.

1.2 OVERVIEW

Overall, SPP markets produced highly competitive market results with total market costs around $24/MWh. As with previous years, the largest component of total wholesale costs remains energy costs, which represented almost 98 percent of total costs in 2017. While total costs increased by seven percent in 2017 compared to 2016, a main driver for the increase in energy costs was a 14 percent increase in natural gas prices. For instance, the annual average gas price at the Panhandle hub increased from $2.32/MMBtu in 2016 to $2.65/MMBtu in 2017. When adjusted for fuel prices, average SPP marginal energy prices declined.

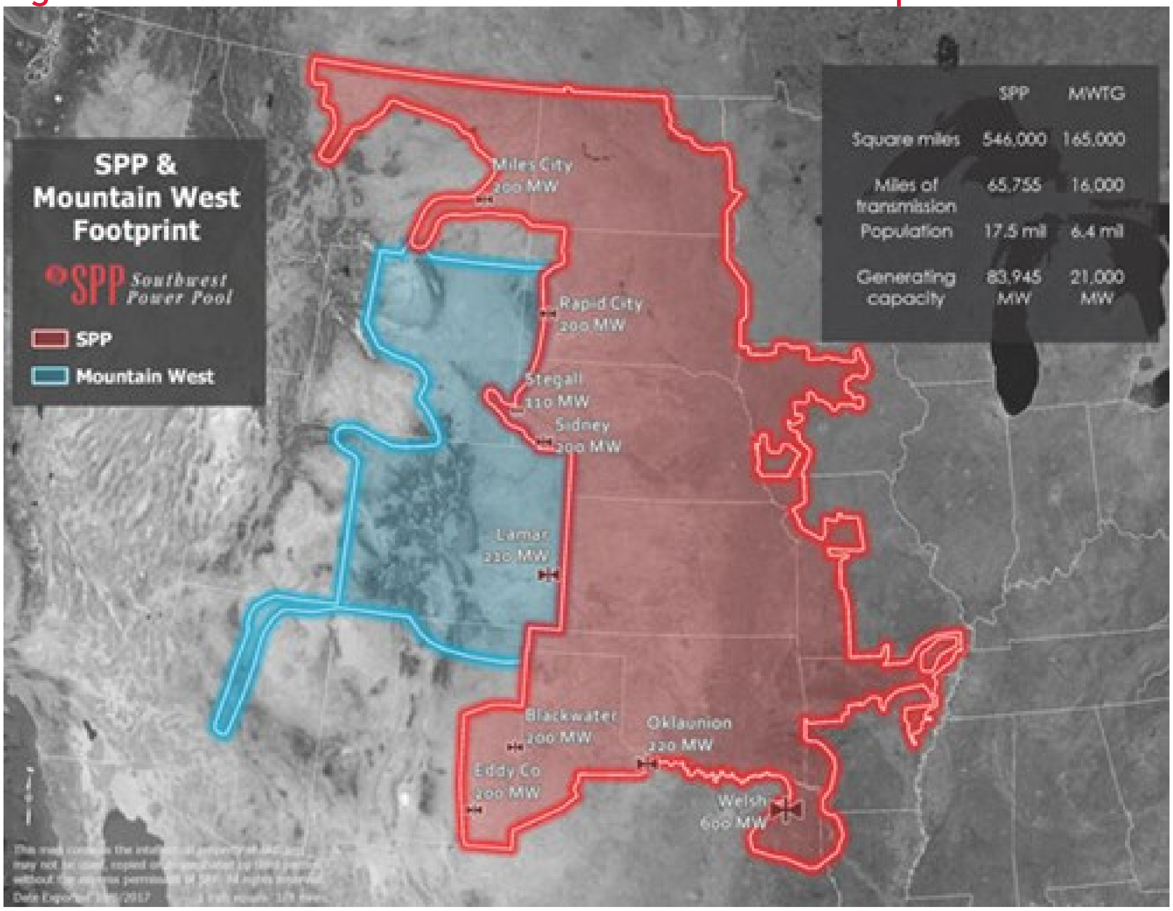
While the annual peak load of 51,181 MW was one percent higher this year compared to last year, total electricity consumption was down about one percent. Much of the 2,200 MW increase in nameplate generation capacity last year was from wind resources. This continues a pattern that has occurred over the past several years. However, the rate of new additions has declined significantly from around 11,350 MW in 2015 and 3,900 in 2016. Even so, wind generation continued to increase as it represented almost 23 percent of system generation, up from 18 percent in 2016 and 14 percent in 2015. Conversely, coal generation continued to decline, representing around 46 percent of total generation last year, down from 48 percent in 2016. Prior to last year, coal represented 55 percent or more generation in SPP.

There were several market based developments in 2017. Foremost of these occurred in September 2017 when the Mountain West Transmission Group announced that they would pursue membership with SPP. The Mountain West Transmission Group consists of entities located in Colorado, Wyoming, New Mexico, Arizona, Nebraska, and South Dakota, and is located in the Western Interconnection.[1,2] A graphical representation of the SPP and the Mountain West Transmission Group footprints is shown in Figure 1–1.

Though the SPP board has approved system integration, further approvals still need to be obtained. Even so, review of market design changes has begun in the SPP stakeholder process. The requisite filings are anticipated to be made with the FERC and other governing bodies in 2018. SPP anticipates integration of the Mountain West Transmission Group into the SPP market by spring 2020. While the MMU has not been involved in the negotiation process, the MMU supports the concept of expanding the market footprint to enhance market efficiencies, and we are reviewing the proposed integration changes along with other SPP stakeholders.

[1] More detail on the Mountain West Transmission Group can be found at https://www.spp.org/mountain-west/.
[2] On April 20, 2018, SPP received notice from Xcel Energy-Colorado, indicating that they are ending their participation in the Mountain West Transmission Group and their effort to pursue membership in SPP. At this time, Mountain West and SPP staff, stakeholders, and board of directors are currently evaluating the implications of this announcement, and determining next steps.

Figure 1–1 Southwest Power Pool and Mountain West footprint



Other significant market events in 2017 included:

- The addition of the phase-shifting transformer to address congestion at the Woodward, Oklahoma substation.[3] Our analysis shows that this transformer has substantially changed the congestion pattern in SPP after deployment, shifting congestion further east.
- Implementation of new tariff language with regard to jointly-owned resources.[4] While this modification was intended to relieve a gaming opportunity, it has had several unintended consequences on settlements and has opened up the opportunity for a new gaming issue. SPP, stakeholders, and the MMU are currently working on a solution.
- Implementation of new scarcity pricing rules.[5] Two sets of changes occurred. The first was in May and was consistent with FERC Order No. 825. This change removed the

[3] See Section 5.1 for further discussion.
[4] See Section 4.3.4 for further discussion.
[5] Scarcity pricing is covered in Section 4.2.

violation relaxation limits for resource capacity constraints, resource ramp constraints, and global power constraints. Additional changes were implemented in August. These changes replaced fixed price demand curves with variable price demand curves.

- Market participant concerns with the effectiveness of the auction revenue rights process to allow participants to receive sufficient hedges for congestion.[6] We observe that while many participants were able to manage congestion, a handful of participants did not have sufficient hedges. There were multiple reasons for this including the nature of congestion patterns, outages, and market participant strategies.

1.3 DAY-AHEAD AND REAL-TIME MARKET PERFORMANCE

While load participation in the day-ahead market continued to be strong in 2017, generation participation, particularly from wind resources contributed to substantial increases in supply in the real-time market and increasing incidence of negative real-time prices. For instance, the average level of participation for the load assets was between 98 percent and 101 percent of the actual real-time load. However, we found that on average for the year, wind generation was over 1,200 MW higher in the real-time market compared to the amount scheduled in the day-ahead market. This represents an increasing challenge to the market as wind generation has increased substantially over the past few years.

While virtual bids and offers may theoretically offset the under-scheduling of renewable supply in the day-ahead market, in net they did not as they averaged around 650 MW of net virtual supply. While about half of all virtual offer activity occurs at renewable locations, the other half does not. Furthermore, it is important to recognize that even if virtual transactions were to match the quantity of under-scheduled renewables, the prices associated with the virtual offers are not likely to fully represent the offer prices of the renewable resources in order to preserve a profit margin.

In general, virtual transactions were increasingly profitable in the SPP market. Total profits increased in 2017 to about $54 million from about $33 million in 2016. When transaction fees are included, net profit for virtual transactions was $35 million in 2017, more than double

[6] Auction revenue rights and transmission congestion rights are covered in Section 5.2.

the amount received in 2016. Net virtual profits were highest in April ($5.9 million) and October ($7.9 million) when winds are typically highest and loads are lower.

Self-commitment of generation continues to be a concern because it does not allow the market software to determine the most economic market solution. Furthermore, it can contribute to market uplifts and low prices. Some of the reasons for self-committing may include contract terms for coal plants, low gas prices that reduce the opportunity for coal units to be economically cleared in the day-ahead market, long startup times, and a risk-averse business practice approach. Generation offers in the day-ahead market averaged almost 55 percent as "market" commitment status followed by "self-commit" status at 31 percent of the total capacity commitments for 2017.[7] In 2016, the "market" and "self-commit" shares were at 48 percent and 36 percent, respectively. While the increase in market commitments and decrease in self-commitments highlights an improvement, self-commitments still represent over 30 percent of generation, a trend that has existed since the Integrated Marketplace began in 2014. In order to improve market commitment in the SPP market, we recommend that SPP and stakeholders look to find ways to address this issue. This is discussed further below.

Day-ahead prices have historically been higher than real-time prices. However, real-time prices were higher than day-ahead prices in nine months last year primarily because of higher real-time price volatility, which almost doubled in 2017 when compared to 2015 and 2016. This increased volatility mostly was caused by scarcity pricing events, which caused short-term real-time prices spikes that typically only occurred for one interval. These scarcity pricing events highlighted ramping limitations, which can be thought of as temporal congestion. Unlike some other RTO/ISO markets, the current SPP model does not account for forecasted ramping needs. Our analysis (see Section 3.3.1) shows that accounting for ramping needs would greatly assist in preparing and compensating generation for both anticipated and unanticipated ramping needs. As such, we recommend, as discussed below, that SPP and stakeholders develop a ramping product.

[7] Other resource commitment statuses are "reliability", "not participating", and "outage" at two percent, three percent, and 10 percent, respectively. These all represent similar numbers when compared over the past several years.

1.4 TRANSMISSION CONGESTION AND HEDGING

Locational marginal prices reflect the sum of the marginal cost of energy, the marginal cost of congestion, and the marginal cost of losses for each pricing interval at any given pricing location in the market. Although the SPP market currently maintains a high reserve margin, certain locations of the footprint experience significant price movements resulting from congestion caused by high wind generation and transmission limitations.

In total, congestion costs were over $500 million in 2017. This was a significant increase from almost $300 million in 2016. While most load-serving entities were able to successfully hedge their congestion exposure with auction revenue rights and transmission congestion rights, a handful of participants were significantly under-hedged. In 2017, the total of all transmission congestion right and auction revenue right net payments to load-serving entities of $408 million was less than the total day-ahead and real-time markets congestion costs of $413 million. However, on an individual basis, some participants were over-hedged, whereas others were under-hedged. Three participants were each under-hedged by over $30 million.

As a result, there were discussions in the stakeholder process about the effectiveness of the auction revenue right process in allocating desired rights. The MMU believes that the lack of allocated auction revenue rights appears to be, in part, related to bidding strategy. The MMU identified instances where both prevailing flow and counter-flow positions that could have been nominated by participants were not nominated. Moreover, transmission service reservations are studied and granted with assumptions that include counter-flow megawatts. This means that without the use of counter-flow, many of the prevailing flow paths are not feasible. Nominating the appropriate counter-flow paths in the allocation will help to increase the amount of prevailing flow paths allocated. This ultimately means the less counter-flow nominated will result in less prevailing flow allocated. MMU and SPP analysis identified that these positions could have improved hedges in some cases.

Finally, modeling of outages in the transmission congestion rights market are not well aligned with actual outages that occur in the day-ahead market. Only around five percent of the number of day-ahead outages were included in the transmission congestion rights market. While each outage can have its own unique impacts on the market, this is a substantial difference and is likely to be a factor influencing the effectiveness of the hedges.

Considering positions including prevailing flow and counter-flow as well as outages will be important as stakeholders continue to consider how to improve hedging mechanisms.

1.5 UPLIFT COSTS

Generators receive make-whole payments to ensure that they receive sufficient revenue to cover energy, start-up, no-load, and operating reserve costs for both market and local reliability commitments. Make-whole payments are additional market payments in cases where prices result in revenue that is below a resource's cleared offers. These payments are intended to make resources whole to energy, commitment, and operating reserve costs.

In 2017, total make-whole payments were approximately $68 million, down slightly from $71 million in 2016. Make-whole payments averaged about $0.26/MWh in 2017, which was about the same as in 2016. In comparison to other RTO/ISO markets, SPP's make-whole payments were on the low end of uplift costs, which varied from $0.22/MWh to $0.57/MWh in 2016.[8]

Day-ahead make-whole payments constituted about 42 percent of the total make-whole payments in 2017. SPP pays about 85 percent of all make-whole payments to gas-fired resources with 65 percent of reliability unit commitment make-whole payments to simple-cycle gas resources.

Last December, FERC found SPP's quick-start pricing practice may be unjust and unreasonable, and argued that pricing enhancements would improve uplifts.[9] Our analysis shows that uplift payments remain fairly low. Furthermore, our assessment of FERC's proposal suggests that, if anything, FERC's proposal would transfer, if not increase, uplifts.[10]

[8] ISO NE State of Market Report https://www.potomaceconomics.com/wp-content/uploads/2017/07/ISO-NE-2016-SOM-Report_Full-Report_Final.pdf , MISO Annual state of Market report http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2016/2016-som-pjm-sec4.pdf , PJM website www.pjm.com
[9] *Order Instituting Section 206 Proceeding and Commencing Hearing Procedures and Establishing Refund Effective Date*, 161 FERC ¶ 61,296 (2017).
[10] Southwest Power Pool Market Monitoring Unit Reply Brief, Docket No. EL18-35-000, March 13, 2018.

1.6 COMPETITIVENESS ASSESSMENT

The SPP market provides effective incentives and mitigation measures to produce competitive market outcomes even during periods when the potential for the exercise of local market power could be a concern. The MMU's competitive assessment using structural and behavioral metrics indicate that market results in 2017 were workably competitive and that the market required mitigation of local market power infrequently to achieve competitive outcomes. Even with these low levels of mitigation, stakeholders proposed market design changes, and significant discussion occurred around changing behavioral mitigation parameters during the stakeholder process in 2017.[11]

As with previous years, structural competitiveness metrics—which review the structural potential for the exercise of market power—indicate minimal potential structural market power in SPP markets outside of areas that are frequently congested. For the two frequently constrained areas, where potential for concerns of local market power is the highest, existing mitigation measures serve well to prevent pivotal suppliers from unilaterally raising prices.

Behavioral indicators—which assess the actual exercise of market power—show low levels of mitigation frequency. Mitigation of day-ahead energy, operating reserve, and no-load offers each occurred less than 0.2 percent of the time and real-time mitigation occurred about 0.01 percent of the time. The overall mitigation frequency of start-up offers was the lowest since the market began in 2014, as it decreased in 2017 relative to 2016 levels to just over three percent.

The decline in mitigation may be the result of declining offer price mark-ups. Both off-peak and on-peak average offer markups were at the lowest levels since implementation of the Integrated Marketplace at around -\$3.50/MWh and -\$1.70/MWh, respectively. Although a lower offer price markup level in itself would indicate a competitive pressure on suppliers in the SPP market, the observed continuous downward trend may raise questions about the commercial viability of generating units and the possibility of generation retirements. Even so, only about 130 MW of generation retired in 2017.

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[11] It is likely that much of this discussion had little to do with the frequency of mitigation, but more to do with the exclusion of major maintenance from mitigated start-up and no-load offers. In January 2018, the SPP board approved a proposal to allow major maintenance costs to be included in commitment costs. This proposal was supported by the MMU.

The monthly average output gap—which measures economic withholding—shows very low levels of economic withholding in all months in 2017. Specifically, there was no measurable output withheld in the two frequently constrained areas. These low levels of economic output withholding reflect highly competitive participation in the market.

This year we introduced a new metric for competitive assessment. This metric measures unoffered generation capacity for potential physical withholding. Specifically, any economic generation capacity that is not made available to the market through derates, outages, or otherwise not offered to the market is considered for this analysis.

Annually for the SPP footprint, the total unoffered capacity (as a percent of total resource reference levels) equaled 1.8 percent in 2015, 2.0 percent in 2016, and 1.9 percent in 2017. When short and long-term outages are removed, the remaining unoffered capacity was 0.03 percent, 0.22 percent, and 0.23 percent, respectively. The majority of the outages were long-term outages due to maintenance during the shoulder fall and spring months. From a competitive market perspective, the results indicate reasonable levels of total unoffered economic capacity and are consistent with the results in other RTO/ISO markets.

1.7 STRUCTURAL ISSUES

Installed generation capacity in the SPP market has grown rapidly over the past several years. This has contributed to high levels of capacity at peak loads. Specifically, the MMU estimates using a new methodology that capacity was 30 percent higher than the peak load in 2017. SPP's current annual planning capacity requirement is 12 percent.

Wind capacity has more than doubled from 8.6 GW in 2014 to 17.6 GW in 2017. At the same time, wind generation has constituted a growing and significant part of the total annual generation, from around 12 percent in 2014 to 23 percent in 2017; the all-time high rate of wind generation penetration was set in March 2018 at 60.6 percent of load. Furthermore, the interconnection process includes almost 48 GW of additional resources, of which 93 percent are renewable resources.

The shift in generation mix towards renewable resources is a significant and positive development; however, it carries both market and operational challenges. This includes an increase in the incidence of negative prices as they increased from 3.5 percent of real-time intervals in 2016 to seven percent of intervals in 2017, and growing congestion charges which were over $500 million in 2017, up from almost $300 million in 2016. Furthermore, these challenges are further exacerbated by the fact that currently 36 percent of the total wind capacity is non-dispatchable.

It is in the best interest of SPP market stakeholders to prepare for the challenges these changes to the market present. Expanding the SPP footprint, is one way to help manage the growing levels of renewable generation. However, additional changes from planning to operations needs to be developed to improve market outcomes. As such, we make several recommendations to address these growing market concerns.

1.8 RECOMMENDATIONS

One of the primary responsibilities of a market monitoring unit is to evaluate market rules and market design features for market efficiency and effectiveness. When we identify issues with the market, one of the ways to correct them is to make recommendations on market enhancements. These recommendations are highlighted in detail in Chapter 7. Below is a summary of our 2017 recommendations.

1.8.1 INCREASE MARKET FLEXIBILITY

The SPP market needs more flexible generation to meet increasing ramping requirements as renewable generation levels continue to increase and as renewable generation dominates the interconnection queue over the next several years. Because of the variable output nature of these renewable energy resources, the market needs increasing capability to respond to the inevitable fluctuations in order to promote efficient market outcomes and ensure reliability. It is imperative for SPP and its members to improve its market mechanisms to address this growing concern. We recommend that SPP:

- **Develop a ramping product** – A ramping product that incents actual, deliverable flexibility can send appropriate price signals to value resource flexibility. This resource flexibility can help prepare the system for fluctuations in both demand and supply that result in transient short-term positive and negative price spikes.

- **Improve rules related to decommitting resources** – Over-commitment of resources in real time suppresses prices and leads to increased make-whole payments. This can be caused by changing conditions between the time a resource is locked into a commitment by the market software and the time the resource actually comes on-line. The MMU recommends that SPP and its stakeholders address this issue by enhancing its market rules to economically decommit a resource that is planned to start.

- **Enhance market rules for energy storage resources** – FERC Order No. 841 requires SPP to develop rules to create a participation model for energy storage resources. We fully concur with FERC's objectives as energy storage resources can add significant market flexibility to address changing demand and supply conditions. We look forward to working with SPP and stakeholders on this enhancement.

1.8.2 IMPROVE MARKET EFFICIENCY

One of the key benefits of the day-ahead market is the unit commitment process. Market participants offer resources into the day-ahead market and the market optimization process minimizes production costs. Inefficient market outcomes can occur when participants self-commit resources and when forecasted generation—such as wind—are withheld from the day-ahead market run, even though their expected generation levels are much higher.

- **Address market efficiency caused by self-committing resources** – While market participants have identified several reasons why they self-commit resources in the market, it is imperative to minimize the need to self-commit resources to realize the full benefits of SPP's market. We recommend that the SPP and stakeholders explore ways to minimize self-committing. One potential approach is through the development of a multi-day unit commitment process.

- **Address market efficiency when forecasted resources are under-scheduled day-ahead** – Our analysis shows that, on average, 82 percent of forecasted wind generation was scheduled in the day-ahead market in 2017, and that under-scheduling of wind is a growing problem. While some of this difference may be related to forecasting challenges, market participants also significantly under-schedule wind relative to their day-ahead forecasted levels. On average for the year, over 1,200 MWh of real-time wind generation was not included in the day-ahead market. This can contribute to distorting market price signals, suppressing real-time prices, and affecting revenue adequacy for all resources.

1.8.3 CONTINUE ALIGNMENT OF PLANNING PROCESSES WITH OPERATIONAL CONDITIONS

Enhancing the accuracy of planning processes with operational realities enables SPP and its members to more effectively plan for future system needs and conditions. Many of the challenges outlined in this report—including increased congestion, negative prices, and low generator net revenues—and some of the improvements—including the Woodward phase-shifting transformer—are, in part, a reflection of planning decisions. The more the planning process can learn from and incorporate operational information, the more planning can identify and address concerns in advance of market operations. While SPP has done much in this area, there are a few additional areas that could benefit by aligning and reflecting operational information. Specifically, the economic studies and the resource adequacy processes are two planning processes that could benefit further from alignment.

1.8.4 ADDRESS OUTSTANDING RECOMMENDATIONS

The MMU has provided recommendations to improve market design in our previous annual reports. Overall, SPP and its stakeholders have found ways to effectively address many of our concerns. However, there are a number of recommendations that remain outstanding. A description of each of these outstanding recommendations are outlined below.

- **Convert non-dispatchable variable energy resources to dispatchable** – In the 2015 Annual State of the Market report, the MMU identified non-dispatchable variable energy resources as a concern because of their adverse impact on market price and system operations. These resources exacerbate congestion, reduce prices for other resources, increase the magnitude of negative prices, cause the need for market-to-market payments, and force manual commitments of resources that can increase uplift. SPP and its stakeholders at the Market Working Group discussed this issue in 2017 and passed an SPP proposal in early 2018 to require conversion of non-dispatchable resources. The MMU fully supports this change, which is currently awaiting further stakeholder review.

- **Address gaming opportunity for multi-day minimum run time resources** – For resources with minimum run times greater than two days, the market participant knows that the resource is required to run and can increase their market offers after the second day to increase make-whole payments. The Market Working Group has identified a potential solution which would limit the make-whole payments for any resource with multi-day minimum run times to the lower of the market offer or the mitigated offer after the first day for resources that bid at or above their mitigated offer on the first day. While a solution has been developed, the proposal remains in the stakeholder process. We recommend that this solution continue to move forward.

- **Convert the local reliability mitigation threshold to a cap –** In the 2016 Annual State of the Market report, the MMU recommended converting the 10 percent mitigation threshold for local reliability commitments to a 10 percent cap. This recommendation addresses an unbalanced risk associated with mitigation of resource commitments for local reliability. This change was approved by the board in October and is pending a FERC filing. The MMU strongly supports this change and will support this when filed at FERC.
- **Replace the day-ahead must offer requirement and add a physical withholding provision –** FERC rejected in fall 2017, SPP's proposal to remove the day-ahead must offer requirement and indicated that it would consider removal of the requirement if it were paired with additional physical withholding provisions. While the MMU remains concerned with the current day-ahead must offer requirement, we recommend that further consideration of this issue be a low priority at this time given competing priorities.

2 LOAD AND RESOURCES

2.1 THE INTEGRATED MARKETPLACE

SPP is a Regional Transmission Organization (RTO) authorized by the Federal Energy Regulatory Commission (FERC) to ensure reliable power supplies, adequate transmission infrastructure, and competitive wholesale electricity prices. FERC granted RTO status to SPP in 2004. SPP provides many services to its members, including reliability coordination, tariff administration, regional scheduling, reserve sharing, transmission expansion planning, wholesale electricity market operations, and training. This report focuses on the 2017 calendar year of the SPP wholesale electricity market referred to as the Integrated Marketplace, which started on March 1, 2014.

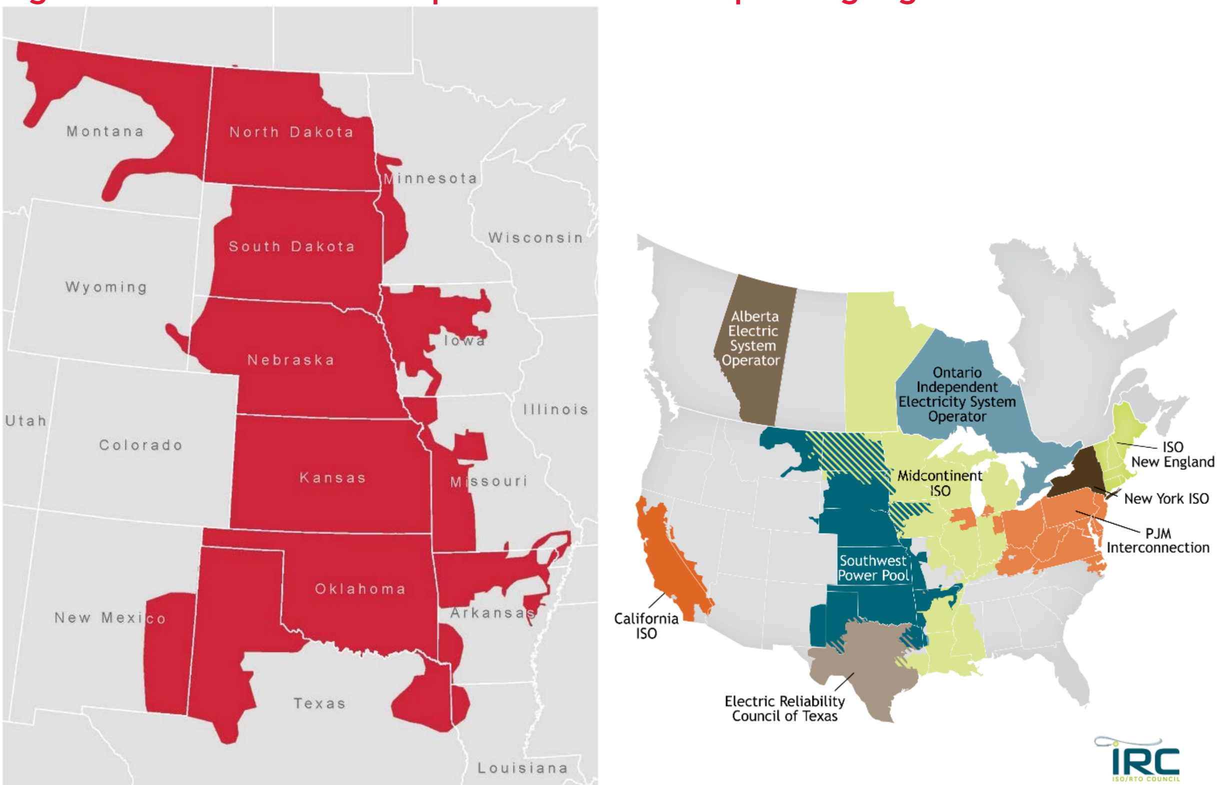
The Integrated Marketplace is a full day-ahead market with transmission congestion rights, virtual trading, a reliability unit commitment process, a real-time balancing market, and a price-based operating reserves market. SPP simultaneously put into operation a single balancing authority as part of the implementation of the Integrated Marketplace. The primary benefit of the introduction of a day-ahead market was to improve the efficiency of daily resource commitments. Another benefit of the new market includes the joint optimization of the available capacity for energy and operating reserves.

2.1.1 SPP MARKET FOOTPRINT

The SPP market footprint is located in the westernmost portion of the Eastern Interconnection, with Midcontinent ISO (MISO) to the east, Electric Reliability Council of Texas (ERCOT) to the south, and Western Electricity Coordinating Council (WECC) to the west. Figure 2–1 shows the current operating regions of the nine ISO/RTO markets in the United States and Canada, as well as a more detailed view of the SPP footprint. The SPP market also has connections with other non-ISO/RTO areas such as Saskatchewan Power Corporation, Associated Electric Cooperative, and Southwestern Power Administration.[12]

[12] Southwestern Power Administration belongs to the SPP RTO, Reliability Coordinator (RC), Reserve Sharing Group (RSG), and Regional Entity (RE) footprints. Associated Electric Cooperative belongs to the SPP RSG.

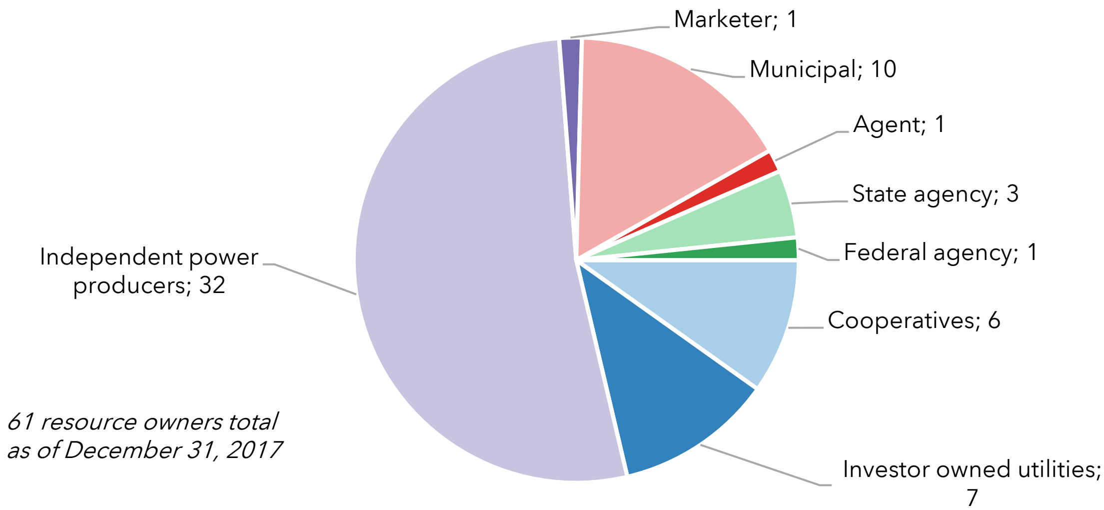
Figure 2–1 SPP market footprint and ISO/RTO operating regions



2.1.2 SPP MARKET PARTICIPANTS

At the end of 2017, 211 entities were participating in the SPP Integrated Marketplace. SPP market participants can be divided into several categories: regulated investor-owned utilities, electric cooperatives, municipal utilities, federal and state agencies, independent power producers, and financial only market participants that do not own physical assets. Figure 2–2 shows the distribution of the number of the 61 resource owners registered to participate in the Integrated Marketplace.

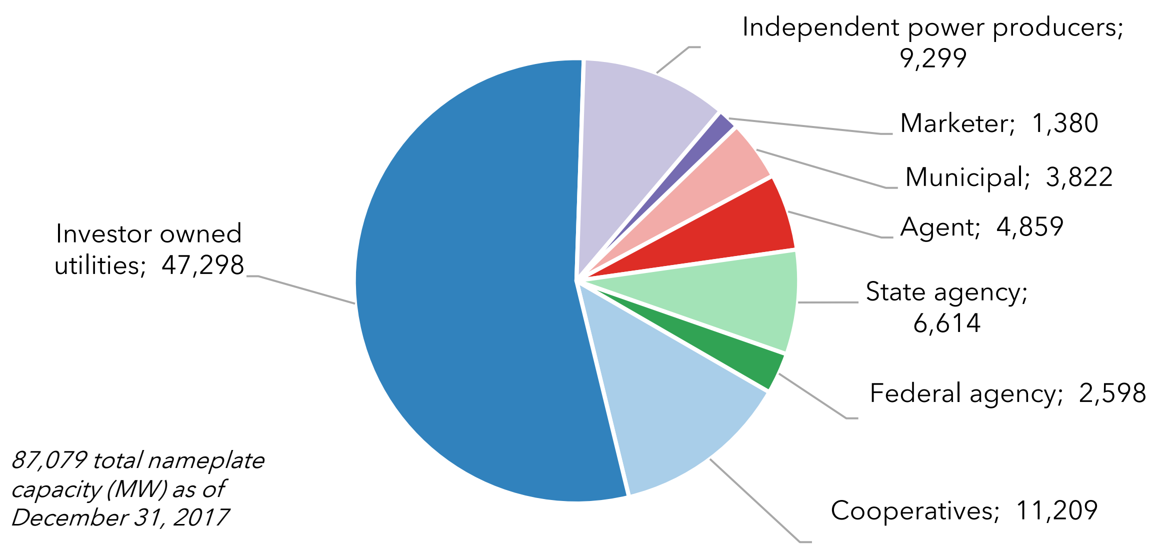
Figure 2–2 Market participants by type



The number of independent power producers is high since most wind producers are included in this category. Market participants referred to as an "agent" represent several individual resource owners that would individually be classified as different types, such as municipal utilities, electric cooperatives, and state agencies.

Figure 2–3 shows generation nameplate capacity owned by the type of market participant. Investor-owned utilities and cooperatives own two-thirds of the nameplate generation capacity in the SPP market.

Figure 2–3 Capacity by market participant type



Although investor-owned utilities represent only a small percent of the number of participants in the market at 11 percent, they own the majority of the SPP generation capacity at 54 percent. This is in contrast to the "independent power producer" category, which has a large number of participants (52 percent) representing only a small portion (11 percent) of total nameplate capacity.

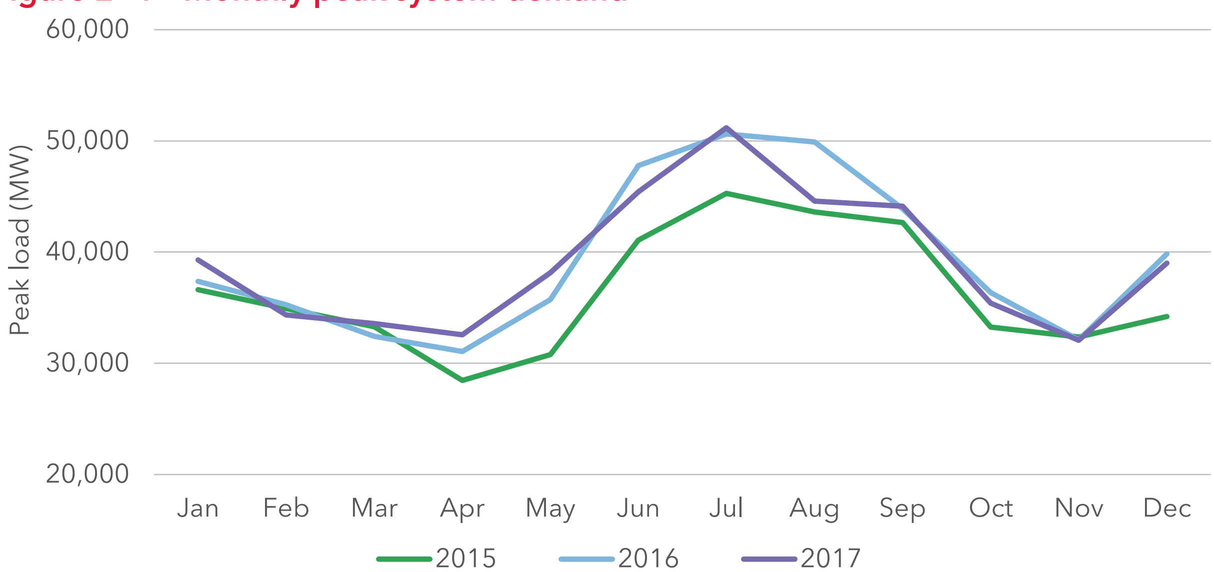
2.2 ELECTRICITY DEMAND

2.2.1 SYSTEM PEAK DEMAND

One way to evaluate load is to review peak system demand statistics over an extended period of time. The market footprint has changed over time as participants were added or removed. The peak demand values reviewed in this section are coincident peaks, calculated out of total generation dispatch across the entire market footprint that occurred during a specific market interval. The peak experienced during a particular year or season is affected by events such as unusually hot or cold weather, and daily and seasonal load patterns.

Figure 2–4 shows a month-by-month comparison of peak-day demand for the last three years. The SPP system coincident instantaneous peak demand[13] in 2017 was 51,181 MW, which occurred on July 20 at 4:30 PM. This is one percent higher than the 2016 system peak of 50,622 MW.

Figure 2–4 Monthly peak system demand

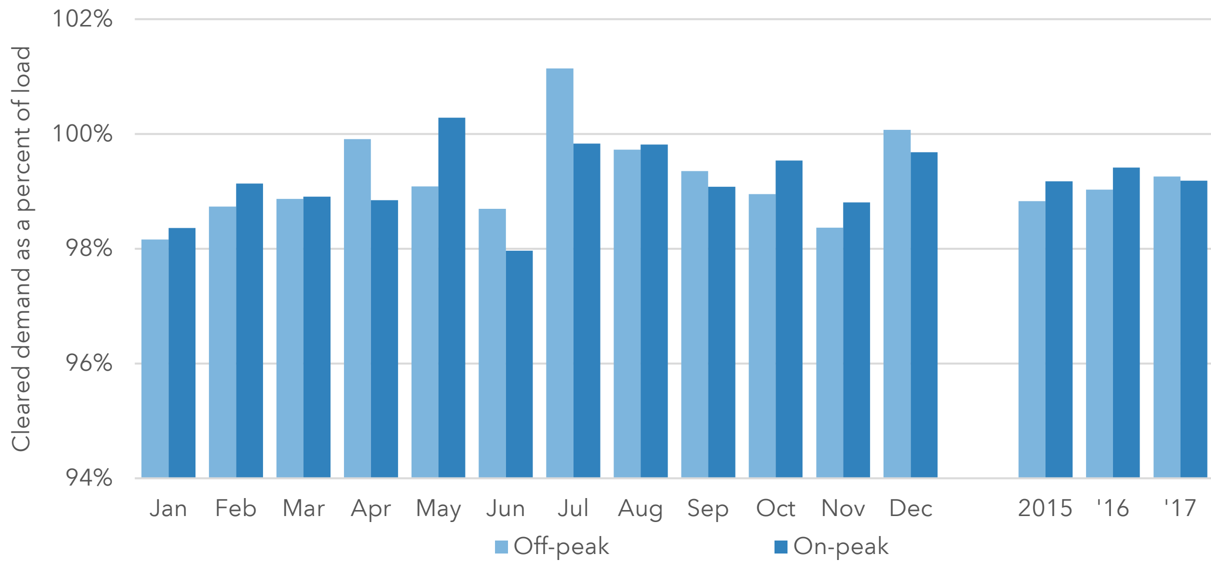


[13] Includes firm sales minus firm purchases, and includes losses.

2.2.2 MARKET PARTICIPANT LOAD

In 2017, load continued to participate in the day-ahead market at high levels as shown in Figure 2–5.

Figure 2–5 Cleared demand bids in day-ahead market



The average monthly participation rates for the load assets on an aggregate level were between 98 and 101 percent of the actual real-time load. Accurate reflection of demand in the day-ahead market economically incents generation to participate in the day-ahead market. Additionally, accurate reflection of the load helps to converge clearing prices. This remains consistent with prior years.

Figure 2–6 depicts 2017 total energy consumption and the percentage of energy consumption attributable to each entity in the market.

Figure 2–6 System energy usage

Name	2015		2016		2017	
	Energy consumed (GWh)	Percent of system	Energy consumed (GWh)	Percent of system	Energy consumed (GWh)	Percent of system
American Electric Power	43,078	18.9%	42,746	17.2%	41,887	17.0%
Oklahoma Gas and Electric	28,433	12.5%	28,078	11.3%	27,747	11.3%
Southwestern Public Service Company	25,590	11.2%	25,658	10.3%	25,826	10.5%
Westar Energy	23,544	10.3%	23,885	9.6%	23,845	9.7%
Kansas City Power and Light, Co	23,642	10.4%	23,951	9.6%	23,470	9.5%
Basin Electric Power Cooperative *	5,147	2.3%	17,859	7.2%	18,665	7.6%
The Energy Authority, NPPD	12,943	5.7%	13,248	5.3%	13,206	5.4%
Omaha Public Power District	10,854	4.8%	11,168	4.5%	11,066	4.5%
Western Farmers Electric Cooperative	9,041	4.0%	8,448	3.4%	8,046	3.3%
Grand River Dam Authority	5,616	2.5%	5,957	2.4%	5,581	2.3%
Empire District Electric Co.	5,156	2.3%	5,144	2.1%	4,984	2.0%
Golden Spread Electric Cooperative Inc.	4,840	2.1%	5,132	2.1%	4,817	2.0%
Sunflower Electric Power Corporation	4,646	2.0%	4,732	1.9%	4,693	1.9%
Western Area Power Administration, Upper Great Plains #	1,128	0.5%	4,477	1.8%	4,534	1.8%
Arkansas Electric Cooperative Corporation	3,172	1.4%	3,708	1.5%	3,675	1.5%
Lincoln Electric System Marketing	3,434	1.5%	3,515	1.4%	3,441	1.4%
The Energy Authority, CU	3,270	1.4%	3,332	1.3%	3,227	1.3%
Oklahoma Municipal Power Authority	2,797	1.2%	2,857	1.1%	2,766	1.1%
Kansas City Board of Public Utilities	2,392	1.0%	2,427	1.0%	2,347	1.0%
Midwest Energy Inc.	1,719	0.8%	1,710	0.7%	1,715	0.7%
Northwestern Energy #	394	0.2%	1,651	0.7%	1,632	0.7%
Kansas Municipal Energy Agency	1,437	0.6%	1,480	0.6%	1,473	0.6%
Tenaska Power Service Company	1,212	0.5%	1,363	0.5%	1,365	0.6%
Missouri River Energy Services #	304	0.1%	1,260	0.5%	1,226	0.5%
City of Independence	1,017	0.4%	1,065	0.4%	1,030	0.4%
Municipal Energy Agency of Nebraska	999	0.4%	1,015	0.4%	1,022	0.4%
Kansas Power Pool	857	0.4%	860	0.3%	843	0.3%
City of Chanute	489	0.2%	482	0.2%	487	0.2%
City of Fremont	435	0.2%	441	0.2%	433	0.2%
Missouri Joint Municipal Electrical Utility Commission	448	0.2%	450	0.2%	430	0.2%
MidAmerican Energy Company #	74	0.0%	284	0.1%	280	0.1%
South Sioux City, Nebraska +					225	0.1%
Harlan Municipal Utilities #	4	0.0%	19	0.0%	17	0.0%
NSP Energy #	1	0.0%	4	0.0%	5	0.0%
Otter Tail Power Company ^			41	0.0%	3	0.0%
System Total	**228,113**		**248,446**		**246,009**	

* Expanded footprint in SPP on October 1, 2015
\# Joined SPP on October 1, 2015
^ Load added to the footprint on January 1, 2016
\+ Joined SPP on January 1, 2017

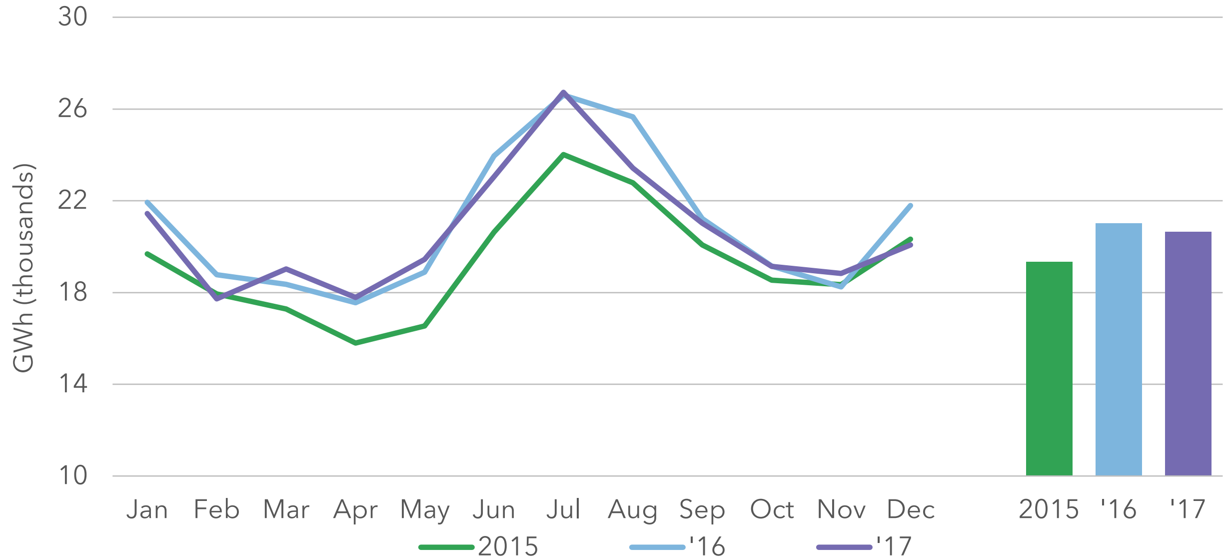
The largest five entities account for 58 percent of the total system energy usage, which is understandable because SPP's market is primarily composed of vertically integrated investor-owned utilities, which tend to be large. Overall, the total system energy usage in 2017 was one percent below the 2016 level, primarily due to cooler weather experienced in August 2017.

Also of note is the pending merger between Westar Energy and Great Plains Energy, parent company of Kansas City Power and Light, and the KCPL GMOC subsidiary.[14] Using 2017 figures, when this merger is completed, the combined company would account for 19.2 percent of total system load. This would make the combined company the largest user of system energy in the SPP market footprint.

2.2.3 SPP SYSTEM ENERGY CONSUMPTION

Figure 2–7 shows the monthly system energy consumption in thousands of gigawatt-hours.

Figure 2–7 System energy consumption, monthly

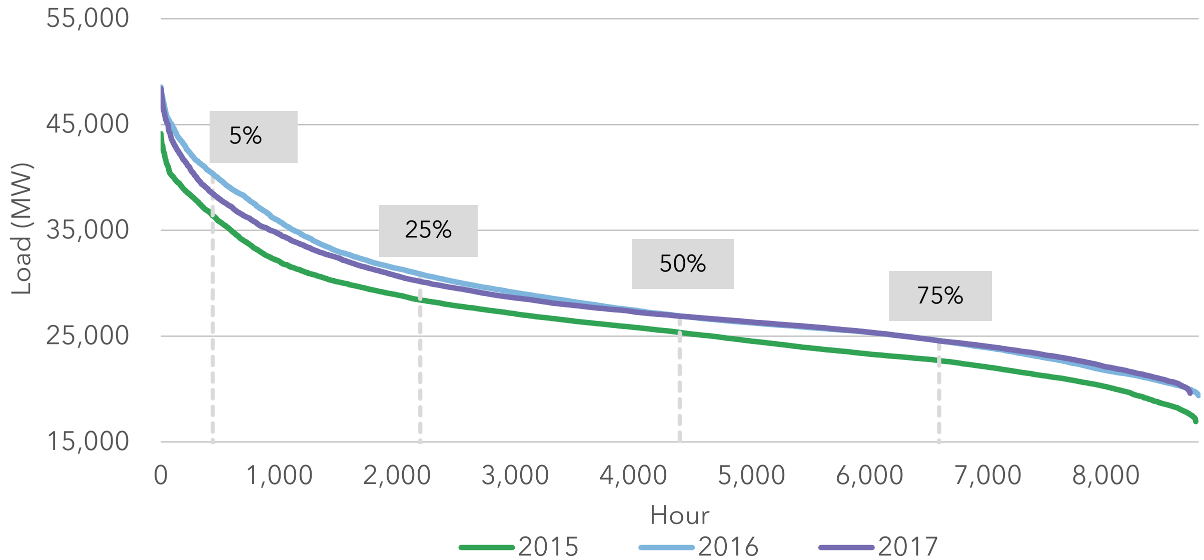


Monthly levels for 2016 and 2017 tracked closely together for most months, with the exception being August, when 2016 load was significantly higher, which was mostly attributed to high temperatures in that month.

Figure 2–8 depicts load duration curves from 2015 to 2017. These load duration curves display hourly loads from the highest to the lowest for each year.

[14] http://www.greatplainsenergy.com/about-gpe/westar-energy-acquisition

Figure 2–8 Load duration curve



In 2017, the maximum hourly average load was 48,375 MW, down just slightly from the high of 48,547 MW in 2016. The minimum hourly load for 2017 was 19,601 MW, which was slightly above the 2016 minimum of 19,377 MW. Comparing annual load duration curves shows differentiation between cases of extreme loading events and more general increases in system demand. If the extremes only are higher or lower than the previous year, then short-term loading events are likely the reason. However, if the entire load curve is higher than the previous year, it indicates that total system demand has increased.

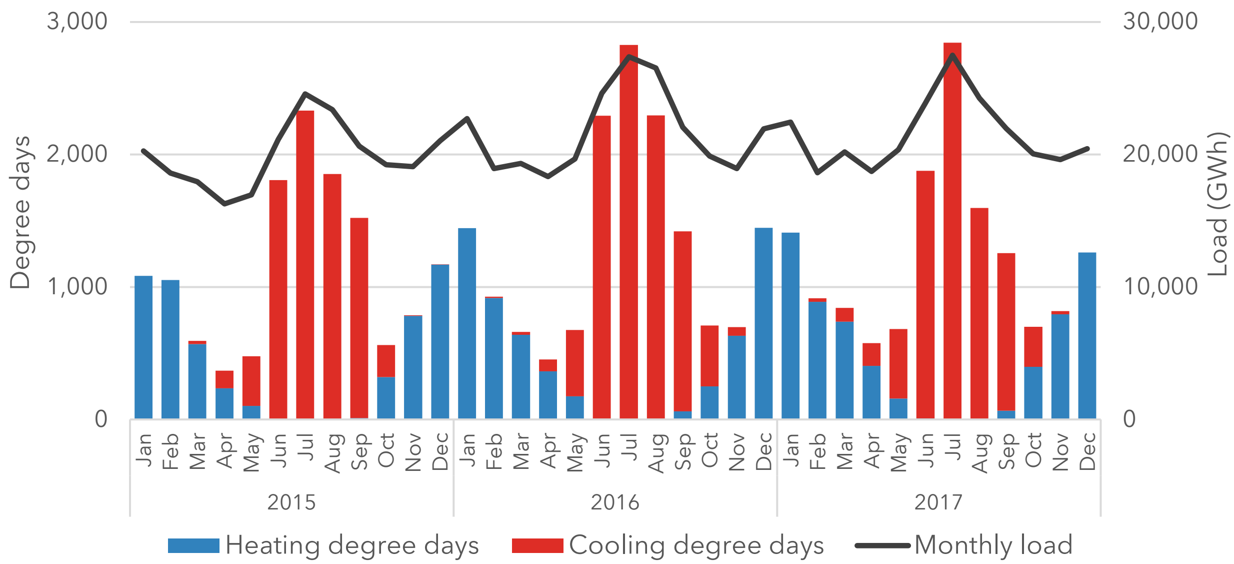
Reference percentage lines indicate a similar load pattern over the last three years at load levels above the 25 percent reference level. The largest notable difference between loads during these three years occurred at the higher load levels around the five percent reference value. Significantly higher temperatures across the footprint occurred in the summer of 2016 compared to the summer of 2017. The consistent difference between 2016 and 2017 compared to 2015 can largely be attributed to the addition of the Integrated System in October 2015.

2.2.4 HEATING AND COOLING DEGREE DAYS

Based on analysis of temperature impact on demand in the SPP footprint from 2011 through 2017, the MMU estimates that normal seasonal temperature variation tends to impact monthly total load by 29 percent (spring vs. summer). Changes in weather patterns from year-to-year have a significant impact on electricity demand. One way to evaluate this impact is to calculate heating degree days (HDD) and cooling degree days (CDD). These values can then be used to estimate the impact of actual weather conditions on energy consumption, compared to normal weather patterns.

To determine heating degree days and cooling degree days for the SPP footprint, several representative locations[15] were used to calculate system daily average temperatures.[16] In this report, the base temperature separating heating and cooling periods is 65 degrees Fahrenheit. If the average temperature of a day at a location is 75 degrees Fahrenheit, there would be 10 (=75-65) cooling degree days at that location. If a day's average temperature is 50 degrees Fahrenheit, there would be 15 (=65-50) heating degree days at that location. Using statistical tools, the daily estimated load impact of a single cooling degree day is much higher than the impact of a single heating degree day. The impact of a single cooling degree day on load is significantly higher than that of a heating degree day in part because of more electric cooling than electric heating.

Figure 2–9 Heating and cooling degree days



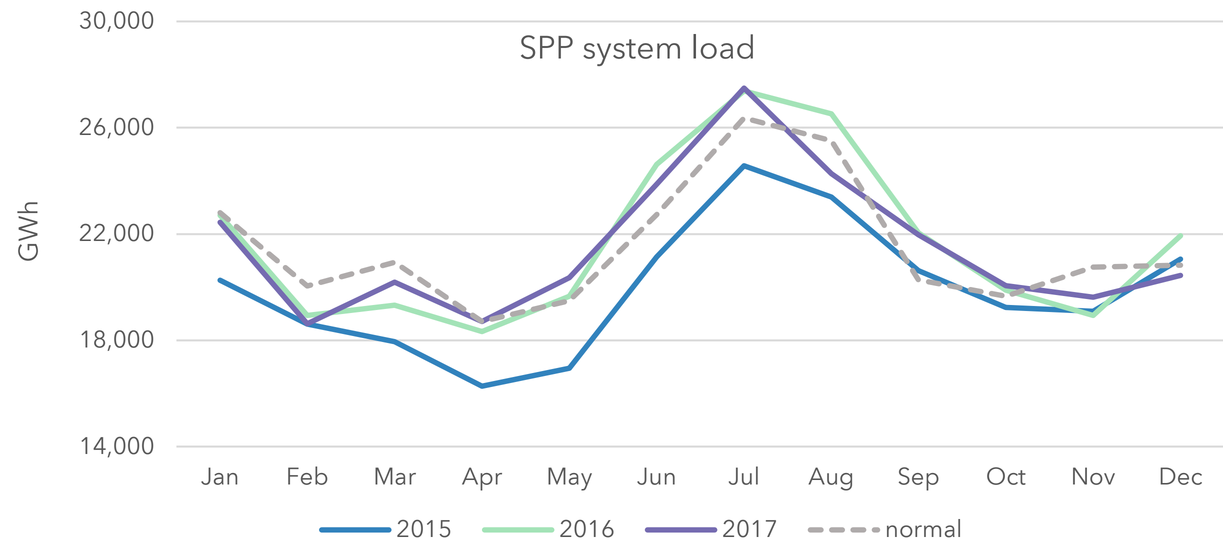
The SPP market footprint experienced cooler temperatures in June and August 2017 which resulted in a steeper monthly demand curve during that time period as compared to the two previous years. August temperatures were milder than normal, explaining the sharp drop in

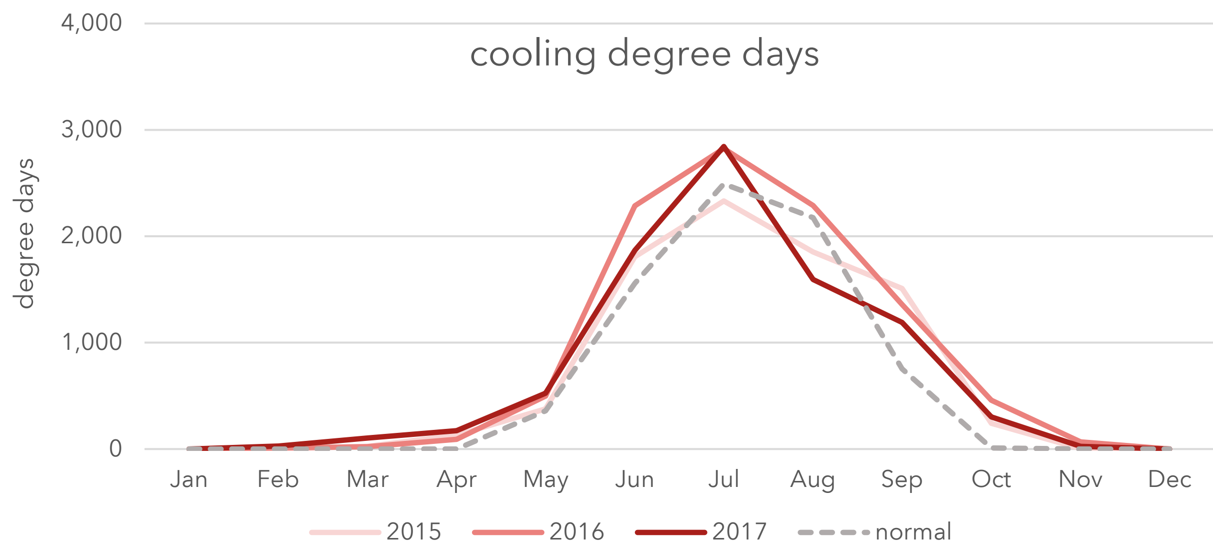
[15] Amarillo TX, Topeka KS, Oklahoma City OK, Tulsa OK, and Lincoln NE. After October 1, 2015, Bismarck ND was added to represent SPP's expanded market footprint.
[16] Daily average temperature is calculated as the average of the daily lowest and highest temperatures. The source of temperature data is the National Oceanic and Atmospheric Administration (NOAA).

market load from July to August. Otherwise, 2017 SPP footprint load and temperatures (as measured by degree days) were similar to 2016.

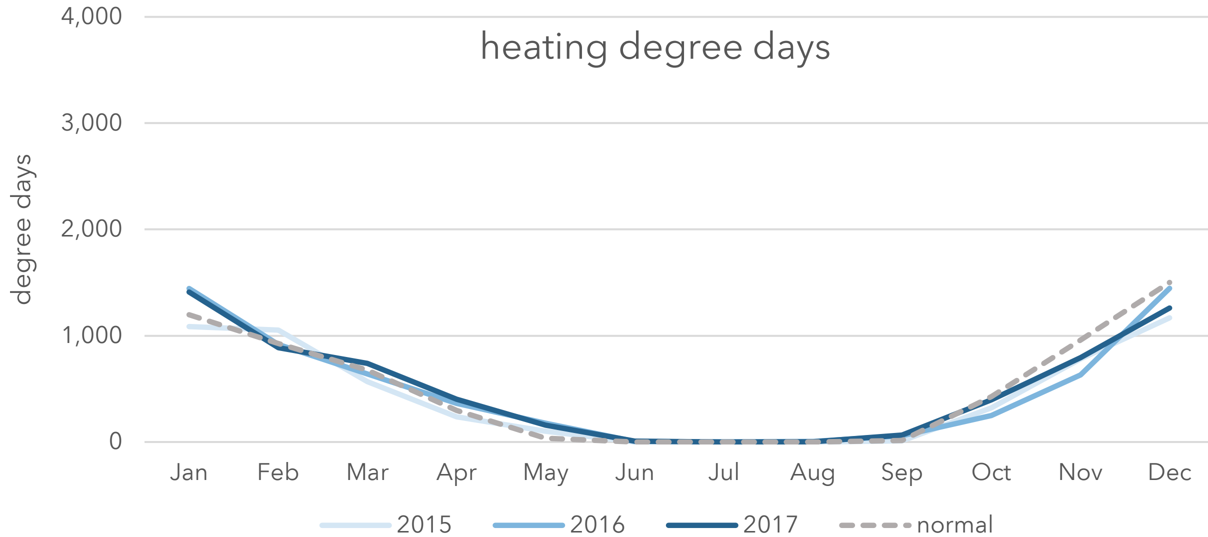
Figure 2–10 shows heating degree days, cooling degree days, and load levels from 2015 through 2017 compared to a normal year.[17] Normal 2017 load was derived from a regression analysis of actual footprint heating degree days, cooling degree days, weekends, and holidays, substituting footprint normal temperatures.

Figure 2–10 Degree days and loads compared with a normal year





[17] 30 year normal temperatures are from the 1981-2010 U.S. Climate normals product from NOAA.



The charts indicate loads are influenced by cooling demand in the late spring and summer months, whereas late fall and winter loads are, to a lesser degree, influenced by heating demand.

2.3 INSTALLED GENERATION CAPACITY

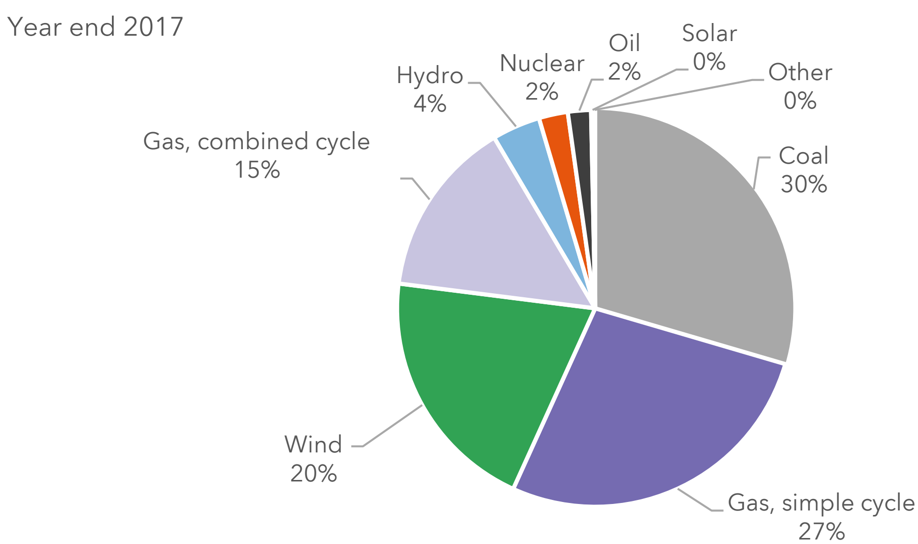
Figure 2–11 depicts the Integrated Marketplace installed generation for the SPP market footprint at the end of the year. Total installed generation in the SPP Integrated Marketplace was 87,079 MW by the end of 2017, representing a very slight decrease of less than one percent from 2016.[18]

[18] The change in total generation capacity from year to year includes additions, retirements, and nameplate rating changes that occur during the year.

Figure 2–11 Generation nameplate capacity by technology type

Fuel type	2015	2016	2017	Percent as of year-end 2017
Coal	28,821	26,939	25,717	30%
Gas, simple-cycle	23,910	24,024	23,737	27%
Wind	12,397	16,114	17,596	20%
Gas, combined-cycle	12,025	12,870	12,618	15%
Hydro	3,430	3,428	3,422	4%
Nuclear	2,629	2,107	2,061	2%
Oil	1,608	1,684	1,639	2%
Solar	50	215	215	0%
Other	74	74	74	0%
Total	84,943	87,453	87,079	

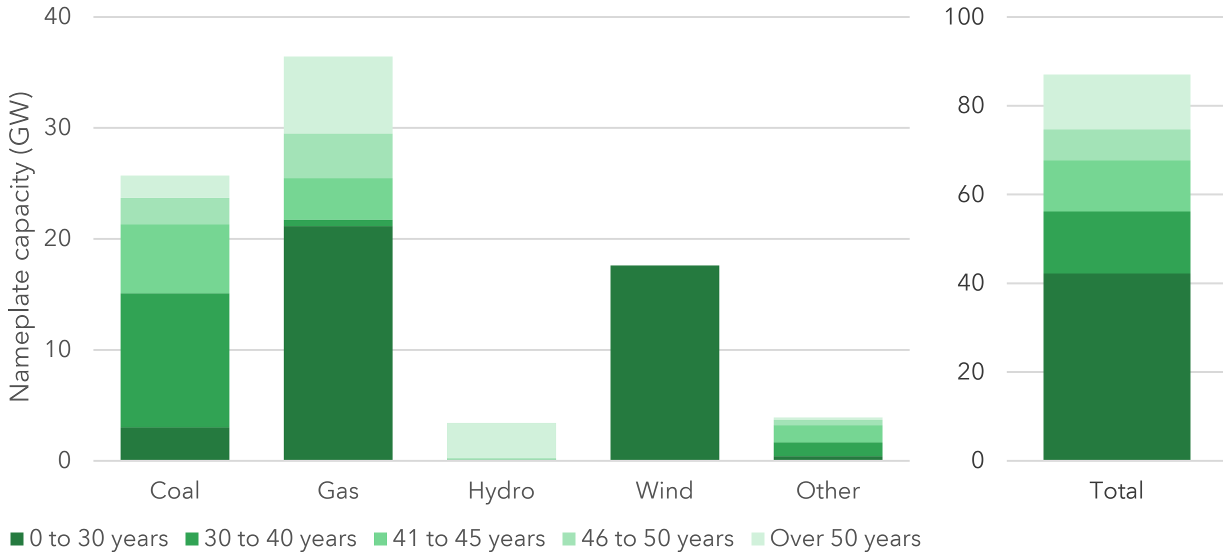
Note: Capacity is nameplate rating at year-end.



Natural gas-fired installed generation capacity still represents the largest share of generation capacity in the SPP market at 42 percent (gas simple-cycle 27 percent, gas combined-cycle 15 percent), with coal being the second largest type at 30 percent. Wind continues to increase due largely to new additions, with a 2017 market share of 20 percent of total capacity in the SPP market.

Figure 2–12 illustrates that certain segments of the SPP generation fleet are aging.

Figure 2–12 Capacity by age of resource



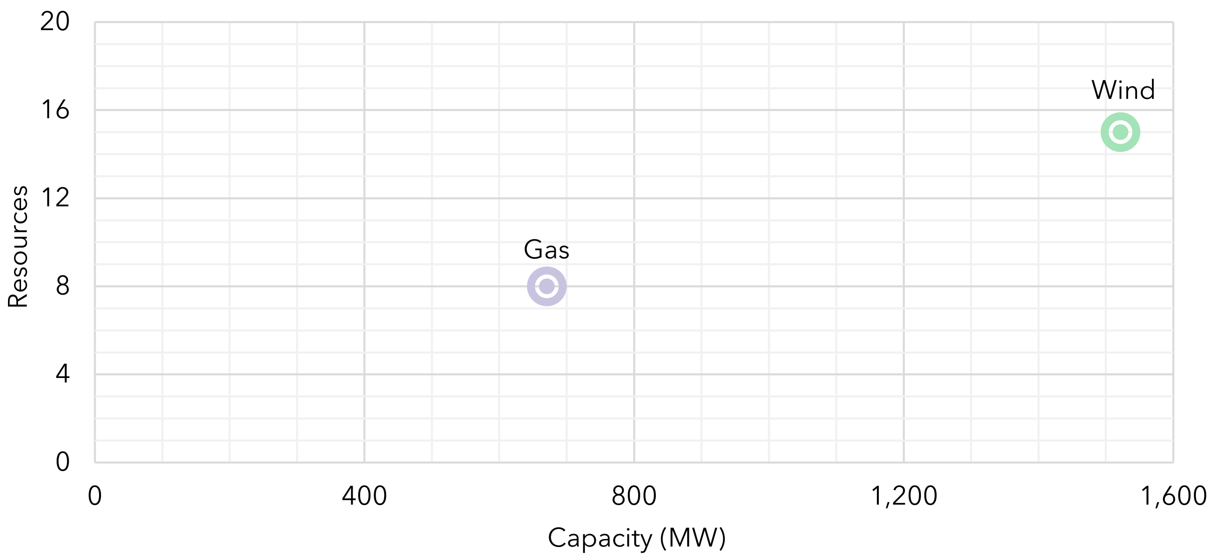
Nearly 52 percent of SPP's fleet is more than 30 years old. In particular, nearly 90 percent of coal capacity and just over 40 percent of gas capacity is older than 30 years. According to the U.S. Energy Information Administration (EIA), the national average retirement age of coal-fired generation that retired in 2015 was 54 years.[19] Aside from the resources that joined SPP from Nebraska in 2009 and the Integrated System in 2015, the great majority of significant new capacity in the SPP footprint over the last 10 years has been wind capacity.

[19] https://www.eia.gov/todayinenergy/detail.php?id=25272

2.3.1 CAPACITY ADDITIONS AND RETIREMENTS

Figure 2–13 shows the capacity by the technology and the number of resources added in 2017.

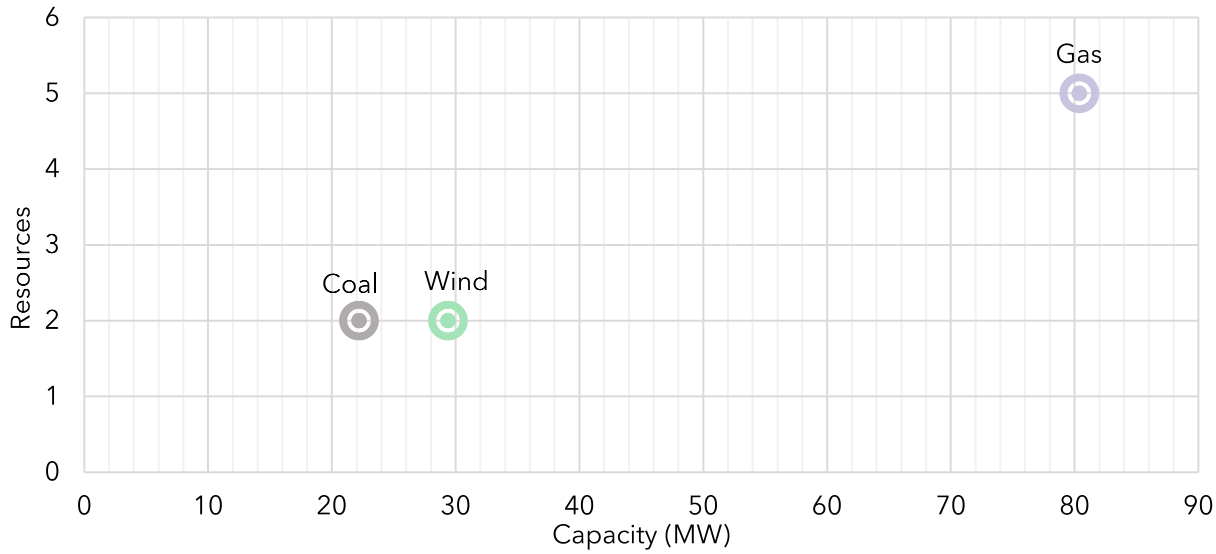
Figure 2–13 Capacity additions



Nearly 2,200 MW of new generation capacity was added to the SPP market during 2017. Two-thirds of the new capacity was wind, with natural gas representing the remaining portion. All of this new market capacity was new construction.

In 2017, the SPP market had a low number of generation retirements amounting to just 132 MW of installed capacity, shown in Figure 2–14.

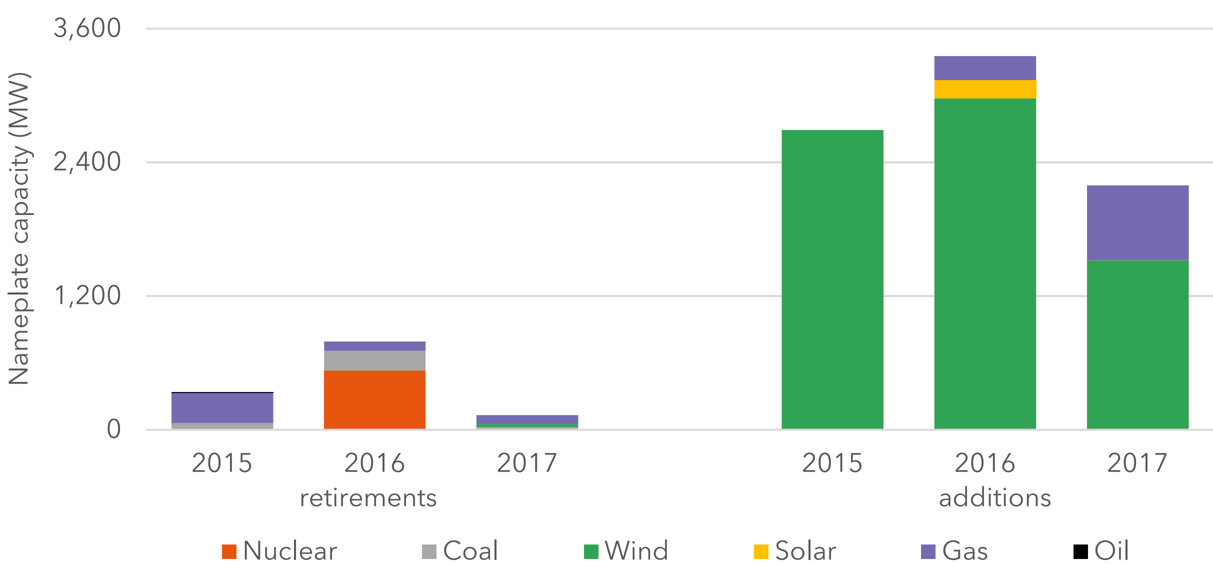
Figure 2–14 Capacity retirements



Two relatively small coal resources representing 22 MW of capacity, two wind resources representing 29 MW of capacity, and five gas resources representing 80 MW of capacity were retired in 2017.

Figure 2–15 shows the annual trend of capacity additions and retirements over the past three years.

Figure 2–15 Capacity additions and retirements by year



Almost all of the coal and gas capacity retired since 2015 has been 1950s era plants. The nuclear unit retired in 2016 was commissioned in the early 1970s. The wind units that retired were first-generation wind resources with very low capacity.

For capacity additions, wind generation additions slowed in 2017 compared to prior years with just over 1,500 MW of capacity added in 2017, compared to over 2,600 MW in each of the two prior years. Almost 100 MW of solar generation was added in 2016. Looking forward, the amount of solar resources in the generation interconnection queue has grown over four-fold in the past year. This is discussed more below in Section 2.3.3 of this report.

2.3.2 GENERATION CAPACITY COMPARED TO PEAK LOAD

The MMU has created a new peak available capacity metric to replace our previous reserve margin metric[20] used in prior reports. The new metric uses a percentage of the average maximum capacity for each resource during July and August, and divides that figure by the nameplate capacity for the resource. This method essentially creates a derated capacity value due to ambient temperatures for each resource and is a more conservative measure of capacity when compared to nameplate, or even summer rated capacity. A percentage is then calculated for each fuel type of resource and that percentage is applied to the total nameplate capacity (as shown in Figure 2–11). Solar resources are derated to 50 percent of capacity. Wind resources are derated to a capacity based on actual production in July and August in the SPP market. From 2014 to 2016, 12 percent of wind generation capacity is included in the calculation. That figure increases to 14 percent for 2017. These percentages are consistent with figures used by other RTOs.[21]

The peak available capacity percent is the amount of extra system capacity available after serving system peak load, and is shown in Figure 2–16.

[20] The reserve margin metric used unit registration ratings (i.e. nameplate capacity) to determine system capacity, with wind counted at only five percent of registered capacity.

[21] https://old.misoenergy.org/Library/Repository/Study/LOLE/2018%20Wind%20Capacity%20Report.pdf

Figure 2–16 Peak available capacity percent

Year	Peak available capacity (MW)	Peak load (MWh)	Peak available capacity percent
2014	61,302	45,301	35%
2015	61,499	45,279	36%
2016	67,319	50,622	33%
2017	66,509	51,181	30%

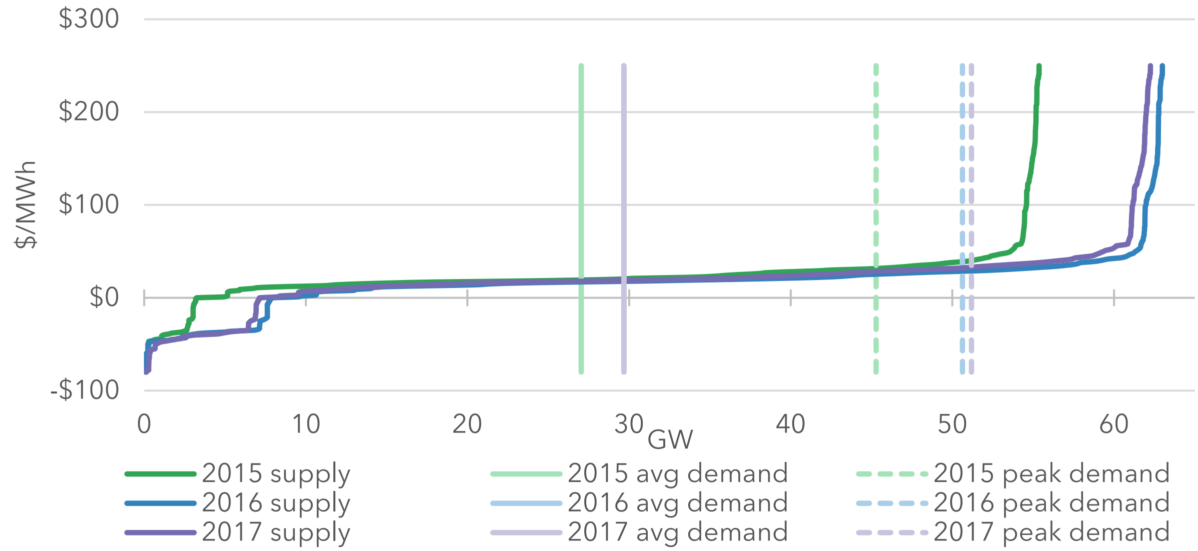
For 2017, the peak available capacity percent was 30 percent, down from 33 percent in 2016, and 36 percent in 2015.[22] The 30 percent peak available capacity percentage is still nearly three times higher than SPP's minimum required planning reserve margin of 12 percent.[23] Also note that the peak availability capacity metric will differ from the reserve margin calculated by SPP because of differences in methodology. Most notably, the SPP methodology only includes capacity with firm transmission, whereas our metric includes all system resources interconnected with the SPP grid using derate factors that are consistent with other regions.

A relatively high peak available capacity percentage such as this has positive implications for both reliability and for mitigation of the potential exercise of market power within the market. However, it also contributes to downward pressure on market prices, negatively affects revenue adequacy, and can burden ratepayers with additional and potentially unnecessary costs.[24]

Figure 2–17 shows the total SPP aggregate real-time generation supply curves by offer price, peak demand, and average demand for the summers of 2015 to 2017. Resources in "outage" status were excluded from the supply curve. To calculate the summer supply curves, a typical summer day was used for each analysis year. Using the real-time offers of non-wind resources and wind forecast data for wind resources, the aggregate generation supply curves were developed.

[22] 2015 uses the total capacity on September 30, prior to the addition of the Integrated System.
[23] SPP Planning Criteria 4.1.9.
[24] We recognize that grid resiliency is a topic of concern and discussion. However, we feel that resiliency must be properly measured and evaluated in the SPP market to ensure that ratepayers are not burdened by unnecessary costs of excess capacity.

Figure 2–17 Aggregate supply curve, typical summer day



Total aggregate real-time generation supply for summer 2017 was 62,252 MW, compared to 62,988 MW for summer 2016, just a one percent difference. This difference can mostly attributed to varying of the wind forecast, as well as differing outages, on those days. Total aggregate real-time generation supply in summer 2015 was significantly lower, at 55,260 MW. As discussed earlier in this report, the SPP Integrated Marketplace footprint expanded on October 1, 2015 to include the Integrated System (IS), which added more than 7,600 MW of generating capacity to SPP market.

Also evident is the approximately 20 GW gap between this maximum supply and the total installed nameplate generation capacity. This is primarily a result of excluding the resources in "outage" status from the available supply (approximately 4 GW), reduced summer capacity due to high ambient temperatures (approximately 6 GW), as well as the difference between the wind forecast and installed capacity of wind resources (approximately 8 GW).

The section of the offer curve below $0/MWh is mostly due to subsidized wind and solar energy and can vary between 1,000 and 13,000 megawatts, based on wind and solar availability. The sharp uptick in price around 62 GW in 2017 represents the transition from natural gas units to oil units.

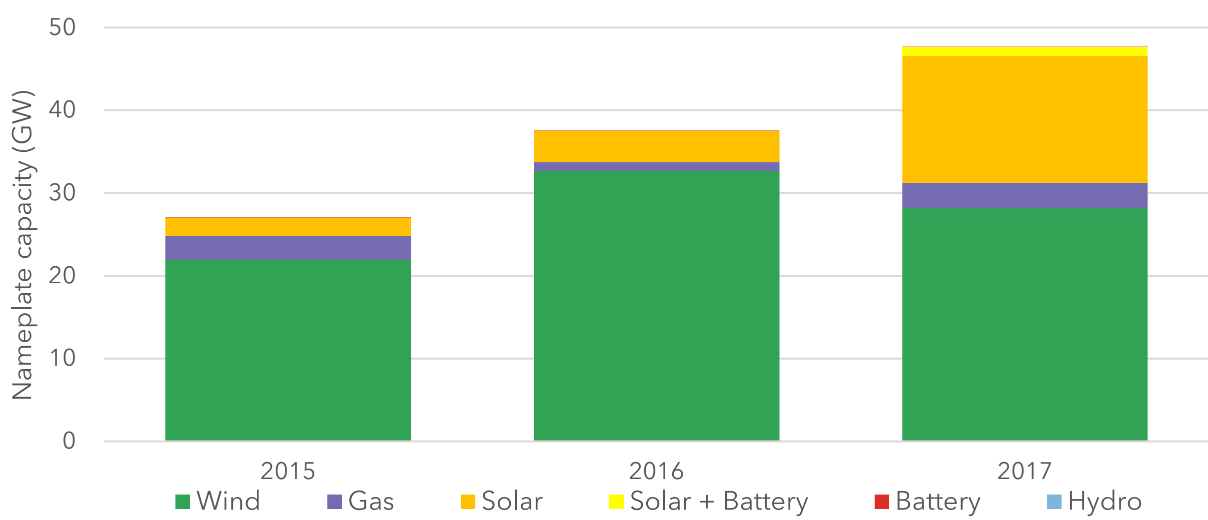
2.3.3 GENERATION INTERCONNECTION

SPP is responsible for performing engineering studies to determine if the interconnection of new generation within the SPP footprint is feasible, and to identify any transmission development that would be necessary to facilitate the proposed generation. The generation interconnection process involves a cluster study methodology allowing participants several windows to submit requests for evaluation.[25]

Figure 2–18 shows the megawatts of capacity by generation technology type in all stages of development. Included in this figure are interconnection agreements in the process of being created; those under construction; those already completed, but not yet in commercial operation; and those in which work has been suspended as of year-end 2017.

Figure 2–18 Active generation interconnection requests, megawatts

Prime mover	2015	2016	2017
Wind	21,930	32,690	28,147
Gas	2,900	1,080	3,122
Solar	2,200	3,770	15,306
Battery	60	40	52
Solar + battery[26]	0	0	1,083
Hydro	10	0	0
Total	27,100	37,580	47,710



As can be seen in the table, generation capacity from renewable resources accounts for the vast majority of proposed generation interconnection, representing 93 percent of the total. Interestingly, the amount of wind generation in the interconnection queue decreased from

[25] See Guidelines for Generator Interconnection Requests to SPP's Transmission System http://sppoasis.spp.org/documents/swpp/transmission/studies/GuidelinesAndBusinessPracticesForGIP.pdf.

[26] The solar + battery category represents a generation interconnection request where the site is both a solar farm and a battery storage site.

the previous year for the first time in the SPP market, but was still greater than the 2015 amount. Interconnection requests for solar generation, on the other hand, increased over four-fold from 2016 to 2017. Although the level of battery only interconnection requests remains minimal, over 1,000 MW of interconnection requests for combined solar farm/battery storage sites were received in 2017.

Development of renewable generation in the SPP region is expected to continue and the proper integration of wind and solar generation is fundamental to maintaining the reliability of the SPP system. Additional wind impact analysis follows in the Section 2.5.

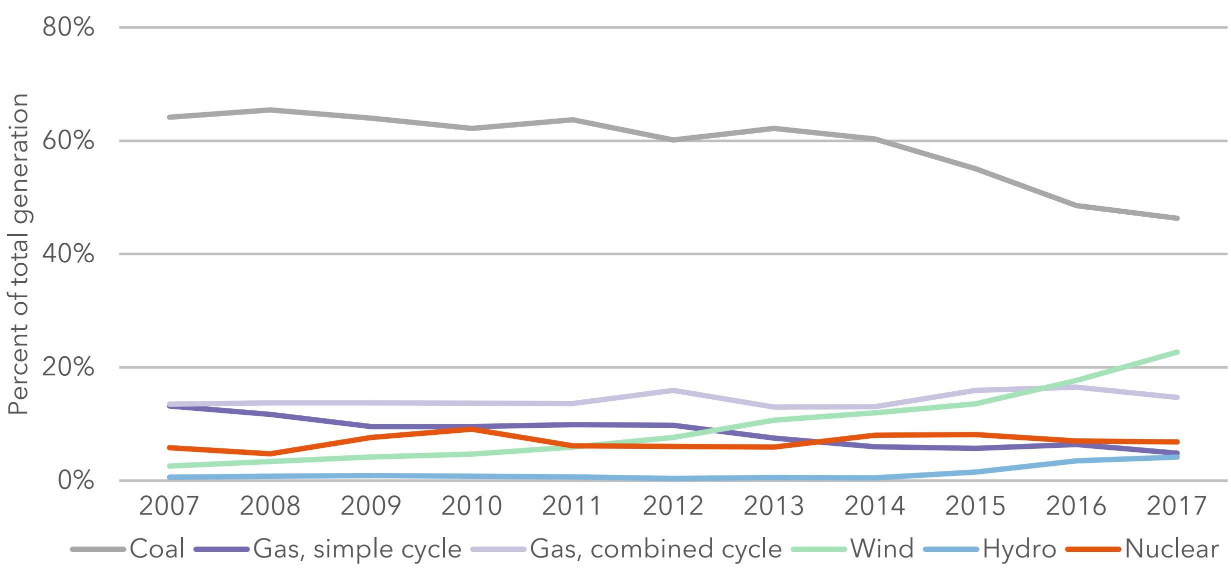
2.4 GENERATION

2.4.1 GENERATION BY TECHNOLOGY

An analysis of generation by technology type used in the SPP Integrated Marketplace is useful in understanding pricing, as well as the potential impact of environmental and additional regulatory requirements on resources in the SPP system. Information on fuel types and fleet characteristics is also useful in understanding market dynamics regarding congestion management, price volatility, and overall market efficiency.

Figure 2–19 depicts annual generation percentages in the SPP real-time market by technology type for the years 2007 through 2017.

Figure 2–19 Generation by technology type, real time, annual



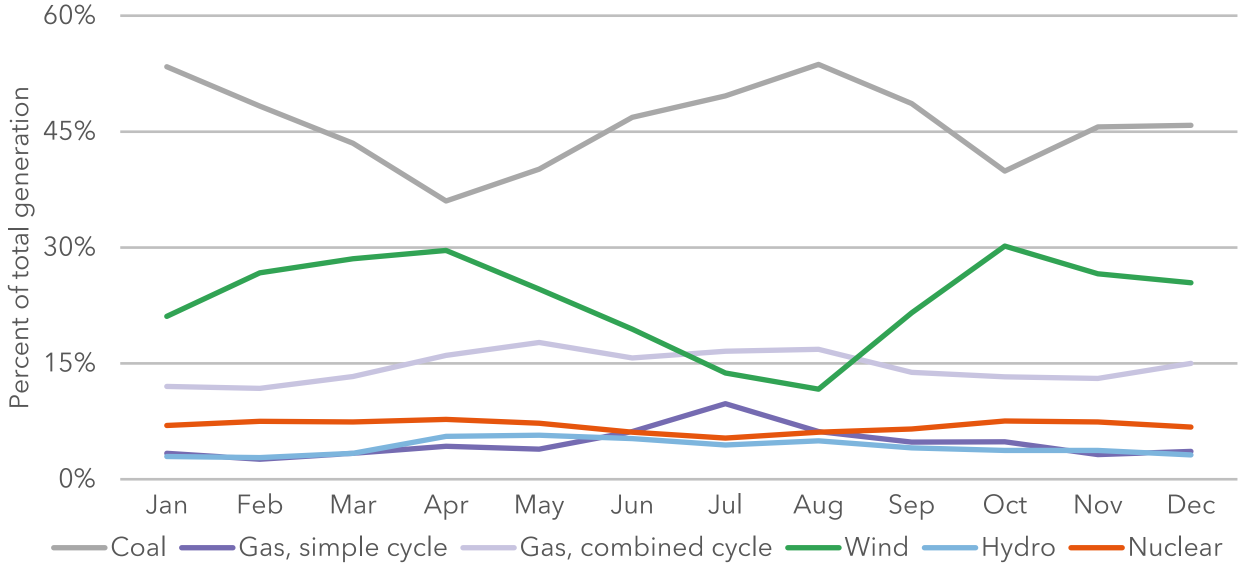
Generation from simple-cycle gas units such as gas turbines and gas steam turbines has seen a significant decline over the past few years, decreasing share from 13 percent in 2007 to just under five percent in 2017. Gas combined-cycle generation has remained relatively stable at about fifteen percent for the past three years, which can mostly be attributed to low gas prices. Wind generation share continues to increase from nearly three percent in 2007 to nearly 23 percent in 2017. Coal generation share decreased to 46 percent of total generation in 2017, down from 48 percent in 2016. The long-term trend for coal-fired generation had been relatively flat through 2014 at around 60 to 65 percent of total generation, but has declined to under 50 percent in 2016 and 2017. This can primarily be attributed to increasing wind generation and low gas prices.

Some of the annual fluctuations in generation by technology type shares are driven by the relative difference in primary fuel prices, namely natural gas versus coal. Gas prices in 2012, and 2015 to 2017 were extremely low, resulting in some displacement of coal by efficient gas generation, as can be seen in the higher generation from combined-cycle gas plants. Another trend appears to be the increase in wind generation pushing simple-cycle gas generation up the supply curve, making it less competitive.

Retirement of older coal generation, environmental limits, along with competition from wind and natural gas technologies are some of the factors that will continue to put pressure on coal generation levels. Wind generation is expected to continue to increase in the years ahead.

Figure 2—20 depicts the 2017 monthly fluctuation in generation by technology type.

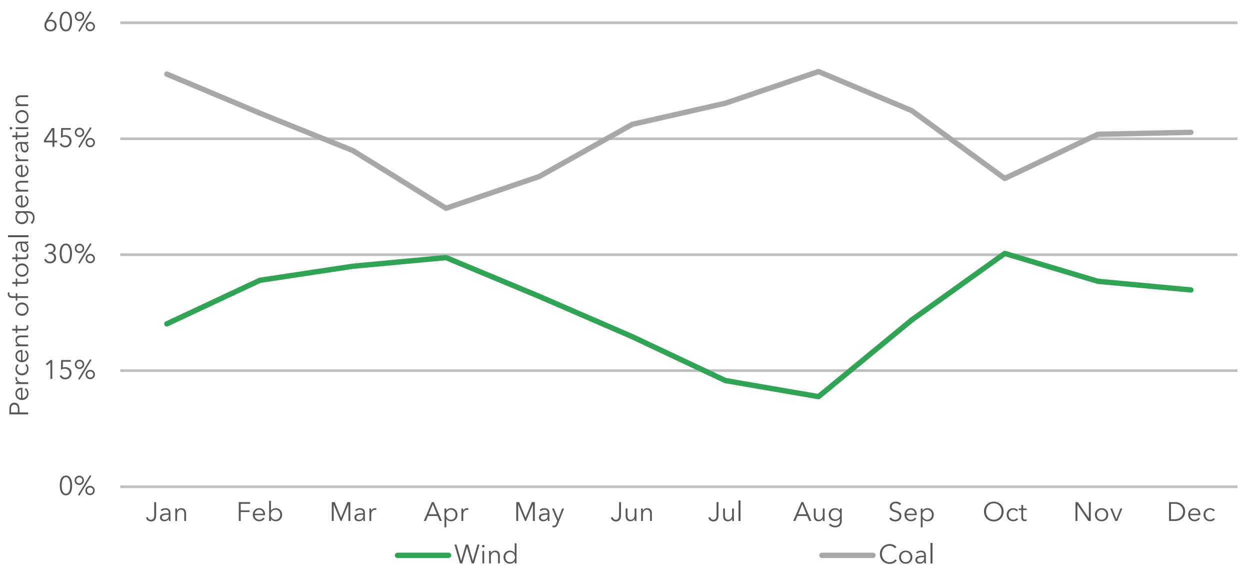
Figure 2–20 Generation by technology type, real time, monthly



Wind generation fluctuates from around 12 percent in the summer months to peaks around 30 percent in the highest wind generation months of April and October. The increase in wind generation accompanied with low natural gas prices resulted in coal-fired generation market share falling to below 40 percent in both April and October 2017.

Figure 2–21 below uses the data from Figure 2–20 above, but only shows monthly coal and wind generation.

Figure 2–21 Comparison of generation by coal and wind resources

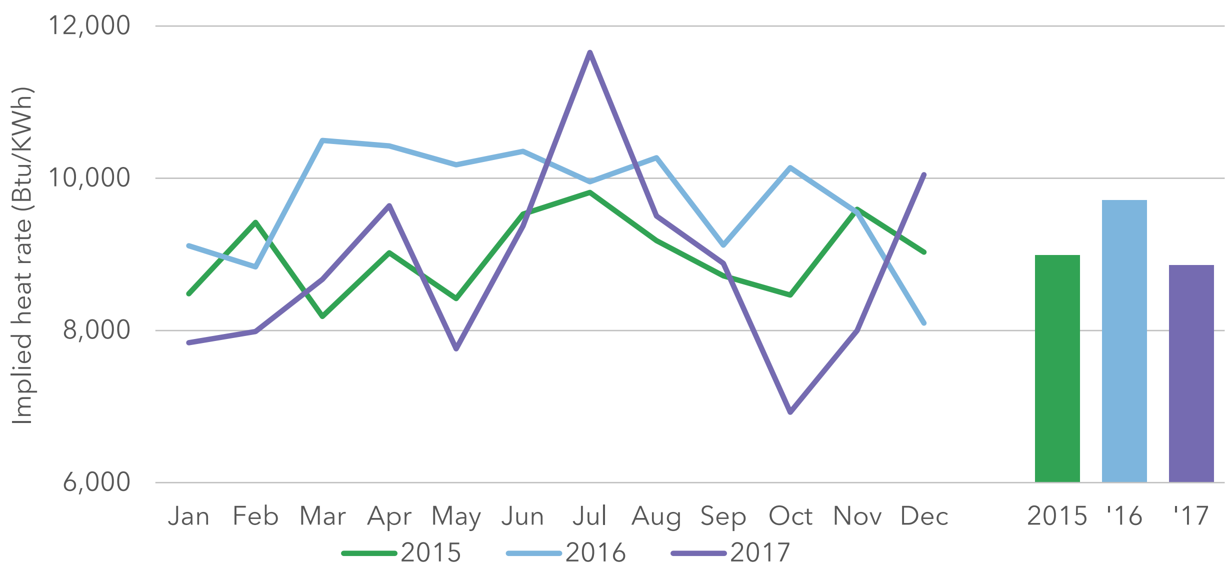


The monthly generation percentages show an inverse relationship between monthly levels of wind and coal generation in 2017, as wind generation increases, coal generation decreases and vice versa.

One method commonly used to assess price trends and relative efficiency in electricity markets originating from non-fuel costs is the implied heat rate. The implied heat rate is calculated by dividing the electricity price, net of a representative value for variable operations and maintenance (VOM) costs, by the fuel (gas) price.[27] For a gas generator, the implied heat rate serves as a "break-even" point for profitability such that a unit producing output with an operating (actual) heat rate below the implied heat rate would be earning profits, given market prices for electricity and gas. If the price of natural gas was $3/MMBtu, and the electricity price was $24/MWh, the implied heat rate would be (24/3) = 8 MMBtu/MWh (8,000 Btu/KWh). This implied heat rate shows the relative efficiency required of a generator to convert gas to electricity and cover the variable costs of production, given system prices.

Figure 2–22 shows the monthly implied heat rate using real-time electricity prices for 2015 to 2017, along with an annual average for those years.

Figure 2–22 Implied heat rate



[27] For the implied heat rate calculation, natural gas units are assumed to be on the margin and accordingly, gas prices are taken as the relevant fuel cost. We ignore emission costs in fuel cost as they rarely apply in the SPP market.

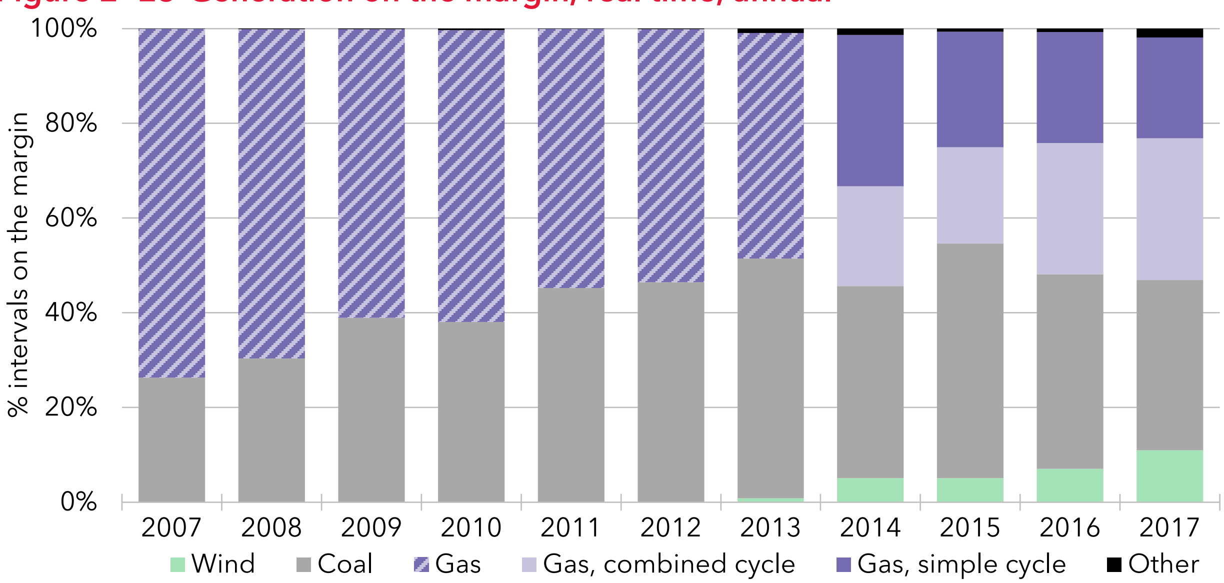
The chart shows an overall decline in implied heat rates in 2017 compared to 2016 and 2015. In particular, the 2017 implied heat rate was more variable monthly, even though natural gas prices were fairly constant for most of the year. Of note, wind generation and load affected electricity prices in 2017. For instance, wind affected electricity prices in May and October, lowering average heat rates, whereas high temperatures in July increased load and electricity prices.

2.4.2 GENERATION ON THE MARGIN

The system marginal price represents the price of the next increment of generation available to meet the next increment of total system demand. The locational marginal price at a particular pricing node is the system marginal energy price plus any marginal congestion charges and marginal loss charges associated with that pricing node.

Figure 2–23 illustrates the frequency with which different technology types were marginal and price setting. For a generator to set the marginal price, the resource must be: (a) dispatchable by the market; (b) not at the resource economic minimum or maximum; and (c) not ramp limited. In other words, it must be able to move to provide the next increment of generation.

Figure 2–23 Generation on the margin, real time, annual



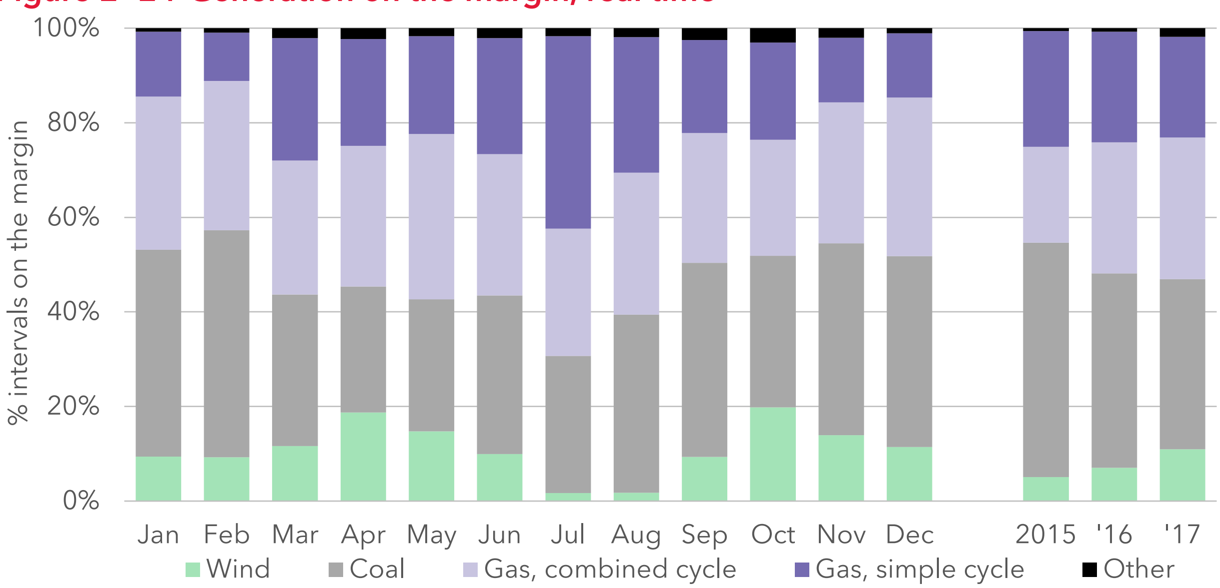
This chart illustrates the dramatic shift in technology on the margin with natural gas representing about 75 percent in the first year of an SPP market in 2007 to only about 50 percent in 2017. There is a corresponding shift in coal generation on the margin from about

25 percent in 2007, peaking at around 50 percent in 2015, then declining to 36 percent by 2017. This change is driven by market efficiency improvements as reflected in the decline in simple-cycle natural gas generation as shown in Figure 2–19. As a result of these market efficiency improvements, along with low natural gas prices, coal-fired plant owners are experiencing more daily swings in dispatch level, which are reflected in this generation on the margin analysis.

It is worth noting the increase in wind generation being on the margin—from five percent in 2014 and 2015 to nearly 11 percent in 2017. With the growing amount of dispatchable wind generation and an overall quantity of 20 percent of total nameplate capacity, wind generation is increasingly becoming the marginal technology a higher percentage of the time. At the end of 2017, 64 percent of wind capacity was dispatchable, compared to 60 percent at the end of 2016, 46 percent at the end of 2015, and 27 percent at the beginning of the Integrated Marketplace in March 2014. The recommendation to convert non-dispatchable variable energy resources to dispatchable variable energy resources is discussed in Section 7.4.1 below.

Figure 2–24 shows monthly values for real-time generation on the margin for 2017.

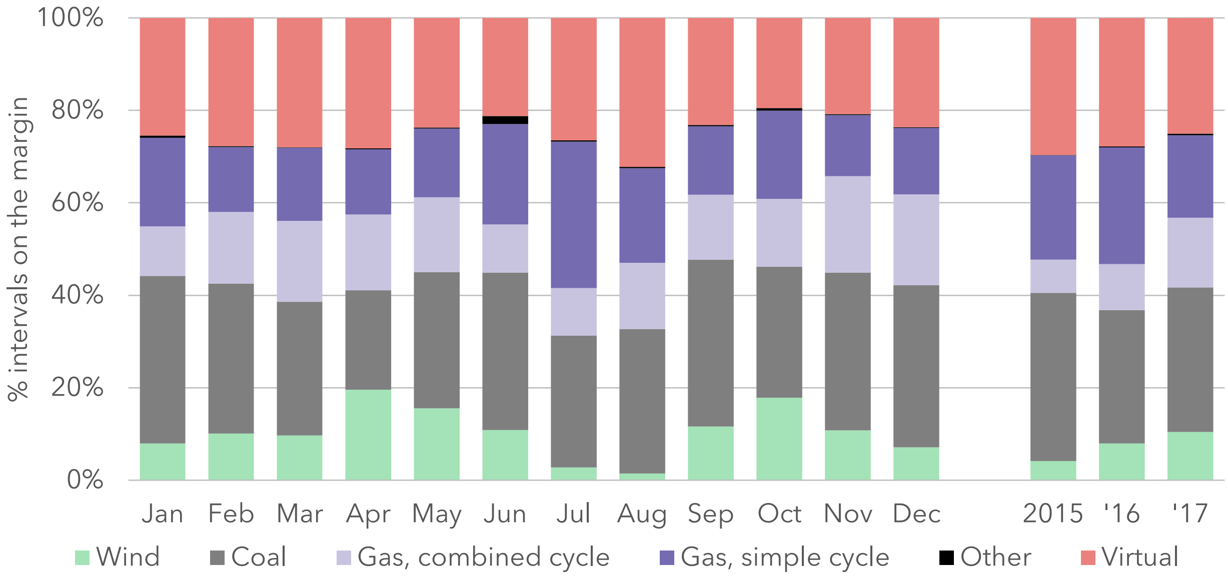
Figure 2–24 Generation on the margin, real time



Intervals with coal generation on the margin are typically lower in the spring and fall months, resulting in more coal-fired units running as base load units with less cycling. The increased wind generation is also affecting prices to some extent in every month of the year. The higher wind generation on the margin values in the spring and fall are as expected given that these periods are the windiest time of the year, as well as the lowest demand periods in the SPP footprint.

Day-ahead generation on the margin, shown in Figure 2–25, is different from real time in that the day-ahead market includes virtual transactions. The real-time market does not include virtual transactions and is required to adjust to unforeseeable market conditions such as unexpected plant and transmission outages.

Figure 2–25 Generation on the margin, day-ahead



Wind generation on the margin is comparable in the day-ahead and real-time markets with a similar annual cyclical pattern. Both coal and gas generation on the margin in the day-ahead market is noticeably lower than in the real-time market. The most significant difference is the displacement of natural gas-fired generation by virtual offers in the day-ahead market. Virtual energy offers on the margin have been declining over the past three years, with 25 percent of the marginal offers in the day-ahead market in 2017, compared to 28 percent in 2016 and 30 percent in 2015. While marginal virtual offers occur at all types of settlement locations, 57 percent of marginal virtual offers are at resource settlement locations, with a significant amount of activity at non-dispatchable wind generation resource locations. Note that high virtual activity frequently occurs at wind locations because wind generation resources are typically under-scheduled in the day-ahead market.

2.5 GROWING IMPACT OF WIND GENERATION CAPACITY

2.5.1 WIND CAPACITY AND GENERATION

The SPP region has a high potential for wind generation given wind patterns in many areas of the footprint. Federal incentives and state renewable portfolio standards are additional factors that have resulted in significant wind investment in the SPP footprint during the last five years.

Figure 2–26 below shows a high potential for wind development in the SPP footprint, which is outlined in black.

Figure 2–26 Wind speed map

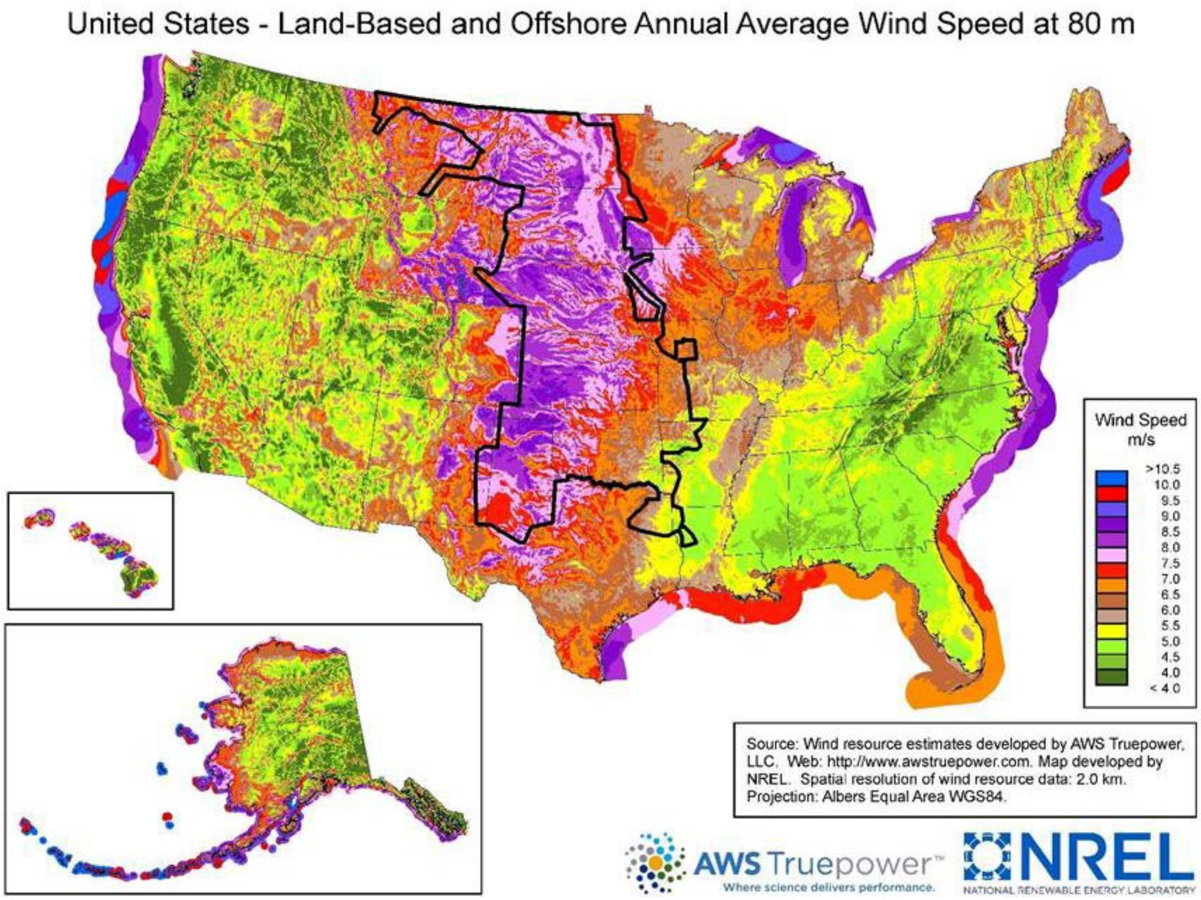
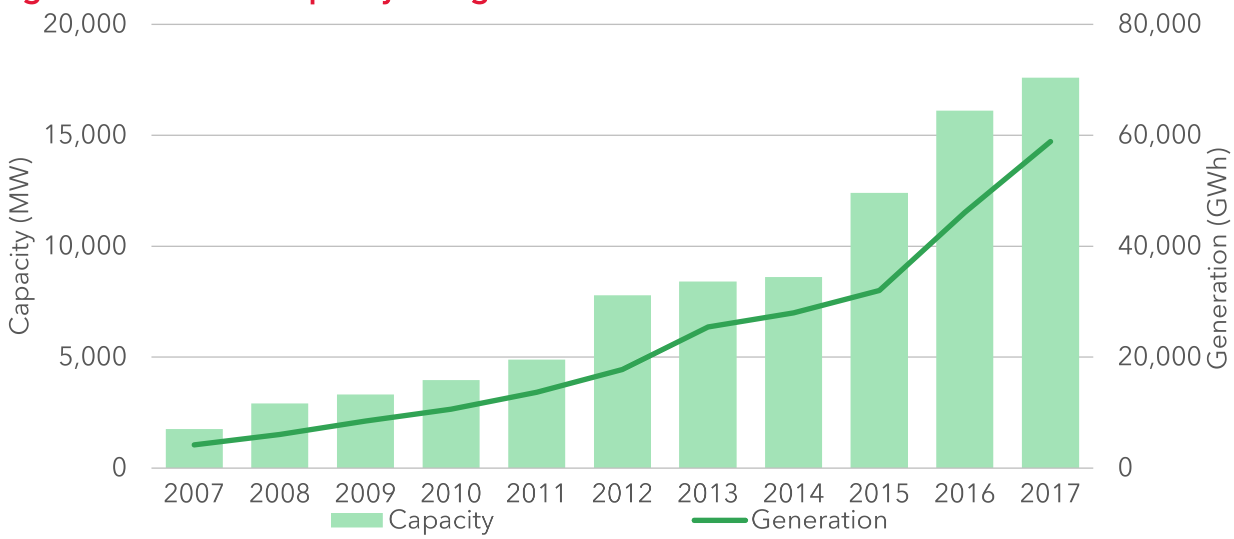


Figure 2–27 depicts annual nameplate capacity and total generation from wind facilities since 2007. Total registered wind capacity at the end of 2017 was 17,596 MW, an increase of nine percent from 2016. However, wind generation output increased 28 percent in 2017 to nearly 60,000 GWh produced, mostly due to the addition of several wind resources in late 2016.

Figure 2–27 Wind capacity and generation

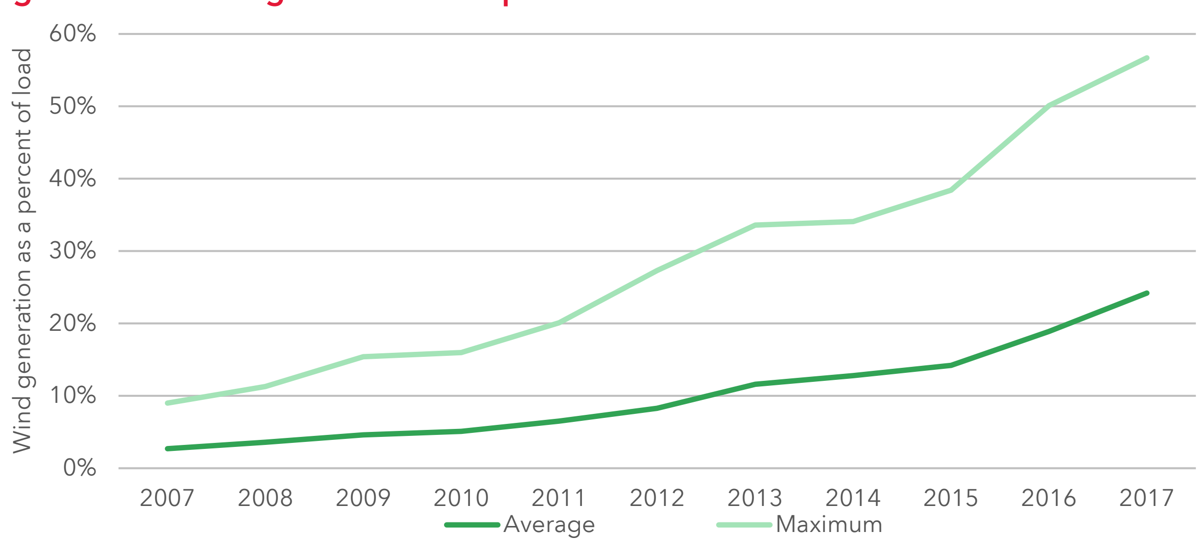


Wind resources comprise about 20 percent of the installed capacity in the SPP market, behind only natural gas with 42 percent and coal with 30 percent. Consistent with previous years, wind generation fluctuated seasonally, where summer was usually the low wind season, and spring and fall were the high wind seasons. Also typical of wind patterns is lower production during on-peak hours than off-peak. Furthermore, wind generation tends to fall across the morning ramp periods.

2.5.2 WIND IMPACT ON THE SYSTEM

Average annual wind generation as a percent of load continues to increase as shown in Figure 2–28.

Figure 2–28 Wind generation as a percent of load

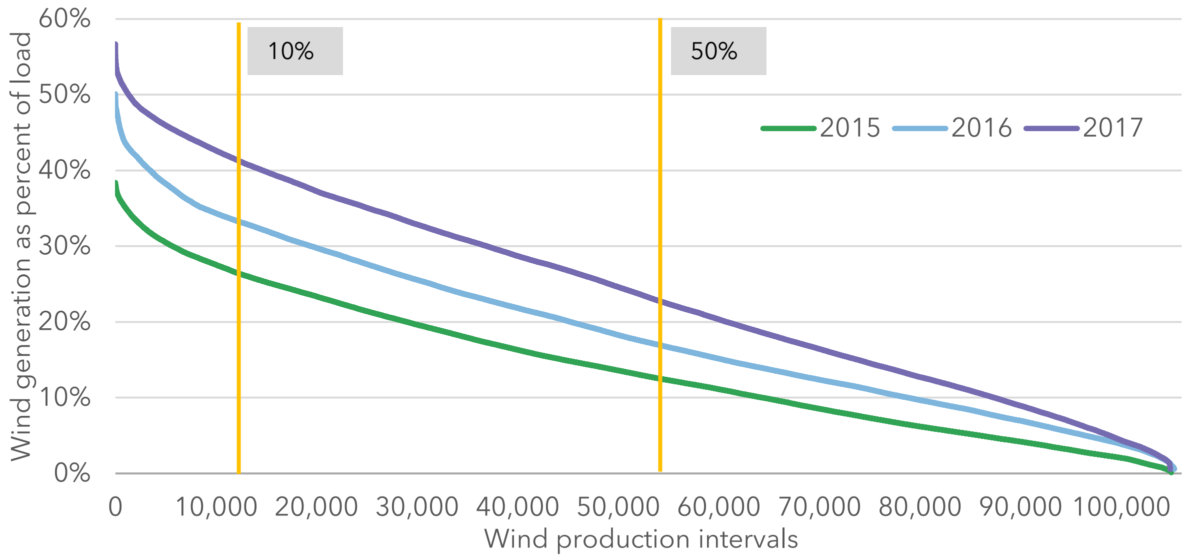


Wind generation as a percent of load increased in the real-time market to just over 24 percent in 2017, up from 19 percent in 2016, and 14 percent in 2015. Wind generation peaked at just over 15,675 MW in 2017 on a five-minute interval basis. Wind generation as a percent of load for any five-minute interval reached a maximum value of nearly 57 percent, which was higher than just under 50 percent in 2016 and 38 percent in 2015.

The chart also shows the trend for average and maximum wind generation as a percent of load since 2007, illustrating the dramatic increase since the start of the SPP markets.

Figure 2–29 shows wind production duration curves that represent wind generation as a percent of load by real-time (five-minute) interval for 2015 through 2017.

Figure 2–29 Wind production curve



The shift upward for the curve from year to year reflects an increase in total wind generation on an annual basis. Wind generation in 2017 served at least 24 percent of the total load during half of the year, compared to 17 percent in 2016 and 13 percent in 2015. It is also important to note that the low end to curve continues to gradually approach zero while the high end of the curve increases very steeply.

2.5.3 WIND INTEGRATION

Wind integration brings low cost generation to the SPP region but does not count for much accredited capacity. There are a number of operational challenges in dealing with substantial wind capacity. For instance, wind energy output varies by season and time of day.

This variability is estimated to be about three times more than load when measured on an hour-to-hour basis. Moreover, wind is counter-cyclical to load. As load increases (both seasonally and daily), wind production typically declines. The increasing magnitude of wind capacity additions since 2007, along with the concentration, volatility, and timeliness of wind, can create challenges for grid operators with regard to managing transmission congestion and resolution of ramping constraints (which began being reflected in scarcity pricing in May 2017) as well as challenges for short- and long-run reliability. Several price spikes occurred because of wind forecast errors. Wind forecast errors are also the leading cause of day-ahead and real-time price divergence.

In the SPP market, wind and other qualifying resources were allowed to register as non-dispatchable variable energy resources, provided the resource had an interconnection agreement executed by May 21, 2011 and was commercially operated prior to October 15, 2012. Because 36 percent (6,364 MW) of the existing installed wind capacity is composed of non-dispatchable variable energy resources, and these generally produce without regard to price, grid operators must still issue manual dispatch instructions to reduce or limit their output at certain times.

Figure 2–30 illustrates dispatchable variable energy resources (DVERs) and non-dispatchable variable energy resources (NDVERs) wind output since the beginning of the Integrated Marketplace, with dispatchable variable energy resource output mirroring the increasing percentage of installed wind capacity.

Figure 2–30 Dispatchable and non-dispatchable wind generation

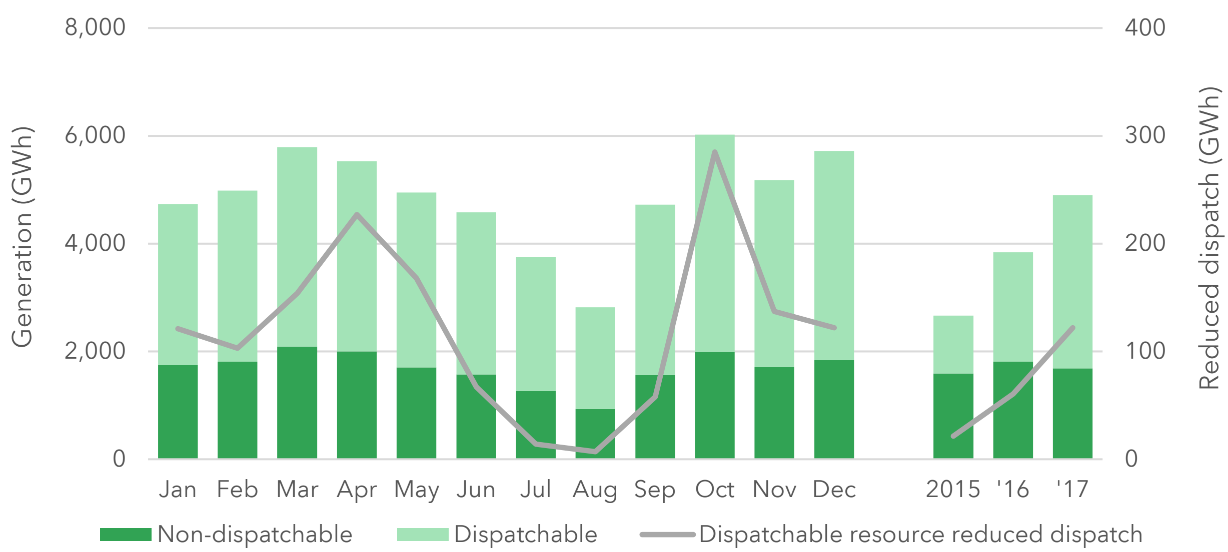
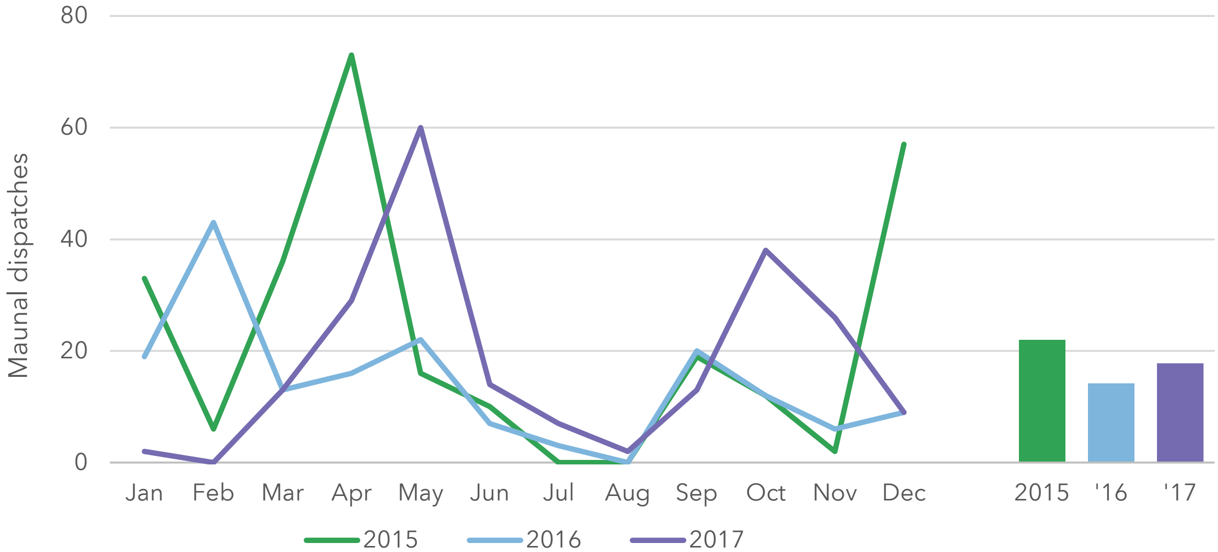


Figure 2–30 also shows the amount of reduced output of dispatchable variable energy resources below their forecast. This depicts the increase in reductions of dispatchable variable energy resource dispatch output, which is expected due to the increase in wind capacity and transmission limitations. This also follows the seasonal pattern of lower wind output during the summer months, resulting in the decrease in need to reduce dispatchable variable energy resource output during these times. This increase in dispatchable wind capacity has helped in the management of congestion caused by high levels of wind generation in some of the western parts of the SPP footprint. October 2017 saw over 6,000 GWh of monthly wind production, which was the highest since the start of the Integrated Marketplace and over a third of this output originated from non-dispatchable variable energy resource capacity.

Substantial transmission upgrades in the SPP footprint over the past few years have provided an increase in transmission capability for wind-producing regions, helping to address concerns related to high wind production, and resulting congestion. It is worth noting that the increased transmission capability directly reduces localized congestion, creating a more integrated system with higher diversity and greater flexibility in managing high levels of wind production. However, given the historical growth of wind capacity and indicators of future additions in the generation interconnection queue, additional transmission upgrades may only entice further development of wind capacity.

Figure 2–31 shows the number of out-of-merit energy directives (manual dispatches) initiated for dispatchable and non-dispatchable variable energy wind resources for the past three years.

Figure 2–31 Manual dispatches for wind resources



As expected, manual dispatches are fewer during the lower wind output and higher demand months of summer. In 2017, 33 percent of the 470 manual dispatches were for dispatchable variable energy wind resources, whereas 27 percent were for non-dispatchable variable energy wind resources. Line loading in excess of 104 percent, operating guides, and outages caused 75 percent of dispatchable manual dispatches. These same factors plus transmission switching[28] caused 80 percent of non-dispatchable manual dispatches.

SPP is at the forefront among RTOs in managing wind energy integration. The Integrated Marketplace has reliably managed wind generation when it represented more than 50 percent of load. Even though the use of manual dispatch is limited and SPP continues to see an expanding dispatchable wind generation fleet, ramping capability is needed because of the variability of wind. Ramp shortages began being reflected in prices in May 2017.

2.5.4 CHALLENGES WITH NON-DISPATCHABLE VARIABLE ENERGY RESOURCES

A non-dispatchable variable energy resource is defined as "a variable energy resource not capable of being incrementally dispatched down by the transmission provider."[29] This

[28] Transmission switching out-of-merit instructions are issued to accommodate switching of 345kV transmission lines, due to stability concerns during the switching process. Typically these instructions last from two hours prior to switching to two hours after switching is completed, whereas the 345kV line may be out of service for a longer time frame.
[29] SPP Tariff, Attachment AE, Section 1.1.

definition does not delve into the requirements of a non-dispatchable variable energy resource. However, the market design requires that these resources, barring absence of fuel or mechanical limitations, follow close to their current output or forecast. This concept also applies to dispatchable variable energy resources not receiving a signal to follow dispatch and all resources in manual control status that are not in start-up or shutdown. Significant deviation from the most recent actual or forecasted output causes market inefficiencies that will be evaluated by the MMU.

Large swings in generation from non-dispatchable variable energy resources responding to the ex-ante real-time price is known as "price chasing". This behavior introduces oscillations on constraints, adversely impacting prices and dispatch instructions for other resources as well as an impact on regulation products. Price chasing occurs when non-dispatchable variable energy resources or resources on manual control respond to prices by curtailing output in response to lower prices and increasing production when prices rise. Such behavior can cause operational problems. For instance, it can create breaches on flowgates when these resources raise output in response to a price increase. This in turn causes more relief than necessary and security constrained economic dispatch effectiveness declines. Other impacts include additional volatility in the real-time market, more regulation needs, and more output loss due to increased regulation. Operators have at times resorted to reducing line ratings to ensure system reliability. As a result, out-of-merit energy directives are issued to other resources, which means extra cost (uplift) to the system, which translates into lower market efficiency.

In addition to the inefficiencies introduced to the market because of price chasing behavior, there are also inefficiencies introduced by non-dispatchable variable energy resources when they are physically incapable of responding to dispatch signals or when they are acting as "price takers". These inefficiencies exist at times when a non-dispatchable variable energy resource is operating uneconomically even when considering any (state or federal) subsidies or contract terms outside the market. This results in transmission congestion not being relieved by the most efficient unit possible, greater price differences, and volatility.

Consistent with its 2015 recommendation, the MMU reiterates the need for non-dispatchable variable energy resources to transition to dispatchable variable energy resource status in order to lessen the negative impact of such resources on the market. Other markets have taken measures to move their resources from non-dispatchable variable energy resources to dispatchable variable energy resources status as much as possible. For instance, FERC approved ISO-NE market rule changes in December 2016 that required nearly 1,200 MW of non-dispatchable generation assets to become dispatchable by early 2018,[30] and denied a request by the California ISO to delay transitioning resources from becoming dispatchable.[31]

2.6 EXTERNAL TRANSACTIONS

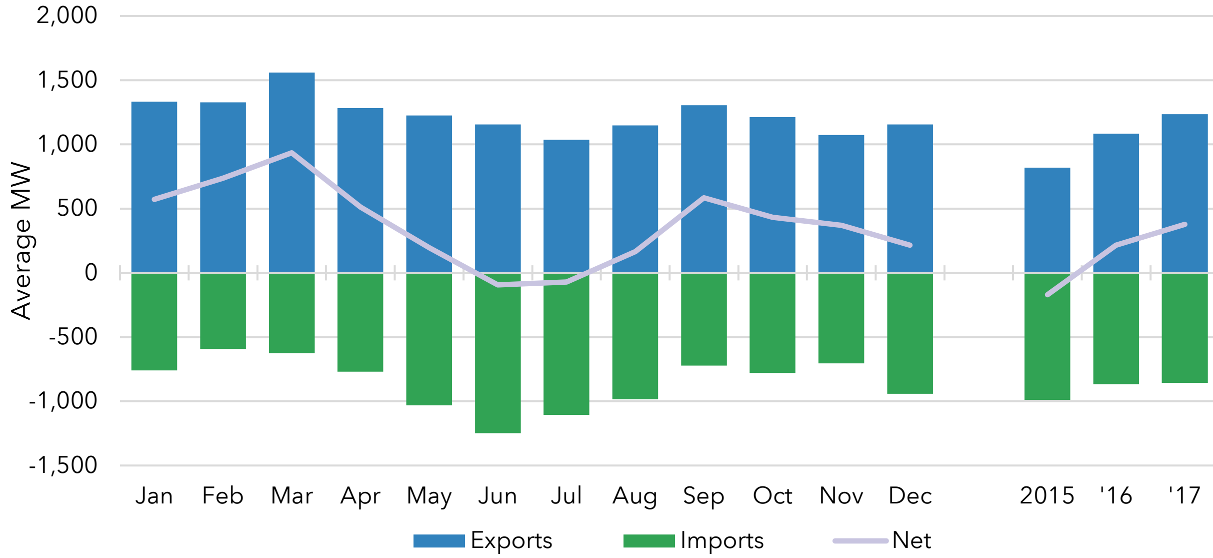
2.6.1 EXPORTS AND IMPORTS

The SPP Integrated Marketplace has greater 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.

As shown in Figure 2–32, SPP is a net exporter in real time in 2017, as it was in 2016, while it was a net importer in 2015. The two primary drivers for this shift from net importing to net exporting are the increase in wind generation, and the Integrated System addition in October 2015. Prior to the addition of the Integrated System to SPP, Western Area Power Administration (WAPA) generally exported to SPP. Since the integration, those transactions became internal transactions within the SPP footprint.

[30] See the FERC ruling at https://www.ferc.gov/CalendarFiles/20161209170835-ER17-68%20-000.pdf.
[31] See FERC Docket No. ER17-1337-000.

Figure 2–32 Exports and imports, SPP system



Generally SPP exports follow the wind production curve for the day. 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 see the highest exports.

Southwestern Power Administration hydro power is imported to serve municipals tied to SPP transmission and is highest during on-peak hours, but is scheduled day-ahead. MISO interchange generally follows wind production, while AECI interchange is coordinated on an ad hoc basis. DC tie imports and exports are scheduled hourly, and the DC ties are not responsive to real-time prices. Nonetheless, many exports and imports with ERCOT and MISO are adjusted based on day-ahead price differences in the organized markets and expectations of renewable generation. Interchange with SPA, AECI, and Western Interconnection parties is less responsive to prices. Figure 2–33 through Figure 2–35 show the data for the three most heavily used interfaces in real time, namely SPA, MISO, and AECI.

Figure 2–33 Exports and imports, Southwestern Power Administration interface

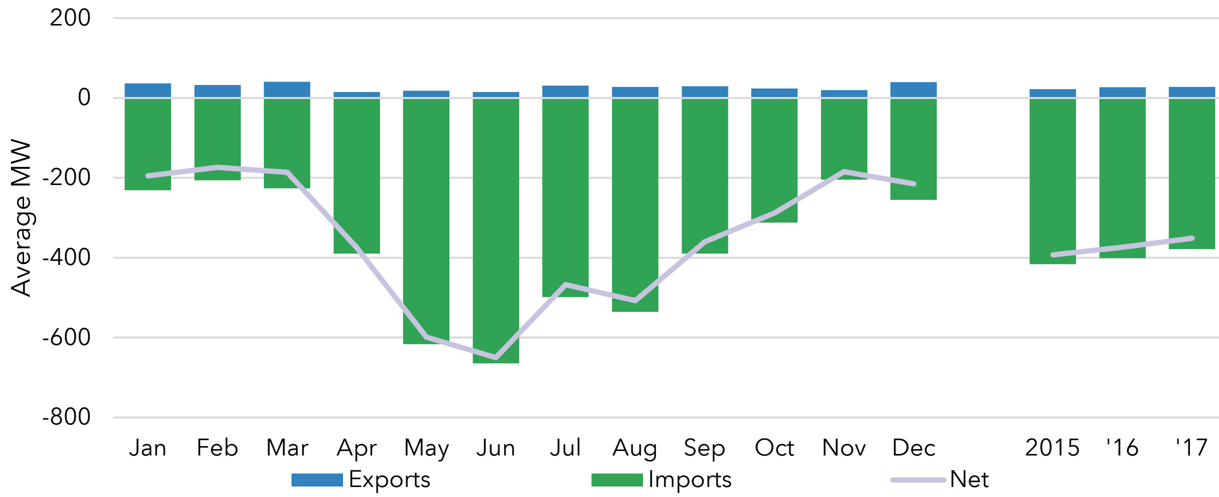


Figure 2–34 Exports and imports, MISO interface

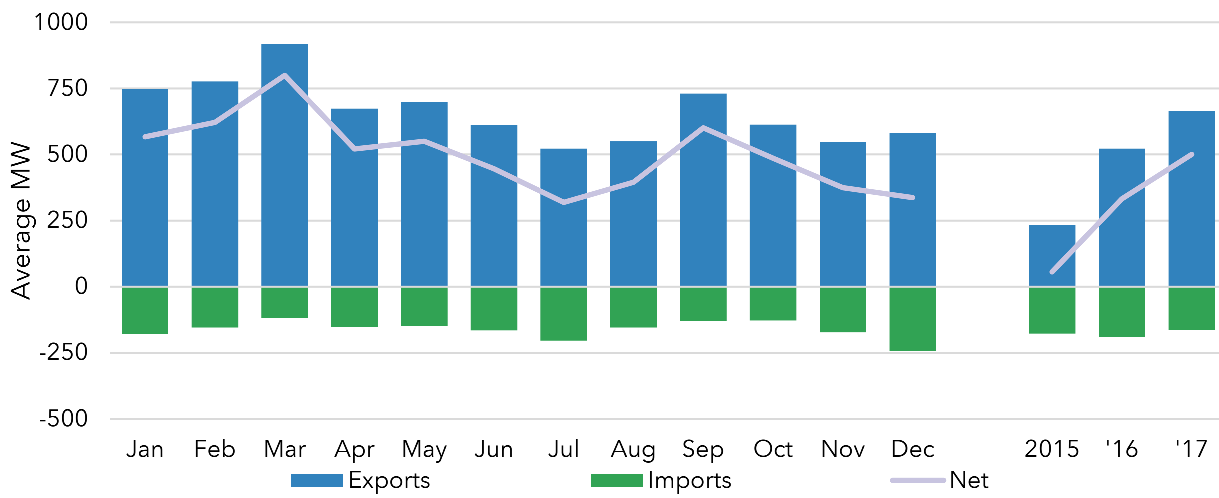
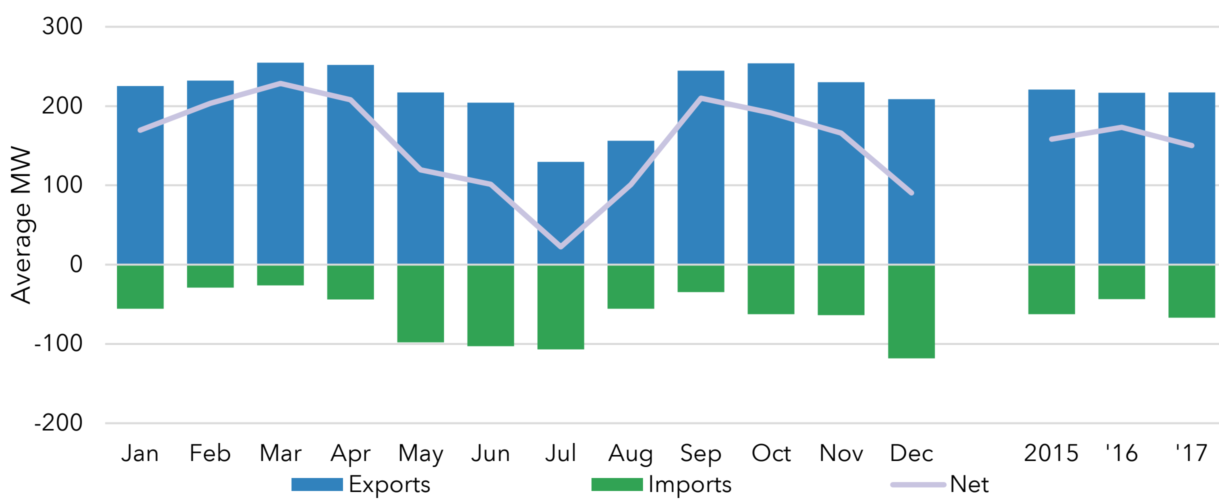


Figure 2–35 Exports and imports, Associated Electric Cooperative interface



Interchange transactions in the SPP market can be scheduled in the real-time market, as well as in the day-ahead market. The day-ahead market has three types of interchange transactions:

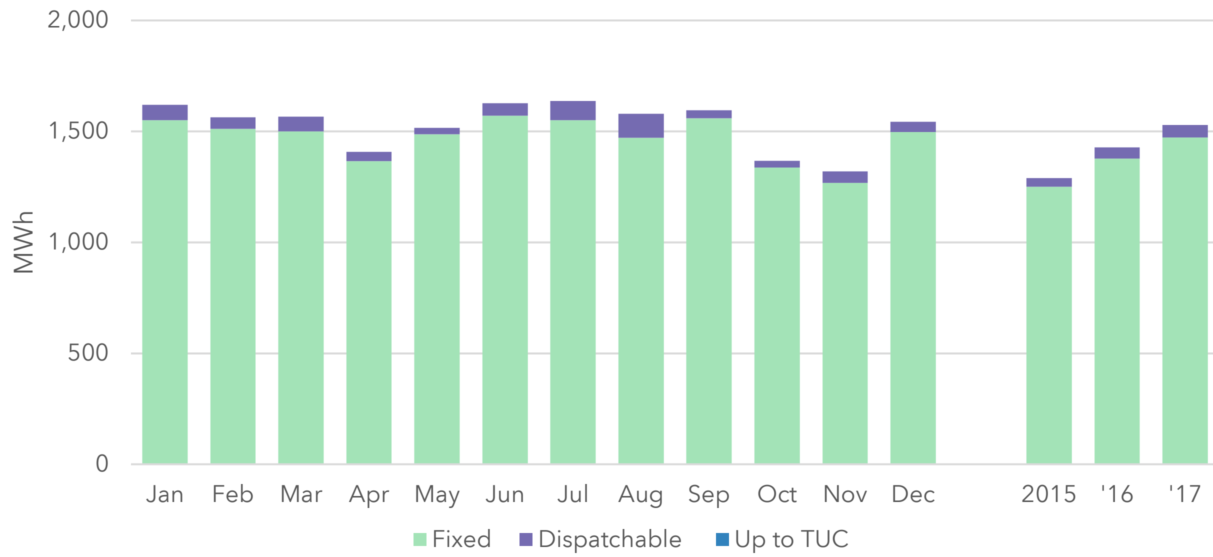
- Fixed interchange transactions are physical transactions that bring energy into or out of the SPP balancing authority. Energy prices are settled at the price at the applicable external interface settlement location. Submitters of this type of transaction in the Integrated Marketplace are price takers for that energy.
- Dispatchable interchange schedules are physical transactions that bring energy into or out of the SPP balancing authority and specify a bid or offer for an amount of megawatts. These schedules are supported in the day-ahead market only and also must meet all market requirements. Prices are determined in the day-ahead market at the appropriate external interface settlement location representing the interface between the SPP balancing authority and the applicable external balancing authority.
- An up-to-transmission usage charge (or up-to-TUC) offer on an interchange transaction specifies both a megawatt amount and the maximum amount of congestion cost and marginal loss cost the customer is willing to pay if the transaction is cleared in the day-ahead market.

All interchange transactions cleared in the day-ahead market, regardless of type, become fixed interchange transactions in the reliability unit commitment and real-time market.[32]

As shown in Figure 2—36, 96 percent of all interchange transactions cleared in the day-ahead market are fixed, four percent are dispatchable, and none are up-to-TUC.

[32] Per Market Protocols section 4.2.2.7 Import Interchange Transaction Offers.

Figure 2–36 Imports and export transactions by type, day-ahead



Some reasons for the fixed transactions that make up the vast majority of interchange transactions include bilateral contracts with external entities, SPA hydro contracts, and lower prices of the SPP market compared to other RTOs. To enhance market efficiency, market participants should consider further use of the dispatchable and up-to-TUC imports and exports, which allow for a specific strike price to be set, allowing for more economic imports and exports.

2.6.2 MARKET-TO-MARKET COORDINATION

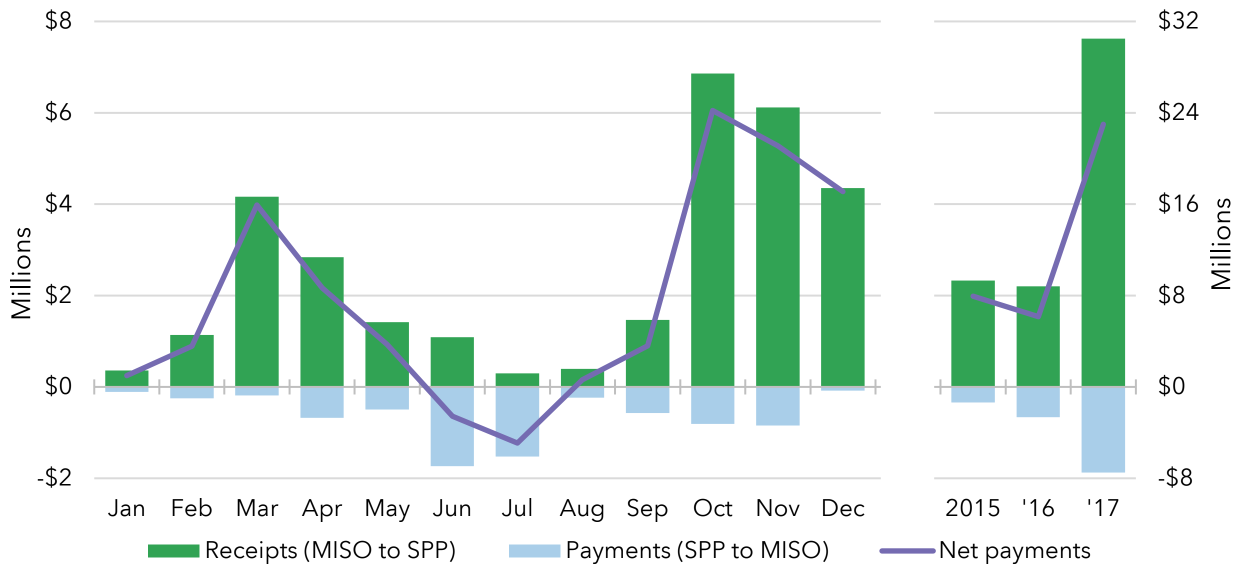
SPP began the market-to-market (M2M) process with MISO in March 2015 as part of a FERC requirement that also included regulation compensation and long-term congestion rights. These were required to be implemented one year after go-live of the SPP Integrated Marketplace. The market-to-market process under the joint operating agreement allows the monitoring RTO and non-monitoring RTO 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 relieve congestion.[33]

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

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

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. It pays if above its firm flow entitlement. Figure 2–37 shows payments by month between SPP and MISO (positive is payment from MISO to SPP and negative is payment from SPP to MISO.)

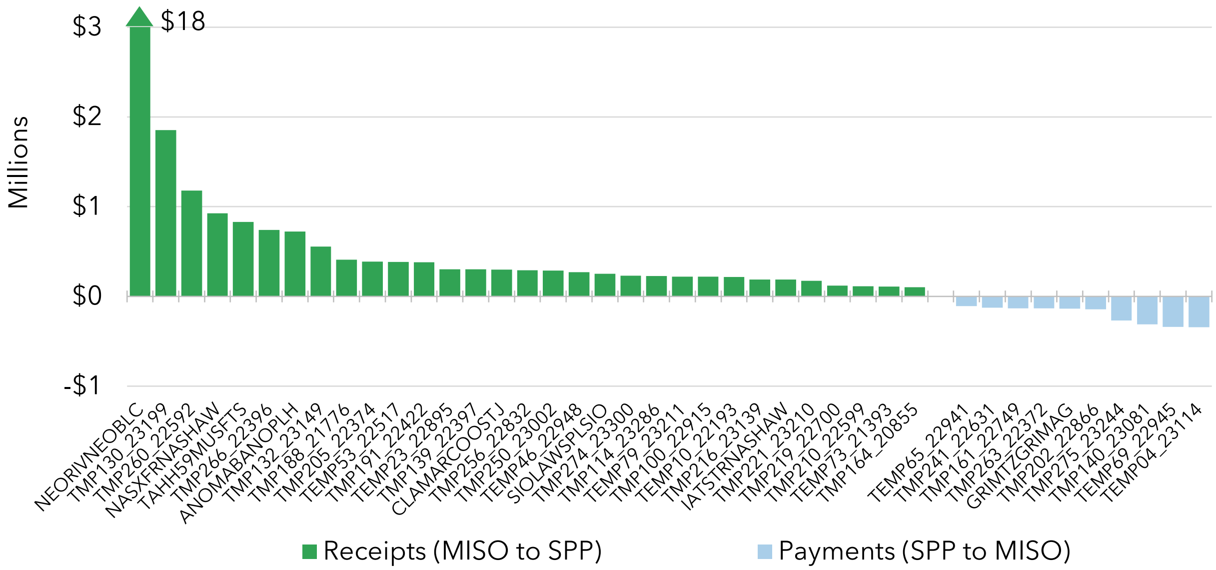
Figure 2–37 Market-to-market settlements



For 2017, total market-to-market payments from MISO to SPP totaled just over $30 million, while market-to-market payments from SPP to MISO totaled nearly $8 million, resulting in a net payment of approximately $23 million from MISO to SPP for the year. This increase from previous years can be attributed to the Neosho – Riverton 161kV constraint discussed more below.

Figure 2–38 shows market-to-market payments (over $100,000 either from SPP to MISO, or MISO to SPP) by flowgate for 2017.

Figure 2–38 Market-to-market settlements by flowgate



Only eight flowgates had payments from MISO to SPP over $500,000. The highest payment from SPP to MISO was just over $340,000. The Neosho-Riverton 161kV flowgate was highly congested in the latter half of 2017 and was impacted by wind and external flows. This is discussed in more detail in Section 5.1.4.3. Market-to-market payments from MISO to SPP in 2017 on this flowgate alone totaled over $18 million. This was a ten-fold increase above the next highest flowgate, which had total payments in 2017 of $1.8 million.

Market-to-market allows for a coordinated approach between markets to provide a more economical dispatch of generation to solve congestion. In most cases, MISO is paying SPP to help resolve congestion at a lower cost than what was available to MISO and in a few cases, SPP pays MISO to help resolve congestion. The following are points of discussion between MISO and SPP mentioned in the previous annual report and the MMU feels improvements in these areas could lead to improved benefits for both markets. Two areas which were addressed in a memorandum of understanding executed between SPP and MISO in June 2017 were; 1) monitoring/non-monitoring designation and 2) market-to-market flowgate coordination. These are discussed below. Other points discussed below are use of transmission loading relief and market flow methodology. These topics were not discussed in 2017 but are operational practices or design concepts that can impact market-to-market settlements.

2.6.2.1 Monitoring/non-monitoring designation

SPP and MISO implemented the ability to transfer monitoring and non-monitoring RTO roles in December 2017. MISO and PJM have been utilizing this function to address constraint volatility or power swings when the non-monitoring RTO may have more "effective control" on certain constraints. The MMU feels this added ability of transferring roles will help alleviate power swings on certain constraints bringing about better price convergence.

2.6.2.2 Market-to-market flowgate coordination

In August 2017, SPP and MISO implemented additional criteria and processes to the market-to-market flowgate coordination tests. A series of coordination tests are performed to determine if flowgates should become a market-to-market flowgate. These tests are run when a flowgate is created and reanalyzed periodically. In some cases a flowgate may pass for scenarios that no longer exist such as outages. This may cause the non-monitoring RTO to be asked to provide relief during a configuration that has changed. The additional criteria added in June 2017 per the memorandum of understanding allowed for the removal of several flowgates from market-to-market. These more frequent tests better represent current conditions. The market monitor feels the added criteria and frequent tests better reflect current conditions alleviating unattainable relief by a non-monitoring RTO.

2.6.2.3 Use of transmission loading relief

SPP, per its market protocols, uses the transmission loading relief (TLR) process when tagged impacts or other external impacts are present on an SPP constraint. The market monitor believes that the transmission loading relief process is not needed when the SPP and MISO markets have the majority of impacts, but is still needed when external impacts from non-market (third party) entities are significant. Assuming interface price definitions correctly reflect congestion, tagged transactions should respond to the market conditions and either withdraw or delay submitting tags during congestion. Thus, this should alleviate the need for transmission loading relief when impacts on the constraint are mostly between SPP and MISO.

When third-party impacts exist, the MMU believes transmission loading relief is warranted to subject the third party to redispatch.[34] A scenario observed between SPP and MISO entailed

[34] Third parties include Tennessee Valley Authority, Associated Electric Cooperative Incorporated, and Southwestern Power Administration.

third-party firm network and native load impacts that are not subjected to redispatch by either market. The third party does not have a market signal in the form of a price and by the absence of a transmission loading relief will not have an incentive to provide relief on the constraint. Transmission loading relief is not as efficient as a market using price and dispatch to manage congestion on a constraint. Market-to-market is the preferred method in addressing congestion along the seams, but until further development is made in areas outside RTO markets, transmission loading relief is the current mechanism to manage impacts between markets and non-markets.

2.6.2.4 Market flow methodology

SPP, MISO, and PJM calculate market flows differently. MISO and PJM use a marginal zone methodology (although the margins are derived in different manners), and SPP uses a tagging impact approach. This topic was not discussed in 2017, but because market flow is a component used in market-to-market settlements, the MMU suggests this topic should be revisited to ensure consistency and equitable measurements across RTOs.

3 UNIT COMMITMENT AND DISPATCH PROCESSES

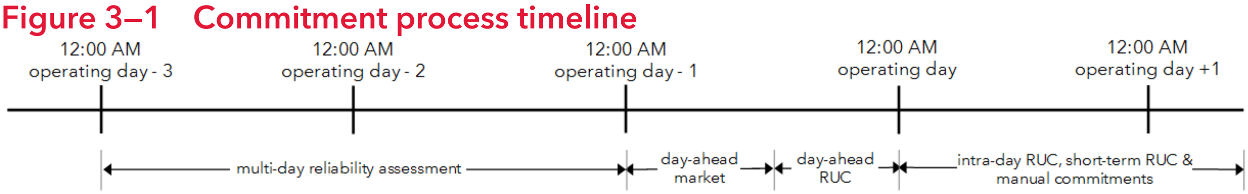
3.1 COMMITMENT PROCESS

The Integrated Marketplace uses a centralized unit commitment program to determine an efficient scheduling and dispatch of generation resources to meet energy demand and operating reserve requirements. The principal component of the commitment program is the day-ahead market, which determines a least cost commitment schedule that meets day-ahead energy demand and operating reserve requirements simultaneously. Most of the time it becomes necessary to commit additional capacity outside the day-ahead market to ensure all reliability needs are addressed and to adjust the day-ahead commitment for real-time conditions. This is done through the reliability unit commitment (RUC) processes. SPP employs five reliability commitment processes:

- multi-day reliability assessment;
- day-ahead reliability unit commitment (DA RUC) process;
- intra-day reliability unit commitment (ID RUC) process;
- short-term intra-day reliability unit commitment (ST RUC) process; and
- manual commitment instructions issued by the RTO.

Figure 3–1 shows a timeline describing when the various commitment processes are executed.

Figure 3–1 Commitment process timeline



Multi-day reliability assessments are made for at least three days prior to an operating day. This assessment determines if any long lead time generators are needed for capacity adequacy for the operating day. Any generator committed from this process is treated as a "must commit" in the day-ahead market. The day-ahead closes at 0930 Central time and is executed on the day before the operating day, with the results posted at 1400 hours. The day-ahead reliability unit commitment process is executed approximately 45 minutes after the posting of the day-ahead market results. This allows market participants time to re-offer their uncommitted resources.

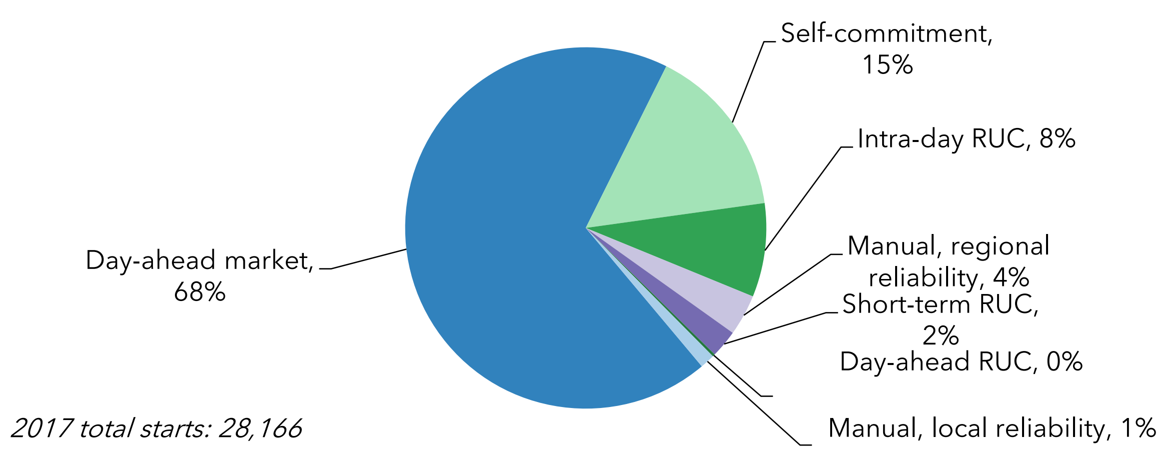
The intra-day reliability unit commitment process is run throughout the operating day, with at least one execution occurring every four hours. The short-term intra-day reliability unit commitment may be executed as needed to assess resource adequacy over the next two hour period as part of the intra-day process. SPP operators may also issue manual commitment instructions for capacity, transmission, or local reliability during the operating day to address reliability needs not fully reflected in the security constrained unit commitment algorithm used in the day-ahead and reliability unit commitment processes. Transmission operators occasionally also issue local reliability commitments.

3.1.1 RESOURCE STARTS

The SPP resource fleet, excluding variable energy resources, had 28,166 starts during 2017. This is up 13 percent from 24,881 starts last year. The following two tables and graphs provide a breakdown of the origins of the commitment decisions for resources. For all generation participation offers in the day-ahead market by commitment status see Figure 3–10.

Figure 3–2 Start-up instructions by resource count

	2015	2016	2017
Day-ahead market	49%	59%	68%
Self-commitment	21%	19%	15%
Intra-day RUC	12%	10%	8%
Manual, regional reliability	7%	5%	4%
Short-term RUC		3%	2%
Day-ahead RUC	9%	2%	<1%
Manual, local reliability	1%	2%	1%

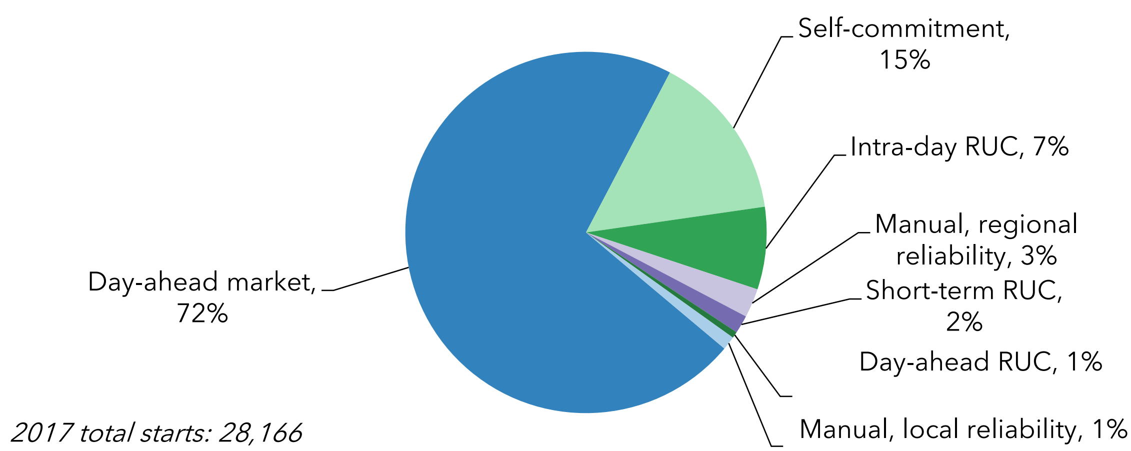


Sixty-eight percent of start-up instructions in 2017 were a result of the day-ahead market. As shown in Figure 3–2, each year there has been an increase in day-ahead market starts and a decrease in self-commitment starts. This is an encouraging trend as it leads to greater market efficiency and suggests that resource owners may be gaining confidence in allowing the market to commit resources. However, a limiting factor on the number of day-ahead commitments is that the optimization algorithm is restricted to a 48-hour window; hence, large base-load resources with long-lead time and long run times may not appear economic to the day-ahead market commitment algorithm. Some market participants choose to self-commit these resources, which contributes to the large number of self-commitments. Nonetheless, many market participants have improved their operating practices to decrease the start-up times on the units to take advantage of the market commitment process. The day-ahead, intra-day, short-term, and manual reliability unit commitments represent 15 percent of the resource start-ups.

Figure 3–3 is based on capacity committed and provides a slightly different look at the data with the percentages based on capacity committed to startup.

Figure 3–3 Start-up instructions by resource capacity

	2015	2016	2017
Day-ahead market	50%	59%	72%
Self-commitment	21%	21%	15%
Intra-day RUC	10%	9%	7%
Manual, regional reliability	6%	4%	3%
Short-term RUC		3%	2%
Day-ahead RUC	11%	3%	1%
Manual, local reliability	2%	2%	1%



One important observation is the percentage differences between Figure 3–2 and Figure 3–3. This is the result of larger resources either self-committed or committed by the day-ahead market, and smaller resources with shorter lead times committed in the day-ahead reliability unit commitment, intra-day reliability unit commitment, and manual commitment processes.

Once within the operating day, commitment flexibility is limited by resource start-up times. As we get closer to the operating hour, fewer resources are eligible to be started. Quick-start units can be directly dispatched by the real-time balancing market and the reliability unit commitment processes will not start other units if the quick-start units are able to resolve the problem. SPP issued more than 73 percent of all start-up instructions to gas-fired generators in 2017, up from 69 percent of all start-ups in 2016.

Figure 3–4 Origin of start-up instructions for gas resources

Commitment Process	Combined-cycle			Simple-cycle - combustion turbine			Simple-cycle - steam turbine		
	2015	2016	2017	2015	2016	2017	2015	2016	2017
Day-ahead market	89%	92%	94%	45%	59%	69%	34%	46%	64%
Day-ahead RUC	0%	1%	0%	14%	2%	0%	34%	16%	3%
Intra-day RUC	1%	1%	1%	20%	15%	12%	20%	18%	15%
Short-term RUC	---	0%	0%	---	6%	4%	---	4%	4%
Manual instruction	0%	0%	0%	15%	11%	7%	5%	9%	2%
Self	9%	6%	5%	7%	7%	7%	5%	8%	11%

Figure 3–4 shows that almost all start-up instructions issued to combined-cycle generators are the result of the day-ahead market. This result is expected given the lower variable costs and different operating parameters for these resources relative to other gas units. SPP issued day-ahead starts for gas-fired generators with simple-cycle combustion turbine technology accounted for 69 percent of their total starts. This is an increase from 59 percent last year. Steam turbine starts saw an increase in the day-ahead market starts as well, with 64 percent compared to 46 percent the year before. While self-commitments have dropped for combined-cycle units, the MMU is concerned about the increase in self-commitments in gas steam units.

Some reliability unit commitments are made to meet instantaneous load capacity requirements; however, this is not a product generators are directly compensated for by the market. Therefore, reliability commitment processes, more often than the day-ahead market, make commitments that may not be supported by real-time price levels. These situations often lead to make-whole payments. The next section discusses the drivers behind the reliability commitments and thus high on-line resource commitments.

3.1.2 DEMAND FOR RELIABILITY

The previous section noted that 15 percent of SPP start-up instructions originated from SPP reliability unit commitment processes. To understand the need for the reliability commitments it is useful to discuss the different assumptions, requirements, and rules that are used in the reliability unit commitment processes versus the day-ahead market. A fundamental difference is the definition of energy demand between the two studies. The energy demand in the day-ahead market is determined by bids submitted by the market participants, and averages between 98 to 101 percent of the real-time values, as shown in Figure 2–5.

Another important difference between the two studies is virtual transactions. Market participants submit virtual bids to buy and virtual offers to sell energy in the day-ahead market. A virtual transaction is not tied to an obligation to generate or consume energy; rather, it is a financial instrument that is cleared by taking the opposite position in the real-time market. Because the reliability unit commitment processes must ensure sufficient generation is on-line to meet energy demand, virtual transactions are not included in the day-ahead, intra-day, or short-term reliability unit commitment algorithms.

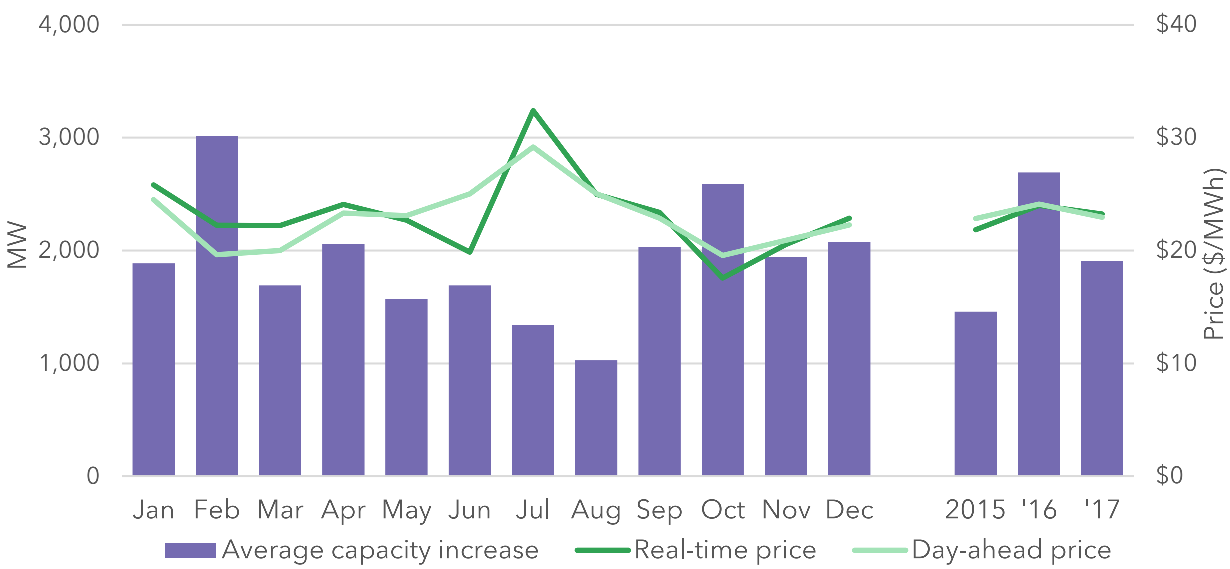
The assumptions regarding wind generation differ as well. Only 82 percent of the real-time wind production cleared in the day-ahead market on an average hourly basis in 2017. While the market participants determine the participation levels for their wind generators in the day-ahead market through the use of supply offers, a wind forecast is used by the reliability unit commitment processes. Import and export transaction data are updated to include the latest information available for the reliability unit commitment processes.

These types of differences are referred to as resource gaps (i.e., a gap in meeting demand) between the day-ahead and real-time markets. The resource gap is the difference between the (1) excess supply between day-ahead and real-time markets, and the (2) excess demand between the day-ahead and real-time markets.

The primary drivers for the negative resource gaps are differences in virtual supply net of virtual demand, differences in real-time wind generation compared to wind cleared in the day-ahead market, and real-time net exports exceeding day-ahead net exports. It is generally true that real-time wind generation exceeds the clearing of wind in the day-ahead market. The mismatch between real-time and day-ahead wind is because some market participants with wind generation assets do not participate or offer the full amount of forecasted capacity in the day-ahead market. Instead, they take real-time positions given the uncertainty of the wind generation.

The resource gaps can help explain why additional commitments occur after the day-ahead market has cleared. Figure 3–5 compares on-line capacity between the day-ahead and real-time markets.

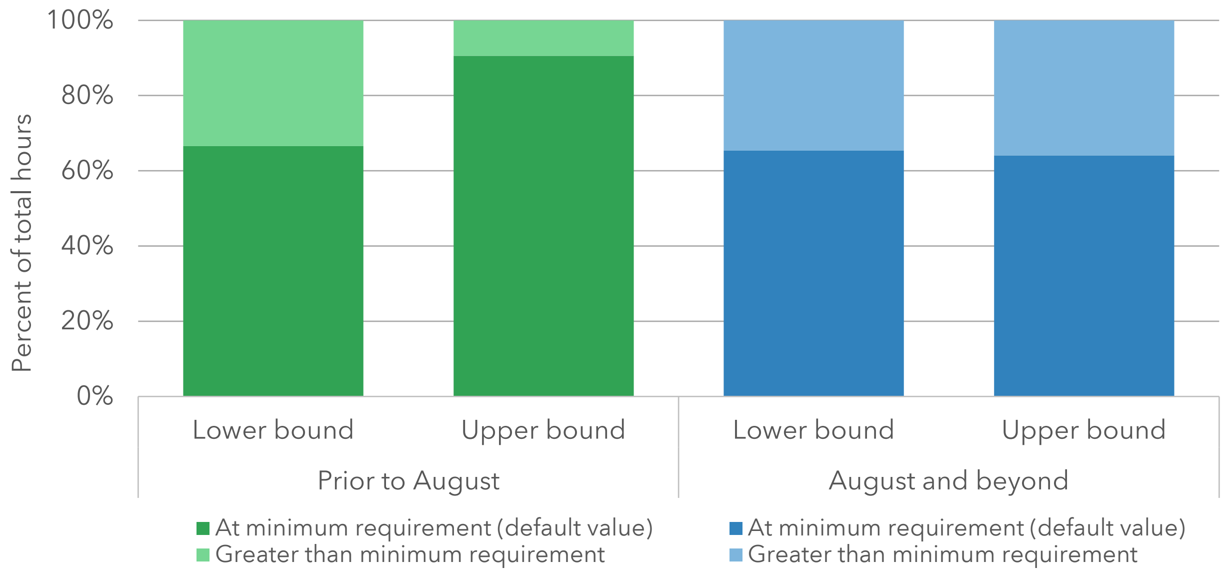
Figure 3–5 Average hourly capacity increase from day-ahead to real time



The chart indicates that in 2017 there was, on average, around 1,900 MW of additional capacity on-line during the real-time market relative to the capacity cleared in the day-ahead market, a reduction of 27 percent compared to 2016.

One well-known and much discussed issue with respect to reliability commitments is the need for ramp capability. The instantaneous load capacity constraint may commit additional resources to ensure there is adequate ramping capacity to meet the instantaneous peak demand for any given hour. The instantaneous load capacity constraint is defined as the greater of the forecasted instantaneous peak load, or an SPP defined default value. A value is calculated for upper bound (upward ramp) and a lower bound (downward ramp). Because the default value is used the majority of the time, the MMU believes that instantaneous load capacity constraint can contribute to reliability commitments in excess of the resource gaps. Figure 3–6 shows the percentage of hours for which the default value is used for the upper bound and lower bound of instantaneous load capacity.

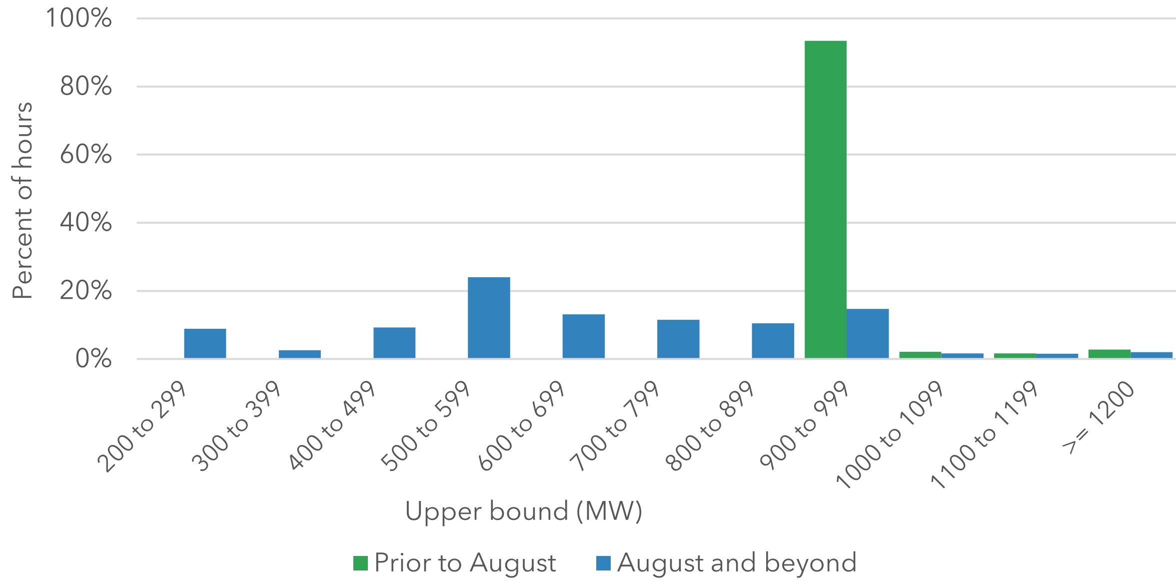
Figure 3–6 Instantaneous load capacity required



Before August 1, only one value was used for the upper bound for the entire day. The same is true for the lower bound. During this time the upper bound default was 900 MW and the lower bound was 500 MW. The upper bound default value was used for 91 percent of total hours during this first part of the year. After August 1, a software update allowed for an hourly value. After this change, default values were used less, approximately 65 percent of all hours.

During the second part of the year, the default values for the upper bound ranged from 200 to 900, and were less than 900 MW for most hours, as seen in Figure 3–7. The lower bound default values remained at 500 for all hours of the day.

Figure 3–7 Instantaneous load capacity upper bound default levels



Resources committed to provide ramp capability, whether as a result of applying the instantaneous load capacity constraint in a reliability commitment algorithm or a manual process, can affect real-time prices. Without the appropriate scarcity pricing rules that reflect the market value of capacity shortages due to ramp capability the cost of bringing the resource on-line may not be fully reflected in the real-time prices.

Reliability commitments, along with wind exceeding the day-ahead forecast, can dampen real-time price signals, as is evidenced by 58 percent of make-whole payments made for reliability unit commitments.

3.1.3 QUICK-START RESOURCES COMMITMENT

A quick-start resource can be started, synchronized, and begin injecting energy within 10 minutes of SPP notification. Proposed changes to the definition of quick-start resources also include a minimum run time of an hour or less.[35] There are 87 resources in the SPP footprint that have both a 10-minute start time with a minimum run time of an hour or less. Nameplate

[35] RR116 defines a Quick-Start Resource as, "A Resource that can (i) be started, synchronized and inject Energy within ten minutes of Transmission Provider notification, (ii) operate with a Minimum Run Time of one hour or less…" See RR116 Recommendation Report, available at (https://www.spp.org/Documents/30429/mrr116.zip). FERC required SPP to "Include in the definition of quick-start resources a requirement that those resources have a minimum run time of one hour or less". See *Order Instituting Section 206 Proceeding and Commencing Hearing Procedures and Establishing Refund Effective Date*, 161 FERC ¶ 61,296 (2017) at 25.

capacity for the quick-start capable resources totals 4,566 MW and consists of a mix of gas-fired, hydro, and oil-fired generators. During 2017, the reliability unit commitment processes committed 67 of the 87 quick-start capable resources.

Figure 3–8 summarizes the start-up instructions issued to resources with real-time offers indicating a 10-minute start-up capability and a minimum run time less than one hour. In 2017, 817 start instructions originated in a reliability commitment process, 5,044 start instructions originated from the day-ahead market, and 508 were manually committed. Of particular interest is the average lead time for reliability commitment start-up orders. The lead time is calculated as the number of hours between the commitment notification time and the first hour of the 10-minute resource's commitment period.

Figure 3–8 Commitment of quick-start resources

Commitment process	Number of starts	Committed capacity (MW)	Lead time (hours)	Hours in original commitment	Actual hours on-line
Day-ahead RUC	0	N/A	N/A	N/A	N/A
Intra-day RUC	517	28,129	1.7	3.9	5.9
Short-term RUC	300	13,451	0.3	2.5	4.9
Manual	508	26,642	0.6	4.0	6.4

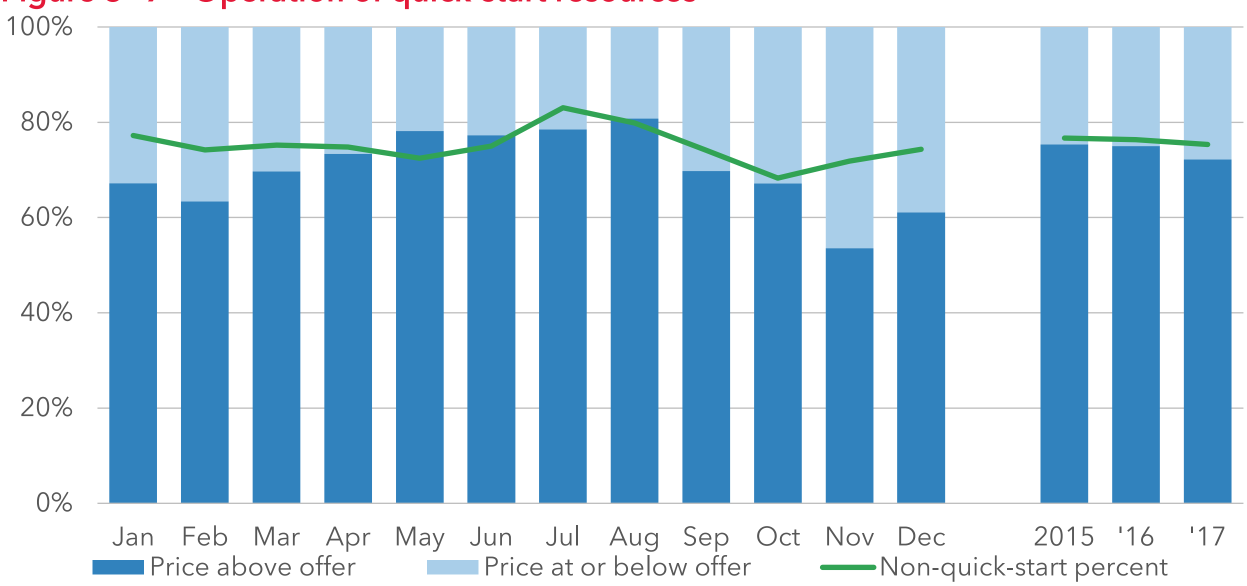
The level of make-whole payments associated with the commitment of quick-start resources in the reliability processes is still noteworthy. In 2017, 78 percent of the reliability processes commitments for quick-start units resulted in real-time make-whole payments. This is similar to 2015 and 2016 which were 75 and 79 percent, respectively. In 2017, quick-start resources received $9.5 million in real-time make-whole payments and $485,000 in day-ahead make-whole payments. This is a slight increase from their respective 2016 make-whole payments of $9.3 million and $439,000 respectively. The MMU believes that the commitment costs of quick-start resources needs to be included in the commitment decisions of these resources, which is consistent with changes developed through the stakeholder process.

With the inception of the short-term reliability unit commitment process in February 2016, there has been a significant reduction in the number of day-ahead reliability unit commitments for these units. The short-term reliability unit commitment can commit units in as little as 15 minutes ahead, increasing certainty of the need for the unit. Before the short-term reliability unit commitment process was implemented, units had often been committed hours ahead of the actual start time—sometimes more than a day—ignoring the value of their flexible capability. The short-term unit commitment process was brought into the market in February 2016, and can evaluate intervals 15 minutes ahead. This leaves time to commit these quick-start resources when needed, but allows the commitment to be held off longer providing, more certainty of the need of the resource. This also minimizes the time these units are at minimum load levels with market prices below their marginal costs.

The Integrated Marketplace protocols[36] describe the real-time market dispatch and registration options of resources with quick-start capability. Resources use these quick-start capabilities in their real-time offer, and registered as quick-start capable, can choose not to receive start-up and/or shutdown orders out of the short-term, intra-day RUC.

Figure 3–9 shows the percent of time quick-start resources generated power and the relationship of prices to their offer.

Figure 3–9 Operation of quick-start resources



Over the last three years, 25 percent of the megawatt-hours produced by quick-start resources had energy prices below real-time energy offers. This is consistent with relative relationship of offers to energy price for other resources in the SPP footprint, which is represented by the green line in Figure 3–9. Quick-start resources directly dispatched in real time using the quick-start logic are not eligible for a make-whole payment nor is the

[36] Integrated Marketplace protocols, Section 4.4.2.3.1 and Section 6.1.1.

minimum run time respected.[37] This is a concern that revision request 116 is designed to address.

In order to deal with the issue of uneconomic production, SPP staff presented a new quick-start design proposal that was well-received by stakeholders in May 2015. Subsequently, this proposal was submitted to the Market Working Group (MWG) by Golden Spread Electric Cooperative[38] and was approved in September 2015. The MMU agrees with the proposal and believes that incorporating commitment costs in the evaluation of the commitment will help reduce the incidence where these resources are committed and prices are insufficient to cover costs.

While this change was pending FERC filing, FERC began a Section 206 proceeding[39] in late-December 2017 finding SPP's current practices regarding pricing of quick-start resources may be unjust and unreasonable. In response, the MMU filed an initial brief and reply comments highlighting the following positions:

- Commitment costs should be evaluated as part of market optimization to ensure production costs are minimized.
- Quick-start resources should have a minimum run time of less than or equal to one hour.
- Economic minimum operating levels should not be reduced (relaxed) to zero because the approach would set prices based on resource flexibility and availability that is false (does not exist) and would likely require another optimization run that could put pressure on performance time and affect the real-time mitigation process.
- SPP's screening run and subsequent pricing and scheduling runs are reflective of actual available resources and that the optimization logic uses appropriate operational and reliability constraints (i.e., relies on a resources' physical offer parameters that determine how and when a resource should operate).
- The Commission's proposal departs from the marginal pricing methodology upon which the SPP market is based and would likely result in average cost pricing.
- Uplift would likely be transferred under the Commission's proposal and not necessarily reduced.

[37] Protocols 4.4.2.3.1 states that only the offer curves are used to dispatch.
[38] Revision Request 116 (Quick-Start Real-Time Commitment) by the SPP board, but was placed on hold in lieu of FERC's Order issued December 21, 2017.
[39] https://www.ferc.gov/whats-new/comm-meet/2017/122117/E-5.pdf

- Tariff language regarding the basis of parameters needs to be revised to ensure that information is accurate and based on physical and environmental factors.

FERC is expected to respond to comments and propose further direction on modeling of quick-start resources by fall 2018.

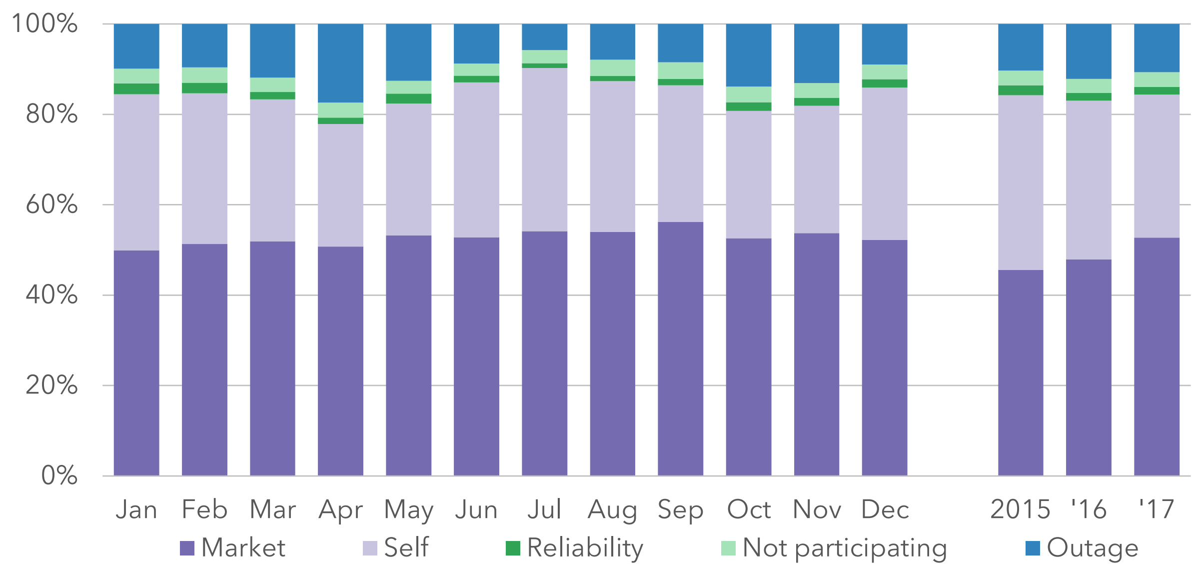
3.2 GENERATION SCHEDULING

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 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.

In 2017, participation in the day-ahead market was robust for both generation and load. 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 3–10 shows generation participation offers in the day-ahead market by commitment status.

Figure 3–10 Day-ahead market offers by commitment status

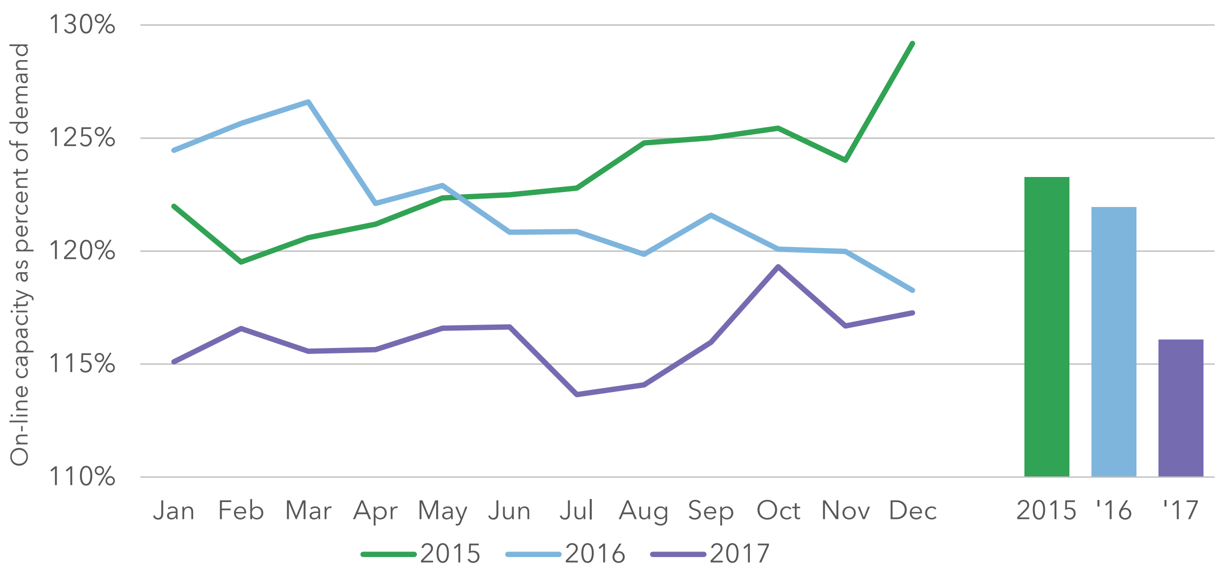


The "market" commitment status averaged 53 percent and "self-commit" status averaged 31 percent of the total offered capacity for 2017, which is a slight change from 2016.[40] Resources with commitment statuses of "reliability" and "not participating" averaged one percent and three percent, respectively, which is close to what was experienced in 2016. "Outage" status accounted for the final 10 percent, a decrease from 12 percent in 2016. While self-commits decreased from 2016, they still constitute a large amount of the capacity offered into the market.

Compared with Figure 3–2 and Figure 3–3 in Section 3.1.1, which shows origins of only initial starts, these values represent commitment status of all generation capacity offered including those on-line. Initial starts show 15 percent being self-committed in 2017 where all capacity offered averaged 31 percent. This can be attributed to desire to keep resources on-line after its initial start even during low prices.

Figure 3–11 shows on-line capacity commitment as a percent of load.

Figure 3–11 On-line capacity as a percent of load



The capacity commitment as a percent of load has decreased significantly over the past few years. Some factors in 2017 that contribute to lower levels of on-line capacity are fewer self-committed coal plants and the continued growth of wind capacity and generation. As more renewables are added to the system, there have been an increasing incidence of negative

[40] Of the self-committed resources, qualifying facilities (QF) account for three to four percent. Qualifying facilities often use self-commit status to exercise their rights under the Public Utilities Regulatory Policies Act of 1978 (PURPA).

prices (see Section 4.1.6) and higher real-time price volatility (see Section 4.1.4). Lower on-line capacity levels may be a consequence as market participants and market operators adjust to these changes in market conditions.

3.3 DISPATCH

The real-time market co-optimizes the clearing of energy and operating reserve products out of the available offered capacity based on the offer price for each product while respecting physical parameters. The real-time market clears every five minutes for all products. The settlement of the real-time market also occurs at the five-minute level, and the settlement is based on market participants' deviations from their day-ahead positions.

3.3.1 RAMP CAPABILITY PRODUCT

Evidence suggests that a ramp capability product would be beneficial to the market. A resource's ability to ramp should be planned for and should be valued by a price to the extent the ramp is beneficial to the market.

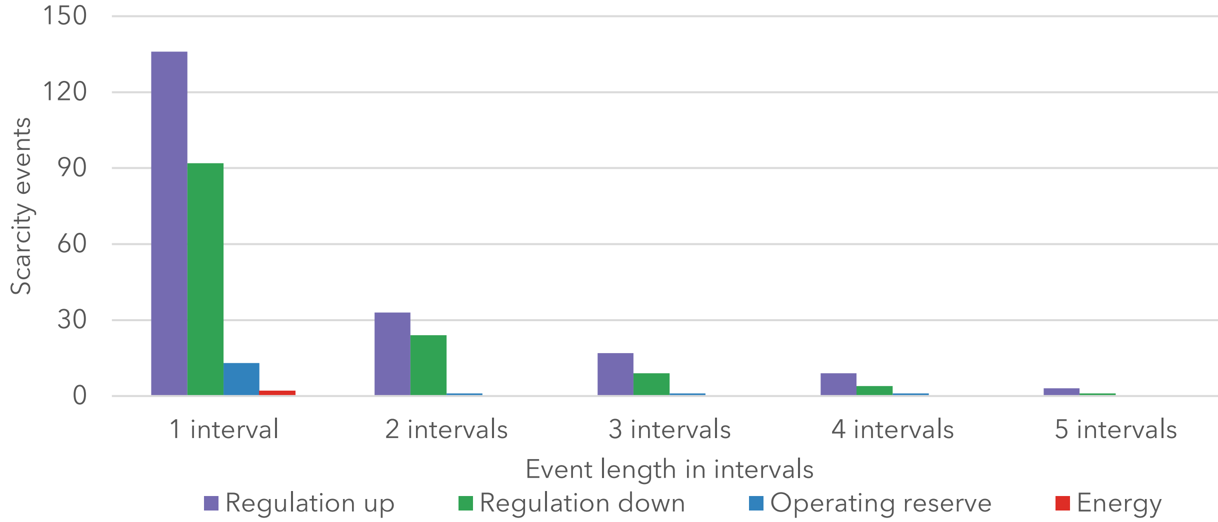
3.3.1.1 Ramping limitations affecting market outcomes

The real-time dispatch does not consider future intervals. It simply calculates one value: a dispatch instruction for the next interval. The increase or decrease of the resource's output to achieve the next dispatch instruction is called "ramp". The number of megawatts a resource can ramp in one minute is the resource's "ramp rate". While the real-time balancing market considers a resource's ramp capability for the purpose of calculating the dispatch instruction for the next interval, ramp is not considered for any interval after that. Ramp is not currently accounted for in terms of the next dispatch instructions even though ramp is the very capability that allows a resource to get to the next dispatch instruction.

When ramp capability is not considered for future intervals, then the market clearing engine may not be able to procure enough energy to serve the load or provide sufficient operating reserves in the next interval. Even when enough capacity is available, a lack of ramp renders that capacity unreachable. This often leads to short-term transitory price spikes,[41] as seen in Figure 3–12.

[41] This is essentially temporal, or time-based, congestion.

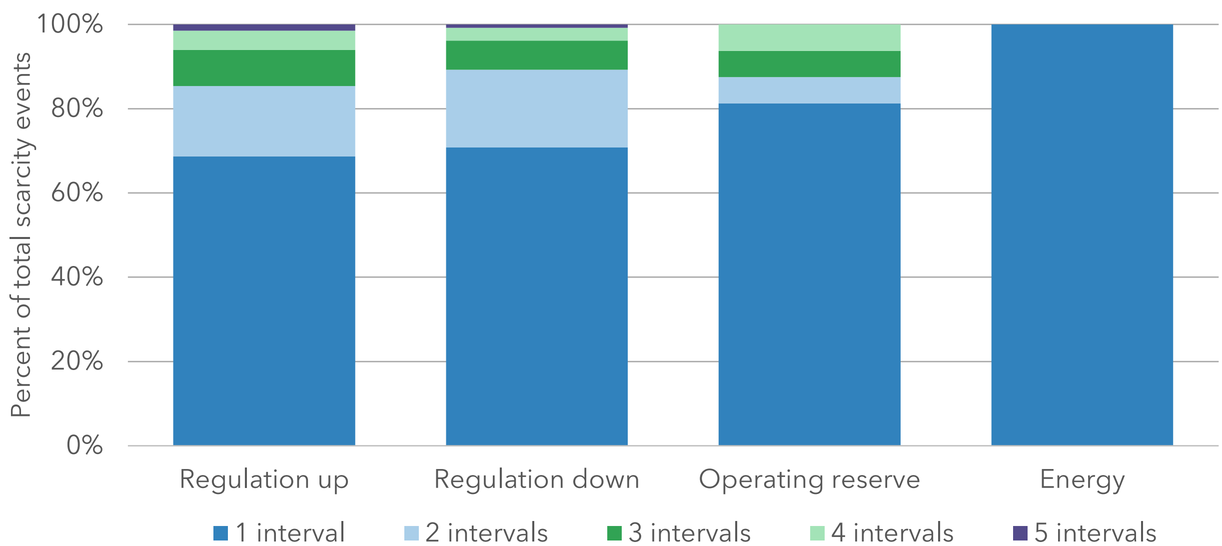
Figure 3–12 Interval length of short-term price spikes



This figure shows that most scarcity pricing events in real time only occur for only one 5-minute interval. Very few scarcity pricing events last more than three intervals.

Figure 3–13 shows the interval length for the different types of scarcity events.

Figure 3–13 Interval length of short-term price spikes, percentage



About 70 percent of regulation-up and regulation-down scarcity events lasted for one interval. About 80 percent of the operating reserve scarcity events lasted only one interval, and no energy scarcity lasted longer than one interval. This indicates that the cause of the scarcity was ramp shortage and not actual capacity shortage. If sufficient ramp were available for these single-interval events, then these scarcities would have been avoided.

Furthermore, instances where sufficient capacity cannot be dispatched, scarcity prices are invoked. Scarcity prices are economic signals alerting market participants to the insufficient supply of a product. The incidence of real-time scarcity events are increasing. Some of the increase is due to FERC Order No. 825 which required SPP to price scarcity events that were not priced in previous years. Almost all of these events were the result of the lack of ramping capability, rather than a reflection of true scarcity of capacity.

In addition, marginal energy prices can be elevated even when energy is not scarce. When ramp in the up direction is short, energy will always be given the highest priority. If there is not sufficient ramp to meet both energy and regulation-up, for instance, then the regulation-up scarcity price will be reflected in the marginal energy price. This causes a high marginal energy price even though there is no energy scarcity. This makes prices more volatile, and the lack of ramp can raise both the regulation-up price and the energy price because the ramp shortage affects both products. This scenario represents about 20 percent of all regulation-up shortages in 2017. If sufficient ramp had been available, then regulation-up scarcity prices would not have raised the marginal energy price. When regulation-up is short, the scarcity price affects energy price. A ramp capability product can ensure that more ramping is available to meet energy so that regulation-up scarcity prices can be avoided. This helps to better reflect system conditions and reduces dispatch volatility.

3.3.1.2 Design limitations accounting for expected ramp

The current market design does not effectively consider ramp in real-time dispatch. As an example, parameters for two resources are shown in Figure 3–14. Assume no congestion, losses, or any constraints other than the ones mentioned; and assume load occurs exactly as forecasted and generation performs exactly as instructed. In this case, all changes are expected.

Figure 3–14 Parameters for ramp example

Offers and parameters	Minimum	Maximum	Offer	Ramp rate
Resource A	20 MW	50 MW	$10/MWh	2 MW/min
Resource B	20 MW	50 MW	$15/MWh	1 MW/min

Figure 3–15 Ramp example, market results not considering ramp

Market results not considering ramp	Initial interval	Interval 1	Interval 2
Resource A	40 MW	50 MW	50 MW
Resource B	20 MW	20 MW	25 MW
Total generation	**60 MW**	**70 MW**	**75 MW**
Total load	**60 MW**	**70 MW**	**76 MW**
Price	$10/MWh	$15/MWh	$5,000/MWh

The cheaper resource has a faster ramp rate, and faster load increases in future intervals. Resource A can ramp 10 MW in a five-minute interval while resource B can ramp only 5 MW in that time. Figure 3–15 shows that in Interval 1, the cheaper resource is dispatched to its maximum limit, and resource B's output remains the same because it is out of the money. In Interval 2, resource B does not have sufficient ramp to serve load. The energy scarcity price of $5,000/MWh[42] is invoked, signaling a shortage of energy. Although the scarcity price is more alarming, a higher-priced resource could cause an unnecessarily high price in this situation as well.

In the above example, the market had enough energy capacity to serve the load. Furthermore, sufficient ramp was also provided. If the dispatch instruction for Interval 1 is constrained by the ramp needed to for Interval 2, then a solution without scarcity is feasible. This is shown in the alternative solution in Figure 3–16.

Figure 3–16 Ramp example, market results considering ramp

Market results considering ramp	Initial interval	Interval 1	Interval 2
Resource A	40 MW	45 MW	50 MW
Resource B	20 MW	25 MW	26 MW
Total generation	**60 MW**	**70 MW**	**76 MW**
Total load	**60 MW**	**70 MW**	**76 MW**
Price	$10/MWh	$15/MWh	$15/MWh

Resource A is not dispatched to its maximum limit in Interval 1. Its dispatch instruction is calculated so that some ramp is held back for Interval 2. No scarcity is invoked because the market was not short. The production cost is significantly lower in the example in which the resources were prepositioned for future ramping needs. Scarcities can be avoided by leveraging load forecast and planning for ramp needs.

[42] $5,000/MWh was the price used for the price spike on June 7, 2017.

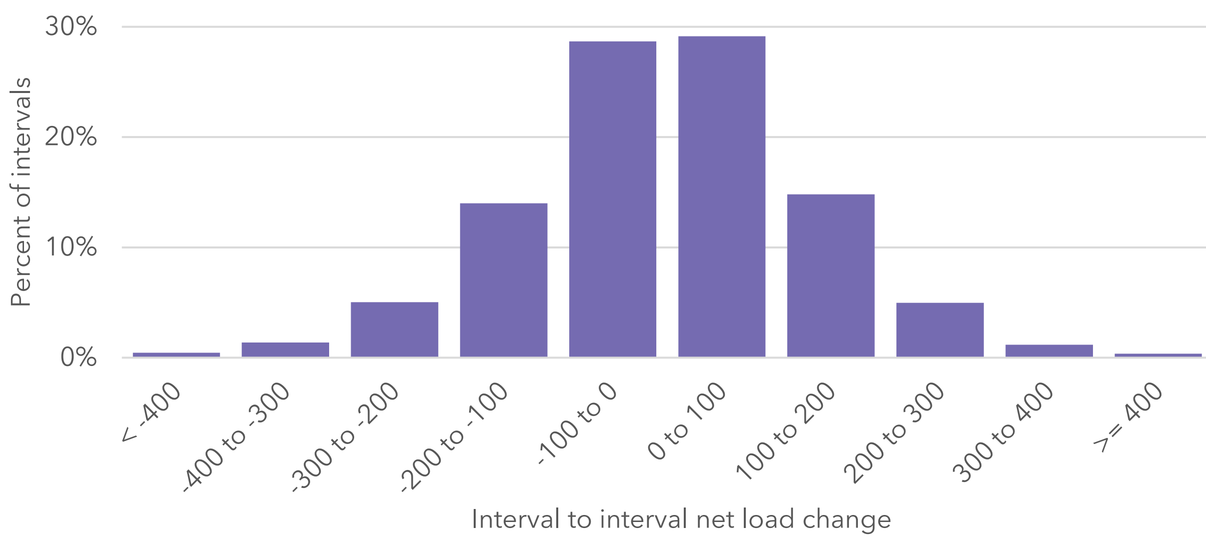
3.3.1.3 Design limitations accounting for unexpected ramp

The above example demonstrated the shortcoming of the current pricing mechanism with the assumption that load occurs exactly as forecasted and generation performs exactly as instructed. These are expected changes. However, the issue is further complicated when the load and generation do not move as anticipated. Unexpected changes in net load also can contribute to shortages as well.

Net load is load net of both variable energy generation and the combination of imports and exports. Each term of this equation is forecasted, and there will always be some error between a forecasted value and the actual value. Load is constantly varying and is not controlled by SPP. Generation is forecasted in that the market clearing software assumes that the dispatch instruction will be followed. Some resources submit a dispatch status reflecting its inability to follow dispatch for various reasons. Even under the best circumstances, dispatchable resources are not able to follow dispatch precisely. Actual imports and exports vary from expected values for similar reasons, particularly during start-up and shutdown periods. For these reasons, the expected net load will always have a margin of error. This margin of error can increase the amount of ramp needed to achieve the next dispatch instruction.

Figure 3–17 shows the frequency of how often the net load changes from one real-time interval to the next.

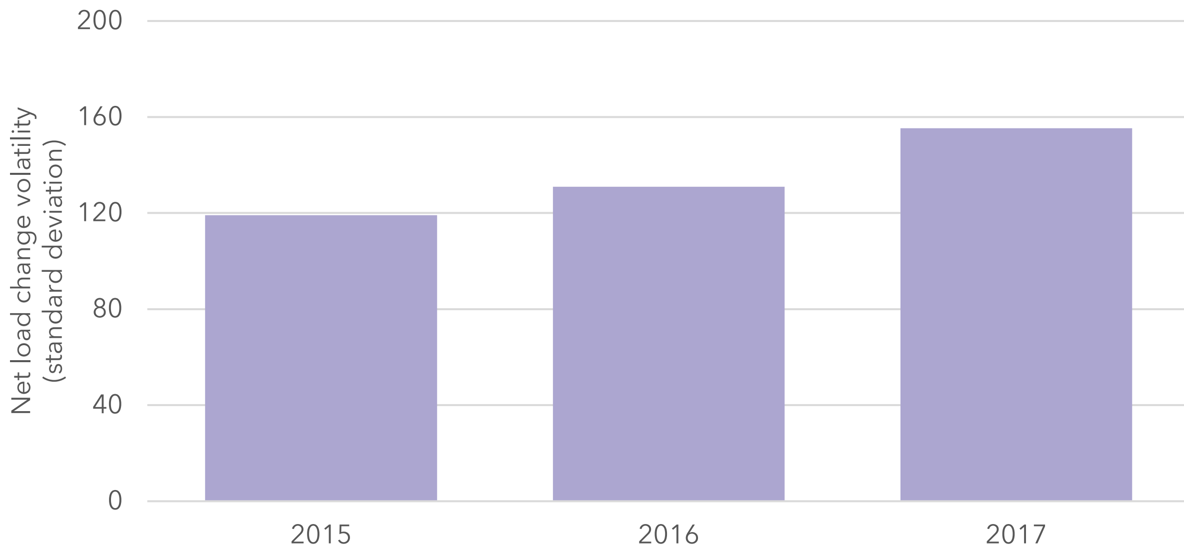
Figure 3–17 Frequency of net load change, real time



About 13 percent of intervals have a net load change of over 200 megawatts when both positive and negative changes are considered. Some of these net load changes peaked over 1,000 megawatts. While the percentage of total intervals is low, these greater deviations cause greater price volatility. This difference must be provided by resources with a flexible dispatch range.

Figure 3–18 below shows that the volatility in net load change increased significantly each year from 2015.

Figure 3–18 Volatility of interval-to-interval net load change



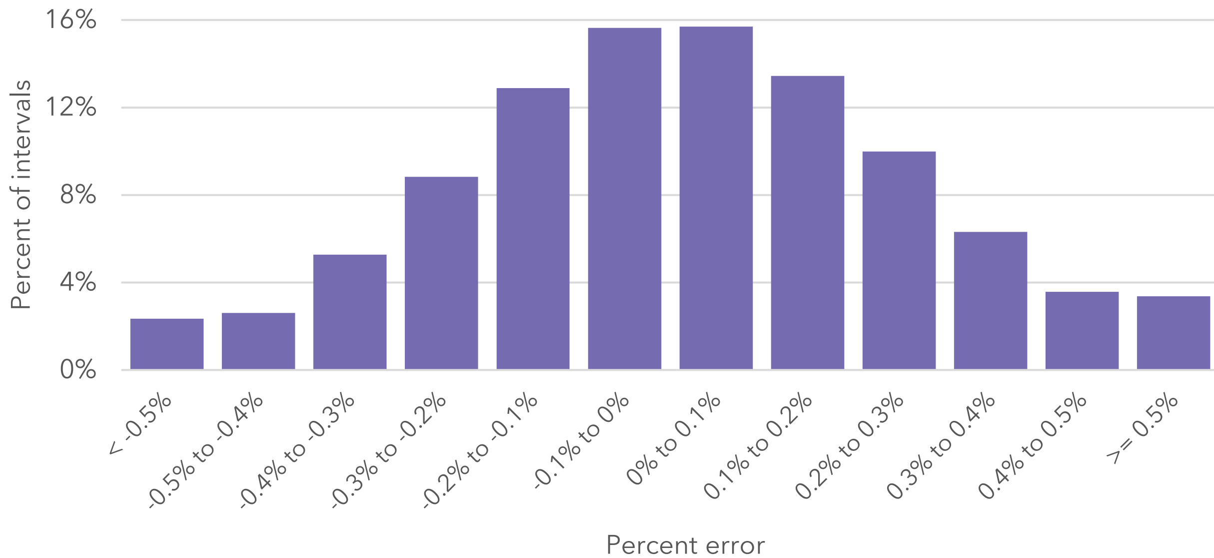
This volatility increased about 10 percent from 2015 to 2016 and about 19 percent from 2016 to 2017.

Variable energy resources typically are assumed to remain at the same output level at which they were last observed. Practically, this will not be the case. This discrepancy can require more ramp in the next interval. In 2017 about 23 percent of total generation was from wind resources. This was a significant source of deviation from anticipated output in 2017. With over 28 gigawatts of wind-powered generation and over 15 gigawatts of solar generation with an active generation interconnection request,[43] this problem will be exacerbated in the future as volatility from variable energy resources increases.

[43] See Figure 2–18.

Although wind and load are forecasted so that their impact can be expected, forecasts are always accompanied by forecast error. While the short-term load forecast, as shown in Figure 3–19, is very accurate overall, the deviations can leave regulation to make up for the error instead of adjusting to the change in load during the five-minute interval.

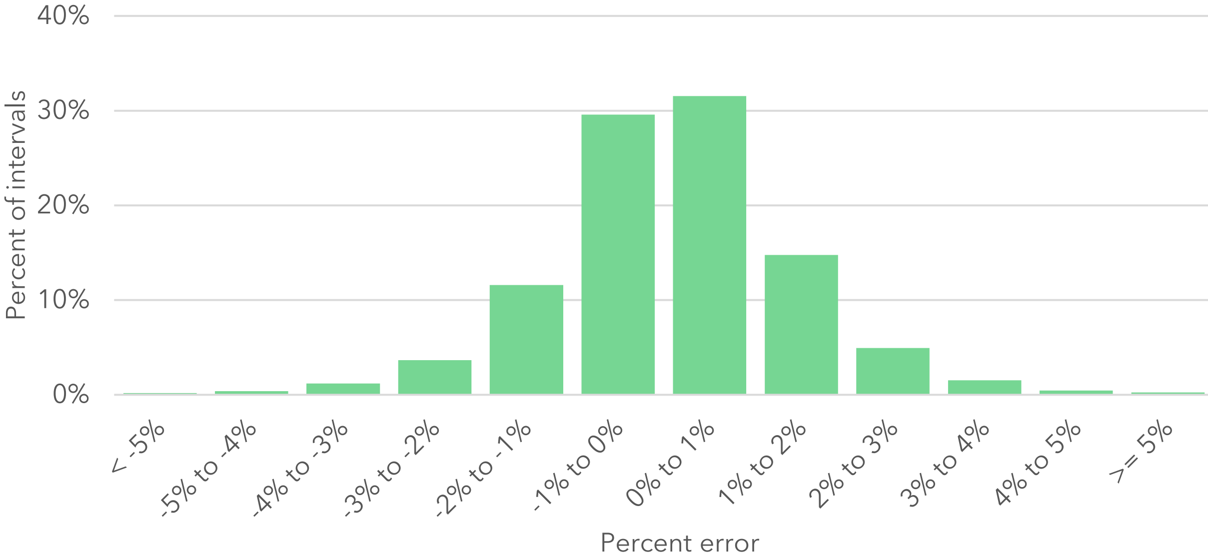
Figure 3–19 Frequency of short-term load forecast error, real time



The largest magnitude of error shown in Figure 3–19 is 0.5 percent for both positive and negative errors. While these categories look small, they make up about six percent of all intervals. This represents about 6,000 intervals during the year, or about 500 hours. During some of these intervals, the load forecast error was around one percent, which represents an error of about 300 megawatts. This is only one source of unexpected net load change.

Another source of unexpected net load change is short-term wind forecast error. This can also occur in both positive and negative directions and is shown in Figure 3–20.

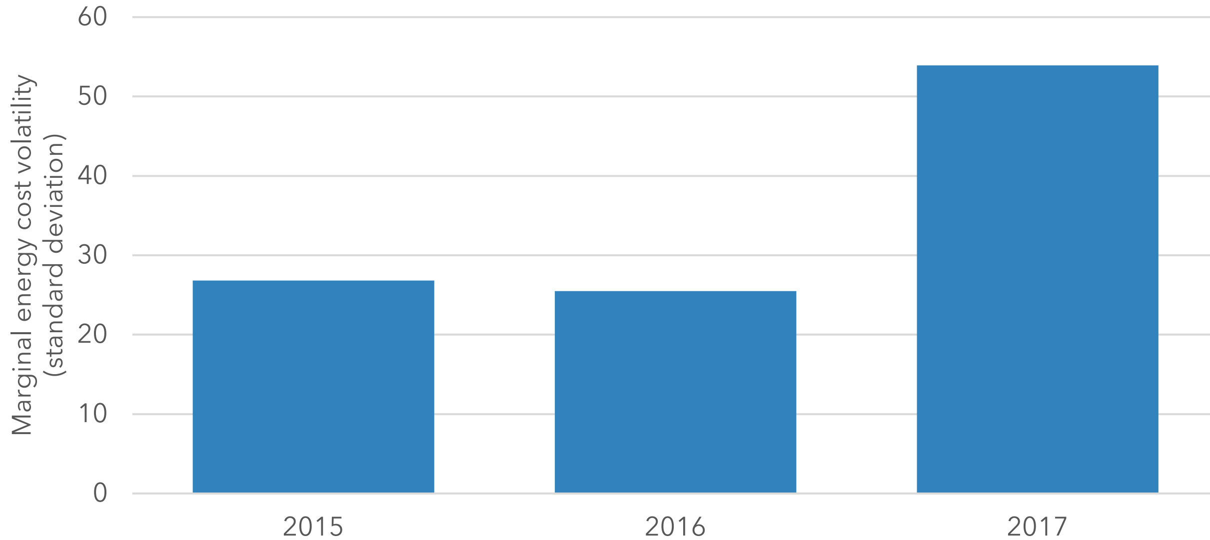
Figure 3–20 Frequency of short-term wind forecast error, real time



While the frequency of wind forecast error in excess of three percent in magnitude for both positive and negative changes is rare, this represents over 4,000 intervals, or about 330 hours. The average wind forecast error for these intervals where the error is greater than +/-3 percent is about 625 megawatts. This too is a significant source of unexpected net load change.

Net load change, with all of its causes, will change the marginal energy price from interval-to-interval because of the constant need to balance generation and load. The volatility of the interval-to-interval difference in the real-time marginal energy price was very high in 2017, as shown in Figure 3–21.

Figure 3–21 Volatility of marginal energy cost interval-to-interval, real time



The amount of interval-to-interval change in the marginal energy component has doubled since 2016, even though it remained steady from 2015 to 2016. A ramp capability product could reduce that volatility by prepositioning resources so that higher prices, because of inflexible dispatch range, are avoided. This should provide steadier prices in real time.

Procuring ramping capability to address both anticipated and unexpected uncertainty has value in smoothing out real-time price volatility and reducing the incidence of scarcity events. Currently, SPP does not value and incentivize this flexibility. A resource's dispatch instruction is currently based solely on the cost of generation at the dispatch instruction. However, because ramp capability adds value to the market, ramping capability should be valued and incentivized by the market.

3.3.1.4 Recommendation

Given the limitations with the current market design in preparing for both expected and unexpected ramping needs, and the growing evidence that market outcomes are increasingly affected by ramping constraints, the MMU recommends that SPP and its members develop a ramping capability product. The benefits of a ramp capability product include increasing reliability through an economic signal and improving market signals.

A ramp capability product can provide ramp more reliably than the current design because it is systematically procured and readily available. The MMU prefers a market-based solution over manual commitments and commitment of capacity to gain ramp. Scarcities, which are not a true reflection of system conditions, can be avoided and the resources that are used to avoid the scarcity should be paid for that benefit that they are providing. This will also incentivize future resources to be flexible.

Other RTO/ISO markets have implemented and designed ramp products that SPP and stakeholders can consider in its design and development. For instance, Midcontinent ISO and California ISO have implemented ramp products, and ISO New England is in the development process. However, at a minimum, we recommend that the design should include the following features:

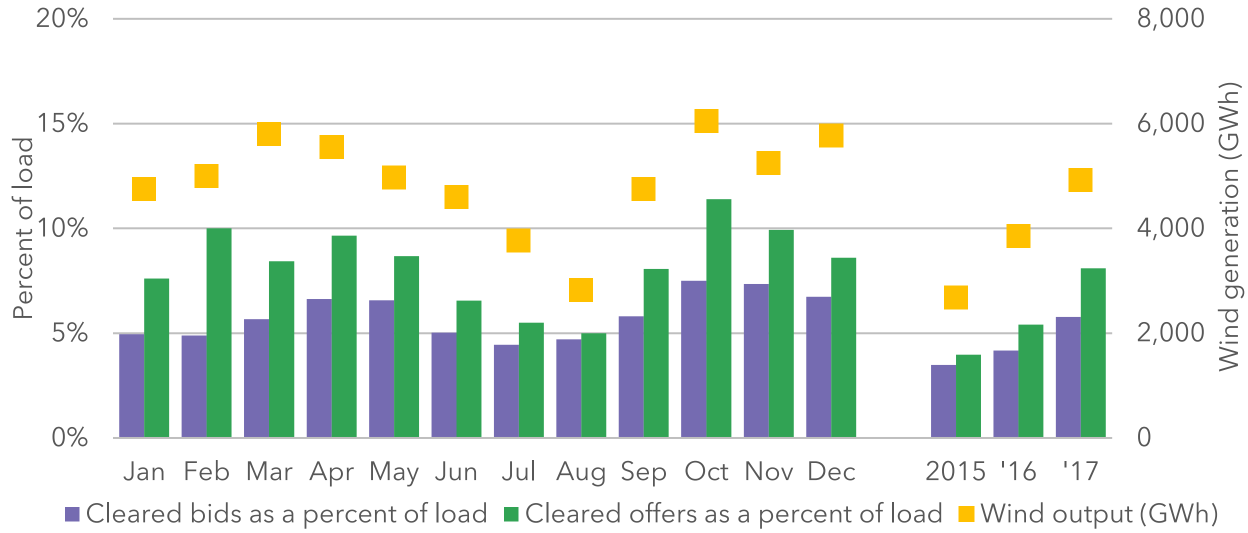
- Two products: ramp capability up and ramp capability down;
- Co-optimization with energy and other products to ensure the most economical solution;
- Opportunity cost basis for pricing;
- No limitations on resource type as long as the resource can reliably provide ramp in the direction for which it is cleared; and
- Consideration of both expected and unexpected ramping needs.

3.4 VIRTUAL TRADING

Market participants in SPP's Integrated Marketplace may submit virtual energy offers and bids at any settlement location in the day-ahead market. Virtual offers represent energy sales to the day-ahead market that the participant needs to buy back in the real-time market. These are referred to as "increment offers", which are like generation. Virtual bids represent energy purchases in the day-ahead market that the participant needs to sell back in the real-time market. These are referred to as "decrement bids", which are like load. The value of virtual trading lies in its potential to converge day-ahead and real-time market prices, and improve day-ahead unit commitment decisions.

In order for virtual transactions to converge prices, there must be sufficient competition in virtual trading; transparency in day-ahead market, reliability unit commitment, and real-time market operating practices; and predictability of market events. Since the market began in 2014, there has been moderate, and increasing levels of virtual participation. Figure 3–22 displays the total volume of virtual transactions as a percentage of real-time market load along with wind output levels.

Figure 3–22 Cleared virtual transactions as percent of real-time load

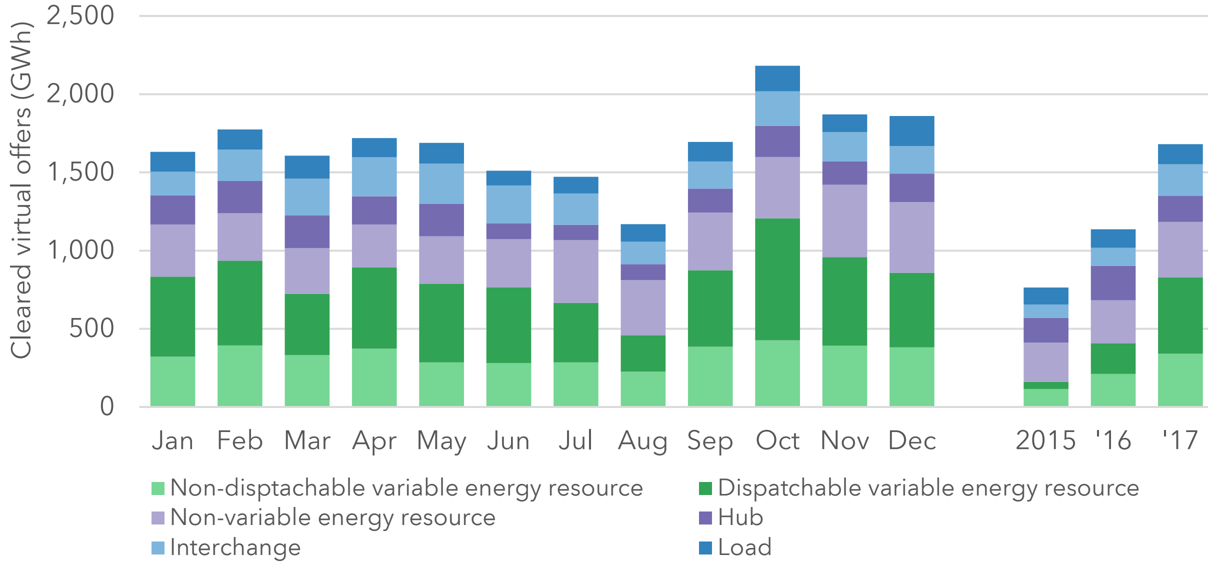


As shown in the figure, virtual transactions averaged 13.9 percent of real-time market load, compared to 9.4 percent in 2016. The greatest increases in virtual transactions as a percentage of load has been with cleared virtual offers, which increased to 8.1 percent in 2017 from 5.4 percent in 2016 and 4.0 percent in 2015. Virtual cleared bids also increased from 3.5 percent in 2015 to 4.2 percent in 2016 and further upward to 5.8 percent in 2017. In particular, there was a large increase in cleared virtual offers in October 2017. Days with high wind output see an increase in virtual offer activity. Virtual bids increase during high load hours.

At about 14 percent of load, the average hourly total volume of cleared virtuals ranged from 3,300 MW of withdrawal, to 5,700 MW of injection. The net cleared virtual positions in the market averaged about 660 MW each hour.

The majority of virtual transactions occurred at wind resources in 2017. This is a trend that has been increasing since mid-2015. Figure 3–23 illustrates the settlement location types where virtual offers clear.

Figure 3–23 Cleared virtual offers by settlement location type

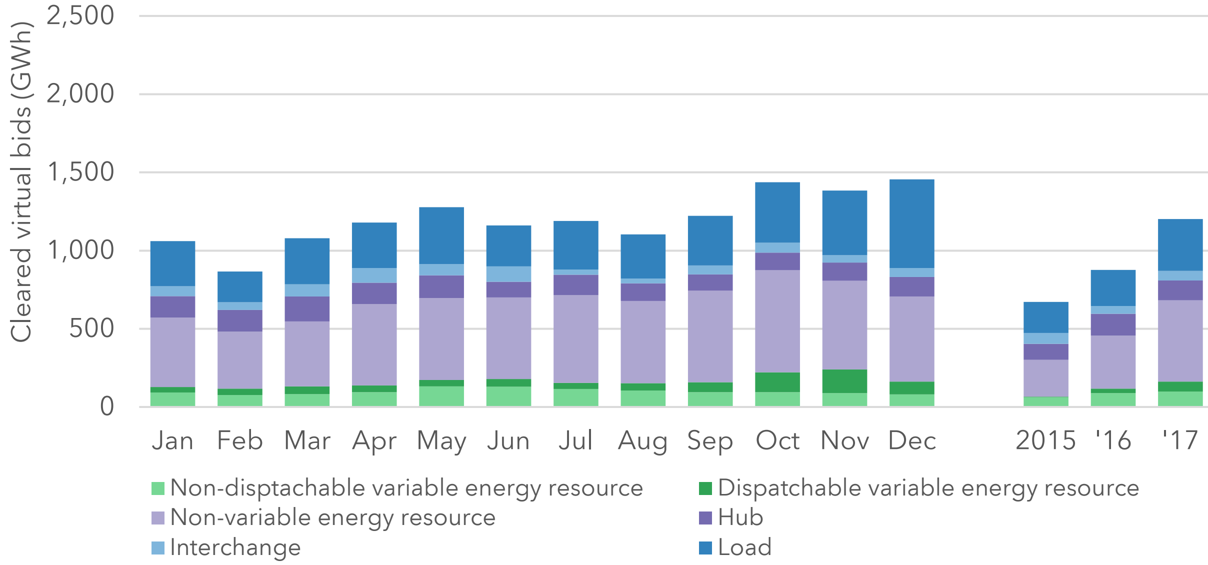


This figure shows that just over 49 percent of the virtual offers cleared at variable energy resources during 2017.[44] This is a significant increase from 35 percent in 2016 and 21 percent in 2015. The large volumes of virtual offers at variable energy resources highlight the fact that those resource types may be missing financial opportunities by under-scheduling in the day-ahead market.[45]

This is in contrast with the locational volumes of virtual bids. Cleared virtual bids were primarily at resources other than variable energy resources, followed by load locations. Figure 3–24, below, shows the cleared virtual bids by settlement location types.

[44] This includes both dispatchable and non-dispatch variable energy locations.
[45] Section 4.1.5 on price divergence discusses the effects of unscheduled wind in the SPP market.

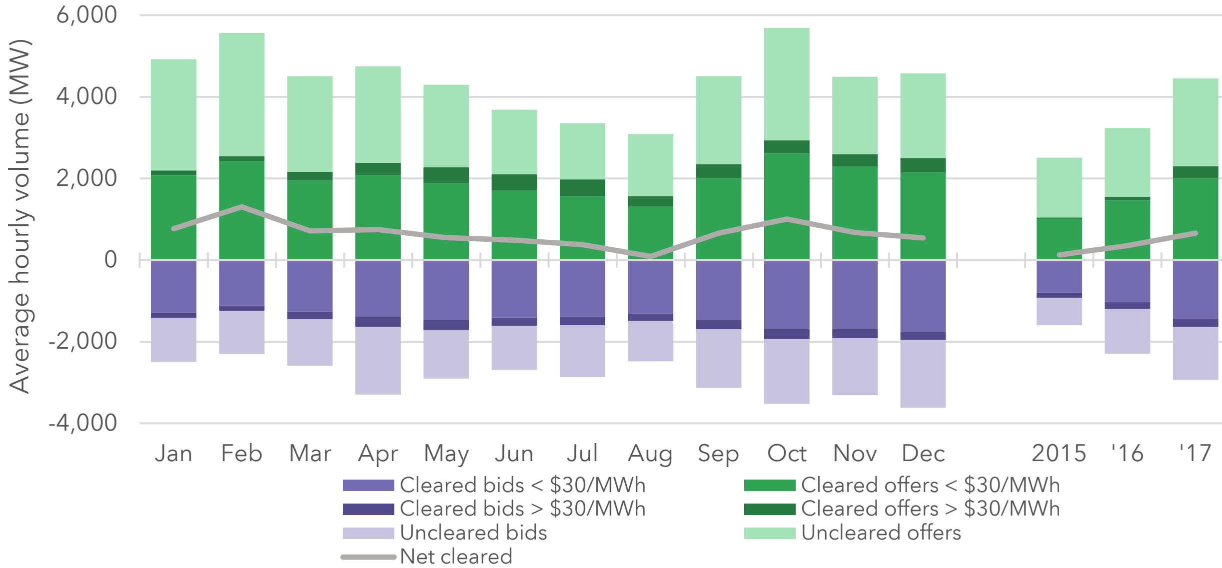
Figure 3–24 Cleared virtual bids by settlement location type



Forty-three percent of cleared virtual bids in 2017 were at non-variable energy resource locations, which is up from the 39 percent in 2016 and the 35 percent in 2015. Another 28 percent of the cleared virtuals bids were at load locations in 2017, which is comparable to the values in 2016 (26 percent) and 2015 (30 percent) when compared on a percentage basis. However, the volume increase in cleared bids at load locations between 2016 and 2017 was over 44 percent.

Figure 3–25 shows cleared demand bids that offered more than $30/MWh over the cleared day-ahead price, and the supply offers offered at less than $30/MWh under the cleared day-ahead price.

Figure 3–25 Virtual offers and bids, day-ahead market



These types of bids and offers are called "price-insensitive" and occurred more often with bids up until 2017. Price-insensitive bids have remained steady with about 12 to 14 percent of cleared bids since 2015, but that number has increased for offers from four percent in 2015 to 13 percent in 2017. Price-insensitive bids and offers are willing to buy/sell at a much higher/lower price that could lead to price divergence rather than competitive, or price-sensitive, bids and offers leading to price convergence between the day-ahead and real-time markets. Price-insensitive bids and offers usually occur at locations with congestion and arbitrage against the day-ahead and real-time price differences. Given that price-insensitive bids and offers are likely to clear, these can be unprofitable if congestion around these locations does not materialize, leading to divergence between the markets.

Financial information for virtual trades is shown monthly and on an annual basis for 2017 in Figure 3–26.

Figure 3–26 Virtual profits with distribution charges

Month	Raw profit	Raw loss	Raw net profit (prior to fees)	RNU charges/ credits	Day-ahead make-whole payment charges	Real-time make-whole payment charges	Virtual transaction fee	Total net profit
January	$13.6	-$8.2	$5.3	$0.1	$0.1	$1.6	$0.0	$3.6
February	10.4	-10.3	0.1	0.1	0.1	0.7	$0.0	-0.8
March	15.7	-11.4	4.3	0.0	0.1	1.2	$0.0	2.9
April	21.4	-13.4	8.0	0.1	0.2	1.7	$0.0	5.9
May	16.0	-12.7	3.3	0.1	0.1	1.7	$0.0	1.4
June	15.5	-11.1	4.4	0.1	0.1	1.5	$0.0	2.8
July	13.3	-8.6	4.6	0.1	0.1	2.3	$0.0	2.2
August	6.0	-6.0	0.1	0.0	0.1	1.1	$0.0	-1.1
September	14.2	-10.6	3.6	0.1	0.2	1.0	$0.0	2.4
October	23.8	-14.3	9.5	0.1	0.2	1.2	$0.0	7.9
November	19.6	-12.2	7.4	0.1	0.2	1.5	$0.0	5.6
December	18.2	-14.7	3.6	0.0	0.2	1.5	$0.0	1.9
Total	**$187.8**	**-$133.5**	**$54.3**	**$0.9**	**$1.6**	**$16.9**	**$0.4**	**$34.6**

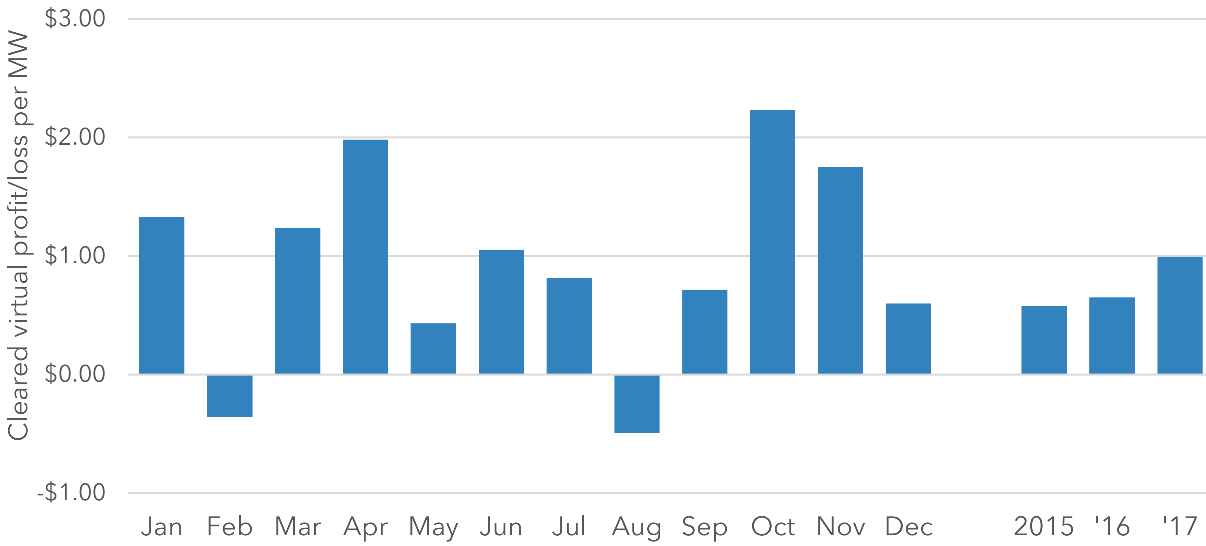
All figures in $ millions

Virtual trades profited in aggregate for the year by about $54 million, which is a 63 percent increase from the $33 million in 2016 and $21 million in 2015, larger than the 39 percent increase in hourly volume. Virtual bids can be charged distribution fees for day-ahead make-whole payments and virtual offers are susceptible to real-time make-whole payment distribution fees. In addition, both types of transactions can receive revenue neutrality uplift charge/credits and a $0.05 per virtual bid or offer transaction fee for processing virtual transactions. The average 2017 rates per megawatt for day-ahead make-whole payments, real-time make-whole payments, and real-time revenue neutrality uplift distributions are $0.11/MWh, $0.90/MWh, and $0.12/MWh, respectively. When factoring in these charges and credits, the total virtual bidding profits for 2017 are reduced by 36 percent to $34.6 million.

Every month in 2017 was profitable in aggregate for virtual transactions before factoring in transaction fees. However, once the fees were accounted for February and August become unprofitable in aggregate. In the 46 months since the market began, only seven months have had a net loss when factoring in fees. The highest payout months in 2017 happened in April and October with net payouts just over $5.9 million and $7.9 million, respectively. These months coincide with high wind periods and low load months when high price differences can occur between day-ahead and real-time markets as a result of under-scheduled wind in the day-ahead market.[46]

Net profits are typically small when assessed on a per megawatt basis. Figure 3–27 illustrates the monthly average profit per megawatt for a cleared virtual in 2017.

Figure 3–27 Profit and loss per cleared virtual, average

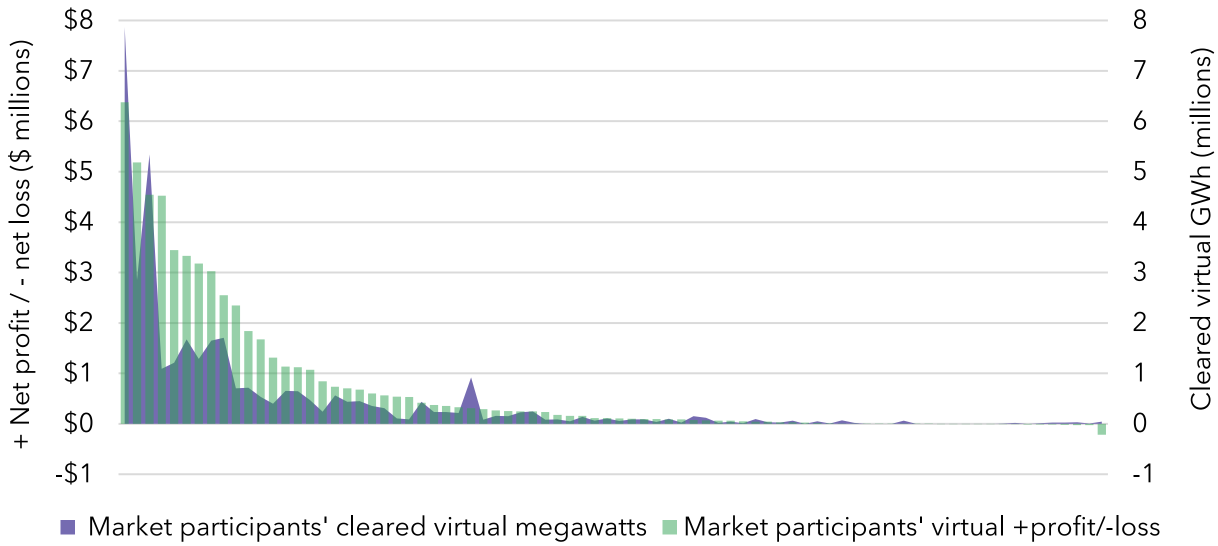


The chart shows that when factoring in all fees the average profit per megawatt for 2017 was $1.00 per cleared megawatt, a more than 50 percent increase from $0.65 in 2016.

There were eighty SPP participants that had virtual transactions in 2017. Figure 3–28 illustrates each virtual participant's net virtual portfolio for the year by both megawatts cleared and net profits. The chart is sorted to show the participants in order from those with the highest net virtual profit to those with the greatest net virtual loss.

[46] Section 4.1.5, Price divergence, discusses the effects of unscheduled wind in the SPP market.

Figure 3–28 Net virtual portfolio by virtual participant



As seen in the chart, the overall profitability in virtual transactions was concentrated with a few market participants. Five participants accounted for over 42 percent of the total aggregate virtual profits and 50 percent of the transactional volume. In aggregate, virtuals were profitable for most participants. However, fourteen participants did have unprofitable virtual portfolios in 2017. The total net losses for these entities was just over $350,000, with one entity accounting for over $200,000 of that loss. Thus, the overall profitability results show that gains far exceeded losses.

Cross-product market manipulation has been a concern in other RTO/ISO markets, and extensive monitoring is in place to detect potential cases in the SPP market. For example, a market participant may submit a virtual transaction intended to create congestion that benefits a transmission congestion right position. Generally, this behavior shows up as a loss in one market, such as a virtual position, and a substantial associated benefit in another market, such as a transmission congestion right position. In the SPP market, eight market participants lost more than $10,000 in 2017, which is only slightly more than in 2016. In addition to the low net losses, few SPP market participants are active in both virtual bidding and with transmission congestion rights, which reduces the potential for cross-product manipulation.

4 PRICES

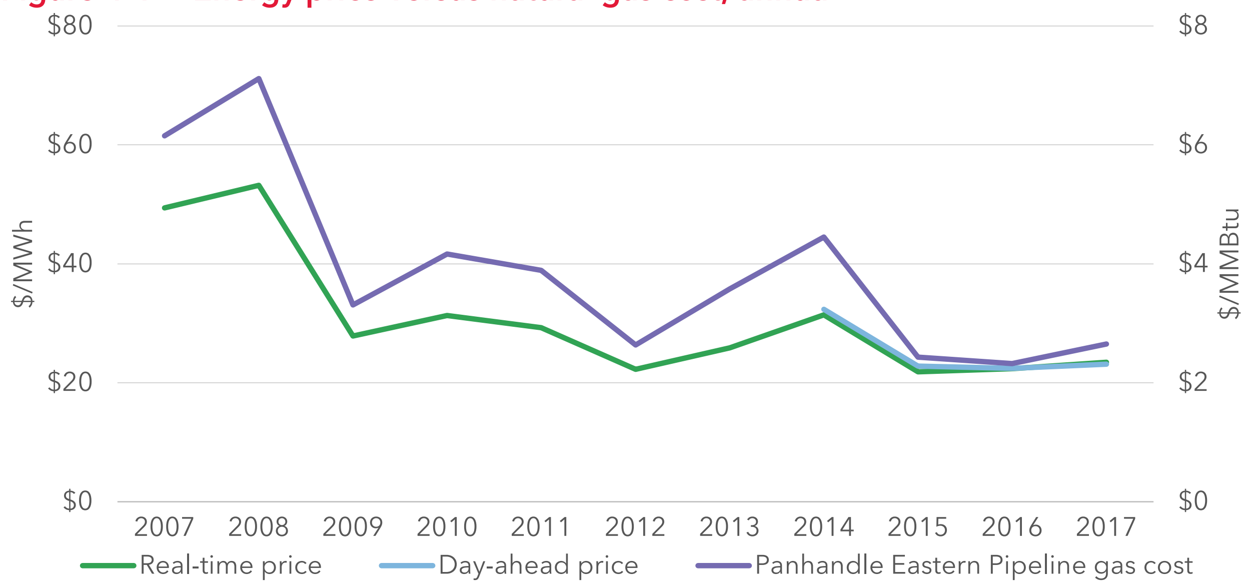
4.1 MARKET PRICES AND COSTS

This section reviews market prices and costs by focusing on the fuel prices, price volatility, negative prices, operating reserve prices, and market settlement results including make-whole payments. Overall, annual prices remained fairly stable compared to previous years with just a slight increase in both the day-ahead and real-time prices in 2017. However, annual numbers mask underlying issues related to market flexibility and efficiency. For instance, we discuss increasing periods of price volatility and instances of negative prices. Chapter 7 discusses recommendations for addressing these issues.

4.1.1 ENERGY MARKET PRICES AND FUEL PRICES

Figure 4-1 below compares day-ahead and real-time prices in SPP between 2007 and 2017[47] with natural gas prices.

Figure 4-1 Energy price versus natural gas cost, annual



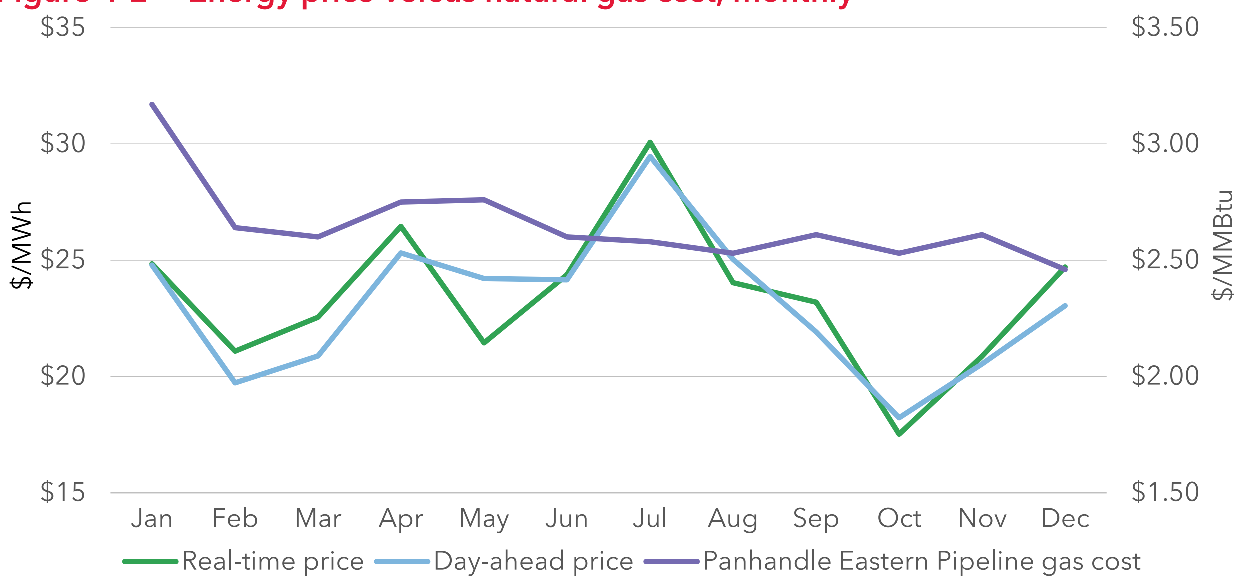
Historically, electric market prices have followed the cost of natural gas. As natural gas prices have remained low overall, so have SPP market prices. Electricity prices remained low in 2017, as day-ahead market prices averaged about $23/MWh in 2017, up about three percent

[47] From 2007 to 2013, the average price from the Energy Imbalance Service market is shown. The 2014 real-time average includes two months of prices from the Energy Imbalance Service market and 10 months of prices from the Integrated Marketplace.

from 2016. The average real-time price for 2017 was $23.43/MWh, an increase of seven percent over 2016. The average gas cost, using the price at the Panhandle Eastern Pipeline (PEPL) increased by 14 percent from 2016 to 2017. This is in sharp contrast to the change from 2014 to 2015, when energy prices dropped by 30 percent, while gas costs dropped by 45 percent.

On a monthly basis, day-ahead and real-time prices were highest in July at about $30/MWh as temperatures increased and loads peaked (as seen in Figure 4-2). Prices were lowest in October at around $18/MWh as periods of high wind generation coincided with low loads. Natural gas prices were highest in January at over $3/MMBtu and lowest in December at around $2.50/MMBtu.

Figure 4-2 Energy price versus natural gas cost, monthly



Changes in gas costs have historically had the highest impact on electricity prices compared to other fuels. This is because natural gas-fired generation frequently is the marginal price setting fuel as coal fired generation is cheaper on a $/MMBtu basis. However, natural gas generators are more flexible than coal generators in scheduling or dispatch by SPP, as they have shorter start-up times and minimum run times. Figure 4-3 compares various fuel price indices with real-time prices.

Figure 4-3 Fuel price indices and wholesale power prices

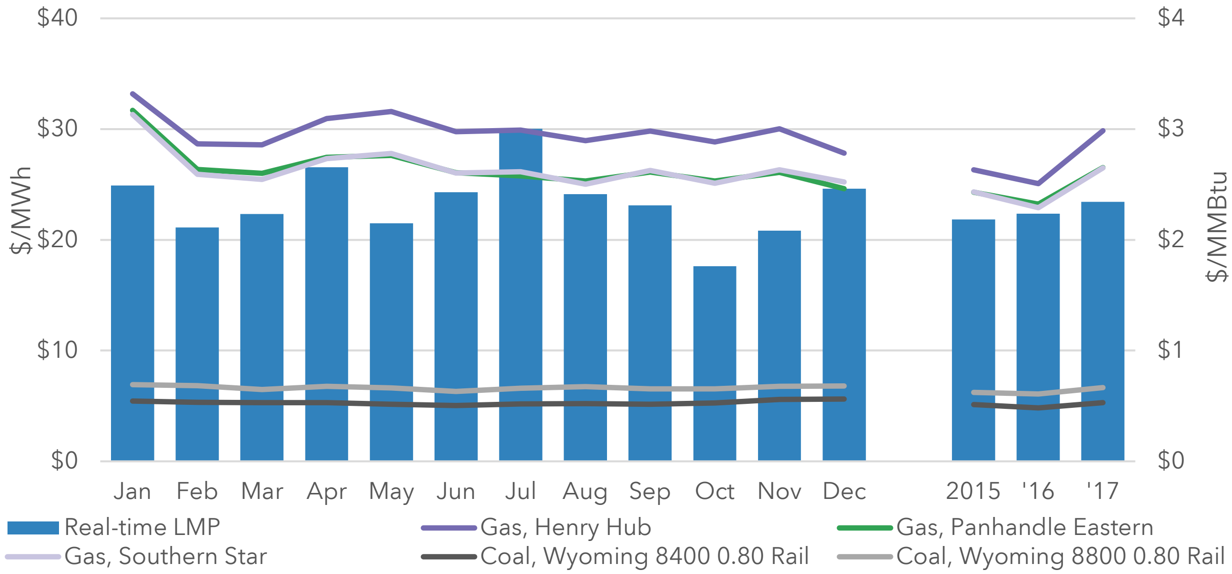


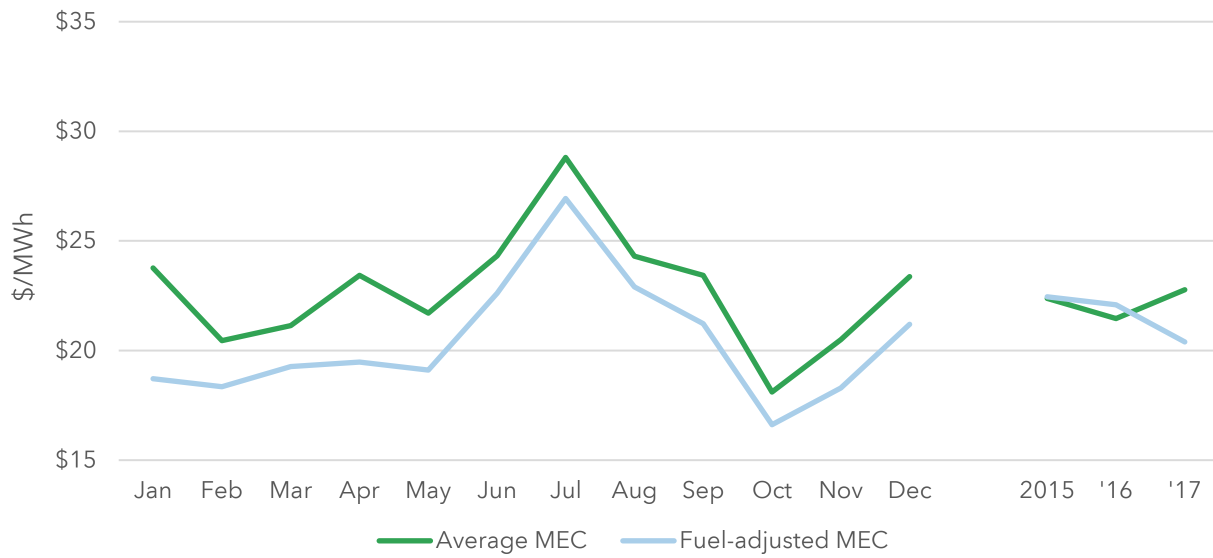
Figure 4-3 shows that regional natural gas prices trended up from 2016 to 2017, following the national trend as represented by the Henry Hub. However, the price for all three indices was still below $3/MMBtu for 2017.[48] The annual average gas price at the Panhandle Eastern hub increased by 14 percent, from $2.32/MMBtu in 2016 to $2.65/MMBtu in 2017.

Coal prices have remained relatively stable since 2015 with a slight increase overall from 2016 to 2017.[49] Annual average coal prices at Powder River Basin for both types, 8,400 Btu/lb., and 8,800 Btu/lb., increased by nearly 10 percent. The price for 8,400 Btu/lb. increased from $0.48/MMBtu in 2016 to $0.53/MMBtu in 2017, and the price for 8,800 Btu/lb. increased from $0.60/MMBtu in 2016 to $0.67/MMBtu in 2017.

[48] The relevant natural gas prices for the SPP market are those of the Henry Hub, the Panhandle Eastern Pipeline (PEPL), and Southern Star. These prices do not include transport costs.
[49] Coal prices are inclusive of transport costs.

Controlling for changes in fuel prices helps to identify the underlying changes in electricity prices from other factors.[50] Figure 4-4 below adjusts the marginal energy cost for changes in fuel costs.[51]

Figure 4-4 Fuel-adjusted marginal energy cost



As the figure shows, fuel adjusted marginal energy costs were lower in 2017 compared to nominal marginal energy costs both annually and in each month. While the average nominal marginal energy cost in 2017 increased six percent from 2016, the fuel-adjusted marginal energy cost decreased by eight percent because of the higher fuel prices and higher wind generation in 2017. Looking by month, the highest fuel-adjusted marginal energy cost occurred in July 2017 during which SPP experienced high-temperature periods and 2017's peak demand. The largest downward movement occurred in January and April which might be due to the high marginal fuel price appeared in these months. The SPP market normally experiences more fuel shortages in these winter months, due to pipeline outages and gas limitations.

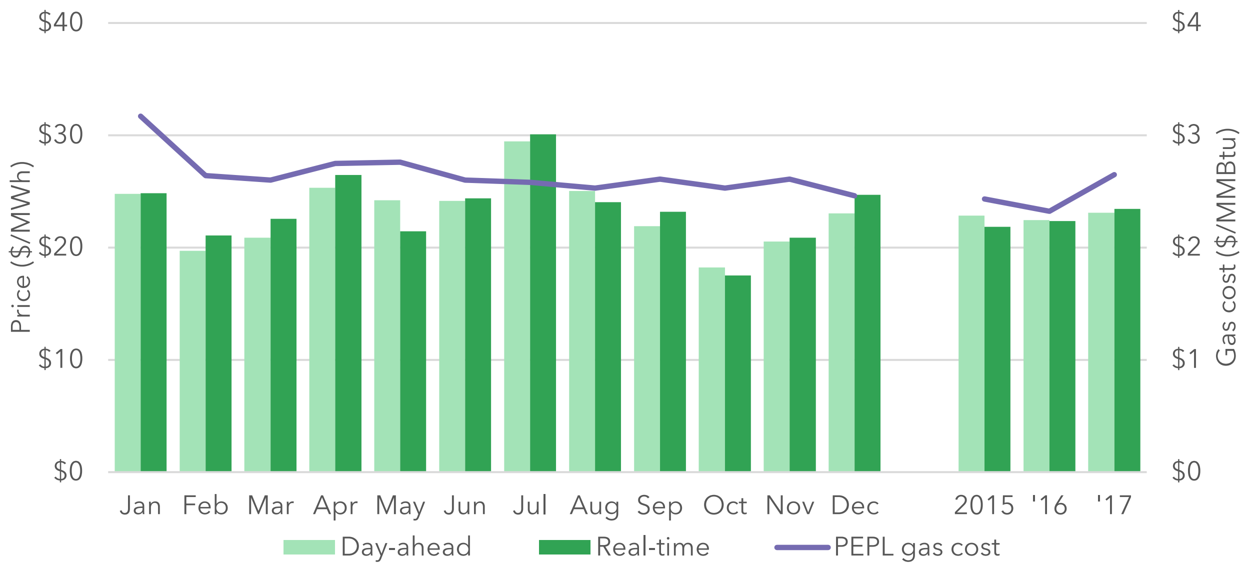
[50] In addition to fuel, other variables also affect real-time prices. These variables include seasonal load levels, transmission congestion, scarcity pricing, and wind-powered generation.

[51] The marginal energy component (MEC) indicates the system-wide marginal cost of energy (excluding congestion and losses). Fluctuations in marginal fuel prices can obscure the underlying trends and performance of the electricity markets. Fuel price-adjusted marginal energy costs is a metric to estimate the price effects of factors other than the change in fuel prices, such as changes in load or changes in supply. It is based on the marginal fuel in each real-time five-minute interval which indexed to the three-year average of the price of the marginal fuel during the interval. If multiple fuels were marginal in an interval, we calculate weighted average marginal energy costs based on the dispatched MW on different fuel types.

4.1.2 REAL-TIME AND DAY-AHEAD PRICE COMPARISONS

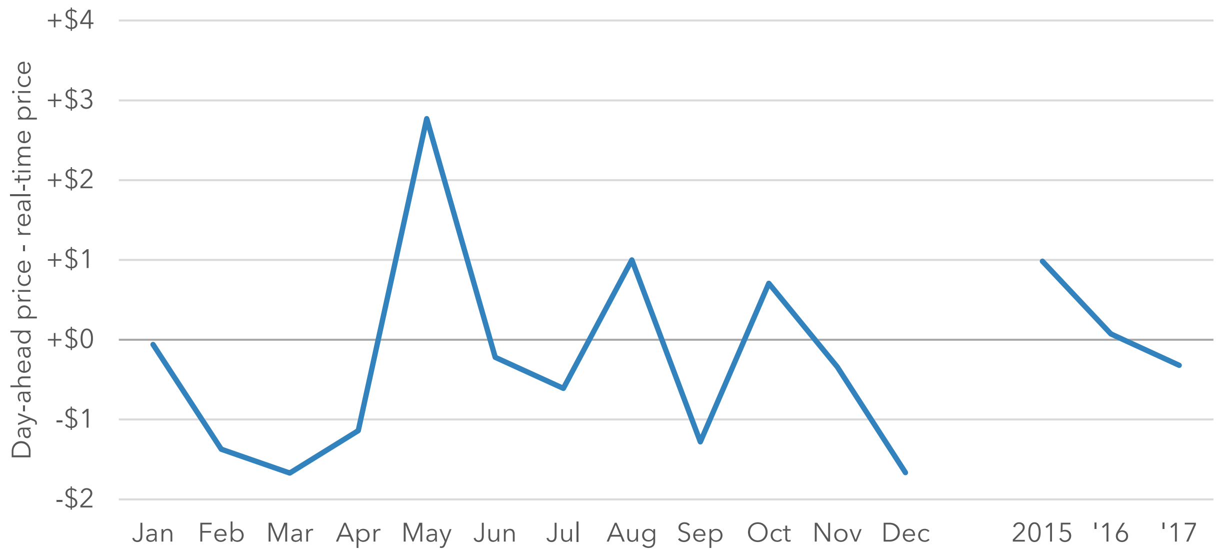
Day-ahead prices have historically been higher than real-time prices. However, average real-time prices exceeded day-ahead prices in 2017. This is primarily a result of increased price volatility in real time because of higher actual (unexpected) congestion, along with load and generation changes. Unexpected congestion is typically more pronounced during the high wind seasons of spring and fall. Figure 4-5 shows day-ahead and real-time market monthly and annual prices compared with the cost of natural gas.

Figure 4-5 Price, day-ahead and real time



In the first 22 months of the Integrated Marketplace, the average real-time price exceeded the day-ahead price only once. In 2016, the real-time price exceeded the day-ahead price during five months. And in 2017, the real-time price exceeded the day-ahead price in all but three months. Figure 4-6 below shows the monthly day-ahead / real-time price premium for 2017, as well as annually for the past three years.

Figure 4-6 Difference between day-ahead and real-time prices



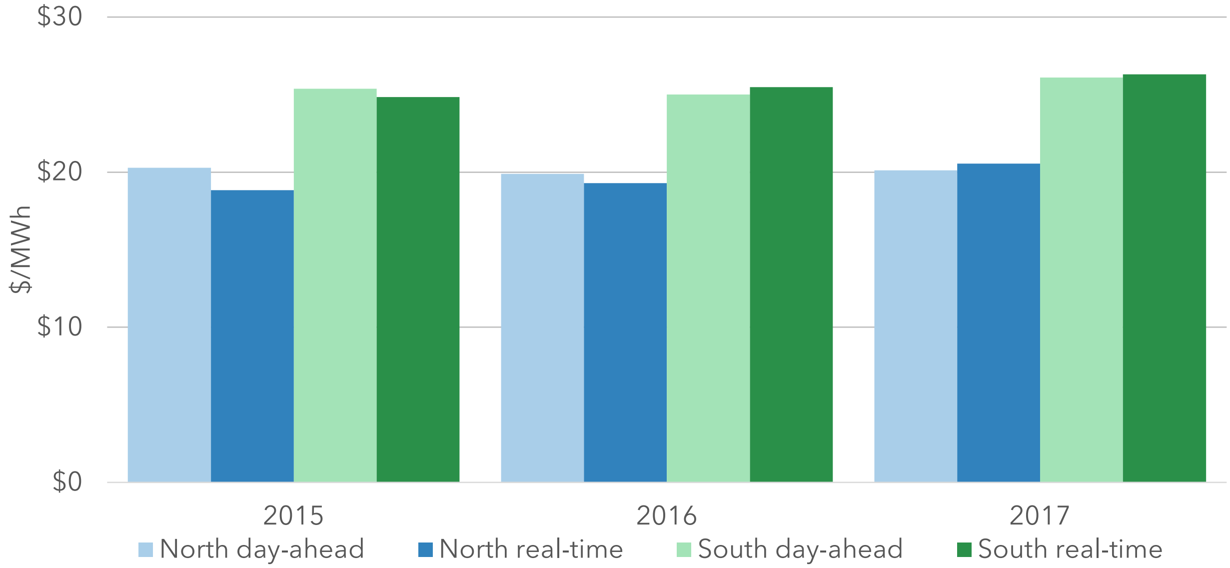
Day-ahead prices exceeded real-time prices in May, August, and October. May had the largest difference with a day-ahead average price $2.77/MWh higher than real time. In both March and December, the real-time average price was $1.67/MWh higher than day-ahead. On an annual basis, the day-ahead premium has gradually gone away with a day-ahead premium of around $1/MWh for 2014 (not shown) and 2015, to a day-ahead premium of $0.07/MWh in 2016, and then moving to a real-time premium of $0.32/MWh for 2017.

4.1.3 HUB PRICES

SPP has two hubs: the SPP North hub, and the SPP South hub. The SPP North hub represents pricing nodes in the northern part of the SPP footprint, generally in Nebraska. The SPP South hub represents pricing nodes in the south-central portion of the footprint, generally in central Oklahoma. Typically, the SPP South hub prices exceed the SPP North hub prices. This was again true in 2017. The general pattern of higher prices in the south and lower in the north is primarily due to fuel mix and congestion. Coal, nuclear, and wind are the dominant fuels in the north and west. Gas generation represents a much larger share of the fuel mix in the south and east.

Figure 4-7 and Figure 4-8 show the day-ahead and real-time energy prices at the two SPP market hubs.

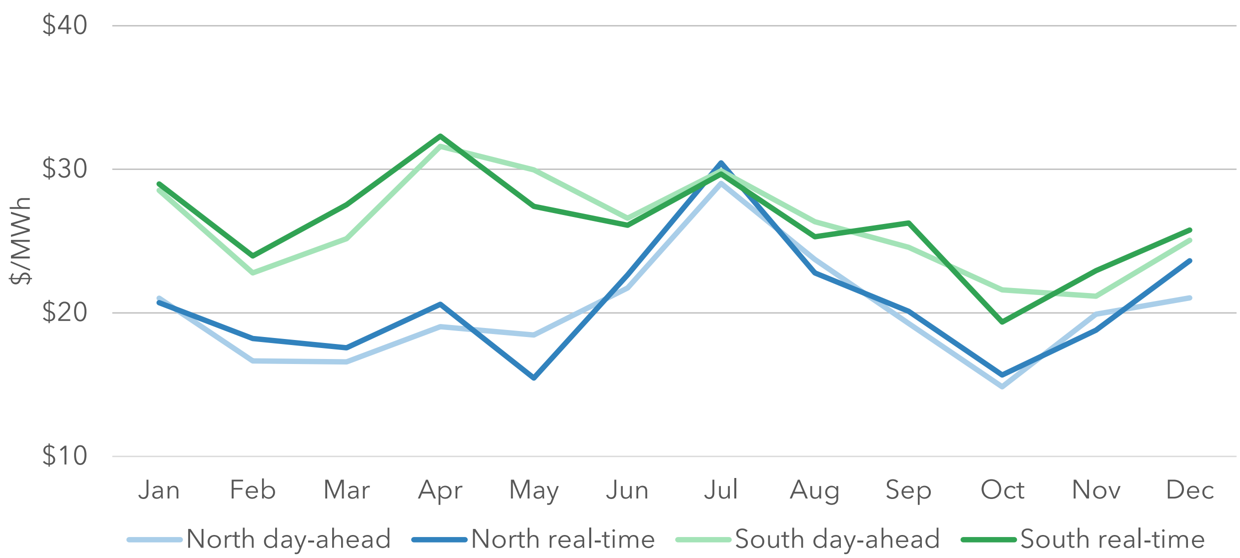
Figure 4-7 Hub prices, annual



On an annual basis hubs prices have remained fairly stable with North hub prices averaging around $20/MWh, and South hub prices averaging around $25/MWh. These prices were slightly higher than 2016 prices.

On a monthly basis, South hub prices were higher than North hub prices in all but one month, as seen in Figure 4-8.

Figure 4-8 Hub prices, monthly



In July, for the first time in the Integrated Marketplace, the North hub real-time price exceeded the South hub real-time price. Temperatures in July were warmer than normal in the northern area, which increased demand and price. For further discussion on temperatures, see Section 2.2.4.

The price separation between the North and South hub averaged $6/MWh in 2017, slightly higher than the $5/MWh spread in 2015 and 2016. The overall level and trend in energy prices were consistent with other RTO/ISO markets, as shown in Figure 4-9. When compared to other regions, the North hub was among the lowest priced hubs in the region.

Figure 4-9 Comparison of ISO/RTO average on-peak, day-ahead prices

	2015	2016	2017
SPP North hub	$ 24	$ 24	$ 25
SPP South hub	$ 29	$ 29	$ 31
ERCOT North hub	$ 31	$ 26	$ 26
ERCOT West hub	$ 31	$ 26	$ 26
MISO Arkansas hub	$ 29	$ 27	$ 31
MISO Louisiana hub	$ 33	$ 34	$ 34
MISO Minnesota hub	$ 27	$ 25	$ 28
MISO Texas hub	$ 32	$ 31	$ 38
PJM West hub	$ 43	$ 35	$ 34

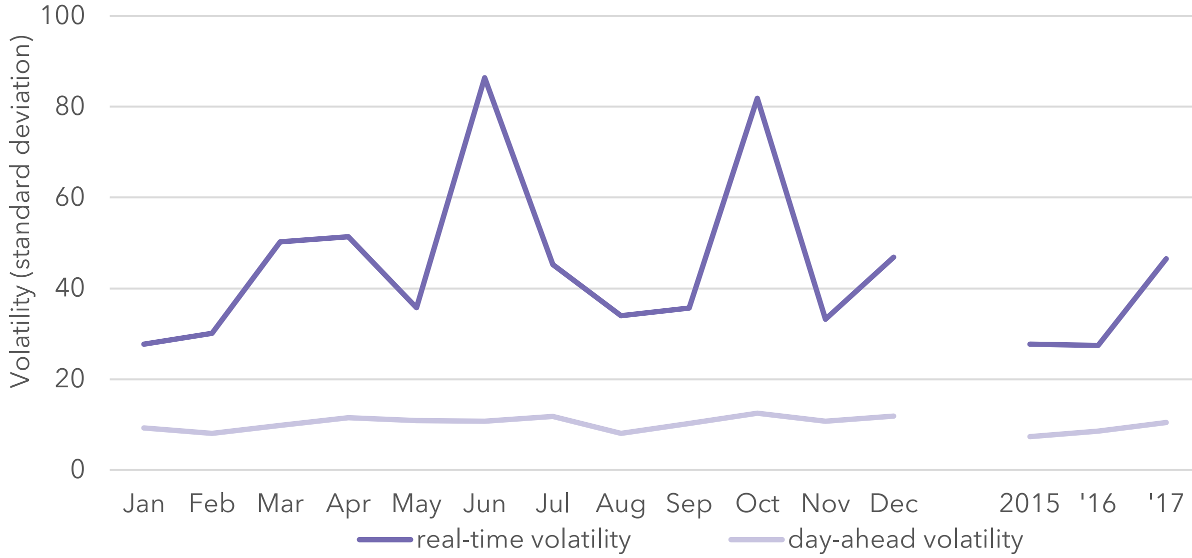
4.1.4 ENERGY PRICE VOLATILITY

Price volatility[52,53] in the SPP market is shown in Figure 4-10 below. As expected, day-ahead prices are much less volatile than those in real time. The day-ahead market does not experience the actual (unexpected) congestion and changes in load or generation found in the real-time market. Real-time volatility tends to peak in the spring and fall, roughly corresponding with times of higher wind and lower load, but can also peak during the summer months due to peak load conditions.

[52] Volatility is calculated as the standard deviation for load-serving entities in the SPP market. The standard deviation is calculated using hourly price in the day-ahead market and interval (five minute) price in the real-time market. In prior reports volatility was measured using the coefficient of variation (standard deviation divided by mean), however, this method gave artificially high volatility to asset owners with a low average price.

[53] A measure of volatility is also shown earlier in this report at Figure 3-19. That volatility calculation is based on the interval-to-interval change in marginal energy cost. The volatility calculation in Figure 4-10 is based on the interval locational marginal prices for load-serving entities in the SPP market. Although the results are different, the magnitude of the annual change is very similar.

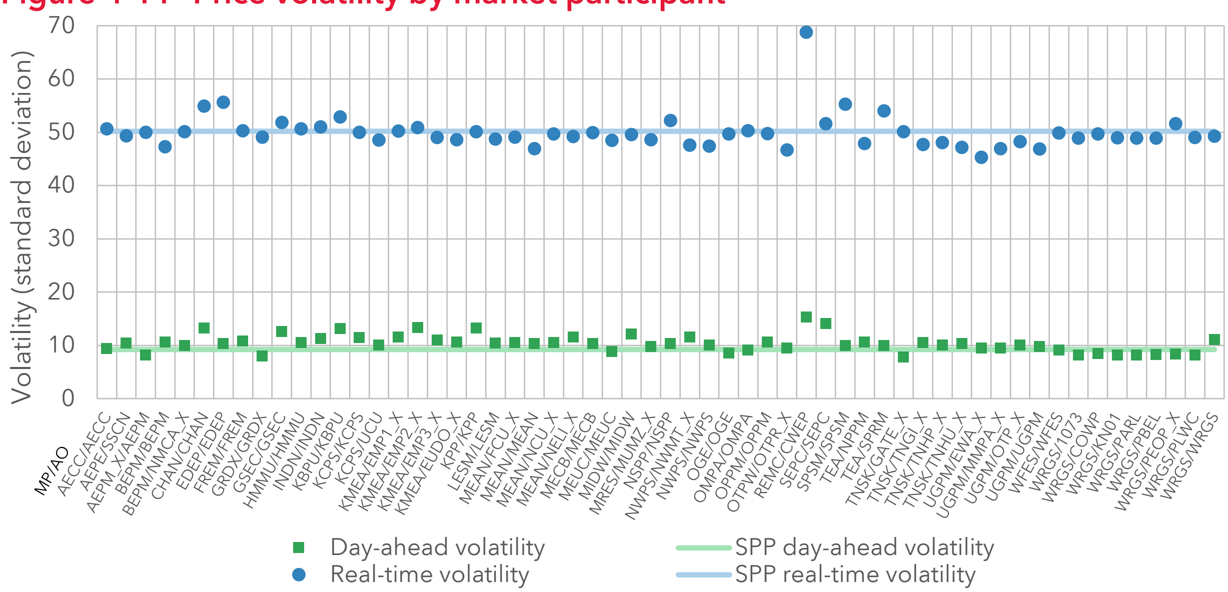
Figure 4-10 System price volatility



Volatility in 2017 was slightly higher than 2016 in the day-ahead market, and has taken a steady upward trend on an annual basis. However, volatility in the real-time market nearly doubled from 2016 to 2017. This can partially be attributed to high levels of wind generation in the spring and fall. High volatility during June can mostly be attributed to several short-lived energy shortages.

Price volatility varies across the SPP market footprint for asset owners primarily due to congestion on the system, which is based on the layout of the transmission system and the distribution of the types of generation in the fleet.

Figure 4-11 Price volatility by market participant



The volatility for the majority of asset owners is grouped very close to the SPP average in both the day-ahead and real-time markets as shown in Figure 4-11. The area of the footprint that experienced the most volatility in 2017 was in southwest Missouri and southeast Kansas. This area experienced a great deal of congestion during the year, mostly on the Neosho-Riverton flowgate, which is discussed in more detail in Section 5.1.4.3.

4.1.5 PRICE DIVERGENCE

As mentioned above, real-time prices were slightly higher than day-ahead prices in 2017. Moreover, system volatility nearly doubled in 2017 compared to 2016 and 2015. These metrics indicate that while average prices are similar, the underlying prices in the day-ahead and real-time markets were different. The averaging of price spikes, and in particular, high prices during periods of scarcity, drove real-time average prices just above day-ahead prices. We attribute these short–term, transient price spikes with limitations in ramping capability.[54] In this section, we highlight underlying differences in prices after controlling for scarcity events. This analysis shows that significant generation, particularly from wind resources not accounted for in the day-ahead market, drives down real-time prices.

Price convergence between day-ahead and real-time prices is important, because the more day-ahead prices reflect real-time prices, the better unit commitment and positioning of resources occurs for real-time operations. However, there are many factors than cause prices to diverge between the day-ahead and real-time markets. Some of those factors may include, but are not limited to:

- Day-ahead offers may include premiums to account for uncertainty in real-time fuel prices.[55]
- Load and wind forecast errors can cause differences in the real-time market results.
- Participants may not offer in all of their load or generation in the day-ahead market.
- Modeling differences including transmission outages between the two markets.
- Generation outages or derates that were different in real time than was anticipated in the day-ahead.
- Impacts from other RTOs, that were not anticipated, affect the SPP real-time market.
- Unanticipated weather changes affect the real-time markets.

[54] For further information on ramping issues, see Section 3.3.1.
[55] Additionally, revision request 239 allowed historic fuel cost uncertainty to be considered in the development of mitigated energy offers.

Figure 4-12, below, shows the marginal energy costs for both the day-ahead and real-time markets during off-peak hours after controlling for scarcity events.[56] Figure 4-13 shows the same information, but for on-peak hours.

Figure 4-12 Off-peak marginal energy prices, excluding scarcity hours

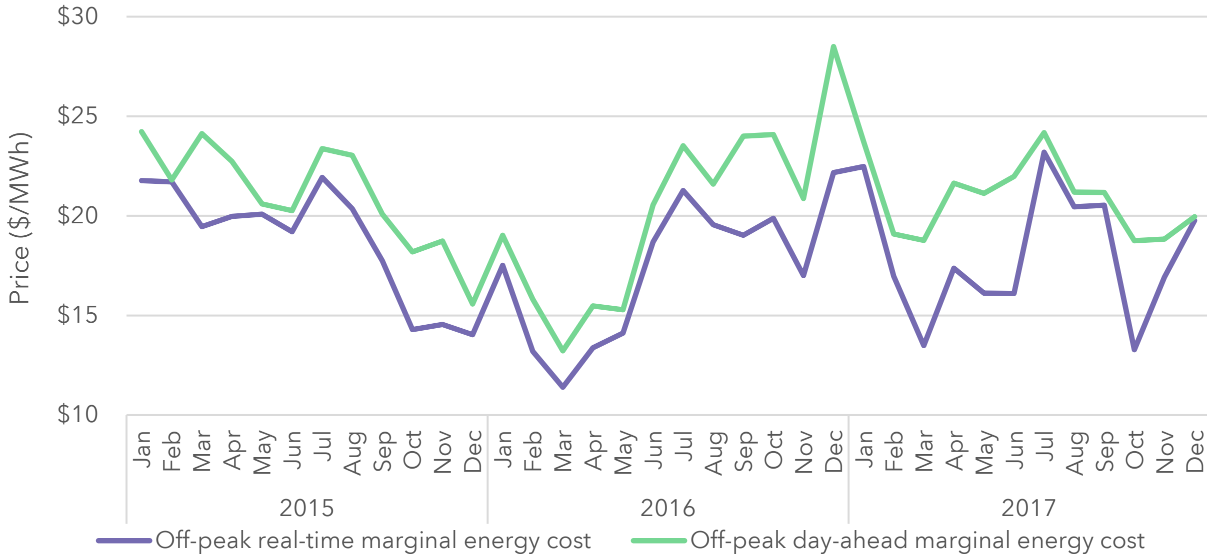
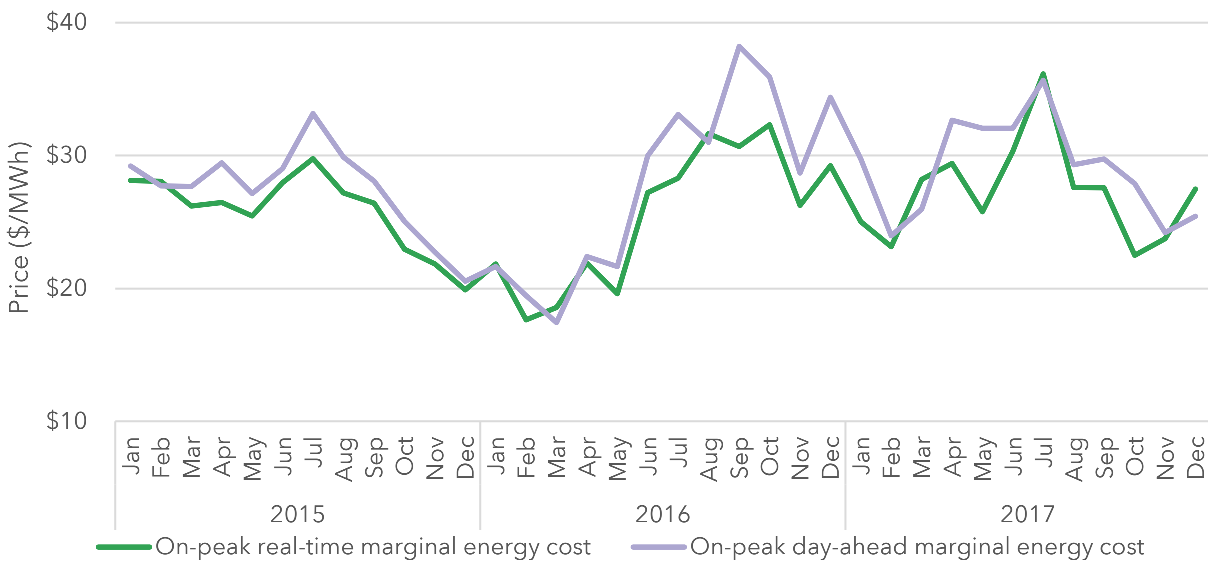


Figure 4-13 On-peak marginal energy prices, excluding scarcity hours



[56] These numbers reflect only hours where scarcity demand curves where not applied. SPP uses scarcity demand curves for intervals when ramp or capacity requirements cannot be met through dispatch. During these intervals the scarcity demand curves can drive marginal energy cost as high as $5,000. Scarcity demand curves are discussed in detail in Section 4.2, below.

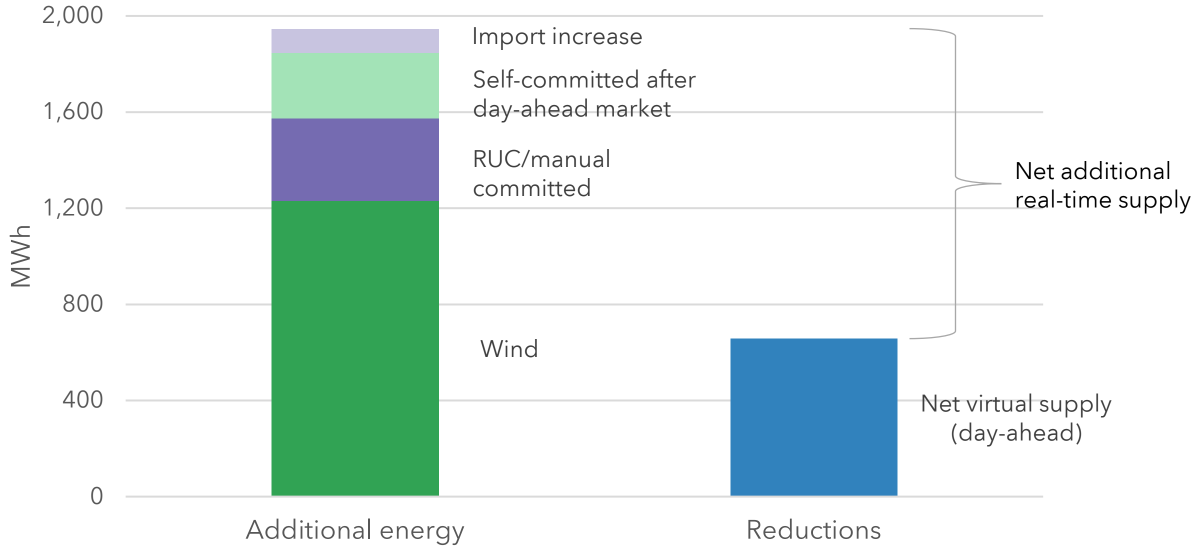
The marginal energy cost is one of three components that factor into location marginal prices and represents the marginal cost to provide the next megawatt of dispatch absent losses and congestion. Both charts clearly show that day-ahead prices are usually at a premium when compared to real-time prices when controlling for scarcity, particularly in the off-peak hours. In 2017, day-ahead marginal energy costs, for all hours, were 10 percent higher than real-time prices.[57] This is slightly higher than the nine percent price divergence in 2016 and slightly lower than the 11 percent in 2015.

The main contributors influencing the price differences are under-scheduling of wind resources in the day-ahead market, self-committing of units after the day-ahead market, and economic reliability unit commitments. In fact, only 82 percent of the wind generation was scheduled in the 2017 day-ahead market. This changes the supply curve by shifting it outward and causes real-time prices to drop relative to the day-ahead market. Furthermore, the real-time market appropriately honors the minimum limits of all committed resources. With the unanticipated generation, many non-wind units fall to their capacity limits, allowing wind to set prices. When this happens prices often go negative as the energy offers for wind units are typically negative to account for production tax credits.[58]

Figure 4-14 shows average hourly incremental differences in megawatts produced between the real-time and day-ahead market in 2017.

[57] The MMU observed that 77 percent of the hours in 2017 had higher marginal energy cost in the day-ahead market than the real-time market. This is after removing any hours associated with scarcity pricing.
[58] Negative prices are discussed in detail in Section 4.1.6.

Figure 4-14 Average hourly real-time generation incremental to day-ahead market



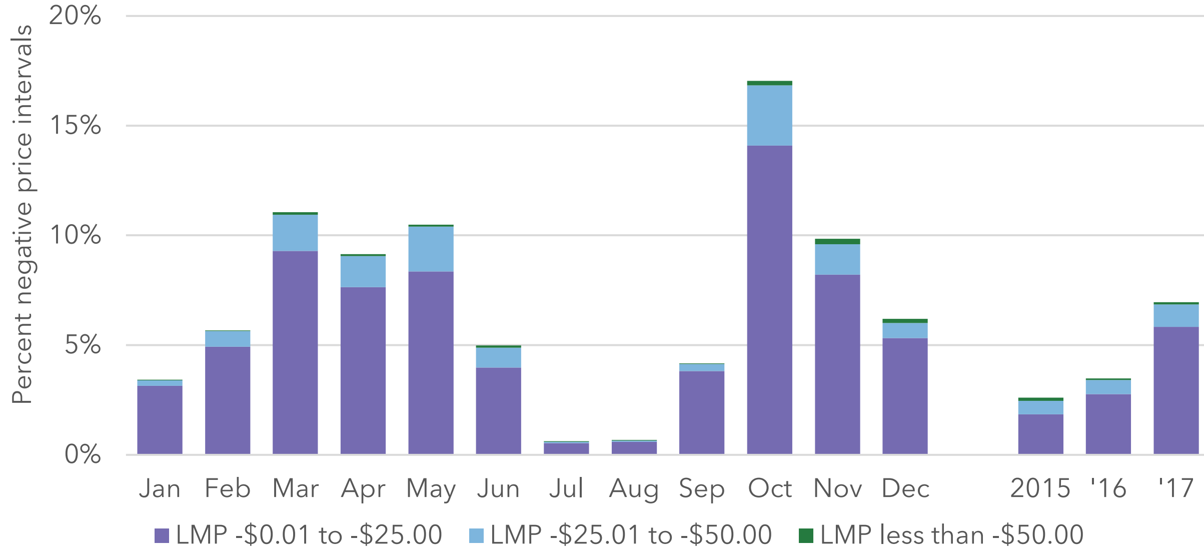
Wind generation had almost one-third of the incremental real-time generation in 2017, with an hourly average of 1,230 MW of additional generation in real time. Self-committed generation accounted for an additional 270 megawatts and reliability unit committed generation averaged about 345 MW. On average, SPP is a net exporter in both the day-ahead and real-time markets and sees an average hourly decrease of 98 MW in the real-time market compared to the day-ahead. This results in additional capacity committed in day-ahead not needed in real time. Net virtual positions helped to offset the additional generation, but only accounted for about 34 percent of the difference for the year.

4.1.6 NEGATIVE PRICES

With the prolific growth of wind generation in the SPP market, the number of intervals with negative prices continues to increase. In October 2017, 17 percent of all asset owner intervals[59] in the real-time market had prices below zero, as shown in Figure 4-15 below.

[59] 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).

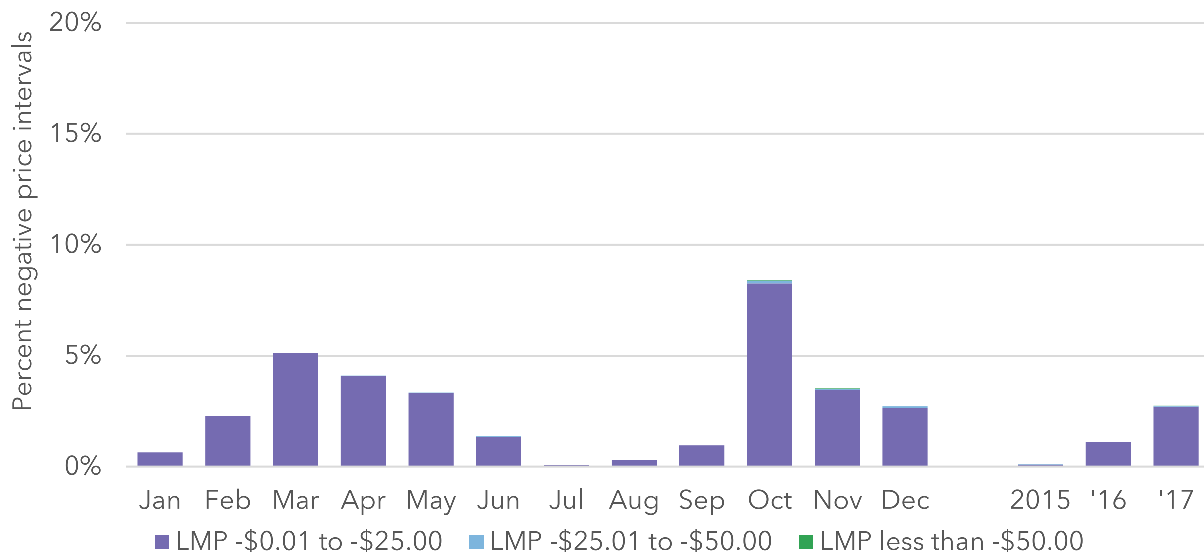
Figure 4-15 Negative price intervals, real time, monthly



On a year-to-year basis, the total percentage of negative price intervals in the real-time market has increased from 2.6 percent in 2015, to 3.5 percent in 2016, and to 7.0 percent in 2017.

While the same pattern holds in the day-ahead market (see Figure 4-16), the magnitude of negative price intervals in the day-ahead market is around half of the real-time market.

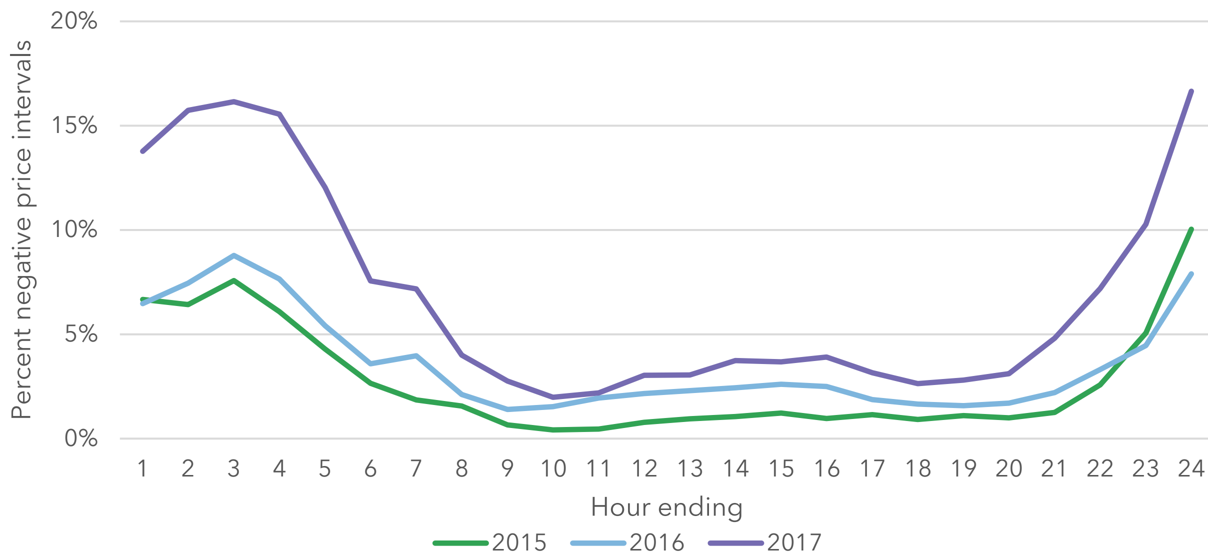
Figure 4-16 Negative price intervals, day-ahead, monthly



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.

Additionally, occurrences of negative prices in the real-time market are most prevalent in the overnight, low-load hours as shown in Figure 4-17.

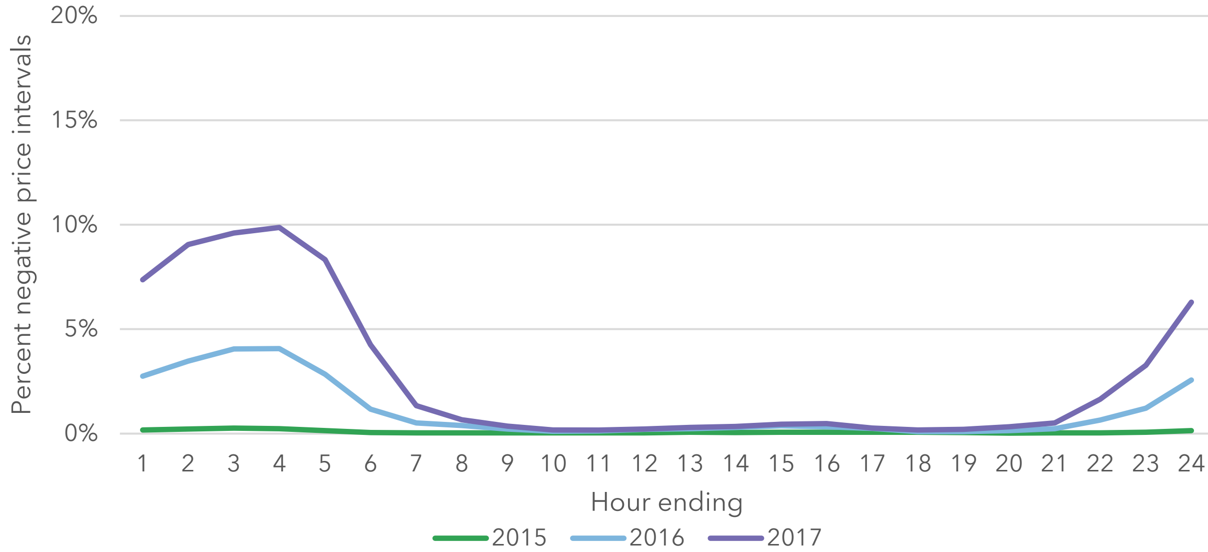
Figure 4-17 Negative price intervals, real time, by hour



This figure shows that the negative price intervals in 2017 during those overnight hours are at one and a half to two times the frequency of 2015 and 2016. During 2017 the first five hours and last two hours of the day experienced negative prices in over 10 percent of all intervals. The highest level in any hour during prior years was just 10 percent.

Negative price intervals in the day-ahead market (see Figure 4-18) follow the same pattern as the real-time market with most negative price intervals occurring in the overnight, low-load hours.

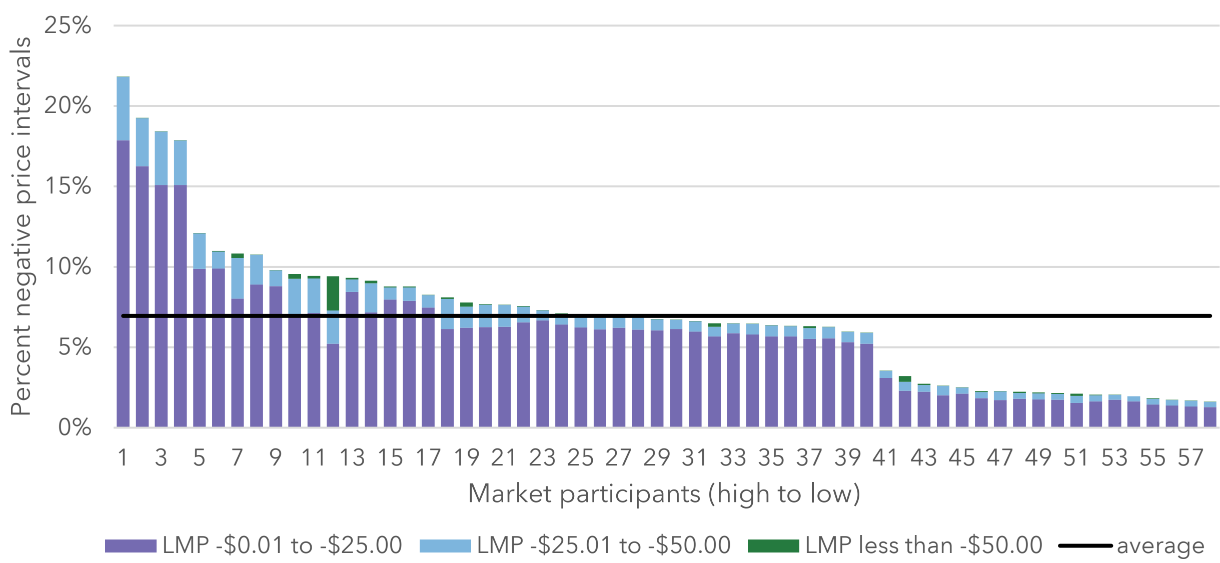
Figure 4-18 Negative price intervals, day-ahead, by hour



But again, this happens at a much lower frequency than in real time. Also of note, during the on-peak hours, less than 0.5 percent of intervals in the day-ahead market were negative. In 2017, the real-time market on average had nearly four percent of intervals with negative prices during the on-peak hours.

At the asset owner level (for those serving load), the distribution of negative price intervals during 2017 is clustered around the footprint average, as shown in Figure 4-19.

Figure 4-19 Negative price intervals, real time, by asset owner



However, four asset owners experienced negative prices in over 15 percent of all intervals. On the low end, 18 asset owners experienced negative prices in fewer than five percent of intervals.

The MMU is concerned with the marked increase in the frequency of negative price intervals. Negative prices may not be a problem in and of themselves, however, they do indicate an increase in surplus energy on the system. This may be exacerbated by the practice of self-committing after the day-ahead market. In the SPP market where there is an abundance of capacity and significant levels of renewable resources, negative prices can occur when renewable resources need to be backed down in order for traditional resources to meet their scheduled generation. Moreover, unit commitment differences, due to wind resources not being in the day-ahead market and then coming on-line for the real-time market, can create differences in the frequency of negative price intervals between the day-ahead and real-time markets. This disparity between the markets negatively impacts the efficient commitment of resources.

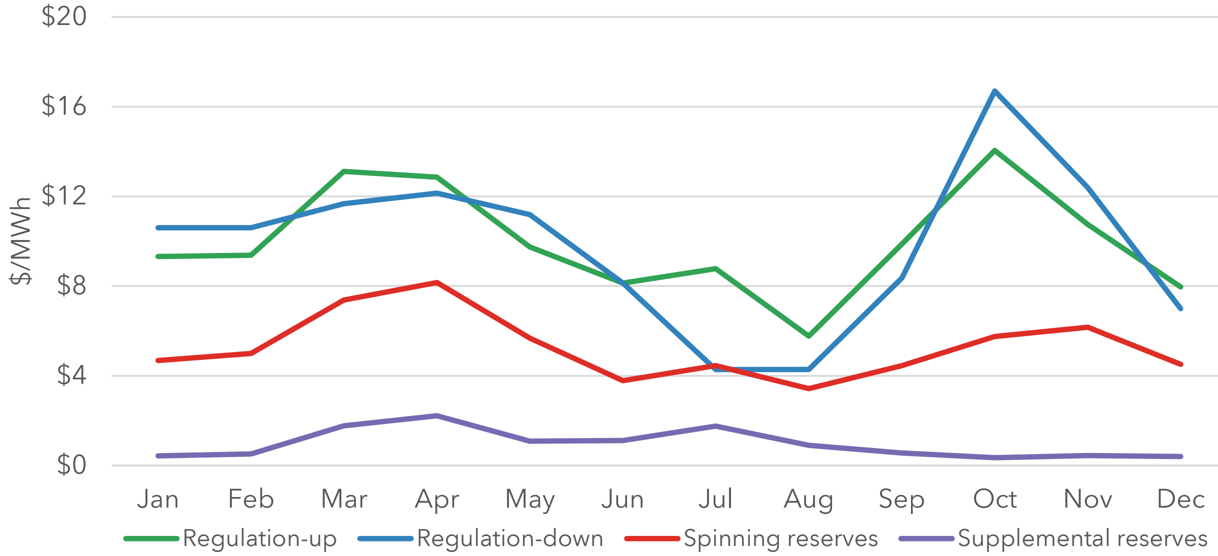
Thus, the growing frequency of negative prices indicates the need for changes in market rules to address self-committing of resources in the day-ahead market and the systematic absence of some forecasted variable energy resources in the day-ahead market to improve market efficiency. These issues are discussed further in Chapter 7.

4.1.7 OPERATING RESERVE MARKET PRICES

Operating reserve is made up of four 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.

Average monthly real-time prices for operating reserve products are presented in Figure 4-20.

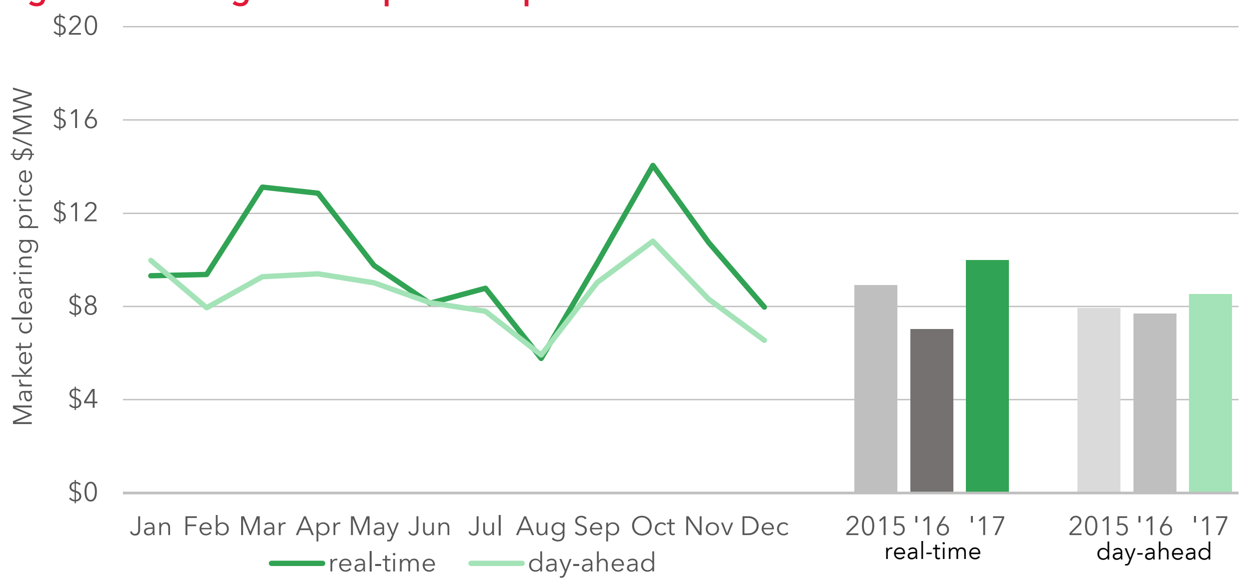
Figure 4-20 Operating reserve product prices, real time



Generally speaking, regulation-up and regulation-down have the highest market clearing prices. Supplemental reserves always have the lowest average prices of the operating reserve products, with prices averaging less than two dollars. Spinning reserve prices fall between regulation-up and supplemental reserve prices.

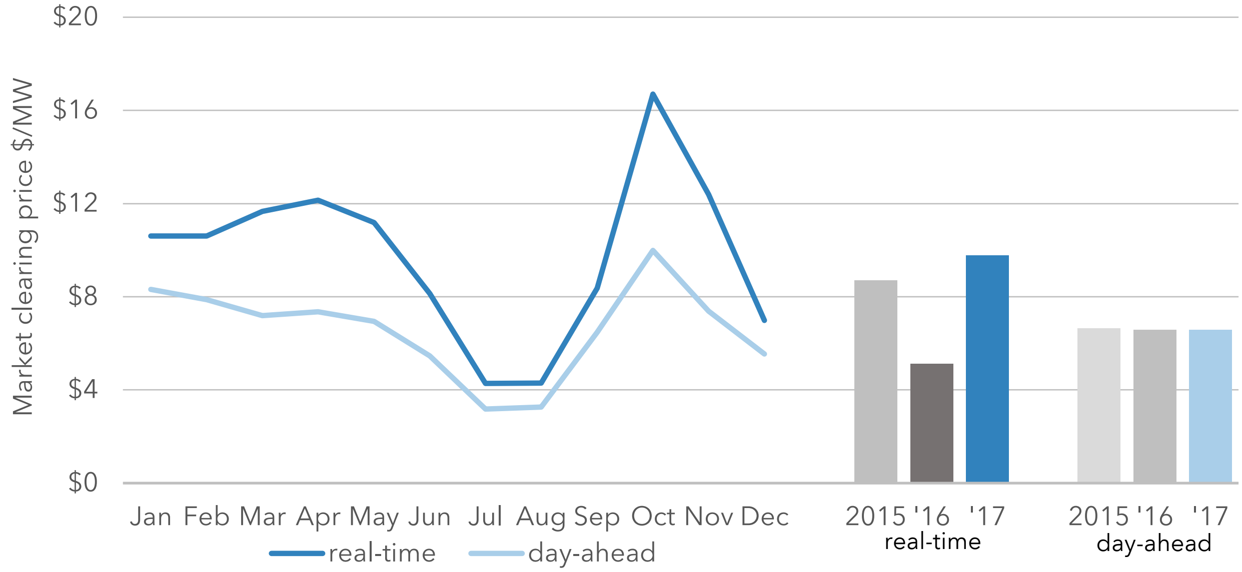
Day-ahead and real-time price patterns vary across the operating reserve products, see Figure 4-21 through Figure 4-24.

Figure 4-21 Regulation-up service prices



From 2016 to 2017, the average real-time market clearing price for regulation-up increased by 42 percent, from $7/MW to nearly $10/MW. Monthly prices for regulation-up were highest in the peak wind months during the spring and fall. The high prices during these periods can mostly be attributed to higher wind penetration levels during these periods.

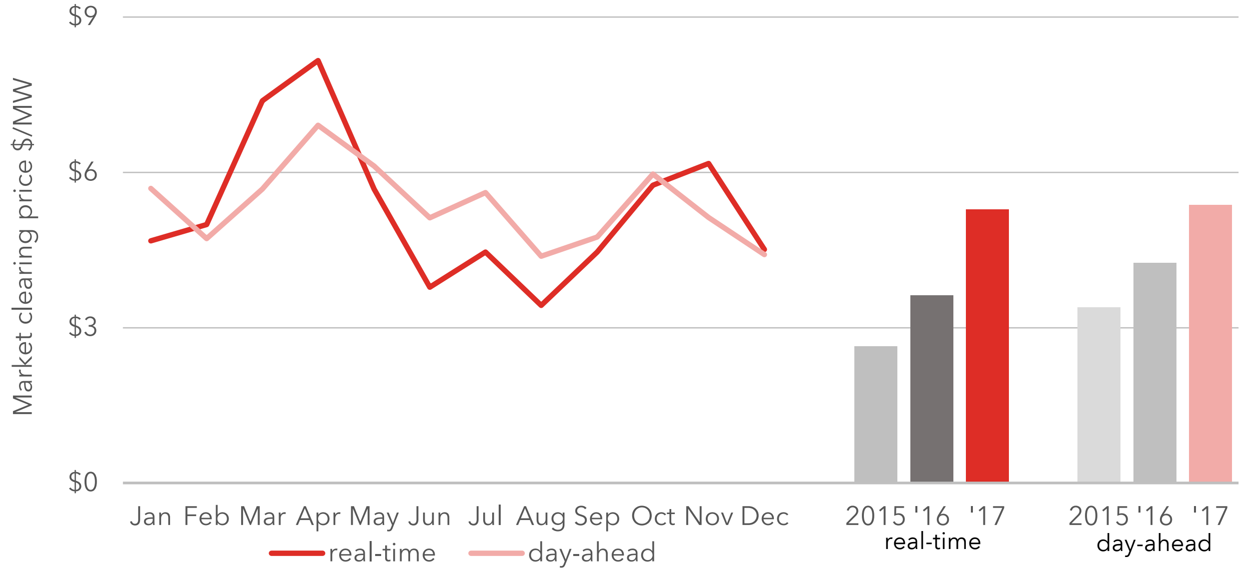
Figure 4-22 Regulation-down service prices



Regulation-down market clearing price in the real-time market nearly doubled from 2016 to 2017, going from just over $5/MW to nearly $10/MW. Day-ahead regulation-down market clearing prices have remained steady the past three years at around $6.50/MW.

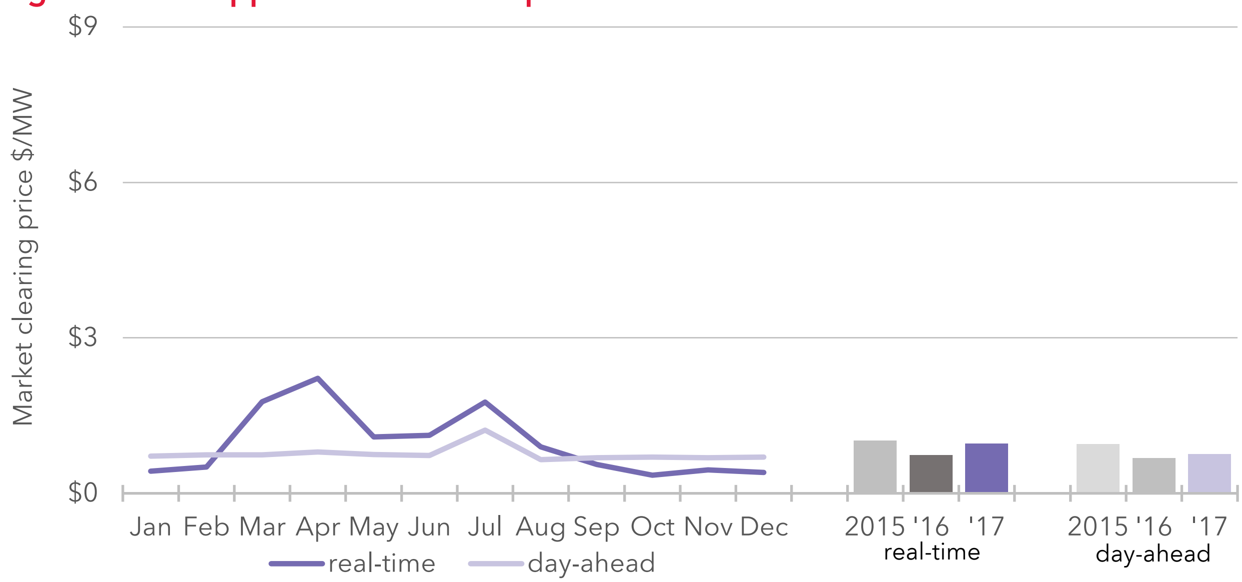
Monthly prices for regulation-down were at typical historical levels through September 2017. However, the real-time regulation-down market clearing price jumped from just over $8/MW in September to nearly $17/MW in October, and then $12/MW in November. The high real-time regulation-down market clearing prices can primarily be attributed to periods of high wind generation and low load. During these periods, many thermal units are operating at their economic minimums, which are lower than regulation minimums. Costs are higher to move these units up to the regulation range.

Figure 4-23 Spinning reserve prices



The market clearing price for spinning reserves continued to climb steadily on an annual basis in both the day-ahead and real-time markets. Even so, spinning reserve prices have been low overall, averaging about $5.25/MW in both markets annually in 2017, and peaking at just over $8/MW in the real-time market in September.

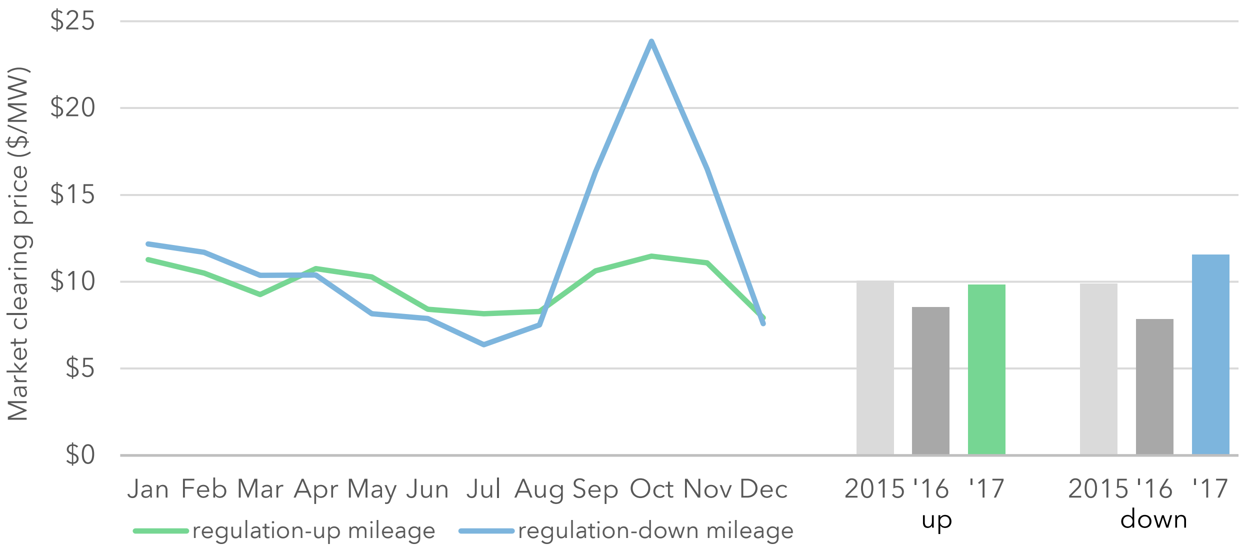
Figure 4-24 Supplemental reserve prices



Supplemental reserve market clearing prices remained low in both markets, with prices averaging less than $1/MW in 2017. On a monthly basis, monthly prices were highest in real time at just over $2/MW in April.

In March 2015, SPP introduced a new product paying regulating units for mileage costs incurred when moving from one set point instruction to another. These mileage payments are paid directly through the operating reserve prices shown for regulation-up and regulation-down, as shown in Figure 4-25. The market calculates a mileage factor for both products each month that represents the percentage a unit is expected to be deployed compared to what it cleared. If a unit is deployed more than the expected percentage, then the unit is entitled to reimbursement for the excess at the regulation mileage marginal clearing price. If the unit is deployed less, it must buy back its position.

Figure 4-25 Regulation mileage prices, real time



On an annual basis, average monthly regulation-up mileage prices for 2017 were almost identical to 2015, at around $10/MW. Levels in 2016 were slightly lower at around $8.50/MW. Average monthly regulation-down prices in 2017 were trending higher than previous year averages. However, the fall months of 2017 experienced very high regulation-down prices, peaking at an average for October of nearly $24/MW. The MMU is exploring the results during this period and will report on any findings in a subsequent forum or report.

4.1.8 MARKET SETTLEMENT RESULTS

The day-ahead market accounted for 98 percent of the energy consumed in the Integrated Marketplace. This is consistent with last year. Figure 4-26 shows that approximately 250 terawatt-hours of energy were purchased in the day-ahead market at load settlement locations, of which only five terawatt hours were in excess of the real-time consumption, requiring a sale back to the market.

Figure 4-26 Energy settlements, load

	Day-ahead purchases	Real-time purchases	Real-time Sales
Load (GWh)	-249,031	-5,332	5,058
Cash flow (millions)	-$ 6,053	-$ 139	$ 116

Just under five and a half terawatt hours of energy were purchased in the real-time market because the real-time consumption was higher than that of the day-ahead. The close relationship of day-ahead load consumption to real-time load consumption demonstrates signs of an efficient day-ahead market.

Negative gigawatt hours denote withdrawals from the grid. Negative cash flows denote charges to load-serving entities. Positive gigawatt hours represent sales of day-ahead gigawatt hours back to the real-time market and negative cash flows represent payments to load owners for those sales.

Day-ahead generation accounted for 89 percent of generation settled in the market, a three percent decrease from last year. Figure 4-27 presents the settlement numbers for the SPP generators.

Figure 4-27 Energy settlements, generation

	Day-ahead sales	Real-time sales	Real-time purchases
Generation (GWh)	254,433	33,103	-27,626
Cash flow (millions)	$ 5,560	$ 478	-$ 563

Eleven percent of the energy cleared in the day-ahead market was settled by purchasing energy in the real-time market rather than generating the energy, which was roughly the same as experienced in 2015 and 2016.

Positive gigawatt hours denote injections into the grid. Positive cash flows denote payments to generators. Negative gigawatt hours represent repurchases in the real-time market and negative cash flows represent charges to generators for those repurchases.

SPP plays the role of the customer in the operating reserve market. At hour ending 8:00 AM on the day before the operating day, SPP posts the forecasted amount of each operating reserve product that is to be procured. This data sets the demand for the products for the day-ahead market. SPP can change the demand levels after the clearing of the day-ahead market. Even though the demand is essentially the same between the day-ahead market and the real-time market, there is considerable activity with respect to the operating reserve products in the real-time market. Figure 4-28 presents the settlements data for operating reserves.

Figure 4-28 Operating reserve product settlements

Settlements (GWh)*	Day-ahead sales	Real-time sales	Real-time purchases
Regulation-up	2,785	936	-938
Regulation-down	2,791	1,040	-1,041
Spinning reserves	6,599	1,948	-1,946
Supplemental reserves	6,601	2,488	- 2,478

Positive numbers represent the cleared gigawatt hours for ancillary services. Negative numbers represent the repurchase of day-ahead cleared ancillary service in the real-time market.

A large percentage of day-ahead sales (34 percent) are settled in the real-time market by repurchasing the operating reserve product rather than supplying the service in the real-time market. This is in contrast to 89 percent of energy generation settled at the day-ahead prices. This trend is down three percent from last year and eight percent from the 40 percent that occurred in the first 12 months of the market.

Sixty-six percent of the 2017 real-time regulation-up service was settled at day-ahead prices, up one percent from 65 percent in the previous year. The corresponding percentages for regulation-down service, spinning reserves, and supplemental reserves are 63 percent, 71 percent, and 62 percent respectively. These results were up slightly from the respective numbers in 2016 of 58 percent, 70 percent, and 61 percent. This essentially means that operating reserve products are being moved around to different resources in about the same volumes as last year, with the exception of regulation-down. It had a five percent increase in real-time volume when compared to day-ahead volume. This is likely a result of differences in generation between the day-ahead and real time including differences in wind generation as well as virtual bids and offers.[60]

4.2 SCARCITY PRICING

The Integrated Marketplace uses scarcity pricing demand curves that administratively set prices during periods of shortage. An efficient electricity price reflects the cost of the marginal action required to meet the market demand. Generally, generators are the marginal price setting resource. However, during shortage pricing events, the marginal megawatt comes from reducing the amount of operating reserves. The scarcity pricing demand curves reflect the administratively determined cost of the marginal action during operating reserve shortages.

FERC Order No. 825 was released in June 2016. The order stated that: "[W]e require each RTO/ISO to trigger shortage pricing for any interval in which a shortage of energy or operating reserves is indicated during the pricing of resources for that interval." At the time of the order, SPP did not price ramp related shortages because those events were considered transient in nature.

Revision request 175 "Ramp Shortage Compliance" was developed to bring SPP in compliance with FERC Order No. 825 and was implemented on May 11, 2017. Specifically, the revision request removed the violation relaxation limits for resource capacity constraints, resource ramp constraints, and global power constraints. It also established an energy demand price of $5,000 and removed the relaxing of each products' ramp requirements, which allowed ramp shortages to be effectively priced.

SPP market participants anticipated that pricing ramp scarcity events would cause more real-time price spikes, increasing real-time price volatility. Revision request 198 was introduced to minimize the impacts of these increased scarcity events and was implemented on August 11, 2017. The revision request put variable price demand curves in place of the fixed price demand curves. These variable price demand curves buffer the impacts of scarcity pricing.

[60] Section 4.1.5 details the differences in generation outputs between the day-ahead and real-time markets.

Prior to revision request 198, each products' scarcity demand curves used one scarcity price. Now regulation-up, regulation-down, and contingency reserves have multiple price points depending on how short the cleared operating reserve was of the requirement. For example, regulation-up and regulation-down had one scarcity price of $600/MW prior to August implementation. This meant that being short just one megawatt of regulation capacity would cause a $600/MW price for that product. Since August 11, regulation-up and regulation-down demand curves now have six monotonically increasing price points. Each month SPP runs an analysis on the per megawatt cost to commit a quick-start resource in the prior month. This cost is used to set the regulation scarcity demand curve prices. Regulation-down works exactly the same as regulation-up, except it will have a separate clearing requirement.

Figure 4-29 is an example of how the regulation-up pricing points look after implementation of revision request 198, assuming the historical cost per megawatt to deploy a quick-start unit was $468/MWh.

Figure 4-29 Regulation-up variable demand curve pricing example

Regulation-up demand curve break points	Percent of average quick-start's cost to start for prior month (assuming cost of $468)	Break point shadow price
Amount cleared is:		
Greater than 80 percent, but less than requirement	0.25	$ 117
Between 60 and 80 percent	0.50	234
Between 40 and 60 percent	0.75	351
Between 20 and 40 percent	1.00	468
Above 0, but less than 20 percent	1.25	585
None	capped at $600	600

Figure 4-30 is an example of how the operating reserve demand curves work after revision request 198.

Figure 4-30 Contingency reserve demand curve pricing example

Contingency reserve demand curve break points	Contingency reserve scarcity factor	Break point shadow price
Amount cleared is:		
Less than or equal to 25 percent of second largest projected resources maximum normal operating capacity	0.25	$ 275
Between 25 and 50 percent of second largest projected resources maximum normal operating capacity	0.50	550
Greater than 50 percent of second largest projected resources maximum normal operating capacity	1.00	1,100

FERC stated that the removal of the violation relaxation limits for resource capacity constraints, resource ramp constraints, and global power constraints was in excess of what was required for compliance with FERC Order No. 825 and informed SPP that the implementation was further than needed. To comply, SPP brought forward revision request 265 to add back those items and remove the $5,000 scarcity price for energy. SPP implemented the changes consistent with this revision request on December 5.

As an outcome of SPP pricing the ramp shortages, the MMU has challenges discerning capacity shortages from ramp shortages. This has to do with how the clearing engine solves for scarcity events. The clearing engine does two runs, one for capacity scarcity, and another for ramp scarcity. The results of these two runs are combined for the total scarcity events. The MMU strongly suggests that SPP capture the decisions of both runs so that the reason for the scarcity will be transparent.

Figure 4-31 displays the number of ramp and scarcity shortage intervals by month prior to the scarcity changes in May. The figure also illustrates the average marginal energy component during those intervals. Figure 4-32 displays the number of ramp and scarcity shortages intervals after the May implementation.

Figure 4-31 Scarcity intervals and marginal energy cost, before changes

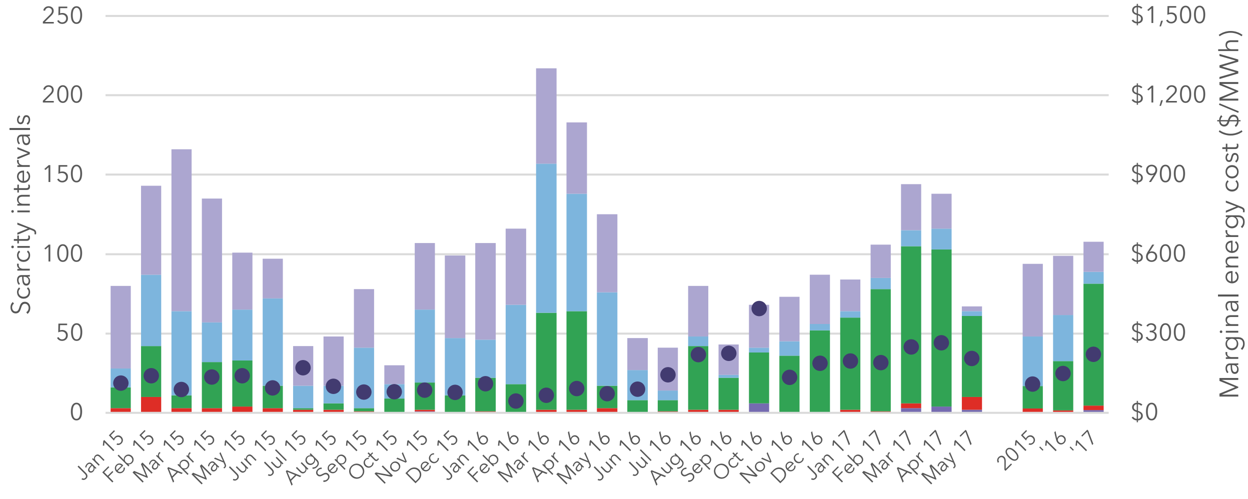
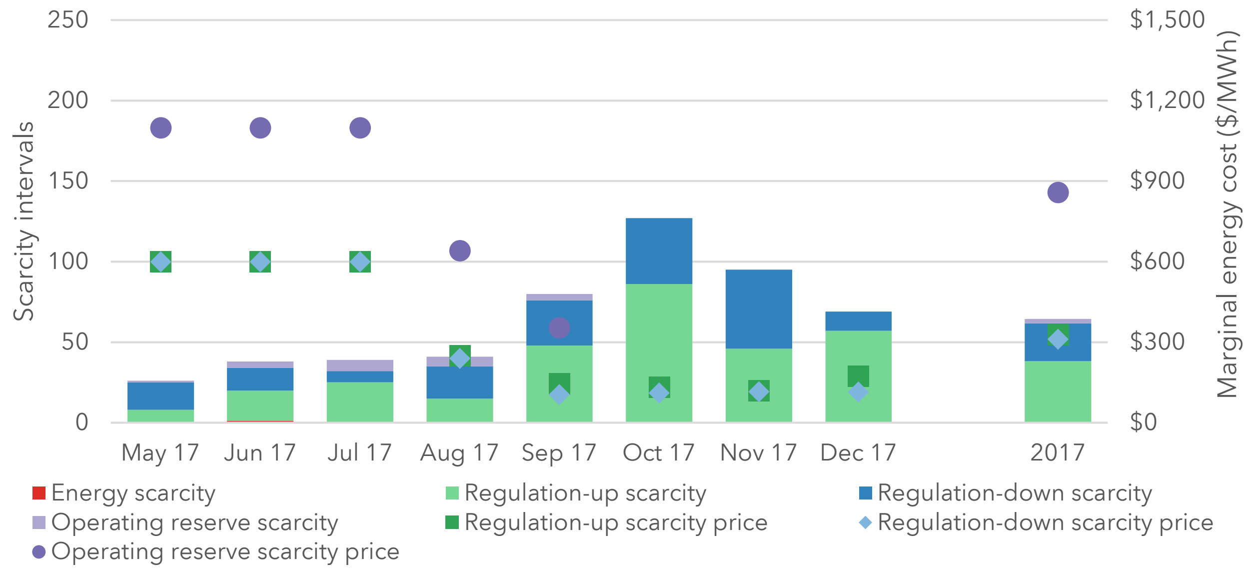


Figure 4-32 Scarcity intervals and marginal energy cost, after changes



Between January 1 and May 11, 2017 there were nine intervals with regulation-up scarcity, no intervals with regulation-down scarcity, 384 intervals of spin scarcity, and 16 intervals with operating reserve scarcity. In addition, there were no regulation-up ramp scarcity events, 37 regulation-down ramp scarcity events, 374 spin ramp scarcity events, and 95 operating reserve ramp scarcity events. However, none of the ramp scarcity events were being priced during this period.

Starting on May 11, there were 304 regulation-up scarcity events, 188 regulation-down scarcity events, and 22 operating reserve events. Figure 4.22 shows the average marginal clearing price of each product during the scarcity intervals. Prior to revision request 198, which was implemented on August 11, the regulation products had one offer price of $600/MW, and the operating reserves had one price of $1,100/MW. After revision request 198, the average price of scarcity for regulation-up was $187/MW, regulation-down was $113/MW, and operating scarcity was $374/MW. This shows that the variable offer curves were successful in reducing the effects of the scarcity events.

There was one energy scarcity event priced at $5,000 in 2017 on June 7. This was because of a system ramp violation caused by the loss of a 632 MW unit during a period when wind generation was falling. However, because the $5,000/MW energy demand price was removed in December, consistent with revision request 265, no subsequent values will occur at this level unless changes are made to increase the value back to $5,000/MW.

4.3 MAKE-WHOLE PAYMENTS

The Integrated Marketplace provides make-whole payments (MWPs) to generators to ensure that the market provides sufficient revenue to cover the cleared offers providing energy and operating reserves for a period in which the resource was committed. To preserve the incentive for a resource to meet its market commitment and dispatch instruction, market payments should cover the sum of the incremental energy cost, start-up cost, no-load cost, transition cost, and cost of operating reserve products. Any revenue beyond those costs supports recovery of fixed costs and provides a profit margin. The make-whole payment provides additional market payments in cases where revenue is below a resource's offers to make the resource whole to its offers of operating reserve products, incremental energy, start-up, transition, and no-load.

For resources that are not combined-cycle, settlements calculations separately evaluate: (1) day-ahead market commitments based on day-ahead market prices, cleared offers and dispatch; and (2) reliability unit commitments based on real-time market prices, cleared offers, and dispatch. Combined-cycle resources can be cleared in both the day-ahead and real-time markets at the same time. This is unique to combined-cycles. As a result, settlements must evaluate the revenues and cost of both real-time and day-ahead commitments when calculating real-time make-whole payments for combined-cycles.

For 2017, day-ahead market and reliability unit commitment make-whole payments totaled approximately $68 million, down from $71 million last year. Make-whole payments averaged about $0.26/MWh for 2017. SPP's make-whole payments are comparable to results in other RTO/ISO markets, which varied from $0.22/MWh to $0.57/MWh in 2016.[61]

Figure 4-33 shows monthly and annual day-ahead make-whole payment totals by technology type. Figure 4-34 shows the same make-whole payment information for reliability unit commitment.

Figure 4-33 Make-whole payments by fuel type, day-ahead

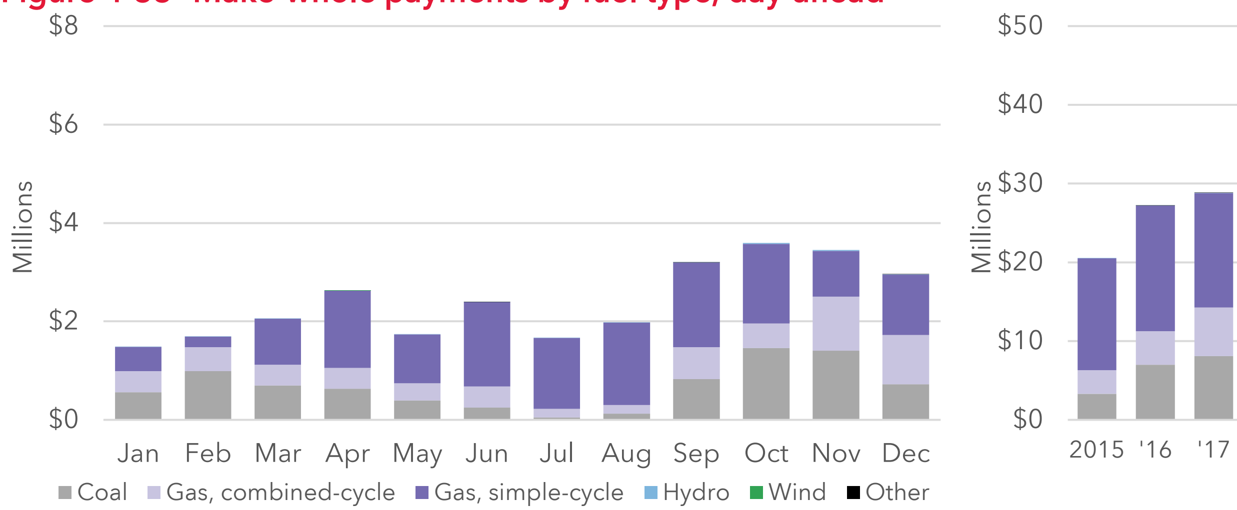
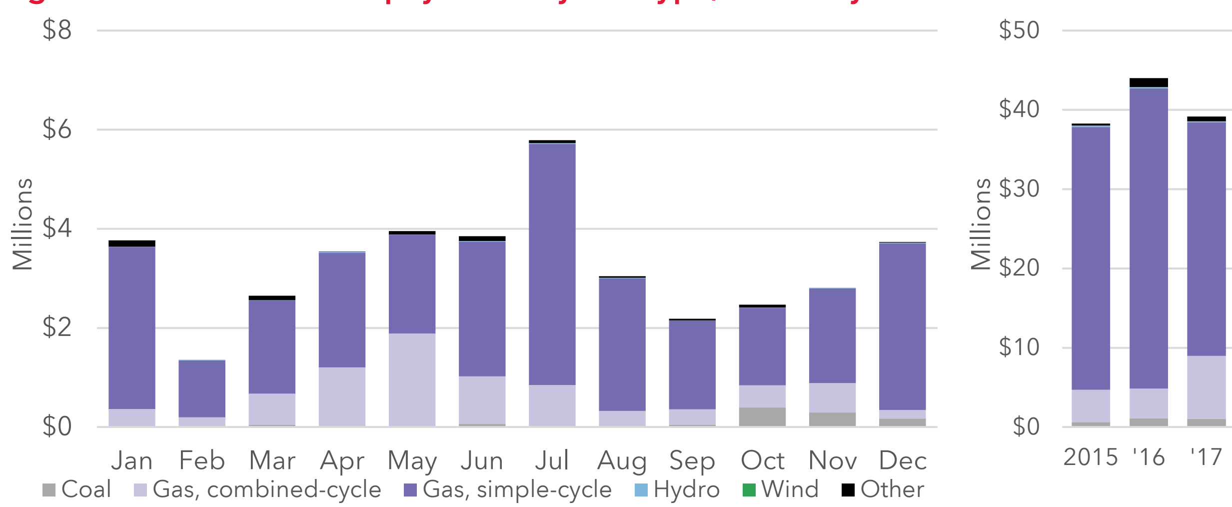


Figure 4-34 Make-whole payments by fuel type, reliability unit commitment



[61] ISO NE State of Market Report https://www.potomaceconomics.com/wp-content/uploads/2017/07/ISO-NE-2016-SOM-Report_Full-Report_Final.pdf , MISO Annual state of Market report http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2016/2016-som-pjm-sec4.pdf , PJM website www.pjm.com

Day-ahead make-whole payments constituted just over 42 percent of the total make-whole payments in 2017. Gas-fired resources represent about 85 percent of all make-whole payments, with 65 percent of all make-whole payments to simple-cycle gas resources through reliability unit commitment make-whole payments.

Make-whole payments occur for several reasons, which include some of the following: local reliability commitments, uncaptured congestion in the day-ahead market, inflexibility of resources to move in economic ranges between on-peak and off-peak hours, and excessive transmission congestion not being solved by the market.

Figure 4-35 shows the share of each cause of make-whole payments in the real-time and day-ahead markets.

Figure 4-35 Make-whole payments, commitment reasons

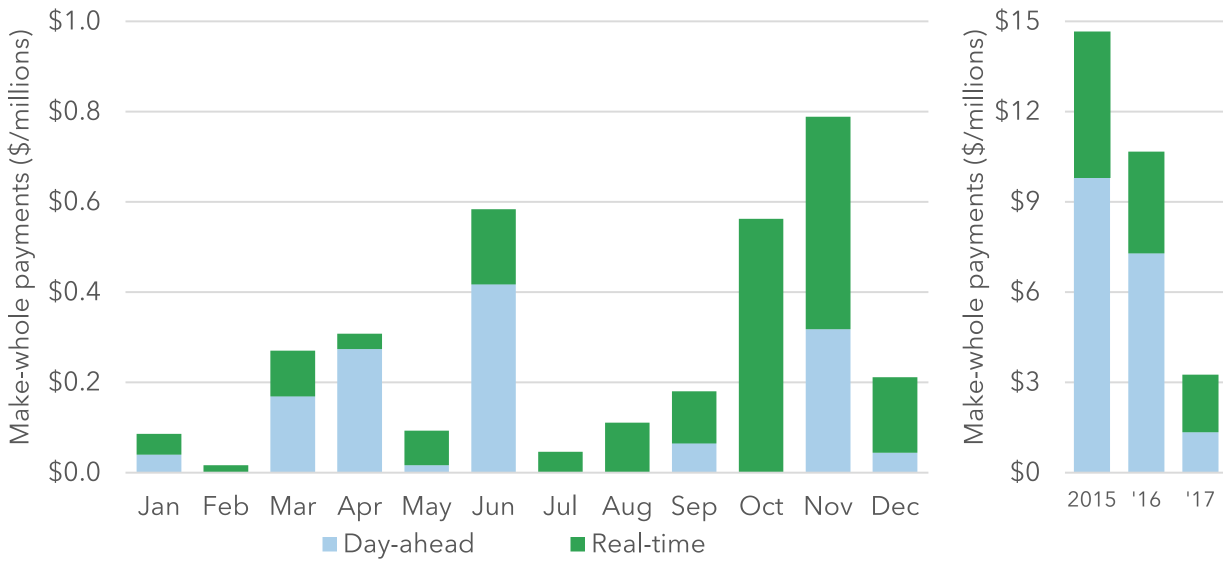
Real-time commitment reason	2015	2016	2017
Intra-day RUC	21.6%	24.4%	35.7%
Manual, SPP transmission	8.9%	23.2%	31.6%
Day-ahead RUC	33.8%	20.1%	7.5%
Short-term RUC	0.0%	12.9%	6.1%
Manual, intra-day RUC	17.2%	8.4%	6.1%
Manual, voltage	13.5%	8.0%	6.4%
Manual, SPP capacity	4.3%	2.6%	4.5%
Manual, day-ahead RUC	0.1%	0.3%	1.2%
Manual, off supplemental	0.0%	0.1%	0.0%
Other	0.6%	0.0%	0.8%

Day-ahead commitment reason	2015	2016	2017
Day-ahead market	53.4%	73.2%	93.7%
Manual, voltage support	46.6%	26.8%	6.3%

Voltage support commitments decreased in 2017 when compared to prior years, declining from 47 percent of make-whole payments in 2015 to about six percent in the day-ahead market in 2017. Real-time voltage payments declined by about seven percentage points over the same period. As a result of this change, make-whole payments for intra-day reliability unit commitment and manual-transmission commitments increased in the real-time market.

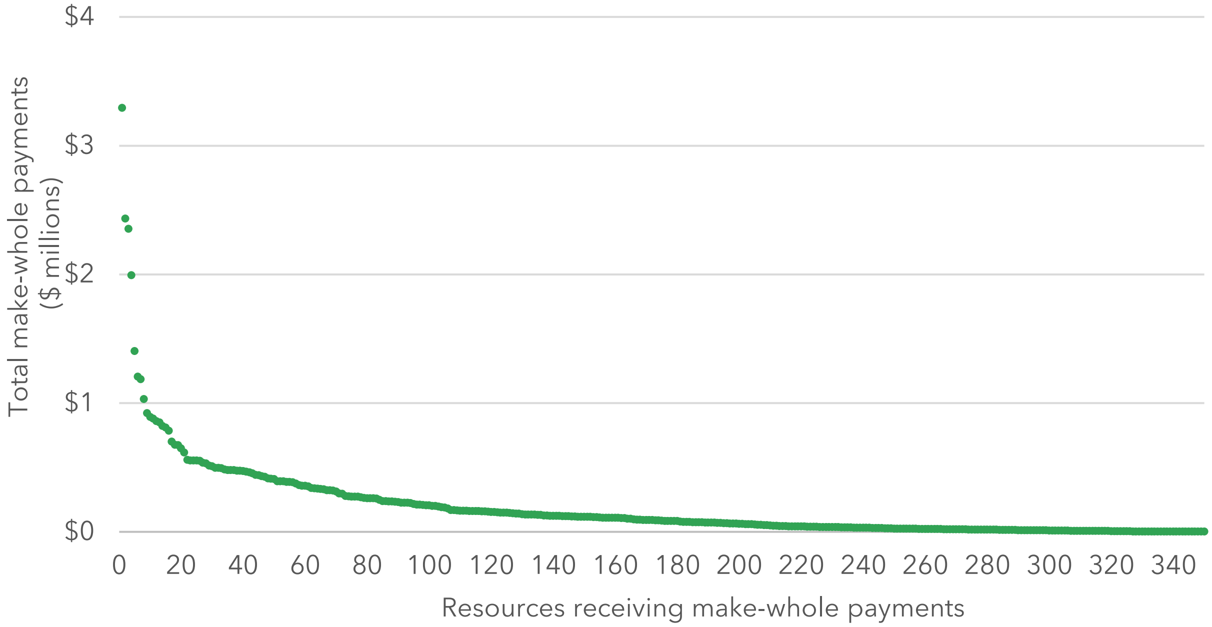
Make-whole payments associated with voltage support commitments do not follow the same uplift process outlined previously in this section. Instead, the cost of these make-whole payments are distributed to the settlement areas that benefited from the commitment by way of a load ratio share. Figure 4-36 illustrates the level of make-whole payments associated with voltage support commitments.

Figure 4-36 Make-whole payments for voltage support



Most SPP resources received modest total annual make-whole payments as highlighted in Figure 4-37.

Figure 4-37 Concentration of make-whole payments by resource



The majority of resources in SPP received less than $200,000 in make-whole payments in 2017. Eight resources received over $1 million, with three of those resources receiving over $2 million. Both of these numbers are twice the level as last year. Five of the top eight resources were run extensively for voltage support, with over 90 percent of the top units' make-whole payments attributed to voltage support commitments. One resource received $3.2 million dollars in make-whole payments, and was mostly committed for reliability reasons.

Figure 4-38 reveals some concentration in the market participants that received the highest levels of make-whole payments. The overall numbers have not changed significantly over the past few years.

Figure 4-38 Market participants receiving make-whole payments

	2015			2016			2017		
	> $1 million	> $5 million	> $10 million	> $1 million	> $5 million	> $10 million	> $1 million	> $5 million	> $10 million
Market participants receiving make-whole payments	12	5	0	12	4	2	12	5	1
% of make-whole payments by category	93%	65%	0%	92%	61%	38%	90%	61%	18%

In 2017, there were 12 market participants that each received annual make-whole payments in amounts greater than $1 million. These 12 market participants accounted for 90 percent of the total make- whole payments paid out in 2017. Those same 12 participants also received over $1 million each in 2016 and 11 of those participants received over $1 million in 2015. There was only one participant in 2015 that was different from 2017 at this level. In 2017, there were five participants that received over $5 million each in make-whole payments and out of that one received $10 million. The participant with $10 million in total make-whole payments accounted for 18 percent of all make-whole payments paid out in 2017.

4.3.1 MAKE-WHOLE PAYMENT ALLOCATION

The allocation of both day-ahead and real-time make-whole payments has important consequences to the market. In principle, for market efficiency purposes uplift cost allocation should be directed to those members that contributed to the need for the make-whole payments (i.e., cost causation).

For the day-ahead market, make-whole payment costs are distributed to both physical and virtual withdrawals on a per-MWh rate. The per-MWh rate is derived by dividing the sum of all day-ahead make-whole payments for an operating day by the sum of all cleared day-ahead market load megawatts, export megawatts, and virtual bids for the operating day. The average per-MWh rate for withdrawing locations in the day-ahead market was just under $0.11/MWh in 2017. This is similar to the 2016 average and slightly higher than the $0.09/MWh average in 2015.

For the real-time market, make-whole payment costs are distributed through a per-MWh rate that is assigned to all megawatt-hours of deviation in the real-time market. The average real-time distribution rate was $0.90/MWh for 2017, down $0.24/MWh from the $1.14/MWh average in 2016. There are eight categories of deviation and each category receives an equal amount per megawatt when the cost of make-whole payments is applied. This can be seen in the settlement location deviation charge, show in Figure 4-39.

Figure 4-39 Make-whole payments by market uplift allocation, real time

Uplift type	Deviation MWs (thousands)	Uplift charge (thousands)	Share of MWP charges	Cost per MW of deviation
Settlement location deviation	35,149	$ 30,902	78.9%	$ 0.88
Outage deviation	4,402	$ 4,066	10.4%	$ 0.92
Status deviation	1,436	$ 1,266	3.2%	$ 0.88
Maximum limit deviation	1,200	$ 1,205	3.1%	$ 1.00
Reliability unit commitment self-commit deviation	629	$ 592	1.5%	$ 0.94
Uninstructed resource deviation	659	$ 584	1.5%	$ 0.89
Minimum limit deviation	283	$ 233	0.6%	$ 0.00
Reliability unit commitment deviation	245	$ 309	0.8%	$ 0.00

Even though each category of deviation is applied the same rate for deviation, approximately 79 percent of the real-time make-whole payment costs were paid by entities withdrawing (physical or virtual) more megawatts in the real-time market than the day-ahead market.

Transactions susceptible to this charge are virtual offer megawatts, real-time load megawatts in excess of the day-cleared megawatts for a unit, exporting megawatts in real time in excess of the export megawatts cleared in the day-ahead market, and units pulling substation power in excess of any megawatts produced by the unit.

4.3.2 REGULATION MILEAGE MAKE-WHOLE PAYMENTS

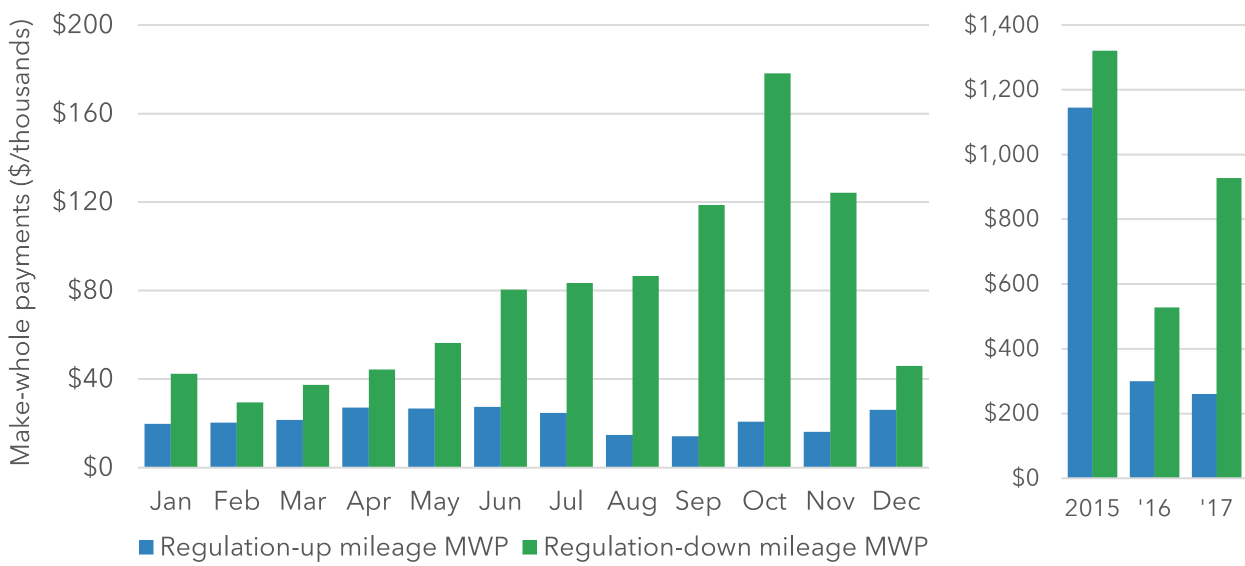
In March 2015, SPP introduced regulation compensation changes for units deployed for regulation-up and regulation-down. One component of the regulation compensation charges is regulation-up and regulation-down mileage make-whole payments for units that are charged for unused regulation-up or regulation-down mileage at a rate that is in excess of the regulation-up or regulation-down mileage offer.

SPP calculates mileage factors monthly for both regulation-up and regulation-down. These mileage factors are ratios of historical averages of the percentage of each regulation product deployed to the regulation product cleared in the prior month. The regulation-up mileage factor and regulation-down mileage factors averaged 18 percent and 24 percent, respectively, for 2017. While the regulation-up mileage factor stayed the same from 2016, the regulation-down mileage factor increased four percent.

The mileage factor is a key component in the computation of mileage make-whole payments. When the mileage factor is greater than the percentage of deployed regulating megawatts to cleared regulating megawatts for each product, the resource must buy back the non-deployed megawatts at the mileage marginal clearing price for the respective product. If the mileage marginal clearing price used for the buyback is greater than the unit's cost for the product a make-whole payment may be granted.

Figure 4-40, below, illustrates the mileage make-whole payments for 2017 and the prior two years.[62]

Figure 4-40 Regulation mileage make-whole payments



The large increase in regulation-down make-whole payments for the second half of 2017 can be directly attributed to a the mileage clearing prices for regulation-down being nearly

[62] There were a large number of mileage make-whole payments paid out in 2015. This is because the mileage process was rolled out in March of that year and there was not historical data to forecast mileage factors, so the factors were set to 100 percent in the first month of the rollout. This resulted in buyback that was eligible for make-whole payments.

$50/MW for some intervals in the latter half of 2017. The MMU continues to review these results and its implications on market design. We plan to report on our conclusions when our findings are complete.

4.3.3 POTENTIAL FOR MANIPULATION OF MAKE-WHOLE PAYMENTS

In the 2014 Annual State of the Market Report, the MMU highlighted four specific vulnerabilities that market participants could potentially manipulate in SPP's make-whole payment provisions. Three of the four vulnerabilities were directly associated with the FERC order regarding the make-whole payments and related bidding strategies of JP Morgan Ventures Energy Corp.[63] Shortly before the launch of the Integrated Marketplace, SPP and the MMU noted the following exposures in SPP's market design:

1) make-whole payments for generators committed across the midnight hour,
2) make-whole payments for regulation deployment, and
3) make-whole payments for out-of-merit energy.

In 2014, one of the MMU's recommendations covered the following with regard to the manipulations of make-whole payment provisions:

1) evaluate solutions adopted by other RTOs to reduce exposure to market manipulation opportunities in make-whole payment provisions for resources committed across the midnight hour,
2) disqualify resources with fixed regulation offers from receiving the regulation deployment adjustment charge, and
3) utilize automatic mitigation provisions for local reliability commitments for local reliability out-of-merit energy events.

In each case, a market participant has the ability to position its resource to receive a make-whole payment without economic evaluation of its offers by the market. While no resolution has been completed for these items at this time, there are solutions at different stages of development for each of these items.

[63] See 144 FERC 61,068.

A revision request was brought forward regarding multi-day minimum run times to ensure that units with long minimum run times could not manipulate their make-whole payments by inflating their offers on days subsequent to the initial commitment.[64] Though the Market Working Group rejected the revision request in early 2017, the MMU successfully appealed the rejection to the Market Operations and Policy Committee and the revision request was remanded back to the Market Working Group for further review. The MMU continues work with the Market Working Group to address this issue. A proposed solution is under development and is currently targeted for SPP board approval in July.

Two revision requests were brought forward to address the issue concerning regulation adjustments. One adds an assessment of economics when deploying units for regulation and the other caps the offers used for the adjustment. The first has been implemented while the latter was approved by FERC in early April 2018. The MMU feels that these two revision requests will adequately close the gaming opportunities present in the regulation adjustment.[65]

Because exposures to all three vulnerabilities are still present, the MMU continues to monitor the market for all three of these gaps. This is necessary to prevent exploitation of the third gap concerning out-of-merit energy make-whole payments. Because of the infrequency of these events, the MMU continues to monitor the gap, as the cost of changes may outweigh the benefits of a market design change at this time.

4.3.4 JOINTLY-OWNED UNIT MAKE-WHOLE PAYMENTS

Another make-whole payment concern existed related to jointly-owned resources and the combined resource option. At the time the MMU made their original recommendation, the market committed jointly-owned units as one unit, dispatched each separate owner on a percentage of ownership, and paid make-whole payments for energy based on the individual owners' energy offers. This allowed a shareowner to benefit from a higher energy offer than its co-owners through high minimum energy costs in the make-whole payment.

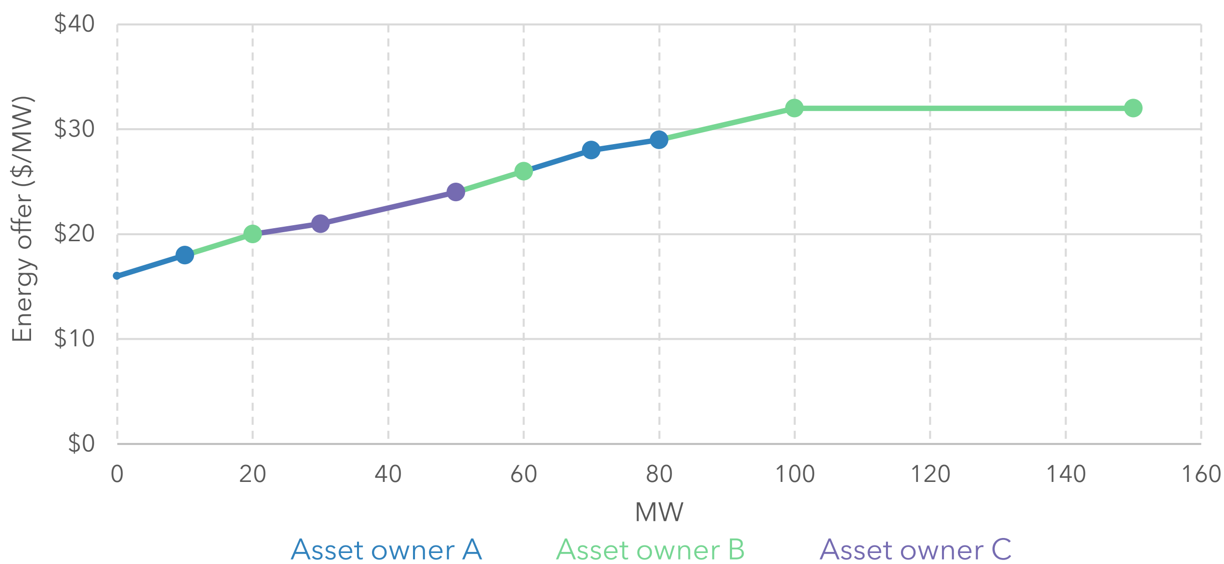
In August 2017, SPP implemented changes based on two revision requests to eliminate the gaming opportunities present in the original design. The new design eliminates the potential

[64] RR 221 (2014 ASOM MWP MMU Recommendation [3-Day Minimum Run Time])
[65] The revision requests were 242 and 243.

gaming opportunity by taking all owners' pricing points of a combined resource option for jointly-owned resources and aggregates those price points into a single energy offer curve for the unit. This revision request also enforced all shares under a combined resource option to have a minimum capacity limit of zero megawatts when being assessed for dispatch. Start-up and no-load costs were still reimbursed on the same percentage of ownership method used prior to the changes.

With the new method, individual shares only received a dispatch instruction greater than zero megawatts based on the new aggregated energy offer curve, which eliminated the original gaming opportunity. Figure 4-41, below, illustrates how a hypothetical energy offer curve looked once aggregated.

Figure 4-41 Aggregated energy offer curve example



If this unit were to clear economically, asset owner A would have been dispatched for the first 10 megawatts. Then asset owner B would be dispatched from 10 MW to 20 MW, as they were the most economical for those segments. This process would have been repeated until the desired quantity was reached.

While the change eliminated the gaming opportunity outlined in the 2014 annual state of the market report, the design introduced new issues. These issues include the following:

1) Allocating self-committed jointly-owned unit costs during uneconomic periods

One of the biggest issues brought forward by participants with jointly-owned units was how the new design allocated costs when these resources were self-committed and uneconomic. For example, if the resource is self-committed, there are times when the price of energy may be negative for several hours during that commitment. During these uneconomic periods the lowest cost parts of the jointly-owned unit will be cleared to meet the unit's minimum physical capacity operating limit. Using the energy offer curve in Figure 4-41, and assuming a minimum physical capacity operating limit of 20 MW, only asset owner A and B will be dispatched to meet the 20 MW requirement. Because the unit is self-committed, no members are eligible for cost reimbursement. However, asset owner A and asset owner B will have to cover the costs of running during periods with negative prices, whereas asset owner C will not have to cover the costs. Under the old method, the cost of negative prices would have been distributed by percentage of ownership, so each asset owner would have to cover this cost.

2) Gap created in real-time make-whole payments for jointly-operated units

Units committed after the day-ahead market are eligible for real-time make-whole payments. Real-time make-whole payments allow eligible units to recover cost on their energy if prices do not cover the cost to produce the energy. The energy cost assessed up to the unit's minimum are the costs submitted at the time of the commitment. The energy cost above the unit's minimum are the cost that are submitted at the time of dispatch. These energy offers at the time of dispatch are known as "as-dispatch" offers. The as-dispatch offers may be updated 30 minutes prior to each operating hour. A jointly-owned unit cleared in any process after the day-ahead market—such as the reliability unit commitment process—can inflate their offers at the time of dispatch and be made whole to that inflated offer, even though the jointly-owned unit may be running at its physical minimum limit. This is because each jointly-owned unit owners' minimum operating limits are considered zero megawatts for settlement even though the unit is only running above zero megawatts because of the physical minimum limits of the unit. Thus, if an asset owner knows that a resource is committed to minimum, they have the ability to increase their energy offers—which do not account for minimum load levels—to increase their make-whole payments.

3) Real-time make-whole payment distributions not accurately applied

The real-time make-whole distribution allocates the cost of real-time make-whole payments to deviating megawatts. One category of deviating megawatts are units that self-commit in the real-time market and are dispatched to their minimum limit. The difference in the megawatts between the minimum limit of the resource and the desired energy level are allocated costs for real-time make-whole payments. Because each co-owners have zero minimum capacity limits in settlements, they are not allocated these costs.

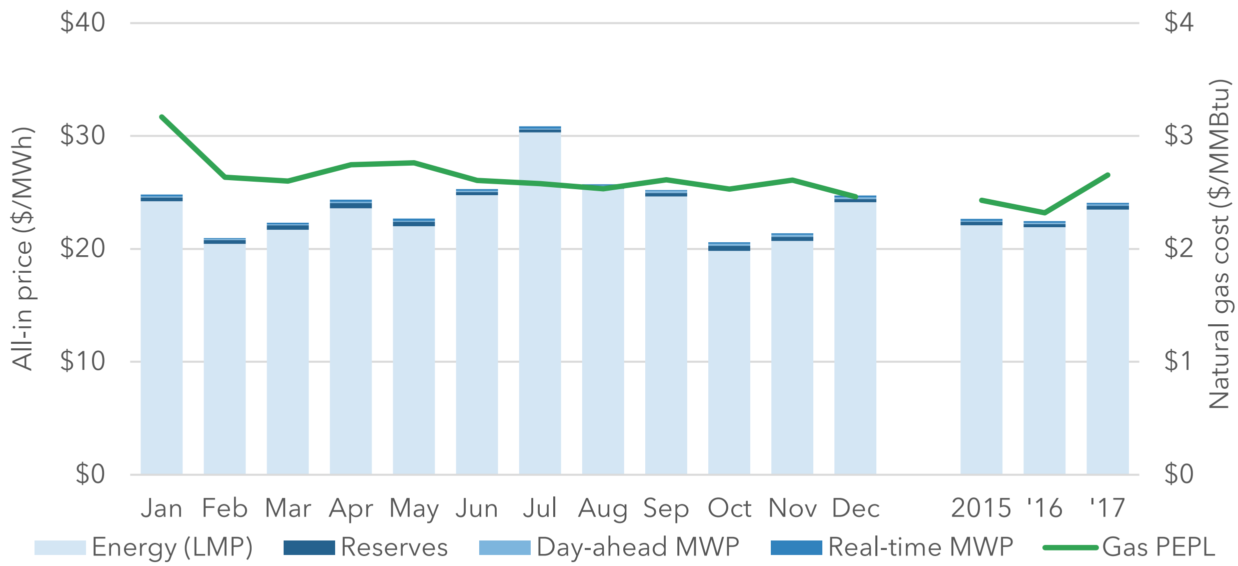
Additionally, there are other deviation calculations that are based on the difference of a unit in manual status output versus where they would be desired to run if the resource were dispatchable. When this happens there is a potential for the combined unit's desired energy to be lower than the physical minimum limit of the unit. This is because the settlement process calculates the desired energy quantities with the assumption that the unit can run at zero megawatts, which is below the physical minimum of the unit. As a result, the jointly-owned unit asset owners could have distribution charges unduly applied.

SPP, stakeholders, and the MMU are currently working on an approach to redesign the approach to jointly-owned units. Stakeholders have unofficially agreed on a design concept that they believe will address these issues and fulfill the MMU's original design gap recommendation. A new design approach is currently in the stakeholder process. This approach requires that jointly-owned units offer in as one unit. The market system will dispatch the resource as one unit, and then the settlements process will allocate the cost and revenues out by percentage of ownership of the resource.

4.4 TOTAL WHOLESALE MARKET COSTS

The average annual all-in price, which includes the costs of energy, day-ahead and real-time reliability unit commitment make-whole payments, operating reserves,[66] reserve sharing group costs, and payments to demand response resources, was $24.08/MWh in 2017. This compares to the average price of energy at load pricing nodes in SPP's real-time market for 2017 of $23.48/MWh.[67] The all-in price was just over seven percent higher than the 2016 average all-in price, which is partially related to the increase in natural gas prices.[68] Figure 4-42 plots the average all-in price of energy and the cost of natural gas, measured at the Panhandle Eastern (PEPL) hub.

Figure 4-42 All-in price of electricity and natural gas cost



The figure shows that the vast majority of costs are from the day-ahead and real-time energy markets.[69] The graph also shows that the market cost of operating reserves and make-whole payments constituted approximately two percent of the all-in price, with make-whole payments and operating reserves amounting to $0.27/MWh and $0.26/MWh, respectively.

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[66] Operating reserves are resource capacity held in reserve for resource contingencies and NERC control performance compliance, which includes the following products: regulation-up service, regulation-down service, spinning reserve and supplemental reserve.
[67] The cost of energy includes all of the shortage pricing components.
[68] The Reserve Sharing Group costs and payments to demand response resources were negligible for both years.
[69] Shortage pricing is included in the energy component and not easily separated out in the SPP settlement data. See Section 4.2 for a discussion of shortage pricing impacts.

4.5 LONG-RUN PRICE SIGNALS FOR INVESTMENT

In the long term, efficient market prices provide signals for any needed investment in new transmission, generation, and ongoing maintenance of existing generation to meet load. Given the very high amount of capacity in the SPP system at peak, which the MMU estimates was about 30 percent in 2017 (see Section 2.3.2), the MMU does not expect market prices to support new entry of non-wind generation investments. In this context, the only explanation for wind and solar generation investments can be the federal and/or state subsidies for those resources.

The MMU conducted an analysis to determine if the SPP market would support investments in new generation by analyzing the fixed costs, and annual fixed operating and maintenance costs of three generation technologies relative to their potential net revenues[70] at SPP market prices. The plants considered include a scrubbed coal plant, a natural gas combined-cycle, and a combustion turbine. Figure 4-43 provides the cost assumptions and Figure 4-44 shows the results of the net revenue analysis. The analysis assumes the market dispatches the hypothetical resource when price exceeds the short-run marginal cost of production. In addition to these assumptions a capital recovery factor of 12.6 percent was used in the annual fixed operating and maintenance cost component.

Figure 4-43 Net revenue analysis assumptions

	Scrubbed coal	Advanced gas/oil combined-cycle	Advanced combustion Turbine
Size (MW)	650	429	237
Total overnight cost ($/kW-yr.)	$ 5,030	$ 1,094	$ 672
Variable overhead and maintenance ($/MWh)	$ 7.06	$ 1.99	$ 1.63
Fixed overhead and maintenance ($/kW-yr.)	$ 69.56	$ 9.94	$ 6.78
Heat rate (Btu/kWh)	9,750	6,300	9,800

Source: EIA Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants, January 2018

[70] Net revenue is equal to revenues minus estimated marginal cost.

Figure 4-44 Net revenue analysis results

Technology	Average marginal cost ($/MWh)	Net revenue from SPP market ($/MW yr.)	Annual revenue requirement ($/MW yr.)	Able to recover new entry cost	Annual fixed O&M cost ($/MW yr.)	Able to recover avoidable cost
Scrubbed coal	$ 27.73	$ 29,199	$ 701,205	NO	$ 69,560	NO
Advanced gas/oil combined-cycle	$ 18.75	$ 51,399	$ 147,320	NO	$ 9,940	YES
Advanced combustion turbine	$ 27.70	$ 29,036	$ 91,167	NO	$ 6,780	YES

Revenues have been insufficient to support the cost of new entry generation for all three technologies since the inception of the Integrated Marketplace, and 2017 was no exception. In 2015 and 2016, prices did support the ongoing maintenance cost of combined-cycle and combustion turbine units, though it did not support the cost of scrubbed coal units. This is consistent with the 2017 results shown above. Declining gas prices, excess capacity, and increasing negative prices are the leading contributors to the decline in the profitability of coal plants.

Figure 4-45 provides results by SPP resource zone, as indicated by the dominant utility in the area.

Figure 4-45 Net revenue analysis by zone

	Scrubbed coal			Gas/oil combined-cycle			Combustion turbine		
Resource Zone	Net revenue from SPP market ($/MW yr.)	Able to recover net entry costs	Able to recover avoidable cost	Net revenue from SPP market ($/MW yr.)	Able to recover net entry costs	Able to recover avoidable cost	Net revenue from SPP market ($/MW yr.)	Able to recover net entry costs	Able to recover avoidable cost
AEP	$ 19,459	NO	NO	$ 65,229	NO	YES	$ 41,761	NO	YES
KCPL	$ 12,031	NO	NO	$ 40,364	NO	YES	$ 29,741	NO	YES
NPPD	$ 8,688	NO	NO	$ 26,780	NO	YES	$ 24,889	NO	YES
OGE	$ 16,002	NO	NO	$ 55,802	NO	YES	$ 35,653	NO	YES
SPS	$ 11,715	NO	NO	$ 40,501	NO	YES	$ 34,587	NO	YES
WAUE	$ 15,740	NO	NO	$ 52,569	NO	YES	$ 10,717	NO	YES
WR	$ 10,822	NO	NO	$ 38,664	NO	YES	$ 30,612	NO	YES

This shows that the conclusions do not vary geographically, even with differing energy prices and fuel costs. Other RTO/ISO markets have experienced a “missing money problem” in their markets, where net revenues do not support needed new investments. The MMU expects the market to signal the retirement of inefficient generation. Aging of the fleet will eventually change the peak available capacity such that price signals for higher net revenue become increasingly important. The ability of market forces to provide these incentives and long-run price signals is a strong benefit of the Integrated Marketplace.

4.6 MUST-OFFER PROVISION

The Integrated Marketplace has a limited day-ahead must-offer provision that was intended to incentivize load-serving entities to participate in the day-ahead market. Market participants that are non-compliant are assessed a penalty based on the amount of available capacity available in the day-ahead market relative to the market participant's real-time load. The requirement is limited in the sense that only market participants with generation assets that serve load are subject to the rules. Load-serving market participants that offer enough generation, and/or provide scheduling information indicating a firm power purchase to cover at least 90 percent of their real-time load are not subject to a penalty. An alternative way to satisfy the provision is to offer all generation that is not on outage. No penalties were assessed in 2017.

In 2014, the MMU recommended that SPP simultaneously eliminate the limited day-ahead must-offer provision and revise the physical withholding rules to include a penalty for non-compliance based on the premise that the recommended penalty provision would be sufficient to ensure an efficient level of participation in the day-ahead market.

Market participants approved a proposal to eliminate the current limited day-ahead must-offer provision of the SPP tariff in late 2015.[71] The removal of the day-ahead must-offer was then tabled by the SPP stakeholders until the Market Working Group completed its review of the physical withholding revisions proposed by the MMU. The MMU engaged the Market Working Group in a discussion on conduct thresholds and impact test requirements for physical withholding penalties, in conjunction with establishing a formula-based penalty structure.[72] As a result of those discussions, the market monitor developed several

[71] RR 125 (Removal of day-ahead limited must-offer) was approved by the Market Working Group in October 2015.
[72] The market monitor submitted RR 135 (Revision of physical withholding rules) to the Market Working Group in December 2015.

modifications to the proposal.[73] The final proposal adjusted the physical thresholds and changed the measurement of financial impact so that it did not require off-line market case re-runs. This final proposal was rejected by the SPP stakeholders.[74] SPP stakeholders then approved the removal of the day-ahead must-offer with no additional physical withholding provisions, and SPP filed the tariff revision with FERC in the summer of 2017. FERC denied the removal of the limited must-offer requirement as it did not include physical withholding non-compliance penalties.[75]

The MMU continues to recommend updating the day-ahead must offer requirement and addressing FERC's concerns. However, given the status of other higher priority initiatives, the MMU assigns a low priority to addressing the issue at this time. See further discussion in Chapter 7.

[73] The market monitor submitted RR 204 (Physical withholding) to the Market Working Group in December 2016.
[74] RR 204 rejected by Market Working Group in February 2017.
[75] See FERC ruling at https://www.ferc.gov/CalendarFiles/20171013130834-ER17-2312-000.pdf

5 CONGESTION AND TRANSMISSION CONGESTION RIGHTS MARKET

5.1 TRANSMISSION CONGESTION

The locational marginal price (LMP) for the almost 20,000 pricing nodes in the SPP market reflects the sum of three components:

1) marginal energy component (MEC) - system-wide marginal cost of the energy required to serve the market,
2) marginal congestion component (MCC) - the marginal cost of any increase or decrease in energy at a location with respect to transmission constraints, and
3) marginal loss component (MLC) - the marginal cost of any increase or decrease in energy to minimize system transmission losses.

$$LMP = MEC + MCC + MLC$$

LMPs are a key feature of electricity markets that ensure the efficient scheduling, commitment, and dispatch of generation given the system load and reliability constraints. LMPs also provide price signals for efficient incentives for future generation and transmission investment and help guide retirement decisions.

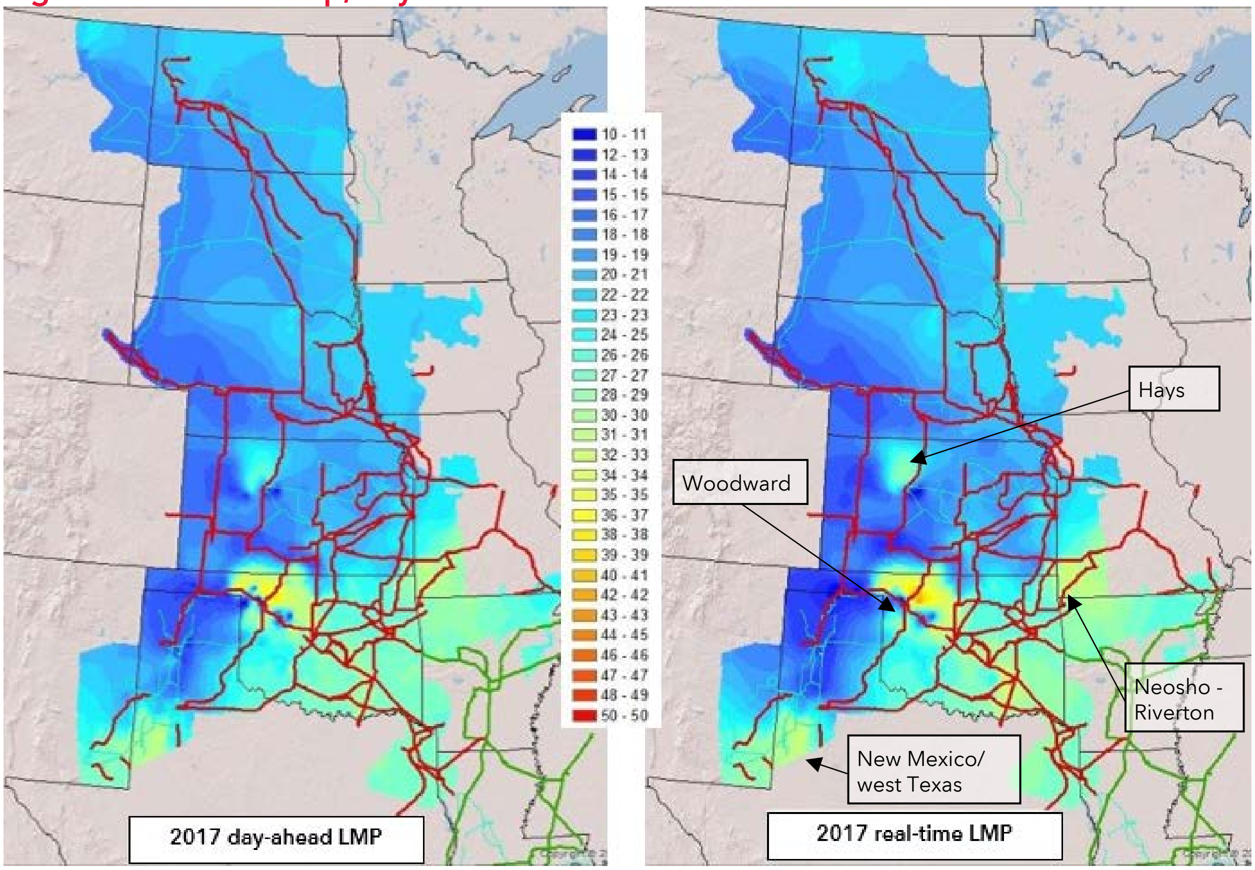
This section focuses on the congestion and loss components of price and related items including:

- geographic pattern of congestion and losses,
- changes in the transmission system that alter congestion patterns;
- congestion impacts on local market power,
- load-serving entities hedging congestion costs in the transmission congestion rights market, and
- distribution of marginal congestion and loss amounts.

5.1.1 PRICING PATTERNS AND CONGESTION

Figure 5–1 shows price contour maps representing the day-ahead and real-time average prices in 2017.

Figure 5–1 Price map, day-ahead and real-time market



Annual average day-ahead market prices ranged from around \$18/MWh on the western edge of the SPP footprint, to around \$36/MWh in the Woodward area of northwest Oklahoma. 2017 continued to see higher prices (\$31/MWh) in the New Mexico and west Texas area, as well as around Hays, Kansas (\$26/MWh). About 74 percent of this price variation can be attributed to congestion and 26 percent to marginal losses, which is consistent with prior years. Because congestion is more volatile in the real-time market, the average geographic price range is slightly larger, from \$12/MWh to \$42/MWh for real-time market prices versus \$16/MWh to \$37/MWh for day-ahead prices.

In May 2017, upgrades were made at Woodward by adding a 138kV phase-shifting transformer. This area was the most frequently constrained area in the SPP market before the upgrade. However, since the phase-shifting transformer has been in service, the frequency of congestion at Woodward has fallen significantly such that the MMU recommended no longer designating Woodward as a frequently constrained area.[76] This upgrade has allowed higher

[76] Frequently constrained areas are discussed further in Section 5.1.6.

levels of low-cost wind generation in the western parts of the SPP footprint to serve load centers located on the eastern portion of SPP. This is evident with continuing wind peak records for 2017, the latest being 15,690 MW set on December 15.

5.1.2 CONGESTION BY GEOGRAPHIC LOCATION

The major drivers of the congestion pattern in SPP are the physical characteristics of the transmission grid and associated transfer capability, the geographic distribution of load, and the geographic differences in fuel costs. The eastern side of the SPP footprint, with a higher concentration of load, also has a higher concentration of high-voltage (345 kV) transmission lines. Historically, high-voltage connections between the west and east have been limited, as have high-voltage connections into the Texas Panhandle area.

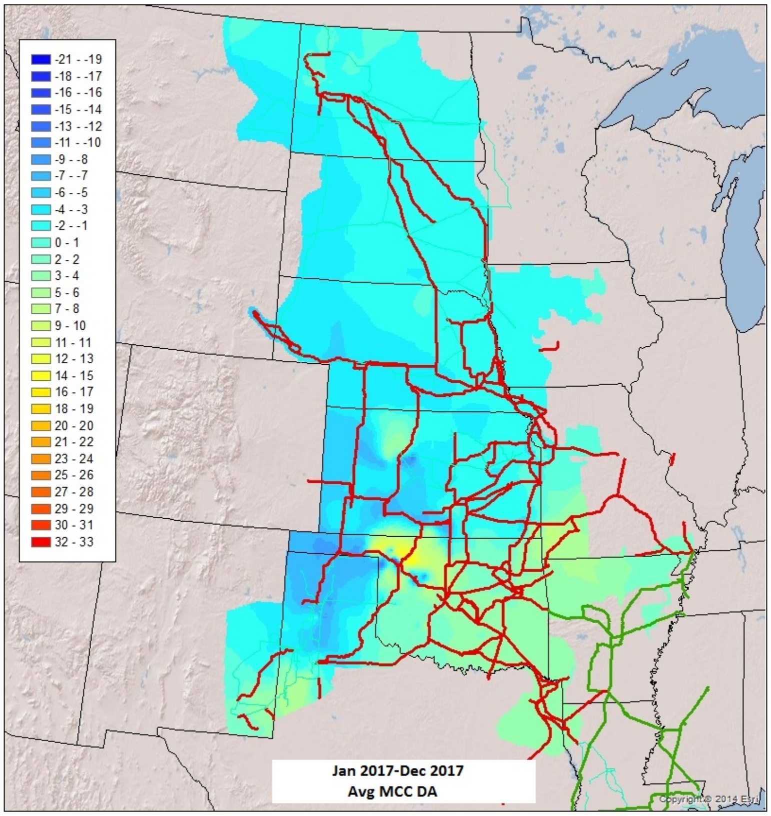
The cost of coal increases as transportation cost rises. Transportation cost increases with distance from the Wyoming Powder River Basin near the northwest corner of SPP's footprint. This is important because coal is SPP's predominant fuel for energy generation at 46% in 2017.

Natural gas-fired generation, SPP's largest fuel type by installed capacity (42 percent in 2017), resides predominantly in the southern portions of SPP. Wind-powered generation generally lies in the western half of the footprint, and nuclear generation resides near the center, while the majority of hydro is located in the north.

These factors combine to create a general northwest-southeast split in prices. The exception is slightly higher prices in the northern area of North Dakota resulting from the growth of, and associated demand from, oil and gas exploration and production facilities. Outside of the extreme northern part of North Dakota, the Integrated System typically sees lower prices compared to the rest of the footprint.

Figure 5—2 depicts the average marginal congestion component for the day-ahead market across the SPP footprint.

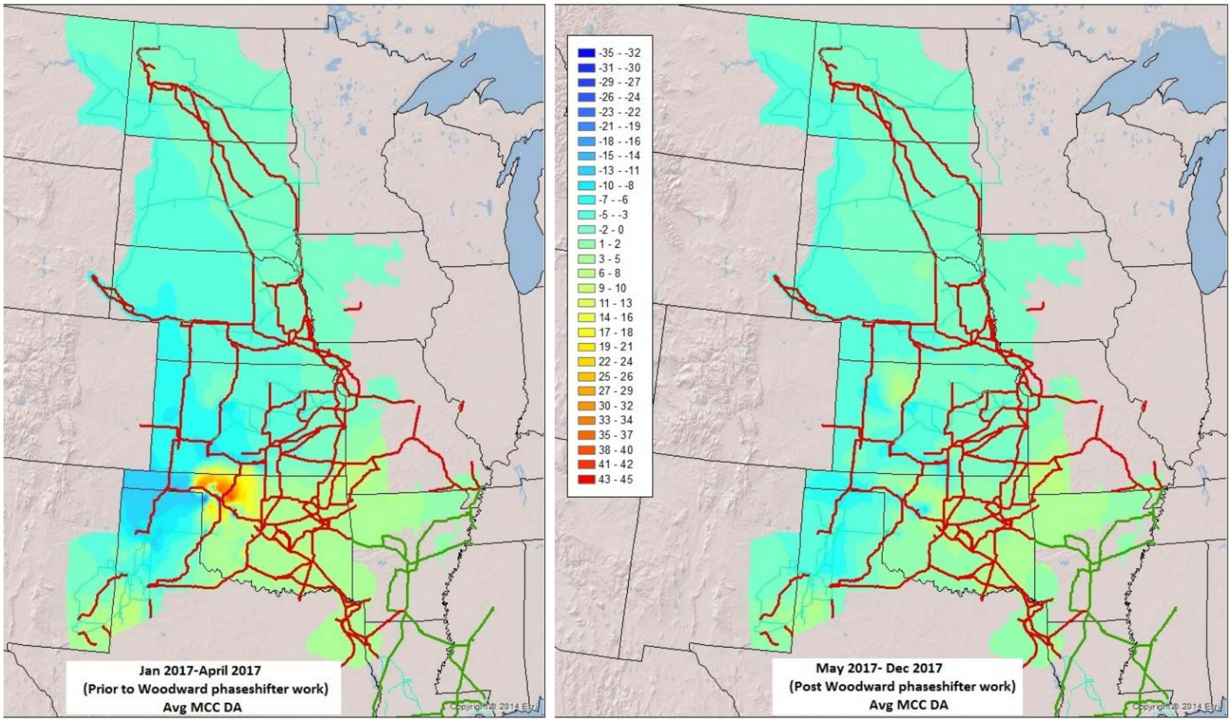
Figure 5–2 Marginal congestion cost map, day-ahead market



The lowest average marginal congestion costs occur in the Oklahoma and Texas Panhandle region, at -$7/MWh, and the highest marginal congestion costs lie in the Woodward, Oklahoma area at $16/MWh, and the New Mexico and west Texas areas at $9/MWh.

The congestion in the Woodward area was persistent in 2017 until the phase-shifting transformer upgrade went into place in May 2017. Figure 5–3 shows the average marginal congestion component for January through April prior to the upgrade, and May through December after the upgrade.

Figure 5–3 Marginal congestion cost map, day-ahead



With the addition of the phase-shifting transformer at Woodward, the congestion has shifted east, but is not as evident as the prior Woodward constraint. This upgrade was in place just before the summer which is typically the lower wind season in SPP, but new wind peaks occurred later in 2017. The Texas Panhandle congestion still remains but has moved further south towards the Lubbock, Texas area.

5.1.3 TRANSMISSION EXPANSION

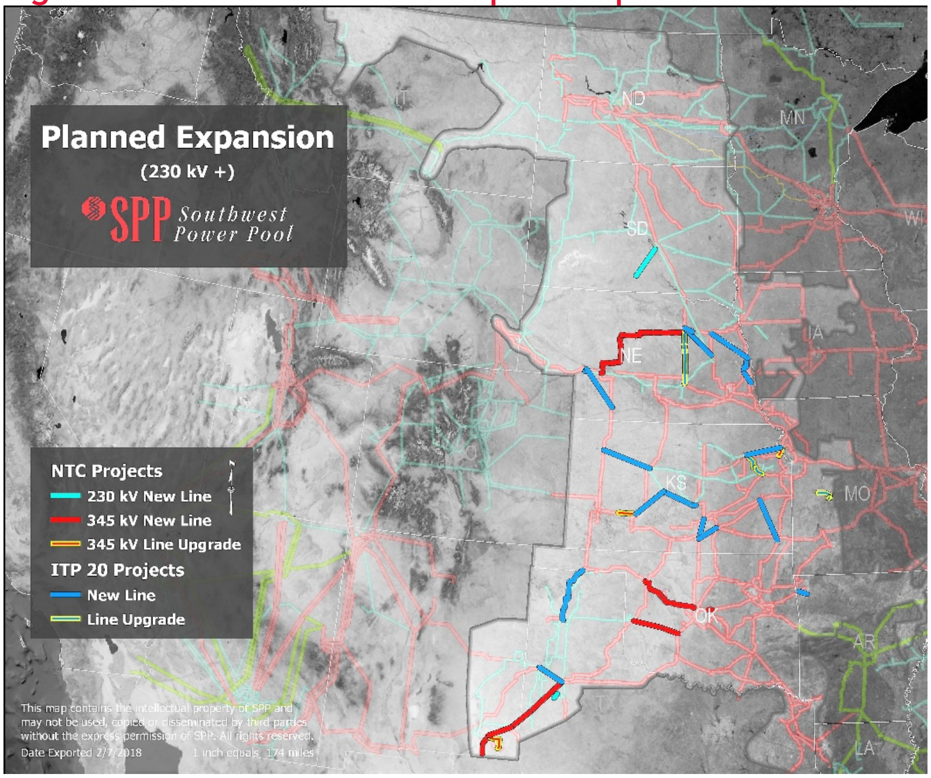
Several major transmission projects were completed during 2017 that will support the efficient transmission of energy across the SPP footprint.[77]

- East Manhattan – Jeffrey Energy Center 230 kV (circuit 1) rebuild
  - location: eastern Kansas
  - energized: April 2017
- Fort Smith transformer 500/161 kV (circuit 5)
  - location: Arkansas/Oklahoma border
  - energized: July 2017
- Mingo transformer 345/115 kV (circuit 2) and terminal upgrades
  - location: western Kansas
  - energized: January 2017
- Woodward extra high voltage phase-shifting transformer 138kV (circuit 1)
  - location: western Oklahoma
  - energized: May 2017

The lines depicted on the map in Figure 5–4 below are projects that will further enhance the SPP transmission grid. The Integrated Transmission Plan (ITP) projects shown are recommended upgrades to the extra-high-voltage backbone (345kV and above) for a 20-year horizon. The ITP process seeks to target a reasonable balance between long-term transmission investments and congestion costs to customers. The notification to construct (NTC) and ITP projects shown have received a written notice from SPP to construct a transmission project that was approved by the SPP board of directors. Planned projects that may provide relief for the most congested areas in SPP are listed in Figure 5–10.

[77] See the 2018 SPP Transmission Expansion Plan Report at https://www.spp.org/documents/56611/2018_spp_transmission_expansion_plan_report.pdf

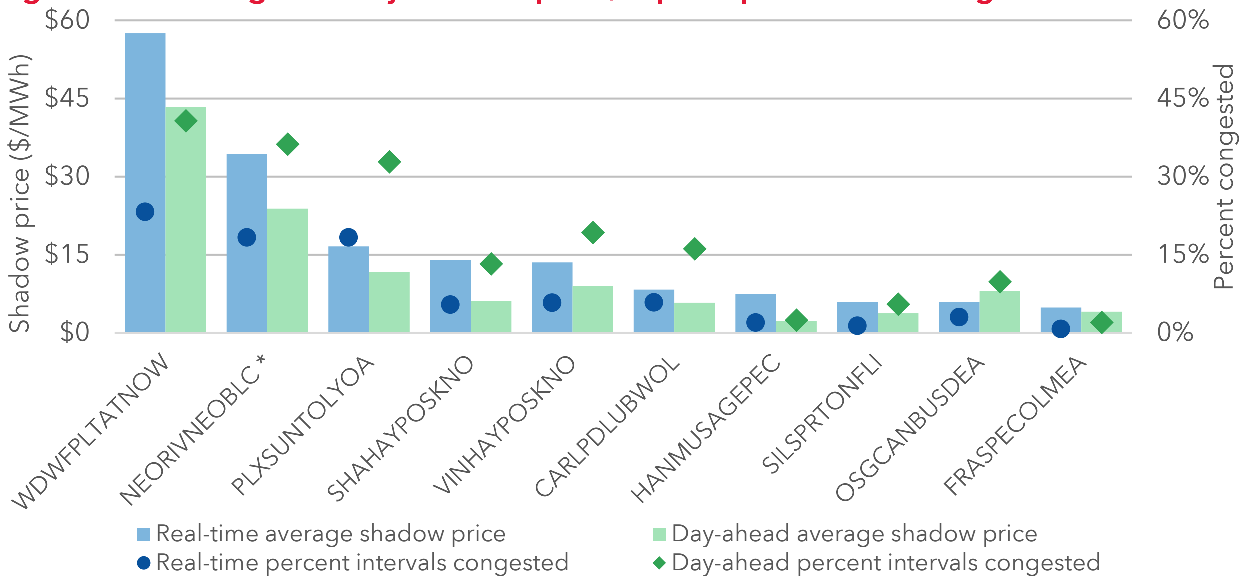
Figure 5–4 SPP transmission expansion plan



5.1.4 TRANSMISSION CONSTRAINTS

Market congestion reflects the economic dispatch cost of honoring transmission constraints. SPP uses these constraints to manage the flow of energy across the physical bottlenecks of the grid in the least costly manner while ensuring reliability. In doing so, SPP calculates a shadow price for each constraint, which indicates the potential reduction in the total market production costs if the constraint limit could be increased by one megawatt for one hour. Figure 5–5 provides the top 10 permanent flowgate constraints by shadow price for 2017. Temporary flowgate constraints are excluded from this graph as in previous annual and quarterly reports. Because of the increase of congestion seen on temporary flowgate constraints, the 2018 winter quarterly report will begin to include these constraints.

Figure 5–5 Congestion by shadow price, top ten permanent flowgates



Flowgate name	Region	Flowgate location
WDWFPLTATNOW	Western Oklahoma	Woodward-FPL Switch (138) ftlo Tatonga-Northwest (345)
NEORIVNEOBLC *	SW Missouri/SE Kansas	Neosho-Riverton (161) ftlo Neosho-Blackberry (345)
PLXSUNTOLYOA	West Texas (Lubbock)	Plant X Sub-Sundown (230) ftlo Tolk Sub-Yoakum (230)
SHAHAYPOSKNO	Western Kansas	South Hays-Hays (115) ftlo Post Rock-Knoll (230)
VINHAYPOSKNO	Western Kansas	Vine-Hays (115) ftlo Post Rock-Knoll (230)
CARLPDLUBWOL	West Texas (Lubbock)	Carlisle-Doud (115) ftlo Lubbock South-Wolfforth (230)
HANMUSAGEPEC	Eastern Oklahoma	Hanncock-Muskogee (161) ftlo Agency-Pecan Creek (161)
SILSPRTONFLI	NW Arkansas	Siloam-Siloam Springs (161) ftlo Tonnence-Flint Creek (345)
OSGCANBUSDEA	Texas Panhandle (Amarillo)	Osage Switch-Canyon East (115) ftlo Bushland-Deaf Smith (230)
FRASPECOLMEA	S Dakota/Nebraska border	Ft Randall-Spencer (115) ftlo Meadow Grove-Kelly (230)

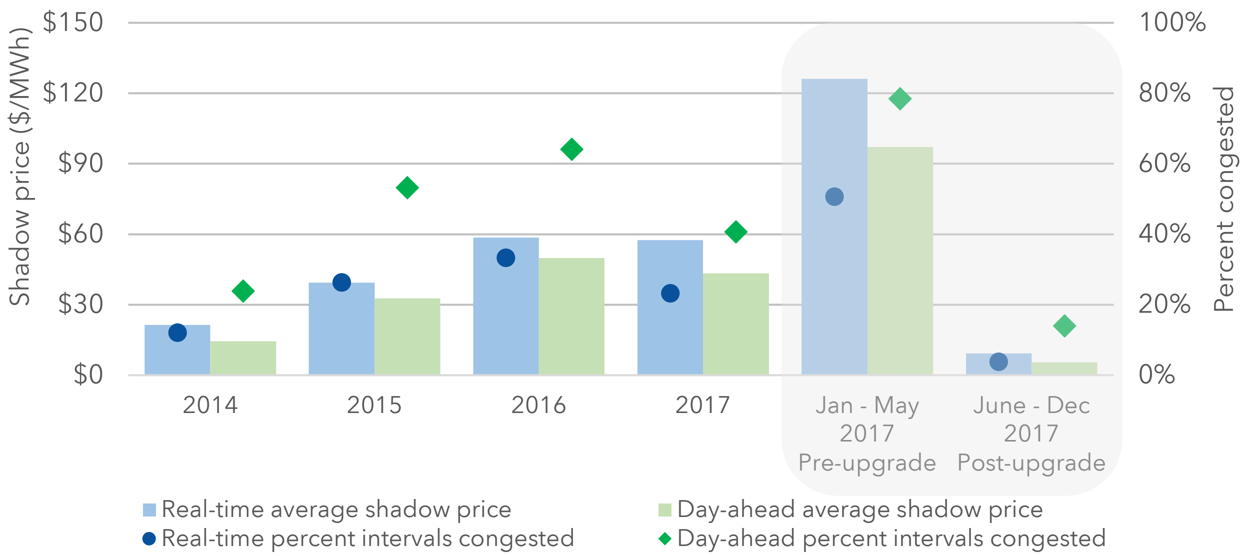
* SPP market-to-market flowgate

Most of the congested corridors on the system are significantly impacted by inexpensive wind generation. The three areas most affected by wind generation are the west-to-east flows through the Woodward, Oklahoma area, the north-to-south flows through west Texas, and the Texas Panhandle, and the flows through western Kansas. The second most congested area is the southwest Missouri/southeast Kansas area, and is also impacted by wind and external flows. Projects are planned throughout the SPP footprint that provide for more transfer of wind generation from west to east and are listed in Figure 5–10. Constraints in all other areas of the footprint are congested less than 10 percent of all intervals in both the day-ahead and real-time markets.

5.1.4.1 Western Oklahoma constraints

Significant upgrades have been made to move more energy from the wind generation corridor in the west to the load centers in the east. Extensive buildout of the extra-high-voltage system can result in complications on the lower voltage system, as seen in the Woodward area since 2014, driving the need for further upgrades. Even with the phase-shifting transformer upgrade at Woodward in May 2017, the Woodward constraint was still the most congested constraint in 2017 with 40 percent of all intervals congested in the day-ahead market and 23 percent of all intervals in real time. Figure 5–6 compares congestion on the Woodward constraint from 2014 through 2017, and also shows a breakdown of congestion before and after the phase-shifting transformer upgrade in May 2017.

Figure 5–6 Woodward congestion pre-/post-upgrade

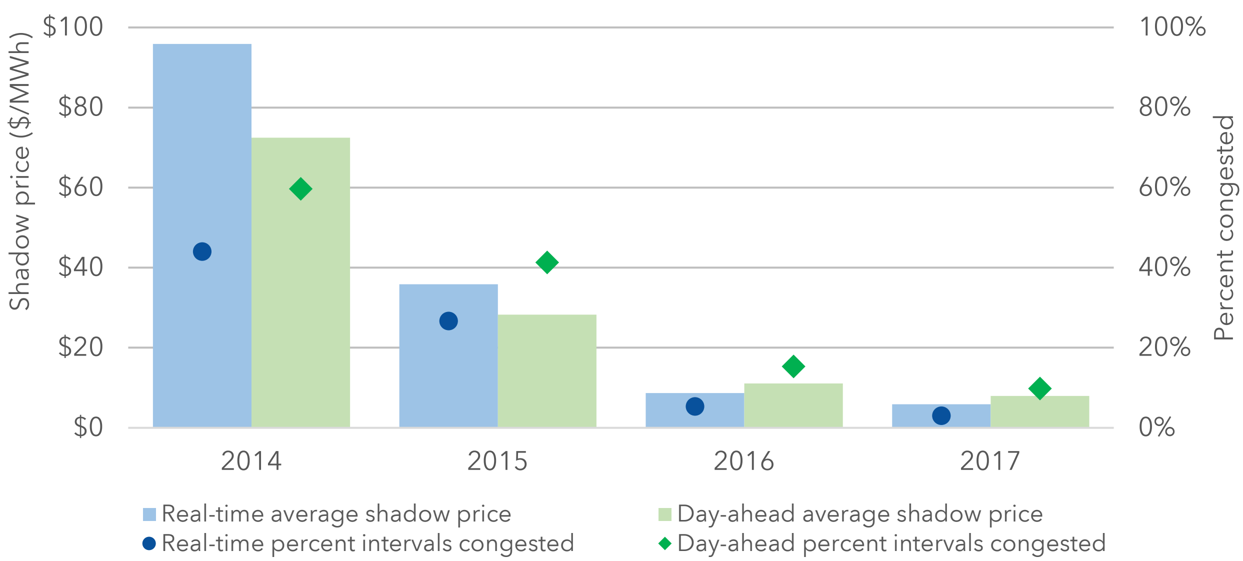


The yearly average shadow prices for both markets in 2017 remained similar to those in 2016, but as seen in Figure 5–6, most of the congestion in 2017 occurred prior to the upgrade in May. The Woodward constraint was congested during 79 percent of all day-ahead intervals prior to the upgrade and only 14 percent after. In the real-time market it was congested during 50 percent of all intervals prior to the upgrade and less than four percent after. New wind peaks occurred in late 2017 indicating higher transfers of wind generation after the upgrade.

5.1.4.2 West Texas and Texas Panhandle constraints

The west Texas and Texas Panhandle between Amarillo and Lubbock down into southeast New Mexico was the most congested transmission corridor at the start of the SPP market. This corridor is impacted by the predominantly natural gas-fired generation in the south that is more expensive than the wind generation to the north. This corridor still remains, but transmission upgrades have resulted in congestion now more prevalent further south in this area. The MMU reflected this change in the latest frequently constrained area report.[78] The Plant X Sub – Sundown 230kV flowgate had the highest real-time market average shadow price for this area at $16/MWh in 2017. The Osage Switch - Canyon East 115kV flowgate was predominantly the most congested constraint in SPP since the beginning of the market. Figure 5–7 compares congestion on the Osage Switch – Canyon East 115kV constraint since the start of the SPP market in 2014.

Figure 5–7 Osage Switch – Canyon East 115kV congestion



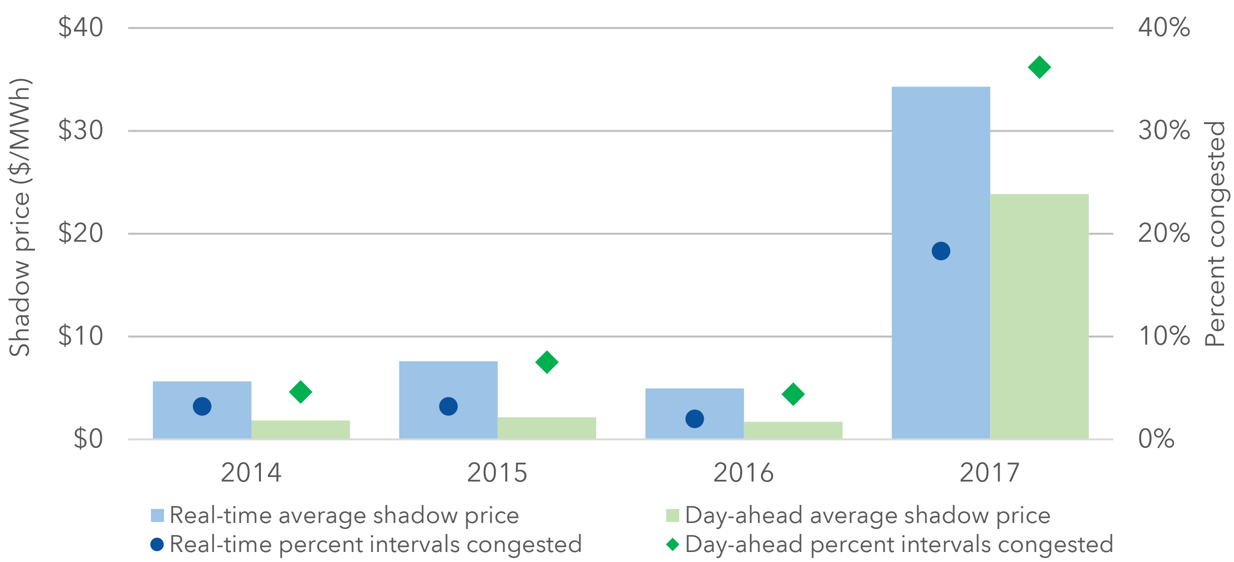
Both the magnitude and frequency of congestion on the Osage Switch – Canyon East 115kV constraint has decreased in both markets because of transmission upgrades. Congestion has moved further south where more prevalent congestion exists on the Plant X Sub - Sundown 230kV flowgate as shown in Figure 5–5.

[78] https://www.spp.org/Documents/56330/FCA%202017%20Report%20-%20FINAL.pdf

5.1.4.3 Southwest Missouri/Southeast Kansas constraints

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.[79] 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. Figure 5–8 compares congestion on the Neosho – Riverton 161kV constraint since 2014.

Figure 5–8 Neosho – Riverton 161kV congestion



Congestion increased substantially on this constraint in 2017 when compared to previous years. Since the upgrade to the Woodward area, this area has been one of the top congested constraints during high wind months. This constraint has been a focus of seams discussions on the amount of market-to-market payments, power swings or volatility, and transmission upgrades that may benefit SPP, MISO, and other neighboring non-market entities. The market-to-market process has settled over $18 million in payments for the Neosho-Riverton constraint from MISO to SPP, and is discussed in Section 2.6.2.

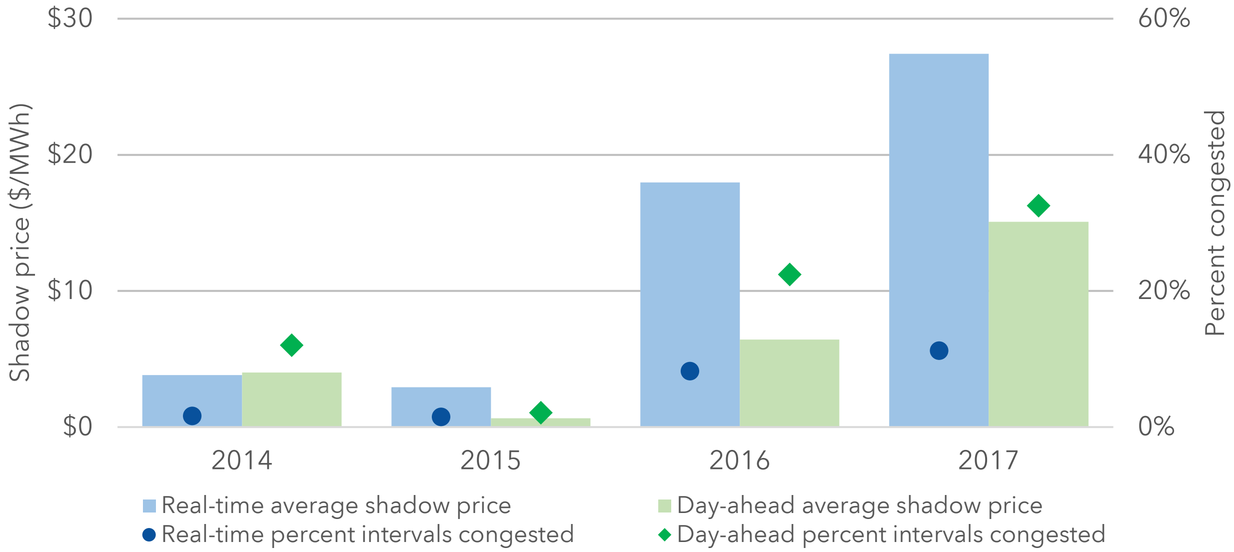
5.1.4.4 Western Kansas constraints

The Hays, Kansas area is also impacted by wind generation and several constraints have appeared consistently since prior to the start of the SPP market. The South Hays – Hays 115kV constraint was terminated in May 2017 and later was replaced with the Vine – Hays

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

115kV constraint. Figure 5–9 compares congestion on the South Hays – Hays 115kV constraint since start of the SPP market. The values for South Hays – Hays 115kV and Vine – Hays 115kV are combined in the 2017 results.

Figure 5–9 Hays, Kansas congestion[80]



For 2017, the Hays, Kansas area continues to see an increase in congestion. These two constraints experienced congestion in over 32 percent of all intervals in the day-ahead market and 11 percent of all intervals in the real-time market. The yearly average shadow price for the real-time market was $27/MWh for 2017 compared to $18/MWh in 2016.

5.1.5 PLANNED TRANSMISSION PROJECTS

Figure 5–10 provides a list of projects that may alleviate congestion on the 10 most congested flowgates in the SPP system.

[80] Values combined for SHAHAYPOSKNO (South Hays – Hays 115kV) and VINHAYPOSKNO (Vine – Hays 115kV) constraints for 2017. South Hays – Hays 115kV terminated May 2017, and Vine – Hays 115kV activated September 2017.

Figure 5–10 Top ten congested flowgates with projects

Flowgate name	Region	Flowgate location	Projects that may provide relief
WDWFPLTATNOW	Western Oklahoma	Woodward-FPL Switch (138) ftlo Tatonga-Northwest (345)	1. Matthewson-Tatonga 345 kV Ckt 2 (February 2018, 2012 ITP10) 2. Tatonga-Woodward 345kV Ckt 2 (February 2018, 2012 ITP10) 3. Degrasse 345/115 kV tap on Woodward-Thistle 345 kV (June 2019, 2016 ITPNT)
NEORIVNEOBLC *	SW Missouri/SE Kansas	Neosho-Riverton (161) ftlo Neosho-Blackberry (345)	Neosho – Riverton 161kV Terminal Upgrades (June 2018, 2017 ITP10)
PLXSUNTOLYOA	West Texas (Lubbock)	Plant X Sub-Sundown (230) ftlo Tolk Sub-Yoakum (230)	1. Matthewson-Tatonga 345 kV Ckt 2 (February 2018, 2012 ITP10) 2. Tatonga-Woodward 345kV Ckt 2 (February 2018, 2012 ITP10) 3. Degrasse 345/115 kV tap on Woodward-Thistle 345 kV (June 2019, 2016 ITPNT)
SHAHAYPOSKNO	Western Kansas	South Hays-Hays (115) ftlo Post Rock-Knoll (230)	Post Rock–Knoll 230kV Ckt 2 (Jan 2019, 2017 ITP10)
VINHAYPOSKNO	Western Kansas	Vine-Hays (115) ftlo Post Rock-Knoll (230)	Post Rock–Knoll 230kV Ckt 2 (Jan 2019, 2017 ITP10)
CARLPDLUBWOL	West Texas (Lubbock)	Carlisle-Doud (115) ftlo Lubbock South-Wolfforth (230)	1. Carlisle-Wolfforth 230 kV Ckt 1 (March 2018, 2013 ITPNT) 2. Yoakum-Hobbs 230/115 kV Tap (December 2019, 2016 ITPNT / 2017 ITP10) 3. Tuco-Yoakum 345 kV Ckt 1 (December 2019, 2014 High Priority / 2016 ITPNT / 2016 AG1)
HANMUSAGEPEC	Oklahoma city area	Hanncock-Muskogee (161) ftlo Agency-Pecan Creek (161)	No projects identified at the time of report publication.
SILSPRTONFLI	NW Arkansas	Siloam-Siloam Springs (161) ftlo Tonnence-Flint Creek (345)	No projects identified at the time of report publication.
OSGCANBUSDEA	Texas Panhandle (Amarillo)	Osage Switch-Canyon East (115) ftlo Bushland-Deaf Smith (230)	1. Carlisle-Wolfforth 230 kV Ckt 1 (March 2018, 2013 ITPNT) 2. Tuco-Yoakum 345 kV Ckt 1 (December 2019, 2014 High Priority / 2016 ITPNT / 2016 AG1) 3. Yoakum-Hobbs 345 kV Ckt 1 (June 2020, 2014 High Priority)
FRASPECOLMEA	Eastern SD / Nebr border	Ft Randall-Spencer (115) ftlo Meadow Grove-Kelly (230)	No projects identified at the time of report publication.

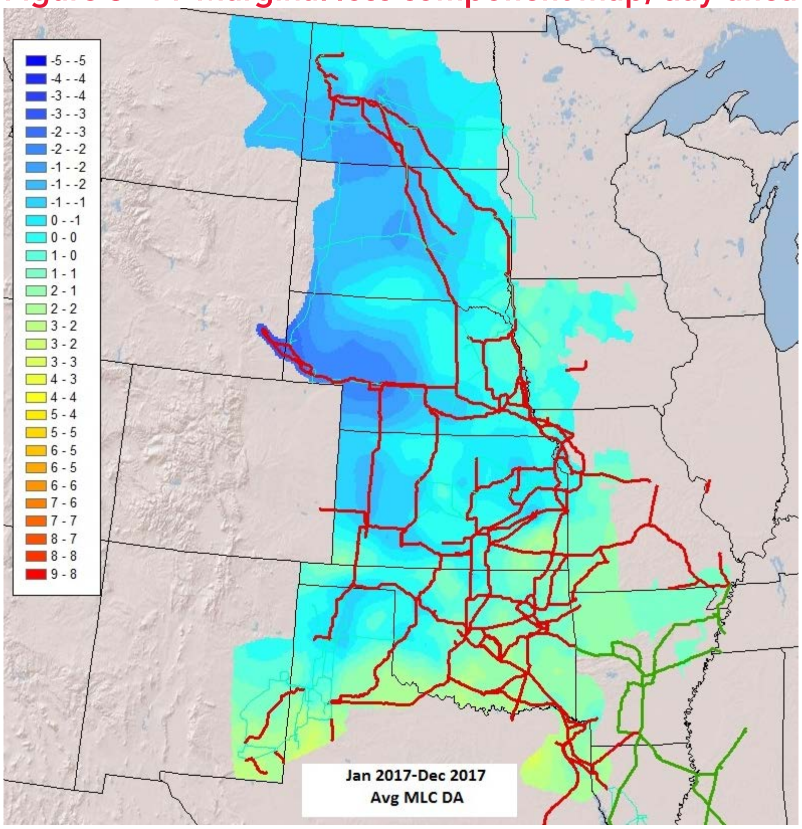
* SPP market-to-market flowgate

5.1.6 GEOGRAPHY AND MARGINAL LOSSES

Variable transmission line losses decrease with increased line voltage or decreased line length for the same amount of power moved. In the SPP footprint, much of the low-cost generation resides at a distance from the load and with limited high-voltage interconnection. The average variable losses on the SPP system for 2017 were 2.7 percent in the day-ahead market. This is up from 2.3 percent in 2016. The marginal loss component of the price captures the change in the total system cost of losses with an additional increment of load at a particular location relative to the reference bus.

Figure 5–11 maps the annual average day-ahead market marginal loss components.

Figure 5–11 Marginal loss component map, day-ahead



The average day-ahead marginal loss component ranges from about -\$3.55/MWh at the Laramie River Station in eastern Wyoming, to -\$2.80/MWh near North Platte, Nebraska, to -\$0.30/MWh in the Kansas City area, to \$0.60/MWh in the Hobbs, New Mexico area, and up to \$1.70/MWh in the southeast corner of New Mexico. Negative values reduce prices through the marginal loss component relative to the marginal energy cost. Positive values increase prices as generation from these locations are more beneficial from a marginal loss perspective. These values were very similar compared to the results in 2016.

5.1.7 FREQUENTLY CONSTRAINED AREAS AND LOCAL MARKET POWER

Congestion in the market creates local areas where only a limited number of suppliers can provide the energy to serve local load without overloading a constrained transmission element. Under these circumstances, the pivotal suppliers have local market power and the ability to raise prices above competitive levels thereby extracting higher than normal profits from the market. SPP's tariff provides provisions for mitigating the impact of local market power on prices, and the effectiveness of market power mitigation is described in Chapter 6. Local market power can be either transitory, as is frequently the case with an outage, or persistent, when a particular load pocket is frequently import-constrained.

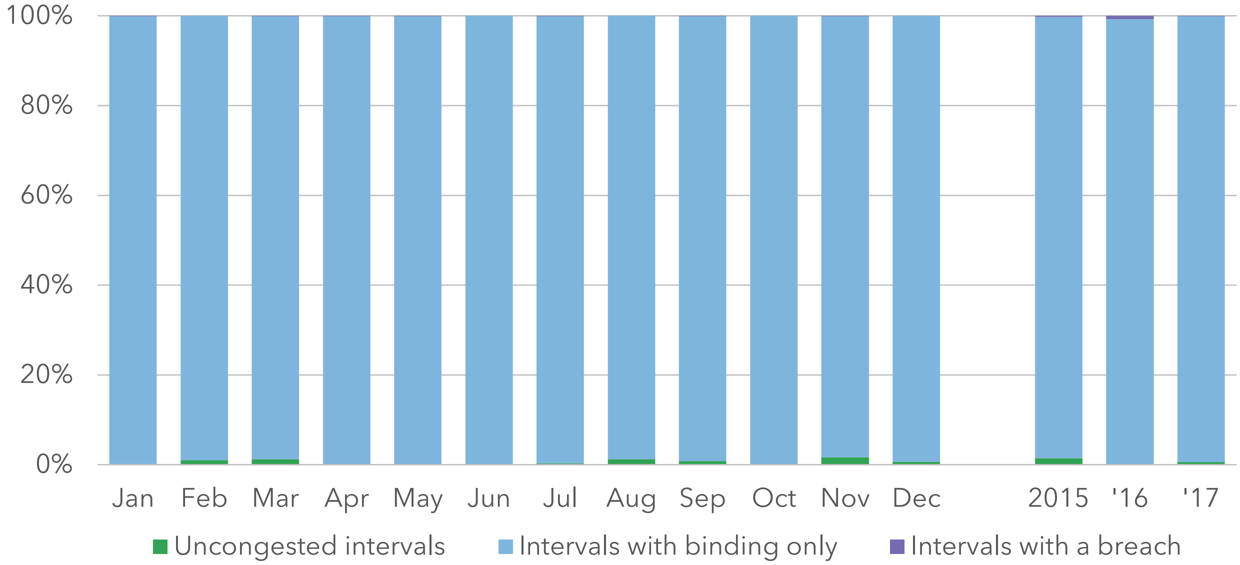
Because the SPP tariff calls for more stringent market power mitigation for frequently constrained areas, the MMU analyzes market data at least annually to assess the appropriateness of the frequently constrained area designations. The Woodward and Texas Panhandle areas remained frequently constrained areas, as recommended in the 2016 study, for 2017. The latest 2017 study identified the decrease in congestion in the Woodward area related to the phase-shifting transformer upgrade in May. Shifting congestion patterns led to the recommendation to eliminate the Woodward frequently constrained area and to reduce the size of the Texas Panhandle frequently constrained area. SPP filed a report with FERC in early 2018, and FERC approved the changes effective April 1, 2018. The final reports are available on the SPP web page.[81]

5.1.8 MARKET CONGESTION MANAGEMENT

In optimizing the flow of energy to serve the load at the least cost, the SPP market makes extensive use of the available transmission up to constraint limits. When constraints reach their limits, they are considered binding. The market occasionally allows transmission lines to exceed their rating if the price to correct the overload becomes too high. This is considered a breached constraint. Figure 5–12 highlights day-ahead market binding, breached, and uncongested intervals.

[81] The reports can be found on the SPP website: https://www.spp.org/spp-documents-filings/?id=25496.

Figure 5–12 Breached and binding intervals, day-ahead market

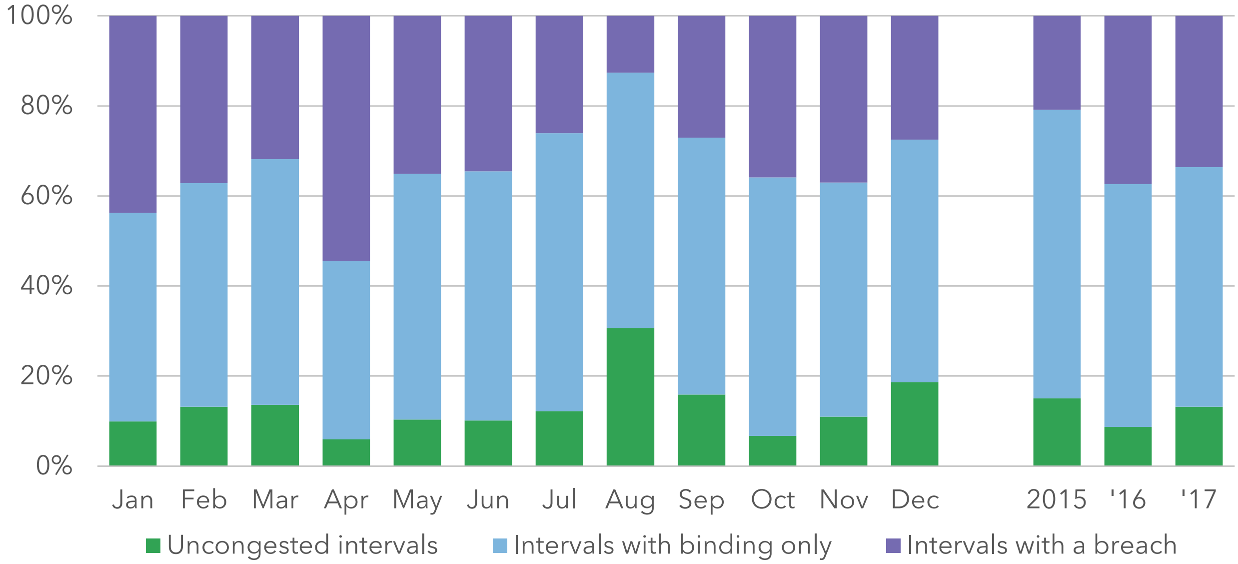


The figure shows that uncongested intervals and breached intervals are rare day-ahead. Historically in the Integrated Marketplace, less than one percent of day-ahead market intervals incur a breached condition compared to nearly 25 percent for the real-time market.[82]

In the more dynamic environment of the real-time market, uncongested intervals and breached intervals occur much more frequently than in the day-ahead market. Real-time congestion is shown in Figure 5–13.

82 SPP uses hourly intervals in the day-ahead Market and five minute intervals in the real-time market for scheduling, dispatch, and settlement purposes.

Figure 5–13 Breached and binding intervals, real time



Uncongested intervals were about 13 percent of intervals for 2017, compared to nine percent in 2016, and 15 percent in 2015. Intervals with a constraint breach were at 34 percent for 2017, down slightly from 37 percent in 2016, and higher than the 21 percent in 2015.

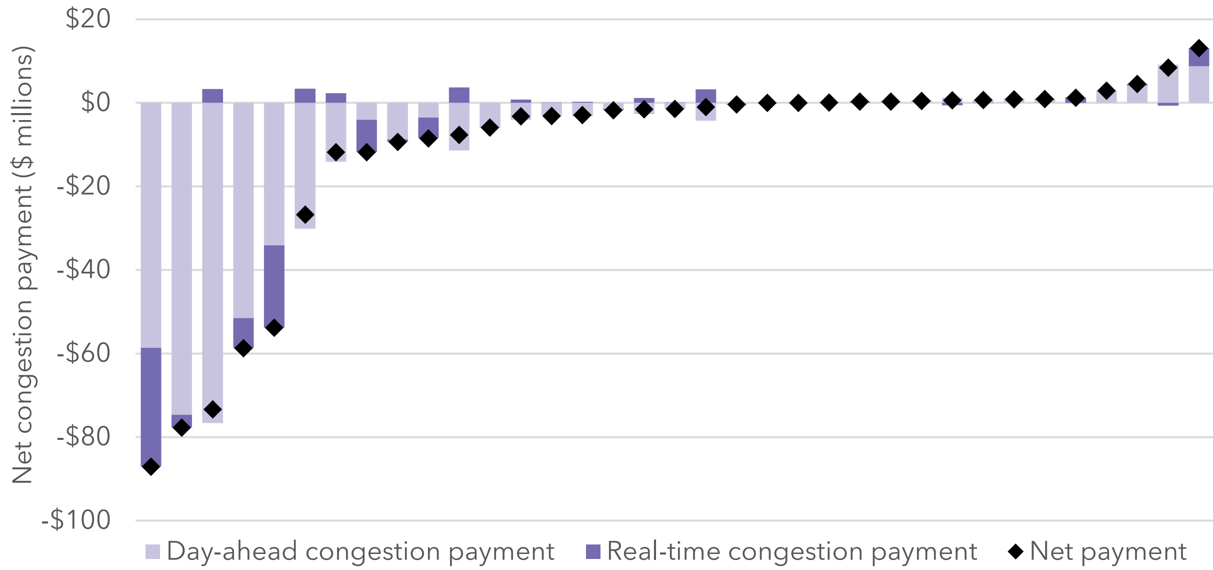
Market-to-market coordination with MISO, as discussed in Section 2.6.2, was implemented in March 2015, and the integration of the Integrated System occurred in October of that year, both of which increased the number of constraint breaches. A market-to-market breach of a MISO constraint could be an indicator that MISO has more efficient generation than SPP to alleviate congestion on that constraint.

5.1.9 CONGESTION PAYMENTS AND UPLIFTS

Market participants in the energy market incur congestion costs and receive congestion payments based on their marginal impact on total market congestion cost through the marginal congestion component of price. Most SPP market participants owning physical assets are vertically integrated, so their net congestion cost depends on two things. The first is whether they are a net buyer or seller of energy. The second is the relative marginal cost component at their generation and load. For financial market participants, congestion costs reflect the impact of virtual positions on a binding or breached constraint in the day-ahead and real-time markets.

Figure 5–14 shows the annual day-ahead and real-time market congestion payments for load-serving market participants during 2017.

Figure 5–14 Annual congestion payment by load-serving entity



Most load-serving entities face congestion costs, depicted as negative payments (charges) in the graph, because they are part of vertically-integrated entities with higher marginal congestion components at load than at resources. Day-ahead congestion payments by ranked load-serving entities ranged from almost $9 million in payments to about $76 million in charges.[83]

Market participants also receive payments and incur costs for real-time market congestion, which are charged and paid based on deviations between day-ahead and real-time market positions. At an aggregate level, absent the additional revenue neutrality uplift costs, 88 percent of the SPP load-serving entities' net congestion costs were hedged with day-ahead prices. Figure 5–15 provides the aggregate congestion costs and hedging totals for load-serving entities, non-load-serving entities, and financial only entities.

[83] Day-ahead congestion collections funds transmission congestion rights. These rights are described in greater detail in Section 5.2.

Figure 5–15 Total congestion payments

(in $ millions)	Load-serving entities			Non-load-serving and financial only entities		
	2015	2016	2017	2015	2016	2017
DA congestion	$ (148.6)	$ (259.6)	$ (364.6)	$ (31.5)	$ (81.2)	$ (219.0)
RT congestion	(3.4)	(20.4)	(48.3)	40.1	63.7	126.1
Net congestion	(152.0)	(280.0)	(412.9)	8.6	(17.5)	(92.9)
RT congestion uplift	(20.8)	(39.4)	(67.8)	(5.4)	(4.0)	(10.0)

Real-time market congestion ranged from over $4 million in payments to over $28 million in costs for load-serving entities. These ranges were from $2 million in payments to $38 million in costs for asset owning non-load-serving entities. Many of the non-load-serving entities incurring costs represent wind farms, which may sell at negative prices or buy back day-ahead market positions. The real-time market congestion payments result in a net positive $70 million for non-load-serving entities. Total real-time market congestion payments for non-load-serving and financial only entities totaled $126 million.

Unlike day-ahead congestion, which funds transmission congestion rights, real-time market congestion costs are allocated to market participants through revenue neutrality uplift (RNU) charges. In 2017, SPP allocated about 87 percent of revenue neutrality uplift charges to load-serving entities, resulting in an additional $68 million in congestion-related charges for load-serving entities.[84]

5.1.10 DISTRIBUTION OF MARGINAL LOSS REVENUES (OVER-COLLECTED LOSSES)

Both the congestion and loss components of prices create excess revenues for SPP that must be distributed to market participants in an economically efficient manner. In the case of marginal loss revenues, this requires that the distribution does not alter market incentives. This was not the case during the first year of SPP's market, and SPP took steps that largely corrected the incentive issues. SPP proposed changes to the method for distributing over-

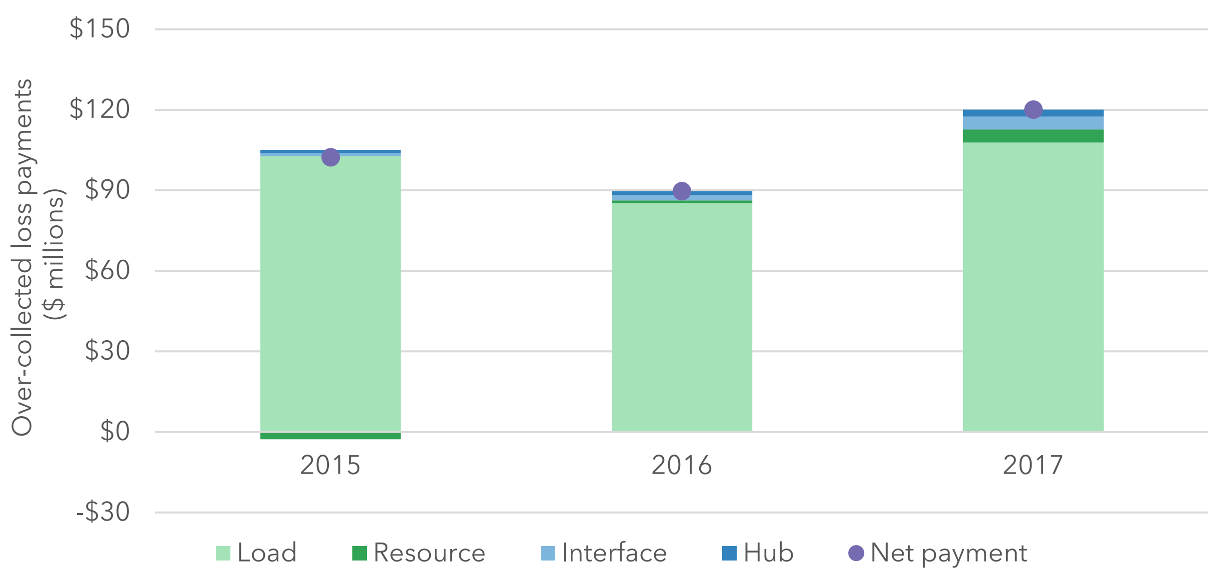
[84] Real-time congestion for load-serving entities and other entities totaled $77.8 million, which is equal to the total real-time congestion uplift. However, real-time congestion uplift is not allocated in the same proportion in which it is collected.

collected losses in FERC Docket No. ER15-763.[85] The Commission accepted these changes, which went into effect in April 2015.

The enhanced design consolidates the distributions of day-ahead and over-collected loss rebates into one distribution. Under this design, both day-ahead and real-time over-collected loss rebates are distributed on just real-time withdrawing megawatts. This includes loads, substation power, exports, wheel-throughs, pseudo-ties, and bilateral settlement schedules (BSS). The only exception is that both day-ahead and real-time bilateral settlement schedules are entitled to the rebate. In addition to consolidating the distributions to only real-time withdrawing megawatts, changes were made to loss pool allocations. Under the old method, virtual transactions drove up the SPP loss pool allocation of over-collected losses rebates, even though virtual activity was not eligible for rebates. This caused real-time exporters to get a large percentage of the over-collected losses rebates which, during that time, were typically a charge. Virtual transactions are no longer considered in the loss pool distributions. These design enhancements better allocate the over-collected losses to the transactions that contributed to the over-collection while removing some of the adverse incentives present under the former design.

Over-collected losses for the past three years are shown in Figure 5–16.

Figure 5–16 Over-collected losses, real time



[85] https://www.ferc.gov/CalendarFiles/20150331172533-ER15-763-000.pdf

A total of $120 million was paid out in over-collected losses rebates during 2017, with $108 million (90 percent) going to load. This is up from $90 million in over-collected losses rebates paid out in 2016 and $103 million paid in 2015.

The use of bilateral settlement schedules changes the distribution of over-collected losses. The bilateral settlement schedules enable market participants to transfer energy from one entity to another at a particular settlement location. It creates a financial withdrawal at the settlement location for the seller and a financial injection at the settlement location for the buyer. As long as the bilateral settlement schedules do not change the net withdrawal at the location, the charges and credits for losses simply change hands between the entities owning the bilateral settlement schedules. Where the bilateral settlement schedules create a net withdrawal that would not otherwise exist, it creates credits and charges that would not otherwise exist. For example, if a bilateral settlement schedule amount at a resource settlement location exceeds the cleared output of the resource, it creates a net withdrawal, and the generation owner receives a loss distribution credit for the excess megawatts of the bilateral settlement schedule. The same occurs with a bilateral settlement schedule at hubs, where no energy is withdrawn, other than a bilateral settlement schedule. The majority of the $4.9 million in distributions at resource settlement locations during 2017 occurred for this reason, as well as $2.6 million at hubs. These distributions cause concern for the MMU, because they create an incentive to game the market rules using bilateral settlement schedules. Exploitation of this aspect of the loss distribution calculation can potentially be market manipulation.

Over-collected losses no longer create charges in the real-time market. Total loss revenues are calculated from both the day-ahead market and the real-time market. SPP distributes them based on real-time market withdrawals only. Virtual transactions no longer factor into the loss pool calculation, reducing the exaggeration of distributions at interfaces and hubs. However, incentives for transacting bilateral settlement schedules in hours with high percentages paid to the SPP loss pool still exist. Additionally, as stated above, bilateral settlement schedules do not contribute to the over-collection of losses, but they are entitled to rebates. Any scenario where a bilateral settlement schedule creates a net withdrawal that would not have existed had the bilateral settlement schedule not been placed creates an opportunity for an over-collected losses rebate. When this happens, the over-collected losses rebate is diluting other rebates that contributed to the over-collection of losses.

A recommendation in the 2014 Annual State of the Market report was to remove bilateral settlement schedule transactions from the over-collected losses distribution calculation. The SPP Market Working Group approved revision request 200[86] in January 2017. This should alleviate the adverse incentives given to bilateral settlement schedules to transact in amounts that vary from the underlying flows of the transaction. The changes are still pending FERC approval, but are expected to be in effect before the end of 2018, if approved.[87]

5.2 TRANSMISSION CONGESTION RIGHTS MARKET

In the Integrated Marketplace, the market generally charges load a higher price than it pays generation. Transmission services are 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. Auction revenue right holders receive payments from the auction revenue that offset the cost of transmission congestion right purchases, and conversions of auction revenue rights into transmission congestion rights.[88]

The purpose of the transmission congestion right market is to provide a market mechanism for SPP load-serving entities to hedge the cost of congestion in the market. It can also be used as a mechanism for speculation and hedging by load-serving entities, generators, and financial entities. The performance of the transmission congestion right market is expressed by the degree to which transmission congestion rights and auction revenue rights provide a congestion hedge to load customers. The degree to which day-ahead market congestion revenues sufficiently fund the transmission congestion rights serves as a measure of load hedging, market efficiency, and transparency.

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[86] RR 200 (Design change for bilateral settlement schedule and over-collected losses distribution)
[87] ER18-792-000
https://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=14815024
[88] Further details about the payment structure of the transmission congestion rights market can be found in the 2016 Annual State of the Market Report, pp. 125-126.

5.2.1 MARKET TRANSPARENCY AND EFFICIENCY

5.2.1.1 Hedging the day-ahead market

The transmission congestion right and auction revenue right net payments paid to entities in the SPP market are shown in Figure 5–17.

Figure 5–17 Total congestion payments [89]

(in $ millions)	Load-serving entities			Non-load-serving and financial only entities		
	2015	2016	2017	2015	2016	2017
DA congestion	$ (148.6)	$ (259.6)	$ (364.6)	$ (31.5)	$ (81.2)	$ (219.0)
RT congestion	(3.4)	(20.4)	(48.3)	40.1	63.7	126.1
Net congestion	(152.0)	(280.0)	(412.9)	8.6	(17.5)	(92.9)
TCR charges	(148.2)	(51.0)	(122.5)	(76.4)	(63.5)	(138.0)
TCR payments	126.7	212.4	308.8	83.3	158.7	314.3
TCR uplift	(18.3)	(21.0)	(24.3)	(15.2)	(18.0)	(31.8)
TCR surplus *	2.2	4.2	4.5	1.4	4.1	5.9
ARR payments	175.6	74.8	147.2	(15.8)	6.5	11.7
ARR surplus	30.6	24.0	94.2	3.4	3.1	7.0
Net TCR/ARR	168.5	243.3	407.9	19.2	90.8	169.1

* remaining at year end

Payments to load-serving entities of $408 million was greater than their day-ahead congestion costs of $365 million for 2017. However, the total of day-ahead and real-time congestion costs were slightly higher at $413 million. This shows that overall, load-serving entities did a good job at hedging congestion through the transmission congestion right market. In aggregate for 2017, non-load-serving and financial only entities collected transmission congestion right and auction revenue right net revenues of $169 million, which exceeded their day-ahead and real-time market congestions costs of $93 million. As mentioned in previous sections and shown in the chart, day-ahead congestion costs have had major increases with a 75 percent increase between 2015 and 2016, and another 40 percent increase in 2017.

[89] Transmission congestion right charges and auction revenue right payments are less in 2016 and 2017 because of the long-term transmission congestion right design. Long-term transmission congestion rights get converted directly to transmission congestion rights, and therefore, are not accessed auction revenue right payments or transmission congestion right charges.

5.2.1.2 Bidding behaviors

A key topic that was discussed in the stakeholder process in 2017 was related to being able to get auction revenue rights to adequately hedge positions. As noted above, in aggregate, load-serving entities received more revenue from their auction revenue rights and transmission congestion rights then they had to pay in day-ahead congestion costs. However, on the individual participant level, some load-serving entities were under-hedged while others were over-hedged. Figure 5–18 shows, by load-serving entity, the day-ahead congestion exposure along with the value of auction revenue right and transmission congestion hedges as well as the net overall position.

Figure 5–18 Net congestion revenue by market participant

The figure highlights that the majority of participants received positive net revenues, while a handful of participants had hedges that significantly did not cover their day-ahead congestion costs. For instance, the bottom three participants paid over $30 million more in congestion costs than was hedged by their auction revenue right and transmission congestion right positions.

Some market participants expressed concern that there were market design issues that were keeping them from getting the appropriate auction revenue rights, which would ultimately be converted into transmission congestion rights to provide a hedge. The main issue discussed was the use of counter-flow in the allocation. In the auction revenue right allocation, counter-flow paths are usually seen as charges and market participants are not required to nominate them. Market participants may make the financial decision to not nominate these counter-flow paths; however, that decision has risks associated with it. If the day-ahead congestion patterns change to where the path is no longer a counter-flow, then the market participant is completely exposed to any congestion. This scenario was observed in 2017. There were many paths that were considered counter-flow paths in 2016 and were not nominated in 2017 by some participants. However, many of these counter-flow paths became prevailing flow, which left the paths unhedged.

Some market participants lost out on valuable hedging mechanisms by choosing not to nominate certain candidate auction revenue rights, which included both prevailing flow and counter-flow paths. Each market participant gets to choose the level of risk it is willing to take by how it nominates its candidate auction revenue rights. Nominating to match the day-ahead position, whether the path is counter-flow or prevailing flow, can lead to lower risk. However, this could also potentially lower the hedge value revenue. At this point, the MMU believes that part of the issue with the lack of allocated auction revenue rights appears to be related to bidding strategy.

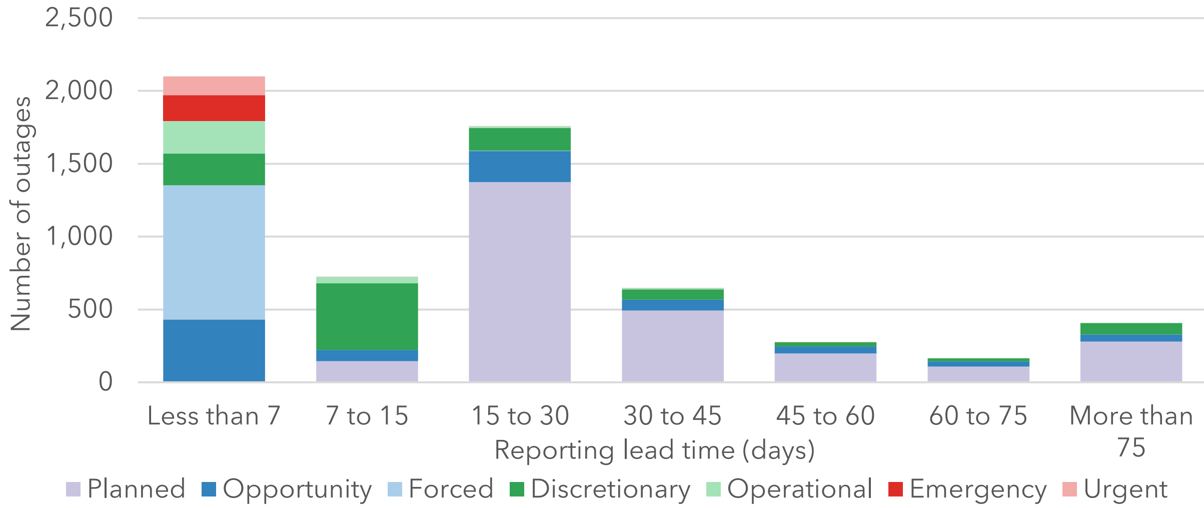
Transmission service reservations are studied and granted with assumptions that include counter-flow megawatts. This means that without the use of counter-flow, many of the prevailing flow paths are not feasible. Nominating the appropriate counter-flow paths in the allocation will help to increase the amount of prevailing flow paths allocated. This ultimately means the less counter-flow nominated will result in less prevailing flow allocated, which could further limit the available transmission congestion hedges.

The difference in prevailing flow and counter-flow can be the result of transmission upgrades, but could also be the result of unmodeled outages. This disconnect between outages modeled in the day-ahead market and the transmission congestion right process is outlined below.

5.2.1.3 Transmission outage modeling

When outages appear in the day-ahead market that were not in the transmission congestion rights market, they reduce system capacity and likely cause underfunding. Figure 5–19 shows transmission outages by the reported lead time.

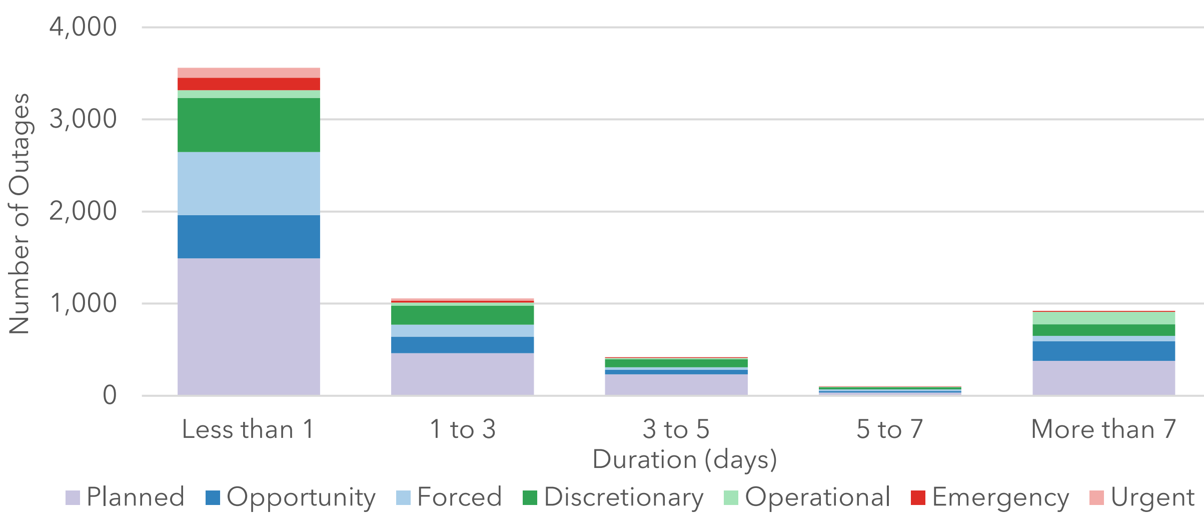
Figure 5–19 Transmission outages by reporting lead time



SPP models only transmission outages that were reported at least 45 days prior to the first of the month in the transmission congestion rights auction.[90] However, SPP only requires transmission owners to submit planned outages 14 days in advance.[91] The above figure shows that the majority of outages are not considered in the transmission congestion rights markets solely due to the submission lead time. Roughly 86 percent of outages are ruled out of the transmission congestion right model by this phase alone.

Figure 5–20 shows the duration in days for the different types of outages.

Figure 5–20 Transmission outages by duration

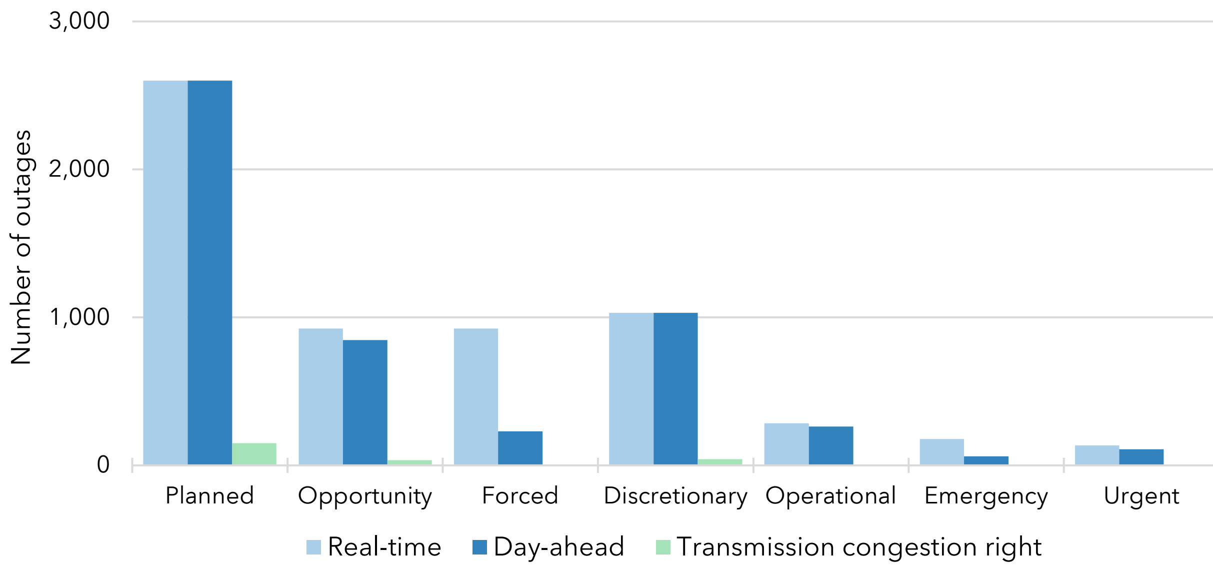


[90] SPP Integrated Marketplace Protocols, Section 6.6
[91] SPP Operating Criteria Appendix OP-2

Outages shorter than five days are excluded from auction revenue right/transmission congestion right processes. This means the vast majority of outages (83 percent) are excluded from the transmission congestion rights models because they are less than five days.

Figure 5–21 shows outages by real-time, day-ahead, and transmission congestion right markets.

Figure 5–21 Transmission outages by market



While the number of outages in the day-ahead and real time are similar, the outages represented in the transmission congestion rights market are only a fraction of the total number of outages. The transmission congestion market only includes outages that are longer than five days, and are submitted at least 45 days in advance of the first of the month. This represented only four percent of total outages in the day-ahead market. These differences in outages can create underfunding of transmission congestion rights.

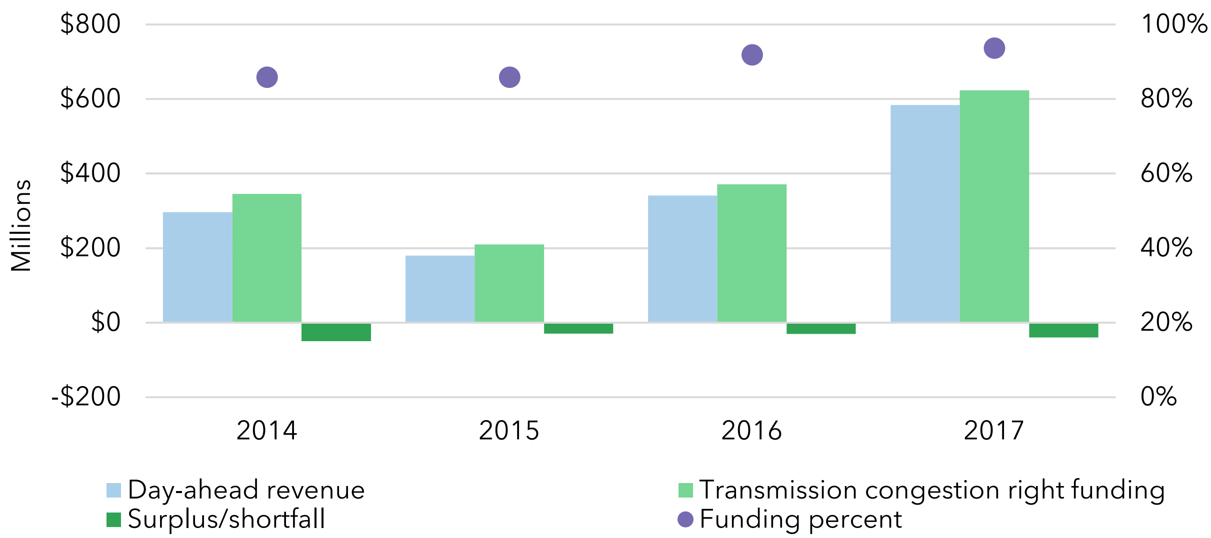
Ideally, outages in the transmission congestion rights markets would be perfectly aligned with the day-ahead market. However, the MMU understands the challenges associated with accounting for outages in the transmission congestion rights market and recognizes that there can never be an exact match among the markets. Even so, improving how outages are handled and accounted for in the auction processes could help to improve underfunding. We encourage stakeholders to consider both counter-flow positions and outages in determining how to improve the funding issues identified by stakeholders in 2017.

5.2.2 FUNDING

Overall funding for transmission congestion rights (94 percent) and auction revenue rights (164 percent) improved in 2017 relative to previous years. This is likely related to changes implemented based on concerns identified in previous years. However, overfunding of auction revenue rights signals a different set of concerns. In particular, we continue to encourage SPP to review and address the reasons for this overfunding.

In the 2014 and 2015 Annual State of the Market reports, the MMU discussed a recommendation and corresponding revision request[92] that was intended to reduce over-allocation of auction revenue rights and the resultant over-selling of transmission congestion rights by reducing the transmission capability in the annual auction revenue right allocation. This revision request made its way through the SPP stakeholder process in 2015 and 2016, in which a final approval was made by FERC in time for the 2016 annual auction revenue right/transmission congestion right processes. The "TCR year" runs from June 1 through May 31 of each year, so it is not in-sync with our annual report year. Looking at a calendar year of data, 2014 and 2015 did not include these revisions, 2016 included the revisions for half the year, and 2017 included the revisions for the entire year. The effects from the revisions can be seen with the annual funding percentage increases in Figure 5–22.

Figure 5–22 Transmission congestion right funding levels, annual

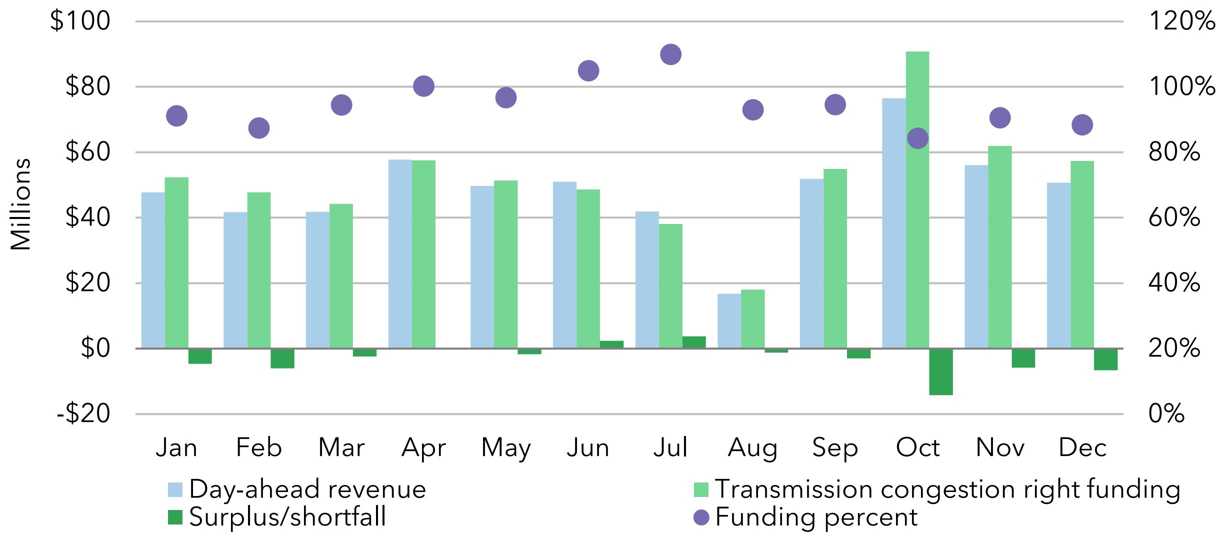


[92] Revision request 91

The 2015 calendar year, which did not include the revisions, showed 86 percent net transmission congestion right funding. The 2016 calendar year, in which about half the year included the revisions, showed 92 percent net transmission congestion right funding. The 2017 calendar year, which included the revisions for the entire year, showed 94 percent net transmission congestion right funding.

Monthly transmission congestion right fund levels and revenue are shown in Figure 5–23.

Figure 5–23 Transmission congestion right funding levels, monthly

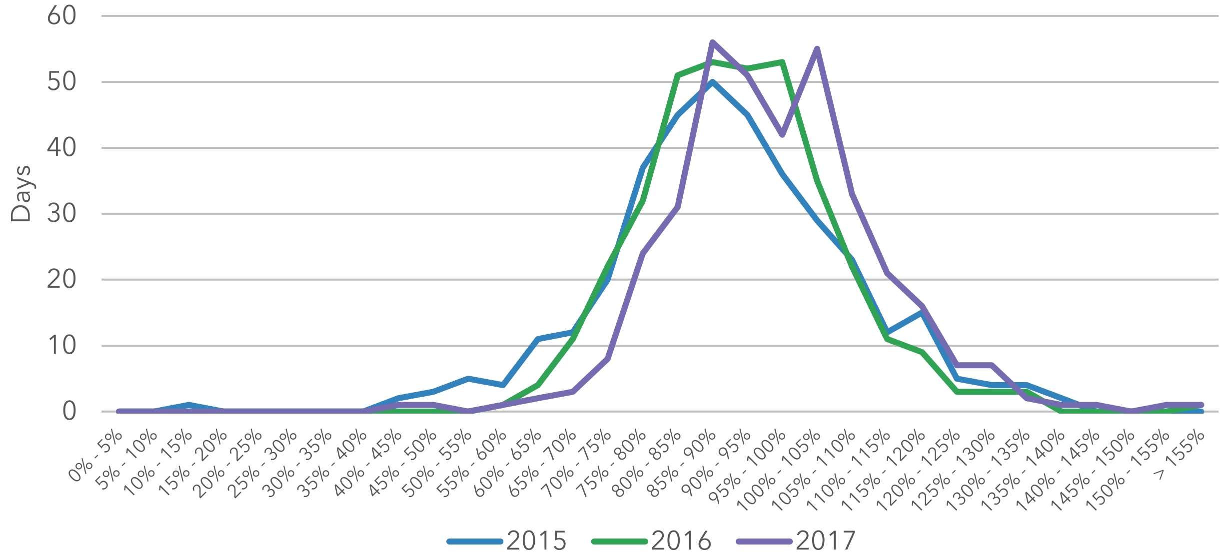


The monthly averages appear fairly consistent, with the majority of the months staying within the 90 to 100 percent target range.[93] While the percent of funding was improved in 2017 by the implementation of revision request 91, higher congestion costs actually increased the amount of underfunding compared to the previous years. The trend of over-selling transmission congestion rights appears to continue, but was reduced by revision request 91.

Daily observations of transmission congestion right funding for the past three years are shown in Figure 5–24.

[93] Target range is specified 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…"

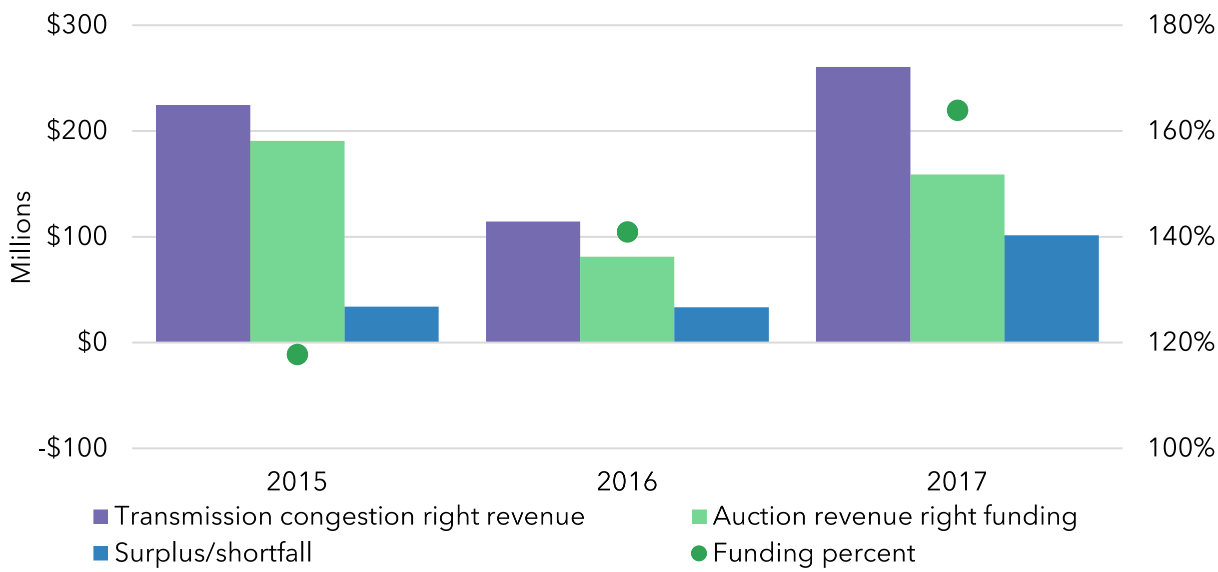
Figure 5–24 Transmission congestion right funding, daily



Most daily observations of transmission congestion right funding falls between 80 percent and 100 percent, as seen in Figure 5–24. While variation in funding can be expected as a result of factors including transmission outages and derates, the fact that the majority of funding falls in this range indicates that the overall process is generally effective.

Figure 5–25 shows that the auction revenue right funding percentage has increased over the last several years as revision request 91 was implemented.

Figure 5–25 Auction revenue right funding levels, annual



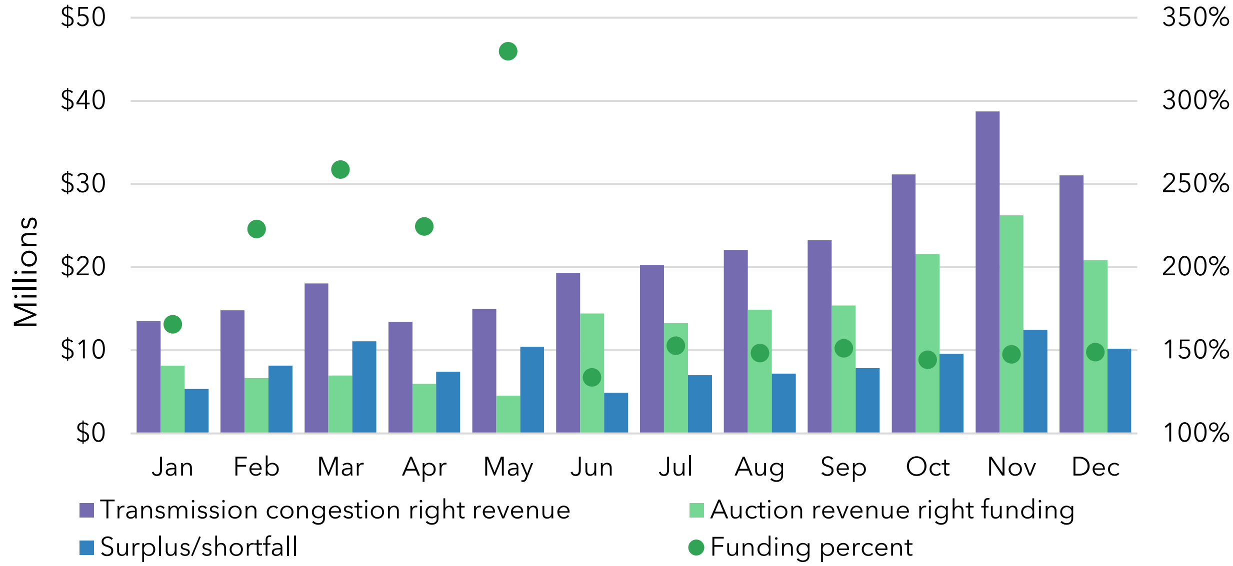
This is likely a result of the decreased amount of auction revenue right megawatts available as a result of reduced transmission capability in the annual allocation. This reduction of auction revenue rights was a known and expected outcome of the design change. Even though there are fewer overall auction revenue rights, the new design better aligns auction revenue rights and transmission congestion rights and allows for better feasibility of auction revenue rights. The increase in auction revenue right funding was not expected from the revision request, and may not be related to the change. This high amount of auction revenue right surplus still presents a potential concern that was identified in last year's State of the Market report.

In 2015, transmission congestion rights were approximately 86 percent funded by the day-ahead market while auction revenue rights were 118 percent funded. In 2016, transmission congestion rights were approximately 92 percent funded by the day-ahead market while auction revenue rights were 141 percent funded. From 2016 to 2017, day-ahead market revenues and transmission congestion right payments rose again because of congestion caused by increased wind generation. In 2017, transmission congestion rights were approximately 94 percent funded by the day-ahead market while auction revenue rights were 164 percent funded.

Interestingly, transmission congestion right annual shortfalls increased by 44 percent from $39 million in 2016 to $56 million in 2017. However, auction revenue right surpluses saw a drastic increase this year from $27 million in 2016 to $101 million in 2017.

Figure 5—26 shows the 2017 monthly funding levels and revenues for auction revenue rights.

Figure 5–26 Auction revenue right funding levels, monthly



The large shift in auction revenue rights in funding in June reflected the change in the TCR year. The figure also shows the auction revenue right funding drastically increasing from 230 percent funding in April to 330 percent funding in May.

5.2.3 MODELING CONCERNS

The MMU has reported on several transmission congestion right modeling issues in its previous annual reports, one of which still presents a cause for concern.

5.2.3.1 Auction revenue right funding

As previously noted, the auction revenue right funding levels are higher than expected. Auction revenue right surplus in conjunction with transmission congestion right underfunding tend to point to an overselling of transmission congestion rights. More revenues are collected from the purchases of transmission congestion rights than are needed to fund the auction revenue rights. Transmission congestion right owners may have paid too much for their transmission congestion rights, but instead of receiving a refund, the over-payment was allocated to the auction revenue right holders.

This extreme amount of surplus causes a concern for a few reasons. First, the entities that make up the pool of transmission congestion right holders are not the same entities that make up the pool of auction revenue right holders. Auction revenue right holders are only those entities with long-term firm transmission service. Second, the allocation of over collections is not related to over-payment. For instance, the over-payment of transmission congestion rights could primarily come from a small constrained area, but the allocation goes back to auction revenue right holders in a method similar to the load ratio share and has nothing to do with where the excess funds came from.

The MMU urges SPP, along with the stakeholders, to review the causes of overfunding, develop a plan to get auction revenue right funding closer to the 100 percent funding level, and analyze the distribution of surplus to ensure it is performed in an equitable manner. We suggest that this be addressed going forward.

6 COMPETITIVE ASSESSMENT

The SPP Integrated Marketplace provides sufficient market incentives to produce competitive market outcomes in regions and periods when there are no concerns with regard to local market power. The MMU's competitive assessment provides evidence that in 2017 market outcomes were workably competitive and that the market required mitigation of local market power infrequently to achieve those outcomes.

The market power analysis in this report considers both the structural and behavioral aspects of market power concerns. The structural aspects can be detected by various techniques such as market share analysis, (market-wide) concentration indices, and pivotal supplier analysis. The structural indicators are used to look for the potential for market power without regard to the actual exercise of market power. Behavioral aspects, on the other hand, assess the actual offer or bid behavior (i.e., conduct) of the market participants, and the impact of such behavior on market prices by looking for the exercise of market power. These behavioral indicators include offer price markup[94] (Section 6.2.1); economic withholding analysis, addressed through automated mitigation (Section 6.2.2); output gap analysis (Section 6.2.3); and physical withholding (Section 6.2.4).[95]

This chapter evaluates the SPP market's competitive environment first by establishing the level of structural market power and then examining market prices for indications of market power impact. The level of structural marker power is assessed both at the general level through concentration indices and at the local—transmission constraint—level through pivotal supplier analysis. Mitigation of economic withholding is accomplished *ex-ante* through automatic market power mitigation processes that limit the ability of generators with local market power to raise prices above competitive levels. The mitigation program is monitored and evaluated to ensure it is efficient and effective. Accordingly, the following subsections examine the significance of market power and the effectiveness of local market power mitigation in the SPP markets.

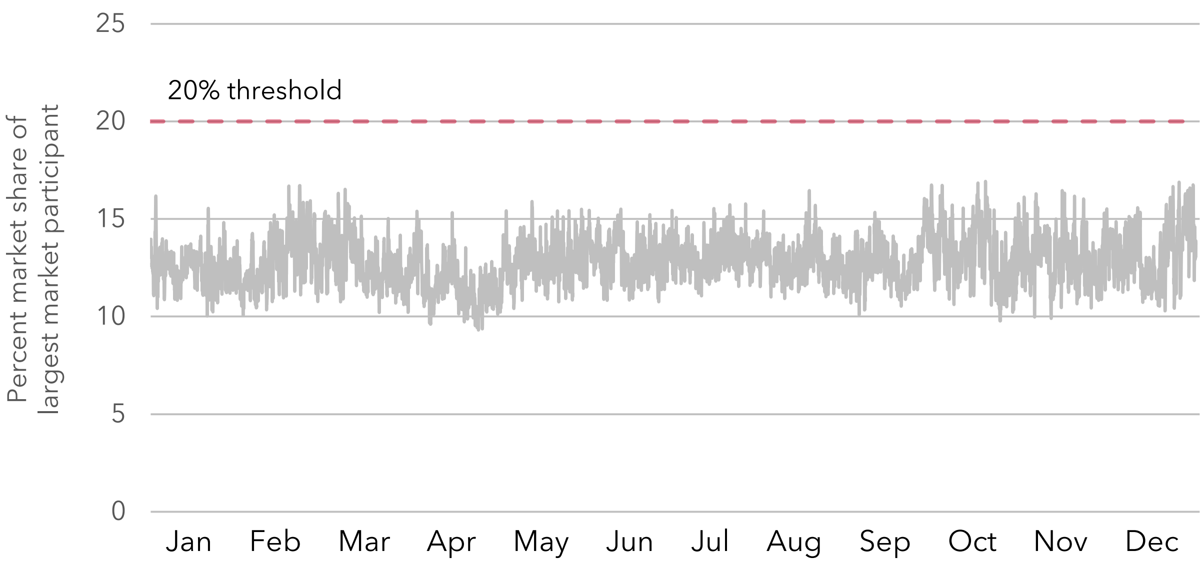
[94] While the SPP MMU uses offer price markup, other market monitors may use price cost markup as a behavioral indicator.
[95] The uneconomic production analysis, as another behavioral indicator, is addressed through FERC referrals.

6.1 STRUCTURAL ASPECTS OF THE MARKET

Three core metrics of structural market power are the market share analysis, the Herfindahl-Hirschman Index (HHI), and pivotal supplier analysis. The first two of these indicators measure concentration in the market and are of a static nature. Pivotal supplier analysis, on the other hand, takes into account the dynamic nature of power markets and considers changing demand conditions and locational transmission constraints in assessing potential market power.

Figure 6–1 displays the market share of the largest on-line supplier (i.e., market participant) in terms of energy output in the real-time market by hour for 2017.

Figure 6–1 Market share of largest supplier



The market share ranged from 9.3 percent to 16.9 percent, never exceeding the 20 percent threshold[96] in any of the hours for the year. This was down slightly from a range of 9.6 percent to 19.7 percent in 2016. The majority of the highest market share hours occurred during the shoulder months of the year.

[96] The 20 percent threshold is one of the generally accepted metrics that would indicate structural market power. Note, however, that neither market share nor the HHI metric alone would be sufficient for the assessment of market power particularly in today's spot electricity markets where load pockets formed by transmission congestion may lead to market power with much smaller market shares and/or HHI values.

The HHI is another general measure of structural market power, analyzing overall supplier concentration in the market. It is calculated by using the sum of the squares of the market shares of all suppliers in a market as follows:

$$HHI = \sum_i \left(\frac{MW_i}{\sum_i MW_i} * 100 \right)^2$$

According to FERC's "Merger Policy Statement,"[97] which is similar to Department of Justice merger guidelines, an HHI less than 1,000 is an indication of an unconcentrated market, an HHI of 1,000 to 1,800 indicates a moderately concentrated market, and an HHI over 1,800 indicates a highly concentrated market.

Figure 6–2 provides the number of hours for each concentration category over the last three years.

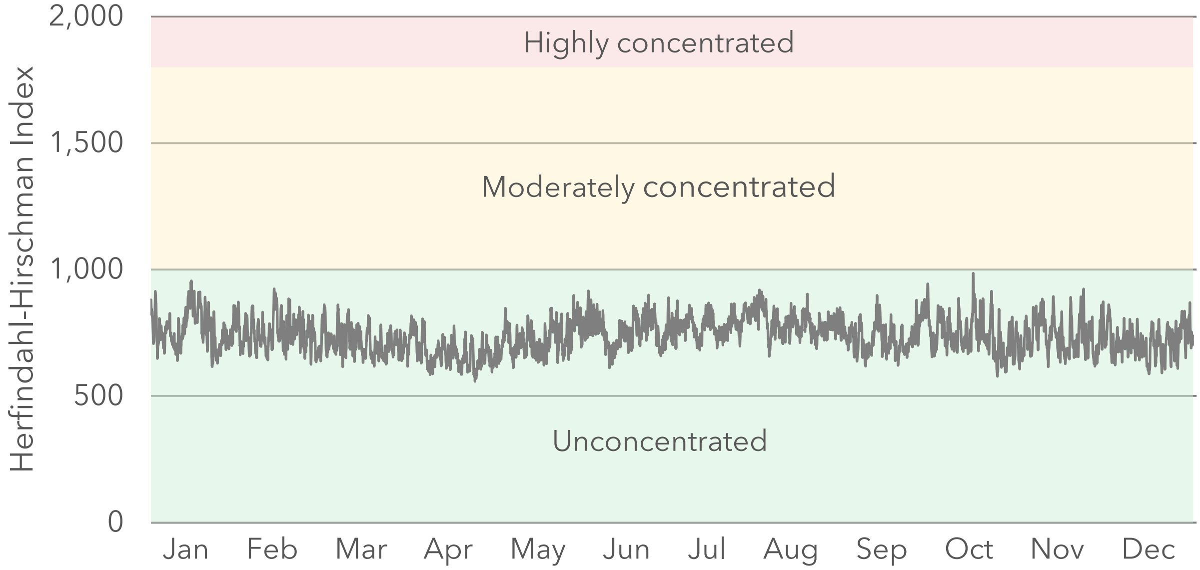
Figure 6–2 Market concentration level, real time

Concentration	HHI Level	2015		2016		2017	
		Hours	% of Hours	Hours	% of Hours	Hours	% of Hours
Unconcentrated	Below 1,000	6,234	71%	8,784	100%	8,760	100%
Moderately Concentrated	1,000 to 1,800	2,526	29%	0	0%	0	0%
Highly Concentrated	Above 1,800	0	0	0	0%	0	0%

In terms of installed capacity, the SPP market was unconcentrated 100 percent of the hours in 2016 and 2017. The HHI in the SPP market has never risen above the highly concentrated threshold of 1,800 since the Integrated System joined SPP in October 2015. Figure 6–3 depicts the hourly real-time market HHI in terms of generation for 2017.

[97] Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement, Order No. 592, Issued December 18, 1996 (Docket No. RM96-6-000).

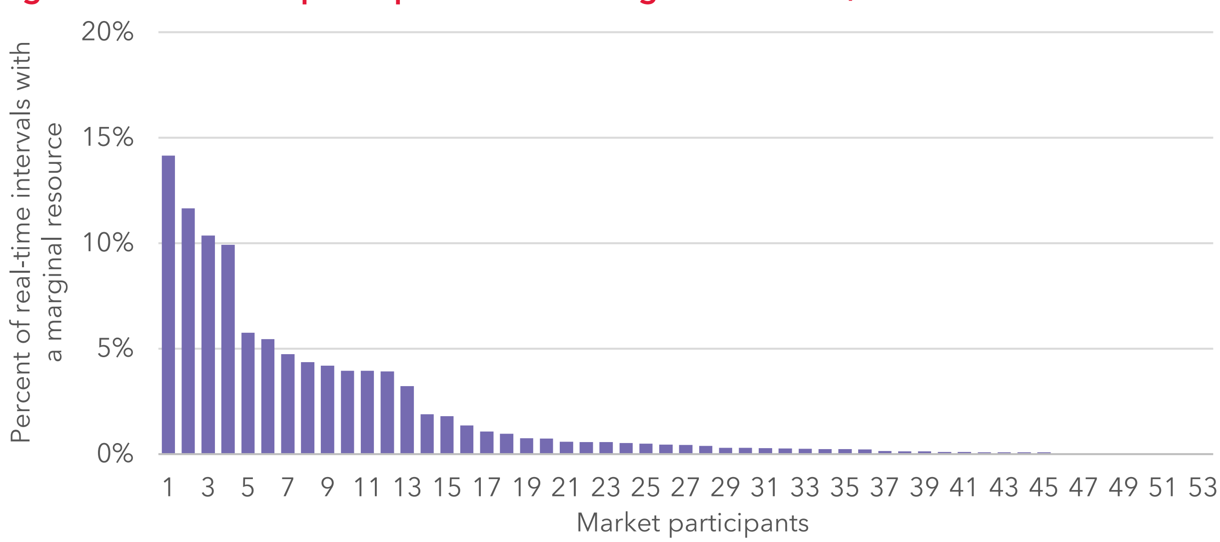
Figure 6–3 Herfindahl-Hirschman Index



Hourly HHI values ranged from 558 to 986 during 2017, which were very similar to the range of values in 2016.

SPP market participants with generation spanning all supply segments,[98] reflecting the technology and fuel mix of resources, have the greatest ability to benefit from structural market power. These market participants may frequently set prices regardless of the technology type on the margin. Figure 6–4 provides the percent of real-time market intervals that each market participant had a resource on the margin.

Figure 6–4 Market participants with a marginal resource, real time



[98] Supply segments include base, intermediate, and peak resources.

The chart shows that the top three market participants each set price in more than 10 percent, but less than 15 percent, of all real-time market time intervals. Conversely, well over half of all participants set price in less than one percent of all intervals.[99]

The MMU's market share analysis and calculated HHI both indicate minimal potential for general structural market power in SPP markets outside of areas that are frequently congested. Structural market power is also assessed at a more localized level and in the context of locational transmission constraints by reevaluating frequently constrained areas periodically and (re)defining them accordingly as was discussed in Section 5.1.7.

Pivotal supplier analysis takes into account the dynamic nature of the power market, particularly demand conditions, and evaluates the potential for market power in the presence of "pivotal" suppliers. A supplier is pivotal when its resources are needed to meet demand. There may be one or more pivotal suppliers in a particular market defined by transmission constraints and load conditions, and a supplier's status of being pivotal may vary between time periods irrespective of its size. In the market clearing process, market power is evaluated locally through a local market power evaluation because the exercise of local market power is relevant for determining prices.

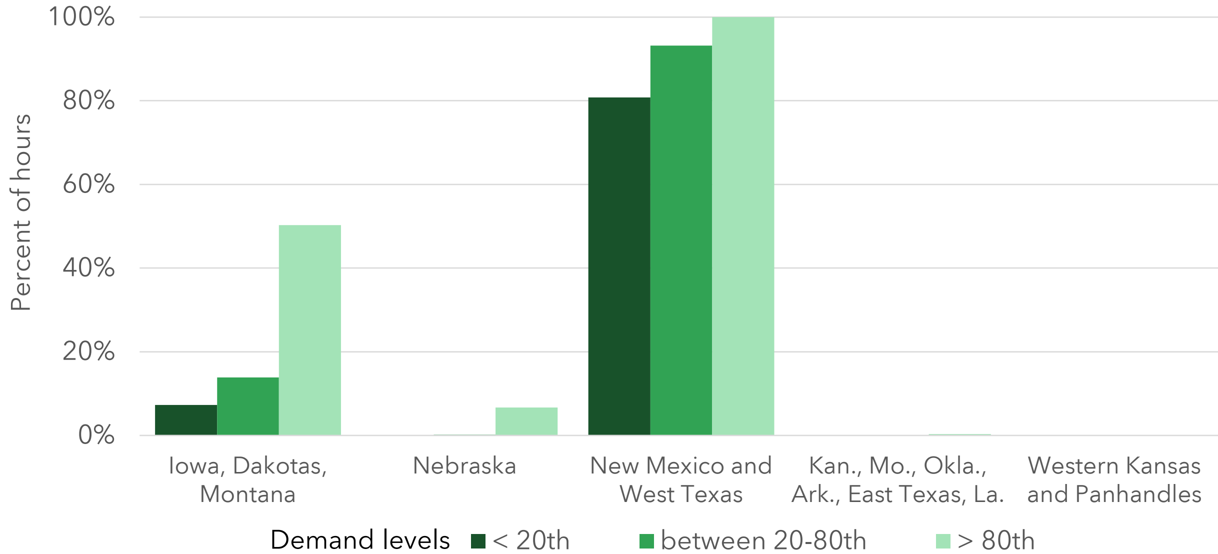
The following analysis identifies the frequency with which at least one supplier was pivotal in the five different reserve zones (regions) of the SPP footprint in 2017.[100] One condition for a supplier to have an ability to raise prices above competitive levels, is the frequency it becomes pivotal. Another market condition is during times of shortage or high demand. The mere size of a supplier has no link to being pivotal; however, suppliers with a high frequency of being pivotal in tight supply periods have an even greater ability to exercise market power. For this reason, the frequency of being a pivotal supplier is also analyzed at various levels of demand across these five regions.

[99] The percentages on this chart are not additive because multiple market participants may have a resource on the margin during any given interval.

[100] SPP divides market resources (generation) into five reserve zones. For the purpose of this report, these reserve zones are named as "Nebraska", "Western Kansas and Panhandles", "New Mexico and West Texas", "Kan., Mo., Okla., Ark., East Texas, La.", and "Iowa, Dakotas, Montana". Thus, each generation resource is mapped to one of these reserve zones. To define a load zone to match with a resource zone, each load settlement location was mapped to a reserve zone to approximate demand within a particular zone. Additionally, import limits are approximated by the average of the reserve zone limits for the times they were activated in 2017.

Figure 6–5 shows how frequently a supplier is pivotal at varying load levels in the five reserve zones in the SPP market footprint.

Figure 6–5 Hours with at least one pivotal supplier



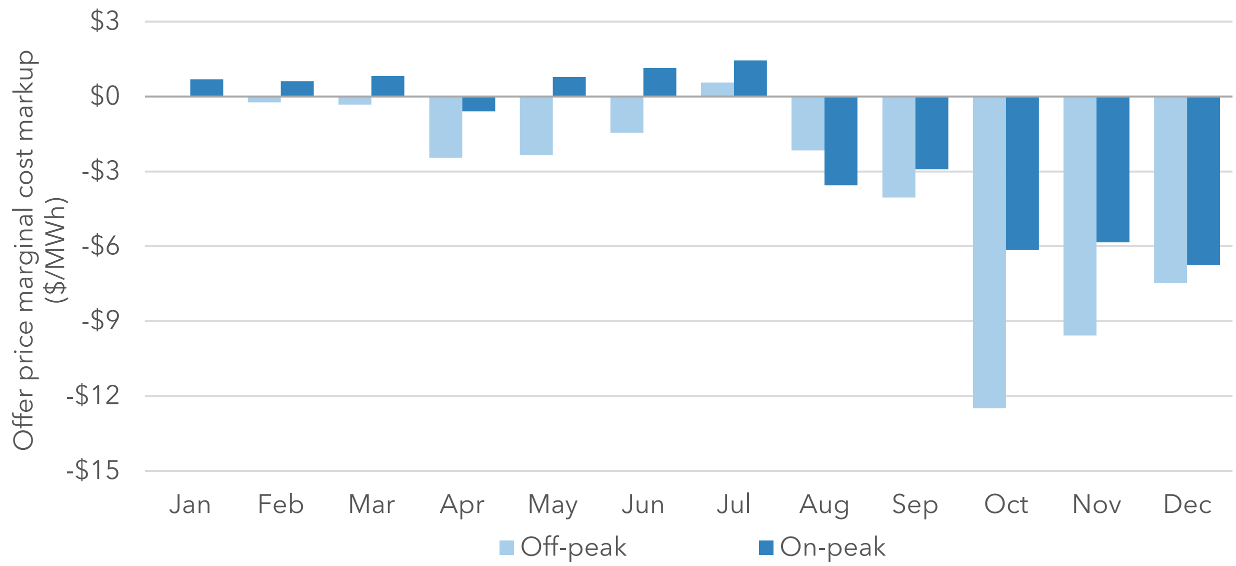
The results indicate that the percent of hours with pivotal supplier is the highest (81 to 100 percent) in the New Mexico and West Texas region, increasing with demand level. This is where one of the SPP's frequently constrained areas in 2017 was located. This region is followed by the Iowa, Dakotas, Montana region where, depending on the level of load, seven to 50 percent of the hours exhibit at least one pivotal supplier. The remaining regions experience pivotal supplier conditions for only negligible periods, and only at the higher load levels.

6.2 BEHAVIORAL ASPECTS OF THE MARKET

6.2.1 OFFER PRICE MARKUP

In a competitive market, prices should reflect the short-run marginal cost of production of the marginal unit. In SPP's Integrated Marketplace, market participants submit hourly mitigated energy offer curves that represent their short-run marginal cost of energy. Market participants also submit their market-based offers, which may differ from their mitigated offers. To assess market performance, a comparison is made between the market offer and the mitigated offer for the marginal resources for each real-time market interval. Figure 6–6 provides the average marginal resource offer price markups[101] by month for on-peak and off-peak periods.

Figure 6–6 Average offer price markup of marginal resource, monthly

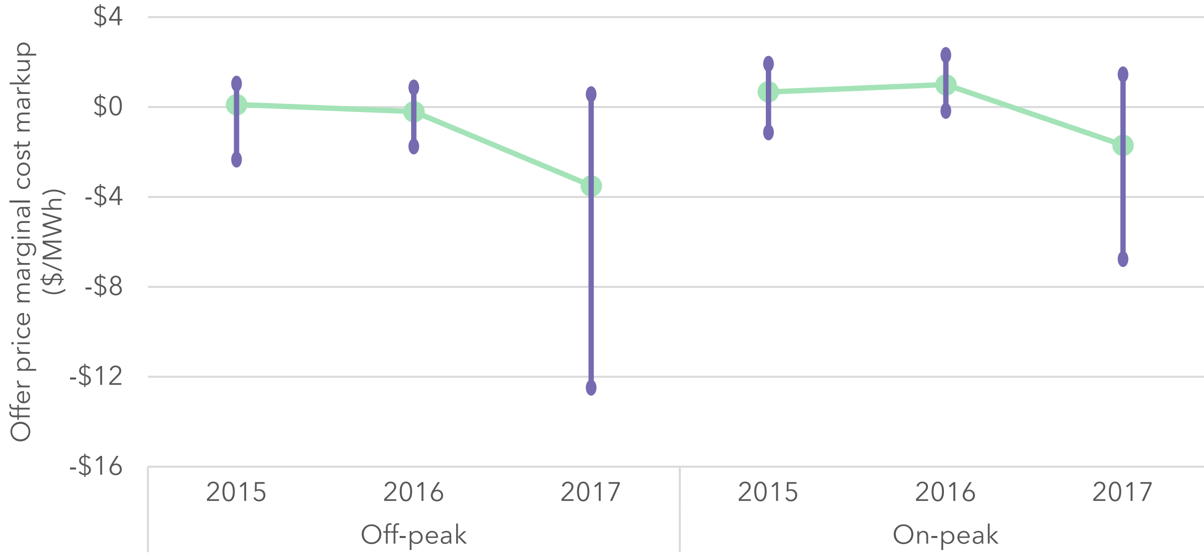


In 2017 the average monthly markups ranged from -$12.48 to $0.56/MWh for off-peak periods and from -$6.75 to $1.44/MWh for on-peak periods. The lowest markups occurred in fall and winter in off-peak hours, when wind generation was generally the highest. During six months the average on-peak markup was also negative at relatively high magnitudes. The negative markups in 2017 were significantly higher compared to 2016 (see Figure 6–7 for annual ranges). The observed levels of negative markups indicate that some market participants' real-time market offers were below their mitigated offers. This could occur where generators decide to offer below their marginal cost to maintain commitments in a very competitive marketplace. Coal plant operators may have a negative opportunity cost resulting from an oversupply of coal or possible exposure to a take-or-pay contract. Negative markups could also occur when wind units become marginal and their (negative) offers clear the market.[102] For instance, wind resources at the margin increased from 7.9 percent of all

[101] Offer price markup is calculated as the difference between market-based offer and the mitigated offer where the market-based offer may or may not be equal to the mitigated offer. The MMU calculates a simple average over all marginal resources for an interval. The markups are not weighted to reflect each marginal resource's proportional impact on the price.
[102] Wind units may have negative mitigated offers because of subsidies related to production tax credits.

resource hours in 2016 to 10.4 percent in 2017, indicating a 31 percent increase. Figure 6–7 below points to a declining annual trend of off-peak and on-peak average markups.

Figure 6–7 Average offer price markup, annual



Both off-peak and on-peak average markups were at the lowest levels since implementation of the Integrated Marketplace at around -$3.50/MWh and -$1.70/MWh, respectively. Although a lower offer price markup level in itself would indicate a competitive pressure on suppliers in the SPP market, the observed continuous downward trend may raise questions about the commercial viability of generating units and the possibility of generation retirements.

6.2.2 MITIGATION PERFORMANCE AND FREQUENCY

SPP employs an automated conduct and impact mitigation scheme to address potential market power abuse through economic withholding. The mitigation applies to resources that exercise local market power in areas of transmission congestion, reserve zone shortages, and manual commitments in instances where there is the potential for manipulation due to a manual commitment that guarantees recovery of a resource's submitted market offers.

SPP resources' incremental energy, start-up, no-load, and operating reserve offers are subject to mitigation for economic withholding when the following three circumstances occur simultaneously in a market solution:

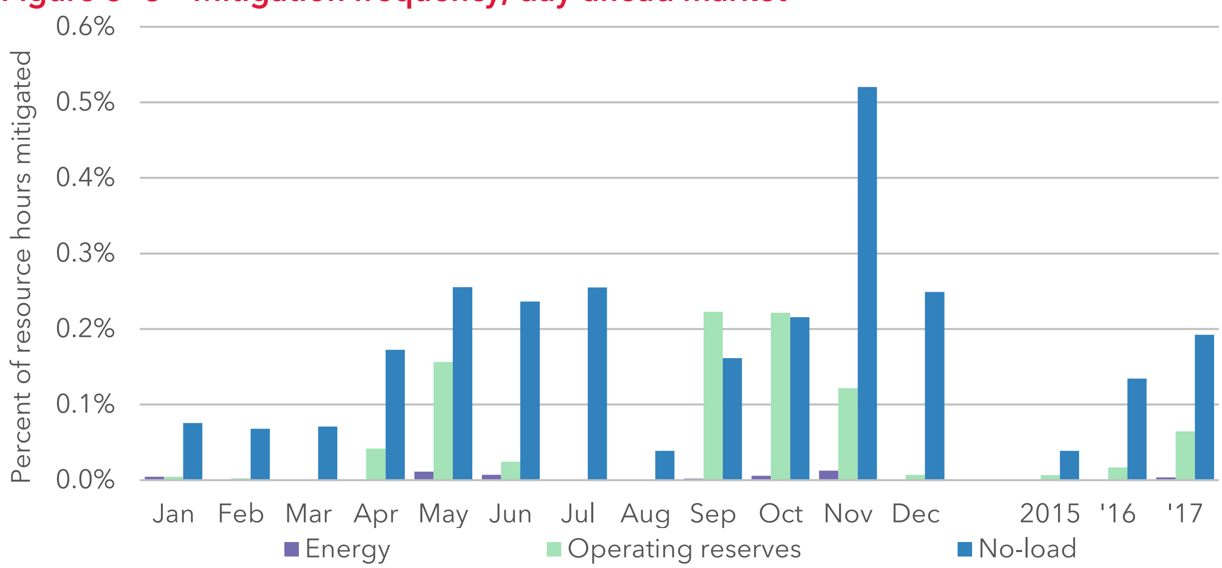
1) The resource has local market power;

2) The offer has failed the conduct test. Resources submit two offers for each product: a mitigated offer representing the competitive baseline costs that must adhere to the mitigated offer development guidelines[103] and a second offer generally referred to as a market offer. An offer fails the conduct test when the market offer exceeds the mitigated offer by more than the allowed threshold; and

3) The resource is manually committed by SPP for capacity, transmission constraint, or voltage support; or by a local transmission operator for local transmission problems or voltage support; and the application of mitigation impacts market prices or make-whole payments by more than the allowed $25/MWh threshold.

Mitigation was very low overall, with some variation across products and markets. Figure 6–8 shows that the mitigation of incremental energy, operating reserves, and no-load was generally infrequent in the day-ahead market in 2017.

Figure 6–8 Mitigation frequency, day-ahead market

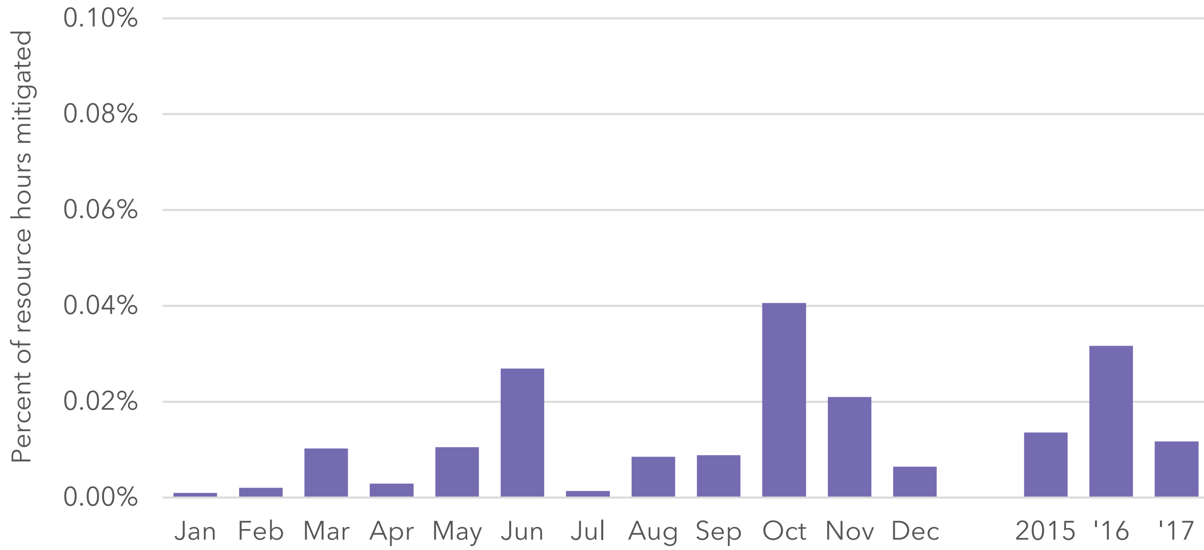


[103] As indicated in Appendix G of the SPP's Market Protocols.

Mitigation frequency in the day-ahead market increased slightly starting in April (with the exception of August), particularly for no-load. The application of mitigation in the day-ahead market occurred at levels of 0.06 percent for operating reserves, 0.19 percent for no-load, less than 0.01 percent for incremental energy, and about three percent of starts.

Mitigation of incremental energy in the real-time market is shown in Figure 6–9 below.

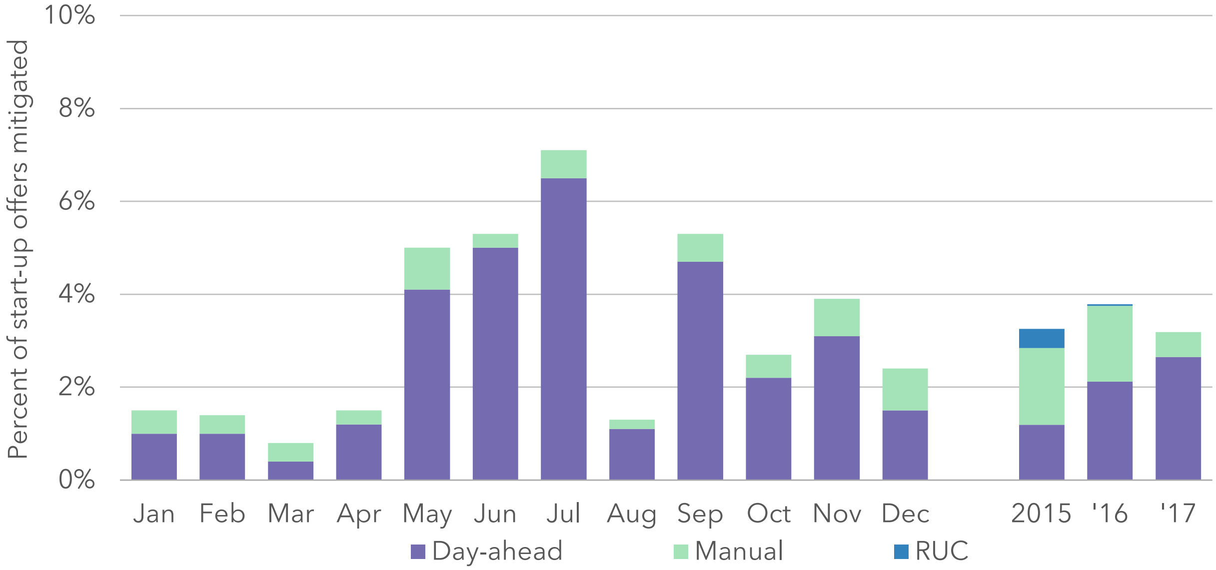
Figure 6–9 Mitigation frequency, real-time market



For the real-time market, the mitigation of incremental energy has been at very low levels since the start of the market with an annual average around 0.01percent in 2017, which is down by a third from 2016 levels.

Figure 6–10 shows the mitigation frequency for start-up offers for the various commitment types.

Figure 6–10 Mitigation frequency, start-up offers



The overall mitigation frequency of start-up offers was the lowest since the market began in 2014, as it decreased in 2017 relative to 2016 levels to just over three percent. While the frequency of manual and real-time mitigation dropped in 2017 compared to 2015 and 2016, day-ahead mitigation increased to 2.7 percent. Day-ahead mitigation accounts for 83 percent of the total start-up cost mitigation. The highest level of mitigation of start-up offers was at seven percent in July and has since fallen to around two percent in December.

6.2.3 OUTPUT GAP (MEASURE FOR POTENTIAL ECONOMIC WITHHOLDING)

Economic withholding by a resource is defined as submitting an offer that is unjustifiably high such that either the resource will not be scheduled or dispatched, or if scheduled or dispatched the offer will set a higher than competitive market clearing price. Accordingly, the output gap metric aims to measure the economic (or competitive) amount of output that was withheld from the market by submitting offers in excess of competitive levels. The output gap is the amount of generation not produced as a result of offers exceeding the mitigated offer above an appropriate conduct threshold. The conduct threshold is employed to compensate for any inaccuracies or uncertainties in estimating the cost, similarly to the one used in economic withholding mitigation. In this report, the output gap is calculated as the difference between the resource's economic level of output at the prevailing market clearing price and the actual amount of production. The economic level of output is produced by a generator between its minimum and maximum economic capacity.[104]

The output gap calculation adopts a new approach this year for calculating economic output.[105] Under this new approach, units were grouped into two categories: economic units that are not committed, and committed units that are dispatched at lower levels than their economic level. Accordingly, we implemented a multi-stage process to determine the economic output level for a unit for output gap evaluation.

In the first stage, we determined if the unit would have recovered its startup, no-load, and incremental costs if ran for its minimum run time at the dispatch point dictated by the prevailing day-ahead energy price. In last year's report, we used the results from the market run to determine the economic commitment status of a resource. This year, the MMU evaluated the commitment process against the market clearing engine prices to determine the economic commitment status of a resource.

During the process, we broke the resources into three groups based on the minimum run time of a resource—longer than 12 hours, one to 12 hours, and one hour or less. For the units with minimum run times longer than 12 hours, we looked if they would have been profitable if committed for the whole day, assuming a 24 hour minimum run time. For the units with minimum run times of one to 12 hours, we only checked two four hour peak times of each day (05:00-09:00 and 16:00-20:00 hours) and assumed a four hour minimum run time. For units with minimum run times of one hour or less, we assumed a one hour minimum run time. We then checked the potential revenue against the total commitment costs including startup, no-load and economic minimum energy cost. If the resulting revenues were positive, then we decided that the unit should have been committed in that day or hour.

In the second stage, if a unit was economic for commitment, we then identified the economic level of incremental output during hours when it was economic to produce energy based on real-time prices. In hours when the unit was not economic to run and on days when the unit

[104] The MMU calculates this metric by including all resources' total (reference level) capacity when calculating output gap percentages.
[105] The new metric is based on the approach used by Potomac Economics. Accordingly, the output gap calculations for 2015 and 2016 were reproduced and displayed along with 2017 data for comparison.

was not economic for commitment, the economic level of output was considered to be zero. To reflect the timeframe in which commitment decisions are actually made, this assessment was based on day-ahead market outcomes for non-quick-start units and real-time market outcomes for quick-start units (mostly gas turbines). This is because most of the energy for non-quick-start resources was awarded in the day-ahead market, whereas quick-start resources are generally committed on short notice and fully exposed to real-time prices. Therefore, we used day-ahead prices for non-quick-start resources and real-time prices for quick-start resources in assessing the output gap.

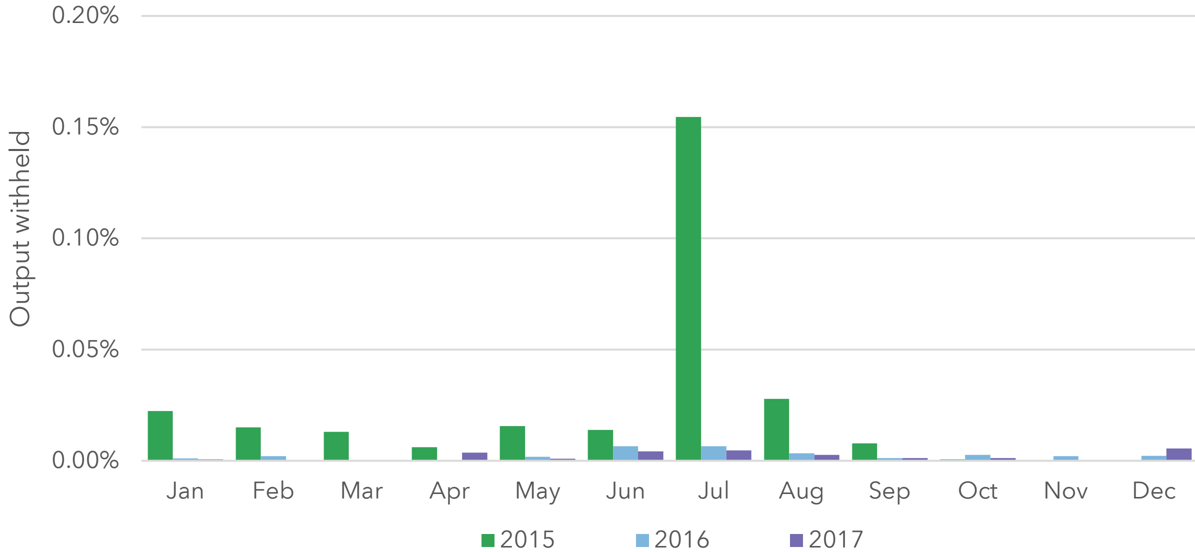
This year the MMU considered the 17.5 percent conduct threshold for the two frequently constrained areas and the 25 percent conduct threshold for the rest of the footprint to reflect the actual thresholds used in economic withholding mitigation.[106] In order to account for the discrepancy between a resource's offered capacity and the dispatched amount (because of possible limitations in real-time market conditions such as transmission constraints, operator actions or ramp limitations, virtual participants), an upward adjustment is made by taking the greater of the day-ahead scheduled or the real-time dispatched amount to reflect the actual amount of production.

Note that certain market conditions such as congestion (supplier location), supplier size, or high demand can create market power and facilitate economic withholding behavior. For this reason, the output gap is calculated as percentages of total economic output withheld compared to total reference capacity for the SPP footprint and for the two frequently constrained areas. In addition, the output gap is calculated for the largest three suppliers (market participant portfolios) in each area comparing the levels to those of the remaining suppliers. Similar to the last year's report, the annual calculations were run at varying levels of demand as a potential market condition that can affect the withholding outcome.

The results in Figure 6—11 below show the SPP footprint-wide monthly levels of the output gap from 2015 to 2017.

[106] The 2016 output gap calculations used only the 25 percent threshold level.

Figure 6–11 Output gap, monthly



The figure indicates that output gap levels were significantly higher in the first nine months of 2015 compared to the period afterwards through 2017. This could be related to the SPP footprint expansion on October 1, 2015 to include the Integrated System, which increased available supply in the market. After the market expansion, output gap levels were 0.007 percent or less in all months in 2016 and 2017, reflecting highly competitive participation in the market, overall.

Figure 6–12 through Figure 6–14 display the output gap calculated by demand level and participant size for the entire SPP market footprint and the two frequently constrained areas. In general more output is expected to be withheld at higher demand levels or by larger suppliers. However, at times, output may also be withheld in low load periods, as prices are often negative during the lowest 20 percent of load hours.

Figure 6–12 Output gap, SPP footprint

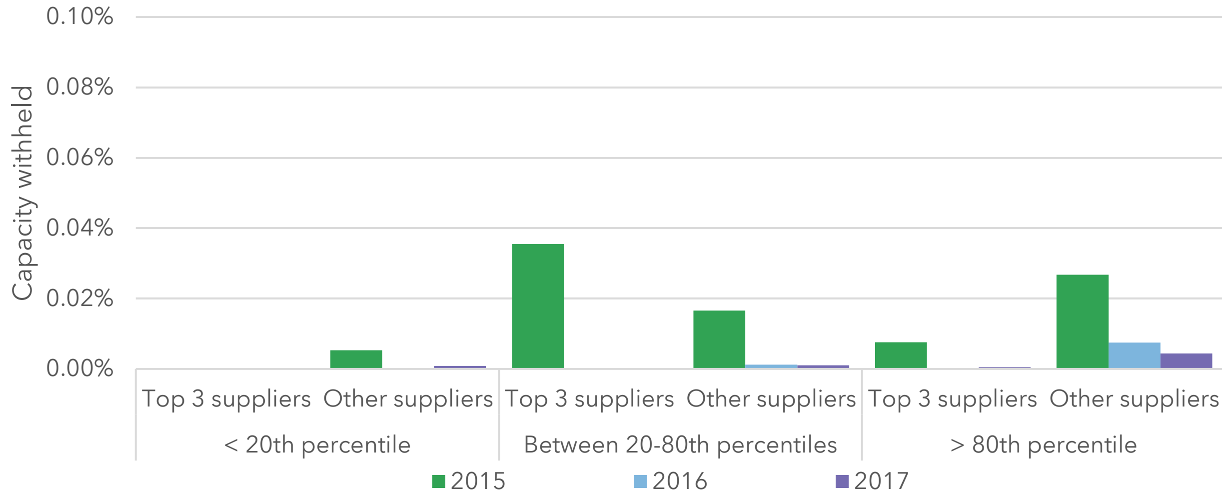


Figure 6–13 Output gap, Texas Panhandle frequently constrained area

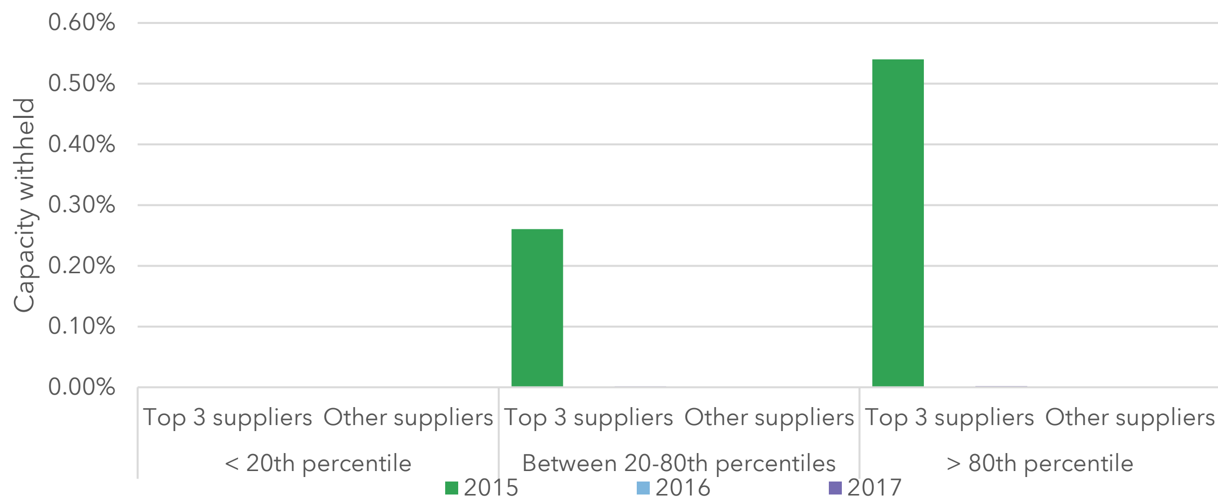
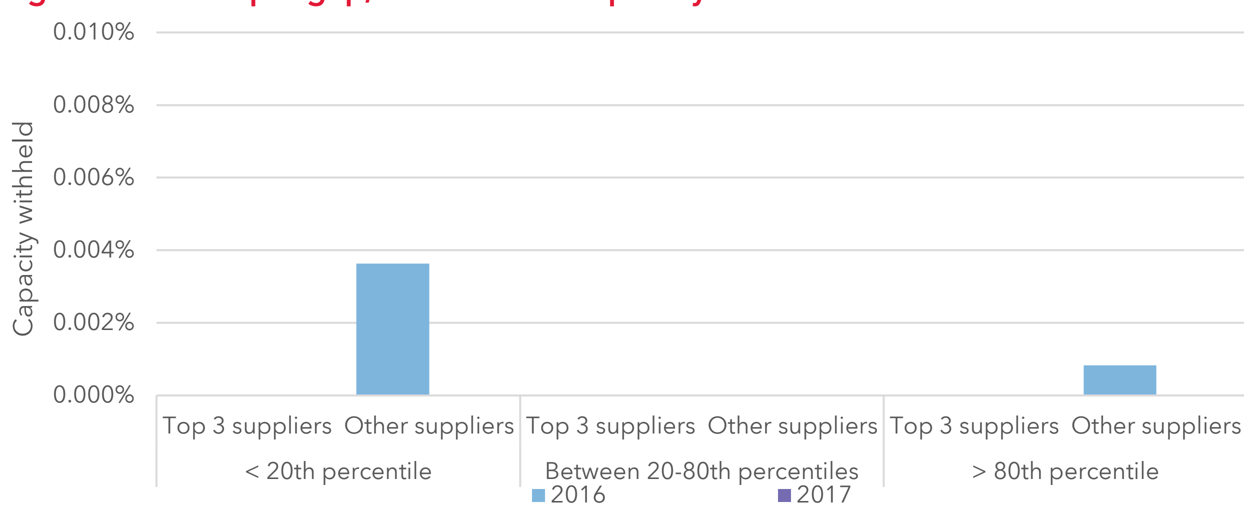


Figure 6–14 Output gap, Woodward frequently constrained area



Compared to 2015, all results indicate much lower levels of (economic) output withheld in 2016 and 2017, and particularly at higher demand levels. Specifically, there was no measurable output withheld in the frequently constrained areas in 2016 and 2017. These outcomes are consistent with the expectations of competitive market conduct.

6.2.4 UNOFFERED GENERATION CAPACITY (MEASURE FOR POTENTIAL PHYSICAL WITHHOLDING)

As part of the competitive assessment, we also looked into the potential physical withholding behavior by generators throughout the 2015 to 2017 period. Physical withholding refers to a conduct where a supplier derates a resource or otherwise does not offer it into the market. Physical withholding may include intentionally not following dispatch instructions, declaring false derates or outages, refusing to provide offers, or providing inaccurate capability limitations. Any economic generation capacity that is not made available to the market via derate, outage, or otherwise not offered to the market is considered for this analysis.[107,108]

We classified total economic capacity that was derated from respective reference levels by reason and duration. Deratings can take the form of planned outages approved in SPP's outage scheduling system, forced outages, or any undesignated unoffered capacity.[109] Any deratings from reference levels including partial deratings are considered in this analysis.

Derates were divided into short-term and long-term. Those with less than seven days duration were classified as short-term and the rest as long-term. This is because the economic capacity that was not offered short-term has more potential for physical withholding relative to long-term derates as it would be less costly—because of loss of sales—for a supplier to withhold capacity for a short duration of time.

As in the case for economic withholding, potential for physical withholding is also affected by various market conditions at the time offers are made including location (congestion), supplier size, or demand levels. Larger suppliers would be in a more advantageous position

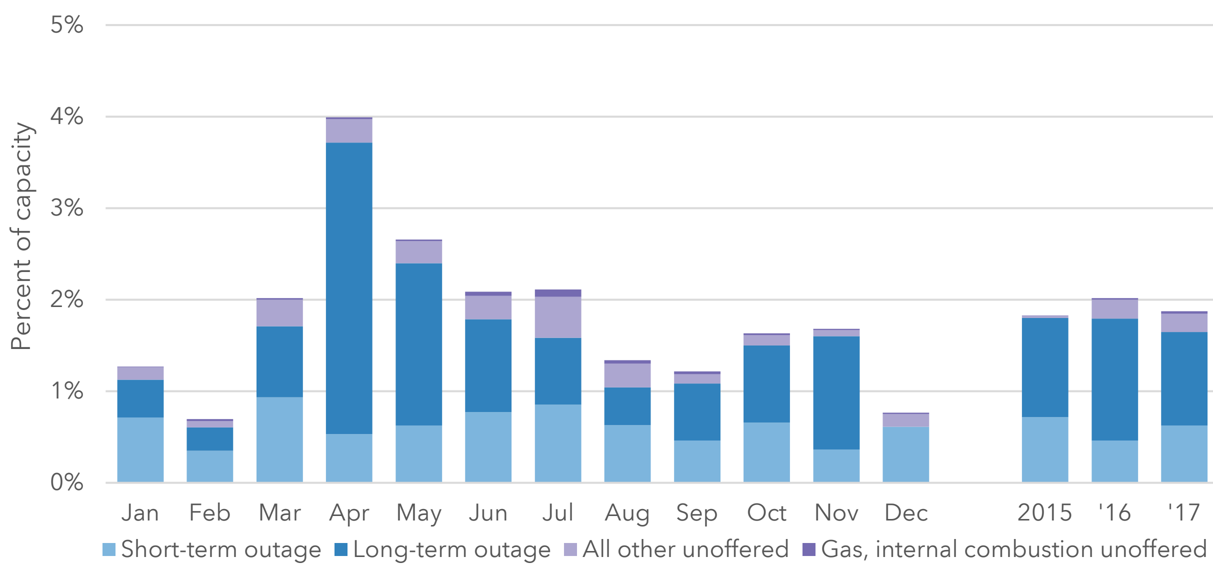
[107] This analysis, in part, draws on "Assessment of the Market Monitoring Metrics for the SPP Energy Imbalance Service (EIS) Market," Potomac Economics, December 2010 and "2016 State of the Market Report For the New York ISO Markets," Potomac Economics, May 2017.
[108] Economic capacity is determined in a similar way as in the output gap analysis in Section 6.2.3 by comparing resource's (cost-based) mitigated offer to the prevailing locational price.
[109] The planned maintenance outages by nuclear generation and unoffered capacity by hydro, wind and solar is excluded in this analysis.

to exercise market power. During tight market conditions, suppliers have more incentive and opportunity to physically withhold capacity for strategic reasons. In addition, scheduling maintenance outages in high demand periods may indicate a strategic behavior to create artificial shortages.

In the assessment, we considered derated and unoffered economic capacity both in day-ahead and real time. Similar to the output gap analysis, the commitment decisions were made based on day-ahead market outcomes for non-quick-start units and real-time market outcomes for quick-start units.[110] The unoffered capacity is calculated as the difference between the unit's economic capacity[111] and its offered maximum economic capacity operating limit during intervals when the unit was deemed economic (i.e., covering its costs given the clearing price).

The following figures show unoffered economic capacity as percent of total resource reference levels by month for the SPP footprint, by frequently constrained area, and by supplier (participant) size against varying load levels.[112]

Figure 6–15 Unoffered economic capacity



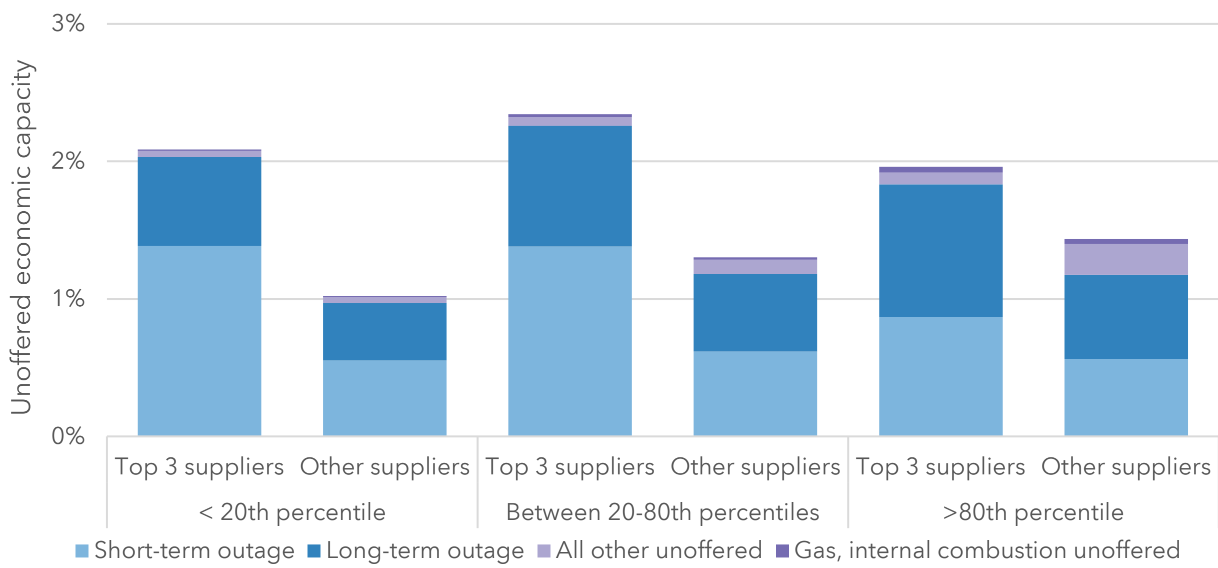
[110] See Section 6.2.3 for explanation of this method.
[111] Bounded by a resource's reference level.
[112] Unoffered capacity percentages are calculated out of the total reference levels of the corresponding area (i.e., SPP footprint or each of the two frequently constrained areas).

Figure 6–15 shows that on an annual average basis the total unoffered capacity equaled 1.8 percent in 2015, 2.0 percent in 2016, and 1.9 percent in 2017.

The figure also shows that the majority of the outages were long-term and concentrated during the fall and spring shoulder months. When short and long-term outages were excluded from the averages, the remaining unoffered capacity amounts to 0.03 percent, 0.22 percent, and 0.23 percent for 2015 through 2017. From a competitive market perspective, the results generally indicate reasonable levels of total unoffered economic capacity. The latter (net of outages) results, which are very low, could also be interpreted to indicate pressure on market participants, particularly on coal-fired resources, to offer–and maintain commitments–given their long-term coal contracts.[113] The general high levels of self-scheduling of supply offers in the SPP market could be another contributing factor in this outcome.

Figure 6–16 shows that short-term outages by either large suppliers or others do not rise with increasing load across the SPP footprint.

Figure 6–16 Unoffered economic capacity at various load levels, SPP footprint



On the other hand, unoffered economic capacity of gas (peaker) units by large suppliers rises with increased load. They are at very low levels of 0.01 percent, 0.02 percent, and 0.04

[113] Coal-fired resources may prefer to offer at times even below their mitigated offers to guarantee to be scheduled or dispatched. See also the offer price markup analysis earlier in Section 6.2.1 and the negative markup results reported therein.

percent of respective load levels. The unoffered economic capacity of gas units by other suppliers increases even at lower levels against load. Unoffered economic capacity compared to load is more apparent for the remaining resource types, however, it does not exceed 0.22 percent for either of the supplier groups.

Another take away from the results is that while long-term outages constitute the majority of total outages in the SPP footprint at higher load levels, short-term outages play a larger role in the two frequently constrained areas (see Figure 6–17 and Figure 6–18). Moreover, short-term outages in those two areas remained more or less the same as load levels increased.

Figure 6–17 Unoffered economic capacity at various load levels, Texas Panhandle area

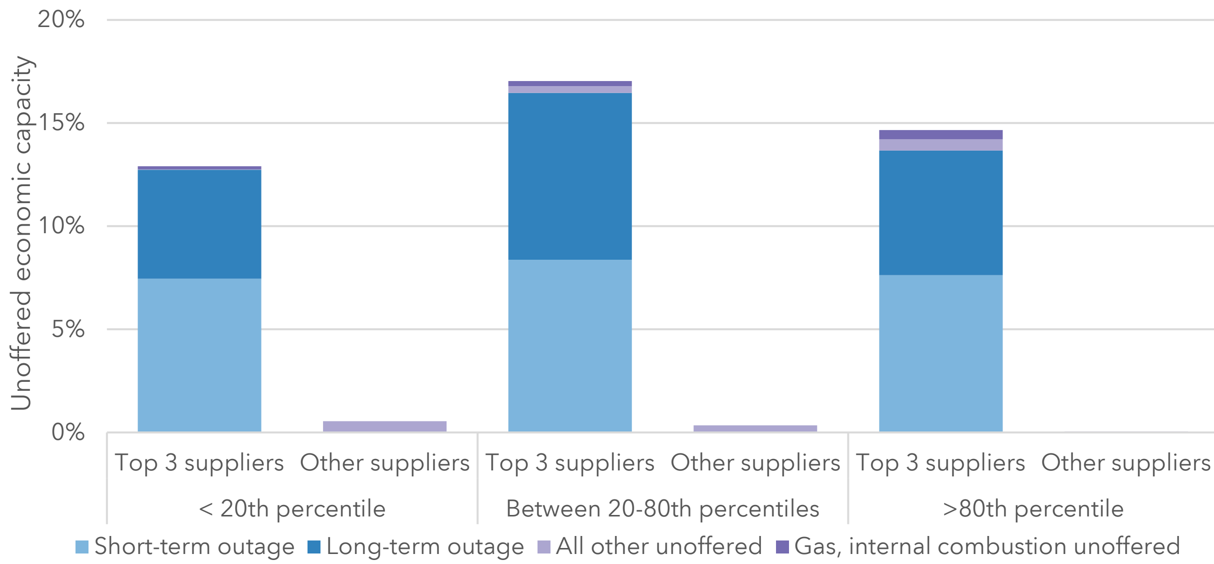
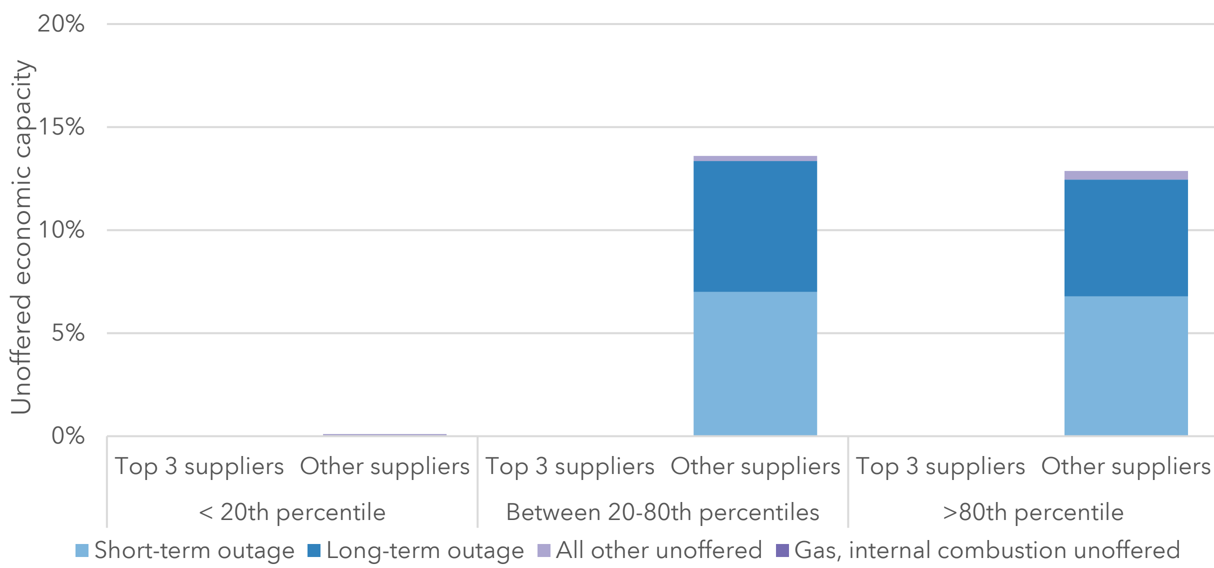


Figure 6–18 Unoffered economic capacity at various load levels, Woodward area



The SPP-wide outage data[114] show that most long-term outages were for maintenance (73 percent). Of those outages, most were scheduled during shoulder months (70 percent). Out of the short-term outages, approximately 40 percent were forced outages, with close to half of them in shoulder months.

In the Texas Panhandle and Woodward frequently constrained areas, 36 and 21 percent of the short-term outages respectively were forced outages with no clear seasonal trend. The Texas Panhandle frequently constrained area shows the dominance of larger participants in declaring long-term and short-term outages. These results are generally consistent with competitive market conduct.

6.3 OFFER BEHAVIOR DUE TO MITIGATION THRESHOLD

As discussed in the 2016 State of the Market report, the MMU has observed inefficient market behavior with regard to the mitigated threshold. The MMU submitted revision request 231 on the mitigation of locally committed resources to address this issue. The change was approved by the SPP board in October and is awaiting FERC filing and approval. This section highlights the nature of the concern and presents the SPP board approved solution.

SPP market rules require that market participants submit both a “market-based” energy offer curve and a “cost-based” mitigated energy offer curve. The offer cap of $1,000/MWh and the floor of -$500/MWh are the only limits to the energy offer curve. Market participants can submit any energy offer curve within these bounds. The market software will use the energy offer curve, unless the resource is mitigated. When mitigated, the mitigated offer curve will replace the energy offer curve.

In order for offers to be mitigated, the resource must fail all three of the following tests: local market power test, conduct test, and impact test. These three criteria for activating mitigation are described in Section 6.2.2.

Market participants directly affect the conduct test, sometimes referred to as the behavior test. When a market participant submits an energy offer that exceeds the mitigated offer by more than the thresholds described below, then the offer fails the conduct test.

[114] Covering all resources in the SPP market including nuclear, hydro, wind and solar generation.

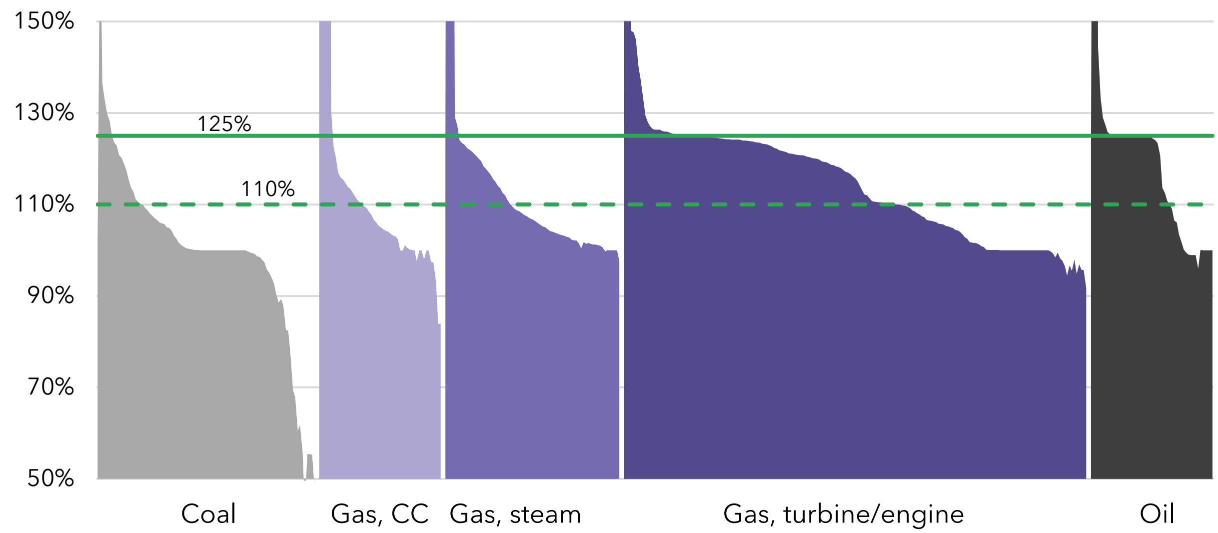
The thresholds are defined as:

- 10 percent above the mitigated energy offer for resources committed to address a local reliability issue,
- 17.5 percent above the mitigated energy offer for resources in a frequently constrained area, and
- 25 percent above the mitigated energy offer for all other resources.

As shown in Figure 6–19, there is again a noticeable plateau of bids at the 110 percent threshold (for gas turbines) and the 125 percent threshold (for oil-fired resources) for 2017. In the figure, the dashed line represents the 110 percent threshold, and the solid line represents the 125 percent threshold. The plateaus appear to be the result of participants offering their resources just under the conduct test thresholds in order to guarantee that they are not mitigated. This self-mitigating behavior at 10 percent can be problematic.

The purpose of mitigation for economic withholding is to protect the market from resources that have the unilateral ability to increase market prices. Resources flagged for economic withholding mitigation have local market power, and allowing inflated market offers only gives them more opportunity to exercise market power. Resources that are committed for a local reliability issue, often for voltage support, should not fall into this category. Even though these resources are needed and must be committed, they are committed outside of the market clearing engine logic, and often do not have the ability to increase prices as they are frequently dispatched down to minimum.

Figure 6–19 Mitigation energy offer mark-up by fuel category



Resources receiving a commitment for local reliability (about 0.4 percent of all commitments in 2017) are subject to a 10 percent mitigation threshold for the duration of their commitment. The market system replaces market offers that are more than 10 percent above the mitigated offer with the mitigated offer for that commitment. Resources that do not receive commitments for local reliability are not at risk of being mitigated down to the mitigated offer level for offers between 10 percent and 25 percent above the mitigated offer (17.5 percent for resources in designated frequently constrained areas, which accounts for nine percent of all resources).

When resource owners decide on a market offer for a resource that has the possibility of receiving a reliability commitment, the owner may factor in the risk of being mitigated to the mitigated offer level for offers above 10 percent. All other resource owners do not face this risk and will not have their market offer reduced to the mitigated offer level, if the market offer does not exceed 25 percent above the mitigated offer. By converting the 10 percent threshold for reliability commitments to a 10 percent cap, the risk of making an offer between 10 percent and 25 percent above the mitigated offer would be the same for all resource owners. This is a subtle but important risk for the small number of market participants that may be committed for reliability commitments. These resource owners are subject to a higher level of risk through no fault of their own.

The MMU recommended in its 2016 report that mitigation measures for resources committed for a local reliability issue be treated separately from the mitigation measures for economic withholding. Resources that fall into this category are not subject to the three tests associated with economic withholding, which is appropriate. The MMU submitted revision request 231[115] to the Market Working Group in May 2017, which proposed converting the 10 percent threshold for local reliability mitigation to a 10 percent cap. The revision request received SPP board approval in October, and is awaiting FERC filing and approval.

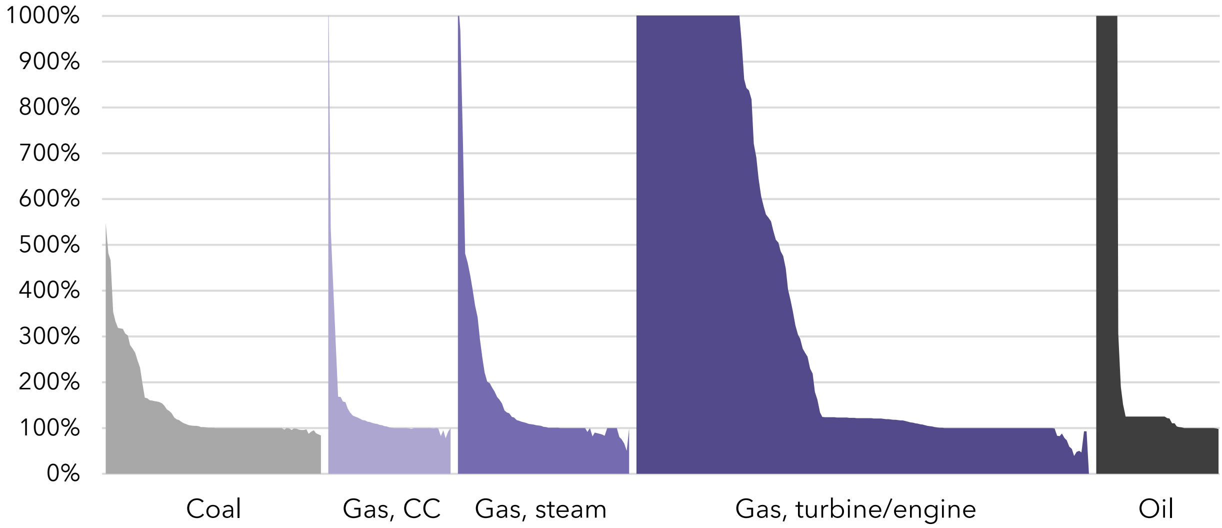
6.4 START-UP AND NO-LOAD BEHAVIOR

Similar analysis with no-load and start-up offers indicated that many market participants were making start-up and no-load offers considerably above their mitigated offer levels as shown

[115] Revision request 231 Mitigation of locally committed resources.

in Figure 6–20. Nonetheless, start-up mitigation only occurred in approximately three percent of intervals in 2017.

Figure 6–20 Mitigation start-up offer mark-up by fuel category



Further analysis and discussion indicated that start-up mitigation was most frequently due to major maintenance costs inherent in the repeated heating and cooling process of starting-up and shutting down units. As the purpose of the mitigated offer is to prevent undue costs not directly tied to a commitment or dispatch decision from being imposed on the market, revision request 245 was developed.[116] This revision request will allow the inclusion of major maintenance costs that can be directly tied to the number of run hours or starts to be included in the mitigated offers for start-up and no-load and properly evaluated by the market clearing engine in determining commitments. Revision request 245 has been approved by the appropriate stakeholder groups and is expected to be filed in April 2018. The MMU is supportive of revision request 245 and feels that it will encourage more units to move into the market commitment status, which will lead to more efficient price formation and reduce starts for units that are less efficient.

6.5 COMPETITIVE ASSESSMENT SUMMARY

Overall, the structural and behavioral metrics indicate that the SPP markets were very competitive in its first four years. The market share, HHI, and pivotal supplier analyses all

[116] RR245 Mitigated Start-Up and No-Load Offer Maintenance Cost.

indicate minimal potential structural market power in SPP markets outside of areas that are frequently congested. There were two designated frequently constrained areas in 2017 where the potential concerns of local market power were the highest. Ongoing analysis shows existing mitigation measures have been an effective deterrent in preventing pivotal suppliers from unilaterally raising prices.

Behavioral indicators were also assessed through the analysis of actual offer or bid behavior (i.e., conduct) of the market participants and the impact of such behavior on market prices to look for the exercise of market power. One such indicator, the negative offer price mark-ups in 2017 show substantially elevated negative offer levels compared to those of 2016. This could occur where—particularly coal—generators decide to offer below their marginal cost to maintain commitments or when wind units become marginal and their (negative) offers clear the market.

Economic withholding mitigation was still at a low level in absolute terms. In particular, the incremental energy mitigation was extremely low in both the day-ahead and real-time markets, at around 0.01 percent in each market for 2017. The overall mitigation frequency of start-up offers in 2017 were at the lowest levels since market started in 2014 as the combined frequency of mitigation of start-up offers for day-ahead, reliability unit commitment, and manual commitments decreased to 3.2 percent in 2017 from 3.8 percent in 2016. While the frequency of no-load, operating reserve, and incremental energy mitigation increased in 2017, the level of mitigation remained low overall. The overall mitigation frequency levels experienced in 2017 are consistent with the levels experienced in other markets.

The system wide output gap results show a very low-level—less than 0.007 percent—of economic withholding in all months in 2016 to 2017 across the SPP footprint. Compared to 2015, all results indicate much lower levels of output withheld in 2016 and 2017, and were particularly lower at higher demand levels. In the two frequently constrained areas, there was no measurable output withheld in 2016 and 2017. These low levels of economic output withheld is consistent with competitive market conduct.

The newly introduced metric, the average unoffered economic capacity was around two percent in the 2015 to 2017 period and was at 1.9 percent in 2017. The majority of the outages were long-term outages, and were primarily the result of maintenance in the shoulder months of fall and spring. The results are generally consistent with the workings of a typical competitive market.

Meanwhile, the very low level—less than one percent—of unoffered capacity net of outages could indicate a pressure on market participants to offer—and maintain commitments—given their longer term agreements. The general high levels of self-committing supply in the market could be another factor in the low levels of unoffered capacity.

Overall, the SPP Integrated Marketplace provides effective market incentives and mitigation measures to produce competitive market outcomes particularly during market intervals where exercise of local market power is a concern. The competitive assessment in this report provides evidence that market results in 2017 were workably competitive and that the market required mitigation of local market power infrequently to achieve those outcomes. Nonetheless, mitigation remains an essential tool in ensuring that market results are competitive during periods when such market conditions offer suppliers the potential to abuse local market power.

7 RECOMMENDATIONS

One of the core functions of a market monitor as defined by FERC in Order No. 719 is "to advise the Commission, the RTO or ISO, and other interested entities of its views regarding any needed rule and tariff changes." The MMU accomplishes this responsibility through many forums, including but not limited to active participation in the SPP stakeholder meetings process, commenting on FERC notices of proposed rulemakings, submitting comments at FERC on SPP filings, and making recommendations in the Annual State of the Market report. This section outlines the MMU recommendations to SPP and stakeholders to address our concerns with the current market design.

Further, this section highlights both new recommendations as well as recommendations made in prior reports. For each recommendation, we present the reasons for our recommendation and assign a priority. We also identify the current status of previous recommendations. Overall, SPP and its stakeholders have made significant progress on most outstanding MMU recommendations. Section 7.5 below lists the status of past and current annual report recommendations.

7.1 INCREASE MARKET FLEXIBILITY

The SPP market needs more flexible generation to meet increasing ramping requirements as renewable generation levels continue to increase (see Section 2.5) and as renewable generation dominates the interconnection queue over the next several years (see Section 2.3.3). As presented earlier in this report, we have seen a doubling of the frequency of negative priced intervals, and an increase in short-term transitory price spikes related to scarcity of ramping. Because of the variable output nature of these renewable energy resources, the market needs increasing capability to respond to the inevitable fluctuations in order to promote efficient market outcomes and ensure reliability. At this juncture, it is imperative for the RTO and its members improve its market mechanisms to address this growing concern.

While there is no single solution, there are existing ways that SPP can increase market flexibility. We outline these solutions below.

7.1.1 DEVELOP A RAMPING PRODUCT

A ramping product that incents actual, deliverable flexibility can send appropriate price signals to value resource flexibility. This resource flexibility can help prepare the system for fluctuations in both demand and supply that result in transient short-term positive and negative price spikes.

Today, the SPP dispatch engine solves for only the current interval and has no look-ahead logic to ensure that there is enough rampable capability to meet the needs of future intervals. This can cause quick-ramping resources to be dispatched to their maximum limits in one interval, and then, in the next interval, there is a shortage of ramp because the only resources able to move have slower ramp rates. In these cases, SPP can have plenty of capacity on-line, but not enough rampable capacity, which can result in scarcity pricing.

As noted above, SPP's scarcity events are very short-term, transient events that are frequently a result of a shortage of rampable capacity. A ramping product will compensate resources for holding back capability in one interval so it can be used as energy in a future interval. This will reduce the frequency of scarcity events and provide value to the resources providing ramping capability.

Both the California ISO and Midcontinent ISO have designed and successfully implemented ramping products. While SPP stakeholders have discussed the possibility of a ramping product for the last several years, the development of a ramping product has only now risen to the top of stakeholder priorities to be addressed in the coming months. We agree with the assessment of SPP and its stakeholders that this is a high priority initiative and recommend that a ramping product be designed in 2018.

7.1.2 IMPROVE RULES RELATED TO DECOMMITTING RESOURCES

Over-commitment of resources in real time suppresses prices and leads to increased make-whole payments. This can be caused by changing conditions between the time a resource is locked into a commitment by the market software and the time the resource actually comes on-line. The MMU recommends that SPP and its stakeholders address this issue by enhancing its markets rules to economically decommit a resource that is planned to start.

Resources are frequently committed by the market software well in advance of when they are actually required to start. This commitment is based on the known assumptions at the time the market engine clears the market. However, conditions change over time. For instance, load forecasts, wind forecasts, and outages change, and resources trip off-line. Resources are committed because the market software evaluates it to be profitable over that study period. When assumptions change, the resource may no longer be profitable; however, the start-up order is not cancelled.

Stakeholders have prioritized the development of design changes to economically decommit a resource that was planned to start but is no longer needed once the resource reaches the time to start. We agree with the assessment and priority of this initiative. The MMU recommends that decommit logic be developed in 2018.

7.1.3 ENHANCE MARKET RULES FOR ENERGY STORAGE RESOURCES

With the increase in wind penetration in the SPP market, there is not only a need for resource flexibility, but also for storage where the frequency of negative prices has increased, as discussed in Section 4.1.6. Stored energy resources have the potential to address both the need for flexibility and reduce the incidence of negative prices. However, SPP's current tariff does not easily allow these resources to integrate in our market. In order to capture the benefits of these new technologies, a new market design needs to be developed.

Though SPP, its members and stakeholders, and the MMU have discussed ways to incorporate stored energy resources in the past, development of tariff language to support energy storage resources has not yet occurred. We believe that the lack of an effective market design may be an influencing factor limiting the integration of storage resources in the SPP market. Enhancing market rules will allow these new resources to enter the market to help address the incidence of negative prices and add needed resource flexibility.

FERC issued an order requiring RTO/ISOs to develop market rules to promote energy storage in February 2018.[117] The MMU agrees with FERC and looks forward to discussion on this topic going forward.

[117] https://www.ferc.gov/whats-new/comm-meet/2018/021518/E-1.pdf

7.2 IMPROVE MARKET EFFICIENCY

One of the key benefits of the day-ahead market is the unit commitment process. Market participants offer resources into the day-ahead market and the market optimization process minimizes production costs. When participants self-commit resources, this can create inefficient market outcomes. Furthermore, market inefficiencies also occur when resources with forecasted generation—such as wind—are withheld from the day-ahead market run, even though their expected generation levels are much higher in the day-ahead reliability unit commitment process. Both of these inefficiencies can result in suppressed, and potentially negative, market prices. Addressing these issues, can improve market results and provide more efficient price signals. We recommend that SPP and its stakeholders address both of these issues.

7.2.1 ADDRESS INEFFICIENCY CAUSED BY SELF-COMMITTED RESOURCES

Market participants have identified several reasons why they self-commit resources in the market. Some of these reasons include contract terms for coal plants, low gas prices that reduce the opportunity for coal units to be economically cleared in the day-ahead market, long startup times, overtime costs, increased major maintenance costs, and a risk-averse business practice approach. However, it is imperative to minimize the need to self-commit resources to realize the full benefits of SPP's market. While there may not be a single reason causing market participants to self-commit resources, there can be ways that SPP and its stakeholders can work to minimize the need to self-commit.

For instance, long lead time and long run time resources are often self-committed in the market and contribute to depressing prices in the SPP market. These resources are not appropriately evaluated in the current structure of the market and can be committed by the market participant during uneconomic periods. The current clearing engine logic does not evaluate commitments beyond the 24-hour period of the next operating day. The creation of a market process that economically evaluates resources over a longer period will allow for more efficient market solutions, as well as decreased production costs.[118]

In the current design, a resource that is required to run for multiple days is not evaluated by the day-ahead market to see if the resource is economic over its minimum run time. The clearing engine may see that it is economic on the first day and issue the commitment, and then in future days the resource must stay on even if it is uneconomic. As such, many resources that have multi-day minimum run times avoid the market clearing process and instead self-commit in the market based not on an evaluation by the market, but on their own evaluation of market conditions. This is not the optimal solution for the SPP market as it removes the ability for the SPP market software to evaluate and commit the resources economically relative to all other resources in the market.

Adding multi-day unit commitment logic is at the top of the current stakeholder market design initiative list. The MMU agrees that this should be a priority item and supports SPP and its stakeholders in attempting to address self-commitments through the development of a multi-day unit commitment process. More broadly, however, the MMU recommends that SPP and its stakeholders continue to explore and develop ways to reduce the incidence of self-commitment of resources outside of the market engine. We view this as a high priority for SPP and its stakeholders as this will enhance market efficiency and improve price signals.

7.2.2 ADDRESS INEFFICIENCY WHEN FORECASTED RESOURCES UNDER-SCHEDULE DAY-AHEAD

Our analysis shows that, on average, 82 percent of forecasted wind generation was scheduled in the day-ahead market in 2017, compared to 89 percent in 2016, and 92 percent in 2015. This under-scheduling continues to grow as more wind is installed. On average for the year, over 1,200 MWh of real-time wind generation was not included in the day-ahead market.[119] When this happens, we frequently observe day-ahead prices exceeding real-time prices. While we also observe virtual participants placing bids and offers at wind locations during these times, we find that price convergence in absolute terms is not improving. As a

[118] This would be different from the current multi-day reliability unit commitment process.
[119] From a reliability standpoint, the reliability unit commitment assesses wind resources at forecasted levels. However, the reliability unit commitment process cannot economically decommit resources scheduled by the day-ahead market.

result, the efficiency of the day-ahead unit commitment process is reduced. In this case, other non-wind resources may be overcommitted in the day-ahead market, which results in real-time prices lower than day-ahead prices.

Systematic under-scheduling of wind resources in the day-ahead market can contribute to distorting market price signals, suppressing real-time prices, and affecting revenue adequacy for all resources. Therefore, the MMU recommends that SPP and its stakeholders address this issue through market rules changes that reduce the incidence of under-scheduling of forecasted supply of resources in the day-ahead market. We consider this a high priority as it helps to enhance market efficiency and improve price signals.

7.3 FURTHER ENHANCE ALIGNMENT OF PLANNING PROCESSES WITH OPERATIONAL CONDITIONS

Enhancing the accuracy of planning processes with operational realities enables SPP and its members to more effectively plan for future system needs and conditions. Many of the challenges outlined in this report—including increased congestion, negative prices, and low generator net revenues—as well as improvements—such as the addition of the Woodward phase-shifting transformer—are, in part, a reflection of planning decisions. The more the planning process can learn from and incorporate operational information, the more planning can identify and address concerns in advance of market operations. The MMU understands that much work has been done by SPP and stakeholders over the past few years to improve and align the planning and operational processes. For instance, SPP in its latest Integrated Transmission Planning manual introduced an assessment for persistent operational needs and the criteria for identifying these needs.[120] The MMU has identified two additional areas where further alignment would be beneficial. Specifically, the economic studies and resource adequacy processes are two planning processes that could benefit by further aligning with operational information.

First, SPP proposed to set the interim default variable operations and maintenance costs for wind resources to $0/MWh in revision request 276. While the Economic Studies Working

[120] See SPP Integrated Transmission Planning Manual (dated July 20, 2017 pending FERC approval of Tariff language), including sections 4.4, 5.3.4, and 6.1.4 (available at https://www.spp.org/documents/22887/itp%20manual%20version%202.0.pdf).

Group rejected this revision request and narrowly passed an amended version of this request, the Market Operations and Policy Committee reversed direction and accepted the original SPP proposal. Based on the review of operational information by the MMU, we find that variable operations and maintenance costs for wind resources are closer to $0/MWh. Using a value in economic planning studies inconsistent with operational realities will distort how stakeholders evaluate the benefits and costs of transmission upgrades. Thus, we recommend that as a permanent solution is designed, the approach should seek to align the variable operations and maintenance costs with the appropriate operational realities.

Second, as discussed earlier in this report, SPP excludes resources without firm transmission from resource adequacy calculations.[121] Even at conservative planning levels, this ignores several hundred megawatts of real-time generation, understating the true generation that is available to SPP at peak load conditions. As shown in our peak available capacity metric (Section 2.3.2), we find that a significant amount of generation is available at peak loads, which helps to contribute to the market challenges noted in this report. Directly recognizing the different levels of generation availability could help inform stakeholders and decision-makers in formulating decisions on generation and capacity needs. Thus, we recommend that SPP highlight the full set of generation that exists as part of the resource adequacy process.

7.4 ADDRESS PREVIOUS RECOMMENDATIONS

The MMU has provided recommendations to improve market design in each of our previous Annual State of the Market reports since the launch of the integrated marketplace in 2014. Overall, SPP and its stakeholders have found ways to effectively address many of our concerns. However, there are a number of recommendations that remain outstanding. A description of each of these recommendations, their currents status, and our assessment of their priority are outlined below.

[121] SPP also excludes resources without physical supply or a firm pipeline reservation.

7.4.1 CONVERT NON-DISPATCHABLE VARIABLE ENERGY RESOURCES TO DISPATCHABLE

In the 2015 Annual State of the Market report, the MMU identified non-dispatchable variable energy resources as a concern because of their adverse impact on market price and system operations. These resources exacerbate congestion, reduce prices for other resources, increase the magnitude of negative prices, cause the need for market-to-market payments, and force manual commitments of resources that can increase uplifts. Going forward, resource flexibility is essential to integrate an increasing volume of wind generation in the SPP market. FERC demonstrated strong support for the elimination of most instances of non-dispatchable resources with the approval of a rule change for the New England market in December 2016.[122] Furthermore, FERC also rejected California ISO's proposal to extend the transition period for protective measures related to non-dispatchable variable energy, thus requiring dispatchability.[123]

In the summer and fall of 2017, SPP and its stakeholders discussed the impacts and implications of non-dispatchable variable energy resources on market outcomes at the Market Working Group. By the end of the year and into early 2018 multiple proposals were brought forth and discussed at the Market Working Group. The Market Working Group passed a proposal by SPP at the February 2018 meeting that required full conversion of non-dispatchable variable energy resources. The MMU strongly supported this proposal and will continue to support this proposal as it continues along the SPP stakeholder process.

Because of the need to increase market flexibility and to address adverse market outcomes associated with non-dispatchable variable energy resources, the MMU strongly recommends that SPP and its stakeholders address this issue. The MMU considers this to be a high priority recommendation.

7.4.2 ADDRESS GAMING OPPORTUNITY FOR MULTI-DAY MINIMUM RUN TIME RESOURCES

Resources with minimum run times greater than two days have the opportunity to game the market. The current market rules limit make-whole payments to the as-committed market offers for the first two days of a resource's minimum run time. However, after the second day,

[122] See FERC Docket Nos. ER17-68-000 and ER17-68-001.
[123] See FERC Docket No. ER17-1337-000.

no rule exists to limit make-whole payments for a resource that increases its offers from the third day onward until the resource's minimum run time is satisfied. For resources with minimum run times greater than two days, the market participant knows that the resource is required to run and can increase their market offers after the second day to increase make-whole payments.

The MMU developed and presented a proposed solution to the Market Working Group in March 2017. This solution would have capped the market offer after the first day to the ratio of the market offers to the mitigated offers. The proposal was rejected by the Market Working Group. The MMU successfully appealed the issue to the Market and Operations Policy Committee (MOPC) which remanded this topic back to the Market Working Group for further review in July 2017. Ongoing discussions among stakeholders have continued into early 2018, and after much discussion the Market Working Group has identified a potential solution. The current proposed solution would limit the make-whole payments for any resource with multi-day minimum run times to the lower of the market offer or the mitigated offer after the first day for resources that bid at or above their mitigated offer on the first day.

The MMU strongly recommends that SPP and its stakeholders address the gaming opportunity that exists for resources with minimum run times greater than two days and supports the current direction of the Market Working Group. Our understanding is that all other RTO/ISO markets address this item. Addressing this matter in a timely manner is a high priority for the MMU.

7.4.3 CONVERT THE LOCAL RELIABILITY MITIGATION THRESHOLD TO CAP

In the 2016 Annual State of the Market report the MMU recommended converting the 10 percent mitigation threshold for local reliability commitments to a 10 percent cap. This recommendation addresses an unbalanced risk associated with mitigation of resource commitments for local reliability.

When market participants decide on a market offer for a resource that has the possibility of receiving a local reliability commitment, the participant must factor in the risk of being mitigated to the mitigated offer level for offers above 10 percent above the mitigated offer. All other resources do not face this risk and will not have their market offer reduced to the mitigated offer level if the market offer does not exceed 25 percent above the mitigated offer. By converting the 10 percent threshold for reliability commitments to a 10 percent cap, the risk of local market power mitigation for offers between 10 percent and 25 percent above the mitigated offer would be similar as for all other resources. This is a subtle but important risk for the small number of market participants exposed to local reliability commitments that are outside of the market.

The Market Working Group passed a proposal in August presented by the MMU to convert the 10 percent mitigation threshold for local reliability commitments to a 10 percent cap as part of a suite of changes and clarifications associated with mitigation. This change was approved by the SPP board of directors in October and is pending a FERC filing. The MMU strongly supports this change and will support this when filed at FERC.

7.4.4 REPLACE DAY-AHEAD MUST OFFER, ADD PHYSICAL WITHHOLDING PROVISION

FERC rejected SPP's proposal to remove the day-ahead must offer requirement and indicated that it would consider removal of the requirement if it were paired with additional physical withholding provisions.

While the MMU remains concerned with the current day-ahead must offer requirement, we recommend that further consideration of this issue be a low priority. The MMU will continue to track market performance concerns related to this provision and will consider raising the priority on this matter if further issues are identified or current issues are exacerbated. Otherwise, we regard other matters as having higher impacts to and priority for development at this time.

7.5 RECOMMENDATIONS UPDATE

The table below lists all of the Annual State of the Market recommendations that were closed in 2016 through the date of this report, those that remain open, and those that are new. Recommendations closed prior to the completion of the previous year's report do not appear in this table. To review closed recommendations that are not covered in this report, please consult earlier reports. All previous annual reports can be found at https://www.spp.org/spp-documents-filings/?id=18512.

Figure 7–1 Annual State of the Market recommendations update

Recommendation	Report year	Current status
1. Develop multi-day commitment process	2017	Planned for stakeholder consideration
2. Address under-scheduling of wind	2017	Awaiting stakeholder engagement
3. Develop ramping product	2017	Planned for stakeholder consideration
4. Enhance unit decommitment logic	2017	Planned for stakeholder consideration
5. Develop energy storage design	2017	Response to FERC order in progress
6. Continue alignment of planning processes with operational conditions	2017	Awaiting consideration and engagement
7. Local reliability commitment mitigation threshold conversion to a cap	2016	Awaiting FERC filing
8. Non-dispatchable variable energy resource transition to dispatchable variable energy resource status	2015	Appeal in progress to SPP board
9. Improved quick-start logic	2014	Awaiting FERC order
10. Manipulation of make-whole payment provisions (multiple items)	2014	Across midnight hour – in progress Out-of-merit payments – withdrawn by MMU Jointly-owned units – in progress Regulation – approved by FERC, awaiting implementation
11. Day-ahead must offer requirement and physical withholding	2014	Day-ahead must offer – request denied by FERC pending physical withholding additions
12. Allocation of over-collected losses	2014	Awaiting FERC approval
13. Increase conduct test thresholds in frequently constrained areas	2014	Withdrawn by MMU

COMMON ACRONYMS

AECC	Arkansas Electric Cooperative Corporation
AECI	Associated Electric Cooperative, Inc.
AEP/AEPM	American Electric Power
ARR	auction revenue rights
BEPM	Basin Electric Power Cooperative
BSS	bilateral settlement schedules
BTU	British thermal unit
CC	combined-cycle
CDD	cooling degree days
CHAN	City of Chanute (Kan.)
CT	combustion turbine
DA	day-ahead
DAMKT	day-ahead market
DA RUC	day-ahead reliability unit commitment
DISIS	definitive interconnection system impact study
EDE/EDEP	Empire District Electric Co.
EHV	extra high voltage
EIA	Energy Information Administration
EIS	energy imbalance service
ERCOT	Electric Reliability Council of Texas
FCA	frequently constrained area
FERC	Federal Energy Regulatory Commission
GI	generation interconnection
GLDF	generator to load distribution factor
GMOC/UCU	Greater Missouri Operations Company (KCPL)
GRDA/GRDX	Grand River Dam Authority
GSEC	Golden Spread Electric Cooperative, Inc.
GW	gigawatt
GWh	gigawatt hour
HDD	heating degree days
HHI	Herfindahl-Hirschman Index

HMMU	Harlan (Iowa) Municipal Utilities
HVDC	high-voltage direct current
IA	interconnection agreement
ID RUC	intra-day reliability unit commitment
IDC	interchange distribution calculator
INDN	City of Independence (Mo.)
IOU	investor owned utility
IPP	independent power producer
IS	Integrated System
ISO	independent system operator
ITP	Integrated Transmission Plan
JOU	jointly-owned unit
KBPU	Kansas City (Kan.) Board of Public Utilities
KCPL/KCPS	Kansas City Power & Light
KMEA	Kansas Municipal Energy Agency
KPP	Kansas Power Pool
kV	kilovolt (1,000 volts)
LES/LESM	Lincoln (Nebr.) Electric System
LIP	locational imbalance price
LMP	locational marginal price
MCC	marginal congestion component
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
MLC	marginal loss component
MM	million
MMBtu	million British thermal units (1,000,000 Btu)
MMU	Market Monitoring Unit
MW	megawatt (1,000,000 watts)
MWh	megawatt hour
MWP	make-whole payment

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	Northern States Power Energy
NWPS	Northwestern Energy
O&M	operation and maintenance
OGE	Oklahoma Gas & Electric
OMPA	Oklahoma Municipal Power Authority
OOME	out-of-merit energy
OPPD/OPPM	Omaha Public Power District
OTPW/OTPR	Otter Tail Power Company
PJM	PJM Interconnection, LLC
PEPL	Panhandle Eastern Pipe Line
PISIS	preliminary interconnection system impact study
RC	reliability coordinator
RNU	revenue neutrality uplift
RR	revision request
RSG	reserve sharing group
RT	real time
RTBM	real-time balancing market
RTO	regional transmission organization
RUC	reliability unit commitment
SC	simple-cycle
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
ST	steam turbine
ST RUC	short-term reliability unit commitment
TCR	transmission congestion right

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