STATE OF THE MARKET 2020

SPP Southwest Power Pool

MARKET MONITORING UNIT

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1 EXECUTIVE SUMMARY

The following list identifies key observations in the SPP marketplace during 2020.

- In 2020, wind generation represented the largest portion of total energy produced at 31.3 percent of the total. Coal generation was slightly behind at 31.0 percent of the total.

- Structural and behavioral metrics indicate that the SPP markets have been competitive over the last several years. The market share, Herfindahl-Hirschman Index (HHI), and pivotal supplier analyses all indicate minimal to moderate potential structural market power in SPP markets.

- Day-ahead market prices averaged $17.69/MWh and the average real-time price was $16.62/MWh for 2020, a decrease of 20 percent for both from 2019. Average gas price for 2020 at the Panhandle Eastern hub was $1.72/MMBtu, down 11 percent from $1.93/MMBtu in 2019.

- The annual peak load of 49,569 MW was three percent lower this year compared to last year, while total electricity consumption was down about three percent.

- The frequency of negative priced intervals increased 35 percent from 2019. Just under 11 percent of all intervals in the real-time market had negative prices, up from seven percent in 2019. Four and a half percent of day-ahead intervals had negative prices, which was up from roughly two percent in 2019.

- Market-to-market payments totaled $82.8 million from MISO to SPP for 2020, this was up significantly from $17.5 million in 2019. The majority of the increase occurred in the last three months of the year.

- Make-whole payments in the reliability unit commitment process were down from $70 million in 2019 to $51 million in 2020, a 27 percent decrease. Make-whole payments in the day-ahead market, however, were up markedly, from $32 million in 2019 to $53 million in 2020, a 69 percent increase.

- Scarcity events in the real-time market increased in 2020 when compared to 2019 levels. Regulation-down scarcity intervals increased by 58 percent and regulation-up increased by 15 percent from 2019 to 2020, while contingency reserve scarcity decreased by 53 percent during the same period.

- Capacity of gas, simple-cycle resources taken out of service for maintenance decreased by 18 percent from 2019 to 2020. Total outages for capacity taken out-of-service for maintenance decreased by four percent from 2019 to 2020. Much of the decrease can be attributed to disruptions and adjustments of outages due to COVID-19 precautions.

- The average percent of total offered capacity by commitment status shows a six percentage point decrease in “self-commit” status and a six percentage point increase in “market” status.

- Average profit per cleared virtual megawatt after fees was unchanged from 2019, at $0.63/MW.

- Day-ahead and real-time congestion costs totaled over $442 million in 2020, an eight percent decrease from 2019.

- Wind nameplate capacity increased to just over 27.3 GW in 2020, up about 22 percent from 2019.

- The generator interconnection process includes nearly 98 GW of additional resources, of which all but 5 MW are renewable or storage.

- SPP continues to have significant excess capacity at peak loads. The MMU estimates that capacity at peak is 36 percent higher than the peak demand level in 2020. This is up from 31 percent in 2019, but can mostly be attributed to a decrease in the peak load in 2020. Available capacity only increased less than one percent from 2019 to 2020.

- Revenues have been insufficient to support the cost of new entry of scrubbed coal, advanced combined-cycle, advanced combustion turbine generation, wind, and solar photovoltaic since the inception of the Integrated Marketplace, and 2020 was no exception.

- Transmission congestion rights funding fell outside the target range. The annual funding percentage fell to 82 percent in 2020, down from 89 percent in 2019, and the annual shortfall worsened by more than $53 million.

1.1 OVERVIEW

The SPP market produced competitive market results overall with total market costs around $20/MWh. As with previous years, the largest component of total wholesale costs remains energy costs, which represented almost 98 percent of total costs in 2020. As total costs decreased by 17 percent in 2020 compared to 2019, the main driver for the decrease in energy costs was a decrease in gas cost of 25 percent. When adjusted for fuel prices, average SPP marginal energy prices decreased by 18 percent.

The annual peak load of 49,569 MW was three percent lower this year compared to last year, while total electricity consumption was down about three percent as well. Of the 4,836 MW increase in nameplate generation capacity from 2019, 4,779 MW was from wind resources, with the remainder from oil, solar, and dispatcahable demand response.

Wind generation as a percent of total generation continued to increase as it represented 31.3 percent of system generation in 2020, up from 27.4 percent in 2019. Conversely, coal generation continued to decline, representing around 31.0 percent of total generation last year, down from 34.8 percent in 2019. This represents the first year that wind generation has been the largest source of total generation in the Integrated Marketplace.

1.2 DAY-AHEAD AND REAL-TIME MARKET PERFORMANCE

Overall, both day-ahead and real-time energy prices were about $4/MWh lower in 2020 compared to 2019. This decrease can primarily be attributed to lower gas costs across the SPP market footprint, with those costs down 11 percent from 2019, along with decreased load and increased levels of low-cost wind generation.

Load participation in the day-ahead market continued to be strong in 2020. For instance, the average level of participation for the load assets was between 99 percent and 101 percent of the actual real-time load. However, on average for the year, wind generation was over 1,700 MW higher in the real-time market compared to the amount scheduled in the day-ahead market on an hourly basis. This represents a continued and increasing challenge to the market as wind generation continues to increase substantially.

Virtual bids and offers may theoretically offset the under-scheduling of renewable supply in the day-ahead market, however, in net they did not as they averaged around 1,200 MW of net virtual supply. 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 profitable in the SPP market. Net profit before fees decreased slightly in 2020 to $72 million, down from $75 million in 2019. When charges and transaction fees are included, net profit for virtual transactions was $36 million in 2020, up from $31 million in 2019.

Generation offers in the day-ahead market averaged just over 62 percent as "market" commitment status followed by "self-commit" status at 18 percent of the total capacity commitments for 2020. This continues the trend of increasing market commitments and decreasing self-commitment since 2016. In order to improve market commitment in the SPP market, the MMU recommends that SPP and stakeholders look to find ways to reduce the incidence of self-commitment and to consider adding an additional day the day-ahead unit commitment process. For more details on the MMU's study of self-commitments in the SPP market, refer to the whitepaper on self-commitment published in December 2019.[1]

During December, the market experienced its first instances of day-ahead scarcity. These instances occurred on back-to-back hours on December 23 and on a single hour on December 30. In all three instances, regulation-up was short less than 1 MW.

Overall, real-time scarcity events increased in 2020 when compared to 2019 levels. 2020 experienced 1,346 five-minute intervals of real-time scarcity, up 10 percent from 1,220 intervals in 2019. Nearly 60 percent of the scarcity intervals happened during four months of 2020 –

[1] *Self-committing in SPP markets: Overview, impacts, and recommendations*, published by the SPP MMU,

March, April, October, and November – months that typically have high wind production, low load, and more generation outages. Additionally, looking at the intervals where scarcity occurs each hour shows that over 35 percent of all scarcity events, and nearly 50 percent of regulation-down scarcity events, in 2020 occurred in the first interval of the hour. One potential reason for this trend is that SPP does not preposition regulating resources to be at their regulating effective maximum and minimum limits prior to the period that the resource is cleared for regulation. Unlike some other RTO/ISO markets, the current SPP model does not account for forecasted ramping needs. SPP has designed a ramp capability product, which is expected to be implemented in early 2022.[2]

1.3 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.

The area that experienced the highest congestion costs in 2020 was the southeastern corner of SPP including eastern Kansas, southwest Missouri, and southeastern Oklahoma. Concentrated areas on the Kansas and Oklahoma border and southeast Oklahoma experienced the lowest congestion costs for the year. The frequently constrained area study for 2020 saw similar congestion patterns as 2019, warranting no additions, so there remains no frequently constrained areas at this time.

In total, net congestion costs were just over $442 million in 2020. This was down slightly from $457 million in 2019. 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 under-hedged. The largest amount over-hedged was nearly $47 million, while the largest amount under-hedged was nearly $11 million.

[2] Tariff Revisions to Add Ramp Capability, FERC Docket No. ER20-1617.

1.4 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 2020, total make-whole payments were approximately $104 million, up slightly from $101 million in 2019. Make-whole payments averaged about $0.40/MWh in 2020, up from $0.37/MWh in 2019.

For 2020, reliability unit commitment make-whole payments constituted 49 percent of the total make-whole payment, while day-ahead make-whole payments constituted 51 percent of the total. A primary driver of these make-whole payments was for manual capacity commitments in the real-time market to meet ramping needs. The increase in capacity commitments was caused by a few factors. First, the increase in generation outages reduced the availability of capacity to meet uncertainty of both supply and demand. Second, the higher level of wind penetration on the system has increased the overall level of uncertainty in the market. Third, very low gas prices – which were negative at times in some regions – resulted in flexible resources being committed for energy in the day-ahead and unavailable to provide additional ramping flexibility in real-time.

The MMU is very concerned about increasing make-whole payments. With the expectation that wind generation will continue to have an increasing role in the SPP market, uncertainty and ramping needs will continue to increase. This increase provides further evidence that both a ramping product and an uncertainty product are needed to provide market signals for flexible ramping capability. Furthermore, additional rules are required to address MMU concerns with outages and their impacts to both market prices and make-whole payments.

1.5 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 2020 were competitive overall and that the market required mitigation of local market power infrequently to achieve competitive outcomes.

Structural competitiveness metrics – which review the structural potential for the exercise of market power – indicate minimal to moderate potential structural market power in SPP markets outside of areas that are frequently congested. The market share of the largest on-line supplier in terms of real-time energy output exceeded 20 percent in 66 percent of all hours in 2020, which represents a significant increase from 2018 and 2019. This trend has been observed since June 2018, which coincides with the merger between Great Plains Energy and Westar Energy to form Evergy, Inc., and is attributable to real-time dispatch of resources owned and controlled by the merged entity. This is up from 2017, when no hours were above the 20 percent threshold, and the highest value was 17 percent.

An additional measure of structural market power is the Herfindahl-Hirschman Index (HHI). This analysis, based on actual generation, indicates that 12 percent of hours in 2020 had values between 1,000 and 1,800, which indicates a moderate level of concentration. The market had been considered unconcentrated since the addition of the Integrated System in October 2015, up until the creation of Evergy in June 2018. Prior to the addition of the Integrated System, nearly 40 percent of all hours were considered moderately concentrated.

While moderately concentrated hours increased following the creation of Evergy, an increase in market share and HHI in themselves does not pose a threat to the structural competitiveness of the SPP market. Other relevant market data including pivotal supplier hours and local market power mitigation must also be evaluated for competitive assessment.

Behavioral indicators—which assess the actual exercise of market power—show low levels of mitigation frequency. Incremental energy offer mitigation in 2020 was extremely low, with approximately 0.03 percent of hours mitigated in both the day-ahead and real-time markets. The combined mitigation frequency of start-up offers for day-ahead, reliability unit commitment, and manual commitments was slightly higher than in 2019 at around 3.5 percent in 2020

Both off-peak and on-peak average offer markups were at the lowest levels since implementation of the Integrated Marketplace at around −$9.54/MWh and −$8.71/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.

The monthly average output gap—that measures economic withholding—shows low levels of economic withholding in all months in 2020, at less than 0.3 percent each month, with only one month above 0.2 percent. These low levels of economic output withholding reflect highly competitive participation in the market.

Another method of competitive assessment is 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 3.2 percent in 2018, 2.9 percent in 2019, and 1.5 percent in 2020. Due to the pandemic of COVID-19 starting in March, many plants cancelled or postponed their regular spring maintenance so the long-term outages did not occur in the spring shoulder months, but show a higher amount in the fall shoulder months. When short and long-term outages were excluded from the averages, the remaining unoffered capacity amounts to 0.39 percent, 0.43 percent and 0.21 percent for 2018 through 2020, 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.

1.6 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 that capacity was 36 percent higher than the peak load in 2020. SPP’s current annual planning capacity requirement is 12 percent.

Wind capacity has continued its steady growth, from 8.6 GW in 2014 to 27.3 GW in 2020. 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 over 31 percent in 2020. Furthermore, the interconnection process includes nearly 98 GW of additional resources, of which all but 5 GW are renewable resources.

A recent wave of generator retirements, particularly of coal-fired generation, has been widely observed throughout the country. The SPP market is expected to follow this trend because of excess capacity, aging fleet, and cost disadvantages of certain types of generation technologies vis-à-vis the prevailing market prices.

The MMU believes that SPP and stakeholders should prepare for the challenges these changes, and potential changes, to the market present. 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.

1.7 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 8. Below is a summary of our 2020 recommendations.

1.7.1 NEW RECOMMENDATIONS FOR 2020

2020.1 Update market and outage requirements to improve funding for transmission congestion rights

The MMU has observed a continued downward trend in the overall funding of transmission congestion rights from day-ahead market congestion rents. To improve funding, the MMU recommends implementing new market incentives and more stringent outage requirements. The underfunding of transmission congestion rights lessens their usefulness as a hedge against day-ahead congestion and lessens their value in the transmission congestion rights auctions.

When constraints differ between the network model used by the auction and the network model used by the day-ahead market, transmission congestion rights may be under or over sold in the auctions. The main reason for differences in the network model between the transmission congestion rights auctions and the day-ahead market are outages and changes in line ratings.

The MMU highly recommends updating outage requirements and developing incentive-based market rules associated with outages to better align the network models used by the transmission congestion rights auctions and the day-ahead market.

2020.2 Enhance market-to-market efficiencies through collaboration with MISO

Through a joint study with MISO's independent market monitor, Potomac Economics, the MMU identified inefficiencies in the processes and mechanisms that manage market-to-market congestion on the seam between the SPP and MISO regions. The market-to-market agreement with MISO allows the adjacent RTOs to manage congestion more economically through monitoring shadow prices at designated flowgates and requesting economic relief to that congestion from the neighboring RTO. The MMU recommends the processes and mechanisms used to effectuate the market-to-market agreement between SPP and MISO be evaluated through a joint study that addresses the inefficiencies previously identified.

2020.3 Raise offer floor to minus $100/MW

The MMU recommends that the energy offer floor be raised to -$100/MWh. The MMU has observed resources offering at the offer floor, -$500/MWh, and setting price. These offers do not represent cost and are often costly to the offering resource and are harmful to nearby resources. Raising the offer floor is simple and cost effective solution that avoids any limitation of what costs can be included in a market offer.

1.7.2 PREVIOUS RECOMMENDATIONS

The MMU has provided recommendations to improve market design in our previous annual reports, these recommendations are summarized here.

2019.1 Improve price formation

The MMU highly recommends SPP and stakeholders review price formation during scarcity events and establish graduated demand curves that incentivize proper price formation. In the short-term, scarcity prices can ensure resources are performing at their maximum limits and that energy imports are incentivized. Even when no more capacity is physically available and imports are exhausted, improved price formation may not result in more product availability during a scarcity event, but will produce a price signal that will incentivize future availability.

2019.2 Incentivize capacity performance

The MMU observed that the capacity adequacy requirements did not have any actual performance requirements. Other RTOs use methods to compensate resources that are available more often than the average or by adjusting the next year's capacity accreditation based on availability during a certain timeframe. Another option is to develop time estimates of forced outages and maintenance outages during high-demand periods and prorate the available MW for capacity accreditation. A true-up of available capacity at the end of the year would be required to determine whether a market participant met their capacity requirement. This helps to ensure that capacity is actually available during the most important days of the year, and helps to reduce the number of conservative operations events. The Supply Adequacy Working Group, an SPP stakeholder group, has formed a Generator Testing Task Force to address capacity performance among other matters. We highly recommend that this task force work to incentivize capacity performance.

2019.3 Update and improve outage coordination methodology

During a review of outages in 2019, MMU observations identified the need to update and improve the outage coordination methodology. The MMU recommended that the outage coordination methodology be updated to cover reserve shutdown outages and to consider a lower threshold. At a minimum, all market participants should review their outage procedures to ensure they are compliant with SPP's Outage Coordination Methodology, in particular, with requirements to accurately report outage reasons and times. These recommendations would have also helped with the 2021 Cold Weather event. These revisions are pending at the Operating Reliability Working Group.

2018.1 Limit the exercise of market power by creating a backstop for parameter changes

The MMU recommends that SPP strengthen the language regarding non-dollar-based parameters so that the expectation for the basis of these values is clear and the potential exercise of market power is much more limited. The expectations for the basis of the parameters should be clear and well defined. Changes to these parameters should be limited to actual capability and should be verified, at a minimum, in the presence of market power. One option would be to require parameters to always reflect actual limitations. Actual limitations could include physical and environmental limitations and potentially other true and verifiable limitations. Another option could be to automatically apply parameter mitigation in the presence of market power, and congesting a transmission line, similar to the automatic mitigation of dollar-based offer components. SPP and stakeholders added this initiative[3] to the SPP Roadmap with final approval estimated for 2021.

2018.2 Enhance credit rules to account for known information in assessments

SPP and its stakeholders generally agree that updating the SPP credit policy to protect from exposure such as that experienced in PJM is a priority. SPP stakeholders have proposed a two-phase approach to mitigate SPP's exposure. The first phase includes both quantitative and qualitative enhancements, such as position collateral minimums, know-your-customer best practices, and stronger capitalization requirements. The second phase will incorporate forward-looking information into financial security requirements. The phase one package is working through the SPP stakeholder process. The phase two package is in the research phase. The MMU recommends that SPP continue to move forward with both phases of credit policy development, as the second phase directly addresses one of the major sources of risk that GreenHat had in PJM.

2018.3 Develop compensation mechanism to pay for capacity to cover uncertainties

The Market Working Group added the initiative[4] to implement an uncertainty market product as part of the SPP Roadmap and has been actively engaged in developing an uncertainty product for the market. The MMU has been engaged in the Market Working Group activities and fully

[3] SIR 22 - Limit Market Power Through Physical Parameters
[4] SIR 19 - HITT R4: Implement Uncertainty Market Product

supports these efforts to compensate capacity used to cover uncertainty of generation and load. SPP stakeholders approved the design at the April 2020 Market Working Group meeting.

2018.4 Enhance ability to assess a range of potential outcomes in transmission planning

In the 2020-2021 timeframe, the SPP stakeholders voted 2022 ITP to maintain 2021 ITP's two-scenario approach, having primarily a similar set of features of the 2021 ITP. (The MMU initially recommended that the ESWG consider three futures for the 2022 ITP scope development however, stakeholders voted to carry over the two future approach of the 2021 ITP. Accordingly, the MMU revised its original recommendation to produce a two future approach).

Meanwhile, the SPP stakeholders approved a four-future scope for the 20-year assessment, Future 3 and Future 4 representing *decarbonization* features. While Future 3 stayed as initially recommended by the MMU, Future 4 assumed zero hurdle rates for interchange transactions between SPP and MISO markets. Therefore, the MMU's above mentioned recommendation was fulfilled by the 20-year assessment.

2018.5 Improve regulation mileage price formation

The MMU discussed our concerns with the Market Working Group at its August 2018 meeting. While an action item was developed requesting SPP staff and the MMU to review the effectiveness of the regulation mileage pricing process and present further options, no additional work has been done since that time. We recommend that SPP staff review the performance of regulation mileage, and develop potential approaches to improve regulation mileage price formation. Furthermore, we recommend that SPP staff consider adjusting the mileage factor. We believe that SPP staff and stakeholders should include these items as part of its analysis and change development processes for moving forward. SPP and stakeholders included this initiative[5] on the SPP Roadmap with final approval estimated for 2022.

2017.1 Develop a ramping product

[5] SIR 20 - Improved Economic Incentive of Regulation Mileage

SPP, stakeholders, and the MMU worked together to complete a ramping product design in April 2019 which was approved by the Market Operations and Policy Committee in October 2019. This design was approved by FERC in July 2020.[6]

The MMU will continue to monitor price increases due to capacity shortages and true ramp shortages through and after implementation. Implementation is currently scheduled for early 2022.

2017.2 Enhance commitment of resources to increase ramping flexibility

The MMU recommends that SPP and its stakeholders address this issue by enhancing its markets rules to enhance the commitment of resources to increase ramping flexibility. The MMU recommends that SPP and stakeholders explore options to enhance commitment of resources and increase flexibility. The MMU views this as a high priority item and the initiative[7] has been added to the SPP Roadmap with final approval estimated for the 2022-2023 timeframe.

2017.3 Enhance market rules for energy storage resources

The MMU views integration of storage resources in the SPP markets as an ongoing high priority as several outstanding items beyond compliance with FERC Order No. 841 need to be addressed in order to fully integrate electric storage resources in the SPP markets. These areas include further enhancements to electric storage integration include addressing the potential for storage resources to exercise downward market power, the potential for market storage resources (MSR) to manipulate the transmission market, possible market design gaps regarding major maintenance and quick-start resource requirements, and the inefficient commitment of

[6] *Order Accepting Tariff Revisions*, Docket No. ER20-1617, https://elibrary.ferc.gov/eLibrary/filelist?document_id=14877340&optimized=false.

[7] SIR 9 - Enhanced Commitment

non-continuously dispatchable resource requirements in relation to market storage resources.[8] An initiative[9] has been added to the SPP Roadmap that plans for additional design on storage with final approval estimated for the 2021-2022 timeframe.

2017.4 Address inefficiency caused by self-committed resources

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 solution. Further, we recommend, based on its analysis, that SPP and stakeholders consider adding an additional day to the optimization process, as this will best balance forecast accuracy with the ability to commit long lead time and high start-up cost resources. The MMU continues to view reducing self-commitment of generation as a high priority for SPP and its stakeholders as this will enhance market efficiency and improve price signals.

The Holistic Integrated Tariff Team adopted a recommendation to move towards a multi-day market.[10] An initiative[11] was added to the SPP Roadmap to implement these enhancements with final approval estimated for 2022.

2017.5 Address inefficiency when forecasted resources under-schedule day-ahead

At the November 2020 Market Working Group, SPP staff presented on analysis regarding offer requirements for variable energy resources in the day-ahead as part of a recommendation from SPP's Holistic Integrated Tariff Team.[12] As a result of the SPP and MMU analysis, the MMU proposed an initiative[13] to be added to the SPP Roadmap to address the negative impacts of variable energy resources being underscheduled in the day-ahead market. As part of the

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[8] Some market storage resources have a non-dispatchable range between their charging range and discharging range. The dispatch calculation for this type of non-continuous dispatch range is much more complicated than the typical linear dispatch calculation. SPP's current proposal is to commit this type of market storage resource for either charging or discharging. This type of commitment is inefficient because it does not make the whole dispatch range available. For more detail, see *Motion to Intervene and Comments of the Southwest Power Pool Market Monitoring Unit*, Section I.B.5, Docket No. ER19-460, December 7, 2018.

[9] SIR30 - Energy Storage Resources & ESR Phase 2

[10] *Holistic Integrated Tariff Team Report*, https://www.spp.org/documents/60323/hitt%20report.pdf, page 16.

[11] SIR 18 - HITT R3c: Implement Marketplace Enhancements: Multi-Day Market

[12] *Holistic Integrated Tariff Team Report*, https://www.spp.org/documents/60323/hitt%20report.pdf.

[13] SIR 74 - DAMKT VER Participation

initiative, the MMU noted that the issue should be addressed through multiple avenues including, 1) incentivizing more variable energy resource participation in the day-ahead market 2) incentivizing more virtual energy participation in the day-ahead market and 3) allocating measurable costs to causers. Prioritization and estimated start date of this initiative is still pending

2014.1 Improve quick-start logic

The MMU recommended that quick-start logic be improved after implementation of the Integrated Marketplace.[14] SPP and stakeholders developed a proposal to enhance the quick-start logic several years ago.[15] However, before the proposal was filed, FERC began a 206 process that identified that the treatment of fast-start generators was unjust and unreasonable.[16] In June 2019, FERC issued an order[17] directing SPP to make a compliance filing addressing pricing practices related to fast-start generators. SPP submitted a compliance filing[18] on December 19, 2019 addressing the six issues outlined in the FERC order. The MMU filed comments[19] offering a limited protest to SPP's proposed tariff revisions to comply with the FERC order. FERC approved SPP's compliance filing on October 27, 2020 that has an effective date of May 18, 2022.

Additional enhancements to the fast-start design, which were outside the scope of the FERC order, were approved through the stakeholder process and are scheduled to be implemented in conjunction with the previously FERC approved enhancements.[20]

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[14] SPP MMU *2014 Annual State of the Market* report, https://www.spp.org/Documents/29399/2014%20State%20of%20the%20Market%20Report.pdf , Recommendation 1, page 57.
[15] MPRR116, https://www.spp.org/Documents/30429/rr116.zip
[16] 161 FERC ¶ 61,296, https://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=14782160
[17] FERC ¶ 61,217, https://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=15269476
[18] Docket No. ER20-644-000 SPP compliance filing, https://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=15428342
[19] Docket No. ER20-644-000, MMU comments, https://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=15446258
[20] Revision Request 402, HITT R3 (Fast-Start Resources) - Enhanced Intra-Day Reliability Unit Commitment, https://www.spp.org/search?q=RR402&t=Documents

2014.3 Address gaming opportunity for multi-day minimum run time resources

The SPP board passed a proposal at the July 2018 meeting that would limit make-whole payments for any resource with multi-day minimum run times to the lower of the market offer or the mitigated offer. This limitation only applies for offers falling in hours not accessed by one of the security constrained unit commitment (SCUC) processes and the resource bid at or above their mitigated offer on the first day. The MMU supported the proposal. Subsequent to board approval of the proposal, SPP legal staff identified internally inconsistent tariff language that the revisions revealed, but did not address. An associated additional tariff modification was approved by the stakeholder process. SPP filed these changes with FERC on May 7, 2020[21] and the MMU filed comments in support of the Tariff changes on June 12, 2020.[22] The SPP filing did not note a specific effective date, but rather a first quarter 2022 goal.

2014.4 Address problems with day-ahead must offer requirement

In 2017, 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.

The MMU remains concerned with the design weaknesses of the current limited day-ahead must offer requirement. We recommend that SPP and stakeholders eliminate the limited day-ahead must-offer provision and revise the physical withholding rules to include a penalty for non-compliance, or address the design weaknesses. The MMU has continued to monitor and track market performance concerns and has identified an increase in generator outages, as discussed that are not prevented by the current limited must offer requirement. In light of the increased reliability concerns exacerbated by conservative operations events, the MMU recommends the priority of this issue be elevated to high. The MMU submitted this recommendation as an initiative on the SPP Roadmap. The Market Working Group prioritized this initiative to begin work in 2022 with an estimated final approval in 2023.

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[21] Docket No. ER20-1782, Revisions Regarding Make Whole Payments and Minimum Run Time, https://elibrary.ferc.gov/eLibrary/filelist?document_id=14858744&optimized=false
[22] Docket No. ER20-1782, MMU Comments, https://elibrary.ferc.gov/eLibrary/filelist?document_id=14861491&optimized=false

2 LOAD AND RESOURCES

This chapter reviews load and resources in the SPP market for 2020. Key points from this chapter include:

- Total system energy consumption was down about three percent from 2019 to 2020. Some of the decrease, particularly in March, April, and May can be attributed to effects of the COVID-19 pandemic.

- Variations in demand continue to trend with seasonal temperature changes and departures from normal temperatures.

- Nearly 4,800 MW of wind generation capacity was added to the market in 2020. Wind generation capacity now accounts for 29 percent of installed nameplate capacity in the SPP market.

- The generation interconnection queue has just over 97,000 MW of projects in the queue at the end of 2020. Just over 5,000 MW is from gas, simple-cycle generation, with the remainder from renewable or storage resources.

- In 2020, wind generation represented the largest portion of total energy produced at 31.3 percent of the total. Coal generation was slightly behind at 31.0 percent of the total. By comparison, in the first year of the Integrated Marketplace in 2014, coal generation represented 60 percent of the total, and wind generation accounted for 12 percent of the total.

- SPP remained a net exporter for 2020 with an hourly average of 122 MW, down from 505 MW in 2019. Overall, exports to both MISO and ERCOT declined slightly, and imports from AECI increased slightly.

- Market-to-market payments totaled $82.8 million from MISO to SPP for 2020, this is up significantly from $17.5 million in 2019. The majority of the increase occurred in the last three months of the year.

- Cleared virtual energy bids and offers as a percentage of load for 2020 was 19 percent, up from 17 percent in 2019.

- Average profit per cleared virtual megawatt after fees was unchanged from 2019, at $0.63/MW.

2.1 THE INTEGRATED MARKETPLACE

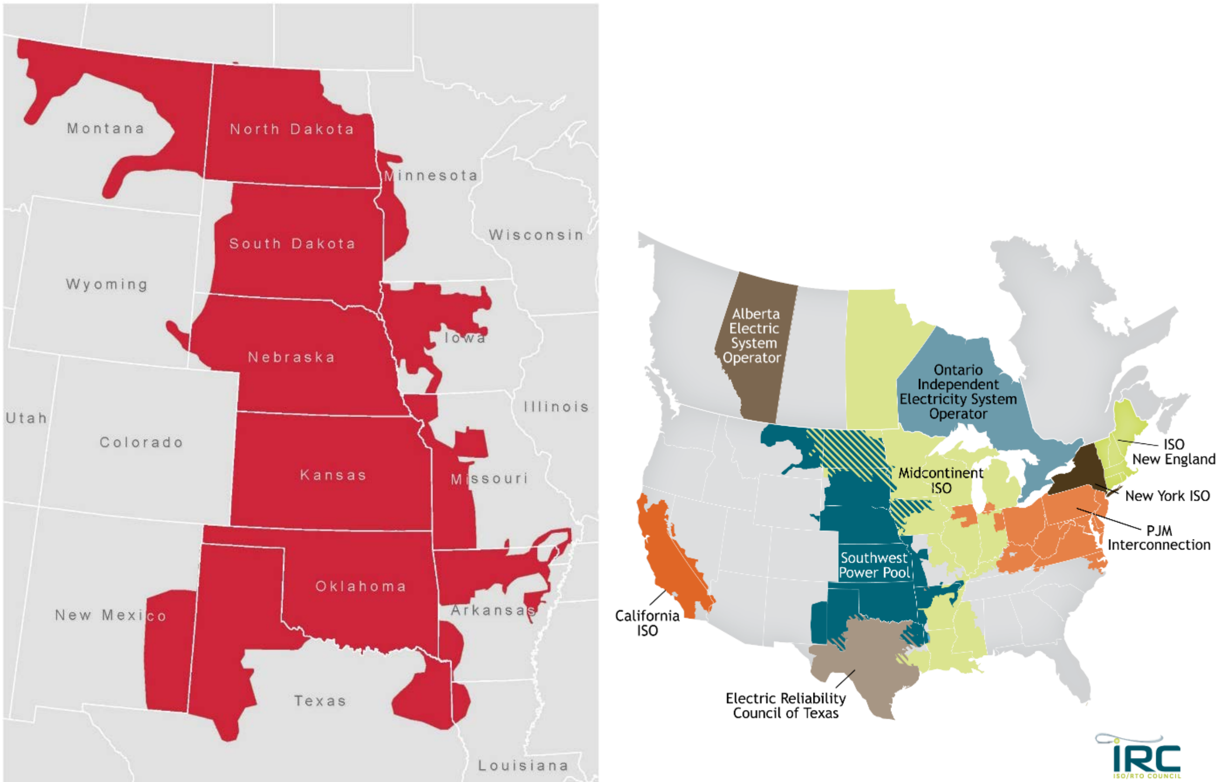
SPP is a Regional Transmission Organization (RTO) authorized by the Federal Energy Regulatory Commission (FERC) to ensure reliable power supplies, adequate transmission infrastructure, and competitive wholesale electricity prices. FERC granted RTO status to SPP in 2004. SPP provides many services to 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 2020 calendar year of the SPP wholesale electricity market referred to as the Integrated Marketplace, which started on March 1, 2014.

The Integrated Marketplace has 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 a day-ahead market is improved efficiency of daily resource commitments. Another benefit of this 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 the Western Interconnection to the west. Figure 2–1 shows the current operating regions of the nine RTO/ISO 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-RTO/ISO areas such as Saskatchewan Power Corporation, Associated Electric Cooperative, and Southwestern Power Administration.[23]

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

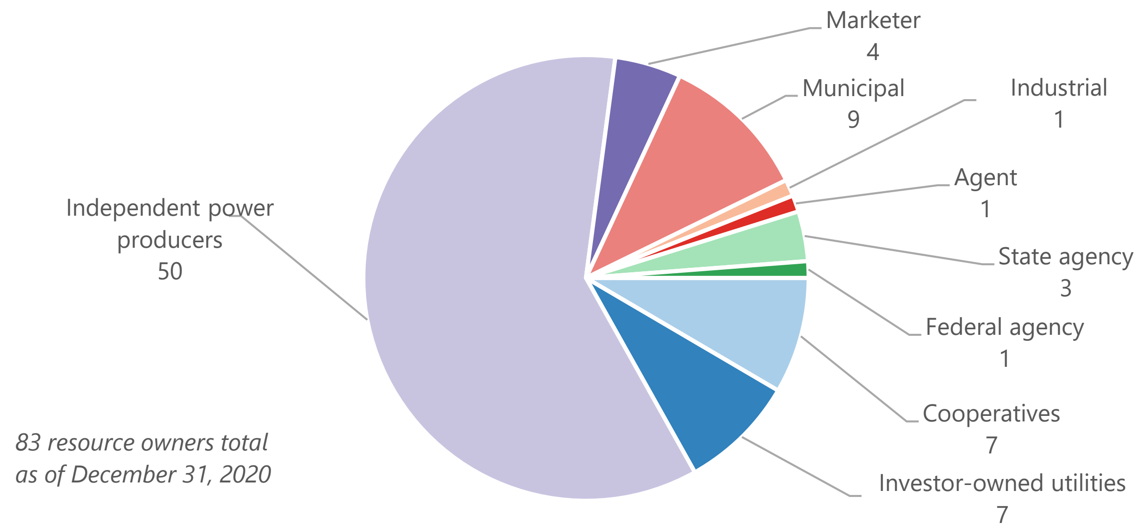


2.1.2 SPP MARKET PARTICIPANTS

At the end of 2020, 284 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 83 resource owners registered to participate in the Integrated Marketplace.

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

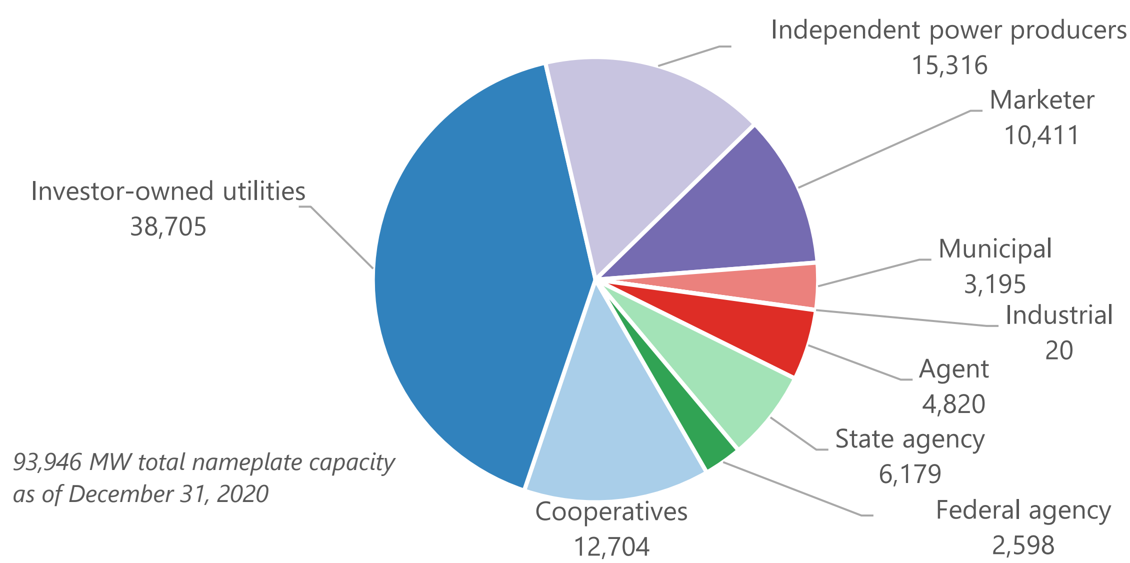
Figure 2–2 Resource owners by type



The number of independent power producers is high because 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 54 percent 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 portion of the total number of market participants at eight percent, they own the highest portion of the SPP generation capacity at 41 percent. This is in contrast to the "independent power producer" category, which has a large number of participants (60 percent) representing only a small portion (16 percent) of total nameplate capacity.

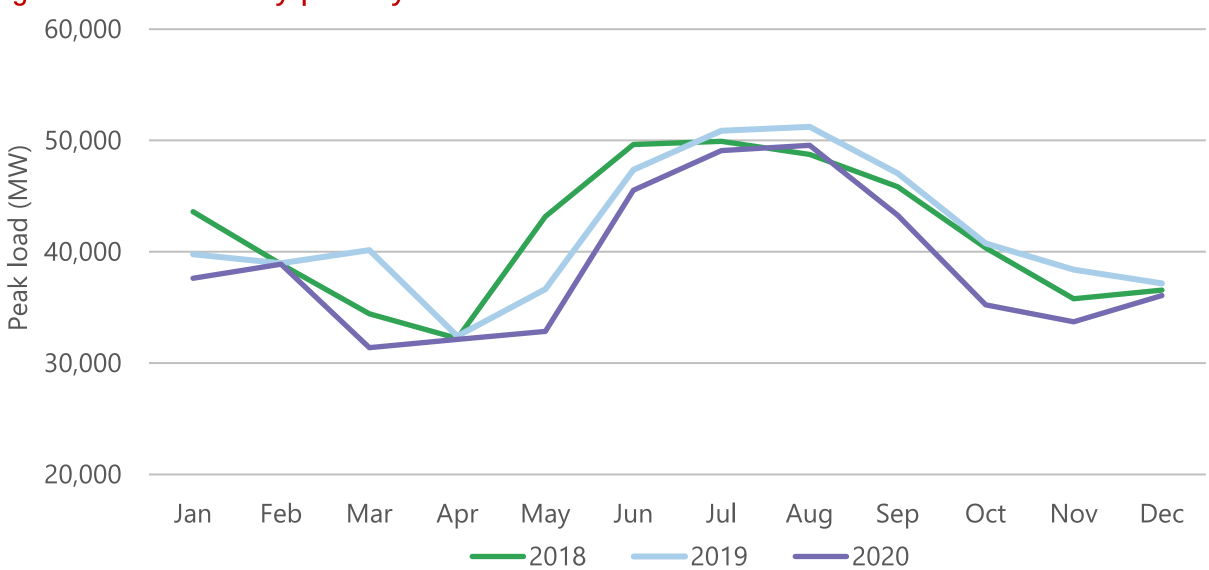
2.2 ELECTRICITY DEMAND

2.2.1 SYSTEM PEAK DEMAND

One way to evaluate load is to review peak system demand statistics over an extended period. The market footprint has changed over time as participants have been added to or withdrawn from the market. 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 real-time market interval. The peak experienced during a particular year or season is affected by events such as unusually hot or cold weather, daily and seasonal load patterns, and economic growth and change.

Figure 2–4 shows a month-by-month comparison of peak-day demand for the last three years. The monthly peak demand in 2020 was lower than the monthly peak demand in both 2019 and 2018 in almost all months.

Figure 2–4 Monthly peak system demand

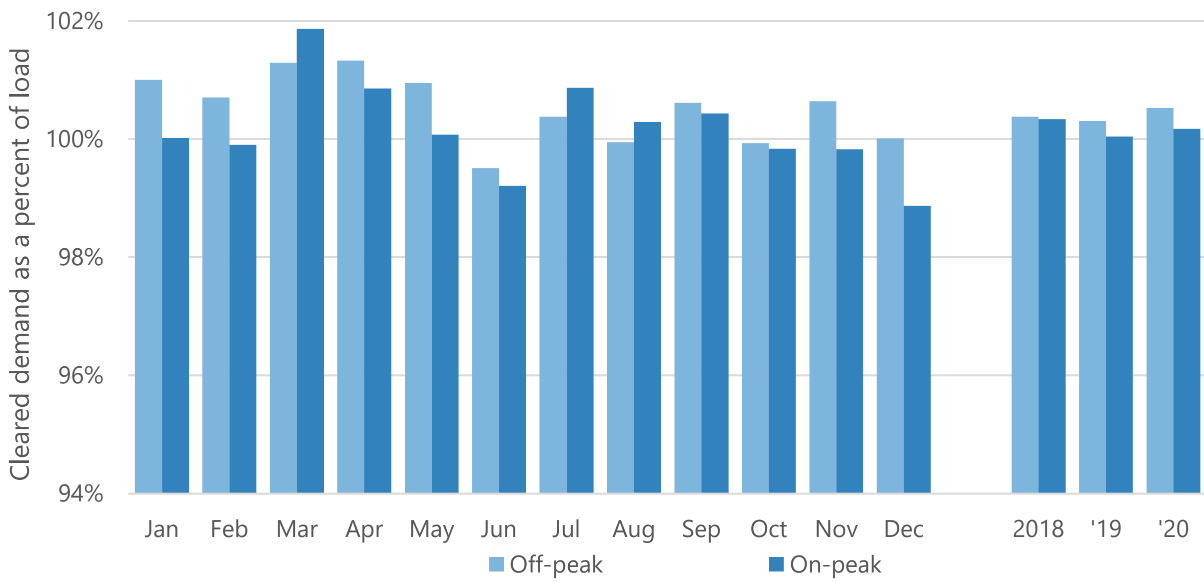


The SPP system coincident instantaneous peak demand in 2020 was 49,569 MW, which occurred on August 25 at 4:00 PM. This is 2.6 percent lower than the 2019 system peak of 51,230 MW.

2.2.2 MARKET PARTICIPANT LOAD

Load continued to participate in the day-ahead market at high levels in 2020 as shown in Figure 2–5.

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



The average monthly participation rates in the day-ahead market for load assets on an aggregate level were between 99 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 prices. Load participation in the day-ahead market has remained at similar levels from 2018 to 2020.

Figure 2–6 depicts 2020 total energy consumption and the percentage of energy consumption attributable to each entity in the market.

The four largest entities then comprise 57 percent of energy consumed in the market. This concentration is understandable as SPP's market is primarily composed of vertically integrated investor-owned utilities, which tend to be large. Overall, the total system energy usage in 2020 was nearly three percent below the 2019 level. Much of this decrease can be attributed to reduced commercial and industrial demand because of the COVID-19 pandemic.

Figure 2–6 System energy usage

	Energy consumed (GWh)	Percent of system	Energy consumed (GWh)	Percent of system	Energy consumed (GWh)	Percent of system
* Evergy, Inc.	49,965	19.2%	49,566	19.2%	47,651	19.0%
American Electric Power	43,109	16.6%	42,485	16.4%	39,680	15.8%
Oklahoma Gas and Electric	29,411	11.3%	29,688	11.5%	28,327	11.3%
Southwestern Public Service Company	27,359	10.5%	27,786	10.7%	26,983	10.7%
Basin Electric Power Cooperative	20,165	7.8%	21,368	8.3%	21,124	8.4%
^# The Energy Authority	16,356	6.3%	16,498	6.4%	16,736	6.7%
Omaha Public Power District	11,431	4.4%	11,378	4.4%	11,518	4.6%
Western Farmers Electric Cooperative	8,312	3.2%	8,446	3.3%	8,011	3.2%
Grand River Dam Authority	5,805	2.2%	5,934	2.3%	6,324	2.5%
Golden Spread Electric Cooperative Inc.	5,684	2.2%	5,342	2.1%	6,018	2.4%
Liberty Utilities (f/k/a Empire District Electric)	5,413	2.1%	5,268	2.0%	4,833	1.9%
Sunflower Electric Power Corporation	4,906	1.9%	4,832	1.9%	4,676	1.9%
Western Area Power Administration, Upper Great Plains	4,471	1.7%	4,381	1.7%	4,434	1.8%
Arkansas Electric Cooperative Corporation	4,258	1.6%	4,248	1.6%	4,142	1.6%
Lincoln Electric System Marketing	3,570	1.4%	3,482	1.3%	3,369	1.3%
Oklahoma Municipal Power Authority	2,846	1.1%	2,593	1.0%	2,543	1.0%
Kansas City (Kansas) Board of Public Utilities	2,530	1.0%	2,402	0.9%	2,268	0.9%
Northwestern Energy	1,748	0.7%	1,806	0.7%	1,747	0.7%
Midwest Energy Inc.	1,762	0.7%	1,764	0.7%	1,623	0.6%
Kansas Municipal Energy Agency	1,557	0.6%	1,487	0.6%	1,461	0.6%
Tenaska Power Service Company	1,418	0.5%	1,411	0.5%	1,382	0.5%
Missouri River Energy Services	1,309	0.5%	1,262	0.5%	1,166	0.5%
East Texas Electric Cooperative	983	0.4%	1,063	0.4%	1,101	0.4%
City of Independence (Missouri)	1,094	0.4%	1,036	0.4%	991	0.4%
Kansas Power Pool	866	0.3%	846	0.3%	825	0.3%
Missouri Joint Municipal Electrical Utility Commission	445	0.2%	432	0.2%	584	0.2%
AEP Energy Partners	261	0.1%	530	0.2%	530	0.2%
Big Rivers Electric Corporation	310	0.1%	491	0.2%	512	0.2%
City of Fremont (Nebraska)	450	0.2%	460	0.2%	493	0.2%
MidAmerican Energy Company	285	0.1%	263	0.1%	253	0.1%
Rainbow Energy Marketing Corporation	–	–	52	0.0%	69	<0.1%
Harlan (Iowa) Municipal Utilities	18	0.0%	18	0.0%	16	<0.1%
NSP Energy	5	0.0%	5	0.0%	5	<0.1%
Otter Tail Power Company	1	0.0%	1	0.0%	4	<0.1%
# Municipal Energy Agency of Nebraska	1,057	0.4%	—	–	—	–
@ City of Chanute (Kansas)	497	0.2%	—	–	—	–
System Total	259,653		259,653		251,399	

* Evergy was formed in June 2018 and is the corporate parent of Evergy, Kansas Central (f/k/a Westar Energy), Evergy, Missouri Metro (f/k/a Kansas City Power and Light), and Evergy, Missouri West (f/k/a Kansas City Power and Light GMOC).

^ The Energy Authority acts as an agent for Nebraska Public Power District and City Utilities of Springfield (Missouri).

Beginning in May 2019, The Energy Authority began to act as an agent for the Municipal Energy Agency of Nebraska and several small municipalities in Nebraska.

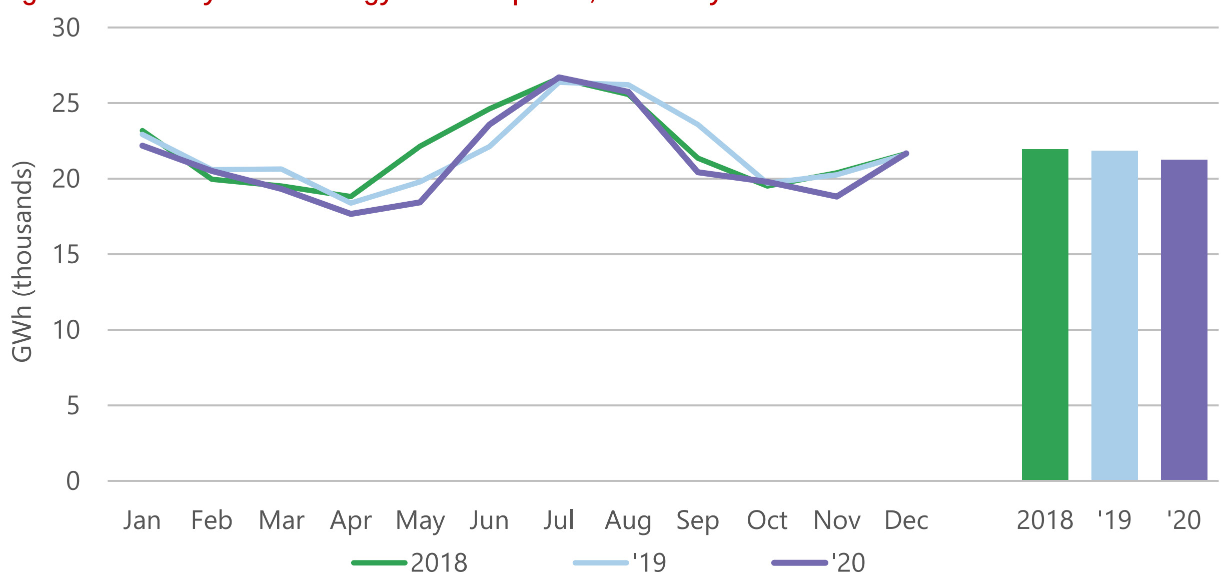
@ Beginning in January 2019, Evergy, Kansas Central began to act as an agent for City of Chanute (Kansas).

	2018		2019		2020	
* Evergy, Inc.	49,965	19.2%	49,566	19.2%	47,651	19.0%
*@ Evergy, Kansas Central (f/k/a Westar	25,101	9.7%	25,605	9.9%	24,427	9.7%
* Evergy, Missouri Metro (f/k/a Kansas City Power and Light, Co.)	16,049	6.2%	15,427	6.0%	14,799	5.9%
*Evergy, Missouri West (f/k/a Kansas City Power and Light, Greater Missouri)	8,815	3.4%	8,534	3.3%	8,425	3.4%
^ The Energy Authority	16,356	6.3%	16,498	6.4%	16,736	6.7%
^ The Energy Authority, Nebraska Public Power District	12,932	5.0%	12,138	4.7%	12,630	5.0%
^ The Energy Authority, City Utilities of Springfield (Missouri)	3,424	1.3%	3,329	1.3%	3,091	1.2%
# The Energy Authority, other	–	–	1,030	0.3%	1,014	0.4%

2.2.3 SPP SYSTEM ENERGY CONSUMPTION

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

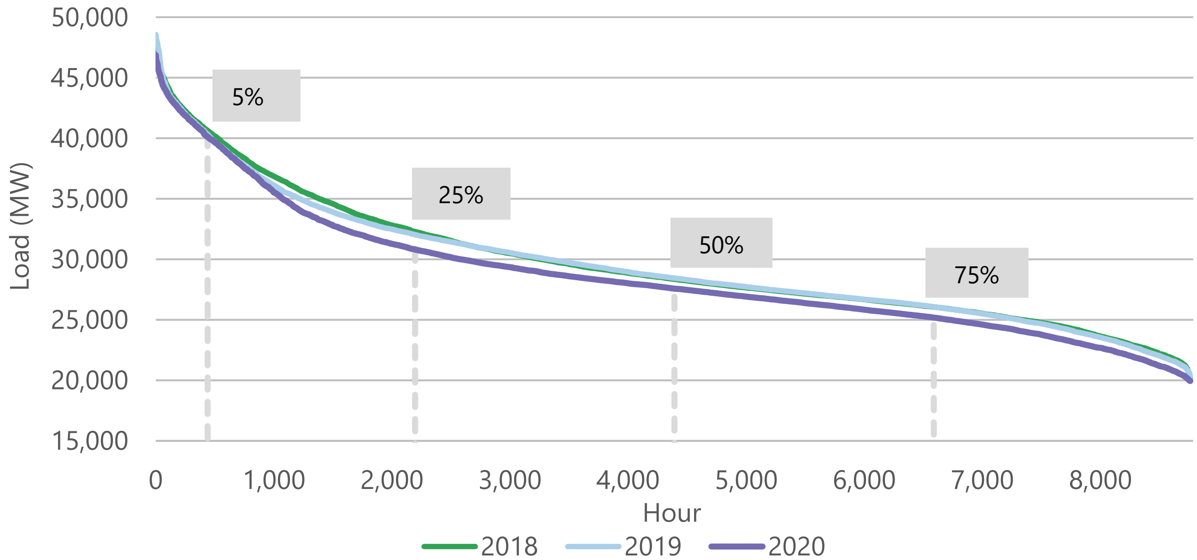
Figure 2–7 System energy consumption, monthly



For the year, monthly average system energy consumption was down just under three percent in 2020 compared to 2019. Lower consumption in March, April, and May can be mostly attributed to effects related to the COVID-19 pandemic. From June on, energy consumption was at very similar levels as prior years.

Figure 2–8 depicts load duration curves from 2018 to 2020. These load duration curves display hourly loads from the highest to the lowest for each year.

Figure 2–8 Load duration curve



In 2020, the maximum hourly average load was 46,877 MW, which was down from both prior years. The minimum hourly load for 2020 was 19,552 MW, which was slightly below both previous years. Comparing annual load duration curves shows differentiation between cases of extreme loading events and more general increases in system demand. If only the extremes are higher or lower than the previous year, then short-term loading events are likely the reason. However, if the load curve throughout the year is below the previous year, as it was in 2020, it indicates that total system demand was down system-wide.

2.2.4 HEATING AND COOLING DEGREE DAYS

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.

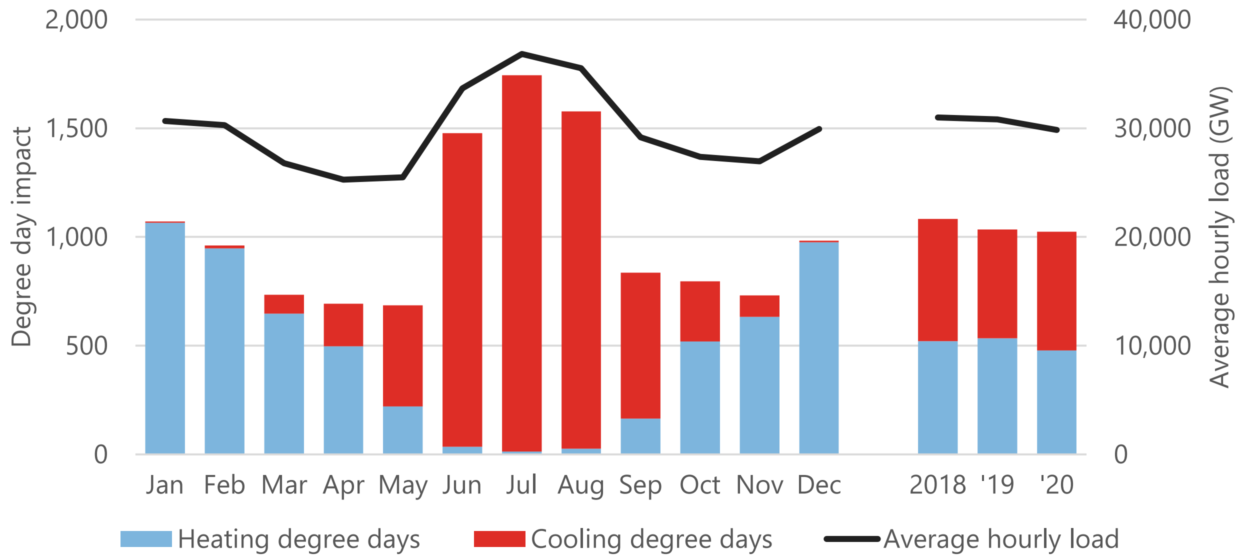
To determine heating degree days and cooling degree days for the SPP footprint, several representative locations[24] are used in the calculation. The base temperature separating heating and cooling periods is 65 degrees Fahrenheit. If the average temperature of a day at a location is 75 degrees Fahrenheit, there would be 10 (=75–65) cooling degree days at that location. If a

[24] Shreveport LA, Lubbock TX, Oklahoma City OK, Amarillo TX, Kansas City, MO, Hays, KS, Omaha NE, North Platte NE, Sioux Falls SD, Rapid City SD, Grand Forks ND, and Williston/Stanley ND.

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 just over four times higher than the impact of a single heating degree day. This is in part because more electric is used for cooling than electric heating. So, in order to show the actual impact of degree days, cooling degree days are multiplied by 4.2 in the chart below.

Figure 2–9 shows monthly heating and cooling degree days' impact over the last three years compared to the average hourly load.

Figure 2–9 Heating and cooling degree days



As shown in the chart, cooling degree days are more prevalent in the higher load months of May through September, whereas heating degree days are more prevalent in the other months.

Figure 2–10, Figure 2–11, and Figure 2–12 show load levels, cooling degree days, and heating degree days for the past three years compared to a normal year.[25] Normal load was derived from a regression analysis of actual footprint heating degree days, cooling degree days, weekends, and holidays, substituting footprint normal temperatures.

[25] The 30 year normal temperatures are from the 1991-2020 U.S. Climate Normals product from the National Oceanic and Atmospheric Association (NOAA).

Figure 2–10 Loads compared with a normal year

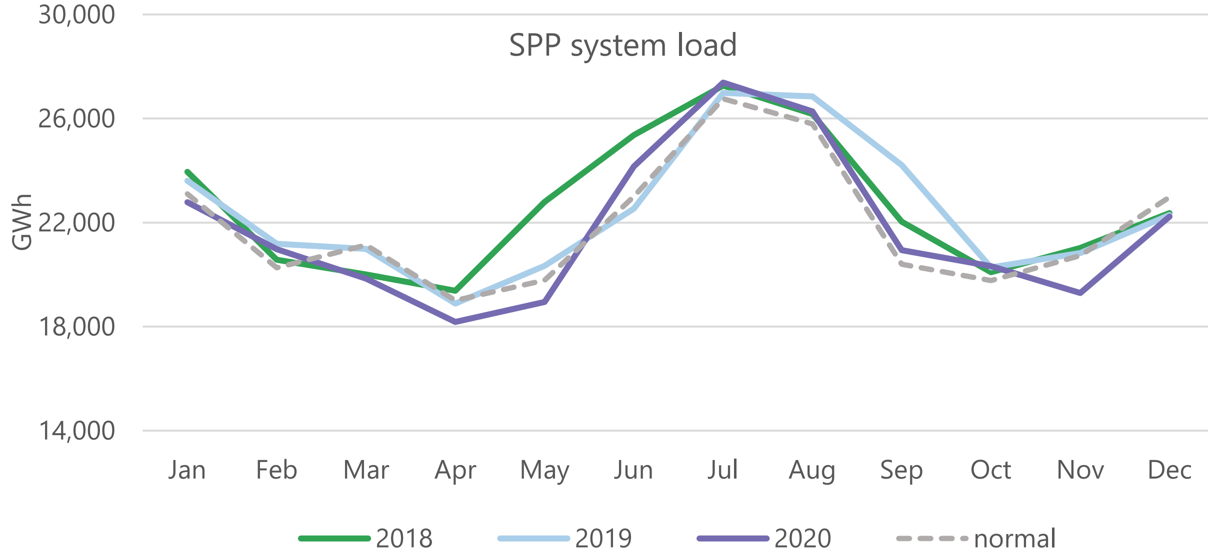


Figure 2–11 Cooling degree days compared with a normal year

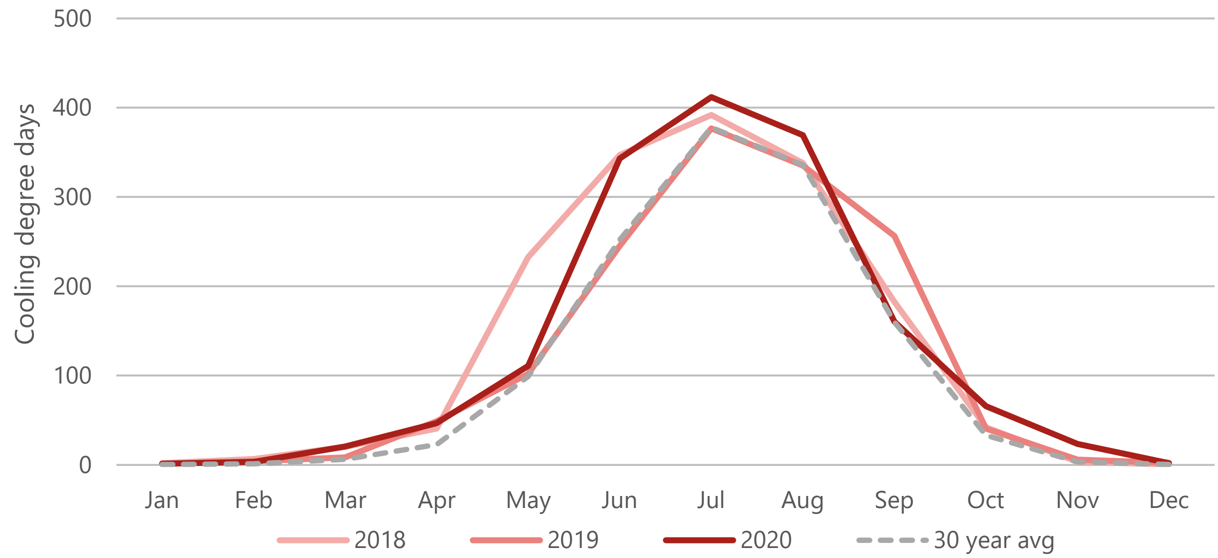
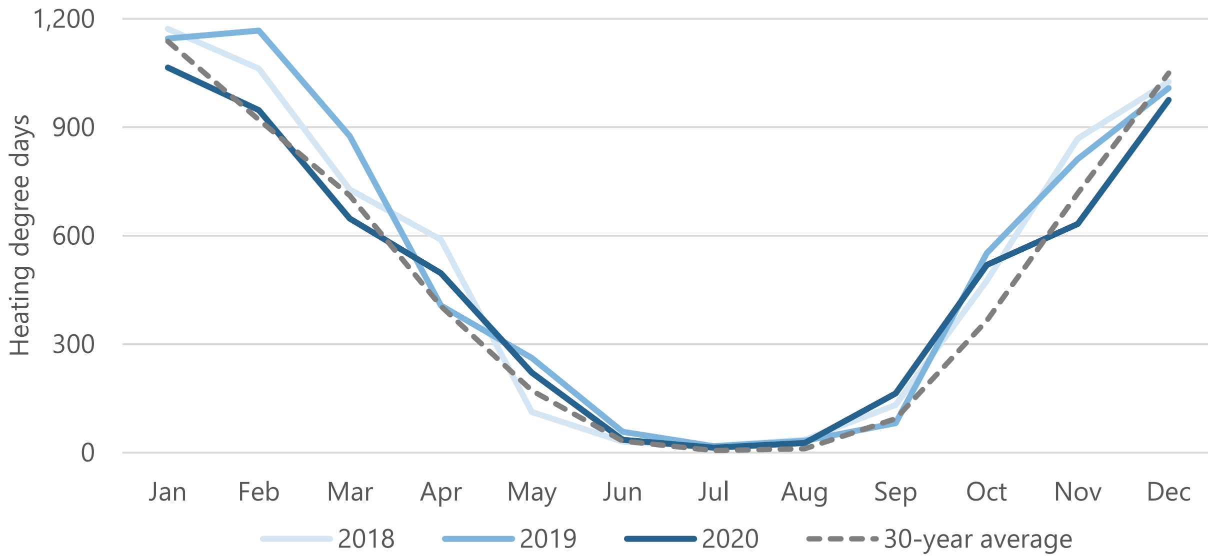


Figure 2–12 Heating degree days compared with a normal year



The figures 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. Moreover, the figures show that cooling degree days in 2020 were above the 30-year average in all "cooling months" (April through October), while heating degree days in "heating months" (January through March, November, and December) were below the 30-year average in all months, except for February. Most notable is the much higher cooling degree days for September 2019, which was well above prior years and the average. The higher temperatures in that month are reflected in the higher load that occurred in September.

2.3 INSTALLED GENERATION CAPACITY

Figure 2–13 depicts the Integrated Marketplace installed generation capacity for the SPP market footprint. Total installed nameplate generation capacity in the SPP Integrated Marketplace was 93,946 MW at the end of 2020, representing an increase of nearly five percent from 2019.[26] This increase was driven by a 22 percent increase in nameplate wind capacity in 2020.

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

Figure 2–13 Generation nameplate capacity by technology type

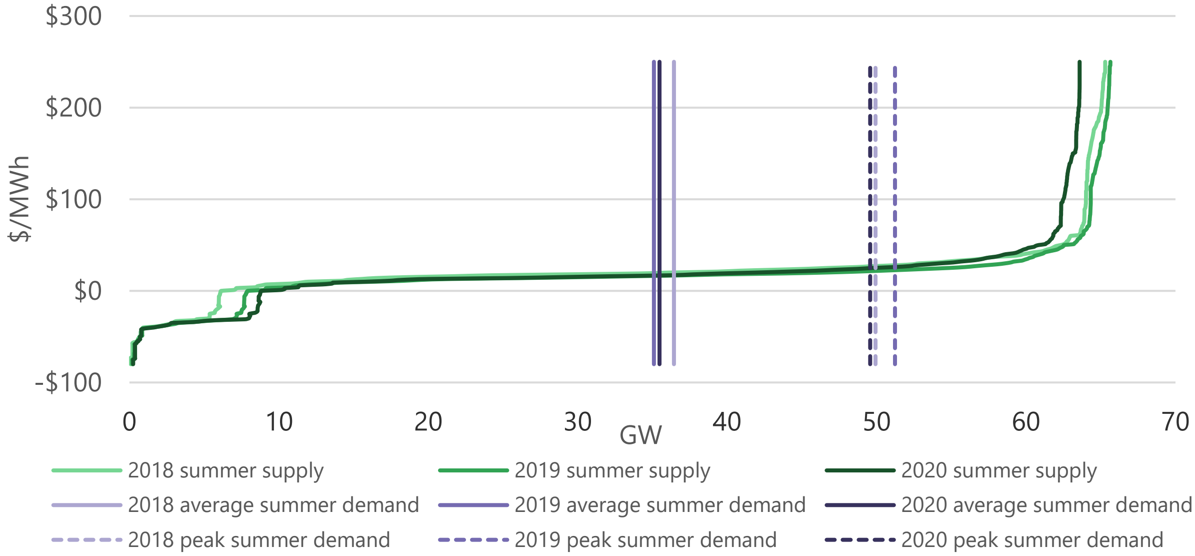
Fuel type	2018	2019	2020	Percent as of
Wind	20,589	22,482	27,326	29%
Coal	25,064	22,920	22,899	24%
Gas, simple-cycle	22,596	23,297	22,762	24%
Gas, combined-cycle	13,498	13,473	13,548	14%
Hydro	3,431	3,431	3,431	4%
Nuclear	2,061	2,061	2,061	2%
Oil	1,639	1,563	1,566	2%
Solar	215	215	235	<1%
Other	74	84	118	<1%
Total	89,166	89,526	93,946	

Note: Capacity is nameplate rating at year-end.

When both types of natural gas resources are combined, natural gas-fired installed generation capacity still represents the largest share of generation capacity in the SPP market at 38 percent (gas simple-cycle 24 percent and gas combined-cycle 14 percent) of nameplate capacity, with coal being the third largest type at 24 percent. Wind continues to increase, due to added capacity, with a 2020 market share of 29 percent of total nameplate capacity in the SPP market.

Figure 2–14 shows the total SPP aggregate real-time generation supply curves by offer price, peak demand, and average demand for the summers of 2018 to 2020, while Figure 2–15 shows the same data for the winter months. Resources in “outage” status were excluded from the supply curve. To calculate the supply curves, the peak day for each season was used for each analysis year. The aggregate generation supply curves were calculated by using the real-time offers of non-wind resources and wind forecast data for wind resources.

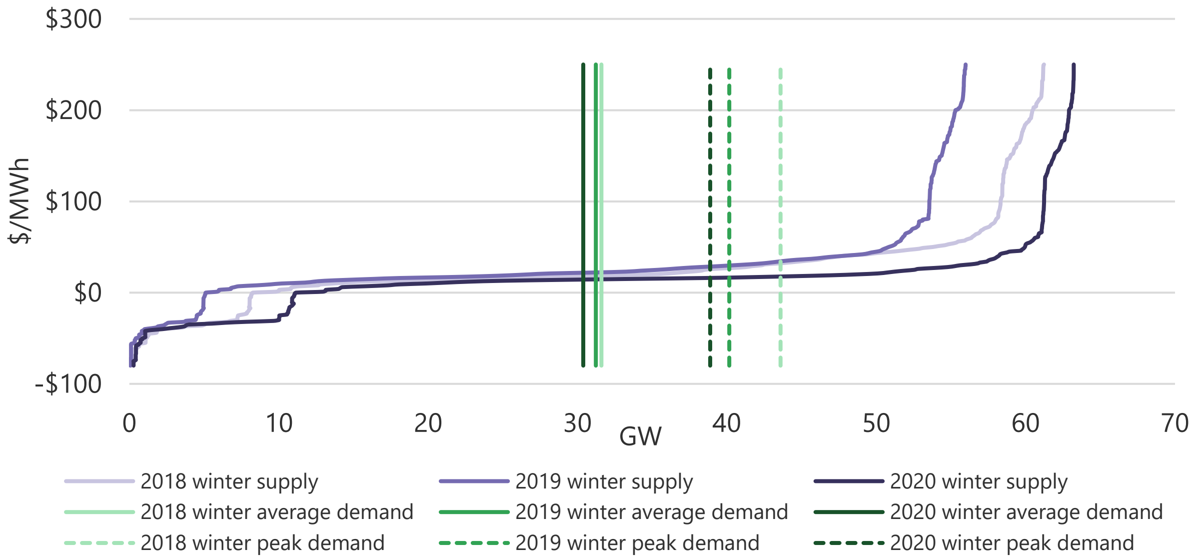
Figure 2–14 Aggregate supply curve, peak summer day



Total aggregate real-time generation supply for summer 2020 was 63,584 MW, compared to 65,645 MW for summer 2019, a decrease of three percent. The system peak demand of 2020 was almost three percent lower than 2019, and less than one percent lower than 2018. On the other hand, there was a 15 percent decrease of average demand in 2020 compared to 2019. Based on the heating and cooling degree days analysis in Section 2.2.4, the SPP market footprint experienced cooler temperatures in August 2020, which resulted in lower demand during that month as compared to the previous year.

Also evident is the approximately 30 GW gap between this maximum supply and the total installed nameplate generation capacity on the peak summer day. This is primarily a result of the difference between the wind forecast and installed capacity of wind resources (approximately 17 gigawatts), resources reporting on outage (approximately ten gigawatts), and reduced summer capacity due to high ambient temperatures (approximately three gigawatts).

Figure 2–15 Aggregate supply curve, peak winter day



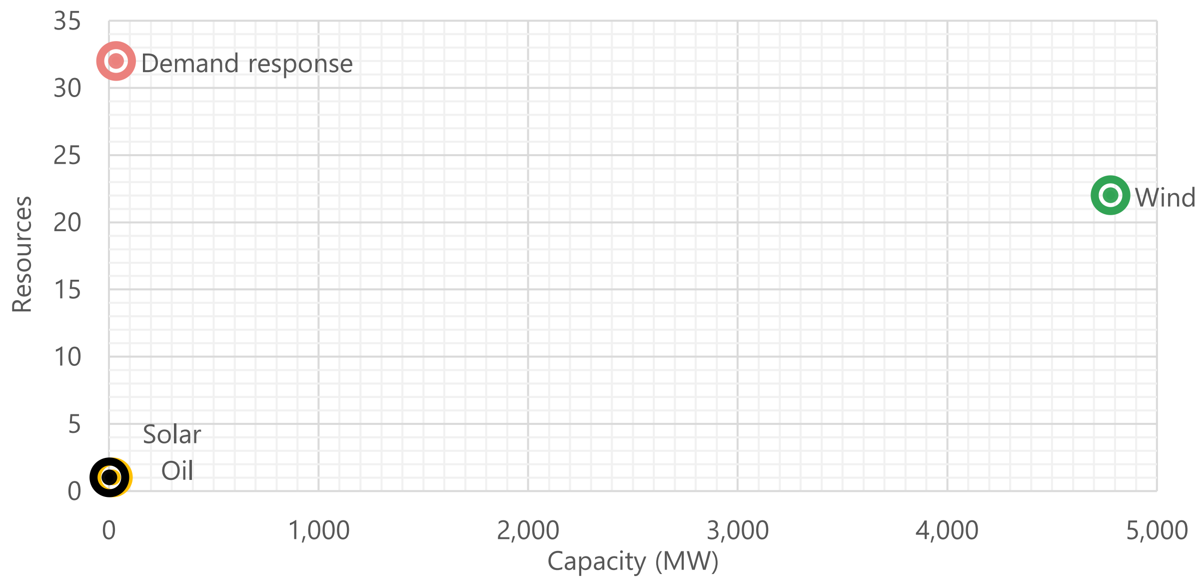
Total aggregate real-time generation supply for winter 2020 was 63,220 MW, compared to 55,982 MW for winter 2019, an increase of 13 percent. Both the system winter peak and average demand for 2020 were almost three percent lower than 2019. On the other hand, there was a 15 percent decrease of average demand in 2020 compared to 2019.

The section of the offer curve below $0/MWh is mostly due to wind and solar energy and can vary between 1,000 and 16,000 megawatts, based on wind and solar availability. Negative offers typically reflect opportunity costs associated with state and federal tax incentives. The sharp uptick in price at the top of the supply curves represents the transition from natural gas units to oil units.

2.3.1 CAPACITY ADDITIONS AND RETIREMENTS

Figure 2–16 shows the capacity by the technology and number of resources added in 2020.

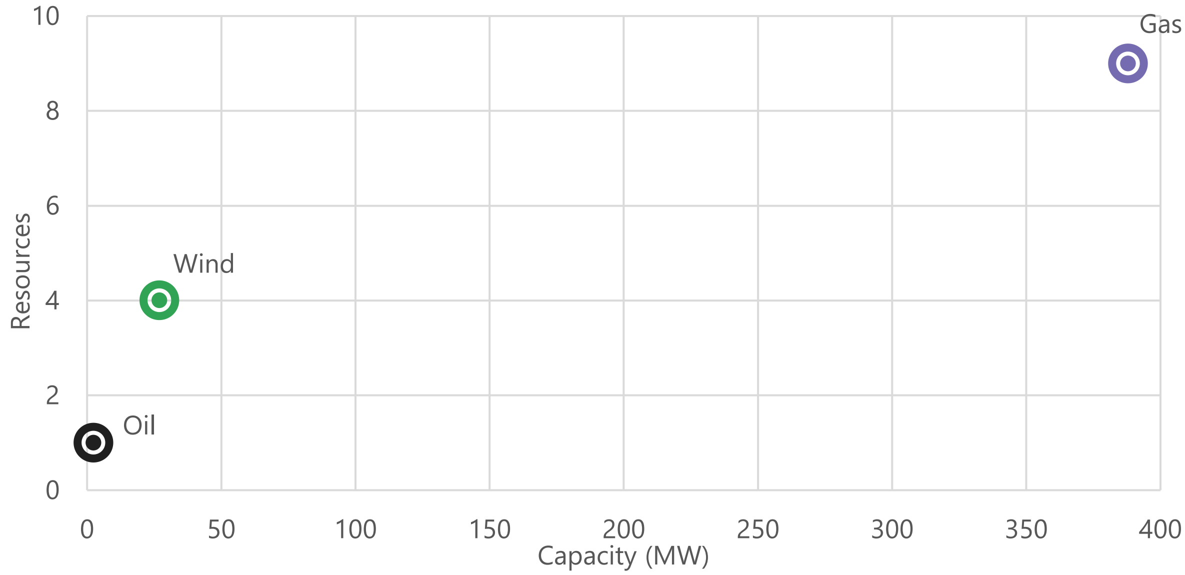
Figure 2–16 Capacity additions



Just under 4,800 MW of generation capacity was added to the SPP market during 2020. Of the new capacity added in 2020, 22 resources were wind resources, totaling 4,779 MW of nameplate capacity; 32 were dispatchable demand response (DDR) resources, totaling 34 MW of nameplate capacity and ranging in size from 0.1 MW to 10 MW, and one each of solar and oil resources, with each resource representing 3 MW of nameplate capacity.

In 2020, the SPP market had generation retirements amounting to just over 400 MW of installed capacity, shown in Figure 2–17.

Figure 2–17 Capacity retirements



Nine simple-cycle gas resources representing 388 MW of capacity, four wind resources representing 27 MW of capacity, and one oil resource representing 2 MW of capacity were retired in 2020.[27]

A look at annual trends in additions and retirements can be found in Section 6.1.1.

2.3.2 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.[28]

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 2020.

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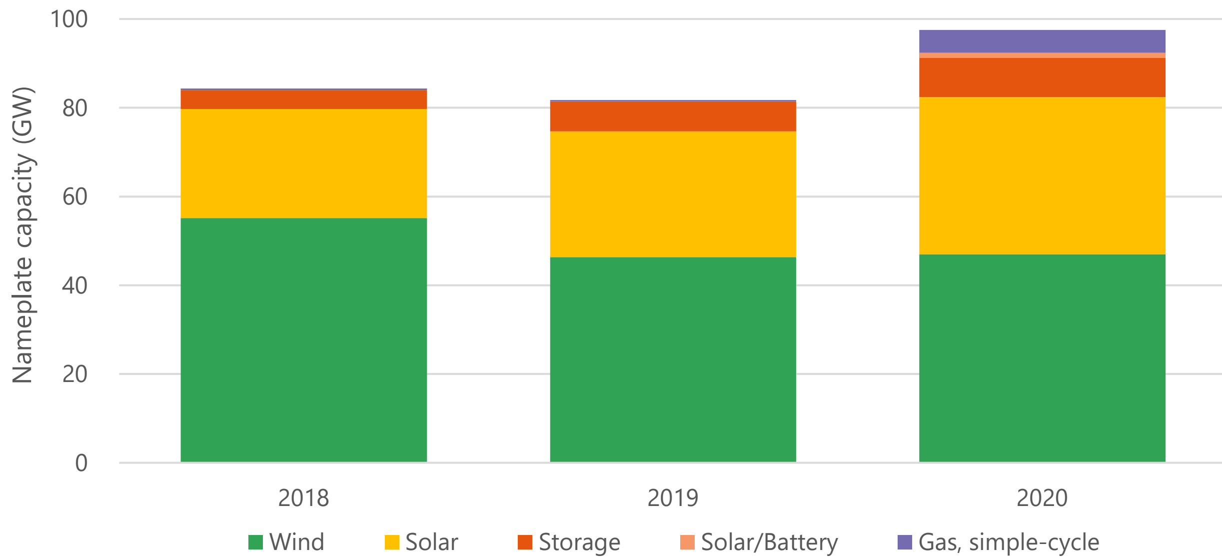
[27] The totals shown in Figure 2-13 differ from the change from 2019 to 2020 shown in Figure 2-15 and Figure 2-16. This can be due to resources being rerated or changing fuel source.
[28] See Guidelines for Generator Interconnection Requests to SPP's Transmission System

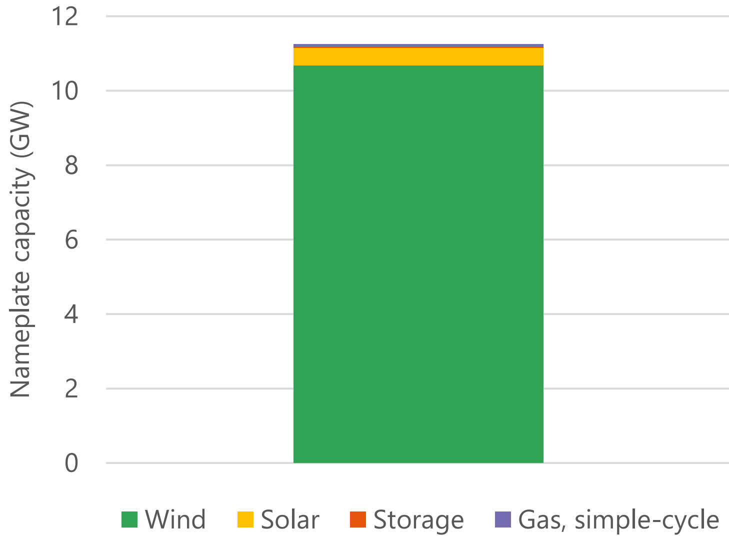
Figure 2–18 Active generation interconnection requests, megawatts



As shown above, generation capacity from renewable resources and storage accounts for the vast majority of proposed generation interconnection, at 92.4 GW of the 97.5 GW in the generation interconnection queue. Wind generation in the queue at the end of 2018 was 55.1 GW. This has dropped to around 46 GW in both 2019 and 2020. Interconnection requests for solar generation continued to increase, rising from 24.6 GW at the end of 2018 to 35.4 GW at the end of 2020. Storage interconnection requests also increased from 2019 to 2020 with nearly nine gigawatts in the queue at the end of 2020.

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 market stability and the reliability of the SPP system.

Figure 2–19 Executed generation interconnection requests, on-schedule



As the chart above shows, at the end of 2020, just over 11 GW of generation have an executed generation request that is on-schedule to be added to the market in 2021 and beyond. It is important to note that generation can still be added or removed from the list, even in the current year. However, there is more surety to the levels of generation scheduled to go into production closer to the current year, and additions and deletions to on-schedule projects are more typical in future years. Additionally, FERC has approved revisions to the SPP Generator Interconnection Procedures, which are intended to address the backlog which exists in the generator interconnection queue today.[29]

The ramping products and uncertainty products recommended in previous years will help with transparency regarding the value of these services. See Section 8.2 for further detail. Additional wind impact analysis is provided in Section 2.6.

2.4 GENERATION

2.4.1 GENERATION BY TECHNOLOGY

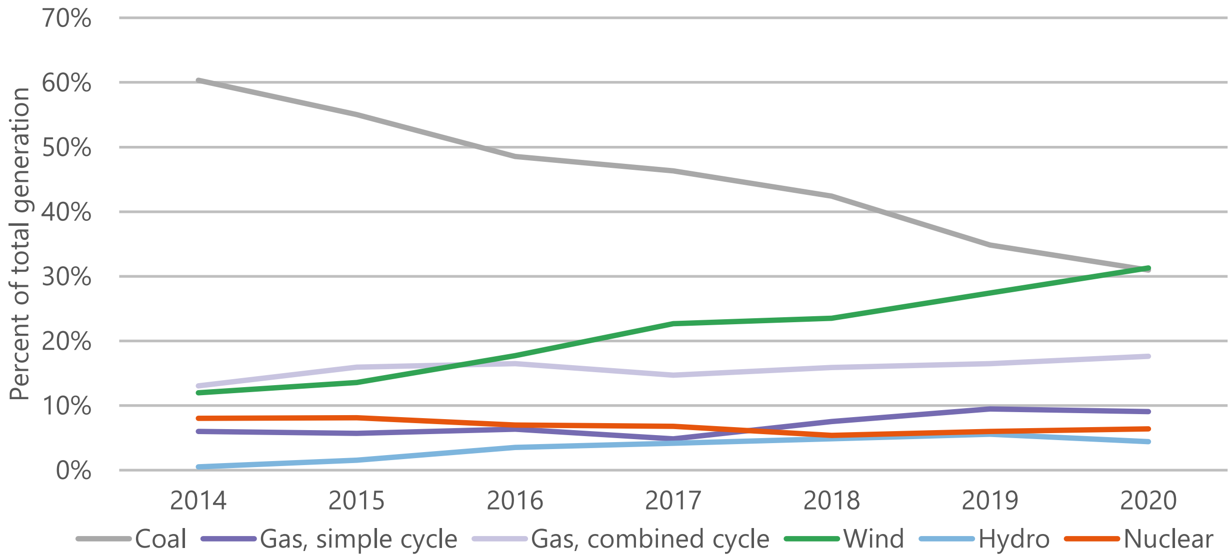
An analysis of generation by technology type used in the SPP Integrated Marketplace is useful in understanding pricing and reliability, as well as the potential impact of environmental and

[29] https://www.ferc.gov/CalendarFiles/20190628123105-ER19-1579-000.pdf

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 2–20 depicts annual generation percentages in the SPP real-time market by technology type for the years 2014 through 2020.

Figure 2–20 Generation by technology type, real-time, annual



The long-term trend for coal-fired generation had been relatively flat prior to 2014 (not shown on chart above), but has been in a steady decline ever since. In 2020, wind generation outplaced coal on an annual basis for the first time, with wind generation accounting for 31.3 percent of total production, and coal accounting for 31.0 percent of production. The other predominant fuel types all stayed near 2019 levels, with only slight variations.

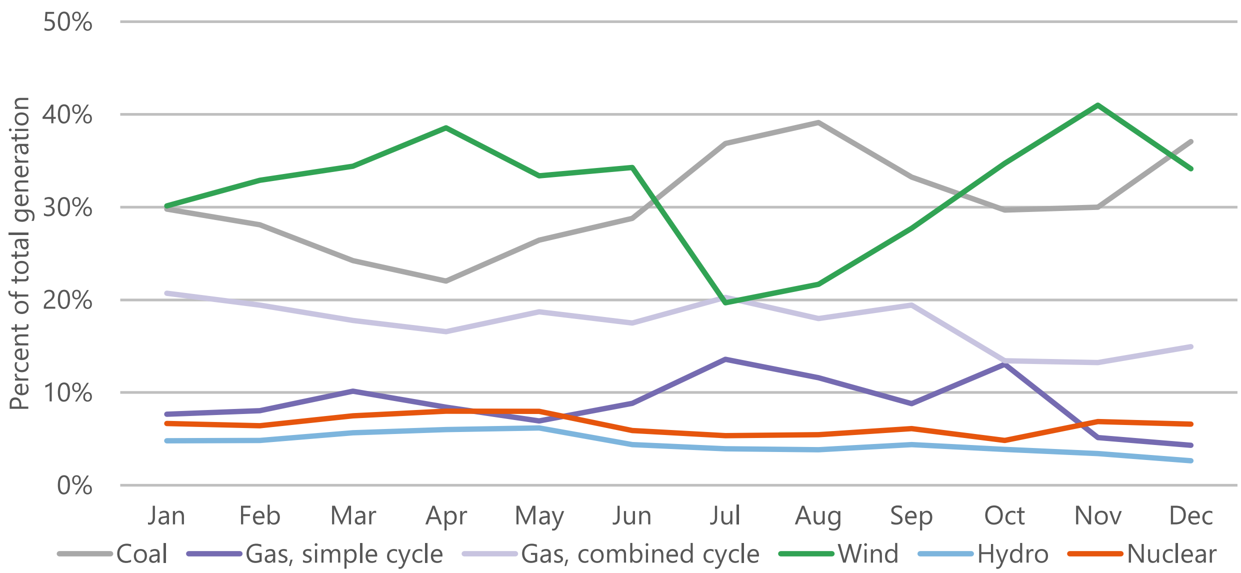
The wind generation share continues to increase, from 12 percent in 2014 to just over 31 percent in 2020. With low gas prices during much of 2018 through 2020, generation from simple-cycle gas units such as gas turbines and gas steam turbines has remained in the 9 to 10 percent range. Gas combined-cycle generation has remained relatively stable between about 15 and 17 percent for the past five years, which can mostly be attributed to 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 from 2015 to 2020 were 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, though this generation has become more competitive as gas prices have fallen.

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 2–21 depicts the 2020 monthly fluctuation in generation by technology type.

Figure 2–21 Generation by technology type, real-time, monthly

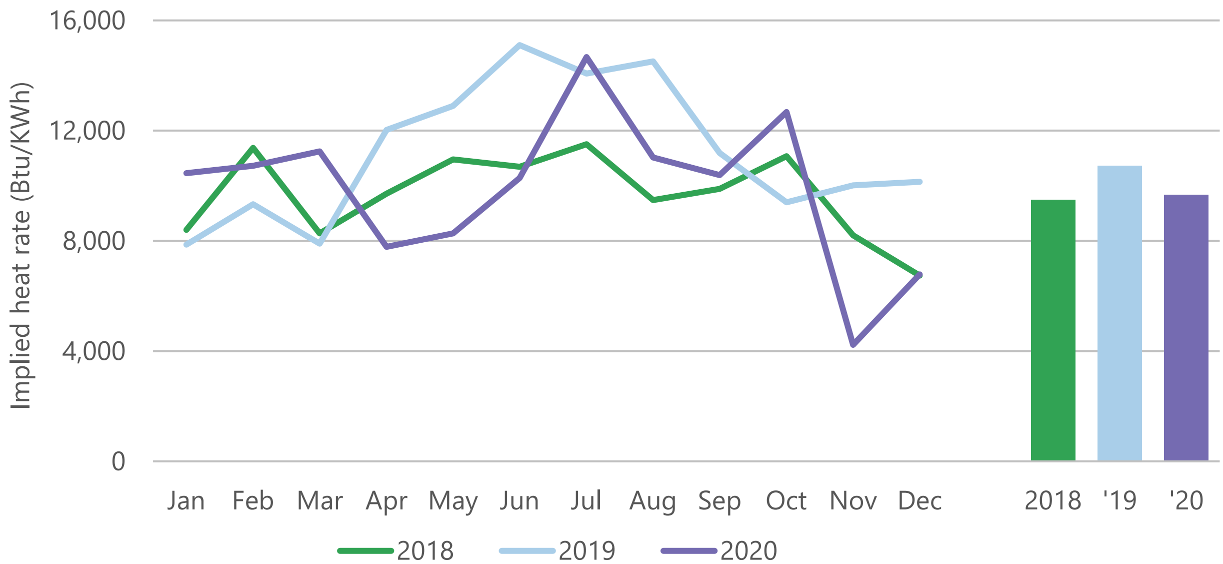


Wind generation as a percentage of total generation is generally lowest in the summer months at levels around 20 percent. In the highest wind generation months in the spring and fall, monthly levels approached 40 percent in 2020. In 2019, for the first time, in April and October, wind generation as a percentage of total generation outpaced coal generation. In 2020, wind generation outpaced coal in seven of the 12 months.

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.[30] 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 market prices.

Figure 2–22 shows the monthly implied heat rate using real-time electricity prices for 2018 to 2020, along with an annual average for those years.

Figure 2–22 Implied heat rate



Most significant in the chart above are the extremely low implied heat rates for November and December 2020. This is driven by low average energy prices for those months. 2020 saw a ten percent decrease in the implied heat rates from 2019. However, taking out those last two months, the average from 2019 to 2020 would be virtually unchanged.

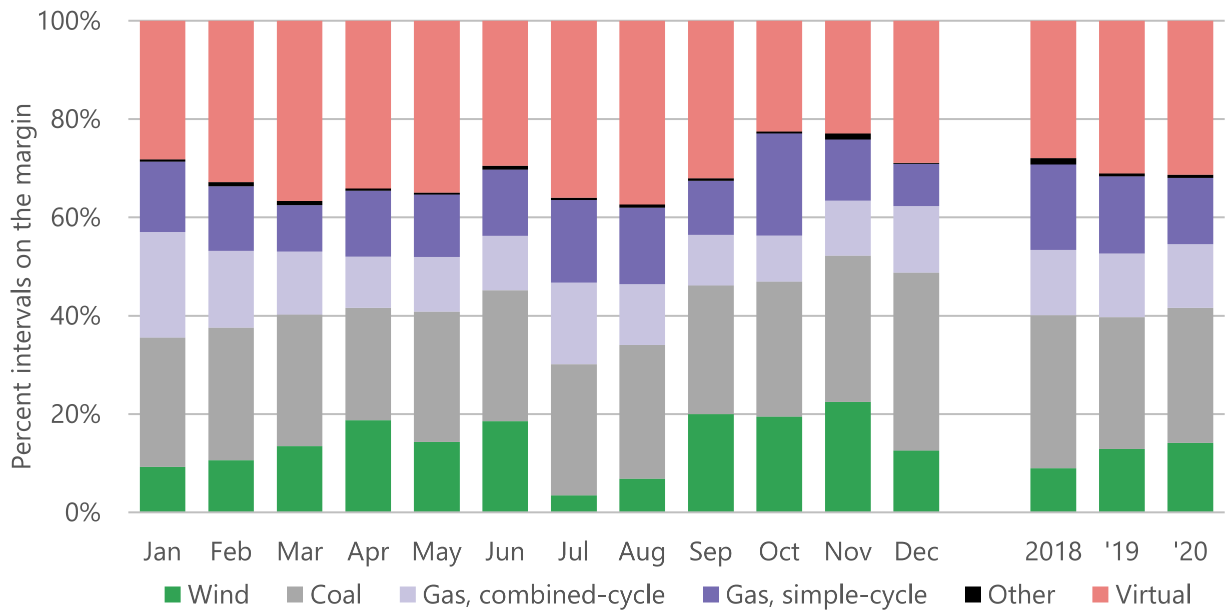
[30] For the implied heat rate calculation, natural gas units are assumed to be on the margin and accordingly, gas prices are taken as the relevant fuel cost. Emission costs are ignored in fuel cost as they rarely apply in the SPP market.

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.

Day-ahead generation on the margin, shown in Figure 2–23, 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.

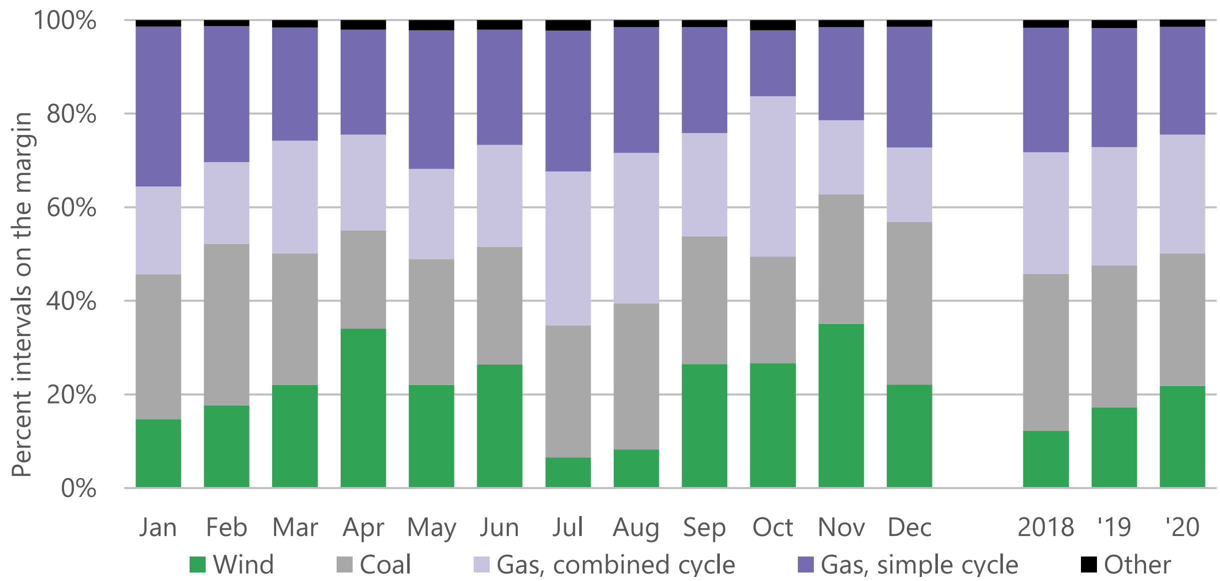
Figure 2–23 Generation on the margin, day-ahead



In 2020, virtual transactions were on the margin most often, setting prices in just over 31 percent of intervals, nearly the same as 2019. Coal generation set prices next most often in the day-ahead market at nearly 28 percent of intervals, followed by gas resources at nearly 27 percent of intervals. (Gas, simple-cycle accounted for 13.5 percent of intervals, while gas, combined-cycle accounted for 13 percent of intervals.) While marginal virtual offers occur at all types of settlement locations, 65 percent of marginal virtual offers are at resource settlement locations, with a significant amount of that activity at wind generation resource locations.

Figure 2–24 illustrates the frequency with which different technology types were marginal and price setting in the real-time market. 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 2–24 Generation on the margin, real-time



It is worth noting the increase in wind generation being on the margin in the real-time market—from five percent in 2014 and 2015 (not shown on the table above) to nearly 22 percent in 2020. With the growing amount of dispatchable wind generation and an overall share of nearly 30 percent of total nameplate capacity, wind generation is increasingly becoming the marginal technology a higher percentage of the time. At the end of 2020, 89 percent of nameplate wind capacity was dispatchable, compared to 76 percent at the end of 2019, and 71 percent at the end of 2018. At the beginning of the Integrated Marketplace in March 2014, just 27 percent of nameplate wind capacity was dispatchable.

The most significant difference between day-ahead and real-time fuel on the margin is the displacement of natural gas-fired generation by virtual offers in the day-ahead market. Virtual energy offers on the margin have been increasing over the past three years, with virtual energy offers representing 31 percent of the marginal offers in the day-ahead market in both 2019 and 2020. However, gas resources were on the margin in 2020 in the real-time market in just over

48 percent of all intervals, compared to just under 27 percent of all intervals in the day-ahead market.

In April 2019, FERC approved a proposed revision to the SPP tariff that would require nondispatchable variable energy resources to become dispatchable by January 1, 2021, or 10 years after starting operations. The conversion is not required for Public Utility Regulatory Policies Act (PURPA) qualifying facilities or run-of-the-river hydro resources that are incapable of following dispatch instructions. Under the timeline, all wind nondispatchable variable energy resources will be converted by October 2022, all non-wind nondispatchable variable energy resources (accounting for approximately 30 MW of capacity) will be converted by January 2027. Wind nameplate capacity by year represented by dispatchable and nondispatchable variable energy resources is shown in Figure 2–25 below.

On a monthly basis, intervals with coal generation on the margin are typically lower in the spring and fall months, offset by wind resources acting as base load units. This results in more coal- and gas-fired units cycling more often. 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 times of the year, as well as the lowest demand periods in the SPP footprint.

2.5 DEMAND RESPONSE

At the implementation of the Integrated Marketplace in March 2014, six demand response resources were registered in the market representing 48 MW of capacity. Those resources withdrew from the market in January 2015. Since that time, there have been no registered demand response resources in the SPP market until December 1, 2019. At that time, three demand response resources became active in the market representing 0.3 MW of capacity. In 2020, 31 additional demand response resources were added, ranging in capacity from 0.1 MW to 20 MW. As of December 31, 2020, there are 34 demand response resources in the SPP market, representing 34.2 MW of nameplate capacity.

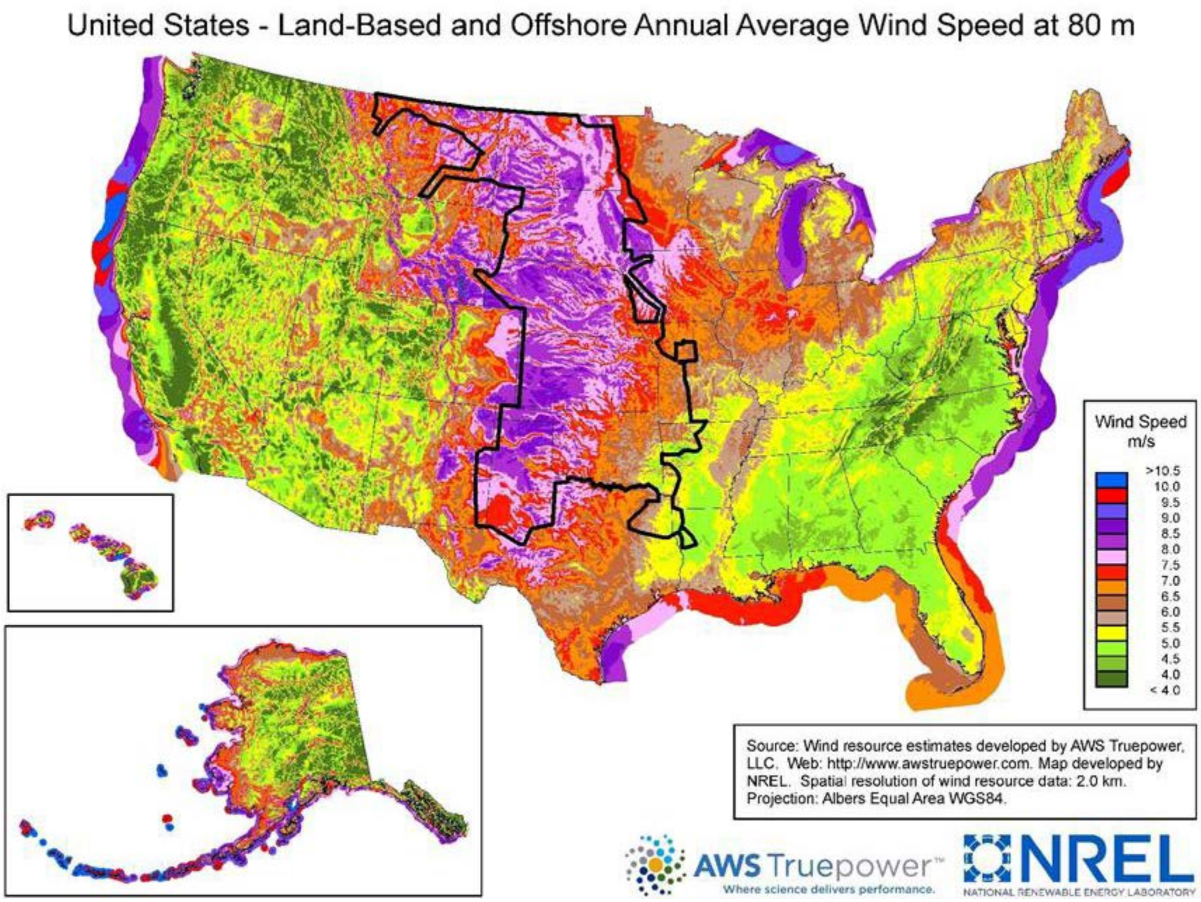
2.6 GROWING IMPACT OF WIND GENERATION CAPACITY

2.6.1 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 and incentives are additional factors that have resulted in significant investment of wind generation capacity in the SPP footprint during the last several years.

Figure 2–25 is a wind speed map of the United States with the SPP footprint outlined in black.

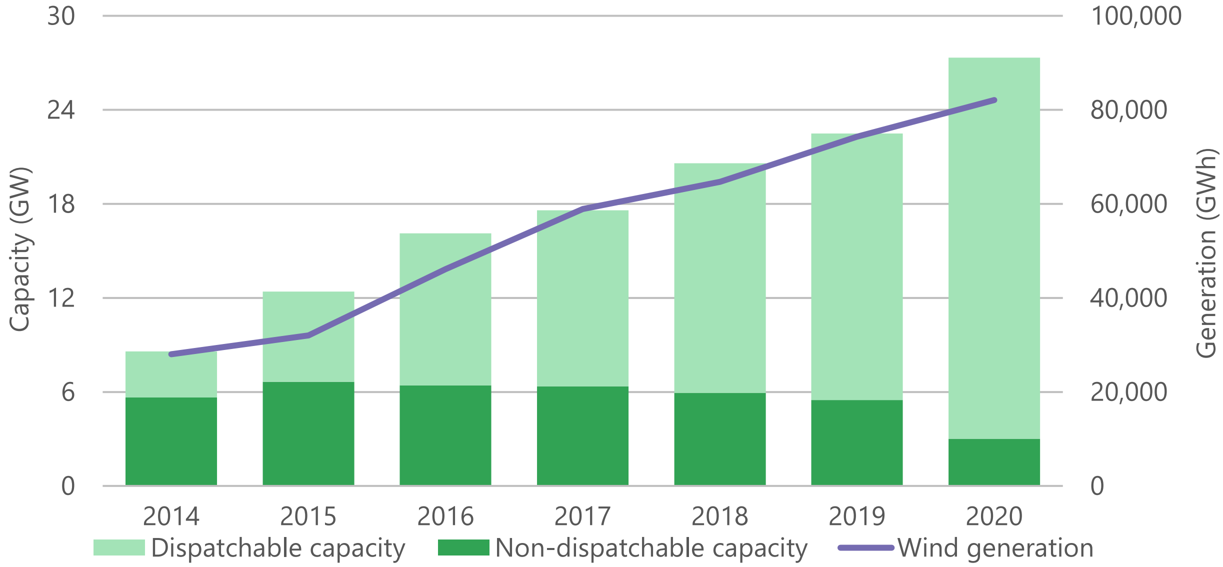
Figure 2–25 Wind speed map



Outside of coastal areas, much of the SPP footprint highlighted on the map is covered with some of the highest wind speeds in the country. As has been discussed, there continues to be a high potential for additional wind resource development in the SPP footprint going forward.

Figure 2–26 depicts nameplate capacity and total generation of SPP wind facilities since 2014.

Figure 2–26 Wind capacity and generation



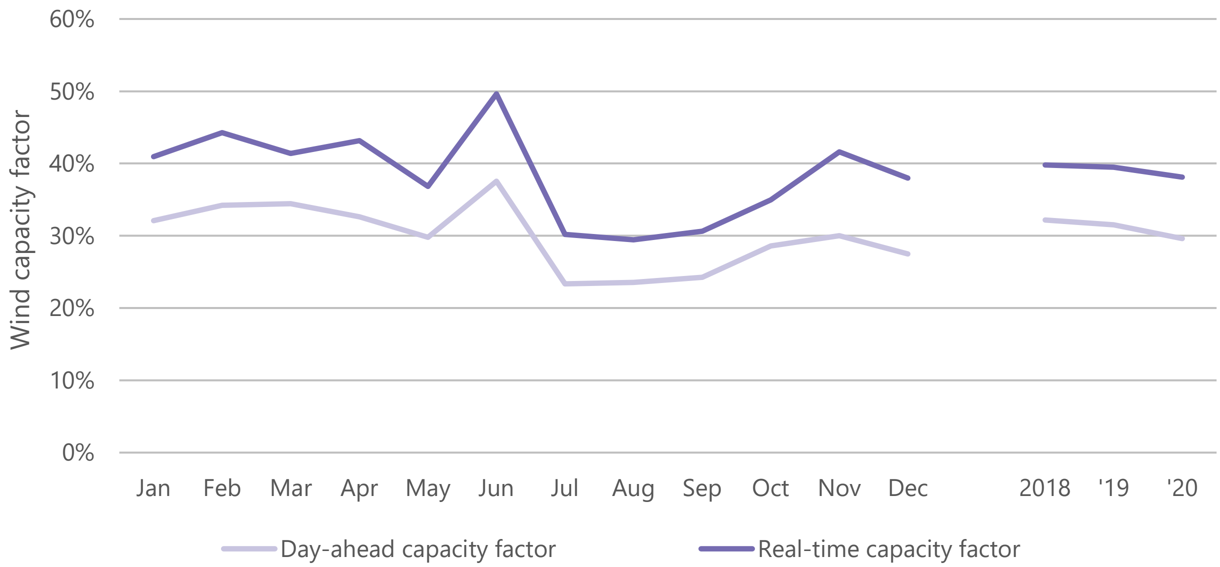
Total registered wind nameplate capacity at the end of 2020 was 27,326 MW, an increase of 22 percent from 2019. At the end of 2020, 89 percent of all nameplate wind capacity was dispatchable, while 11 percent was non-dispatchable. Wind generation output increased by 11 percent in 2020 to just over 82,000 GWh produced.

Wind resources comprised about 29 percent of the installed nameplate capacity in the SPP market at the end of 2020, behind only natural gas with 39 percent. Coal nameplate capacity at the end of 2020 represented 24 percent of installed nameplate capacity. Consistent with previous years, wind generation fluctuated seasonally with summer being the low wind season, as usual, while spring and fall were the high wind seasons. Also typical of wind patterns is lower production during on-peak hours than off-peak. Furthermore, higher levels of wind generation tend to coincide with the morning ramp periods.

Figure 2–27 shows the wind capacity factor. Note that the wind capacity factor is reported for the entire month.[31]

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

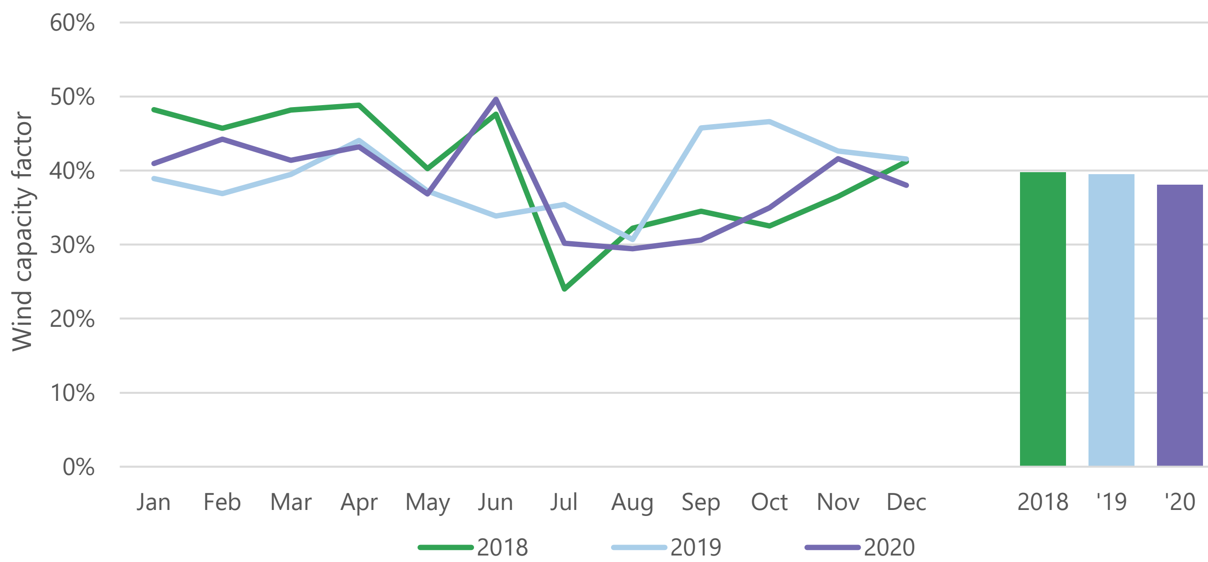
Figure 2–27 Wind capacity factor



The wind capacity factor in the real-time market dropped from nearly 40 percent in 2018 to just over 38 percent in 2020, while the day-ahead wind capacity factor, dropped from just over 32 percent to nearly 30 percent from 2018 to 2020. A 12 percent increase in wind generation from 2019 to 2020, coupled with a 22 percent increase in average monthly capacity, drove this slight drop in real-time capacity factor. The spread between the real-time and the day-ahead wind capacity indicates a disconnect in the amount of wind in the real-time market, compared to the cleared wind in the day-ahead market.

Figure 2–28 shows the monthly real-time wind capacity factor for the past three years.

Figure 2–28 Wind capacity factor by month, real-time

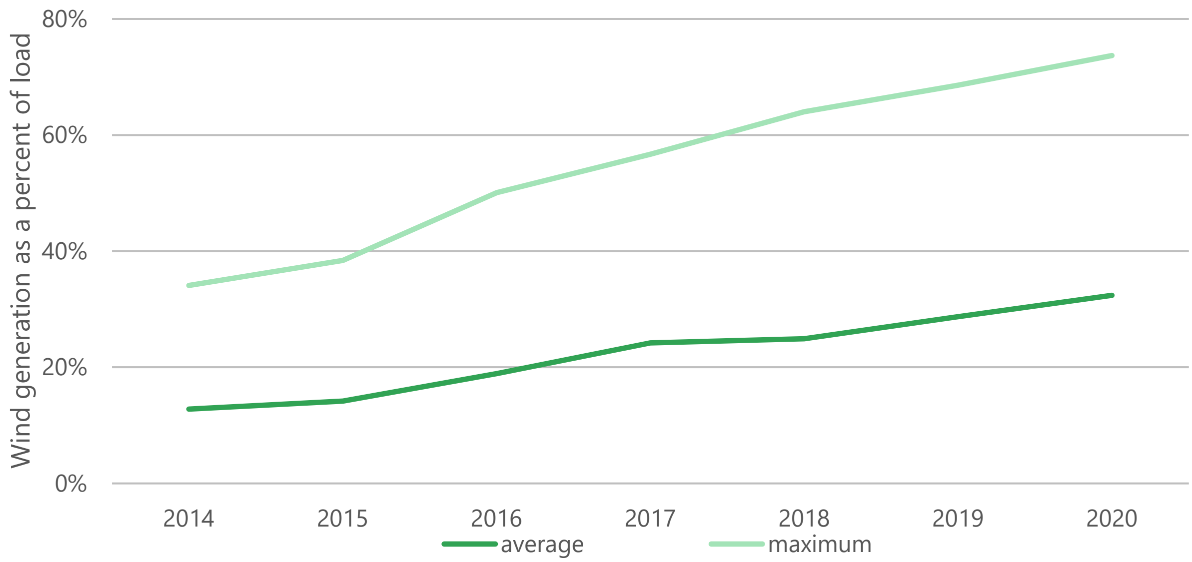


As shown above, the real-time capacity factor in 2020 did not show any clear trend when compared to prior years. However, overall, the average wind capacity factor for all of 2020 was 38.1 percent, down from 39.5 percent in 2019. This lower level is likely due to new wind resources that have been added to the capacity figure, but not in commercial operation, as well as weather patterns.

2.6.2 WIND IMPACT ON THE SYSTEM

Average annual wind generation as a percent of load continues to increase as shown in Figure 2–29. The chart shows the trend for average and maximum wind generation as a percent of load since 2014, illustrating the continued increase since the start of the Integrated Marketplace.

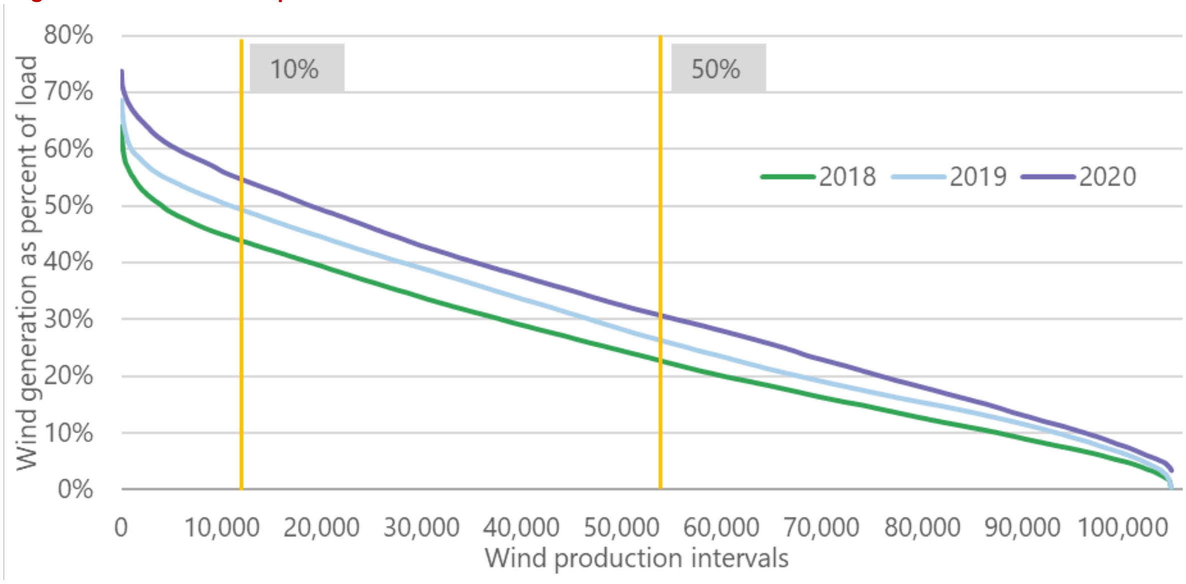
Figure 2–29 Wind generation as a percent of load



Average wind generation as a percent of load in the real-time market increased about three percentage points to just over 32 percent in 2020. After levelling off from 2017 to 2018, the growth of average wind generation as a percent of load has climbed steadily from 2018 to 2020. Wind generation peaked at 19,669 MW in 2020 on a five-minute interval basis, an increase of over nine percent from 17,852 MW in 2019. Wind generation as a percent of load for any five-minute interval reached a maximum value of nearly 74 percent in 2020, which was up from nearly 69 percent in 2019.

Figure 2–30 shows wind production duration curves that represent wind generation as a percent of load by real-time (five-minute) interval for 2018 through 2020.

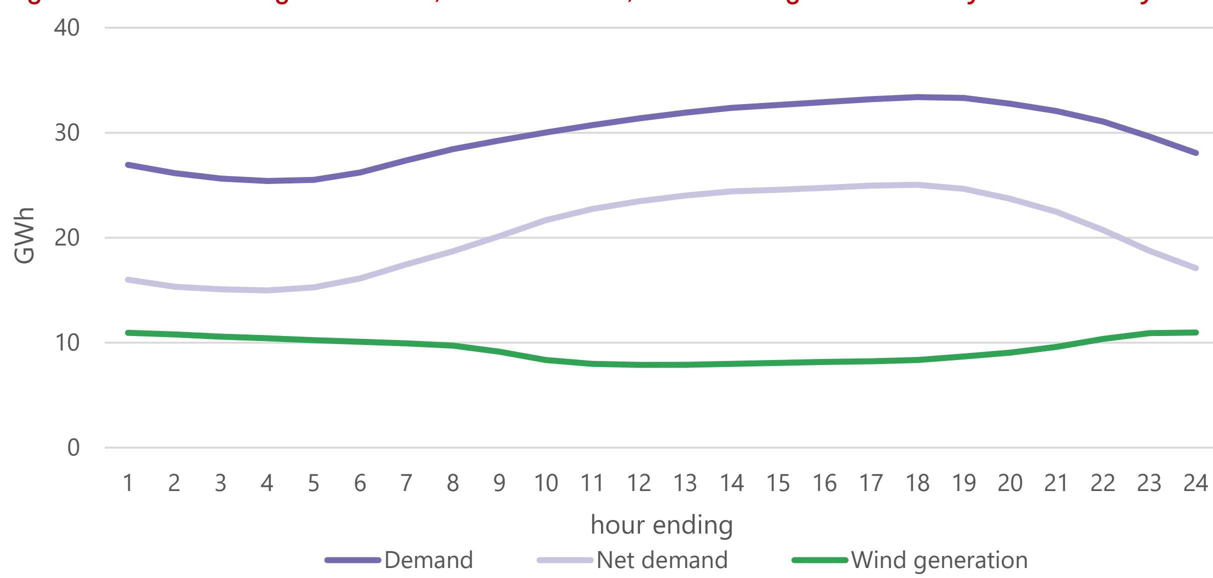
Figure 2–30 Wind production curve



The shift upward for the curve from year-to-year reflects an increase in total wind generation on an annual basis. The wind production curves show a consistent increase at all levels from 2018 to 2020. Wind generation served at least 23 percent of the total load during half of the year in 2018, with that figure increasing to 27 percent in 2019 and just over 31 percent in 2020.

Figure 2–31 below shows average demand by hour of day, along with wind generation, and net demand (demand minus wind generation) for 2020.

Figure 2–31 Average demand, net demand, and wind generation by hour of day



With wind generation at the highest levels in the overnight hours, net demand climbs more steeply than total demand, as wind generation begins to taper off when approaching the peak hours of the day. This can have an impact on the market, as generation needed from traditional resources climbs more quickly than demand. When this occurs, ramp scarcity is more likely. This is discussed in Section 3.2.1

While Figure 2–30 shows the yearly average load, wind, and net demand, there are seasonal differences. For instance, in the summer, wind generation is lower than during other times of the year, and loads are higher. Thus, the effect on net demand is smaller. However, in the shoulder periods, like the spring and fall, loads are lower and wind can have a significant effect on net demand. For instance, in October, net demand during off peak hours is as high as average wind generation, meaning that wind represents about half of all generation in off-peak hours during the month.

2.6.3 WIND INTEGRATION

Wind integration brings low cost generation to the SPP region but does not count for much accredited capacity.[32] 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 four 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, along with the locational 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. Under-scheduling of wind is also the leading cause of day-ahead and real-time price divergence.

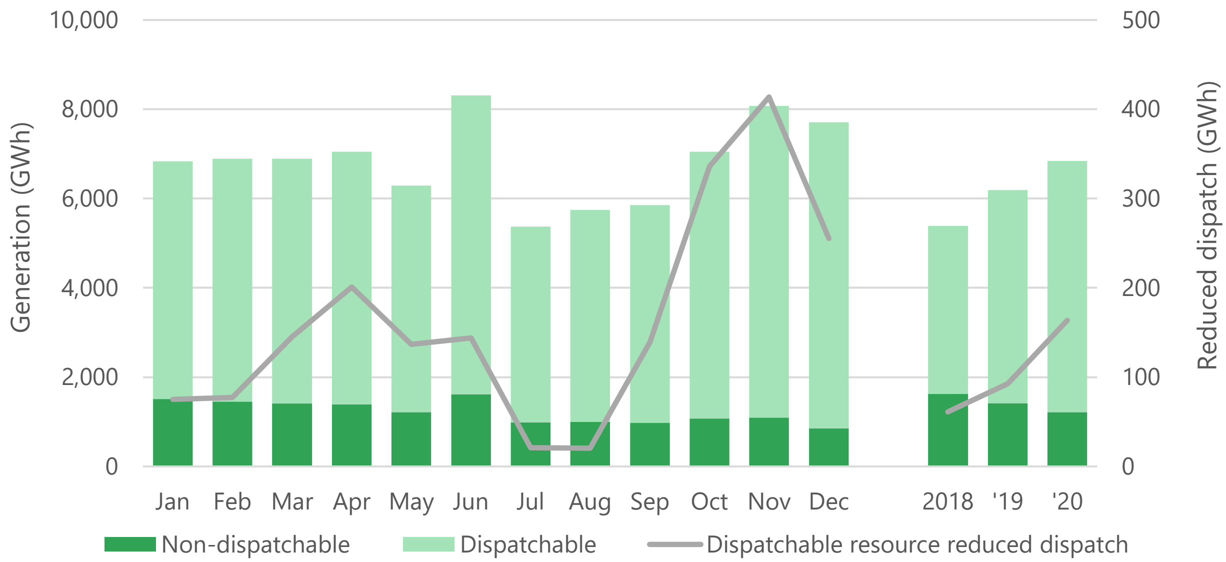
In the SPP market, wind and other qualifying resources were allowed to register as non-dispatchable variable energy resources, provided the resource had an interconnection agreement executed by May 21, 2011 and was commercially operated prior to October 15, 2012.

[32] Additional discussion on accreditation of capacity for wind and solar resources can be found in Section 6.2.

Because 11 percent (3,009 MW) of the existing installed wind capacity is composed of non-dispatchable variable energy resources, and these generally produce without regard to price, SPP operators must still issue manual dispatch instructions to reduce or limit their output at certain times. As discussed in Section 2.4.2, in April 2019, FERC approved a revision to the SPP tariff that would require nondispatchable variable energy resources to become dispatchable by January 1, 2021, or 10 years after starting operations.

Figure 2–32 illustrates dispatchable variable energy resources (DVERs) and non-dispatchable variable energy resources (NDVERs) wind output since 2018.

Figure 2–32 Dispatchable and non-dispatchable wind generation



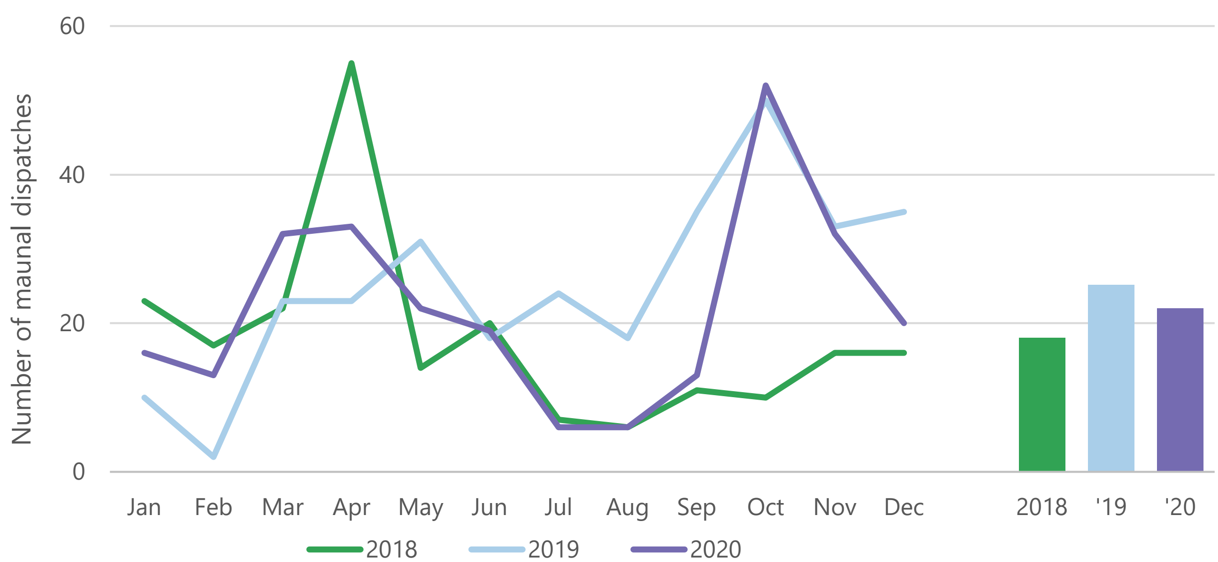
June 2020 saw over 8,300 GWh of monthly wind production, which was the highest since the start of the Integrated Marketplace and 19 percent of this output originated from non-dispatchable variable energy resource capacity. Also of note is the non-dispatchable generation continues to trend downward from year to year as more and more non-dispatchable resources are converted to dispatchable.

Figure 2–32 also shows the amount of reduced real time output of dispatchable variable energy resources below their forecast (grey line). This depicts the increase in reductions of dispatchable variable energy resource dispatch output from 2018 to 2020. This change was likely the result of increased wind output and stable loads. Reductions in dispatchable resource generation also follow 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.

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. The increased transmission capability directly reduces localized congestion, creating a more integrated system with higher diversity, more uniform prices, 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 entice further development of wind capacity.

Figure 2–33 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 2–33 Manual dispatches for wind resources



Manual dispatches are typically fewer during the lower wind output and higher demand months of summer, and more numerous during the higher wind output spring and fall months. Manual dispatches in 2020 were below or near previous year totals in most of the year. In 2020, 65 percent of the 264 manual dispatches were for dispatchable variable energy wind resources, whereas 35 percent were for non-dispatchable variable energy wind resources. Line loading in excess of 104 percent, operating guides, and outages caused 75 percent of manual dispatches for dispatchable variable energy wind resources. These same factors, plus transmission switching,[33] caused 80 percent of manual dispatches for non-dispatchable variable energy wind resources.

SPP is at the forefront among RTOs in managing wind energy integration. The Integrated Marketplace has reliably managed wind generation as it has surpassed 70 percent of load at times. 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. Since May 2017, ramp shortages are reflected in prices. Section 3.2.1 discusses the pricing of ramp shortages.

2.7 SEAMS

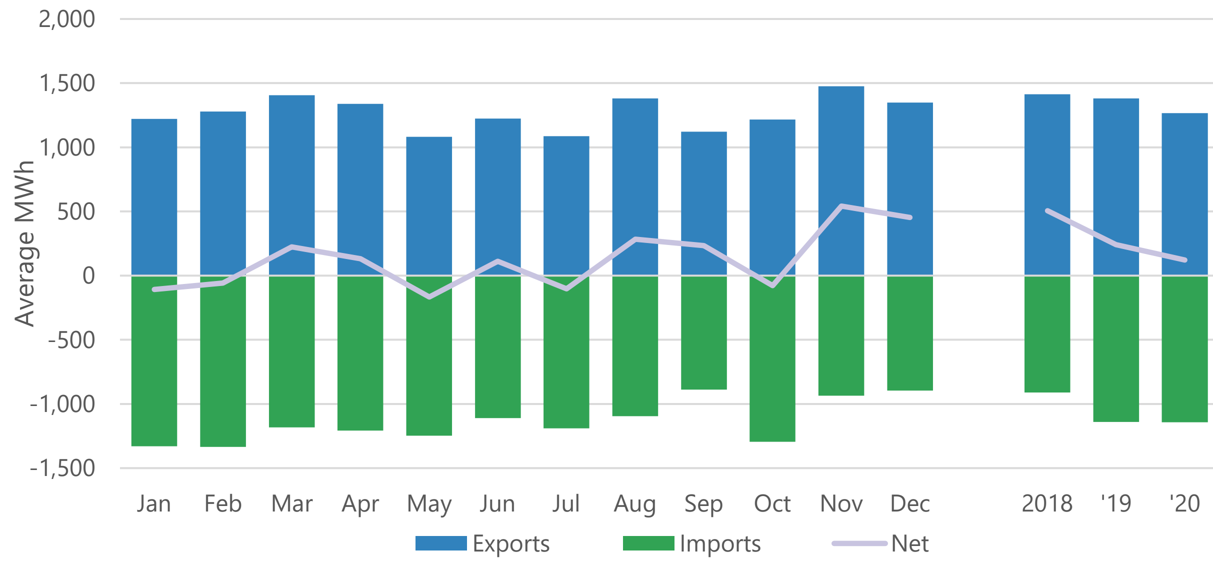
2.7.1 EXPORTS AND IMPORTS

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 the Western Interconnection 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 with the Associated Electric Cooperative (AECI) in Oklahoma and Missouri.

As shown in Figure 2–34, SPP has been a net exporter in real-time since 2017, prior to that it was a net importer.

[33] Transmission switching out-of-merit instructions are issued to accommodate switching of 345kV transmission lines, because of 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 timeframe.

Figure 2–34 Exports and imports, SPP system



Typically, as wind generation increases, exports increase. In 2020, exports were highest in March and November, which were the months with the highest level of wind generation.

Figure 2–35 through Figure 2–38 show the data for the four most heavily used interfaces in real-time, namely ERCOT (includes North and East interfaces), SPA, MISO, and AECI. Exports to ERCOT were driven by tight supply conditions and high prices during the summer months. 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 2–35 Exports and imports, ERCOT interface

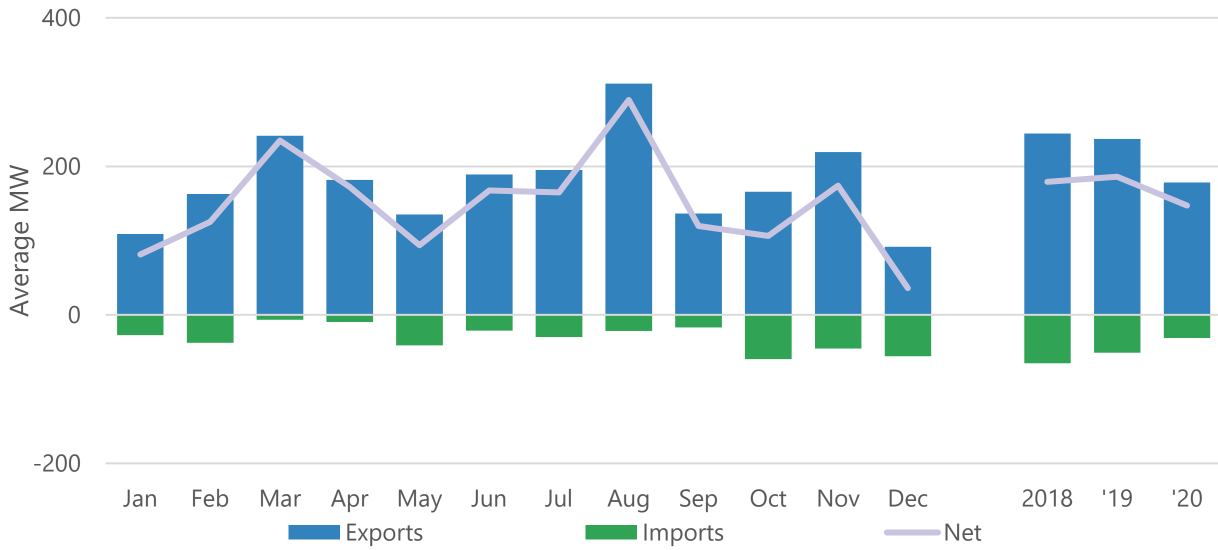


Figure 2–36 Exports and imports, Southwestern Power Administration interface

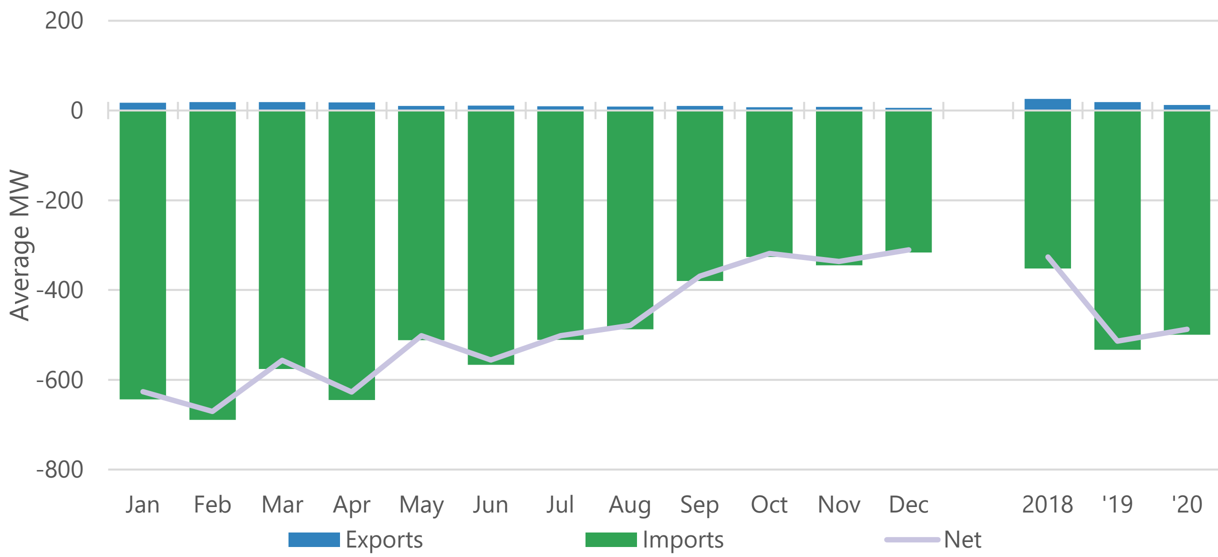


Figure 2–37 Exports and imports, MISO interface

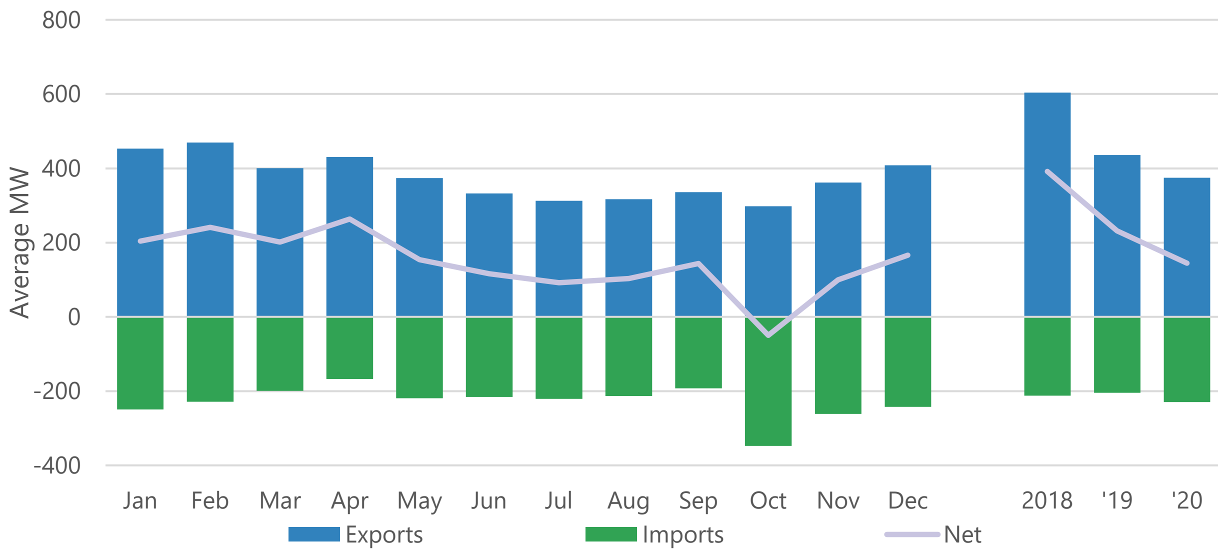
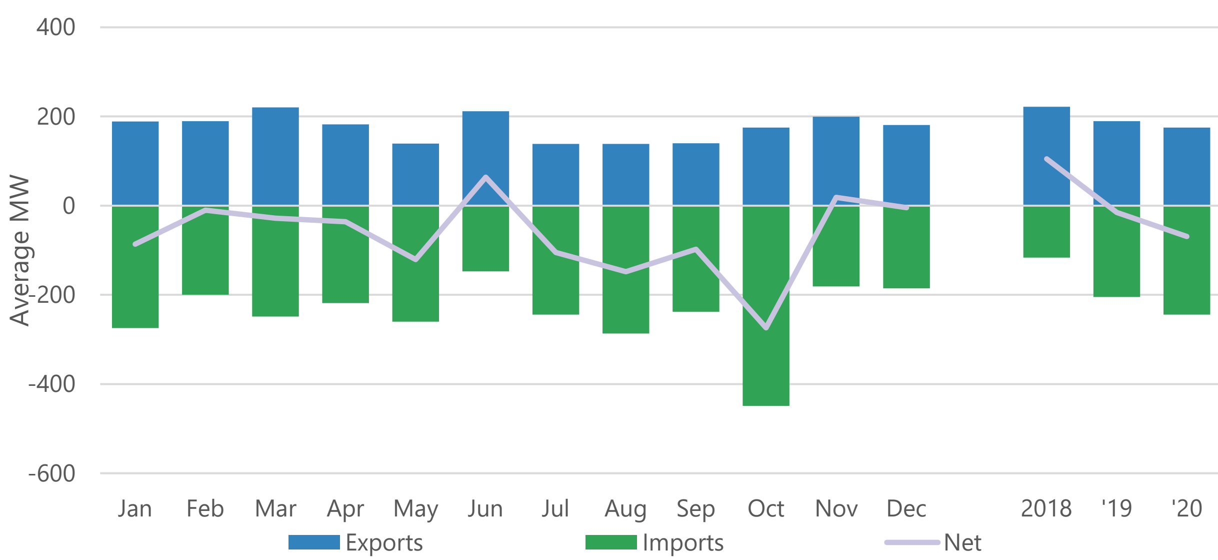


Figure 2–38 Exports and imports, Associated Electric Cooperative interface



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.

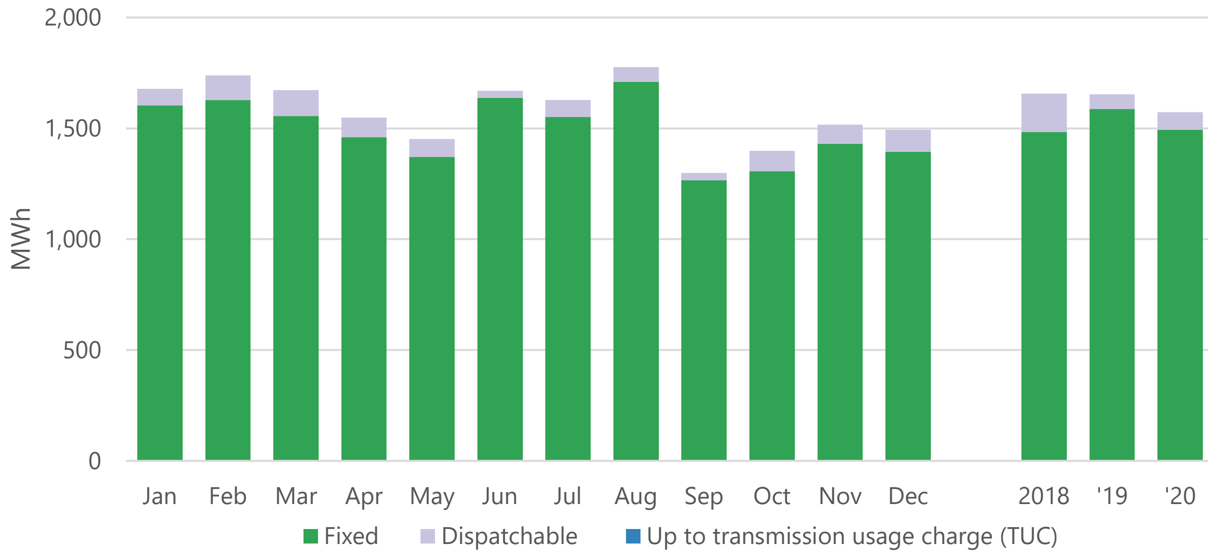
- An up-to-transmission usage charge (or up-to-TUC) offer on an interchange transaction specifies both a megawatt amount and the maximum amount of congestion cost and marginal loss cost the customer is willing to pay if the transaction is cleared in the day-ahead market.

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.[34]

As shown in Figure 2–39, of the 1,573 MW of day-ahead import and export transactions in 2020, 95 percent were fixed in the day-ahead market, five percent were dispatchable, and none were up to transmission usage charge (up to TUC). Dispatchable transactions increased from a monthly average of 65 MW in 2019 to a monthly average of 80 MW in 2020. Dispatchable transactions were highest in February and March, peaking just above 110 MW.

[34] *Integrated Marketplace Protocols*, Section 4.2.2.7, Import Interchange Transaction Offers.

Figure 2–39 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, Southwestern Power Administration hydro contracts, and generally 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.

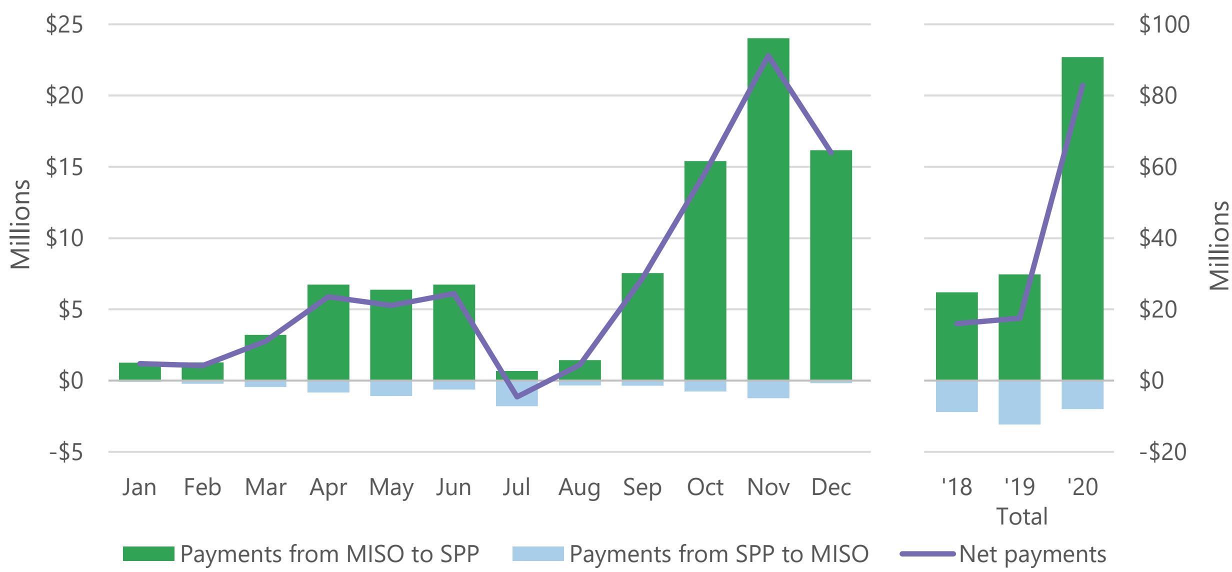
2.7.2 MARKET-TO-MARKET

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.[35]

[35] 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.

Each RTO is allocated property rights on market-to-market constraints. These are known as firm flow entitlements (FFE), and each RTO calculates its real-time usage, known as market flow. RTOs exchange money (market-to-market settlements) for redispatch based on the non-monitoring RTO's market flow in relation to its firm flow entitlement. The non-monitoring RTO receives money from the monitoring RTO if its market flow is below its firm flow entitlement. It pays if above its firm flow entitlement. Figure 2–40 shows payments by month between SPP and MISO (positive is payment from MISO to SPP and negative is payment from SPP to MISO.)

Figure 2–40 Market-to-market settlements



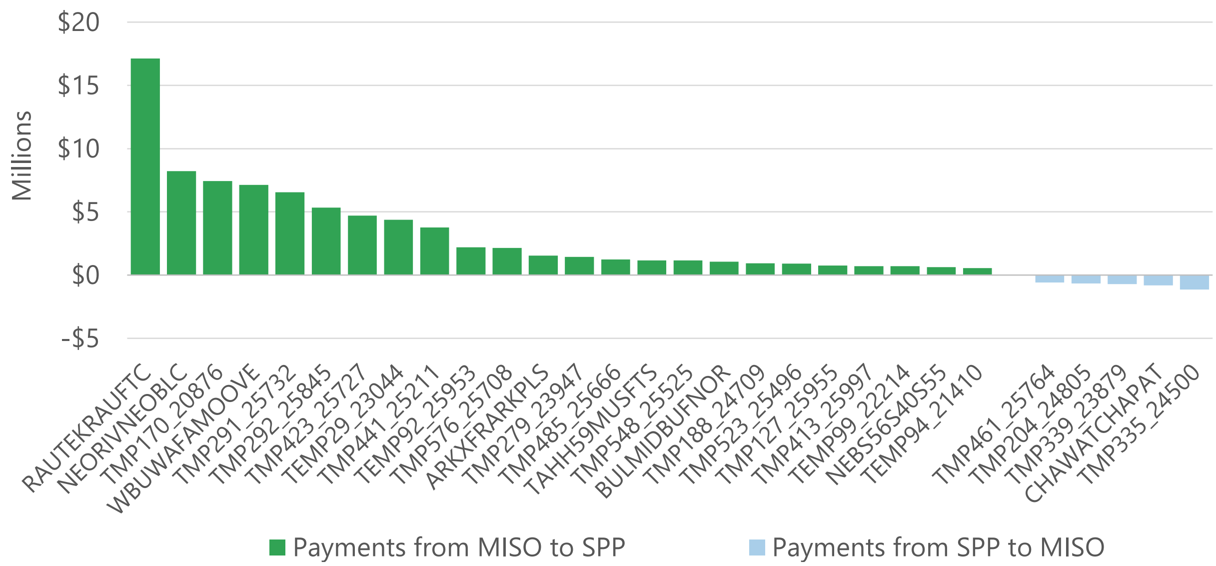
For 2020, total market-to-market payments from MISO to SPP totaled nearly $91 million, while market-to-market payments from SPP to MISO totaled nearly $8 million, resulting in a net payment of approximately $83 million from MISO to SPP for the year. This is up markedly from the $17.5 million paid from MISO to SPP in 2019. Both October and December had total payments from MISO to SPP over $15 million, while November saw payments from MISO to SPP of nearly $25 million. Many SPP market-to-market flowgates are impacted by MISO wind that can increase the amount of market-to-market payments from MISO to SPP. Potomac Economics (external Independent Market Monitor for MISO) notes in their annual report[36] that MISO's wind output was 25 percent higher than in 2019. November was the highest monthly

[36] See Wind Generation section under Real-Time Market Performance in the 2020 State of the Market Report for the MISO Electricity Markets.

average wind output for MISO on record with over eleven gigawatts. Compared to 2019, no month averaged over eight gigawatts of wind output.

Figure 2–41 shows market-to-market payments (over $500,000 either from SPP to MISO, or MISO to SPP) by flowgate for 2020.

Figure 2–41 Market-to-market settlements by flowgate



Seventeen flowgates had payments from MISO to SPP over $1 million for 2020, with six of those flowgates having payments over $5 million. Only one flowgate had payments from SPP to MISO of over $1 million. For 2020, the constraint with the highest payments from MISO to SPP was the Raun-Tekamah 161kV flowgate (located north of Omaha). The constraint with highest payments from MISO to SPP in both 2018 and 2019, the Neosho-Riverton 161kV flowgate, dropped to the constraint receiving the second highest payment in 2020. These constraints are impacted by wind and external flows and are discussed in more detail in Section 5.1.4.2.

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. As part of the Organization of MISO States (OMS) and SPP Regional State Committee (RSC) seams study, Potomac Economics (external Independent Market Monitor for MISO) lead an effort to study the benefit of improving specific mechanics of the market-to-market process. This report[37] was released in May 2020, and the recommendations are discussed in Section 2.7.3 below.

2.7.3 ANALYSIS

The MMU and Potomac Economics collaborated on a joint effort[38] to study seams issues for the SPP Regional State Committee (RSC) and Organization of MISO States (OMS) Seams Liaison Committee. The studies completed in 2019 and 2020 were:

- Rate pancaking and unreserved use
- Joint dispatch
- Market-to-market coordination
- Interface pricing
- Coordinated transaction scheduling

No further analysis will be performed at this time on the following seams issues identified in 2019 by the RSC and OMS Seams Liaison Committee and market monitors:

- Interchange optimization
- Regional directional transfer limit
- Targeted market efficiency projects
- Outage and day-ahead coordination

Rate pancaking and unreserved use

The rate pancaking and unreserved use study[39], published in November 2019, was led by the SPP MMU and focused on the economic efficiency effects on the SPP-MISO seam. Our analysis

[37] OMS-RSC Seams Study: Market-to-Market Coordination
[38] MMU and Potomac Economics joint efforts can be found on the RSC/OMS Liaison Committee Reference Documents page, https://www.spp.org/spp-documents-filings/?id=173559 .
[39] Rate Pancaking and Unreserved Use Study, prepared by SPP MMU

showed that rate pancaking has a very limited effect on import and export volumes with the removal of duplicate transmission charges. The analysis also revealed that SPP and MISO have charged minimal amounts for unreserved use arising from topology changes on the SPP-MISO seam.

Joint dispatch

The joint dispatch[40] study was led by Potomac Economics and published in November 2019. This analysis estimated potential savings from joint dispatch and joint commitment between SPP and MISO. The results estimated annual benefits of $17 million for joint dispatch between SPP and MISO and an annual benefit of $29 million for joint dispatch with joint commitment. These savings represented about 0.1 percent and 0.2 percent of the combined region's total production costs.

Market-to-market coordination

The market-to-market coordination[41] study was led by Potomac Economics and published in May 2020. This analysis evaluated the market-to-market processes used to coordinate congestion on transmission constraints that both SPP and MISO affect. The study identified potential savings by improving key aspects of the market-to-market process. These improvements include automation of constraint coordination tests and activation, relief request improvements, and modeling of neighboring RTO's constraints. Potomac Economics estimated $35 million of reduction in yearly congestion costs by automating processes that identified and activated constraints in SPP and MISO's market-to-market systems in a timely manner. Potomac Economics also estimated congestion benefits of $32 million by optimizing the amount of relief requested on market-to-market constraints. This optimization can also reduce oscillations and breaches on market-to-market constraints. Potomac Economics also identified market-to-market constraint modeling differences in SPP and MISO. SPP either seldom activates MISO constraints in the day-ahead or models them in a manner that causes them not to bind in the

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[40] OMS-RSC Seams Study: Joint Dispatch Evaluation report, prepared by Potomac Economics (MISO IMM).
[41] OMS-RSC Seams Study: Market-to-Market Coordination, prepared by Potomac Economics (MISO IMM).

day-ahead. MISO also has modeling differences through its implementation of a shift factor cutoff where generators falling between negative 1.5 and 1.5 percent are not considered for redispatch for a constraint. Both of these modeling differences cause inefficient commitments in the day-ahead and increase congestion costs in real-time resulting in uplift costs charged to participants to support market-to-market settlements.

Interface pricing

The interface pricing[42] study was led by Potomac Economics and published in August 2020. This study evaluated the efficiency of interface prices and recommended improvements to better incent participants to transact between the SPP and MISO markets and eliminate redundant payments and charges on transactions. Potomac Economic determines that SPP and MISO both include the congestion component in jointly managed market-to-market constraints resulting in redundant congestion payment or charges on transactions between the RTOs. Potomac Economics estimated these redundant payments and charges exceeded $7.5 million between June 2018 and May 2019. The MISO IMM recommends SPP and MISO each modify their respective interface prices to include only the congestion on their own monitored constraints.

Coordinated transaction scheduling

The coordination transaction scheduling[43] study was led by MMU and published in May 2020. This study estimated volume changes in imports and exports for the SPP/MISO seam stemming from a coordinated transaction scheduling process and the benefits the markets might obtain from those increased volumes. Coordinated transaction scheduling would allow market participants to submit price-based interchange offers between SPP and MISO in the real-time market rather than the administration of clearing ramp and reserving and scheduling transmission service. Coordinated transaction scheduling provides a one-stop approach allowing market participants to place a spread offer to clear against forecasted price spreads between the two markets. The coordinated transaction scheduling product will be settled at the

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[42] OMS-RSC Seams Study: Interface Pricing, prepared by Potomac Economics (MISO IMM).
[43] OMS-RSC Seams Study: Coordinated Transaction Scheduling, prepared by SPP MMU.

real-time price spreads which will likely differ from the forecasted price spreads. Coordinated transaction scheduling participants must account for this price forecast risk in their offers.

The MMU estimated an annual $9.4 million to $11.2 million in unrealized value on the SPP/MISO seam. Multiple roadblocks and criteria will need to be addressed including removal of fees, connecting physical ramp in the market to the ramp needed for clearing schedules, and accurately forecasted interface prices are necessary to capture a portion of these estimated benefits. Our analysis found that using current 30-minute look-ahead models forecasts could reduce benefits to a range between $1.4 million benefit to a net harm of $647,000 per year. Using lagging 5-minute prices the MMU estimated benefits between $4 million and $3.2 million per year. This analysis finds that CTS benefits can be unlocked if fees are removed, supply curves are shared between MISO and SPP, actual ramp as opposed to estimated ramp is used, and more accurate forecasted prices are developed or clearing can happen near real-time.

RSC and OMS Seams Liaison Committee recommendations

The Seams Liaison Committee offered recommendations[44] to SPP, MISO, interested stakeholders, and members of both the OMS and RSC. The Seams Liaison Committee encourages members of the RSC and OMS to participate in the SPP Strategic Roadmap process and the MISO Integrated Roadmap process to give priorities to market-to-market coordination, coordinated transaction scheduling, and interface pricing. The Seams Liaison Committee also recommends the creation of a working group focused on further inventorying types of rate pancaking along the SPP/MISO seam and survey transmission owners and stakeholders to measure interest in studying rate pancaking further.

The Seams Liaison Committee also made recommendations regarding issues not studied by SPP MMU or Potomac Economics including; targeted market efficiency projects, generator interconnection, and interregional planning. The Seams Liaison Committee recommends the Interregional Planning Stakeholder Advisory Committee evaluate the need for a targeted market efficiency projects process. This process would include guidelines and criteria for identifying projects on the SPP/MISO seam that would benefit both markets. The Seams Liaison Committee

[44] OMS-RSC Seams Liaison Committee Recommendations, posted March 2021

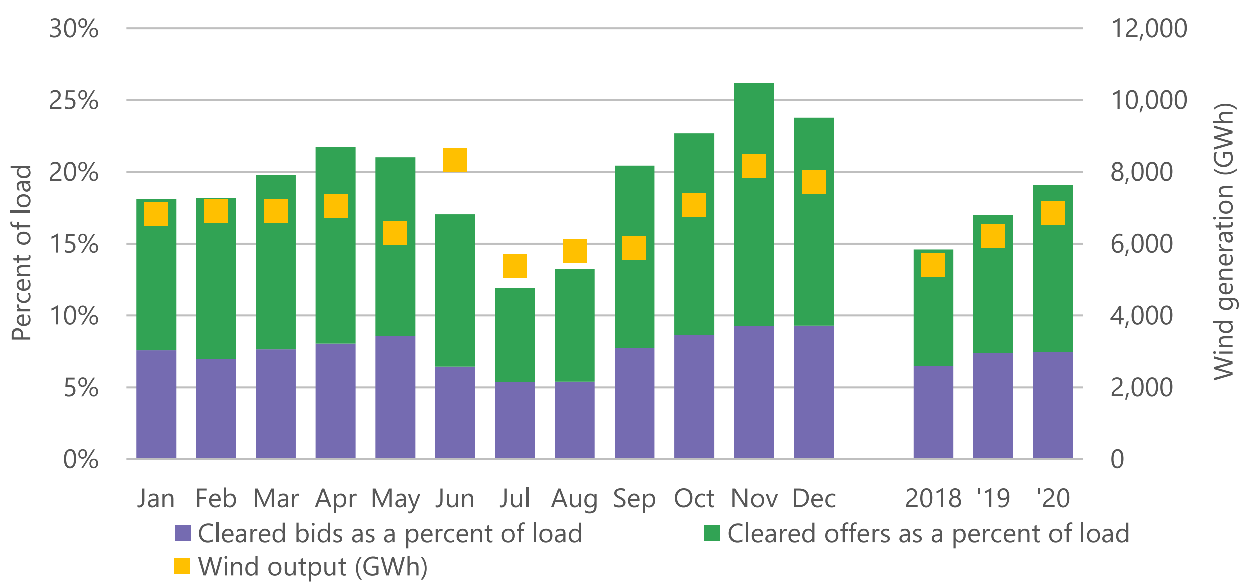
also recommends SPP and MISO provide updates to the RSC, OMS, or Seams Liaison Committee for studies focused on generator interconnection along the SPP/MISO seam and interregional planning activities as well as any changes to their respective processes.

2.8 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 increasing levels of virtual participation. Figure 2–42 displays the total volume of virtual transactions as a percentage of real-time market load along with wind output levels.

Figure 2–42 Cleared virtual transactions as percent of real-time load

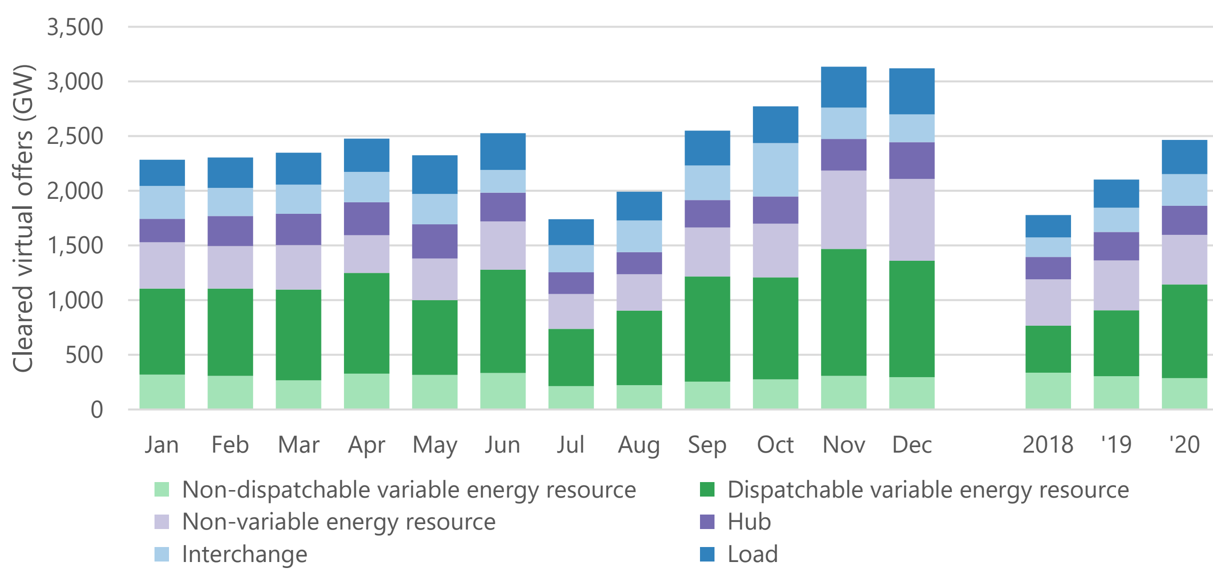


As shown in the figure, virtual transactions averaged 19 percent of real-time market load, compared to 17 percent in 2019 and 15 percent in 2018. Historically, the greatest increases in virtual transactions as a percentage of load have been with cleared virtual offers. This trend continued in 2020, as the percent of virtual offers to load was nearly 12 percent, up from just over eight percent in 2018 and 10 percent in 2019. Virtual cleared bids increased from six and one-half percent in 2018 to roughly seven and one-half percent in 2019 and 2020. Days with high wind output typically see an increase in virtual offer activity. Virtual bids typically increase during high load hours.

At 19 percent of load, the average hourly total volume of cleared virtuals ranged from 2,096 MW of withdrawal to 3,280 MW of injection. The net cleared virtual positions in the market averaged about 1,184 MW of injection, or supply, each hour – a seventy-eight percent increase year-over-year.

The majority of virtual transactions occurred at wind resources in 2020 – a trend that has been increasing since mid-2015. Figure 2–43 illustrates the settlement location types where virtual offers clear.

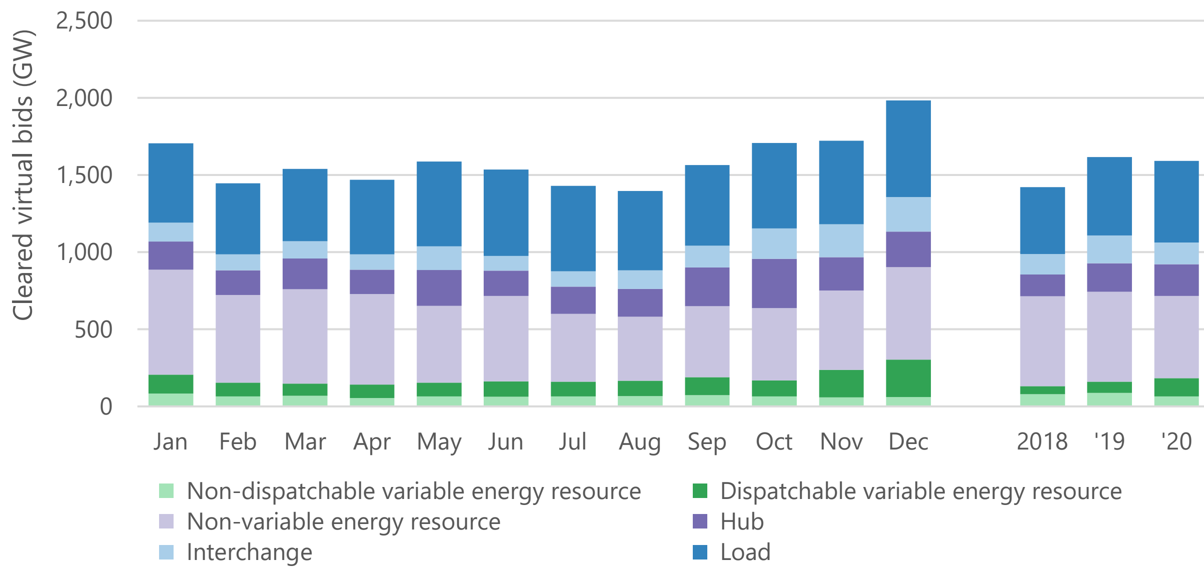
Figure 2–43 Cleared virtual offers by settlement location type



In total, the monthly average of cleared virtual offers for 2020 was nearly 2,500 GW, up from just over 2,100 GW in 2019. This figure shows that an average of almost 1,150 GW of virtuals offers cleared at variable energy resources per month during 2020.[45] This is up from an average of more than 905 GW per month in 2019. Virtual offers at wind locations remain the largest volume of any single location type. These large volumes highlight the possibility that market participants with registered wind resources may be missing financial opportunities by under-scheduling in the day-ahead market.[46]

Figure 2–44, below, shows the cleared virtual bids by settlement location types.

Figure 2–44 Cleared virtual bids by settlement location type



The locations where virtual bids occur are in contrast with the locational volumes of virtual offers. Cleared virtual bids were primarily at resources other than variable energy resources, followed by load locations. Variable energy resources had the lowest volume of virtual bids by location.

Average monthly cleared virtual bids declined from just over 1,600 GW in 2019 to just under 1,600 GW in 2020. Cleared virtual bids at non-variable energy resources had a monthly average of nearly 534 GW cleared at non-variable energy resource locations in 2020, down from 583 GW in 2019. Virtual bids at load locations have been steadily increasing, up to a monthly average of 529 GW in 2020, up four percent from nearly 509 GW in 2019.

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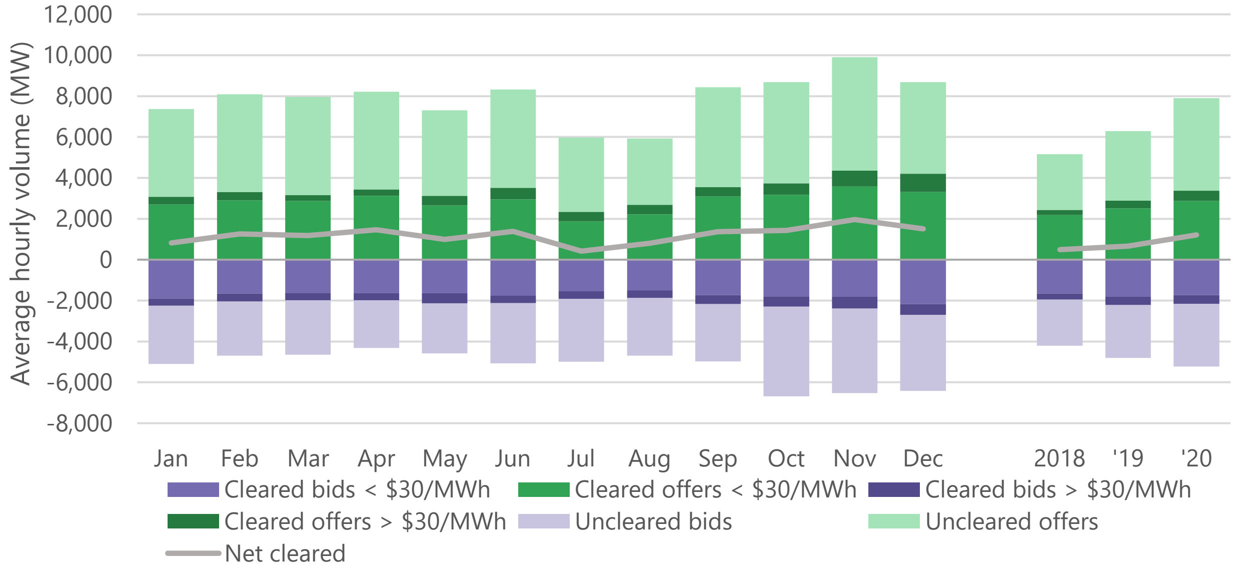
[45] This includes both dispatchable and non-dispatch variable energy locations.

[46] Section 4.1.3 on price divergence discusses the effects of unscheduled wind in the SPP market.

Figure 2–45 shows how virtual bids and offers are offered and cleared at the day-ahead market.

Figure 2–45 Virtual offers and bids, day-ahead market



The 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, are considered "price-insensitive." Compared to 2020, price-insensitive bids increased five percent and price-insensitive offers increased 36 percent. Cleared bids decreased three percent, and cleared offers increased 17 percent. 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 2020 in Figure 2–46

Figure 2–46 Virtual profits with distribution charges, monthly

Month	Gross profit	Gross loss	Gross 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	$ 14.6	$ -12.1	$ 2.4	$ -0.6	$ -0.2	$ -1.4	$ -0.1	$ 0.2
February	12.7	-11.4	1.3	-0.2	-0.2	-1.4	-0.1	-0.6
March	18.2	-12.3	5.9	-0.6	-0.1	-1.6	-0.1	3.5
April	21.3	-12.3	9.0	-0.1	-0.3	-1.2	-0.1	7.3
May	16.3	-15.1	1.2	-0.1	-0.4	-1.6	-0.1	-0.9
June	18.2	-14.5	3.7	0.0	-0.3	-1.5	-0.1	1.7
July	14.5	-12.0	2.5	-0.4	-0.3	-1.8	-0.1	0.0
August	10.7	-9.2	1.6	-0.2	-0.2	-3.6	-0.1	-2.5
September	19.1	-13.9	5.2	-0.9	-0.3	-2.4	-0.1	1.6
October	34.4	-29.4	4.9	-0.5	-0.6	-3.2	-0.1	0.6
November	38.4	-20.1	18.3	-1.4	-0.4	-3.2	-0.1	13.2
December	34.0	-18.1	15.8	-0.4	-0.4	-3.3	-0.1	11.6
Total	$	$ -180.5	$ 71.8	$ -5.4	$ -3.8	$ -26.2	$ -0.8	$ 35.6

All figures in $ millions.

Every month in 2020 was profitable in aggregate for virtual transactions before factoring in transaction fees. However, after accounting for these fees, February and August were unprofitable in aggregate. In the 82 months since the market began, only 13 months have had a net loss when factoring in fees. The highest payout months in 2020 happened in November and December with net payouts of $13.2 million and $11.6 million, respectively. As shown in Section 2.6.3, November and December 2020 saw the second and third highest months of wind production, trailing only June. In addition, times of high wind and low load can create large price differences that can occur between day-ahead and real-time markets as a result of under-scheduled wind in the day-ahead market.[47]

Financial information for virtual trades on an annual basis for the past three years is shown in Figure 2–47.

[47] Section 4.1.3, price divergence, discusses the effects of unscheduled wind in the SPP market.

Figure 2–47 Virtual profits with distribution charges, annual

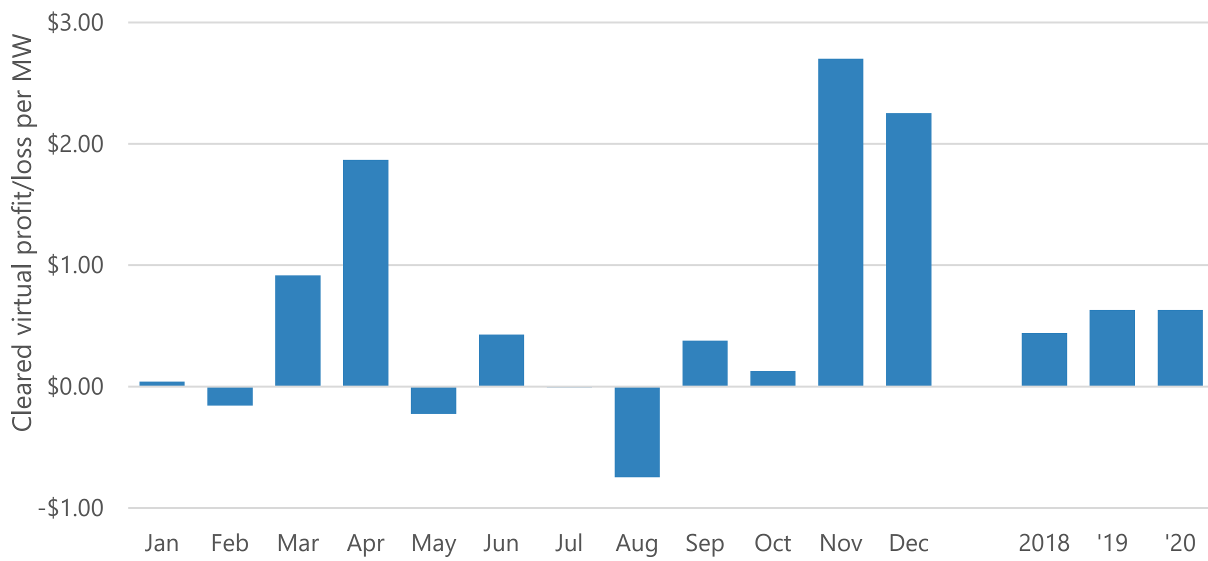
	2018	2019	2020
Raw profit	$ 193.5	$ 260.2	$ 252.4
Raw loss	-149.3	-185.6	-180.5
Raw net profit, before charges and fees	44.2	74.6	71.8
Revenue neutrality uplift charges/credits	-5.4	-10.2	-5.4
Day-ahead make-whole payment charges	-1.7	-2.2	-3.8
Real-time make-whole payment charges	-18.7	-31.0	-26.2
Virtual transaction fees	-0.5	-0.7	-0.8
Net profit	$ 17.8	$ 30.5	$ 35.6

All figures in $ millions

Virtual trades profited in aggregate for 2020 in the amount of $72 million, a four percent decrease from 2019. 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 are assessed a $0.05 per virtual bid or offer transaction fee for processing virtual transactions. The average 2020 rates per megawatt for day-ahead make-whole payments, real-time make-whole payments, and real-time revenue neutrality uplift distributions are $0.08/MWh, $0.54/MWh, and $0.11/MWh, respectively. When factoring in these charges and credits, the net virtual bidding profits for 2020 were $35.6 million, which is about 50 percent of the profit level before fees. Net profits in 2020 increased 17 percent from $30.5 million in 2019.

Net profits are typically small when assessed on a per megawatt basis. Figure 2–48 illustrates the monthly average profit per megawatt for a cleared virtual in 2019.

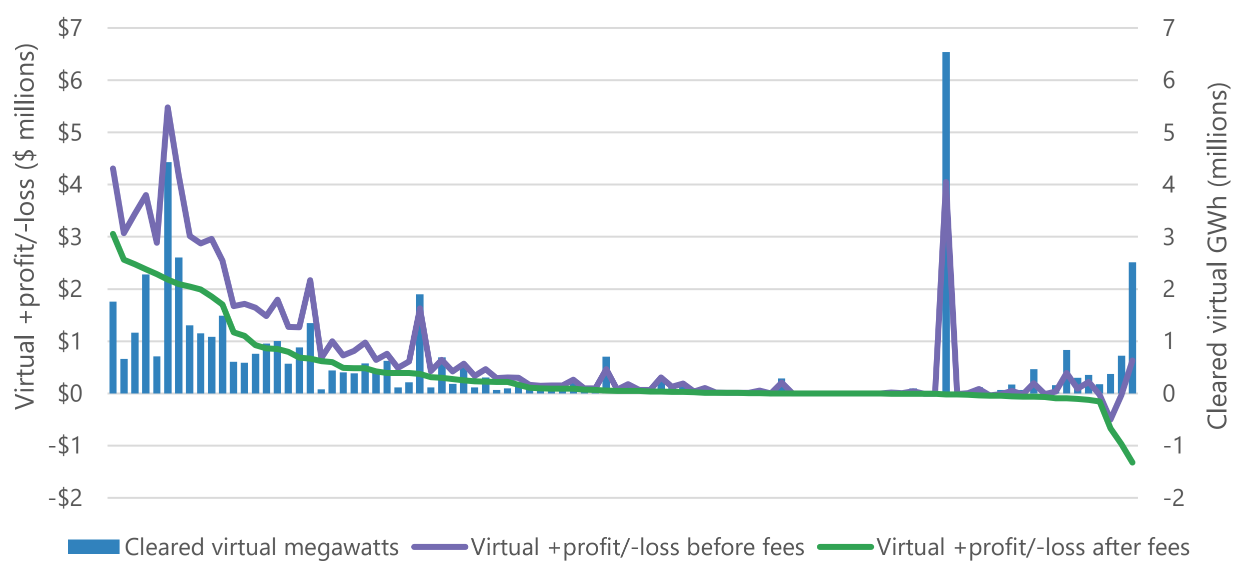
Figure 2–48 Profit and loss per cleared virtual, after fees



The chart shows that, when factoring in all fees, the average profit per megawatt for 2020 was $0.63 per cleared megawatt, unchanged from 2019, and a 43 percent increase from $0.44 per cleared megawatt in 2018.

Ninety-four participants transacted virtuals in 2020, an increase of six from 2019. Figure 2–49 illustrates each virtual participant's virtual portfolio for the year by both net megawatts cleared and net profits before adjusting for fees.

Figure 2–49 Virtual portfolios by market participant



Seven participants accounted for about 48 percent of the virtual profits after fees, which can also be referred to as net profits. These participants account for roughly 28 percent of the transactional volume in the market. In aggregate, virtual trading generated net profits for sixty-three participants. However, 31 virtual participants lost money on a net profit basis. The total losses after fees amounted to roughly $4 million, and three entities accounted for nearly $3 million of that loss.

Additionally, Figure 2–49 highlights the disparity in the trading fees paid by each market participant. These fees totaled over $36 million in 2020; they include: virtual transaction fees (two percent), real-time revenue neutrality uplift fees (15 percent), day-ahead make-whole payment fees (ten percent), and real-time make-whole payment fees (72 percent). Virtual bids are subject to virtual transaction fees, real-time revenue neutrality fees, and day-ahead make-whole payment fees. Virtual offers are subject to virtual transaction fees, real-time revenue neutrality fees, and real-time make-whole payment fees. Nearly three-quarters of the total fees assessed to virtual transactions are assessed only to virtual offers.

The discrepancy in virtual fees relates to the quantity calculation associated with payers of real-time make-whole payments – specifically, the real-time net settlement location deviation hourly amount. This determinant accounted for over 82 percent of the real-time make-whole payments in 2020, or roughly $42 million. As the name implies, the quantity applied to applicable non-virtual transactions includes only the incremental deviations from day-ahead, however the quantities assessed to virtual offers include the full virtual offer quantity.

This calculation methodology, when combined with the larger make-whole payments normally associated with real-time, generally leads to higher fees associated with offers when compared to virtual bids. In 2020, the fees associated with virtual offers amounted to $1.02 per megawatt compared to $0.25 per megawatt for virtual bids. This calculation methodology and associated incentives could be part of the reason why virtual trading offsets only part of the under-scheduling of wind resources in the day-ahead market and should be considered as part of any analysis or evaluated as part of any potential solution to address price divergence. The market monitor will continue to evaluate these trends going forward.

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, one market participant lost more than $100,000 in virtual transactions before fees, and six lost more than $100,000 in virtual transactions after fees in 2020. The market monitor reviews these outcomes and takes actions as needed.

3 UNIT COMMITMENT AND DISPATCH PROCESSES

This chapter covers unit commitment and dispatch, scarcity pricing, and ramp. Key points from this chapter include:

- In 2020, day-ahead commitments decreased by one percentage point and self-commitments increased by five percentage points.
- Capacity of gas, simple-cycle resources taken out of service for maintenance decreased by 18 percent from 2019 to 2020. Total outages for capacity taken out-of-service for maintenance decreased by four percent from 2019 to 2020. Much of the decrease can be attributed to disruptions and adjustments of outages due to COVID-19 precautions.
- In 2020, there were 121 intervals with real-time contingency reserve scarcity, a decrease of over 50 percent from 2019. The average scarcity price for these events was $387/MW, a decrease of 12 percent from 2019.
- Over 40 percent of the real-time regulation-down scarcity and nearly 30 percent of real-time regulation-up scarcity events happened in the first interval of the hour. This trend has held since the inception of the SPP marketplace and continues to increase.
- During December, the market experienced its first instances of day-ahead scarcity. These instances occurred on back-to-back hours on December 23 and on a single hour on December 30. In all three instances, regulation-up was short less than 1 MW.
- SPP has designed a ramp capability product, which will be implemented in early 2022.[48]
- The average percent of total offered capacity by commitment status shows a six percentage point decrease in "self-commit" status and a six percentage point increase in "market" status.

[48] *Tariff Revisions to Add Ramp Capability*, FERC Docket No. ER20-1617.

3.1 COMMITMENT PROCESS

The Integrated Marketplace uses centralized unit commitment to determine an efficient scheduling and dispatch of generation resources to meet energy demand and operating reserve requirements. Most commitments begin in the day-ahead market. The day-ahead market attempts to commit sufficient capacity to meet the loads that were bid into the day-ahead market. Because of differences between day-ahead and real-time and locational issues, it is often necessary to commit additional capacity outside the day-ahead market. This is done through the reliability unit commitment (RUC) processes and manual commitments. SPP employs five reliability commitment processes:

- multi-day reliability assessment (MDRA);
- 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 or are needed to address an emergency 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 1300. 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, often with better information on forecasts and gas markets.

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 issues 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, started 3,111,440 MW of capacity in 2020. That represents a 16 percent increase from 2019. The major contributors of the increase of started capacity came from combined cycle resources in the day-ahead market and resources with hydraulic turbines self-committing in the day-ahead market. Figure 3–2 shows the percentage of capacity from starts by commitment process. For all generation participation offers in the day-ahead market by commitment status, see Figure 3–11.

Figure 3–2 Start-up instructions by resource capacity

	2018	2019	2020
Day-ahead market[49]	75%	76%	75%
Self-commitment[50]	13%	9%	14%
Intra-day RUC	5%	7%	4%
Manual, regional reliability[51]	4%	5%	4%
Short-term RUC	2%	1%	1%
Day-ahead RUC	<1%	<1%	<1%
Manual, local reliability	1%	1%	1%
Multi-day reliability assessment	0%	0%	<1%

As shown in Figure 3–2 above, 75 percent of online capacity in 2020 was a result of the day-ahead market, which continues to be the primary commitment process. The day-ahead market is the preferred method of start-up. However, a limiting factor on the number of day-ahead commitments is that the optimization algorithm is restricted to a 48-hour window;[52] hence, large base-load resources with long lead-times 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 amount of self-commitments.

Within the operating day, commitment flexibility is limited by resource start-up times. As the operating hour approaches, fewer resources are eligible to be started. The reliability unit commitment processes—day-ahead,[53] intra-day, short-term, and manual—represent about 10 percent of the started capacity. Many of these commitments are due to uncertainty of the forecasted resources or needing additional ramp-able capacity. The ramp product and

[49] For this table, the day-ahead market category excludes resources started due to self-commitment in the day-ahead market.
[50] Self-commitment includes resources started in the day-ahead market due to a self-commitment.
[51] Manual commitments for regional reliability include commitments for additional capacity and manually staggering start-up or shutdown times.
[52] Commitments are evaluated over 48-hour window which covers the operating day and the next day. Although two days are evaluated, start-up and shutdown instructions are issued for the operating day only. The day after the operating day is evaluated to decrease inefficiencies across day-boundaries (e.g., shutting down a resource at the end of one day only to start it an hour later on the next day).
[53] This is day-ahead reliability unit commitment process, not the day-ahead market.

uncertainty products should help reduce these amounts after implementation.[54] Figure 3–3 shows that a large majority of 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.

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

Commitment process	Combined-cycle			Simple-cycle, combustion turbine			Simple-cycle, steam turbine		
	2018	2019	2020	2018	2019	2020	2018	2019	2020
Day-ahead market	89%	89%	88%	75%	75%	77%	73%	63%	56%
Day-ahead RUC	0%	0%	0%	0%	0%	0%	2%	2%	3%
Intra-day RUC	2%	2%	2%	8%	8%	5%	14%	18%	16%
Short term RUC	<1%	<1%	0%	4%	2%	3%	2%	2%	2%
Manual, local reliability	0%	0%	0%	1%	2%	2%	1%	1%	1%
Manual, regional	0%	1%	1%	7%	9%	9%	2%	4%	7%

For gas-fired generators with simple-cycle combustion turbine technology, the day-ahead market accounted for 77 percent of their total starts, slightly higher than 2019. Steam turbine starts decreased in the day-ahead market with 56 percent in 2020, compared to 63 percent the year before.

Some reliability unit commitments are made to meet instantaneous load capacity requirements. However, this is not a product that generators are directly compensated for by the market. These commitments are often not supported by real-time prices and can lead to make-whole payments. The next section discusses the drivers behind reliability commitments.

[54] The ramp product is discussed in further detail in Section 3.2.3.2, and the uncertainty product is discussed in Section 3.2.3.2.3.

3.1.2 DEMAND FOR RELIABILITY

Figure 3–2 noted that five percent of SPP start-up instructions by capacity 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 after the day-ahead market.

One difference between day-ahead and real-time is wind generation. Eighty-one percent of the real-time wind production cleared in the day-ahead market in 2020. Market participants determine the participation levels for their wind resources in the day-ahead market through supply offers. In contrast, SPP's wind forecast is used by the reliability unit commitment processes.

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 reliability unit commitment processes used in day-ahead, intra-day, or short-term.

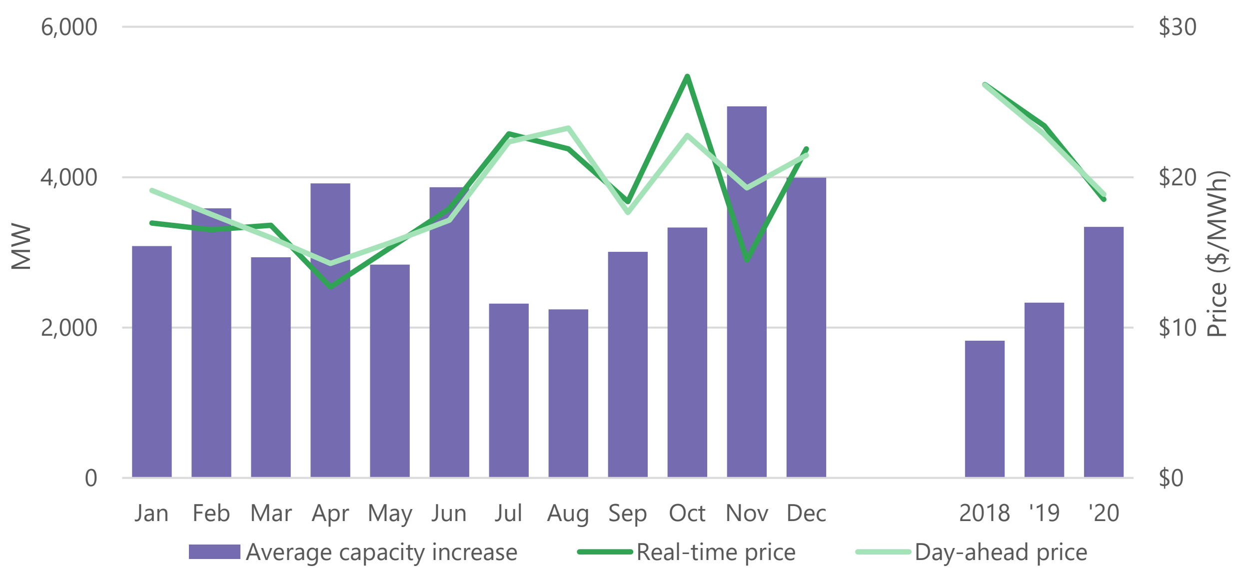
Other differences also affect net energy demand. Net energy demand is demand net of both variable energy generation, the combination of imports, exports, and parallel flows from other markets. Import and export transaction data are updated to include the latest information available for the reliability unit commitment processes. A fundamental difference between the two studies is the definition of demand. In the day-ahead market, demand is determined by bids submitted by the market participants whereas, in the real-time market, demand is physical. Demand bids in the day-ahead market average around 100 percent of the real-time values, as shown in Figure 2–5. Other smaller differences between the two markets include losses and operating reserves.

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 excess price-following, physical generation cleared in the day-ahead market that was not needed in real-time. A negative resource gap would indicate that the total generation cleared in the day-ahead market is insufficient to serve real-time demand. The resource gap is typically positive, indicating more dispatchable generation is cleared in the day-ahead market than was necessary to serve real-time load.

The primary drivers for the resource gaps are: (i) differences in virtual supply net of virtual demand, (ii) differences in real-time wind generation compared to wind cleared in the day-ahead market, and (iii) real-time net exports exceeding day-ahead net exports. It is generally true that the day-ahead market clears less wind generation than is produced in real-time. The mismatch is partly because some market participants with wind generation assets, recognizing the uncertainty of the wind forecast in day-ahead, offered such that the full amount of forecasted capacity did not clear in the day-ahead market. This may cause other generation to clear in the day-ahead market that will not be needed in real-time when the wind replaces it.

The resource gaps can help explain why some generators produce much less in real-time or why additional commitments occur after the day-ahead market has cleared. Figure 3–4 compares on-line capacity between the day-ahead and real-time markets.

Figure 3–4 Average hourly capacity increase from day-ahead to real-time



The chart indicates that in 2020 there was, on average, around 3,300 MWh of additional dispatchable generation cleared in the day-ahead market, an increase of 43 percent compared to 2019. As previously mentioned, two of the main drivers of the excess capacity in day-ahead are shown in Figure 3–5.

Figure 3–5 Average hourly capacity increase from day-ahead to real-time with wind and virtual components

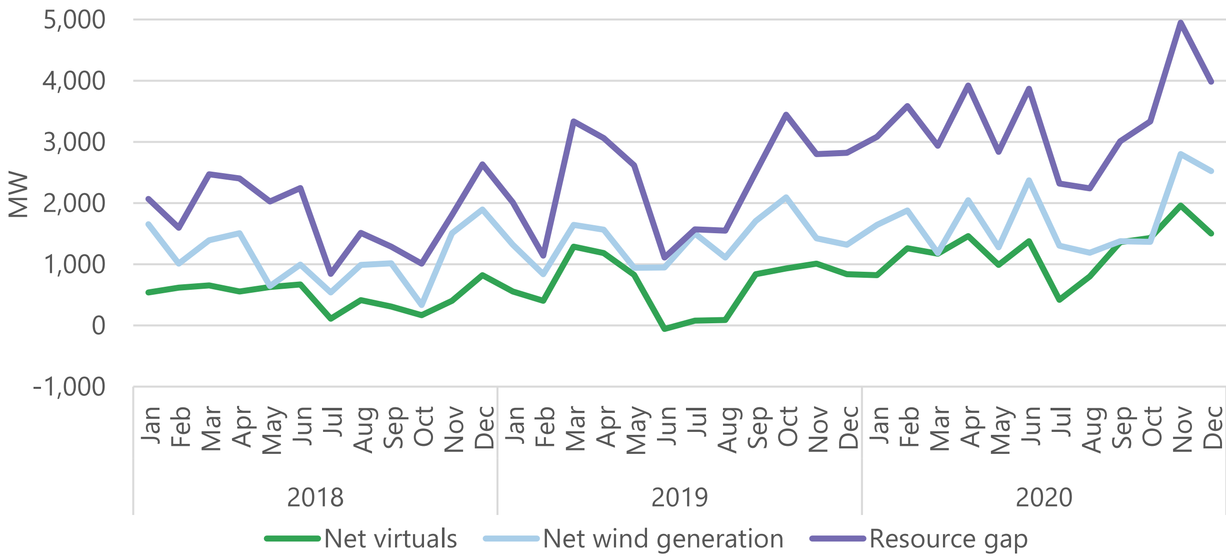


Figure 3–5 shows that the gaps due to wind and virtuals are largely increasing and driving the changes in the resource gap. From 2019 to 2020, the gap due to wind generation and virtuals, together, increased by about 900 MW while the resource gap increased by about 990 MW. The increase in the overall resource gap is made up mostly of the wind gap and virtual gap. As these two components increase, the overall resource gap will continue to increase.

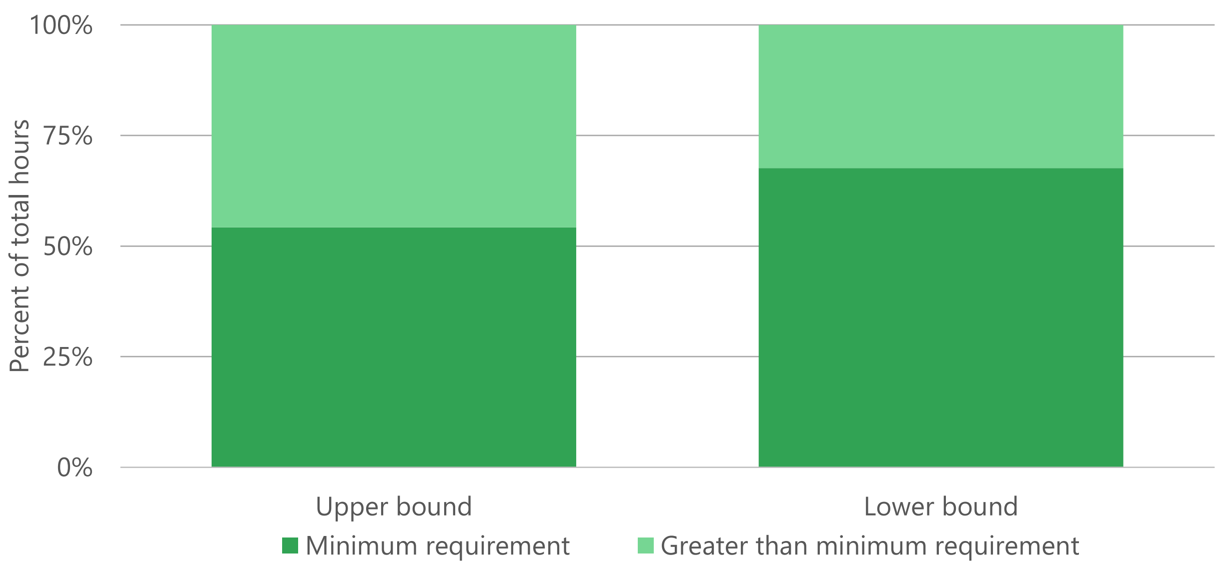
In the graphed gaps shown in Figure 3–5, the shapes of the wind gap and virtual gap very nearly match the shape of the overall resource gap. This indicates that the wind and virtual gap are driving the variations of the overall resource gap. As discussed in section 2.8, virtuals occur mostly at wind generator locations. The effect of this is seen in Figure 3–5 as the shape of the virtual gap largely follows the shape of the wind gap. This indicates that, on average, the virtuals are reacting to the changes in wind generation. Therefore, the increasing resource gap is ultimately caused by the wind gap.

The wind gap can be caused by insufficient clearing of wind generation in the day-ahead market. To balance this insufficiency, the day-ahead market may then clear other generation that represents physically dispatchable generation in real-time. Then, in real-time, the actual wind generation replaces the additional dispatchable generation that was cleared in day-ahead. The result can be that the day-ahead market clears excessive generation. In real-time, this excess generation will likely run at minimum output. The excess generation's minimum output can cause other generators to run lower on their offer curve, which can lower the real-time energy price, making real-time prices diverge from day-ahead prices.

On average, the market-wide resource gap is positive, and no additional capacity is needed in real-time. However, in some cases, the day-ahead market can clear insufficient generation. This can be a case that is not represented by the average, a locational insufficiency due to congestion, or a parameter that is not directly or sufficiently cleared in the day-ahead market such as ramp. When the day-ahead market clears insufficient generation, additional capacity may be committed for reliability after day-ahead.

One of the reasons for 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. 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.

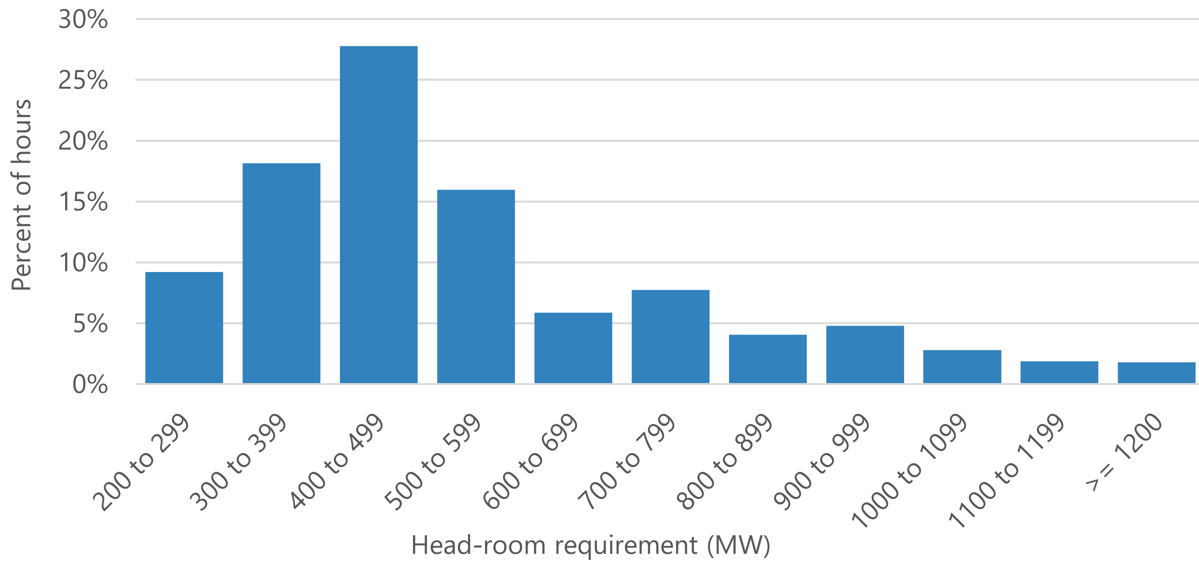
Figure 3–6 Frequency of minimum requirement for instantaneous load capacity



A value is calculated for upper bound (upward ramp) and a lower bound (downward ramp) based on forecasted load. However, the default, or minimum requirement, is not based on market information. Because the default value is used more than half of all intervals, the instantaneous load capacity constraint can contribute to reliability commitments that are not based on current market information. The default requirements are hourly values as low as 200 MW. SPP evaluates the default values quarterly.

The percent of hours at various upper bound requirements is shown in Figure 3–7.

Figure 3–7 Instantaneous load capacity upper bound requirements



The most frequent observations were from 400 MW to 499 MW at around 28 percent. There were more observations in lower requirements than last year, which is an improvement. While a market-based product is more appropriate for a market efficiency improvement, this reduction may help lower unnecessary make-whole payments.

Resources committed to provide ramp capability can affect real-time prices, whether as a result of applying the instantaneous load capacity constraint in a reliability unit commitment process or a manual process. 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. The resource keeping the market from being scarce may not be paid to provide the needed capability. Additionally, manual commitments made during conservative operations, while possibly needed for capacity, similarly suppress the price signals when they are needed most.

Reliability commitments, along with wind exceeding the day-ahead forecast, can dampen real-time price signals, as is evidenced by 28 percent of make-whole payments made for reliability unit commitments, as shown in Figure 4-36.

3.1.3 QUICK-START RESOURCES COMMITMENT

A quick-start resource[55] can start, synchronize, and begin injecting energy within 10 minutes of SPP notification. This section will detail the ways quick-start resources are used, which includes quick-start resources dispatched by the real-time market without a commitment.[56]

To be included as a quick-start resource, the resource must have been dispatched from an off-line state by the real-time market without a commitment. In 2020, 97 resources counted as quick-start resources, all of which have been offered and used by the real-time market at least once during 2020 in this capacity.

Figure 3–8 summarizes the deployment[57] methods available for quick-start resources with the number of times each method was selected, lead time, original commitment hours, and actual hours on-line.

[55] SPP is in the process changing the quick-start market design to have separate dispatch and pricing runs. The dispatch run will not change, but the pricing run will relax the minimum of fast-start resources to zero MW and will be based on an offer that includes start-up and no-load costs. See RR375 (FERC Order on Fast-Start Pricing), a revision for compliance with FERC's fast-start order (Docket No. EL18-35 and Docket No. ER20-644).

[56] *Integrated Marketplace Protocols*, Section 4.4.2.3.1.

[57] The more encompassing term "deployment" is used to account for both commitment and dispatch of resources.

Figure 3–8 Deployment of quick-start resources

Commitment process	Number of starts	Committed available capacity (MW)	Lead time (hours)	Hours in original commitment	Actual hours on-line
Day-ahead RUC	1	45	28.1	5.0	5.0
Intra-day RUC	233	10,957	2.2	4.3	6.6
Short-term RUC	319	12,889	.2	3.3	5.2
Manual	638	25,493	1.0	5.2	3.1
Day-ahead market	16,790	585,023	21.7	6.7	15.9
Real-time market	2,406	72,558	0.1	0.1	0.6[58]

The level of make-whole payments associated with the commitment of quick-start resources in the reliability processes is noteworthy.[59] In 2020, 76 percent of the reliability commitments for quick-start units resulted in real-time make-whole payments, which is similar to 2019 and 2018. In 2019, quick-start resources received $6.8 million in real-time make-whole payments and $232,000 in day-ahead make-whole payments. The real-time make-whole payment is about the same as 2019, and the day-ahead make-whole payment is up slightly from 2019.

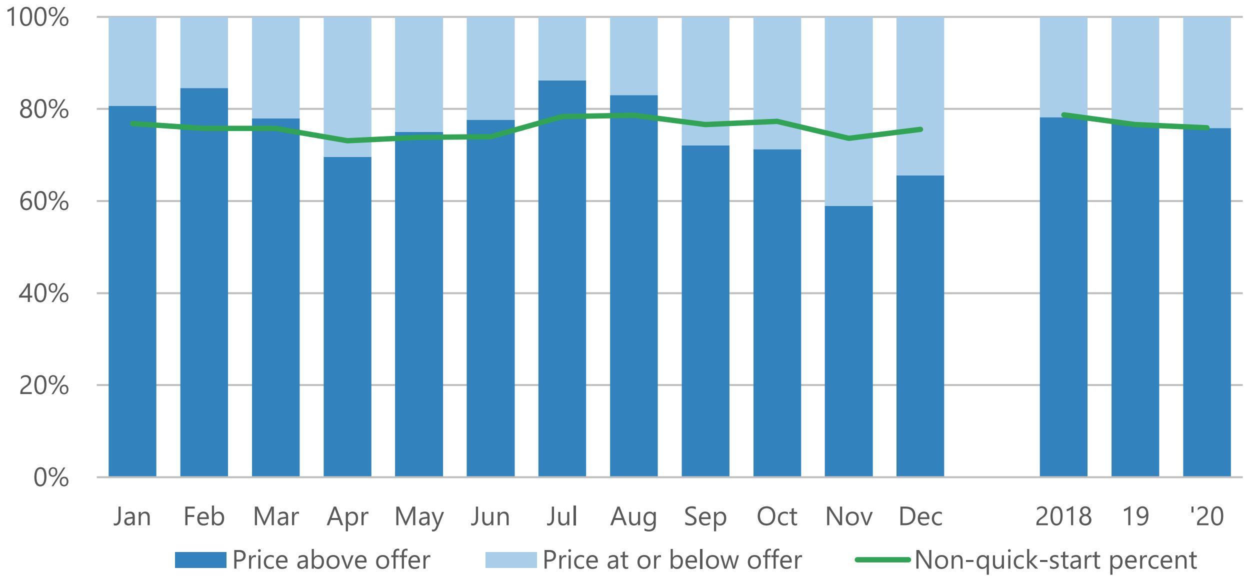
The short-term reliability unit commitment can commit units in as little as 15 minutes ahead. The 15-minute lead-time leaves time to commit these quick-start resources when needed, which allows the commitment to be held off longer, providing more certainty of the need of the resource. This also minimizes the time these units are at minimum load levels with market prices below their marginal costs, while still allowing for a make-whole payment.

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

[58] The real-time market actual on-line hours represent the total amount of time quick-start resources were dispatched by the market and does not include any on-line commitment time that may have directly proceeded or followed the quick-start dispatch period.

[59] Quick-start resources started by the real-time market are not eligible for any make-whole payments.

Figure 3–9 Operation of quick-start resources



Over the previous two years, about 25 percent of the megawatt-hours produced by quick-start resources[60] had energy prices below their real-time energy offers. In 2020 this decreased to 24 percent. This is about the same as the percentage 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.[61] Revision Request 375 proposes to make SPP-committed fast-start resources whole and to eliminate the dispatch of uncommitted fast-start resources.[62]

3.1.4 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 reserve, and supplemental reserve, 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 offered capacity. All day-ahead market products are traded and settled on an hourly basis.

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[60] Quick-start resources are defined as those resources with a 10 minute start-up time and a minimum run time of one hour or less. Variable energy resources for which SPP forecasts the output are not considered quick-start resources.

[61] *Integrated Market Protocols*, Section 4.4.2.3.1 states that only the offer curves are used to dispatch.

[62] RR375 is scheduled to be implemented mid-2022.

In 2020, participation in the day-ahead market was robust for both generation and load. Load-serving entities that also own generation assets 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. However, as seen in Figure 3–10, merchant generators self-commit at a much lower rate than load-serving entities. This is likely because merchant generators have incentive structures in place based primarily on market outcomes.

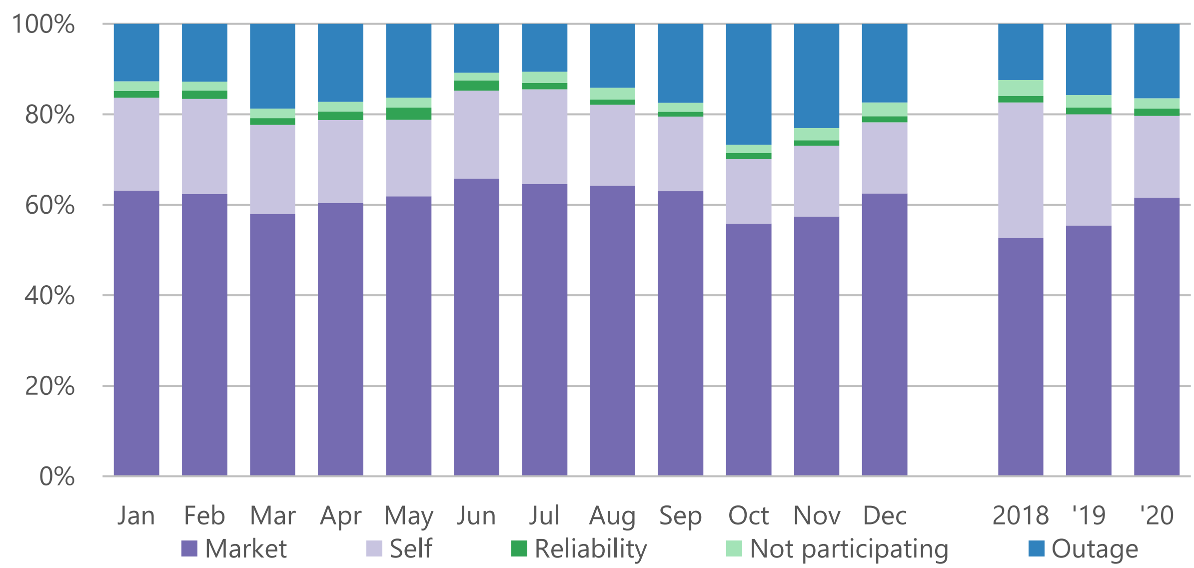
Figure 3–11 shows day-ahead market offers by commitment status and participant type.

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

Resource type	Owner type	Market	Self	Reliability	Not participating	Outage
Fossil fuel resources	Load-serving entity	56%	27%	2%	1%	14%
	Merchant	67%	10%	0%	0%	23%
Variable energy resources	Load-serving entity	52%	42%	0%	0%	6%
	Merchant	54%	14%	0%	18%	14%

Figure 3–11 shows generation capacity in the day-ahead market by commitment status.

Figure 3–11 Day-ahead market capacity by commitment status

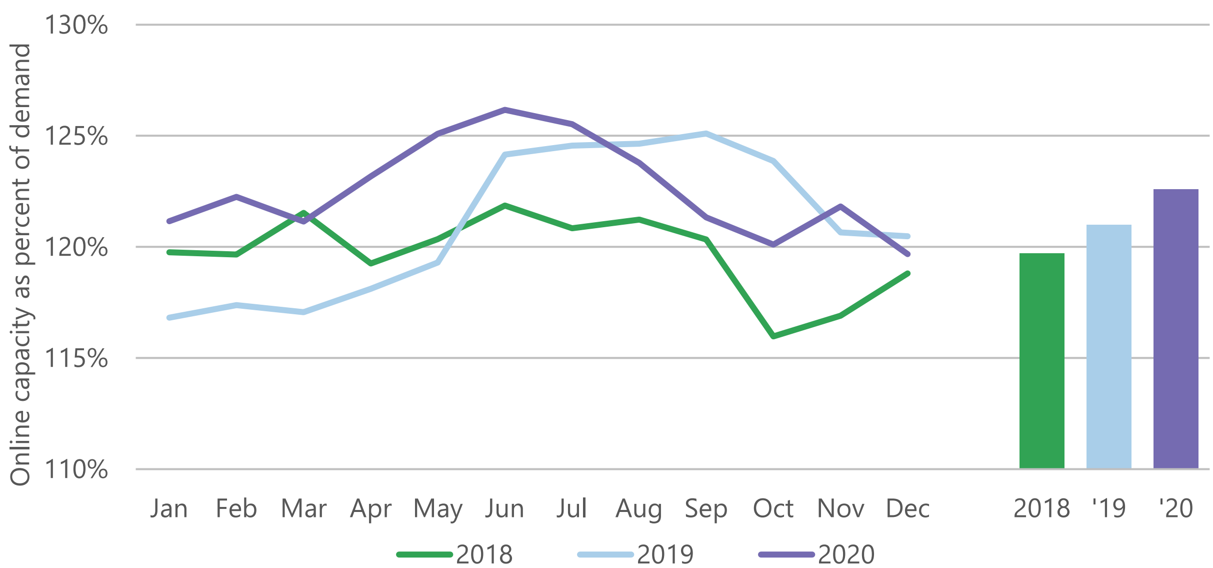


The average percent of total offered capacity by commitment status shows a decrease in the "self-commit" status and a slight increase in the "outage" status. The "market" commitment status averaged 62 percent while resources with commitment statuses of "reliability" and "not participating" both averaged around two percent. The "outage" commit status averaged 16 percent. The "self-commit" status averaged 18 percent of total offered capacity which was a decrease compared to 25 percent in 2019. While self-commitments decreased from 2019, they still constitute a large amount of the capacity offered into the market.

Compared with Figure 3–3 in Section 3.1.1, which shows origins of only initial started capacity, these values represent commitment status of all generation capacity offered including those on-line. Self-committed resources accounted for 14 percent of initial started capacity but 18 percent of all capacity offered on average. While self-commit started capacity increased from eight to 14 percent in 2020, the self-commit percent of all capacity offered decreased from 25 percent to 18 percent.

Figure 3–12 shows on-line capacity commitment as a percent of load.

Figure 3–12 On-line capacity as a percent of load



Capacity commitment as a percent of load is increasing. Beginning in 2016, capacity as a percent of load decreased yearly through 2018. However, in 2019 and 2020, there has been a small increase from 120 percent in 2018, to121 percent in 2019 and 123 percent in 2020. Although the changes are small, the percent of capacity online compared to demand has returned roughly to the 2015 level. Since 2018, the overall magnitude of online capacity is decreasing annually, but demand is decreasing slightly faster. From 2019 to 2020, online capacity decreased about two and a half percent, but demand decreased three and a half percent, causing the online capacity as a percent of load to increase again.

While these changes are small, they are increasing, and the benefit is ambiguous. Having too much capacity on-line with non-zero minimums causes other resources to operate lower on their offer curves, which can contribute to under-recovery of fixed cost and, therefore, increased make-whole payments.

Additional capacity may be beneficial for necessary rampable capacity. However, there is currently no rampable capacity requirement other than instantaneously load capacity, which has a reserved use. The lack of requirement for available ramp means that the additional capacity may not be rampable and, therefore, may not provide any benefit. Though there is usually some incidental ramp available, the market clearing software currently has no process to optimize or price the clearing of rampable capacity for each interval.

3.1.5 MUST-OFFER PROVISION

The Integrated Marketplace has a limited day-ahead must-offer provision that was intended to incentivize load-serving entities with generation assets to participate in the day-ahead market.[63] Market participants that are non-compliant are assessed a penalty based on the amount of capacity available in the day-ahead market relative to the market participant's peak hourly real-time load. The requirement is limited in the sense that not all resources or capacity must be offered. Only market participants with generation assets that serve load are subject to the must-offer requirement, and they are required to offer only enough generation to cover most of their load plus reserve obligations, per asset owner, which may not be all of their resources or

[63] 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. 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 2017. FERC denied the removal of the limited must-offer requirement, as it did not include physical withholding non-compliance penalties. See FERC ruling at https://elibrary.ferc.gov/eLibrary/filedownload?fileid=14710297.

available capacity. An alternative way to satisfy the provision is to offer all generation that is not on outage. In 2020, six day-ahead must-offer penalties, totaling $42,679, were assessed. Two penalties were assessed in 2019. While this provision does highly encourage available generation to be offered, it does not impose a penalty for excessive outages, which has been cited as a reason for conservative operations in the past. The day-ahead must-offer provision also does not tie into Attachment AA, which defines the resource adequacy requirement in the SPP tariff.

The MMU continues to recommend updating the day-ahead must offer requirement and addressing FERC's concerns. In light of the increased volume of outages that contributed to conservative operations in 2019, the MMU has assigned a higher priority to addressing the issue. See further discussion in Section 8.2

3.2 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 is based on market participants' deviations from their day-ahead positions.

3.2.1 SCARCITY PRICING

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

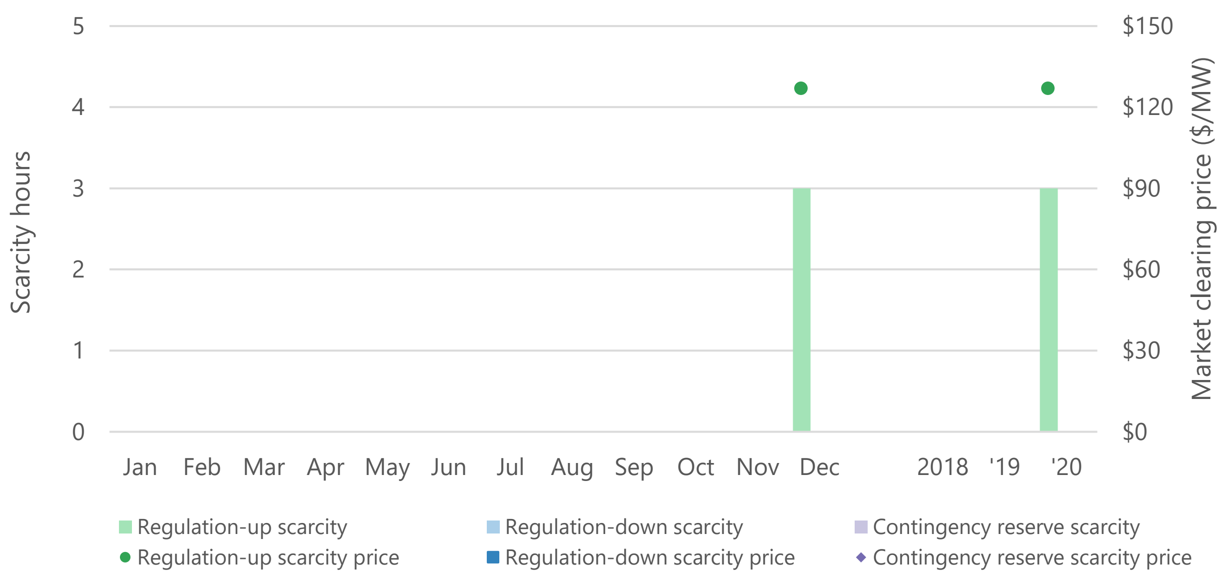
When an insufficient amount of regulation-up service, regulation-down service, or contingency reserve is cleared, a scarcity price is set by a demand curve. The scarcity of these products can be caused by a lack of capacity or a lack of ramp. Scarcities are due to capacity when there are insufficient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

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

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

Figure 3–13 displays the number of scarcity intervals in the day-ahead market and average prices by month, along with an annual average of values.

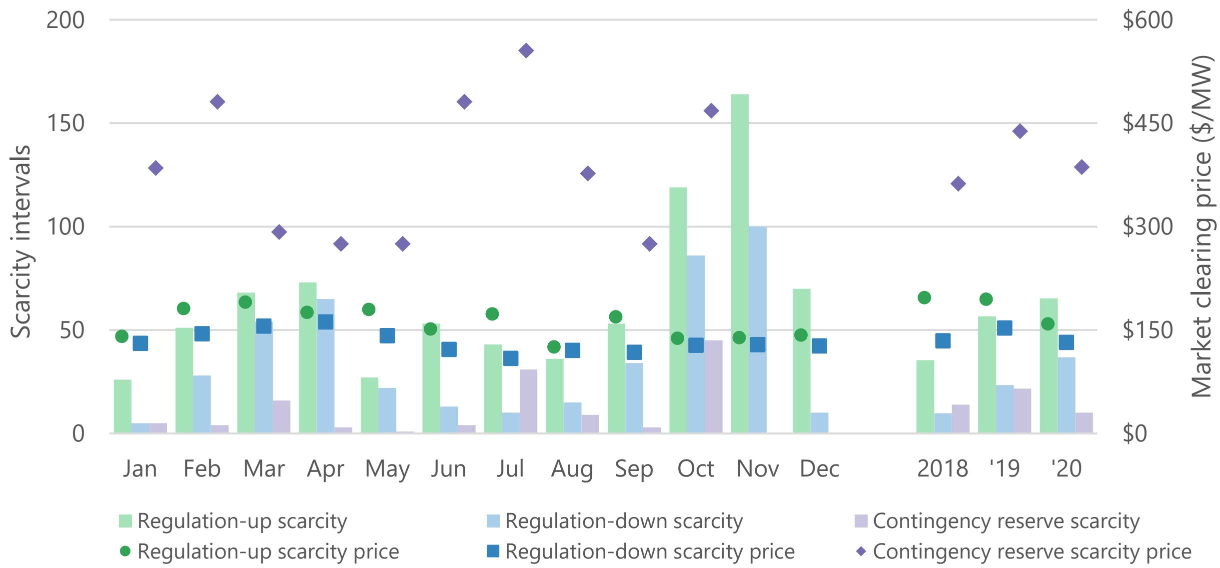
Figure 3–13 Scarcity intervals and marginal energy cost, day-ahead



During December, the market experienced its first instances of day-ahead scarcity. These instances occurred on back-to-back hours on December 23 and on a single hour on December 30. In all three instances, regulation-up was short less than 1 MW.

Figure 3–14 displays the number of scarcity intervals in the real-time market and average prices for each product by month, along with an annual average of monthly values.

Figure 3–14 Scarcity intervals and marginal clearing price, real-time



In 2020, there were about 780 intervals with regulation-up reserve scarcity, about 440 intervals with regulation-down scarcity, and about 120 intervals with contingency reserve scarcity. There are far more regulation-up scarcities than regulation-down scarcities. This is likely because more regulation-down is typically available. First, variable energy resources are able to provide regulation-down and not regulation-up, so there are more resources able to regulate down. Second, the market dispatches energy from a resource's minimum until it is no longer profitable or until the resource is limited by a parameter, such as ramp rate up or a maximum operating limit. Consequently, many resources are operating closer to their maximum than their minimum which provides more downward capability than upward capability.

Total scarcity events in 2020 were about 10 percent higher than 2019. Regulation-up scarcities increased by about 15 percent, and regulation-down scarcity increased by about 58 percent of 2019 values. Contingency reserve scarcities decreased by about 54 percent from 2019, about the same as 2018. While many factors affect scarcities, about 60 percent of regulation-up scarcities and about 62 percent of contingency reserve scarcities happened in intervals when variable energy production increased the amount of ramp up needed.[64] About 47 percent of regulation-down scarcities happened in intervals when variable energy production increased the amount of ramp down needed.[64]

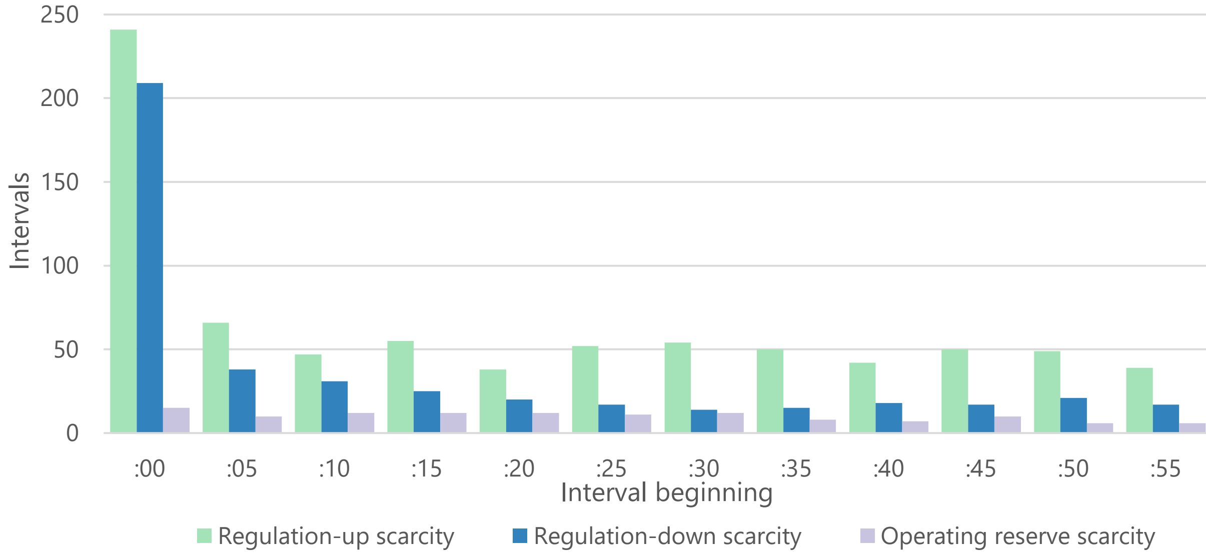
About 40 percent of all scarcity intervals occurred in October and November. Over 20 percent of regulation-up and regulation-down scarcities occurred in November while over 35 percent of contingency reserve scarcities occurred in October. These months typically have high wind production, low load, and more generator outages. Because wind provides a relatively high amount of capacity, fewer flexible resources are available to provide reserves. When wind production is volatile, the dispatchable resources' highest priority is to provide energy, with reserves as a lower priority.

The average scarcity prices for the regulation-up, regulation-down and contingency reserve events were $159/MW, $132/MW, and $387/MW respectively. The highest monthly average regulation-up, regulation-down, and contingency reserve scarcity prices occurred in March, April, and July respectively. The average scarcity prices for each scarcity type are lower than 2019.

Scarcity related price spikes happened more frequently at the beginning of each hour. Figure 3–15 below illustrates a count of the 2020 scarcity events in the real-time market by the 12 intervals of each hour.

[64] If scarcities happened at random and irrespective of variable energy production, these percentages would be around 25 percent.

Figure 3–15 Scarcity events by interval of the hour, real-time



Just under half of regulation-down reserve scarcity intervals occurred in the first interval of the hour. The same pattern continued, although to a lesser degree, with about 30 percent of regulation-up reserve scarcity events. Contingency reserve scarcity intervals are more equally dispersed across the hour. The pattern of regulation scarcity events at the beginning of the hour has occurred since the inception of the marketplace.

One potential reason for this pattern is that SPP does not pre-position regulating resources to be within their regulating maximum and minimum limits prior to the period that the resource is cleared for regulation. Consider a resource that is currently dispatched to its minimum of 100 MW. If this resource clears 20 MW of regulation-down reserves in the next hour, it will need to move up to 120 MW. If the resource's ramp rate does not allow it to ramp up 20 MW in one interval, the resource cannot provide regulation-down in the first interval. If this causes a scarcity, the resource may have to buy back a day-ahead position at scarcity prices. However, if the resource moves there prior to the hour, it will deviate from its current dispatch instruction, which has financial penalties.[65] Consequently, resources often follow dispatch until the first

[65] Resources that deviate from their dispatch signals can receive Uninstructed Deviated Charges for the deviated megawatts. The median price per megawatt for deviation in 2020 was about $0.60. However, the maximum price charged for deviation was about $6.00. In addition to this charge, resources do not receive cost reimbursement for any deviated megawatts in the event energy prices are lower than energy cost.

interval of the regulation commitment, contributing to shortages in the first interval of the regulating commitment.

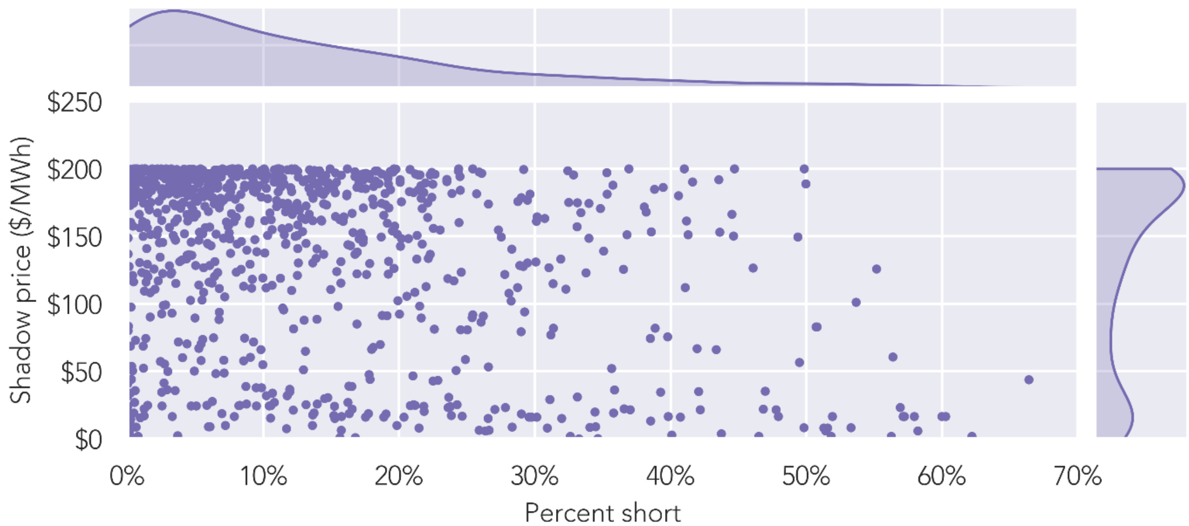
There are reasons for SPP to pre-position resources to their regulating ranges prior to the regulation period. However, should opportunity costs occur for these resources during the pre-position period, this may need to be addressed.

Though scarcity prices apply to regulation-up, regulation-down, and contingency reserves, spinning reserve scarcity is currently not priced by a scarcity demand curve.[66] Instead, SPP uses a violation relaxation limit (VRL) during periods of spin scarcity. The VRL for spinning reserve scarcity is set at $200/MW. This means that SPP will keep dispatching resources to meet the spinning reserve requirement up to the point the redispatch cost reaches $200/MW. At this point, the market will relax the spinning reserve requirement to the quantity of spinning reserve megawatts that can be obtained at a redispatch cost under the $200/MW shadow price. The spinning reserve price will be the price of the marginal resource cleared at the relaxed limit for that product, plus any scarcity pricing from an operating reserve scarcity event. Because spinning reserve is a higher-priority product than supplemental reserve, the market will never set the spinning reserve price lower than the supplemental reserve price.

In most instances, when the VRL shadow price is reached, the marginal clearing price is set near $200/MW. However, in circumstances where the spinning reserve is scarce because of competition with other products, the spinning reserve shadow prices can be set at or near $0/MW. Even though the shadow prices are $0/MW, the actual spinning reserve clearing prices are typically set by an operating reserve scarcity event price. Figure 3–16 shows a scatter plot of 2020 spinning reserve shortages with distribution curves for each axis showing where shadow prices and shortage percentages are clustered.

[66] The operating reserve scarcity price is based on a requirement that is the sum of requirements for (i) regulation-up, (ii) spinning reserve, and (iii) supplemental reserve. This requirement is separate from the regulation-up requirement and scarcity price. If cleared spinning reserve is short of the spinning reserve requirement, then additional regulation-up or supplemental reserves can count towards the operating reserve requirement. Even though the spinning reserve requirement is not met, scarcity pricing may not be invoked.

Figure 3–16 Spinning reserve shortages



This figure plots spinning reserve shadow prices, during periods of shortage, against the percentage of spinning reserves short. The chart shows that shadow prices were frequently near the $200/MW VRL limit, mostly when spinning reserve was slightly short. However, as the distribution curve on the right shows, shadow prices were also frequently near or at $0/MW. As the shortage percent increases, the high shadow prices become less frequent. In about 30 percent of spinning reserve shortages, the shadow price was less than $100/MW. This means that the cost to meet the requirement was more than $200/MW, but the market valued it at less than half-price. This is significantly below the value of the reliability that this spinning reserve provides. Rather than pay the marginal price, the market procured insufficient spinning reserve.

Energy shortages are currently priced using the VRL process. There are three VRL constraints associated with energy shortages. The current energy shortage VRL shadow prices are $5,000/MW for ramp shortages, $50,000/MW for balancing resources' dispatch to load consumption, and $100,000/MW for resource capacity shortages. If these requirements are not met, the requirement will be relaxed and prices may feasibly be no higher than without a shortage.

When product prices and shadow prices do not reflect shortages, beneficial behavior is not incentivized and investment signals for the addition of new generation or demand response resources are distorted. In some cases, this pricing may cause harmful behavior, such as when prices remain low during a shortage causing exports to increase while SPP remains short.[67] Demand curves relax the physical requirement while pricing the value of scarce product. Therefore, the MMU highly recommends SPP and stakeholders review price formation during scarcity events and establish graduated demand curves that incentivize proper price formation.[68]

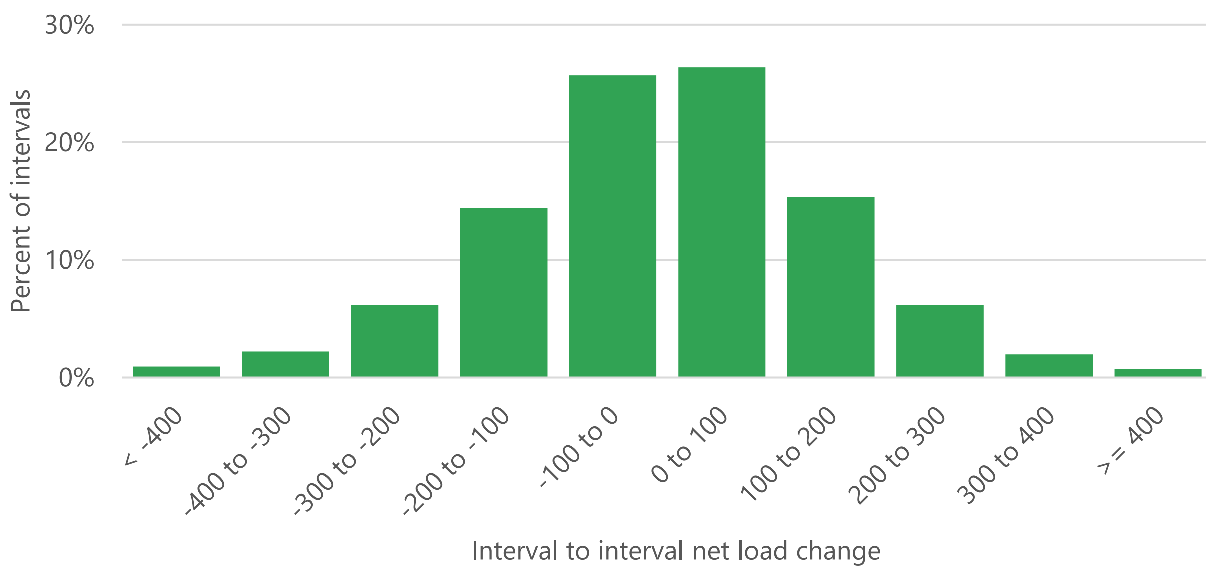
3.2.2 RAMPING

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."

In real-time, resources are increasing and decreasing output to meet changes in both load and non-dispatchable generation. These changes can be measured as changes in net load. Net load is net of both non-dispatchable generation, the combination of imports, exports, and parallel flows from other markets.

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

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

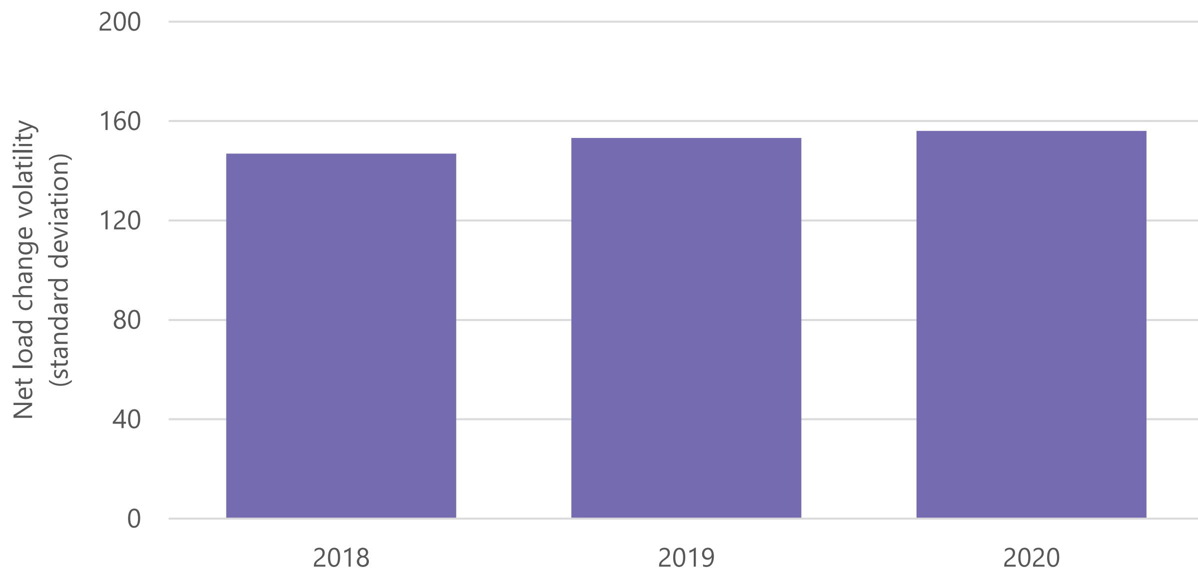


[67] This could be a particular concern with the development of the coordinated transaction scheduling between SPP and MISO, see Coordinated Transaction Scheduling (CTS) Study.
[68] See recommendation in Chapter 8.

Figure 3–16 represents decreases in net load and increases in net load for the year. Of the net load changes between real-time intervals, 95 percent were between a decrease of about 320 MW and an increase of about 305 MW. This is up from 2019 when the decrease was about 310 MW and the increase was about 300 MW. The 95th percentile net load changes, both positive and negative, have continued to increase by about 10 MW each year. This means that the market is seeing a slow but steady increase in net load swings. These changes in net load must be balanced by resources with a flexible dispatch range, or ramp capability.

Figure 3–18 below shows the volatility in net load change.

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



Net load volatility increased about two percent from 2019 to 2020. Net load volatility has slowly increased since 2018.

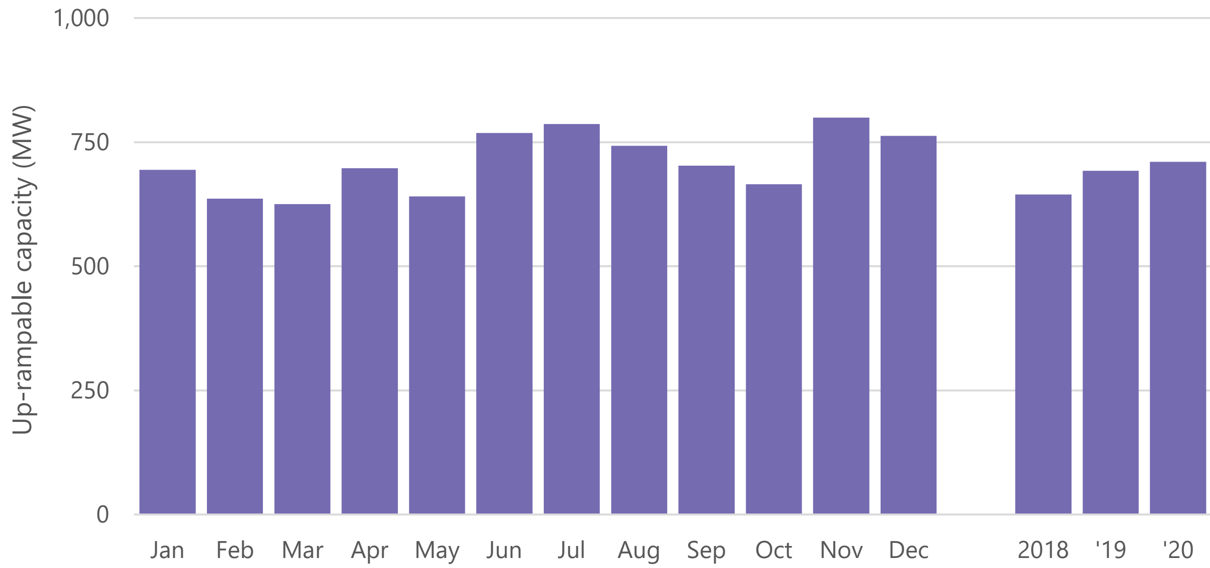
As variable energy resources serve more load, volatility is expected to increase. About one-third of total generation was produced by wind and solar resources in 2020. When variable energy resource production changes by the same amount or in the same direction as the load change, it can reduce the magnitude of the net load change, which decreases the ramp required from more dispatchable resources. However, when variable energy production does not change in the same direction, it can increase the magnitude of the net load change, which increases the ramp required from more dispatchable resources. Wind resources increased the net load change, both up and down, in about 75 percent of intervals. Of these intervals, the need for ramp down increased an average of about 76 MW while 95 percent of intervals required less than about 210 MW. The need for ramp up increased an average of about 75 MW, while 95 percent required less than about 207 MW. With over 46 GW of wind-powered generation and over 35 GW of solar generation with an active generation interconnection request,[69] this problem will likely increase in the future as volatility from variable energy resources increases. The soon-to-be implemented ramp product should help compensate resources for this ramping reliability need.

In any interval, resources typically have a range either above or below their current operating point that they can move to in the next interval. The rate at which they can move is their ramp rate. The total amount they can ramp is their rampable capacity.[70] SPP operators count on this rampable capacity to meet future energy needs and to protect against uncertainty.

Figure 3–19 shows the average up-rampable capacity by month after energy and operating reserve obligations are accounted for.[71]

[69] Interconnection requests may be viewed at http://opsportal.spp.org/Studies/GIActive.
[70] Rampable capacity may be limited by a resource's ramp rate parameter and/or maximum or minimum operating limit. When a resource is near its maximum operating limit, even though its ramp rate allows it to ramp quickly, the amount it can ramp up is limited.
[71] The figures showing average rampable capacity are approximations. The market clearing engine allows for ramp sharing and also allows for some products to go short so that higher priority products can clear. There can be different amounts of rampable capacity available depending on the product. These graphs average the amount of load increase or decrease that would cause a shortage on the product that is nearest to a shortage.

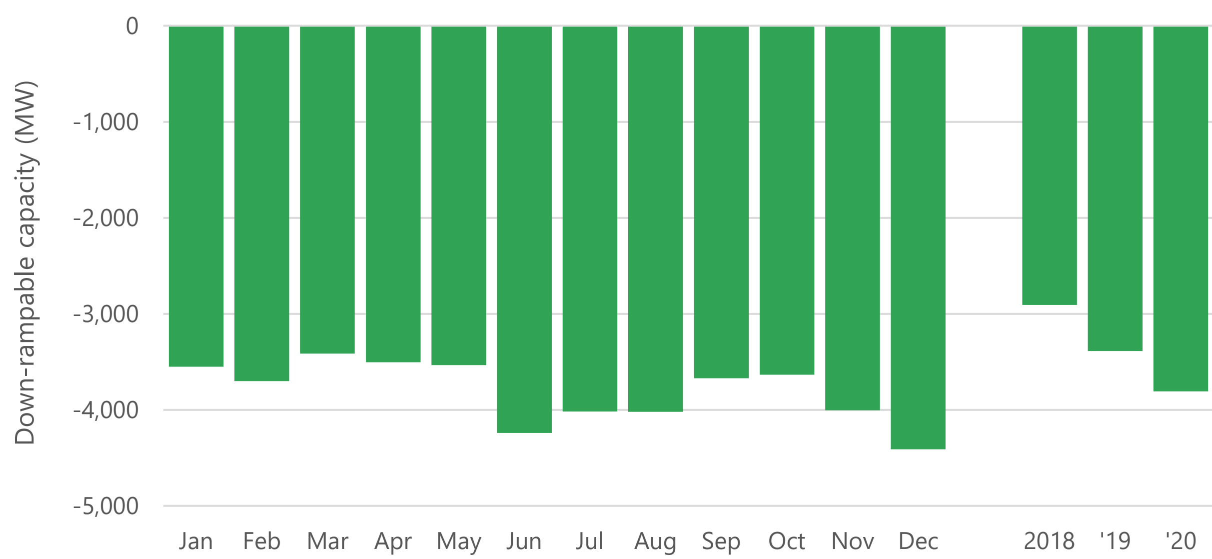
Figure 3–19 Average up-rampable capacity



Although many factors affect available ramp, rampable capacity in the up direction, when averaged by month, is lowest in March, when wind production is typically high.

The amount of rampable capacity in the down direction is much larger than in the up direction when averaged by month, as shown in Figure 3–20.

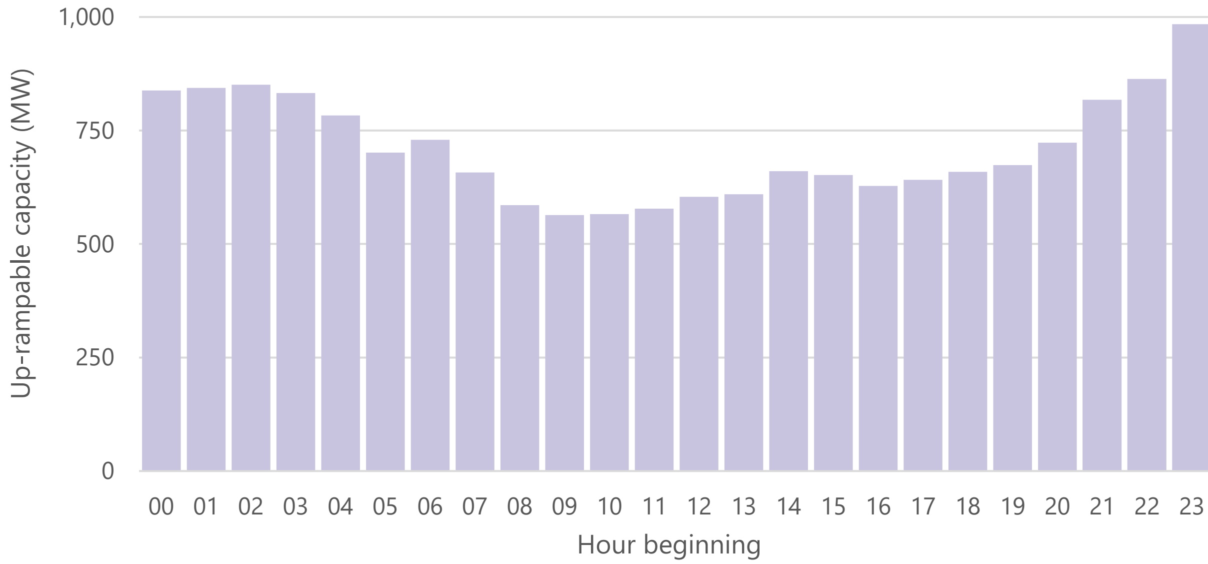
Figure 3–20 Average down-rampable capacity



While the monthly averages do not change significantly throughout the year, the up-rampable capacity is on average three percent higher and the down-rampable capacity is on average 12 percent higher in 2020 than in 2019. The downward ramp increase is likely the result of an overall increase in wind production and the continuing conversion of wind resources from non-dispatchable to dispatchable.

Figure 3–21 shows the average rampable capacity in the up direction by hour of the day.

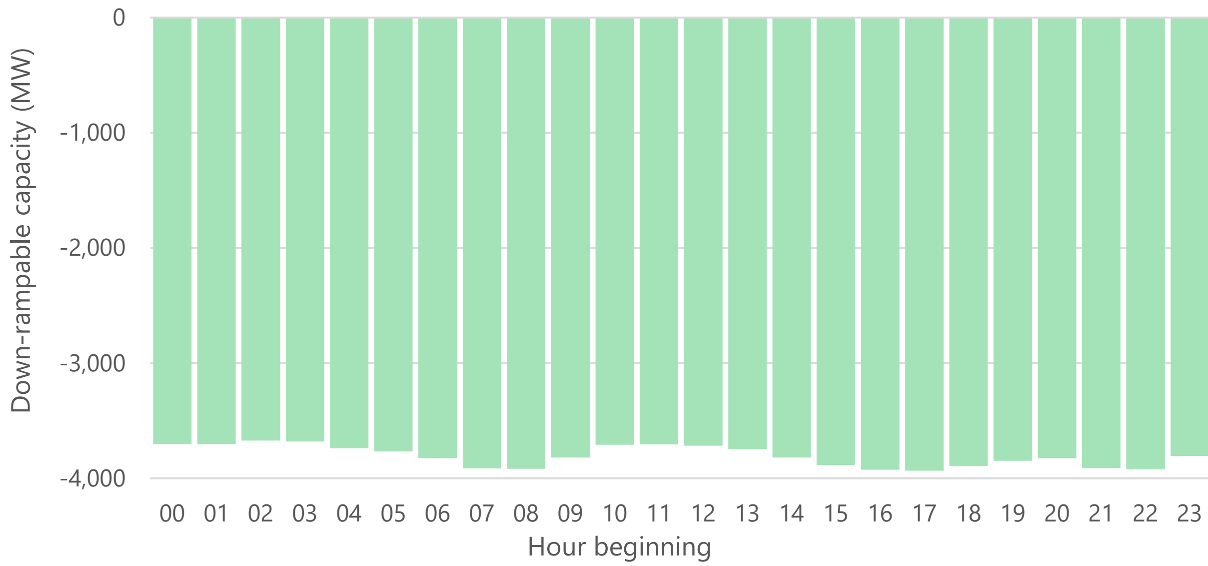
Figure 3–21 Average up-rampable capacity by hour



Rampable capacity in the up direction is lowest following the morning ramp in hours beginning 08, 09, 10, and 11. From hour beginning 12 until hour beginning 20, the rampable capacity increases slightly but remains lower. This is when load is relatively high for the day and resources operate closer to their maximums. As resources move closer to their minimum limits during the night, this rampable capacity increases. Since commitments for rampable capacity are not currently being compensated for their rampable capacity, there is no guarantee for it to be available in the future. The ramp capability product is a step in the right direction to incentivize rampable capacity, but it is unclear yet if prices based on lost opportunity will incentivize sufficient rampable capacity long term.

Figure 3–22 shows the average rampable capacity in the down direction by hour.

Figure 3–22 Average down-rampable capacity by hour



As previously mentioned, there is much more rampable capacity in the down direction than in the up direction. Although this rampable capacity is less in the early morning and late evening hours, this amount does not vary significantly throughout the day.

Ramp capability is needed to meet all of these changes in generation and load from interval to interval. A resource's ramp rate is used to calculate its dispatch instruction. A resource will generally not be dispatched beyond the capability of the resource's ramp rate. However, unlike capacity, the market clearing engine does not specifically procure ramp ahead of time to meet these intra-hour net load changes, although committed capacity usually comes with incidental ramp capability.

3.2.3 RAMP CAPABILITY PRODUCT

The MMU believes that a properly designed ramp capability product will be beneficial to the market, as it will properly price the need for rampable capacity. The volume of scarcity events highlighted in Figure 3–13, illustrates the need for ramp capability. A resource's ability to ramp should be part of the clearing and dispatch decision and should be valued at a price to the extent the ramp is beneficial to the market.

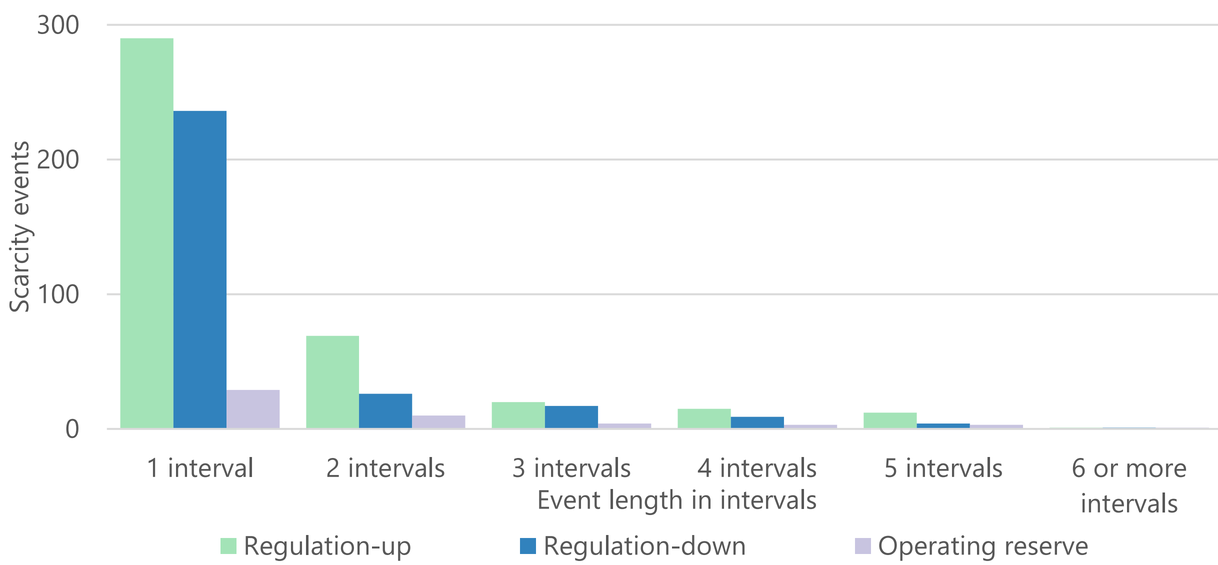
SPP has designed a ramp capability product, which is expected to be implemented in early 2022.[72] The MMU is in general support of the proposed design; however, there are some concerns with the current design,[73] which are discussed later in this section.

3.2.3.1 Ramping limitations affect market outcomes

The real-time dispatch does not consider future intervals. It simply calculates one value: a dispatch instruction for the next interval. 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 subsequent dispatch instructions even though ramp is the very capability that allows a resource to get to future dispatch instructions.

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 those future intervals. Even when enough capacity is available, a lack of ramp renders that capacity unreachable. Moreover, sufficient ramp has typically been offered, by the market participants, but the clearing process has not left enough available for future use. This often leads to short-term transitory price spikes,[74] as seen in Figure 3–23.

Figure 3–23 Interval length of short-term price spikes

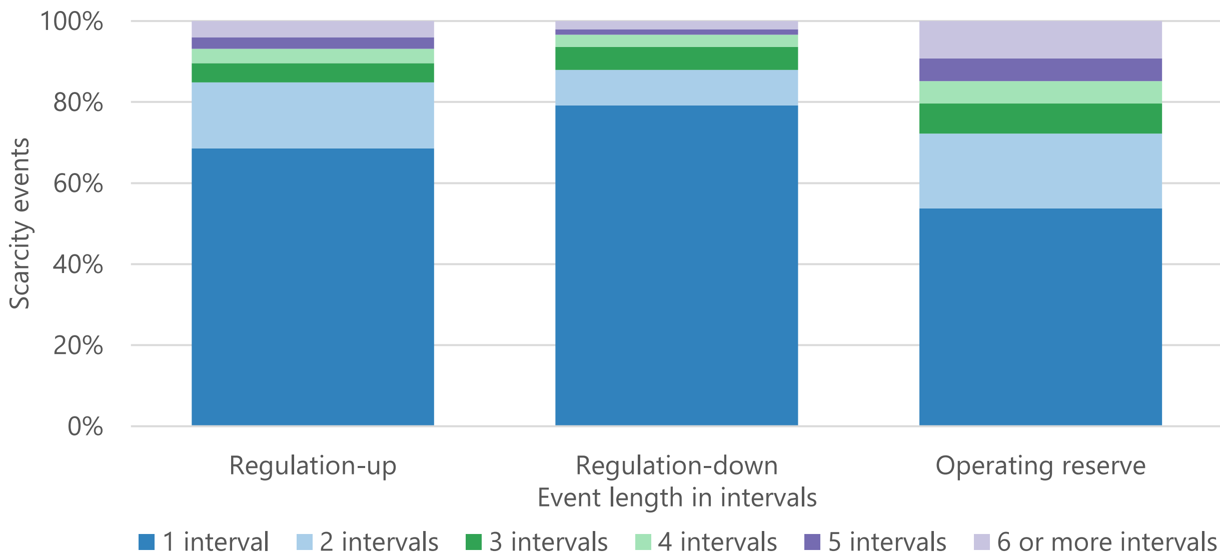


[72] See RR361, RR441, and Docket No. ER20-1617.
[73] See MMU comments in Docket No. ER20-1617.
[74] This is essentially temporal, or time-based, congestion.

This figure shows that a scarcity pricing event in real-time was most likely to occur for only one five-minute interval. Very few scarcity pricing events last more than two intervals. This pattern has been consistent in recent years, but the total number of scarcity events increased by about nine percent from 2019 to 2020.

Figure 3–24 shows the interval length for the different types of scarcity events.

Figure 3–24 Interval length of short-term price spikes, percentage



Of all the regulation-up scarcity events, about 69 percent lasted for only one interval, and about 16 percent lasted for two intervals. For regulation-down scarcity events, about 79 percent lasted for only one interval, and about nine percent lasted for two intervals. Operating reserve scarcity event lengths were more diverse with about 54 percent lasting for one interval, about 19 percent lasting two intervals, and about seven percent lasting three intervals. Scarcity events in the SPP market continue to be short in duration.

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. Almost all of these intervals with scarcity pricing were due to a lack of cleared ramp and not a lack of capacity. If sufficient ramp were reserved in advance for these scarcity intervals, then these scarcities likely could have been avoided. Ramp availability increased in 2020, but scarcity events have also increased, highlighting the continued need for systematic ramp procurement.

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 because the two products are competing for ramp. This makes energy prices more volatile. If sufficient ramp had been available, then regulation-up scarcity prices would not have raised the marginal 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.

3.2.3.2 Proposed design of the ramp capability product

In the 2017 annual report, the market monitor recommended that SPP create a ramp capability product. SPP has designed a ramp capability product that has passed all the stakeholder processes and is awaiting implementation.[75]

The proposed ramp capability product will optimize the resources' dispatch instructions over a ten-minute period to allocate any economically available ramp for the interval starting ten minutes in the future. It will meet this future ramp need by pre-positioning online resources with available ramp if the cost of this action is less than the applicable ramp-scarcity demand curve price. The proposed ramp requirement will be enough ramp to meet forecasted net load changes plus an amount to cover unexpected net load changes based on historical needs. The current design will optimize only online ramp. Off-line ramp will not be eligible to clear the ramp capability product. A market clearing price will be set by the opportunity cost of providing other products. While the market monitor is in general support of the proposed ramp capability design there are some concerns:[76]

3.2.3.2.1 Proposed ramp product demand curve prices are too low

The proposed ramp product prices scarcity with a demand curve. The MMU is concerned that the demand curve prices are too low. Using 2020 prices, the MMU estimates that the demand curve will begin relaxing the ramp requirement when the cost is around $8.33/MW and will

[75] See RR361, RR441, and Docket No. ER20-1617.
[76] See MMU comments in Docket No. ER20-1617.

completely relax the ramp requirement around $49/MW. These prices may not clear physical ramp even though it is available. Consequently, physical ramp may be insufficient, and the price may not reflect the actual value of ramp, which undermines the purpose of a ramp product.

The MMU recommended that the maximum demand curve price be set slightly below the minimum regulation demand curve price. Avoiding regulation scarcity events in the future is the primary goal of a ramp product. A higher scarcity price may be needed to clear physical ramp and to incentivize ramp capability. After implementation, the MMU will analyze the cost effectiveness of the demand curve prices.

3.2.3.2.2 Reduced need for instantaneous load capacity

The process known as instantaneous load capacity is ramp procurement without ramp payment. The instantaneous load capacity ensures that sufficient rampable capacity is committed to ramp from one average hourly load to the next. Resources committed to provide this rampable capacity add value to the market but are not paid for that value. These resources often run at a financial loss for most of the hour and are merely made-whole to their costs. The instantaneous load capacity requirement is not removed or reduced by the proposed ramp product. If more than one ramping timeframe is needed for more than one ramping purpose,[77] then the market monitor could support multiple ramp products.

SPP is currently proposing an uncertainty product that will work similarly to the ramp product, with a one-hour time horizon and off-line resources will be able to participate.[78] This product is in the early stages of the stakeholder process, but is projected to be filed with FERC in mid-2021, if approved by all stakeholder processes. The MMU believes that this product, in conjunction with the proposed ramp capability product, should severely limit the need for the use of committing the uncompensated capacity, currently defined as instantaneous load capacity.

[77] For instance, it may be appropriate to have a ramp product similar to instantaneous load capacity to address inter-hour ramping needs in addition to an intra-hour ramp product to address short-term load variability.
[78] See RR449.

3.3 SELF-COMMITMENTS

The purpose of the centralized unit commitment processes is to commit sufficient resources to serve load, subject to transmission and resource constraints, while minimizing cost. The centralized unit commitment process is able to minimize commitment costs because it has information, such as the amount of capacity required, the current transmission topology, the parameters of each resource, and the current state of each transmission and resource constraint.

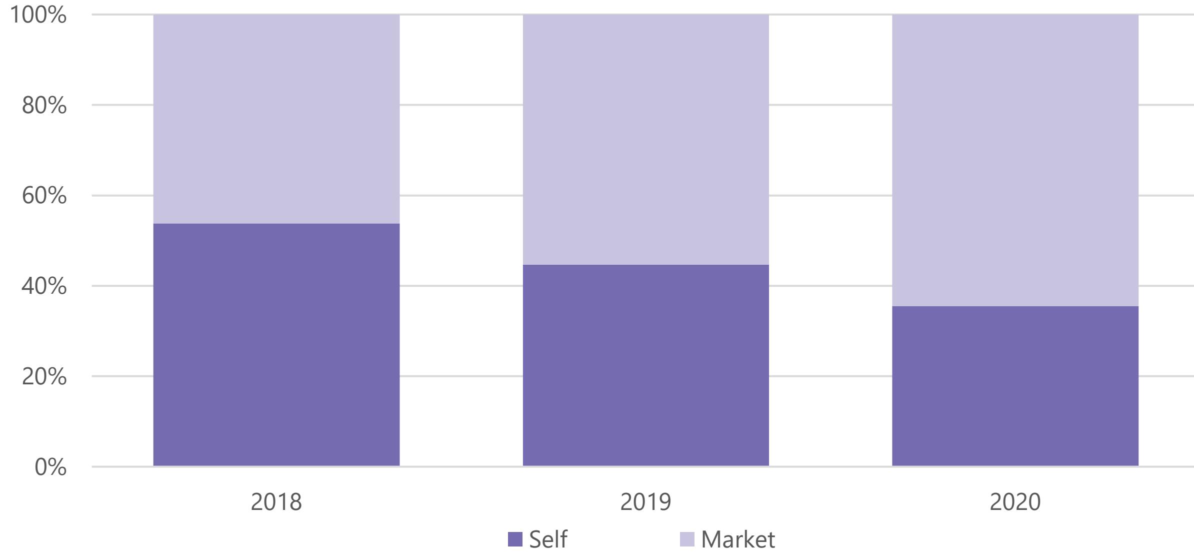
The idea behind centralized unit commitment is essentially this: In the same way a team will likely realize better outcomes when the coach selects both the players and plays, the Integrated Marketplace will also probably realize better outcomes, for the collective, when it commits units in addition to dispatching them. While the team's record might be the same regardless of who is on the field, it is unlikely that the plays called, points scored, or yards gained would be the same.

Much like players choosing when to play, the SPP market allows participants to self-commit resources rather than have the market choose which units to run. While there may be good reasons for this, the practice can distort prices, offer and bid behavior, market outcomes, and investment signals.

Figure 3–25 shows the percentage of dispatch megawatts by commitment status in the day-ahead market.[79] All output from a self-committed unit is counted as self.

[79] For more detail on this and other metrics, see the MMU's whitepaper on self-commitment, *Self-committing in SPP markets: Overview, impacts, and recommendations*.

Figure 3–25 Percentage of megawatts dispatched by commitment status



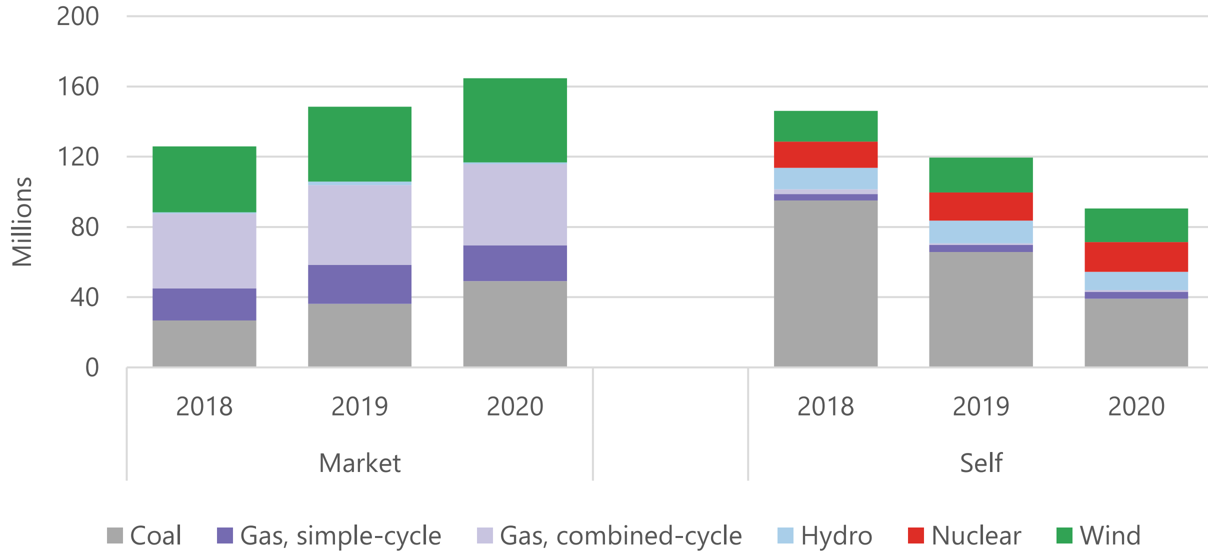
The volume of self-committed megawatts has declined over the last several years, but remains more than one-third of the total dispatch megawatt volumes. In other words, more than one-third of the energy produced in 2020 was from a resource that was not economically selected by the day-ahead market's centralized unit commitment process.[80]

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

Figure 3–26 shows dispatch megawatts by fuel type by commitment type for each year of the study period.

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

Figure 3–26 Dispatch megawatt hours by fuel type by commitment type

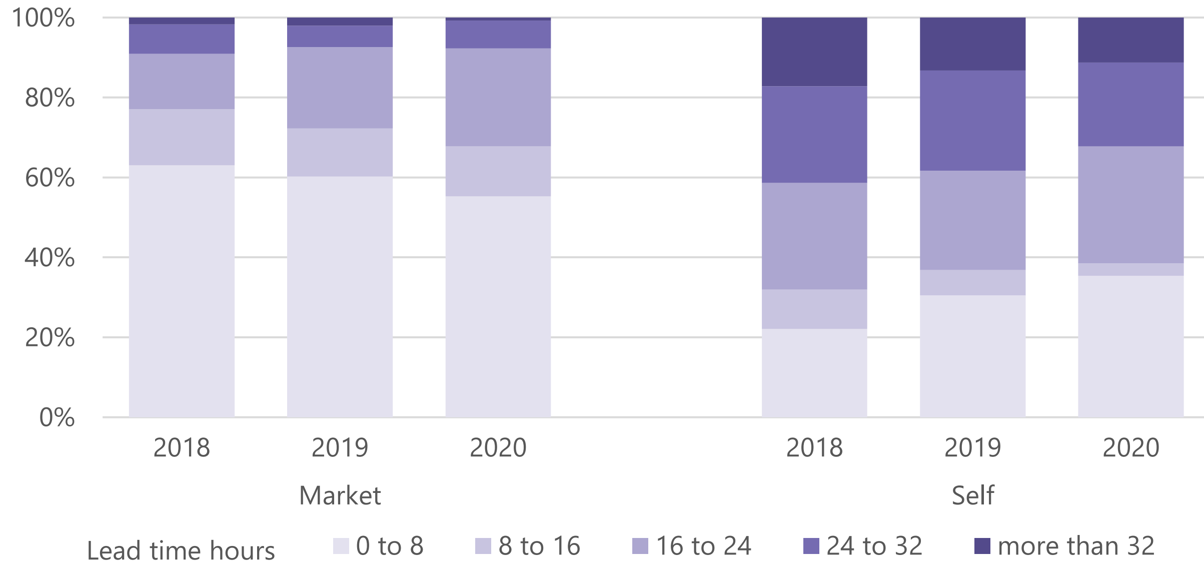


While resources of various fuel types self-commit, coal resources have produced and continue to produce the largest portion of self-committed megawatts. The trend is positive, however, as the overall level of self-commitment is declining, and with coal self-commitments declining by 40 percent between 2019 and 2020.

Resource lead times, also called start-up times, are time-based operational parameters that vary widely by fuel type. In the Integrated Marketplace, resources can submit three different lead times: cold, intermediate, and hot. Thermal resources generally have longer lead times when they are cold as opposed to when they are hot. In the following section, lead times by commitment status and fuel type are examined.

Figure 3–27 shows the relationship between commitment status and start-up time.

Figure 3–27 Lead time hours by commitment status

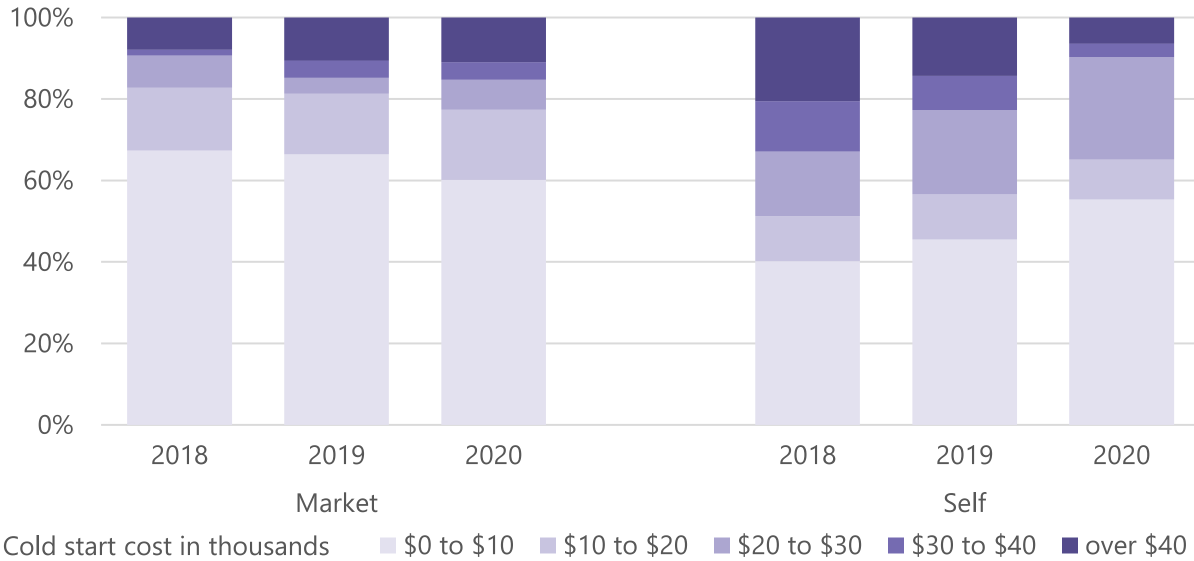


Self-committed resources tend to have longer lead times than market-committed resources. Because the centralized unit commitment must observe constraints other than cost, such as lead time, it may continue to run a unit even when the marginal price falls below that unit's offer. Nuclear units have the longest cold start-up time, followed by coal and natural gas.

Start-up offers are generally representative of the cost that a market participant incurs when starting a generating unit from an off-line state to its economic minimum, as well as the cost to eventually shut the unit down. These offers are submitted in terms of dollars per start.

Figure 3–28 shows the relationship between commitment status and start-up cost.

Figure 3–28 Cold start cost by commitment status



Many of the units with high start-up costs have minimum run times that extend past the day-ahead market window. If the optimization evaluated start-up costs over each resource's full minimum run time, their start-up offers would be more competitive with shorter lead-time resources. This issue compounds for those resources with long lead times and high start-up costs. Because these units cannot come online until much later than the first hour of the day-ahead market day, their start-up cost is optimized over even fewer hours. Similar to lead-time, coal units have the highest cold start-up cost, followed by nuclear and natural gas.

Self-commitment represents a significant portion of the transaction volume in the Integrated Marketplace, and while it cannot be eliminated completely, the practice can likely be reduced substantially. By reducing self-commitment, prices and investment signals will likely be less distorted. A smaller distortion will likely help market participants make better short-run and long run decisions, which tends to coincide with improved market efficiency and profit maximization.

While the MMU has seen gradual reductions in self-commitments over the last few years, generation from self-committed generators still represents about one-third of the generation in the SPP market. Given its significance, the MMU recommends that the SPP and its stakeholders continue to find ways to further reduce self-commitments including developing a multi-day economic assessment.[81]

3.4 GENERATION OUTAGES

Generators cannot run constantly at full capacity and occasionally need to be outaged or derated. When a generation resource is on outage, its entire capacity is unavailable for dispatch. When a generation resource is on derate, a portion of the capacity of the generation resource is unavailable for dispatch.

Two major reasons that outages and derates occur are that the generator needs maintenance or it was forced out of service. Generally, maintenance outages are planned or scheduled in advance in order to perform routine work, whereas forced outages are generally not scheduled and are difficult to predict in advance.

SPP assesses outages and derates to determine real-time and future reliability of the bulk electric system. As the reliability coordinator and balancing authority, SPP approves, denies, or reschedules outages and derates to ensure system reliability.

A central tenet of SPP in 2020 was that "reliability and economics are inseparable." Practically speaking, the more efficient and effective the market, the more economic incentives drive behavior that increase reliability. However, circumstances exist that are not promoting reliability through economic incentives. Some of the circumstances exacerbating the separation of economics from reliability in the market are outage driven.

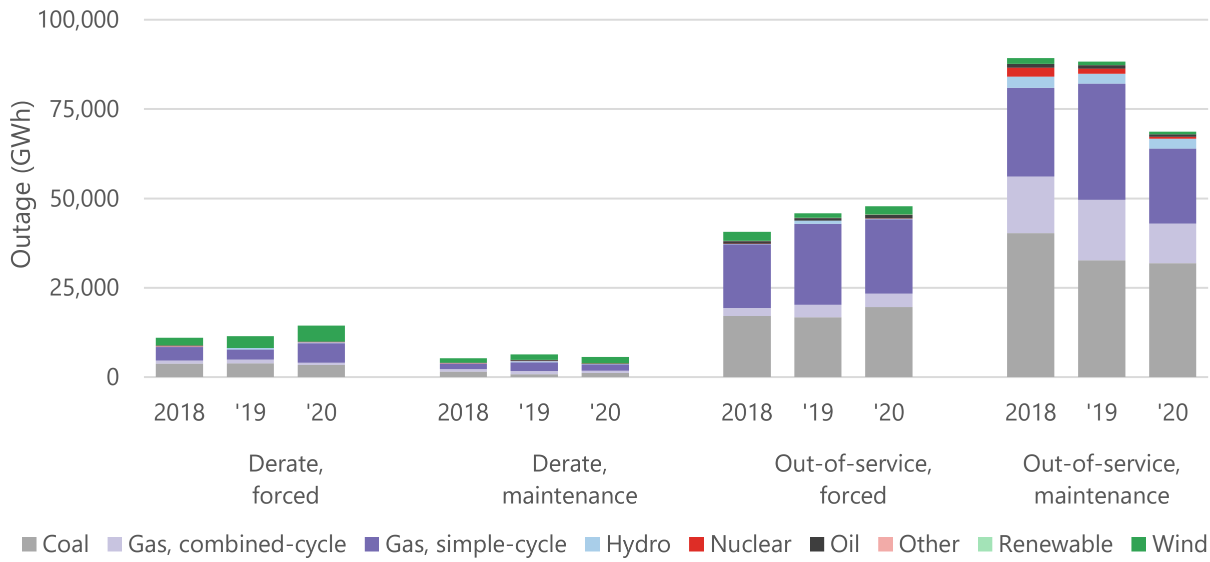
3.4.1 OVERVIEW

Although outaged capacity has historically trended upward, in 2020, outaged capacity decreased by ten percent. The overall decrease of outaged capacity is a combination of maintenance outages decreasing by 21 percent and, in contrast, forced outages increasing by

[81] Chapter 8, recommendation 2017.4 "Address inefficiency caused by self-committed resources" for more information.

nine percent. This can be seen in Figure 3–29, which shows capacity derated and taken out-of-service by reason—forced or maintenance.[82] Each reason is further categorized by fuel type.

Figure 3–29 Generation outages



As in previous years, capacity taken out-of-service for maintenance accounts for the largest share of capacity on outage. This is followed by capacity forced out-of-service; then by forced derates; and finally by maintenance derates. Coal provided about 31 percent of generation[83] and accounted for about 41 percent of outaged capacity in 2020. Combined cycle gas provided about nine percent of generation and about 12 percent of outaged capacity, a similar ratio to coal. However, simple cycle gas provided about 18 percent of generation but about 36 percent of outaged capacity, a higher ratio than coal or combined cycle gas. The amount of capacity on outage is largely influenced by the amount of generation, but simple cycle gas has the highest rate of outaged capacity per generation. Asset owners have expressed concern that these simple cycle resources are starting and stopping much more than intended by the manufacturer.

Although there are multiple factors that contribute to the occurrence and completion of outages, the distinguishing factors of 2020 have been disruptions and adjustments of outages

[82] For purposes of this study, forced outages include forced, emergency, and urgent outage priorities. All other outage priorities, planned, opportunity, and operational, are classified as maintenance. Excess capacity/economic and upcoming model change outages were excluded from the results. Derated resources are still available to the market at a reduced capacity. Out-of-service resources are entirely unavailable.

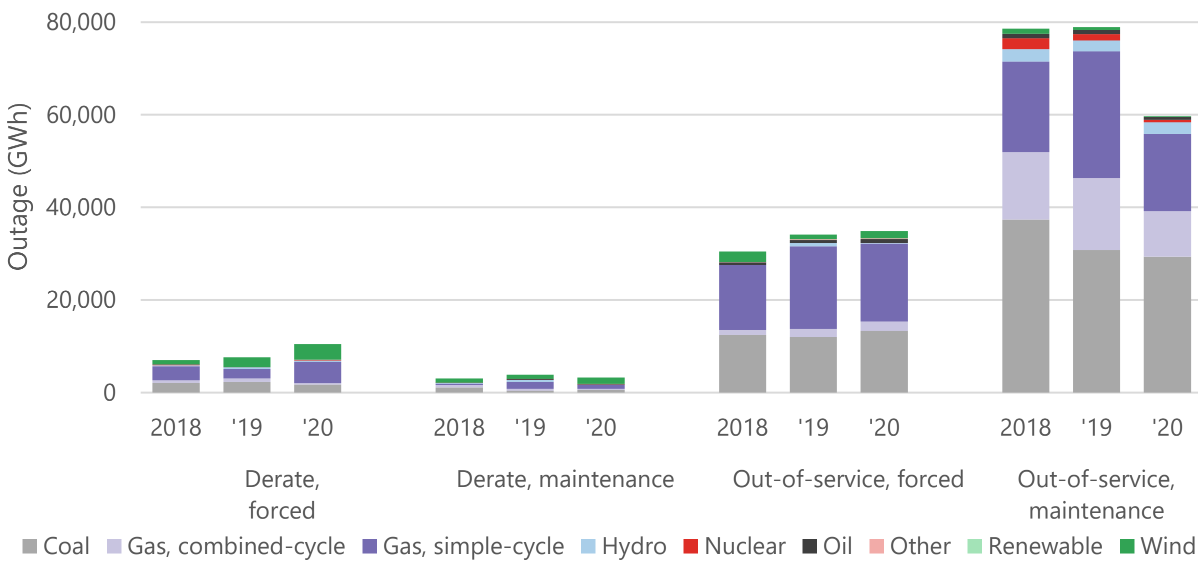
[83] See Figure 2–19.

due to COVID-19 precautions. The MMU has observed delays in the commencement of maintenance outages, as evidenced by the 21 percent decrease in maintenance outages during 2020. The decrease of maintenance outages was offset by a nine percent increase in forced outages. This is likely because a delay of routine maintenance lead to a higher rate of unplanned failures.

Although there are many reasons for delays which contribute to the occurrence and completion of outages, 2020 saw a previously unimaginable level of supply chain disruptions as well as shipping and travel restrictions due to COVID-19 precautions. These types of disruptions have resulted in issues such as procuring parts, shipping equipment, and securing staff.

Figure 3–30 shows capacity on outage for long-term outages (greater than seven days).

Figure 3–30 Long-term outages (greater than seven days)

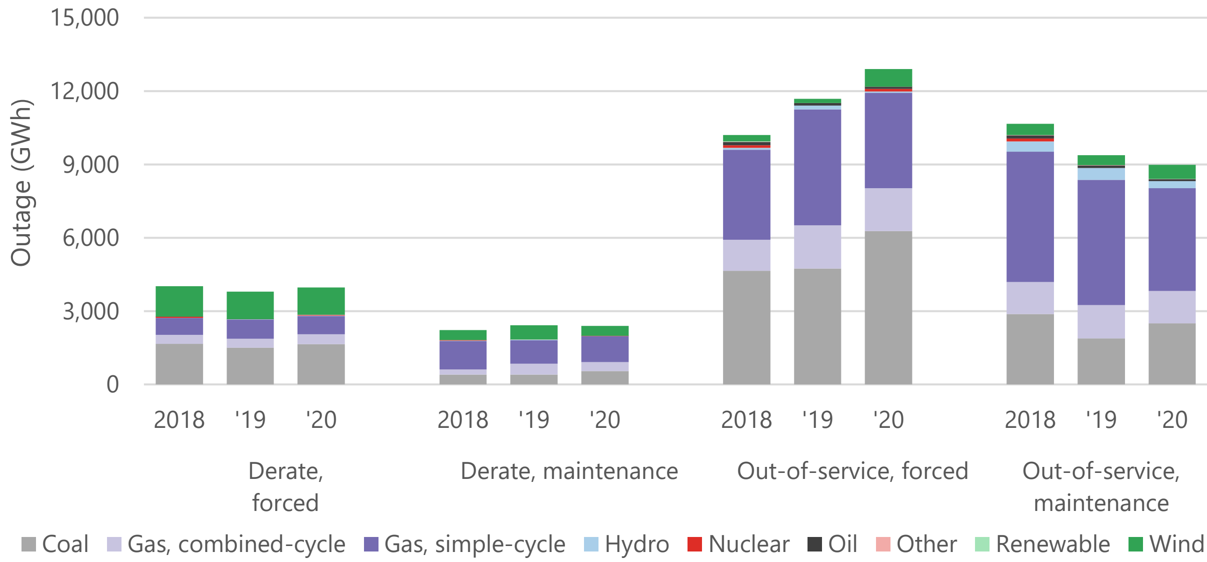


Outages that last longer than seven days are considered long-term. The majority of long-term outaged capacity is for maintenance. Overall, long-term outaged capacity decreased by about 13 percent from 2019 to 2020. Of the overall decrease for long-term outages, capacity of forced outages increased by about nine percent and maintenance decreased about 24 percent.[84] This follows the same patterns for overall maintenance and forced outages in Figure 3-28.

[84] The maintenance change is a percent of 2019 maintenance, and the forced change is a percent of 2019 forced. Because there were different amounts of capacity outaged for maintenance and forced, the percent differences will not sum to the overall change.

Figure 3–31 shows capacity on outage for short-term outages (seven days or less).

Figure 3–31 Short-term outages (seven days or less)



Outages that last seven days or less are considered short-term. The majority of short-term outages are forced outages. Overall, short-term outages increased about four percent from 2019 to 2020. Of the overall increase of short-term outages, capacity for maintenance decreased by about four percent and forced increased by about nine percent.[84] This is also consistent with the pattern of overall maintenance and forced outages in Figure 3–28.

When it comes to outages, 2020 should be viewed as an outlier due to the unusual conditions produced by COVID-19. Additionally, there were no conservative operations events in 2020. In 2019, generation outages were specifically cited as a reason for several of the conservative operations events. RTO and stakeholder efforts established in 2019 need to continue to be refined, developed, and implemented. Overall, the MMU is concerned about outages as outages affect both reliability and market efficiency. The MMU maintains that there is a lack of appropriate incentives to promote resource availability.

While 2020 circumstances were unique, a robust market design can help prepare for the best possible response to unforeseen difficulties by appropriately incentivizing availability through appropriate price formation, generation availability compensation, or true-up, such as a claw back or receiving less credit for resource adequacy.

SPP formed the Generator Outage Task Force (GOTF) in 2020 in the wake of 10 separate Conservative Operations events, as well as an Energy Emergency Alert Level 1 (EEA1) event. The continued work of the GOTF includes the development, implementation, and refinement of the Generation Assessment Process (GAP) as well as the review and refinement of various governing documents such as the SPP Outage Coordination Methodology, SPP Membership Agreement, and SPP Open Access Tariff.

3.4.2 INSUFFICIENT INCENTIVES TO BE AVAILABLE

Even though there are legitimate reasons for resources to be on outage, proper incentives can promote reliability. However, there are several outage-related areas where economic and reliability incentives may diverge.

3.4.2.1 Real-time and day-ahead market incentives

The SPP market tends to have relatively low prices as evidenced in Figure 4–1. As shown in Figure 2–5, on aggregate, load cleared around 100 percent of its real-time consumption in the day-ahead market. Typically, real-time generation procurement is not due to a load gap between day-ahead and real-time.

Low prices in the real-time and day-ahead markets are less likely to provide financial incentive for generators to complete maintenance and repairs as soon as possible. MISO provides a price floor during a maximum generation event based on the highest non-emergency offer.[85] ERCOT removes some reliability units from pricing and applies a risk adder to the price in certain situations.[86] In SPP, during conservative operations, resources have historically been paid large amounts in make-whole payments, while the prices were relatively low.

Low market prices during emergencies do not adequately reflect the value of reliability while large out-of-market payments are not transparent and do not properly inform investment decisions for new generation or demand response resources. In order for maintenance and repair costs to be recovered, the value a resource provides must be reflected in some type of market price. A market price could also inform generators about the most reliable time to take

[85] *MISO Tariff*, Schedule 29A. II. D.
[86] *ERCOT Protocols*, Section 6.5.7.3.1

outages. The current pricing mechanisms are not sending proper price signals to incentivize generation availability.

The MMU recommends that SPP and its stakeholders review price formation rules to consider if prices (i) appropriately incentivize generation availability during emergencies and outages and (ii) would likely reduce outage volume and duration and increase the value of fuel certainty.

3.4.2.2 Resource adequacy incentives

The resource adequacy requirement, Attachment AA to the tariff, lacks appropriate incentives for resources to remain available. Anticipated availability of summer capacity is evaluated on February 15. Currently, no tariff mechanism addresses units that were claimed as capacity but become unavailable after February 15. Instead, full summer capacity can be claimed, and the capacity deficiency payment can be avoided, even if that capacity is unavailable for the entire summer. Additionally, the resource adequacy requirement[87] completely omits capacity shortages in non-summer months. However, capacity shortages can occur during non-summer months. For instance, capacity shortages can occur during extreme winter weather when natural gas can have deliverability issues and/or when wind resources experience icing or wind outside of threshold/tolerance. Planning for peak summer days lacks the necessary complexity to ensure reliability year-round.

In numerous forums, SPP operations has described the importance of the availability of schedulable resources with a dependable fuel source due to the volatility of variable energy resources, particularly in the event that wind resources experience a decline in output. Yet nothing in the resource adequacy requirement mandates a minimum level of realized availability.[88] Furthermore, coal resources have been less dependable during floods, and gas resources have been less dependable during extreme winter weather. The MMU believes that improved financial mechanisms could incentivize market participants to keep adequate resources available to serve peak load and planning reserve obligations.[89] Alternatively, these resources claimed for capacity adequacy could be considered in a must offer requirement.

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[87] *SPP Open Access Transmission Tariff*, Sixth Revised, Volume No. 1, Attachment AA, Section 9
[88] *SPP Open Access Transmission Tariff*, Sixth Revised, Volume No. 1, Attachment AA, Section 9
[89] The Market Monitor is advisory in nature and presents possible solutions from an economic perspective. Other solutions of a regulatory nature are also under consideration by SPP.

Some resources claimed for resource adequacy credit experience natural gas outages as a result of interruptible service. Others experience fuel curtailments despite possessing firm service. This is often due to pipeline maintenance which occurs predominantly in the summer months. Because of very low natural gas prices, gas-powered generation has been in high demand. As gas-powered resources are serving a large portion of load, the importance of proper incentives is essential to reliability.

Incentivizing availability in the resource adequacy requirement does not necessarily depend on the day-ahead and real-time market rules. The day-ahead and real-time markets require only available resources to participate in the market and do not have requirements for resources to be available for a minimum number of intervals.[90] Nevertheless, the absence of availability requirements in the resource adequacy requirement undermines its purpose of ensuring adequate resources will be able to serve load reliably. Addressing availability in the resource adequacy requirement could be pursued independent of improvements to the day-ahead and real-time markets.

SPP and its stakeholders should continue to work on mechanisms that reward resources that perform more reliably and are available when needed by SPP operations. One option is for resources with higher than required realized availability be paid by resources with lower than required realized availability. Compensating units with excess realized availability may encourage asset owners to minimize downtime by minimizing part repair or replacement delays, storing adequate spare parts on-site, scheduling repair and maintenance work during off-peak times and minimizing unnecessary work stoppages. Without realized capacity incentives, asset owners are incentivized to minimize repair costs at the expense of availability, which can be detrimental to system reliability.

Alternatively, the amount of capacity a resource can count toward the resource adequacy requirement could be its tested capacity discounted by its availability rate from the previous

[90] Generally, outages must be approved by SPP's outage approval process. Non-forced outages are not approved if they pose a significant reliability risk. Additionally, the day-ahead and real-time markets have physical and economic withholding rules that guard against unreasonable outages.

year or season. The previous availability rate could be derived from the days most important to reliability such as a certain season, yearly average, or conservative operations days.

Another option is to require a percentage of capacity used to satisfy the resource adequacy requirement to be offered in the day-ahead and real-time markets and considered by the must offer provisions.

SPP should continue to consider these options and others to ensure that the resource adequacy requirement is effective to serve load reliably.

3.4.2.3 Outage coordination methodology

Resources are not required to enter an outage request for outages less than 25 MW, yet the tariff requires registration at 10 MW.[91] SPP should consider aligning the minimum gross reduction in capacity threshold for outage reporting with the threshold for registration requirement. Market participants and generator operators generally adhered to the Conservative Operations Alert notice to report all outages during the conservative operations event.

Resources that are in reserve shutdown, but can be recalled, started, and synchronized within seven days are not required to report the outage to SPP. This rule allows resources to take an outage without the knowledge or approval of SPP. Furthermore, there is no guarantee, or even attempt to consider, if an emergency condition may occur during this time. The MMU highly recommends that SPP update the Outage Coordination Methodology to require review of all reserve shutdown outages and provide approval through the existing process.

The outage coordination methodology[92] requires a reason and planned end date for the outage at both the time of the outage submittal and at the submittal of each change. An exception is that a forced outage can be submitted with an unknown cause, but the cause and planned end date are required to be updated promptly as soon as more information is known. Moreover, a forced outage (due to a failed pump, for example) with a planned or opportunity maintenance

[91] *SPP Reliability Coordinator Outage Coordination Methodology*, Section 3, Generation Outages and Derate Submission Requirements; and *SPP Open Access Transmission Tariff*, Sixth Revised, Volume No. 1, Attachment AE, Section 2.2(6).
[92] *SPP Reliability Coordinator Outage Coordination Methodology*

outage for a pipeline requires the participant to submit additional outage requests for work outside the original scope of work for approval. The MMU has observed insufficient, omitted, delayed, and incorrect outage information that does not meet the requirements of the outage coordination methodology. Because outage submissions are intended to be used for assessing real-time and future reliability of the bulk electric system,[93] the MMU recommends SPP enhance and that market participants adhere to the outage coordination methodology. Material misstatements of outage information could be considered providing false information to the RTO and may result in referral to FERC.[94]

3.4.2.4 Pipeline availability

Gas generator outages may be the result of natural gas pipeline maintenance. Generally, the natural gas industry takes pipeline outages during its low demand period, which is typically the summer. These pipeline outages often coincide with peak annual electric demand. Specifically, resources with interruptible service often experience interruptions. Additionally, the natural gas industry can experience low supply and high demand scenarios during winter weather events. Pipelines can charge shortage prices, or stop filling nominations made after the timely cycle. Even firm gas can be interrupted during shortages or limited deliverability. A secondary fuel source and/or a stored fuel source is more dependable than firm gas. Incentives are insufficient to change behavior for these predictable generation shortages. Rules should measure dependability and availability of the generation fleet and incentivize sufficient procurement of firm natural gas service as well as investment in secondary and/or stored fuel sources for capacity resources.

3.4.2.5 Fuel procurement

Although SPP and market participants made adjustments to the day-ahead market commitment schedule through the stakeholder process, natural gas timely nominations are still due prior to market participants receiving their commitment schedule.[95] Depending on the pipeline's capacity and the type of service the gas generator has, this could have multiple undesired consequences.

[93] *SPP Reliability Coordinator Outage Coordination Methodology*, Section 1
[94] 18 CFR § 35.41
[95] Docket No. ER19-2681.

First, a market participant could opt not to procure fuel without a day-ahead commitment. If the generator receives a day-ahead commitment or a reliability unit commitment, the market participant will likely pay a premium to procure fuel in a non-timely cycle. Additionally, at times of low pipeline capacity, non-timely cycle purchases are more likely to be curtailed. In this case, without a secondary fuel source or backup fuel, the market participant may have to buy back its day-ahead position at real-time prices and/or pay make-whole distribution charges.

Second, a market participant could opt to procure fuel without a day-ahead commitment. If the generator does not receive a day-ahead commitment or a reliability unit commitment, the market participant could be charged natural gas fees, typically referred to as parking fees in dollars per MMBtu. The parking fees are generally assessed per day until the fuel is moved from the pipeline. Rules should incentivize procurement of the most reliable lowest cost natural gas service, firm timely natural gas service, when appropriate, as well as investment in secondary and/or stored fuel sources for capacity resources.

3.4.2.6 Summary

Outages appear to be causing circumstances that are detrimental to reliability. While 2020 was an outlier due to conditions caused by COVID-19 the otherwise upward trend of outages can be cause for reliability and market concerns.

The MMU recommends the use of economic incentives to drive behavior that increases reliability. Specifically, the MMU recommends review of price formation to consider if prices appropriately incentivize generation availability, which would reduce outage capacity and increase the value of fuel certainty.

SPP could:

1) Consider a mechanism to reward resources that perform more reliably and are available when needed by SPP operations, and

2) Consider aligning the minimum gross reduction in capacity threshold for outage reporting with the threshold for registration requirement.

SPP should:

1) Update the Outage Coordination Methodology to require review of all reserve shutdown outages and provide approval through the existing process,

2) Enhance and adhere to the outage coordination methodology,

3) Review rules to consider if they appropriately incentivize procurement of sufficient firm natural gas service, as well as investment in secondary and/or stored fuel sources, and

4) Review rules to consider if they appropriately incentivize procurement of the most reliable lowest cost natural gas service, firm timely natural gas service, as well as investment in secondary and/or stored fuel sources.

See Chapter 8 of this document for a full list of recommendations.

4 MARKET PRICES AND COSTS

This chapter covers market prices and costs in the SPP market, along with related metrics on negative prices, make-whole payments, and long-run price signals for investment. Highlights of this chapter include:

- Day-ahead market prices averaged $17.69/MWh and the average real-time price was $16.62/MWh for 2020, a decrease for both of 20 percent from 2019. Lower gas prices and lower demand, combined with increasing wind penetration levels appear to be large contributors for the decrease.

- Average gas price for 2020 at the Panhandle Eastern hub was $1.72/MMBtu, down 11 percent from $1.93/MMBtu in 2019.

- The price differences in the SPP North and South hub remained relatively small, with only a $0.23/MWh average day-ahead price difference between the two in 2020. The price convergence between the regions can be primarily attributed to reductions in congestion due to transmission expansion, as well as a milder summer in the southern region.

- Price divergence between the day-ahead and real-time markets decreased slightly in 2020, dropping 11 percent to $1.07/MWh from $1.20/MWh in 2019. Analysis has found that wind forecast errors, under-clearing of renewable resources, and capacity committed after the day-ahead market are drivers for the continued divergence.

- The frequency of negative priced intervals increased 35 percent from 2019. Just under 11 percent of all intervals in the real-time market had negative prices, up from the seven percent in 2019. Four and a half percent of the day-ahead intervals had negative prices, also up from the roughly two percent seen in 2019. The MMU remains concerned about the continued increasing 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.

- The average make-whole payment per megawatt-hour for resources committed in real-time was $18.94/MWh in 2020, down slightly from the $19.64/MWh in 2019, but up from $14.73/MWh in 2018.

- There was a shift in make-whole payments from real-time to day-ahead. In 2020, real-time make-whole payments totaled just under $51 million, down from the roughly $70 million in 2019. However, total day-ahead make-whole payments totaled just over $53 million in 2020, up 69 percent from the $32 million in 2019.

- One resource received $7.9 million dollars in make-whole payments, and has continued to be the highest reimbursed resource for three consecutive years. This resource is in an area with frequent congestion and most of its make-whole payments stem from manual commitments needed to control regional transmission and voltage support issues.

- Roughly 83 percent of real-time make-whole payments' costs were allocated to loads, virtual offers, exports, and sub-station power that withdrew more in real-time than their day-ahead market cleared megawatts. Virtual offers were again the largest source of payments, paying for just under 48 percent of the 2020 total real-time make-whole payments.

- Revenues have been insufficient to support the cost of new entry of scrubbed coal, advanced combined-cycle, advanced combustion turbine generation, wind, and solar photovoltaic since the inception of the Integrated Marketplace, and 2020 was no exception.

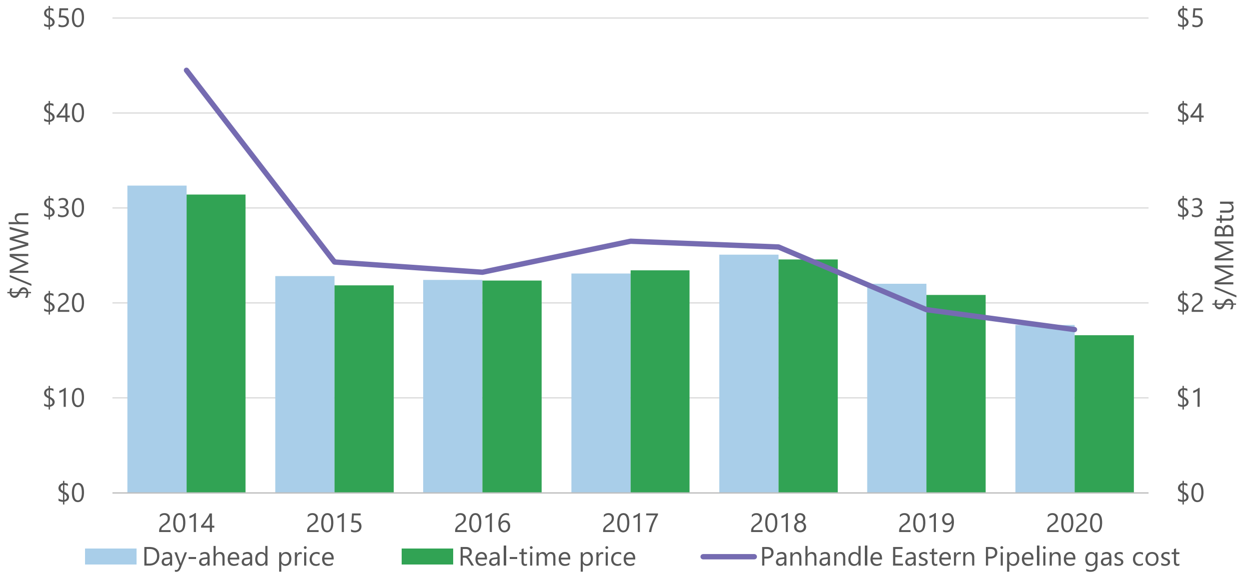
4.1 MARKET PRICES AND COSTS

This section reviews market prices and costs by focusing on the energy market and fuel prices, price volatility, negative prices, operating reserve prices, and market settlement results. Overall, annual energy prices were down from previous years in both the day-ahead and real-time markets. This decrease can be mostly attributed to lower demand and declining fuel prices—primarily gas but also coal—in addition to increased share of wind in total generation again in 2020. Furthermore, the 2020 percentage of negative price intervals saw a substantial increase in the both markets, when compared to previous years.

4.1.1 ENERGY MARKET PRICES AND FUEL PRICES

Figure 4–1 below compares day-ahead and real-time prices[96] in SPP between 2014 and 2020[97] with natural gas prices.

Figure 4–1 Energy price versus natural gas price, annual



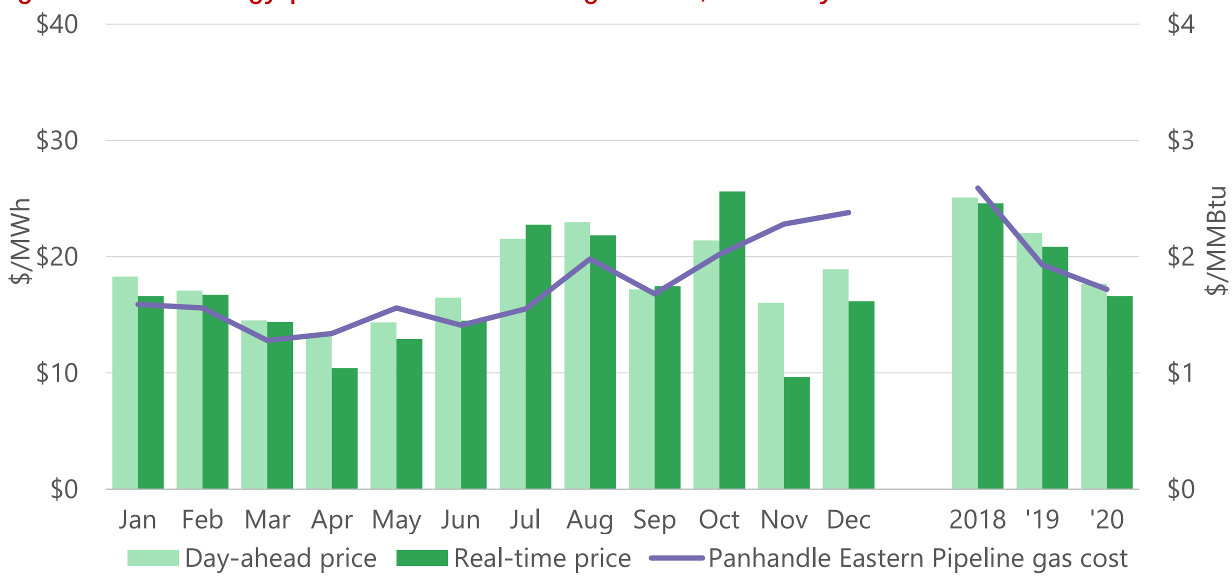
Historically, electric market prices have followed the cost of natural gas. As natural gas prices have remained low overall, so have SPP market prices. The average gas cost in 2020, using the price at the Panhandle Eastern Pipeline (PEPL), was $1.72/MMBtu, down $0.21/MMBtu from 2019, and $0.87/MMBtu from 2018. Day-ahead market prices averaged $17.69/MWh in 2020, down 20 percent from 2019. The average real-time price for 2020 was $16.62/MWh, a decrease of 20 percent from 2019. In addition to gas prices declining from 2019 to 2020, load saw a three percent reduction from 2019, pushing generation down supply offer curves and causing wind to be the predominant source of generation for several hours during the year. This reduction in energy consumption was affected by the pandemic related slowdown of economic activity. This was coupled with wind generation as a percent of load increasing steadily year over year, driving

[96] Day-ahead and real-time prices shown are calculated using the average of the SPP North and SPP South hub prices for each period.
[97] 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.

up the percentage of intervals with negative prices as seen in Figure 4–18 for day-ahead intervals and Figure 4–19 for real-time intervals.[98]

Figure 4–2 illustrates day-ahead and real-time energy prices, as well as gas costs, on a monthly basis for 2020, along with an annual comparison for the past three years.

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

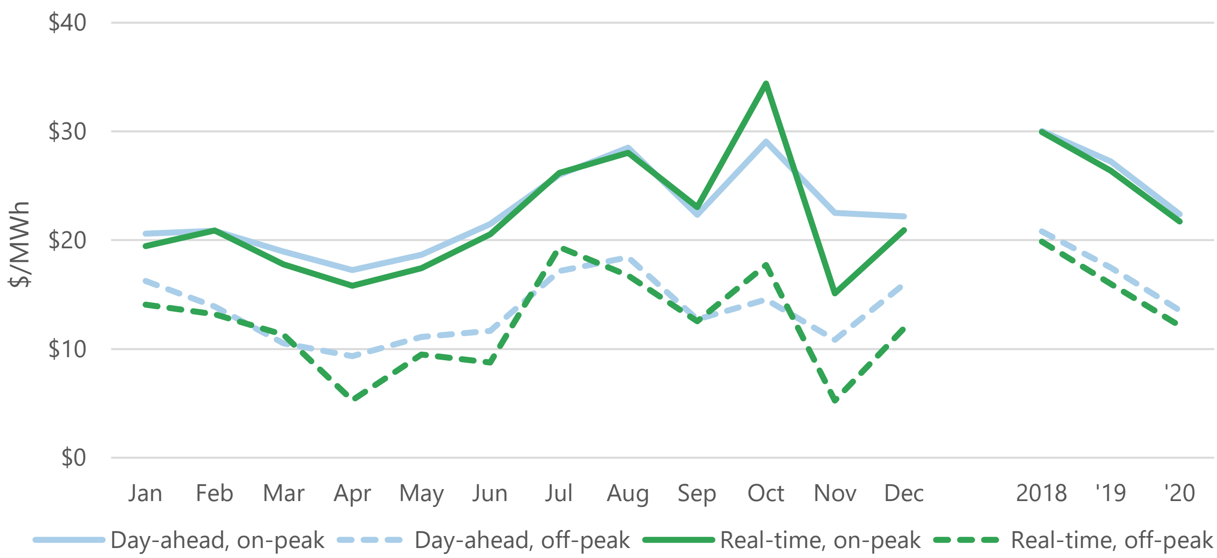


On a monthly basis, natural gas prices averaged around $1.72/MMBtu for 2020 at the Panhandle Eastern hub. As seen in Figure 4–2, gas prices at the Panhandle Eastern hub stayed below $1.60/MMBtu for the first seven months of the year. Starting in August 2020 gas prices began climbing, culminating at $2.38/MMBtu in December. Even with this uptick in the latter half of the year, the 2020 average monthly spot price at the Panhandle Eastern hub was down $0.21/MMBtu from the 2019 monthly average. Day-ahead energy prices were highest in August at around $23/MWh, and real-time prices were highest in October at around $26/MWh. October's high prices can be attributed to an increase in operating scarcity reserve events. Prices were lowest in April, with day-ahead prices just over $13/MWh and real-time prices above $10/MWh, as periods of high-wind generation coincided with low load levels and low natural gas prices.

[98] Wind generation as a percentage of consumed load averaged 32 percent in 2020, up 3 percent from 2019 and up just under 8 percent from 2018.

Additionally, energy prices can be broken down into on-peak and off-peak prices as shown in Figure 4–3. As can be expected, on-peak prices are consistently higher than off-peak prices.

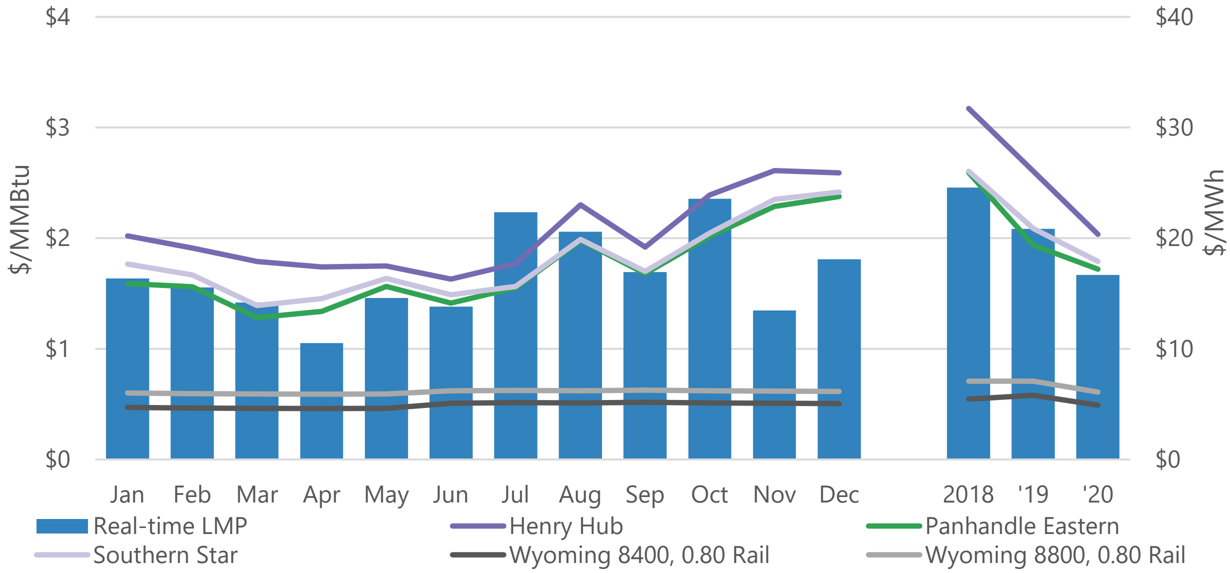
Figure 4–3 Energy price, on-peak and off-peak



As shown above, on-peak prices tend to average about $10/MWh higher than off-peak prices, in both day-ahead and real-time. In the real-time market, the largest on-peak/off-peak price spread was just under $12/MWh in June, and the smallest was just over $5/MWh in January. In the day-ahead market, the largest on-peak/off-peak price spread was just under $15/MWh in October and the smallest was just over $4/MWh in January. The differences between on-peak and off-peak prices can be mostly attributed to lower loads and a higher percentage of lower cost wind generation in off-peak hours.

Changes in gas prices have historically had the highest impact on electricity prices compared to other fuels. This is because the short-run marginal costs of coal-fired generation historically have been cheaper than natural gas-fired generation. However, as natural gas prices have fallen, the short-run marginal costs of natural gas fired generation have been more competitive with coal fired generation, and in some instances displacing coal generation. Figure 4–4 compares various fuel price indices with real-time prices.

Figure 4–4 Fuel price indices and energy prices



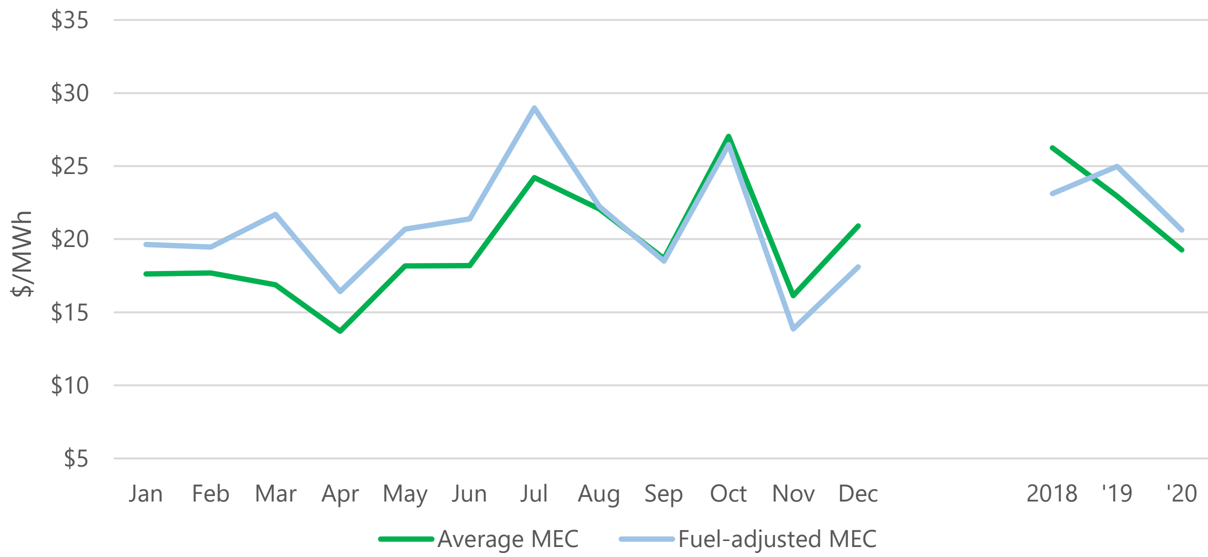
This figure shows that regional natural gas prices declined steeply from 2018 to 2020, on an annual basis, but started trending upwardly in the second half of 2020. The Henry Hub gas price averaged $2.04/MMBtu for 2020, while the Southern Star was $1.79/MMBtu and Panhandle Eastern averaged $1.72/MMBtu in 2020.[99] The difference between Henry Hub prices and Panhandle Eastern and Southern Star prices has grown over the last few years, but in 2020 those gaps grew smaller, with differences averaging $0.57/MMBtu in 2018, $0.66/MMBtu in 2019, and $0.23/MMBtu in 2020. This difference is likely driven by pipeline constraints in the Texas and Oklahoma area. Often, natural gas is a byproduct of oil drilling. Natural gas production has continued to outpace takeaway capacity in this area, with incremental production volumes quickly inundating any available space in the pipelines and keeping supply-area prices at discounts compared to other trade hubs. Much like last year, natural gas prices in West Texas (Waha and El Paso) have been less than $1/MMBtu on a number of days, and in fact, had some periods of negative natural gas prices, which have helped high heat rate units in this area be profitable.

[99] 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.

Coal prices have remained relatively stable since 2016, but saw a slight dip in 2020.[100] The price for 8,400 Btu/lb. at Powder River Basin decreased from $0.58/MMBtu in 2019 to $0.49/MMBtu (down 16 percent) in 2020, and the 2020 price for 8,800 Btu/lb. was $0.61/MMBtu down roughly ten cents from the 2018 and 2019 averages. The dip in coal prices in 2020 can likely be attributed to a reduction in demand.

Controlling for changes in fuel prices helps to identify the underlying changes in electricity prices from other factors.[101] Figure 4–5 below adjusts the marginal energy cost for changes in fuel costs.[102]

Figure 4–5 Fuel-adjusted marginal energy cost



[100] Platt's coal prices are exclusive of transport costs. Transportation costs can have a significant impact on a coal resource's short-run marginal costs, and may often exceed commodity costs
[101] In addition to fuel, other variables also affect real-time prices. These variables include seasonal load levels, transmission congestion, outages, scarcity pricing, and wind-powered generation.
[102] 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, or heat rate (efficiency) improvements. It is based on the marginal fuel in each real-time five-minute interval, when indexed to the three-year average of the price of the marginal fuel during the interval. If multiple fuels were marginal in an interval, weighted average marginal energy costs are based on the dispatched energy of different fuel types.

As the figure shows, fuel-adjusted marginal energy costs were higher in 2020 compared to nominal marginal energy costs[103] both annually and the first six months of the year. There were steep declines in both fuel-adjusted marginal energy cost and nominal marginal energy cost when compared to 2019 outcomes, with the respective annual declines being 17.5 percent and 16 percent. The largest differences between nominal and fuel-adjusted prices occurred in March, where the fuel-adjusted energy cost was roughly $5/MWh higher than the real-time energy cost.

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 pattern has declined over the last two years, with just $0.23/MWh of average price separation in 2020. 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. In May 2018, a major upgrade was completed in the upper-central region of Oklahoma which relieved a large component of the north to south congestion flows.

Figure 4–6 shows the average day-ahead prices and Figure 4–7 shows the average real-time prices at the two SPP market hubs.

[103] Nominal marginal energy costs represent the non-fuel adjusted marginal energy costs.

Figure 4–6 Hub prices, day-ahead

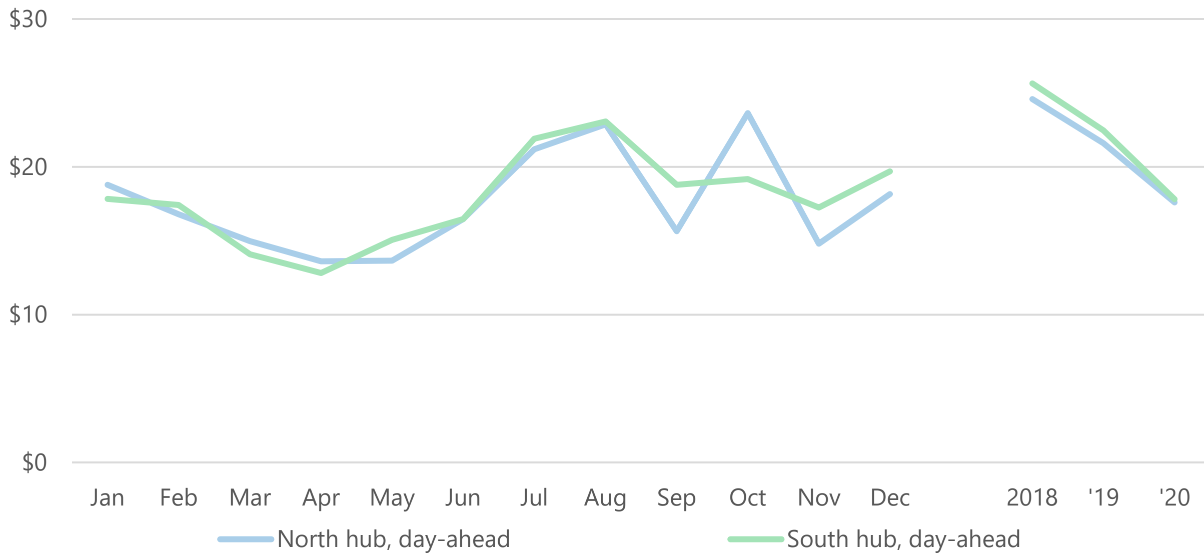
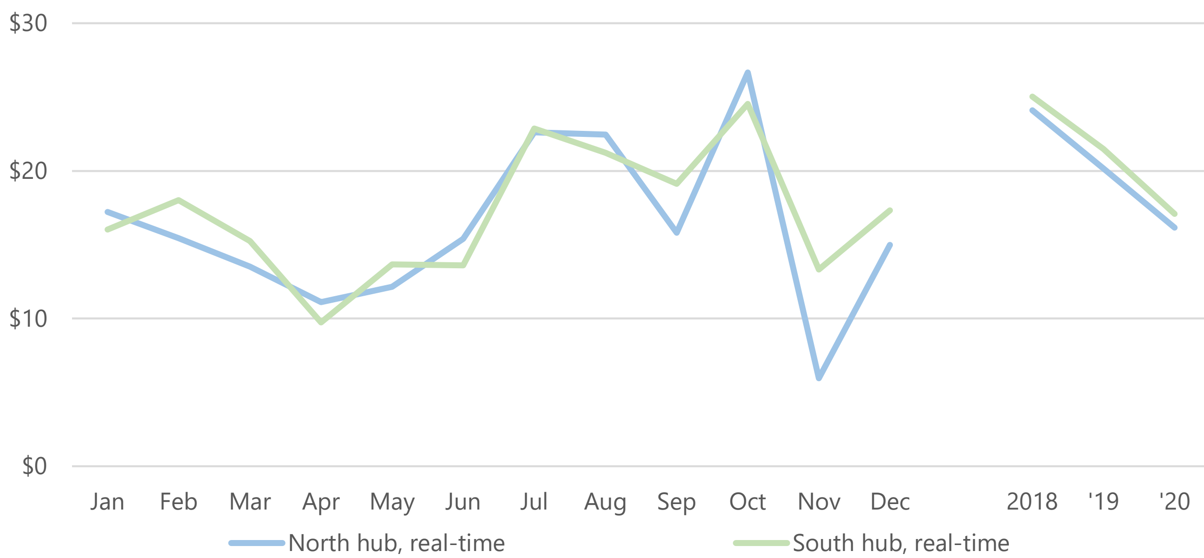


Figure 4–7 Hub prices, real-time



The North hub prices averaged around $16/MWh, and South hub prices averaged around $17/MWh for 2020. Historically, the South hub price had been on average about $5/MWh higher than the North hub price. As stated earlier, this reduction in price spread can be attributed to reductions in marginal cost of congestion, which was primarily a result of the addition of the second circuit of the Woodward to Mathewson 345kV line in mid-2018.

Starting in July 2017, months started to appear where the North hub real-time average price exceeded the South hub real-time average price. In 2020, the North hub exceeded the South hub in the months of January, March, April, June, August, and October in both the day-ahead and real-time markets. This is two more months than 2019.

It is important to understand how SPP's day-ahead prices compare to prices in other regions. Average on-peak, day-ahead prices for the SPP hubs, as well as other RTO hubs in the region are shown in Figure 4–8.

Figure 4–8 Comparison of RTO/ISO average on-peak, day-ahead prices

	2018	2019	2020
SPP North hub	$30	$27	$22
SPP South hub	$30	$28	$23
ERCOT North hub	$42	$56	$27
ERCOT West hub	$39	$55	$25
MISO Arkansas hub	$34	$27	$23
MISO Louisiana hub	$44	$31	$24
MISO Minnesota hub	$32	$26	$21
MISO Texas hub	$36	$31	$27
PJM Western hub	$42	$31	$25

Average on-peak day-ahead prices dropped at both the North and South hubs of SPP. In fact, all of the other RTOs' day-ahead average hub prices at the SPP seams decreased in 2020. The average on-peak day-ahead SPP South and North hub prices were less than a dollar different on average. The transmission expansion completed in mid-2018 appears to be still relieving the congestion previously seen between the North and South regions. The price decreases in each region is likely a combination of multiple factors including decreased demand seen from the 2020 pandemic, low natural gas prices relative to prior years, and increased penetration of renewable generation.

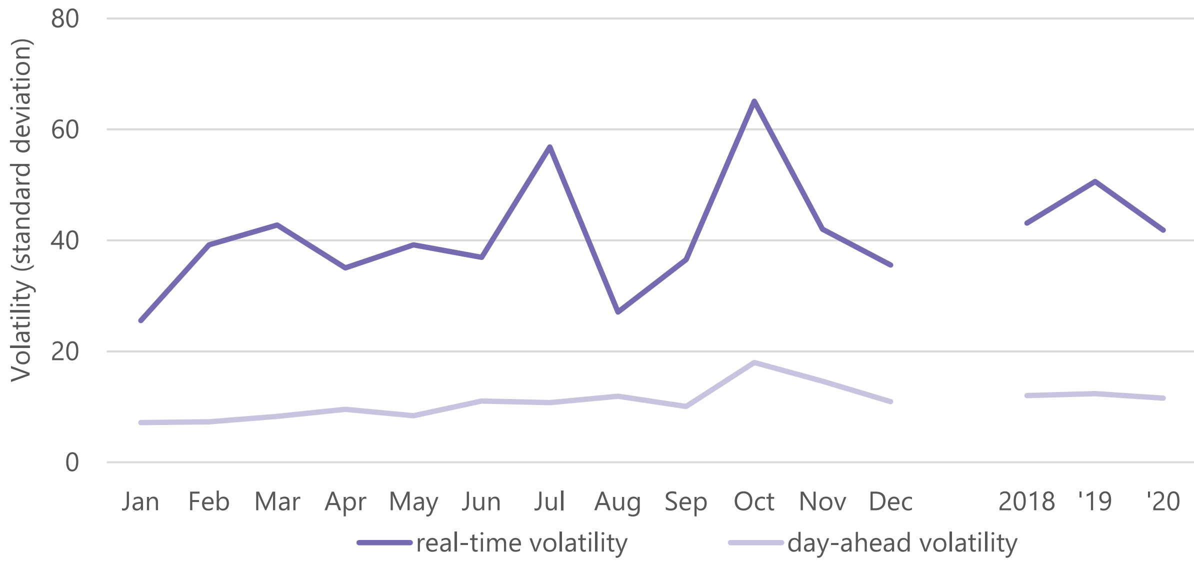
4.1.2 ENERGY PRICE VOLATILITY

Price volatility[104] in the SPP market is shown in Figure 4–9 below. As expected, day-ahead prices are much less volatile than those in real-time. The day-ahead market does not experience the

[104] Volatility is calculated as the standard deviation for prices received by 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.

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 because of peak load conditions.

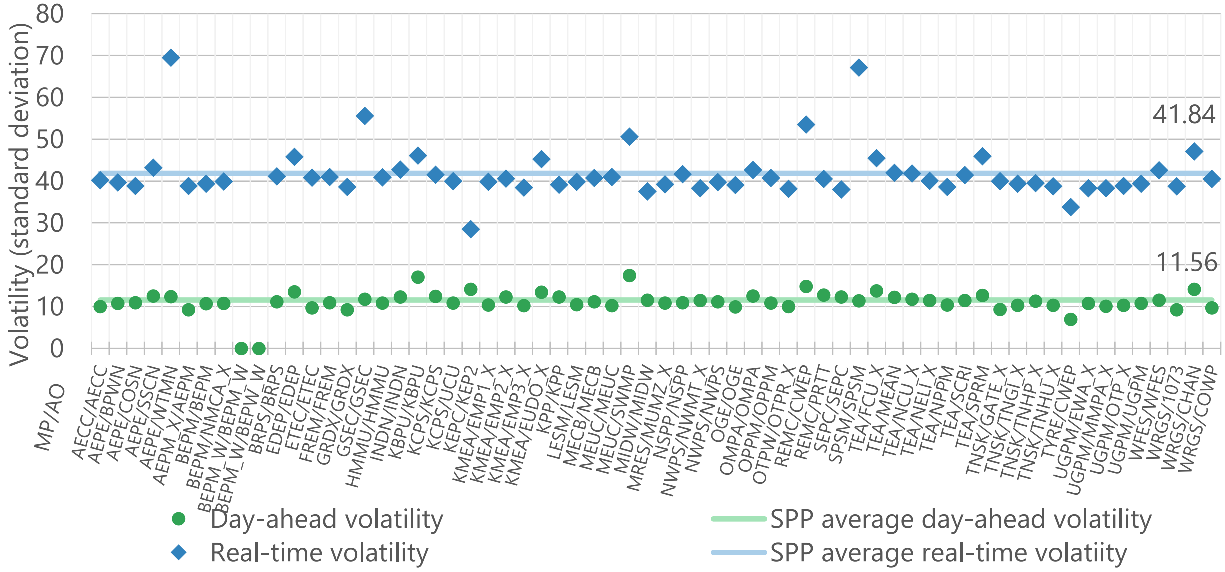
Figure 4–9 System price volatility



Volatility in the 2020 day-ahead market has decreased six percent from 2019, while the 2020 real-time volatility decreased 17 percent from 2019, putting it in line with 2018's average.

Price volatility varies across the SPP market footprint for asset owners primarily because of varying levels of 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. The volatility for the majority of asset owners is consistent with the SPP average in both the day-ahead and real-time markets as shown in Figure 4–10.

Figure 4–10 Price volatility by asset owner

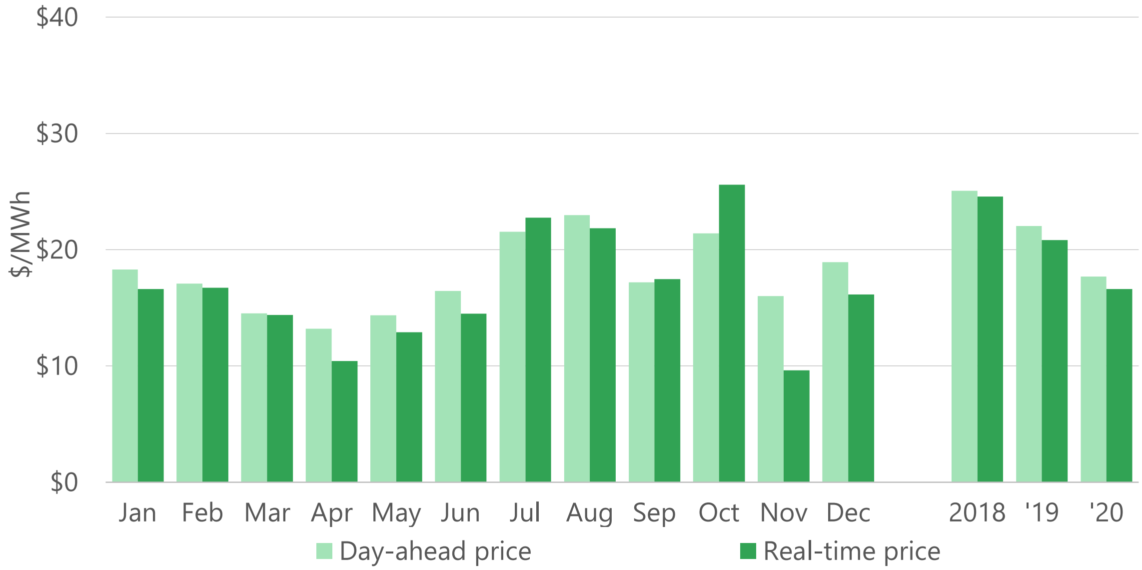


While overall price volatility was down in the SPP market, we saw increased volatility in certain geographic areas. Areas in the Texas panhandle, west Texas and eastern New Mexico all had high price volatility. This volatility was present in prior years, but saw a significant increase in 2020. The southwest Missouri/southeast Kansas area also had a high levels of volatility in 2020. This area was impacted by external flows and congestion during the year, mostly on the Neosho-Riverton constraint, a market-to-market flowgate, which is discussed in more detail in Section 5.1.4.1.

4.1.3 DAY-AHEAD AND REAL-TIME PRICE CONVERGENCE

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. Figure 4–11 shows day-ahead and real-time prices monthly for 2020 and annually for the past three years.

Figure 4–11 Day-ahead and real-time prices



While average prices in the day-ahead and real-time markets have been close over the past several years, average prices can mask real-time volatility and underlying price differences. The averaging of price spikes, and in particular, high prices during periods of scarcity, drove real-time average prices up, closer to day-ahead prices. These short-term, transient price spikes can be attributed to limitations in ramping capability.[105]

In this section, underlying differences in prices after controlling for scarcity events are highlighted. This analysis shows that a significant volume of generation, particularly from wind resources, not cleared in the day-ahead market, drives down real-time prices.

Many factors cause prices to diverge between the day-ahead and real-time markets. Some of these factors may include, but are not limited to:

- Day-ahead offers may include premiums to account for uncertainty in real-time fuel prices.[106]
- Load and wind forecast errors can cause differences in the real-time market results.

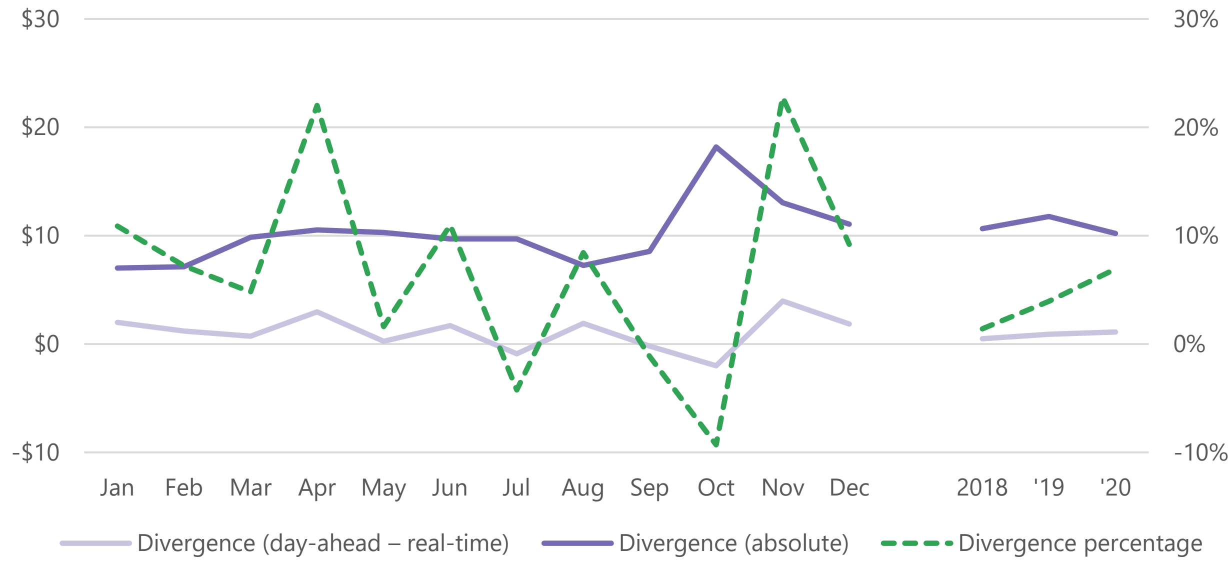
[105] For further information on ramping issues, see Section 3.2.1.
[106] Additionally, Revision Request 239 allowed historic fuel cost uncertainty to be considered in the development of mitigated energy offers.

- Participants may not bid in all load or offer all 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.
- Changes in imports and exports from other systems in the real-time markets.
- Unanticipated weather changes affect the real-time markets.

Price divergence[107] between the day-ahead and real-time markets at the system level is shown in Figure 4–12 below. Market participants may be willing to pay a premium for more price certainty in in day-ahead market. This can result in higher prices in the day-ahead market. A large divergence between day-ahead and real-time prices may also indicate that actual conditions in the market do not match expected conditions. An extended period of a large variance between day-ahead and real-time prices may indicate a structural or design deficiency in the market.

[107] Price divergence is calculated as the difference between day-ahead and real-time prices, using system prices for each five-minute (real-time) or hour (day-ahead) interval. The absolute divergence is calculated by taking the absolute value of the divergence for each interval.

Figure 4–12 Price divergence



The absolute price divergence has decreased by 15 percent from 2019 to $10.20/MWh in 2020. Analysis by the MMU and RTO has found that under-clearing of renewable resources and short-term ramping limitations are primary drivers of this divergence. SPP intends to implement a ramping product in early 2022, which should help address improve price convergence. Moreover, the MMU recommends that additional work be done to improve price divergence related to under-clearing of renewable generation in the day-ahead market.

Figure 4–13, below, shows the marginal energy costs for both the day-ahead and real-time markets during on-peak hours after controlling for scarcity events.[108] Figure 4–14 shows the same information, but for off-peak hours.

[108] These numbers reflect only hours where scarcity demand curves where not applied for any interval during the hour. SPP uses scarcity demand curves for intervals when ramp or capacity requirements cannot be met through dispatch. Scarcity demand curves are discussed in detail in Section 3.2.1.

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

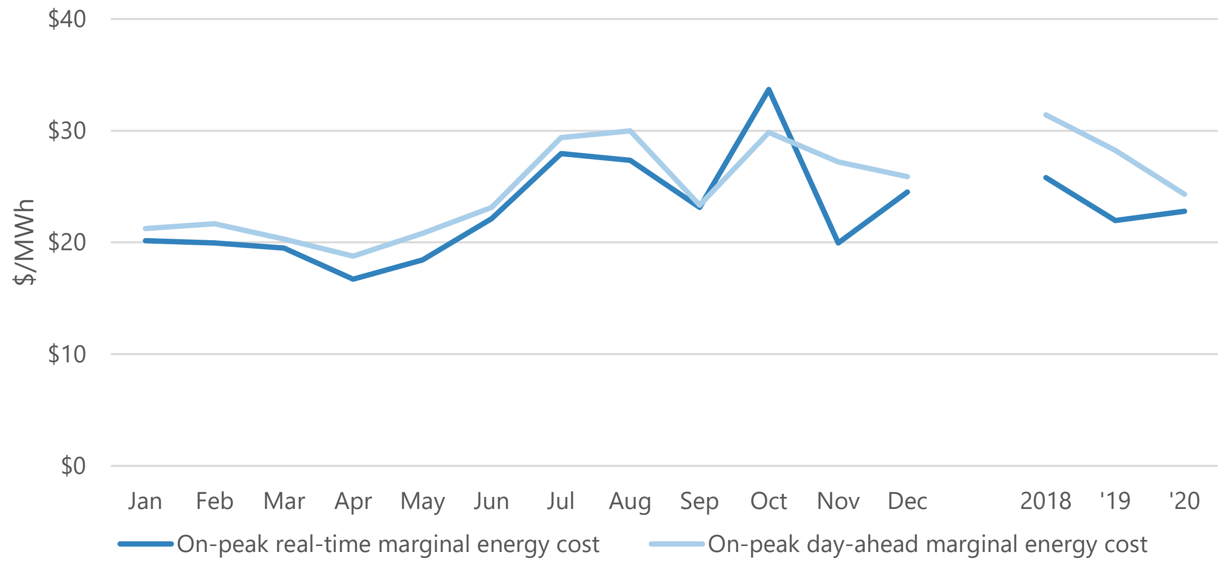
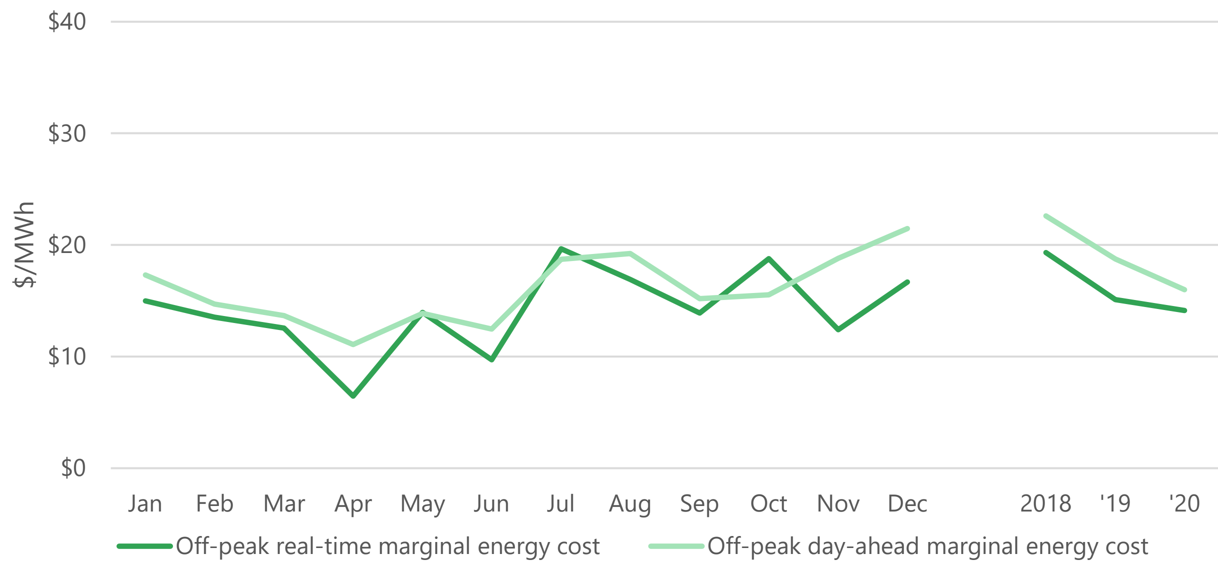


Figure 4–14 Off-peak marginal energy prices, excluding scarcity hours

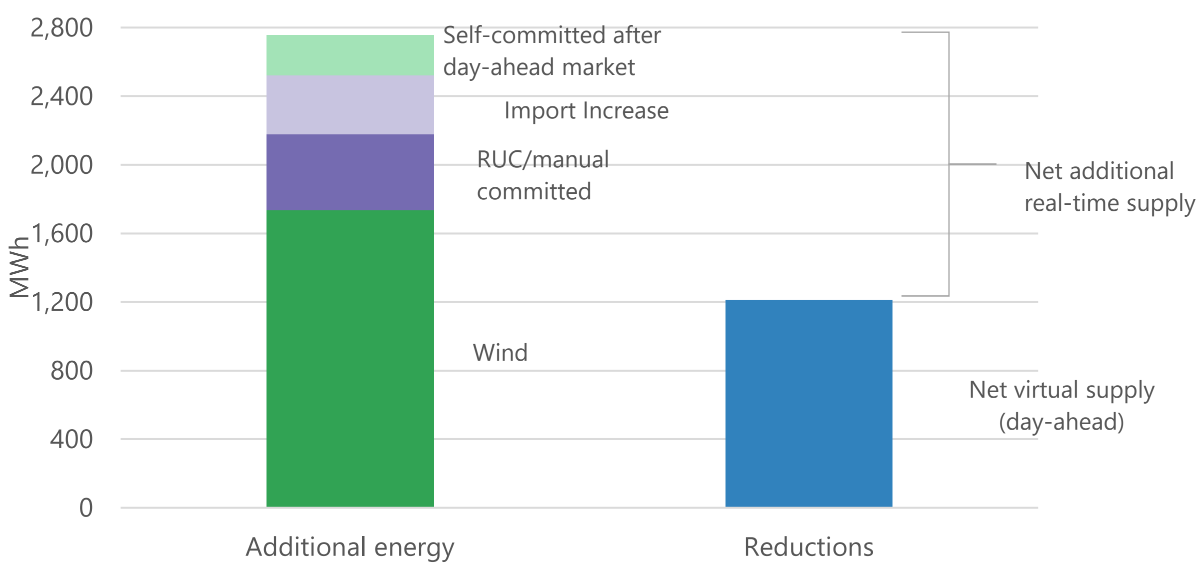


The marginal energy cost is one of three components that factor into locational marginal prices and represents the marginal cost to provide the next increment of dispatch absent losses and congestion. Day-ahead prices are generally at a premium when compared to real-time prices (excluding scarcity pricing), particularly in the off-peak hours. In 2020, day-ahead marginal energy costs for all non-scarce hours, were just over 29 percent higher than real-time prices. This is higher than the 26 percent price divergence in 2019 and the 19 percent in 2018.

The main contributors influencing the price differences between markets are offered megawatts versus cleared megawatts of wind resources in the day-ahead market, reliability unit commitments needed in real-time not seen in the day-ahead market, and increased imports after the day-ahead market. In fact, only 81 percent of the wind generation was cleared in the 2020 day-ahead market, down three percent from 2019, and down four percent from 2018. This changes the supply curve in real-time by shifting it outward and causes real-time prices to drop relative to the day-ahead market. Furthermore, the market appropriately honors the minimum submitted limits of all committed resources. With the unanticipated generation, many non-wind units are dispatched down by the market to their minimum 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.[109]

Figure 4–15 shows average hourly incremental differences in megawatts produced between the real-time and day-ahead market in 2020.

Figure 4–15 Average hourly real-time generation incremental to day-ahead market



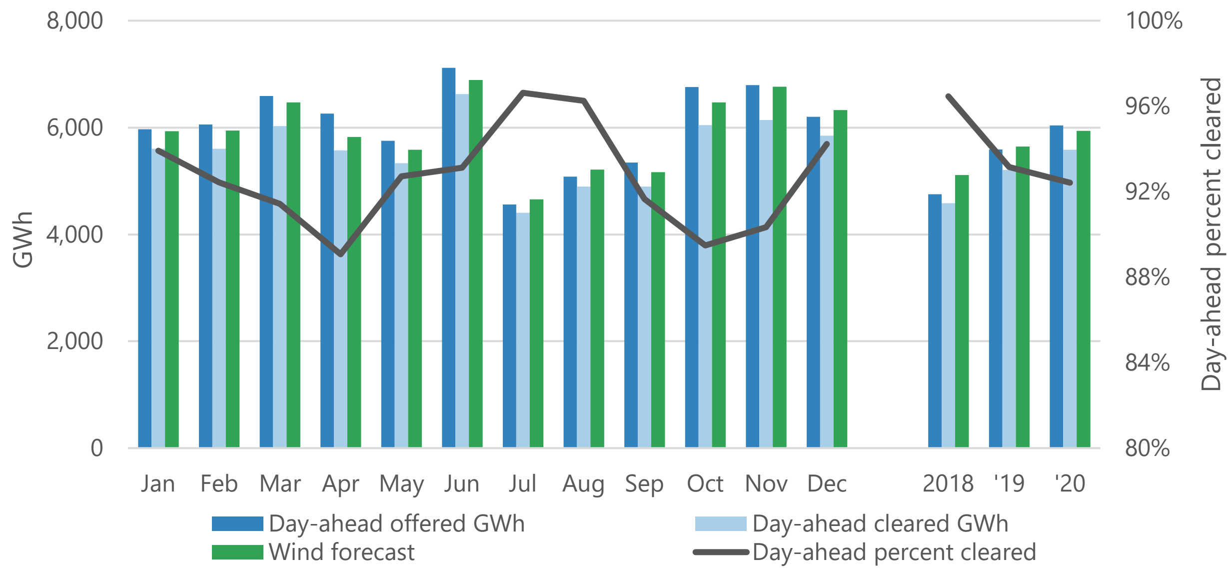
Wind generation had 63 percent of the 2,757 MW of incremental real-time generation in 2020, with an hourly average of 1,734 MW of additional generation in real-time. Self-committed generation accounted for an additional 236 MW and reliability unit committed or manually committed generation averaged about 446 MW. While SPP is a net exporter in both the day-

[109] Negative prices are discussed in detail in Section 4.1.4.

ahead and real-time markets on average, it sees an average hourly increase of 342 MW in real-time market net imports compared to the day-ahead. This results in additional capacity committed in day-ahead not needed in real-time. Averaging 1,214 MW an hour, net virtual positions helped to offset the additional generation, but only accounted for about 44 percent of the difference for the year. This is up significantly from the 660 MW (28 percent) in 2019 and 490 MW (27 percent) in 2018. Netting out the changes in virtual transactions, there was just under 1,550 MW of additional net supply in real-time in 2020.

Figure 4–16 shows the difference between the day-ahead offered wind generation and the day-ahead cleared wind generation. The wind forecast figure is derived from the mid-term wind forecast, which is created one day prior to the operating day.

Figure 4–16 Day-ahead wind offered versus cleared



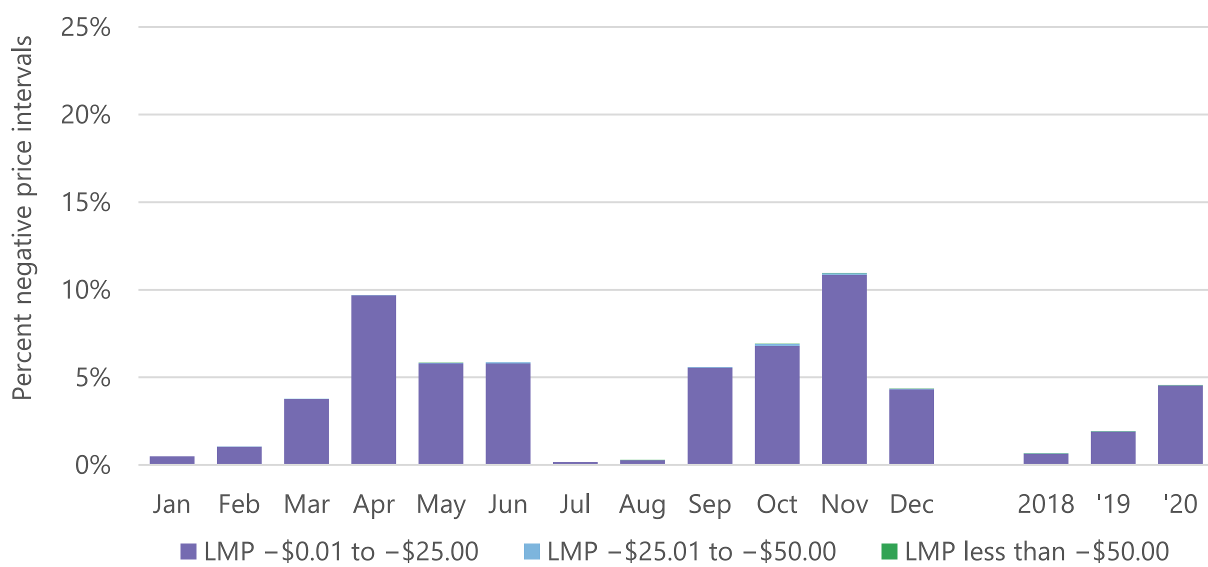
In 2020, 92 percent of the wind offered in the day-ahead, cleared. This is down from the 93 percent in 2019 and the 96 percent in 2018. Starting in 2019 the percentage of wind offered in the day-ahead began increasing. In 2018, 93 percent of forecasted wind was offered into the day-ahead, increasing to 99 percent in 2019 and 102 percent in 2020. However, even though wind resources are generally offering in full forecasted capacity to the day-ahead, they are not in general economically offering in the total capacity. Typically, wind will clear all of the megawatts that are physically offered into the day-ahead market, if the economic offers are consistent with the real-time offers. The MMU observed that almost all wind megawatts offered into the day-ahead market and not cleared had higher economic offers in the day-ahead market than real-time. In fact, the percentage of wind offered in the day-ahead and clears has been decreasing.

Systematic under-scheduling of wind resources in the day-ahead market can contribute to distorted price signals, suppressing real-time prices and affecting revenue adequacy for all resources. Variable energy resources are generally able to produce close to a forecasted amount. Therefore, the MMU continues to recommend that SPP and its stakeholders address this issue through market incentives and rule changes that focus on market inefficiencies associated with under-scheduling of variable energy resources in the day-ahead market based on forecasted supply. These rule changes could focus on changing incentives for wind resources, or alternatively encouraging virtual transactions.

4.1.4 NEGATIVE PRICES

With the prolific growth of wind generation in the SPP market, the incidence of intervals with negative prices continues to be a growing concern. The frequency of negative price intervals increased over the last three years, as shown in Figure 4–17. This increase was primarily due to an increase of negatively priced wind-generation supplying a relatively stable demand for energy in 2018 and 2019, with decreasing demand and increasing wind output in 2020.

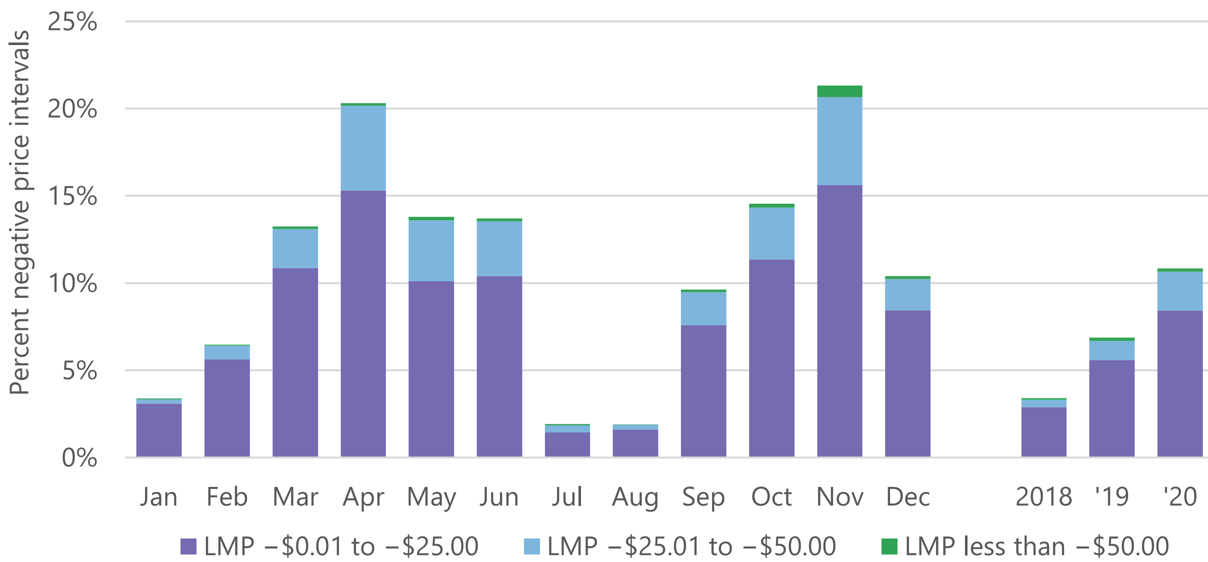
Figure 4–17 Negative price intervals, day-ahead, monthly



In 2020, just over four and half percent of all asset owner intervals[110] in the day-ahead market had prices below zero, as shown in Figure 4–18. This is up from the two percent of all intervals in 2019 and the one percent in 2018.

While the same pattern holds in the real-time market (see Figure 4–18), negative price intervals in the real-time market occurred almost two and a half times more frequently than in the day-ahead market. November had the highest percentage of negative intervals in the day-ahead market, at just under 11 percent

Figure 4–18 Negative price intervals, real-time, monthly

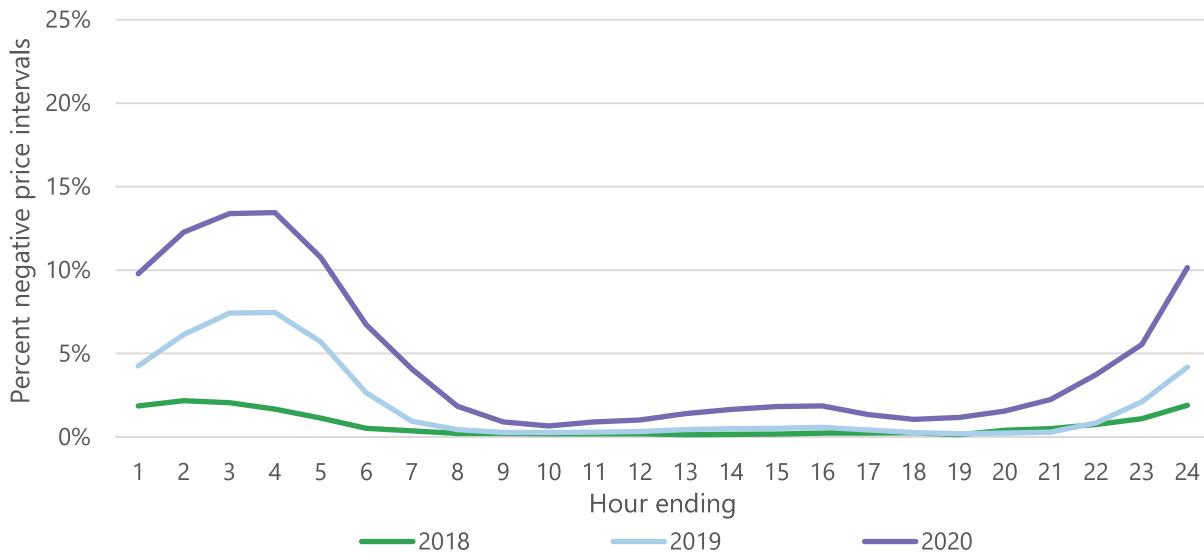


The frequency of negative price intervals in the real-time market was just under eleven percent of 2020 intervals, up from just under seven percent in 2019. Negative prices in the day-ahead market were almost exclusively between −$0.01/MWh and −$25/MWh, with only 0.03 percent of intervals with negative prices having prices lower than −$25/MW. However, in the real-time market just over two percent of intervals with negative prices had prices lower than −$25/MWh.

[110] 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).

Additionally, occurrences of negative prices in the day-ahead market are most prevalent in the overnight, low-load hours as shown in Figure 4–19.

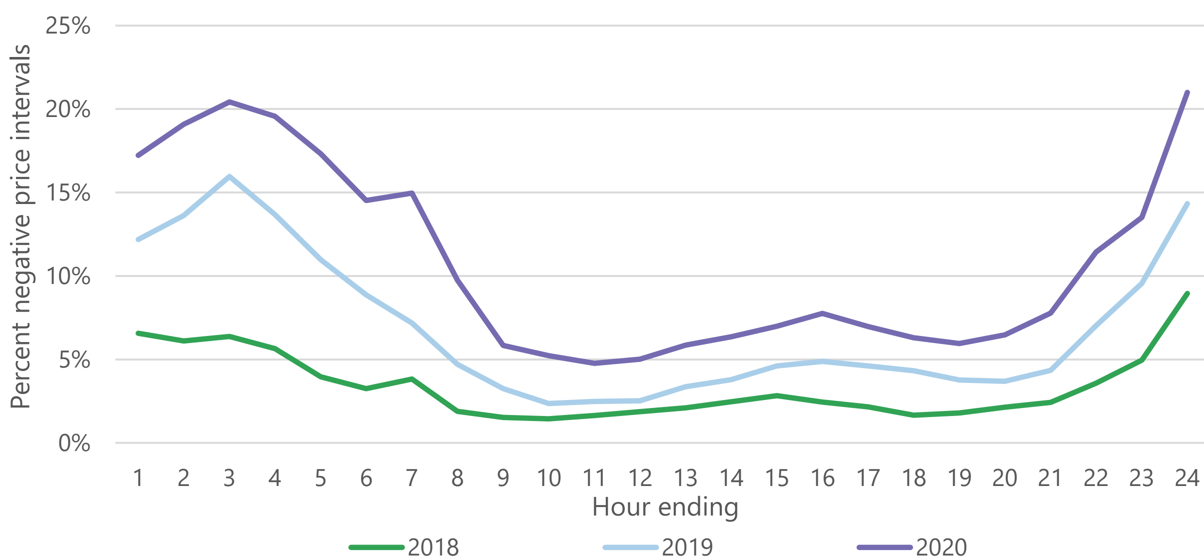
Figure 4–19 Negative price intervals, day-ahead, by hour



This figure shows that the day-ahead negative price intervals in 2020 during overnight hours are higher than the 2019 and 2018 numbers. A majority of this increase can be attributed to lower demand in 2020 combined with increased wind generation.

Negative price intervals in the real-time market (see Figure 4–20) follow the same pattern as the day-ahead market with most negative price intervals occurring in the overnight, low-load hours.

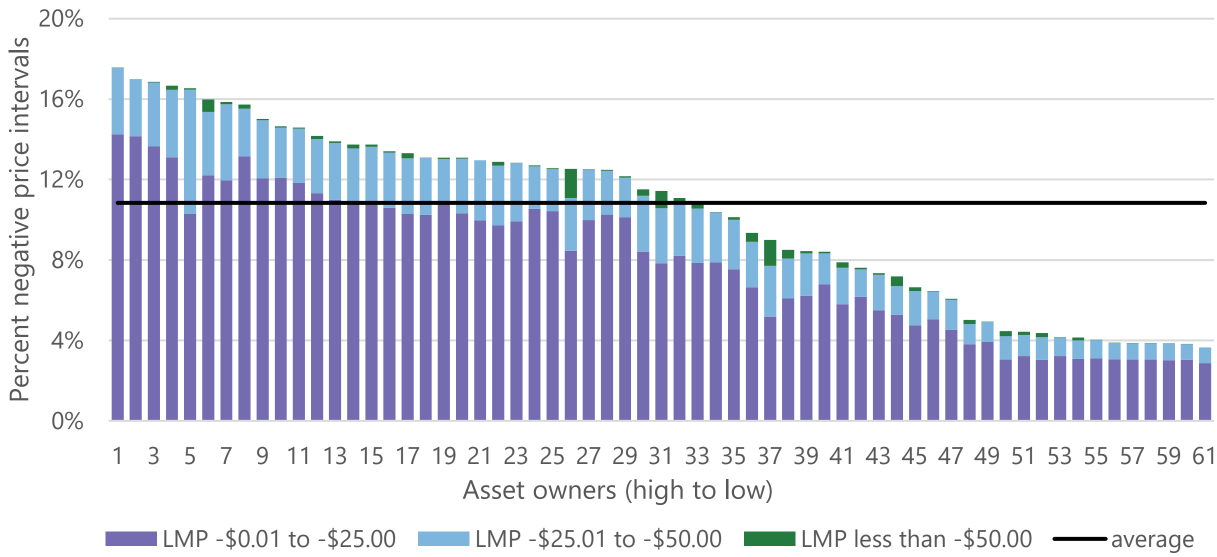
Figure 4–20 Negative price intervals, real time, by hour



These negative price intervals in the real-time market occur much more frequently than the day-ahead market, with a 2020 peak of 21 percent of intervals in real-time in the third hour of the day, compared to a peak of just over 13 percent in day-ahead. During 2020, the first five hours and last hour of the day experienced negative prices over 15 percent of the time. However, 2019 had only one hour of negative prices over 15 percent of the time, and 2018 had no intervals with negative prices over 10 percent of the time. In 2020, the real-time market had an average of about seven percent of intervals with negative prices during on-peak hours. This is up from the four percent seen in 2019.

At the asset owner level (for those serving load), the distribution of negative price intervals during 2020 clustered around the footprint average, as shown in Figure 4–21.

Figure 4–21 Negative price intervals, real-time, by asset owner



In 2020, 21 asset owners experienced negative prices in more than 10 percent of intervals. This is a substantial increase from 2019, where only seven asset owner experienced negative prices in excess of 10 percent of intervals and vastly more than 2018 that only had one asset-owner above this level. Eighty percent of the market participants received negative prices for five percent or more of the intervals in 2020. This is in stark contrast to 2018 where only ten percent experienced negative prices more than five percent of all intervals, but only five percent higher than the 75 percent in 2019.

The MMU remains concerned about 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 of resources and manual commitments for capacity. 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 committed generation. Moreover, unit commitment differences, due to under-clearing of wind resources in the day-ahead market and then producing more in 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.

In some cases the energy price at a resource location is -$500/MWh because a resource offered and cleared at -$500/MWh, the offer floor. Based on these extremely low prices, the Holistic Integrated Tariff Team (HITT) recommended that SPP "evaluate whether generation offer requirements, including those for renewable resources, provide adequate safeguards against uneconomic production."[111] The MMU researched the issue and published a whitepaper.[112] The MMU determined that the reasons for such low offers were (1) power purchase agreements (PPAs) contract limitations and (2) avoiding real-time buy back by following the day-ahead position. The purpose of these offers is to avoid being dispatched down. These unduly low offers are problematic because they do not represent any specific costs and therefore do not properly inform the market. To inform the market properly, prices should be based on actual costs.

These extremely low offers affect both the market participants who submit them and other nearby resources. Market participants submit extremely low offers so that their resources can be at the bottom of the supply stack. This makes their resources much less likely to be dispatched down but causes them to lose significant revenue when setting price. These low

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[111] *Holistic Integrated Tariff Team Report*, page 25, published by HITT, (July 23, 2019), (https://www.spp.org/Documents/60372/HITT%20Report%2020190730.pdf), ("HITT Report").

[112] *Study of Unduly Low Offers*, published by Southwest Power Pool Market Monitoring Unit, (November 10, 2020), (https://www.spp.org/Documents/60372/HITT%20Report%2020190730.pdf), ("HITT Report").

prices also affect other nearby resources that are undispatchable because they are running at their minimums or are starting up or shutting down.

The MMU recommends that the energy offer floor be raised to -$100/MWh. SPP's existing offer of -$500/MWh is on the low end compared to other ISO/RTOs. The raised offer floor will not significantly affect those offering unduly low and will improve price formation.

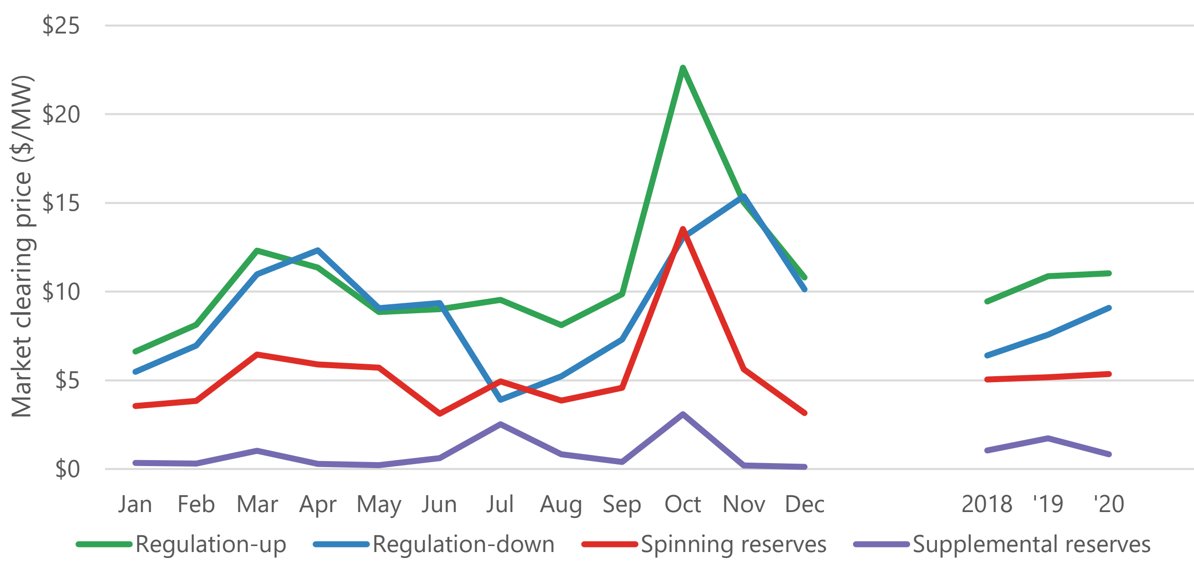
As more wind generation is anticipated to be added over the next several years, the frequency of negative prices has the potential to increase. Negative price intervals in the day-ahead highlight the need for changes in market rules to address self-committing of resources in the day-ahead market and addressing differences in supply between day-ahead and real time. These issues are discussed further in Chapter 8.

4.1.5 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 4–22.

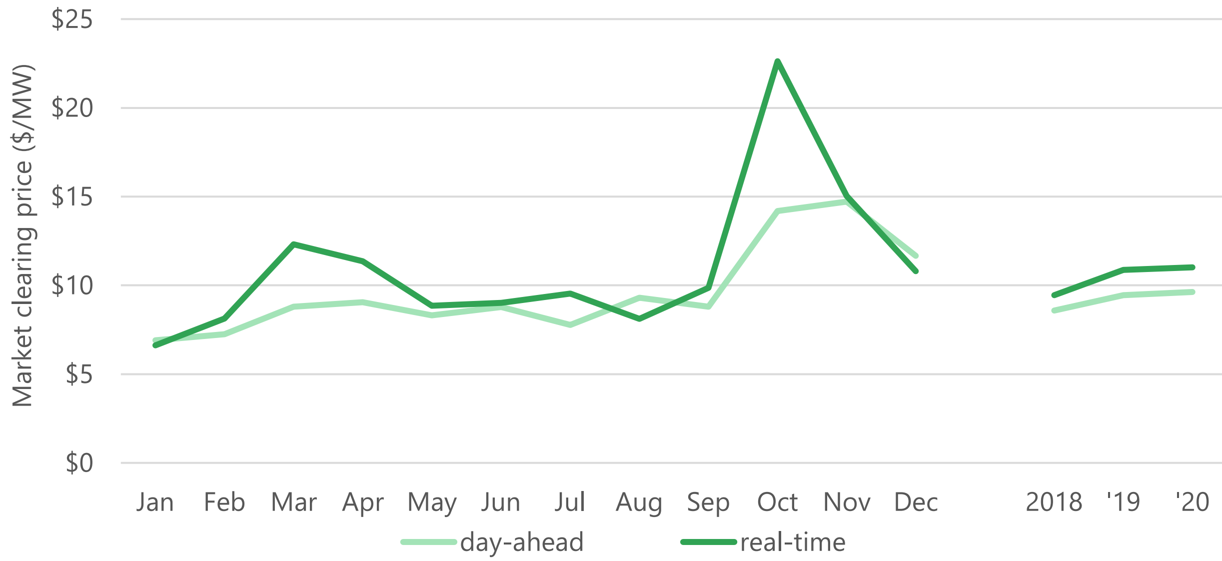
Figure 4–22 Operating reserve product prices, real-time



Generally speaking, regulation-up and regulation-down usually 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 on an annual basis.

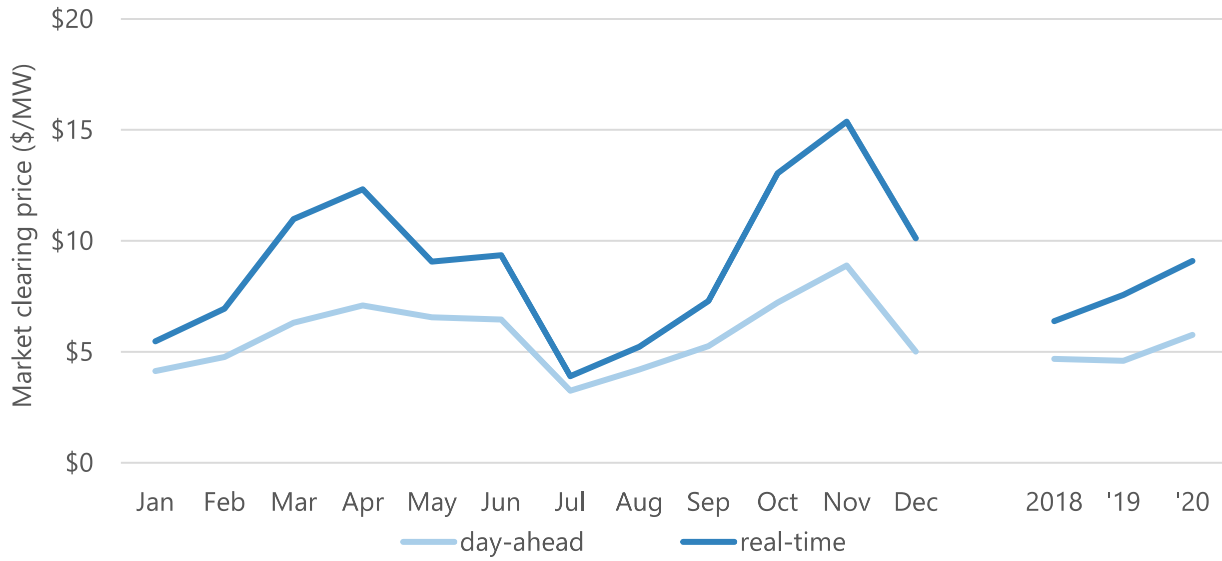
Day-ahead and real-time price patterns vary across the operating reserve products, see Figure 4–23 through Figure 4–26.

Figure 4–23 Regulation-up service prices



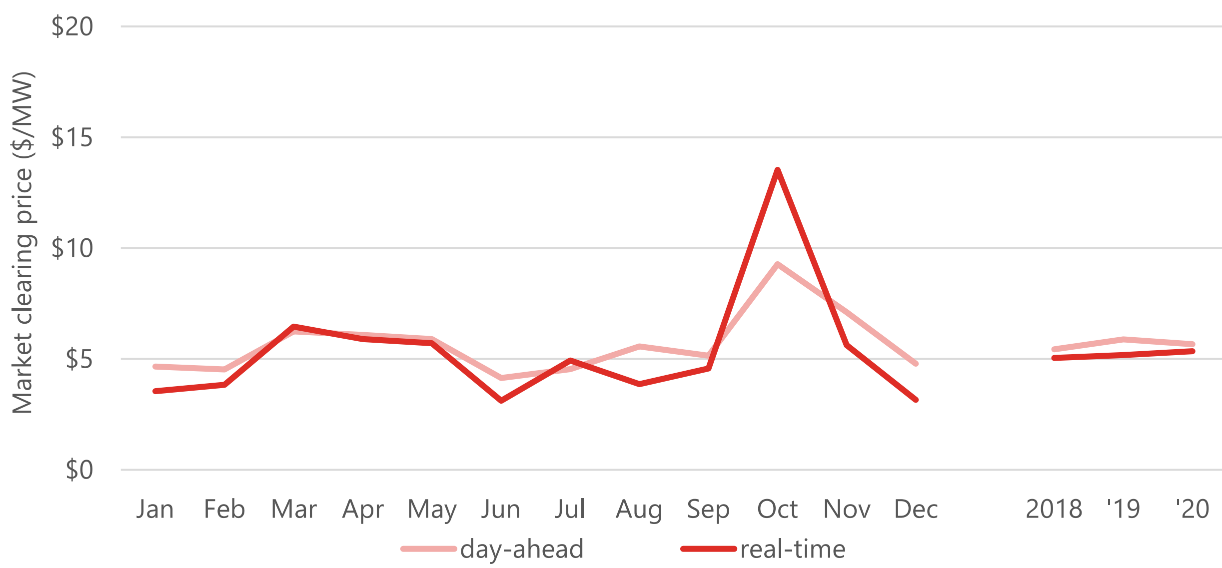
From 2019 to 2020, the average real-time market clearing price for regulation-up stayed relatively the same at around $11/MW. Average day-ahead regulation-up market clearing price increased eighteen cents from 2019 to 2020, with the average day-ahead regulation-up 2020 price at $9.63/MW. Monthly prices for regulation-up were highest in the peak wind months during the spring and especially in the fall. The high prices during these periods can mostly be attributed to higher wind penetration levels during these periods. This was especially true in October 2020.

Figure 4–24 Regulation-down service prices



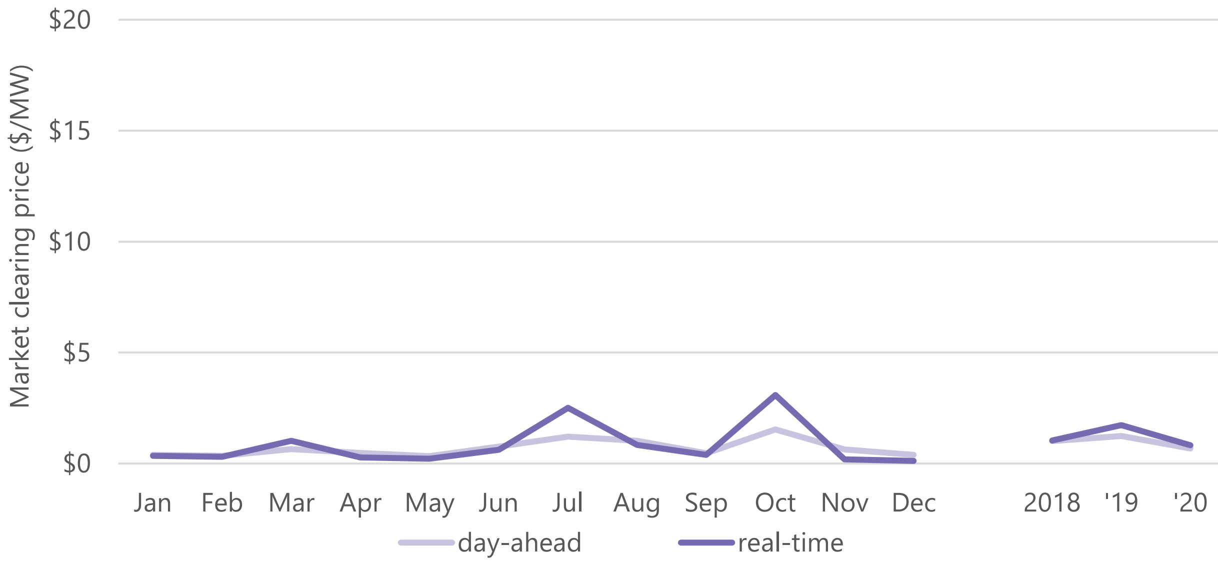
Regulation-down market clearing price in the real-time market averaged about $9.09/MW in 2020, up from the 2019 average price of $7.57 and the average in 2018 at nearly $6.90/MW. Day-ahead regulation-down market clearing prices averaged $5.76/MW for the year. This is up from the 2019 average of $4.60/MW.

Figure 4–25 Spinning reserve prices



The market clearing price for real-time spinning reserves averaged $5.35/MW in 2020, an increase of $0.17 from 2019. October experienced the highest monthly market clearing price in 2020 for real-time spinning reserves at $13.53/MW. This can mostly be attributed to the higher volume of operating reserve scarcity events in that month. Day-ahead spinning reserves had a slightly higher annual average than real-time at almost $5.66/MW.

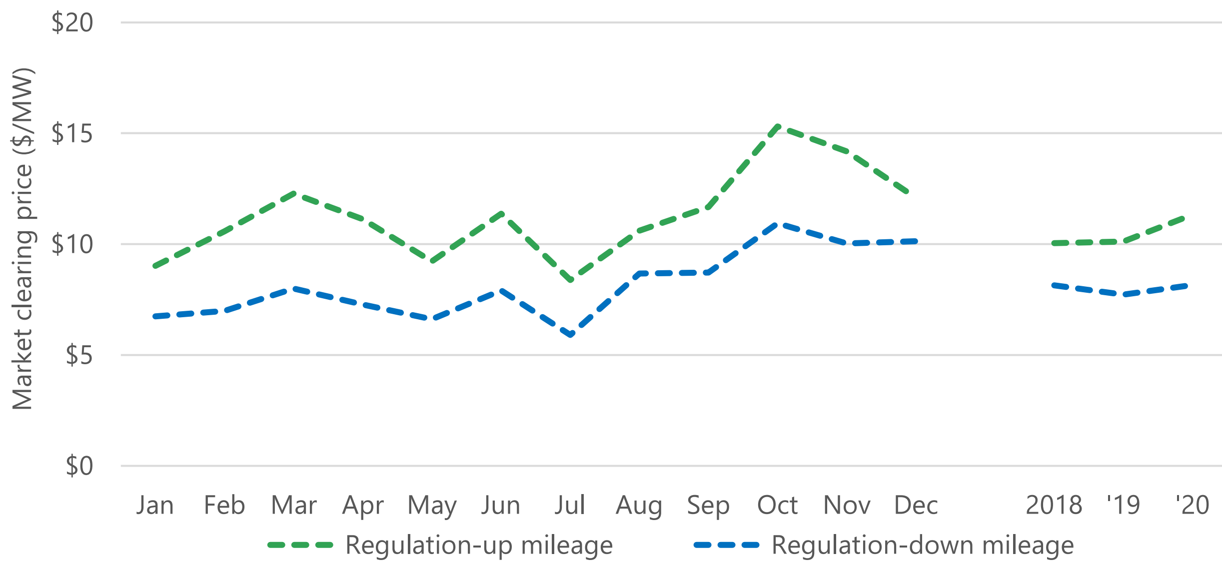
Figure 4–26 Supplemental reserve prices



Supplemental reserve market clearing prices remained low in both markets, with prices averaging about $0.83/MW, down from the $1.73/MW average in 2019. This price does not indicate a large need for generators to be standing by. On the other hand, there have been several concerns raised by SPP operations staff regarding wind uncertainty and outages. Wind uncertainty is better addressed through the proposed ramp product and the uncertainty product. Increased outages and outage duration may point to issues with price formation as discussed in Section 8.2. October had the highest average real-time market clearing price for supplemental reserves at just over $3/MW.

Regulating units are compensated 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 4–27. 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 price. If the unit is deployed less, it must buy back its position at the real-time mileage clearing price.

Figure 4–27 Regulation mileage prices, real-time



On an annual basis, average monthly regulation-up mileage prices for 2020 was roughly $11.30/MW, up $1.21/MW from the $10.11/MW in 2019, and up $1.27/MW from the $10.05/MW in 2018. Average monthly regulation-down mileage prices in 2020 were roughly $8.17/MW, up from the $7.72/MW average in 2019 and $8.14/MW in 2018.

The MMU analyzed regulation mileage prices in 2017 and found a design inefficiency. This design inefficiency was still present in 2020. The issues occur because mileage prices are not set by the marginal resource's cost like other products. Instead, resources are cleared for regulation based on their service offers. These service offers are derived by taking the competitive offer for regulation and adding the mileage offer to it after discounting the mileage offer by the applicable mileage factor. For instance, the service offer of a resource with a competitive regulation-down offer of $1 and a regulation-down mileage offer of $36 would be $10 if the mileage factor is 25 percent.[113] If the $10 service offer is economic, then the resource will clear for regulation-down and the regulation-down mileage price will be set at $36 if this is the highest mileage price that cleared in the market.

The MMU has observed instances where resources cleared with regulation-down competitive offers of $0 and mileage offers just under $50. These units consistently cleared with this offer

[113] $1 + $36 * 0.25 percent = $10

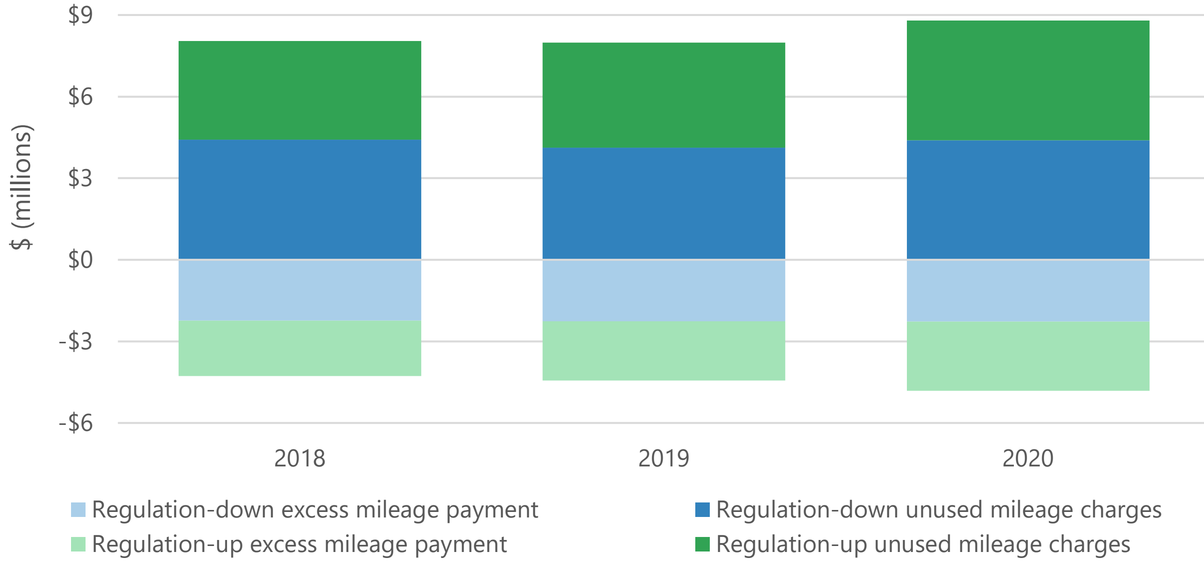
strategy because the service offer was near $10.50 (e.g. 21 percent * $50) which was lower than the services offers of other resources offering in higher competitive offers. For instance, another resource may offer in a $12 competitive offer and $0 mileage offer. This would make that resource's service offer $12 (($12 + $0) * 21 percent). In this circumstance, the resource with the highest service offer will set the regulation-down price at $12, but the mileage offer will be $50, set by the highest cleared mileage offer.

In addition, the MMU observed systematic overpayment of regulation mileage in the day-ahead market, which appears to be the result of the mileage factor being set consistently too high relative to actual mileage deployed. This occurred because the mileage factor is being set on historical instructed regulation megawatts rather than deployed regulation. When resources have to buy back their position, they typically have to buy back at the inflated mileage offer. Using the example above, if a resource clears for 10 megawatts it will receive the $12 clearing price for a total payment of $120, which was set using a $0 mileage offer. However, if it does not get deployed for regulation it will have to buy back 2.1 megawatts at the $50 mileage offer, because they performed less than expected. The unit was paid 2.1 megawatts at a $0 price for expected mileage at the clearing, but the buyback is now $105. This makes the total payment to the resource for clearing regulation $15 or $1.50 per cleared megawatt.

The instructed values for regulation are on average two and a half times what resources perform. If the mileage factor was forecasted in the exact amount of what was performed then the excess mileage payments should closely offset the unused mileage charges. However, this is not the case. The reason for the difference is that regulation is deployed on a four second basis, but it is settled on a five minute basis. Resources could be directed to move up 10 megawatts at the beginning of the interval. However, 20 seconds later they may be directed to hold off on providing that regulation. If their ramp rate is only 10 megawatts per minute, they will only have provided 3.3 megawatts of regulation. This is generally what causes the instructed values to vary from the actual values.

Figure 4–28 below illustrates the differences between the unused mileage charges and the excess payments.

Figure 4–28 Regulation mileage payments and charges



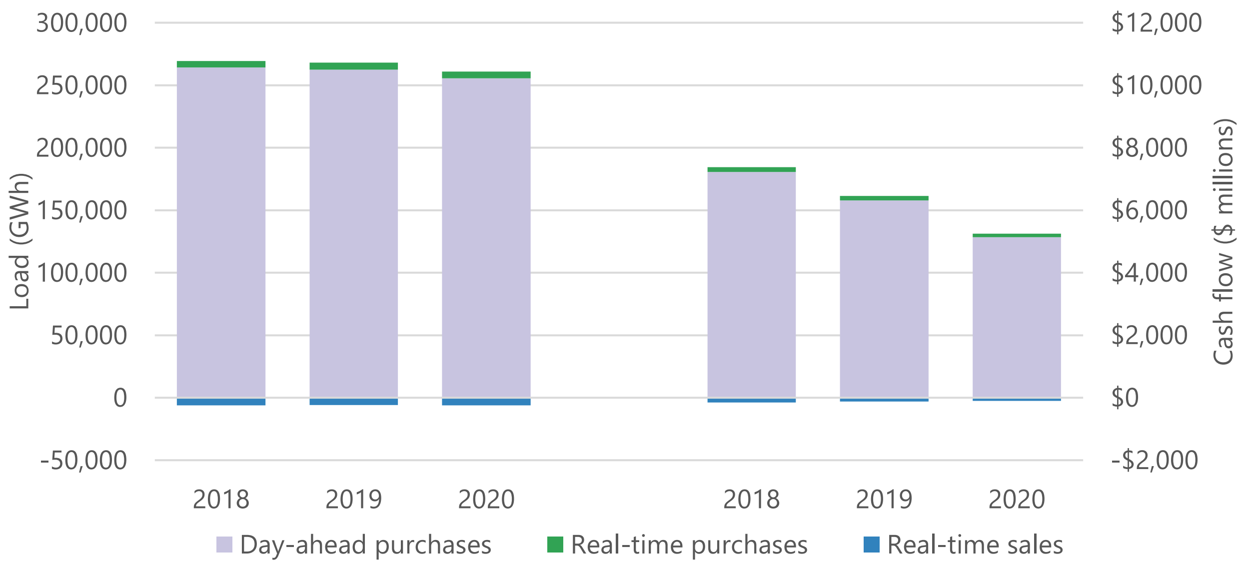
Negative values represent the payments made to resources that deployed for more regulation megawatts than were expected and positive values represent charges made to resources that deployed for less than what was expected. In 2020, roughly twice as much was charged for mileage buyback as was paid out for excess mileage deployment, with $4.8 million being paid for excess mileage and $8.8 million being charged for unused mileage. This ratio of charges to payments is consistent with all prior years. These net charges reduce the profitability of resources clearing regulation.

The MMU is concerned that participants with resources frequently deployed for regulation will have an incentive to inflate the mileage prices by offering in $0 regulation offers and high mileage offers. The MMU also has concerns that the inflated mileage factors are causing units to buy back megawatts at the inflated amounts which can ultimately lead to higher uplift costs in the market. As such, the MMU has recommended that SPP review and revise the regulation mileage pricing approach to send more appropriate price signals.

4.1.6 MARKET SETTLEMENT RESULTS

The day-ahead market accounted for 98 percent of the energy consumed in the Integrated Marketplace. This is line with 2018 and 2019. Figure 4–29 shows that approximately 256 terawatt-hours of energy were purchased in the day-ahead market at load settlement locations, of which just over six terawatt hours were in excess of the real-time consumption, requiring a sale back to the market.

Figure 4–29 Energy settlements, load

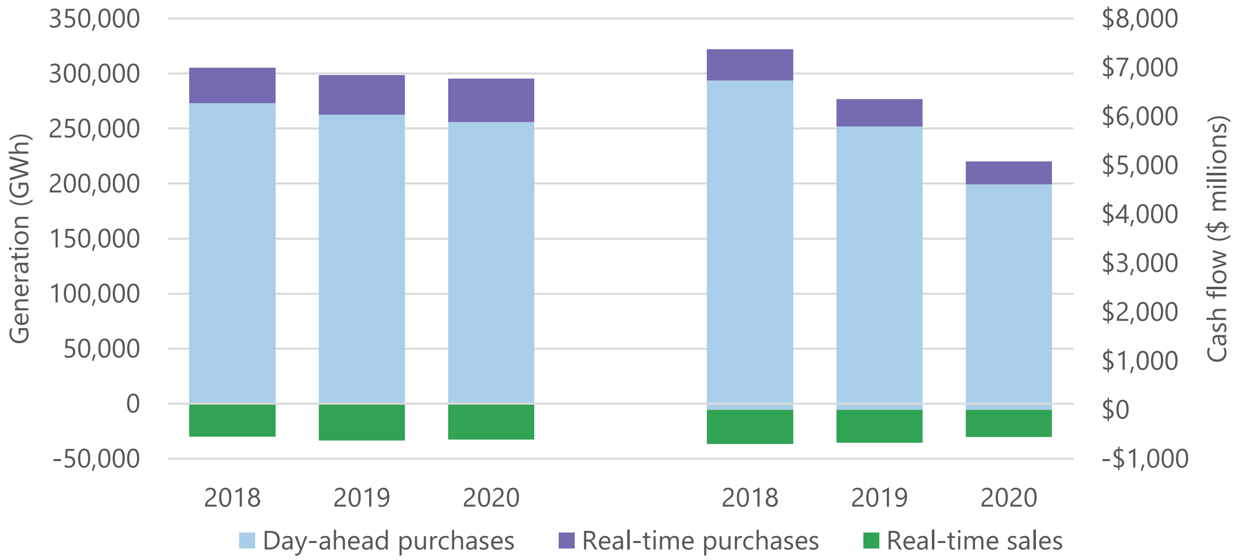


Negative gigawatt hours denote withdrawals from the grid. Negative cash flows denote charges to load-serving entities. Positive gigawatt hours represent sales of day-ahead gigawatt hours back to the real-time market and negative cash flows represent payments to load owners for those sales. As stated above, during several hours of 2020 load over purchased in the day-ahead market causing a sale back in real-time. However, there were also several hours where the load consumed in real-time was greater than the day-ahead cleared quantities.

In aggregate, just over six terawatt hours of energy was purchased in the real-time market because the real-time demand was higher than that of the day-ahead market. The close relationship of day-ahead load consumption to real-time load consumption is a sign of an efficient day-ahead market. The below charts illustrate that while generation output stayed relatively the same as 2018 and 2019, the payments for those generated megawatts were down from those prior year levels. This can be attributed to the lower day-ahead and real-time energy prices seen in Figure 4-1.

Day-ahead generation accounted for 88 percent of generation settled in the market, which is roughly one percent lower than 2018 and 2019.[114] Figure 4–30 presents the settlement of SPP generators.

Figure 4–30 Energy settlements, generation

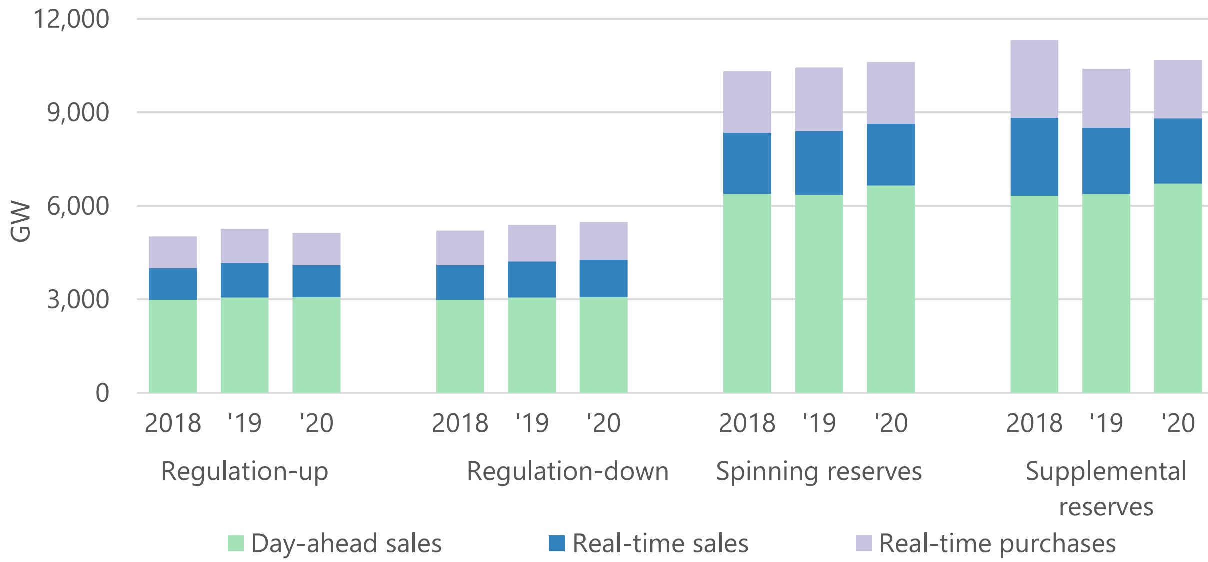


Positive gigawatt hours denote injections into the grid. Positive cash flows denote payments to generators. Negative gigawatt hours represent repurchases in the real-time market and negative cash flows represent charges to generators for those repurchases. Twelve percent of the energy cleared in the day-ahead market was settled by purchasing energy in the real-time market rather than generating the energy, which is up one percent from the prior year and up two percent from 2018.

SPP plays the role of the customer in the operating reserve market. At hour ending 6:00 AM on the day before the operating day, SPP posts the forecasted amount of each operating reserve product that is to be procured during each hour. 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, but this a rare occurrence. 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 shifts in the clearing of the operating reserve products in the real-time market. Figure 4–31 presents the settlements data for operating reserves.

[114] Previous years settlements can change slightly due to resettlement.

Figure 4–31 Operating reserve product settlements



Sales represent the cleared gigawatt hours for operating reserves in each market. Purchases represent the repurchase of day-ahead cleared operating reserves in the real-time market.

A large percentage of day-ahead sales (31 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 15 percent of the real-time energy generation in excess of day-ahead cleared generation, which is settled at real-time prices.

Sixty-six percent of the 2020 real-time regulation-up service was settled at day-ahead prices, two percent more than the previous year. The corresponding percentages for regulation-down service, spinning reserves, and supplemental reserves are 61 percent, 71 percent, and 70 percent respectively. These results were similar with the respective numbers in 2019 of 63 percent, 68 percent, and 68 percent. This essentially means that operating reserve products are being moved around to different resources, due to their day-ahead and real-time clearing, in about the same volumes as last year. This causes some resources to buy back their day-ahead cleared megawatts at real-time prices, while other resources clear those same quantities of megawatts and get paid real-time prices for their clearing.[115]

[115] When operating reserve products become scarce, they borrow from their respective scarcity demand curves. This can make the aggregate cleared megawatts for each product different between the day-ahead and real-time markets even though the requirement did not change.

The above numbers represent the aggregate repurchases of operating reserves. However, it is important to analyze the repurchase rates at the resource level. The aggregate revenue from all 351 resources that cleared operating reserves was $84.7 million in 2020. Thirteen resources had net negative cash-flows on operating reserves for a total amount of $908,000. These negative cash flows are not inclusive of any margins gained on energy cleared in real-time that caused the purchase of the day-ahead positions for operating reserves. In fact, 92 percent of those resources' negative cash flows from operating reserves products occurred at seven wind resources that cleared regulation-down in the day-ahead market.

Resources that clear for contingency reserve in the day-ahead market and get deployed for a contingency reserve event could have to buy back the contingency reserve in intervals subsequent to the event at higher prices than they were paid in the day-ahead market. This is because resources deployed for the contingency reserve often get deployed to their maximum limits, which means those resources cannot clear contingency reserves in subsequent intervals as they have not had time to be dispatched down to clear the product. However, those intervals often have scarcity pricing, due to the product's shortage, making the buyback expensive in relation to the amounts paid in the day-ahead market for the product.

Most resources had positive cash-flows from each operating reserve product, even without taking the money made on energy margins into account. Twelve resources had negative cash flows from regulation-down, five from regulation-up, five from spin, and five from supplemental. The total negative cash flows for these resources' products were $0.9 million, $0.01 million, $0.01 million, and $0.02 million, respectively. These numbers appear small considering the overall total of money transacting for energy and reserves in the Integrated Marketplace.

4.2 MAKE-WHOLE PAYMENTS

The Integrated Marketplace provides make-whole payments 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. The make-whole payment provides additional market payments in cases where revenue is below a resource's offer to make the resource whole to its offers of operating reserve products, incremental energy, start-up, transition, and no-load.

For the resources that are not combined-cycle, settlements 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, which 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 2020, day-ahead market and reliability unit commitment make-whole payments totaled approximately $104 million, up three percent from $101 million last year, but up forty-three percent from $72 million in 2018. Total make-whole payments averaged about $0.40/MWh for 2020, $0.02 higher than 2019, but $0.14 higher than the 2018 average of $0.26/MWh. In comparison to other RTO/ISO markets, SPP's make-whole payments per megawatt-hour of generation were on the higher end with other markets varying from $0.17/MWh to $0.33/MWh in 2019.[116] This $0.40/MWh represents the total cost of uplift in 2020 to all megawatts generated. However, roughly 36 percent of SPP's generation in 2020 was provided by self-committed resources.[117] These resources are not eligible for make-whole payment reimbursements. Only resources committed under reliability or market status are eligible for cost reimbursement.

Figure 4–32 illustrates the 2018 to 2020 average make-whole payments per each megawatt eligible for cost reimbursement, or in other words those megawatts generated under market or reliability status. These include manual commitments made by operators.

[116] *2019 ISO NE State of Market Report*, https://www.iso-ne.com/static-assets/documents/2020/06/iso-ne-emm-2019-report-final.pdf.
[117] See Section 3.3, Figure 3–24.

Figure 4–32 Make-whole payments for eligible megawatts[118]

	2018	2019	2020
Day-ahead market make-whole payments / eligible MWh	$0.22	$0.21	$0.32
Real-time market make-whole payments / eligible MWh	$18.94	$19.64	$15.77

Day-ahead make-whole payments per eligible megawatt increased in 2020. This appears to be mostly caused by a shift of resources previously self-committing in the day-ahead market now market committing. For the three years prior to 2020 day-ahead make-whole payments per eligible megawatt had been going down. This was likely due to decreasing gas prices and increasing wind generation as a percentage of total generation. The real-time make-whole payments per eligible megawatt went down in 2020. Prior to 2020, the real-time make-whole payments per eligible megawatt had been increasing. This can be partially attributed to the increased real-time market volatility and the need for more rampable capacity. Operators often commit resources when the available ramp capacity needs in future intervals is perceived to be short. These actions often reduce the occurrence of scarcity events. However, this has the effect of potentially suppressing the price signal that would indicate a problem as capacity is brought on to meet the perceived ramp shortage. Additionally, the resources that were manually committed are typically expensive in comparison to the energy prices for which they run, requiring them to receive cost reimbursement through make-whole payments. Another way to view the real-time make-whole payments is that on the average $15.77/MWh was paid to avoid reliability problems that were not able to be addressed directly by the real-time market.

In addition, most scarcity events last less than two intervals and most resources have minimum-run times much longer than this period. This means that even if these resources are able to capture one to two intervals of the high prices, they may have to run an hour or two longer with less economic price levels, leading to the need for cost reimbursement.

[118] These numbers were not presented under this method in prior years. Prior years reported total make-whole payments divided by total generation. This method shows total make-whole payments divided only by megawatts eligible for cost reimbursement.

The MMU believes that the proposed ramp capability and uncertainty products, if designed properly, will help provide the appropriate pricing and compensation mechanisms for meeting ramp capacity needs in the market. This includes reducing make-whole-payments and bringing transparency to the market. They will also help to better compensate resources that are providing the much needed ramping flexibility, as well as reduce the need for manual commitments for capacity.

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

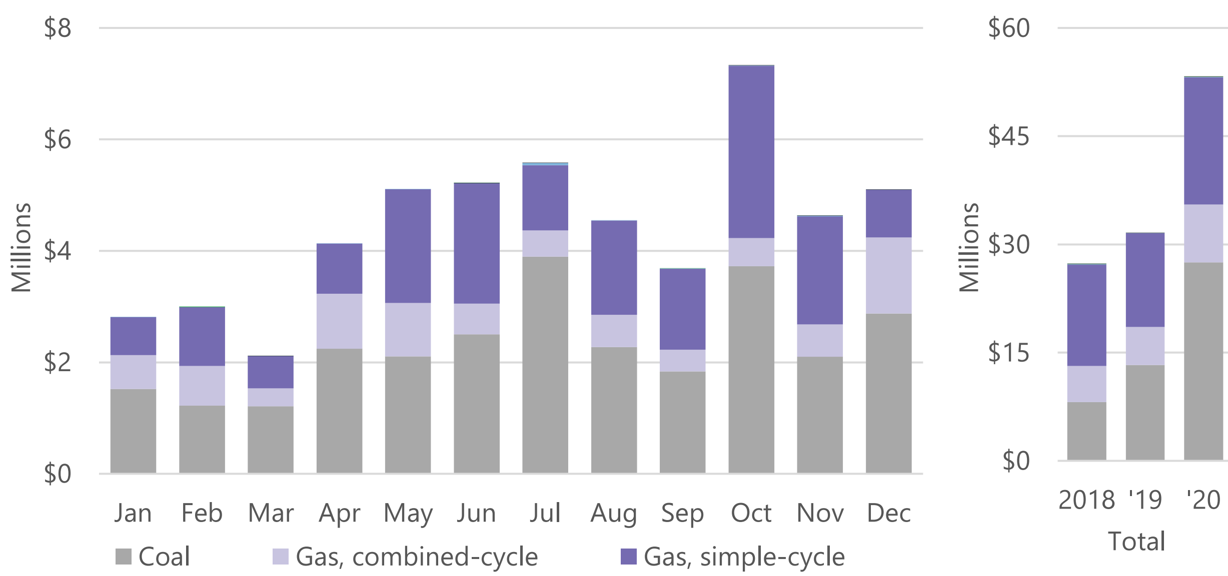
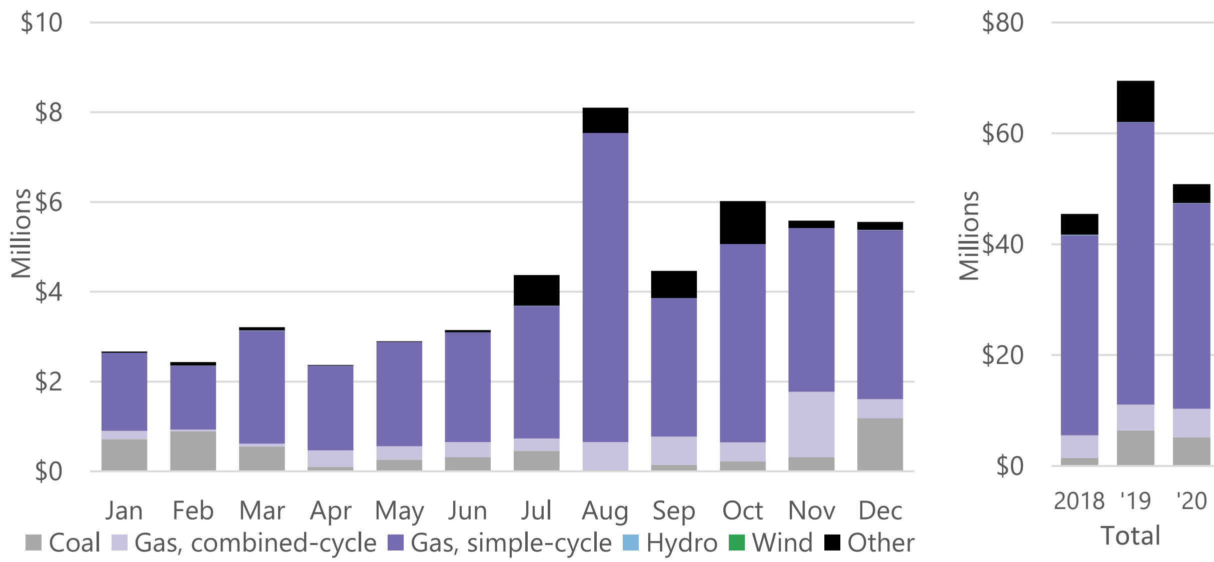


Figure 4–34 Make-whole payments by fuel type, reliability unit commitment



Day-ahead make-whole payments constituted 51 percent of the total make-whole payments in 2020. Gas-fired resources represent about 65 percent of all make-whole payments, with 55 percent of all make-whole payments to simple-cycle gas resources through reliability unit commitment make-whole payments. While real-time make-whole payments decreased 27 percent from 2019 to 2020, there were substantial increases in day-ahead make-whole payments. 2019 contained periods of conservative operations, which had a large amount of real-time make whole payments. Day-ahead make whole payments increase as the market prices decrease, which they have each year since 2017, and tend to be higher outside of the summer period. Day-ahead make-whole payments where just over $53 million in 2020, up nearly 69 percent from 2019. Real-time make-whole payments in 2020 totaled $51 million, down from $70 million in 2019.

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 or go offline between on-peak and off-peak hours, and excessive transmission congestion not being solved by the market. Make-whole payments to resources in the “other” category primarily represent payments to oil-fired resources.

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	2018	2019	2020
Manual, SPP transmission	27.5%	27.7%	34.6%
Manual, SPP capacity	24.9%	33.8%	22.8%
Intra-day RUC	26.1%	22.2%	16.0%
Manual, voltage	4.4%	6.6%	11.7%
Short-term RUC	13.7%	4.7%	8.0%
Day-ahead RUC	1.8%	2.4%	3.9%
Manual, stagger	0.9%	2.6%	2.7%
Other	0.3%	0.0%	0.2%

Day-ahead commitment reason	2018	2019	2020
Day-ahead market	93.7%	99.7%	97.1%
Manual, voltage support	6.3%	0.3%	2.9%

In recent years, there has been a large increase in make-whole payments occurring during periods that resources are manually committed for capacity. In fact, just under 23 percent of the real-make-whole payments were paid to resources committed manually for capacity needs. This is much better than the 34 percent in 2019. However, there was a large increase in resources committed for transmission. These commitments had just under 35 percent of the real-time make whole payments in 2020, up from 28 percent in 2019.

Also, as shown in Section 2.4.1 wind generation as a percentage of total generation has been steadily increasing.[119] Wind can be difficult to forecast, causing the market to be scarce in rampable capacity, leading to the need for operator intervention. In fact, because of the emergency conditions seen on May 31, 2018, an Uncertainty Response Team was established by SPP. The Uncertainty Response Team consists of SPP Operations staff that provides daily assessments to ensure the SPP region has the required rampable capacity to serve demand after accounting for load, resource, and wind uncertainties. For instance, the Uncertainty Response Team looks back at a historical average of differences between forecasted generation needs and actual generation needs and takes the 95th percentile of deviation seen during the time

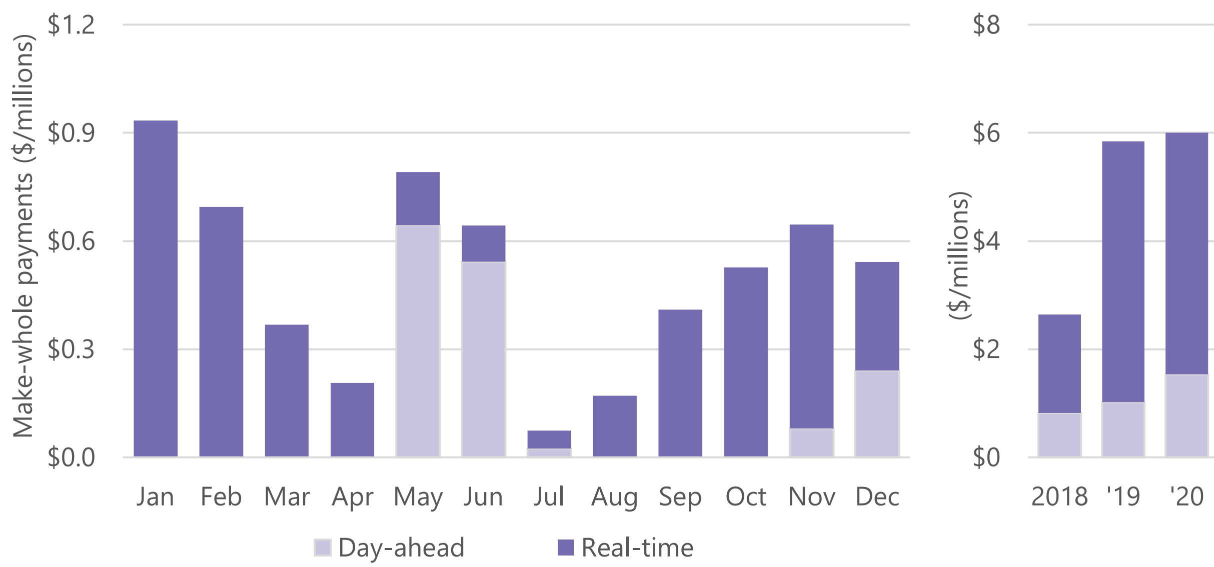
[119] Section 2.4.1, Figure 2–19.

assessed. If there is not enough rampable capacity available to meet the forecasted need plus the deviation assessed at the 95th percentile of historical averages, more capacity will be committed. This can lead to more make-whole payments as more resources are online, lowering prices as a result of increased supply and reduced scarcity intervals, even though there is actually a shortage.

As noted earlier in this section, SPP is working on an uncertainty product and plans to implement a ramping capability product later this year. The MMU expects these products to better preposition rampable resources. This should reduce the need for some of the excess capacity currently carried for uncertain events.

Make-whole payments associated with voltage support commitments do not follow the same uplift process outlined in Section 4.3.1. Instead, the cost of these make-whole payments is 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.

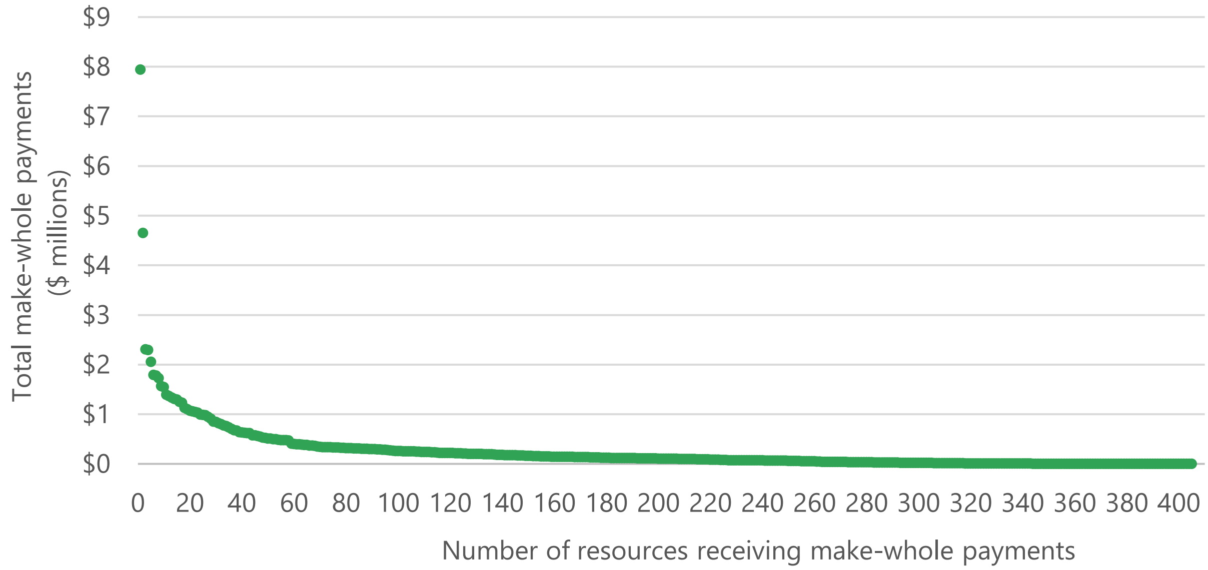
Figure 4–36 Make-whole payments for voltage support



The make-whole payments stemming from voltage support commitments are relatively the same as 2019, with a slight shift for real-time voltage supports commitments moving to day-ahead commitments.

The majority of SPP resources received modest total annual make-whole payments in 2020, as highlighted in Figure 4–37.

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



Seventy-four percent of resources in SPP received less than $250,000 in make-whole payments in 2020. However, 23 resources received over $1 million, compared to just 17 resources with $1 million make-whole payments in 2019, and seven in 2018. In fact, one resource received $7.9 million in make-whole payments, with $2.8 million coming from voltage support commitments. The resource was also the highest reimbursed resource in 2019, with $6.5 million in make-whole payments. This resource is in an area with frequent congestion and most of these make-whole payments stem from manual commitments needed to control regional transmission and voltage concerns.

Figure 4–38 reveals there is concentration in the market participants that receive make-whole payments.

Figure 4–38 Number of market participants receiving make-whole payments

	2018			2019			2020		
	> $1 million	> $5 million	> $10 million	> $1 million	>$5 million	> $10 million	> $1 million	> $5 million	> $10 million
Market participants receiving make-whole payments	16	5	1	16	8	3	12	7	4
% of make-whole payments by category	94%	57%	14%	94%	78%	43%	93%	78%	61%

In 2020, there were 12 market participants that each received annual make-whole payments in amounts greater than $1 million. These 12 market participants accounted for 93 percent of the total make-whole payments paid out in 2020, which is one percent less than 2019 and 2018. All but one of these 12 participants with $1 million in make-whole payments from 2020 also received over $1 million each in 2019.

In 2020, there were seven participants that received over $5 million each in make-whole payments and out of that, four received over $10 million. The participant with the highest cost reimbursement received just under $20 million in make-whole payments in 2020, accounting for 19 percent of the make-whole payments.

4.2.1 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 over $0.19/MWh in 2020. This is approximately eight cents greater than the 2019 average, but ten and a half cent greater than the 2018 average.

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 had steadily been increasing, as has the total volume of real-time make-whole payments, until 2020. The rate was $0.92/MWh for 2020; this is down significantly from the $1.35/MWh 2019 average, but just slightly lower than the $0.98/MWh in 2018. There are eight categories of deviation and each category receives an equal amount per megawatt, which can vary by operating day, when the cost of make-whole payments is applied.

Figure 4–39 shows the total megawatts of deviation by each category, as well as the total real-time make-whole payment uplift charges for each deviation category.

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	46,677	$ 41,925	82.5%	$ 0.90
Outage deviation	4,491	$ 4,717	9.3%	$ 1.05
Maximum limit deviation	1,050	$ 1,007	2.0%	$ 0.96
Status deviation	1,222	$ 1,150	2.3%	$ 0.94
Uninstructed resource deviation	882	$ 890	1.8%	$ 1.01
Reliability Unit Commitment self-commit deviation	860	$ 789	1.6%	$ 0.92
Reliability Unit Commitment deviation	169	$ 205	0.4%	$ 1.21
Minimum limit deviation	157	$ 144	0.3%	$ 0.92

Even though each category of deviation is applied the same rate for deviation, approximately 83 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 cleared, 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. However, virtual offers are the most susceptible as 100 percent of their megawatts are considered incremental. Because of this, virtual offers alone paid 48 percent of all real-time make-whole payments in 2020, slightly down from 50 percent last year.

Cost causation has been an area of concern in the SPP working groups in the past few years. In particular, participants raised concerns that the market is not properly allocating the market cost back to those responsible for causing those costs. With virtual offers bearing such a heavy burden of these costs, it reduces the incentives for behavior changes among those that are causing the cost and it adds a premium to virtual transactions. This should be considered as part of the evaluation of under-clearing of wind in the day-ahead as these incentives likely contribute to the lack of price convergence between day-ahead and real-time.

4.2.2 REGULATION MILEAGE MAKE-WHOLE PAYMENTS

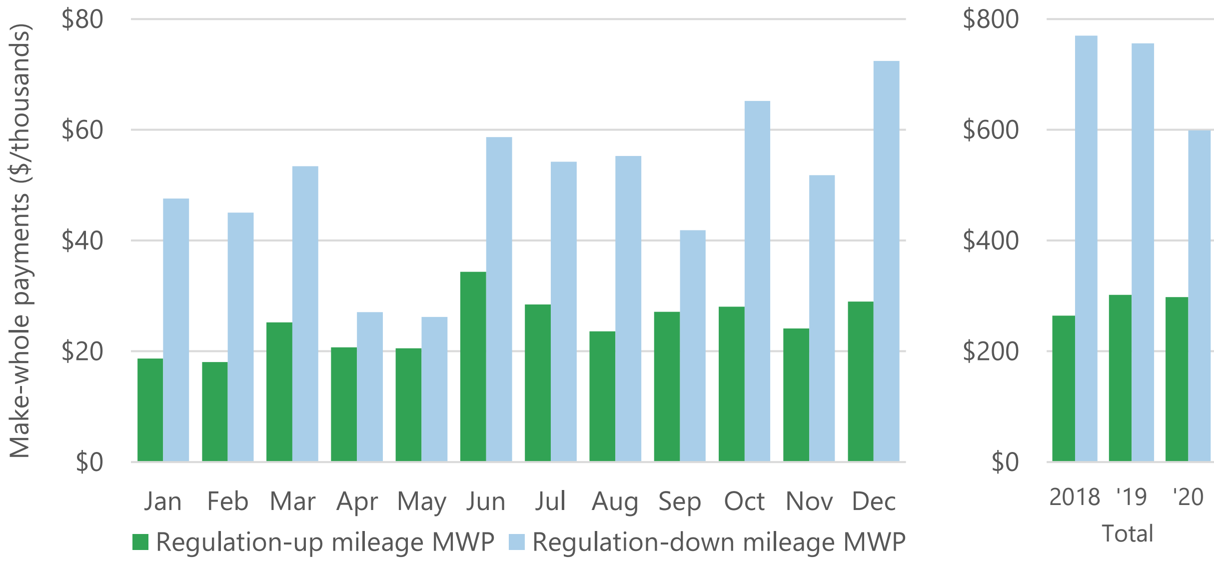
In March 2015, SPP introduced regulation compensation changes for units deployed for regulation-up and regulation-down. One component of the regulation compensation charges is regulation-up and regulation-down mileage make-whole payments for units that are charged for unused regulation-up or regulation-down 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 16 percent and 23 percent, respectively, for 2020. The regulation-up mileage factor is the same as last year and the regulation-down mileage factor is down one 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 2020 and the prior two years.

Figure 4–40 Regulation mileage make-whole payments



Regulation-up mileage make-whole payments were around $300,000 in 2020, down one percent from 2019. Regulation-down mileage make-whole payments were around $600,000 in 2020, down eleven percent from 2019, and down ten percent from 2018. The design deficiency described in section 4.1.6 can be directly attributed to the disparity between the regulation-down and regulation-up mileage make-whole payments seen in Figure 4-41. This design inefficiency is one of the main contributors to the disparity between the mileage make-whole payments paid out to regulation-up and regulation-down.

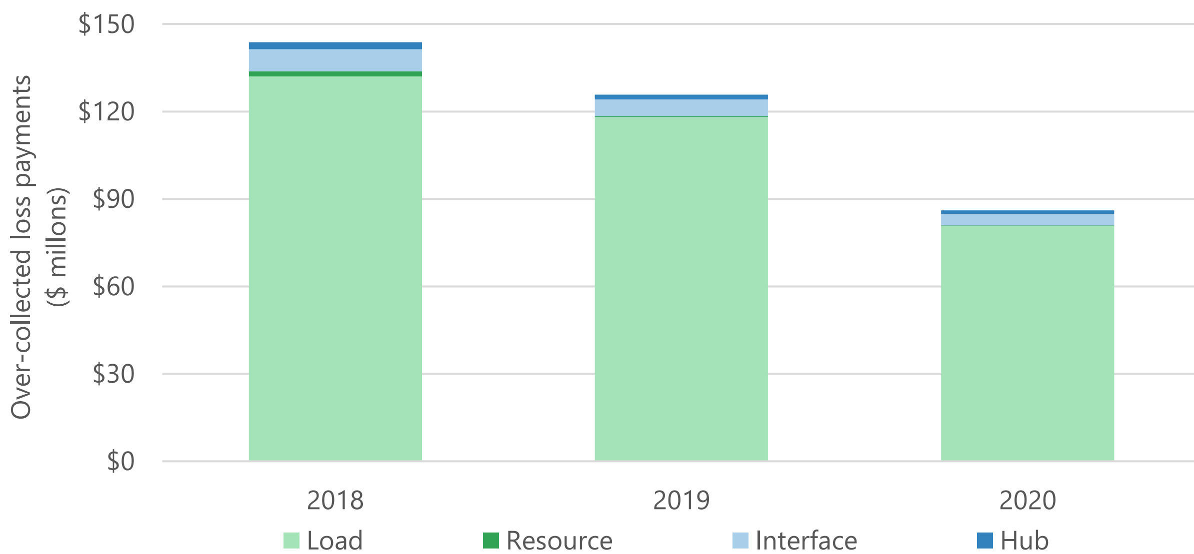
4.2.3 DISTRIBUTION OF MARGINAL LOSSES (OVER-COLLECTED LOSS REVENUE)

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.

The current design consolidates the distributions of day-ahead and over-collected loss rebates into one distribution.[120] 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, as long as the underlying megawatts associated to the bilateral settlement schedules are not less than the megawatts of the bilateral settlement schedule.

Over-collected losses for the past three years are shown in Figure 4–41.

Figure 4–41 Over-collected losses, real-time



A total of $86 million was paid out in over-collected losses rebates during 2020, with $81 million (94 percent) going to load. This is down from the $126 million in over-collected losses rebates paid out in 2019, and the $144 million paid in 2018. The decrease in losses between 2019 and 2020 can be attributed to lower energy prices and lower levels of demand.

[120] Prior years over-collected loss designs are described in the *2018 Annual State of the Market* report under Section 4.2.3.

4.2.4 POTENTIAL FOR MANIPULATION OF MAKE-WHOLE PAYMENTS

In the 2014 Annual State of the Market report (and highlighted in every annual report since), the MMU pointed out specific vulnerabilities that market participants could potentially manipulate in SPP's make-whole payment provisions. The vulnerabilities were directly associated with the FERC order regarding the make-whole payments and related bidding strategies of JP Morgan Ventures Energy Corp.[121] At this time only one issue has still not been fully alleviated, which is make-whole payments for generators committed across the midnight hour. Under this scenario, a market participant has the ability to position its multi-day committed resource to receive a make-whole payment without economic evaluation of its offers by the market.

A revision request was passed by the SPP Markets and Operations Policy Committee (MOPC) during the January 2020 meeting to address this design gap.[122] This was subsequently filed with FERC, which they approved in June 2020. It is currently awaiting implementation, with an implementation date not yet set at the time of this report. The revision request corrects the issue by limiting make-whole payments for any resource with multi-day minimum-run times to the lower of the market offer or the mitigated offer. This limitation only applies to offers falling in hours in which the resource's offers were not assessed by one of the security constrained unit commitment (SCUC) processes and the resource bid at or above their mitigated offer on the first day.

The MMU strongly recommends that this be implemented in a timely manner, so that changes can address the gaming concern.

4.2.5 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 recommendations, 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

[121] 144 FERC ¶ 61,068.
[122] Revision Request 382, 2014 ASOM MWP MMU Recommendation (3-Day Minimum Run Time).

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 late 2017, corrections were made to address the issue of co-owners benefiting from higher energy offers. However, with these corrections new issues arose.[123] A new design was implemented on August 1, 2020.

The new design requires that jointly-owned units offer in as one unit. The market system dispatches the resource as one unit, and then the settlements process allocates the cost and revenues out by percentage of ownership of the resource. The new design corrected the concerns outlined above.

4.3 TOTAL WHOLESALE MARKET COSTS AND PRODUCTION 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,[124] reserve sharing group costs, and payments to demand response resources, was $20.05/MWh in 2020. This is comparable to the average price of energy at load pricing nodes in SPP's real-time market for 2020 of $19.29/MWh.[125] The all-in price was just over 17 percent lower than the 2019 average all-in price, which is partially attributed to the decrease in load and the decline in natural gas prices in 2020.[126] Figure 4–42 plots the average all-in price of energy and the cost of natural gas, measured at the Panhandle Eastern (PEPL) hub.

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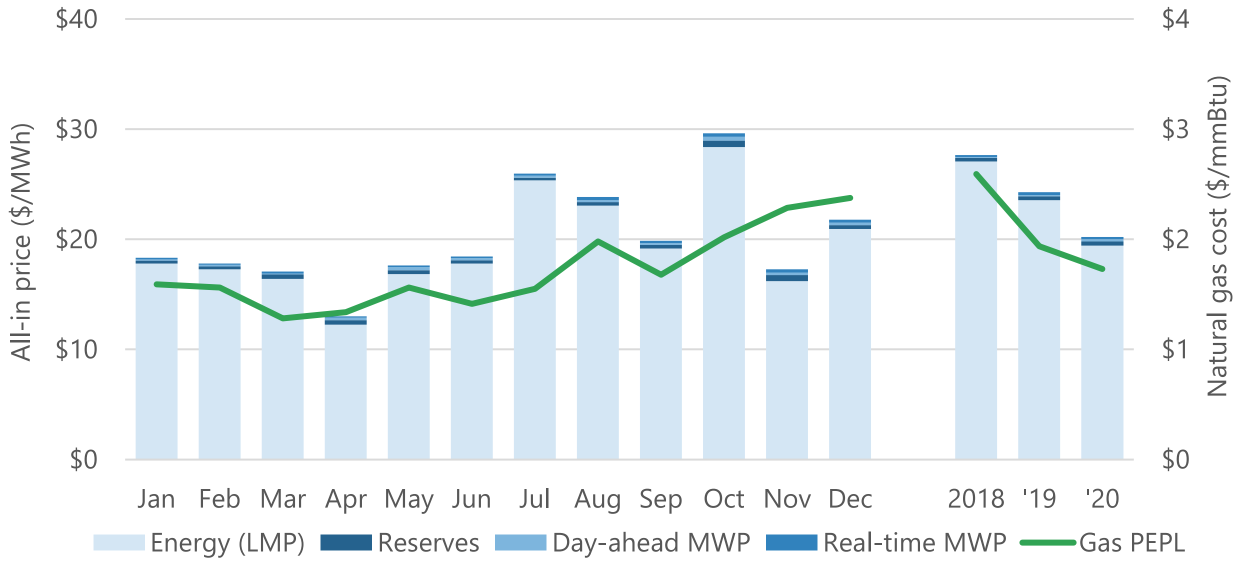
[123] Descriptions of these issues can be viewed in the *2018 Annual State of the Market* report under Section 4.2.5

[124] 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.

[125] The cost of energy includes all of the shortage pricing components.

[126] The Reserve Sharing Group costs and payments to demand response resources were negligible for both years.

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 payments.[127] It also shows that the market cost of operating reserves and make-whole payments constituted approximately four percent of the all-in price, with make-whole payments and operating reserves amounting to $0.41/MWh and $0.37/MWh, respectively.

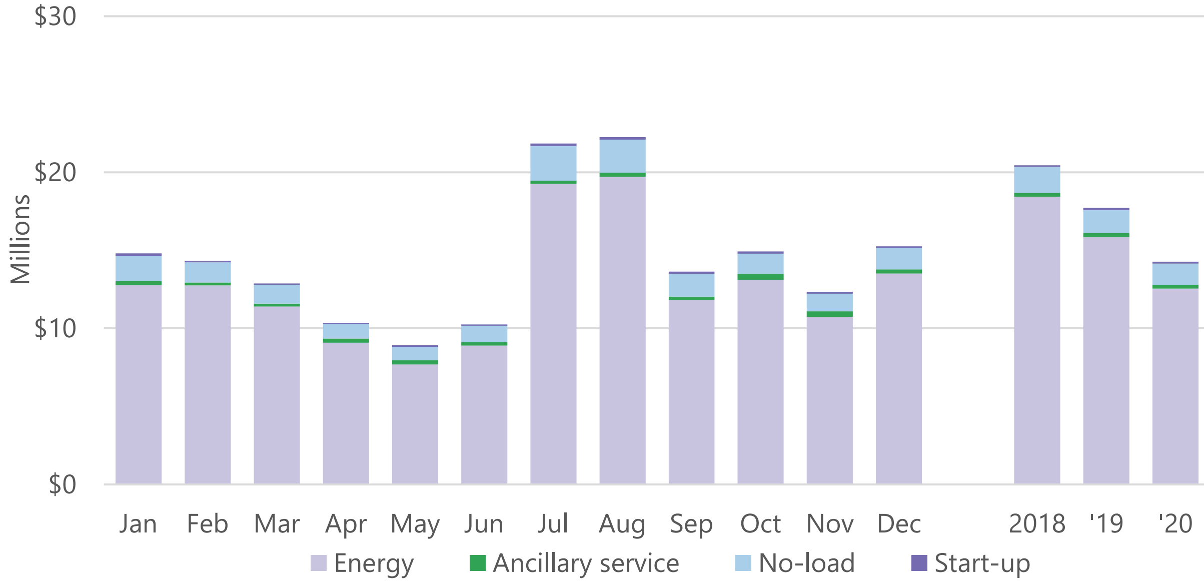
Production cost "is defined as the settlement cost for the market … for all resources."[128] Production cost, in this case, is the sum of four components:

- energy: cleared megawatts multiplied by locational marginal prices;
- ancillary service: cleared operating reserves multiplied by market clearing prices ;
- start-up: "… the out of pocket cost that a Market Participant incurs in starting up a generating unit from an off-line state …;"[129] and
- no-load: "… the hourly fee for operating a synchronized Resource at zero … output."[130]

Figure 4–43 shows the average daily production cost for the day-ahead market.

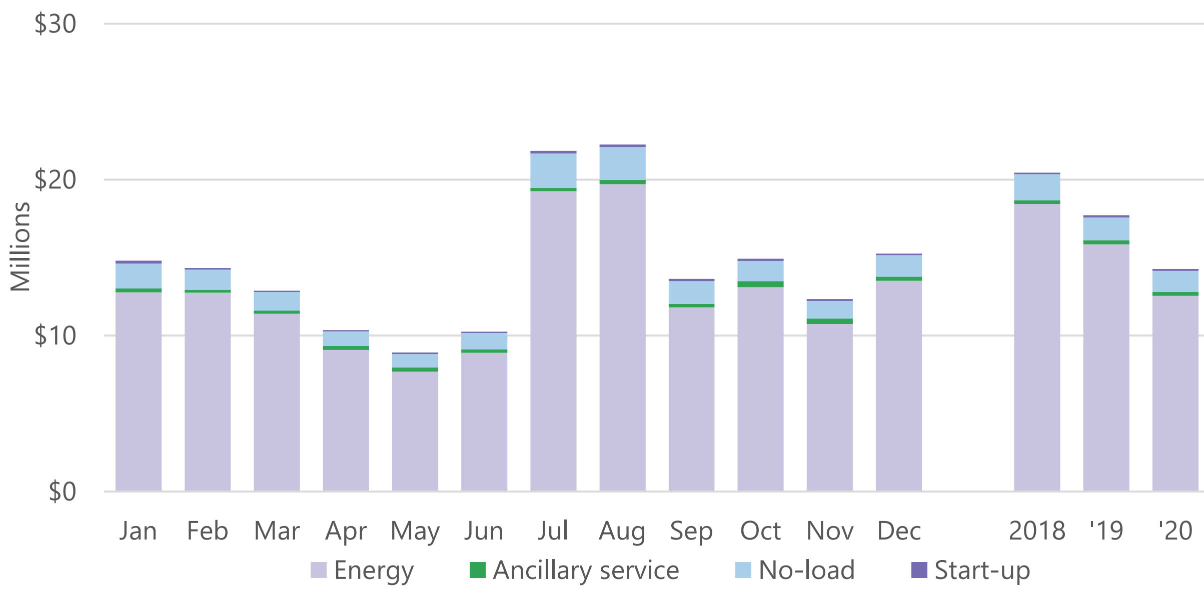
[127] Scarcity pricing is included in the energy component and not easily separated out in the SPP settlement data. See Section 3.2.1 for a discussion of scarcity pricing impacts.
[128] *Integrated Marketplace Protocols*, Section 7.2.1
[129] *Integrated Marketplace Protocols*, Start-Up Offer
[130] *Integrated Marketplace Protocols*, No-Load Offer

Figure 4–43 Production cost, daily average, day-ahead



The daily average production cost decreased 19 percent from 2019 to 2020. The decrease in production cost was almost fully attributed to the energy component, which decreased with gas prices. The energy component is sensitive to numerous inputs, which include fuel cost, amount of subsidized renewable energy, operating reserve scarcity, and load levels. The range of the 2020 daily day-ahead production costs exceeded $35 million ranging from $1 million to $36 million. Additionally, nearly 94 percent of the daily production costs ranged between $5 million and $30 million.

Figure 4–44 Production cost, daily average, real-time



Real-time production cost decreased more than 19 percent from 2019 to 2020. The decrease in production cost, similar to day-ahead, was also almost fully attributed to the energy component. The range of the 2020 daily real-time production costs ranged from −$6 million to almost $83 million. However, 94 percent of the daily production costs in real-time ranged between $5 million and $30 million.

4.4 LONG-RUN PRICE SIGNALS FOR INVESTMENT

In the long term, market prices provide signals for investment in new transmission and generation, as well as ongoing maintenance of existing generation and transmission assets to meet load. Given the relatively low average SPP market prices, the MMU does not expect SPP market prices to support new entry of generation investments. While the SPP market on its own offers low incentives for new generation, some reasons for new generation investments include expansion of corporate renewable goals, SPP out-of-market payments, bilateral contracts, purchase power agreements, SPP market protocol requirements, federal and/or state incentives, state-regulated investments, emerging technologies, and emission reduction plans.

The MMU conducted 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 five generation technologies relative to their potential net revenues[131] at SPP market prices. The plants considered include scrubbed coal, natural gas combined-cycle (combined-cycle), natural gas combustion turbine (combustion turbine), wind, and solar photovoltaic – tracking (solar).

Figure 4–45 provides the cost assumptions. Solar capital costs have been credited to account for investment tax incentives. In addition to these assumptions, a capital recovery factor of 12.6 percent was used in the annual fixed operating and maintenance cost component.

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

Figure 4–45 Net revenue analysis assumptions

	Scrubbed coal	Combined-cycle	Combustion turbine	Wind	Solar
Size (MW)	650	418	237	200	150
Total overnight cost ($/kW-yr)	$4,595	1,082	$709	$1,846	$1,612
Variable O & M ($/MWh)	$7.11	$2.56	$4.52	$0	$0
Fixed O & M ($/kW-yr)	$54.57	$14.17	$7.04	$26.47	$32.33
Heat rate (Btu/kWh)	9,751	6,431	9,905	n/a	n/a

Source: EIA Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2021

Figure 4–46 shows the results of the market-wide net revenue analysis. The analysis assumes the market dispatches the hypothetical resource when day-ahead[132] price exceeds the short-run marginal cost of production. Natural gas prices were based on the Panhandle Eastern Pipeline Company (PEPL) pipeline. Wind was attributed a capacity factor of 39 percent across all hours while solar was attributed a capacity factor of 49 percent during peak hours. Additionally, the average marginal cost of wind has been credited to account for production tax incentives.

[132] Real-time prices form the same results.

Figure 4–46 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	$26.99	$8,659	$631,590	NO	$54,570	NO
Combined-cycle (single-shaft)	$21.16	$50,965	$150,043	NO	$14,170	YES
Combustion turbine (industrial frame)	$33.16	$16,336	$96,073	NO	$7,040	YES
Wind	-$30.00	$159,382	$258,283	NO	$26,470	YES
Solar PV (tracking)	$0.00	$34,688	$234,758	NO	$32,330	YES

SPP market revenues have been insufficient to support the cost of new entry of thermal generation since the inception of the Integrated Marketplace in 2014, and 2020 was no exception. Since 2015, prices have supported the ongoing maintenance cost of combined-cycle and combustion turbine units, though they have not supported the ongoing maintenance cost of coal units. This is consistent with the 2020 results shown above. In 2020, SPP market revenues were also insufficient to support the cost of new entry of renewable generation, wind and solar. However, similar to natural gas generation, 2020 prices supported the ongoing maintenance cost of renewables. A large contributor to the low revenues relative to total costs for all resource types is low market prices. The average day-ahead market price was less than $18/MWh, as shown in Figure 4–1.

Figure 4–47 provides results by SPP resource zone, as indicated by the dominant utility in the area.

Figure 4–47 Net revenue analysis by zone

	Coal			Combined-cycle			Combustion turbine		
Resource zone	Net revenue from SPP market ($/MW yr)	Able to recover net entry cost	Able to recover avoidable cost	Net revenue from SPP market ($/MW yr)	Able to recover net entry cost	Able to recover avoidable cost	Net Revenue from SPP market ($/MW yr)	Able to recover net entry cost	Able to recover avoidable cost
AEP	$10,684	NO	NO	$58,514	NO	YES	$19,812	NO	YES
KCPL	$12,247	NO	NO	$50,224	NO	YES	$17,996	NO	YES
NPPD	$7,843	NO	NO	$38,134	NO	YES	$11,403	NO	YES
OGE	$7,947	NO	NO	$43,713	NO	YES	$12,251	NO	YES
SPS	$8,794	NO	NO	$73,191	NO	YES	$39,780	NO	YES
WAUE	$8,170	NO	NO	$38,811	NO	YES	$10,686	NO	YES

	Wind			Solar		
Resource zone	Net revenue from SPP market ($/MW yr)	Able to recover net entry cost	Able to recover avoidable cost	Net revenue from SPP market ($/MW yr)	Able to recover net entry cost	Able to recover avoidable cost
AEP	$163,155	NO	YES	$36,816	NO	YES
KCPL	$161,157	NO	YES	$36,145	NO	YES
NPPD	$153,990	NO	YES	$31,921	NO	YES
OGE	$157,556	NO	YES	$33,992	NO	YES
SPS	$157,458	NO	YES	$33,821	NO	YES
WAUE	$155,302	NO	YES	$31,812	NO	YES

Overwhelmingly, the conclusions do not vary geographically, despite differing energy prices and fuel costs. The SPS region has higher net revenues than other regions for gas resources. This is likely because combined-cycle plants and combustion turbines in the Permian Basin (West Texas) region consistently experience below average natural gas prices.

Based on these results, the MMU expects the market to signal the retirement of some coal generation while also not signaling the investment of other types of new generation. A decrease in overall available capacity—along with the recently observed higher outages since 2017—and changes in the generation fleet profile could present challenges for reliability.

External economic decisions can provide additional impetus needed for new generation investments, such as the expansion of corporate renewable goals, SPP out-of-market payments, bilateral contracts, purchase power agreements, SPP market protocol requirements, federal and/or state incentives, state-regulated investments, emerging technologies, and/or emission reduction plans. However, market prices, by themselves, have not signaled new generation entry since the inception of the Integrated Marketplace. Other revenue streams for value added could change this conclusion. For instance, resources could be paid to ensure their generation is highly dependable, or resources could be paid to remain available for specific performance requirements in the short to medium timeframe. As the market is currently designed, it does not incentivize new entry for energy capacity.

Out-of-market actions by SPP operators, and the resultant uplift payments, for reliability (manual) commitments reflect some of the symptomatic issues. However, these do not necessarily signal the overall need for more generation. Make-whole payments fund cost recovery and do not necessarily increase net revenue. If these make-whole payments were represented in a market price for a product, then this would likely reduce make-whole payments for manual commitments, but it would not necessarily increase net revenue. Because make-whole payments do not increase net revenue, they do not necessarily indicate the need for additional energy capacity. However, as previously mentioned, products could be implemented to pay for specific performance requirements, such as highly dependable available generation, schedulable generation, or rampable capacity. If such products were implemented, these product prices may indicate the need for these specific, non-energy capacity products.

As the MMU has indicated throughout this report as well as in other forums, the MMU advises SPP and members to implement products such as ramp (which is scheduled to be implemented in early 2022) and uncertainty[133] to value flexibility and to produce accurate price signals. Furthermore, SPP should consider emergency pricing for situations in which operators declare an emergency and generation is committed to avoid the emergency. The MMU also recommends developing accreditation factors and performance-based metrics to obtain

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[133] *SPP Holistic Integrated Tariff Team Report*, https://www.spp.org/documents/60323/hitt%20report.pdf

accurate capacity ratings based on actual performance that will more appropriately incentivize reliable operation and price formation in the SPP Integrated Marketplace.

Continuing to value flexibility will be important going forward. Compensation for reliable summer performance could be an additional revenue stream to high-performing generation. This is discussed in more detail in Section 8.1 of this report. The effectiveness of the pricing of such products and capacity ratings to align reliability and economics will shape future price signals for investment in the SPP market.

5 CONGESTION AND TRANSMISSION CONGESTION RIGHTS MARKET

This chapter reviews transmission congestion in the SPP market footprint, as well as the transmission congestion rights market in the Integrated Marketplace. Key points from this chapter include:

- The area that experienced the highest congestion costs in 2020 was the southeastern corner of SPP including eastern Kansas, southwest Missouri, and southeastern Oklahoma. Concentrated areas on the Kansas and Oklahoma border and southeast Oklahoma experienced the lowest congestion costs for the year.
- Overall, congestion was similar as the previous year in the SPP footprint. Intervals having no congestion remained consistent but intervals having a breached constraint increased in 2020 with most being market-to-market constraints.
- The frequently constrained area study for 2020 saw similar congestion patterns warranting no additions, so there remains no frequently constrained areas at this time.
- Market participants were generally effective in hedging congestion in the SPP market using SPP's congestion hedging products. In aggregate, Load-serving entities covered 148 percent of their congestion cost and non-load-serving entities covered 69 percent of their total congestion cost.
- Individual market participants hedged congestion with varying degrees of effectiveness — overall 80 percent of load-serving entities recovered at least all of their congestion cost.
- Transmission congestion rights funding fell outside the target range. The annual funding percentage fell to 82 percent, and the annual shortfall worsened by more than $53 million. Auction revenue right funding decreased from 129 percent to 123 percent; relatedly, the ARR surplus decreased by more than $18 million.
- Participants can transfer congestion rights through use of a bulletin board or sell back positions in the auction. However, most congestion rights are not transferred or sold.

No bulletin board trades cleared during 2020. Intra-auction sales[134] increased slightly in volume, and continue to average only about five percent of the total auction volume.

5.1 TRANSMISSION CONGESTION

The locational marginal price (LMP) for the over 1,100 settlement locations 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:

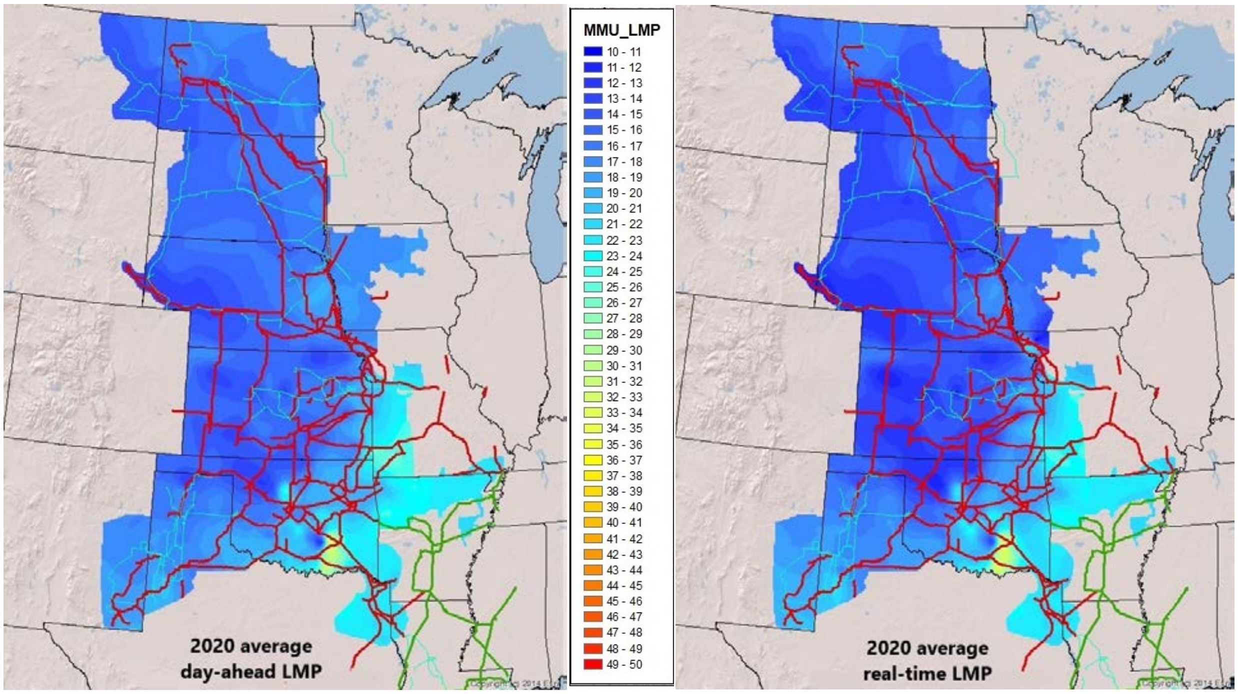
- geographic pattern of congestion and losses,
- changes in the transmission system that alter congestion patterns,
- congestion impacts on local market power,
- load-serving entities hedging congestion costs in the transmission congestion rights market, and
- distribution of marginal congestion and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

[134] The sale of a previously acquired position in a subsequent auction.

5.1.1 PRICING PATTERNS AND CONGESTION

Figure 5–1 shows price contour maps representing the day-ahead and real-time average prices in 2020.

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



Annual average day-ahead market prices ranged from around $9/MWh in a concentrated area northwest of Oklahoma City to around $36/MWh in the southeast section of Oklahoma. About 75 percent of this price variation can be attributed to congestion and 25 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 $6/MWh to $37/MWh.

Transmission buildout has allowed higher levels of low-cost wind generation in the western parts of the SPP footprint to serve load centers located in the eastern portions of SPP. In addition, congestion has shifted eastward towards the southeastern edge of SPP extending from northern Missouri to south Oklahoma.

The southwest Missouri area along the SPP eastern border continued to see congestion with prices increasing slightly from around $27/MWh in 2019 to around $30/MWh in 2020.

Congestion has also been prevalent around Oklahoma City[135] for the past two years with average real-time prices of $34/MWh in 2019 and $30/MWh in 2020. Lastly, day-ahead prices in the southeast Oklahoma area around market-to-market constraints[136] have averaged over $35/MWh over the past two years.

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 but transmission buildout has resulted in most congestion occurring on the southeastern edge of the SPP footprint.

The costs of coal-fired generation increases as transportation costs rise. For example, transportation cost increases with distance from the Wyoming Powder River Basin near the northwest corner of SPP's footprint. This is important because even though it is declining, coal still accounts for 31 percent of SPP's energy generation in 2020.

Natural gas-fired generation, SPP's largest fuel type by installed capacity (38 percent in 2020), 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.

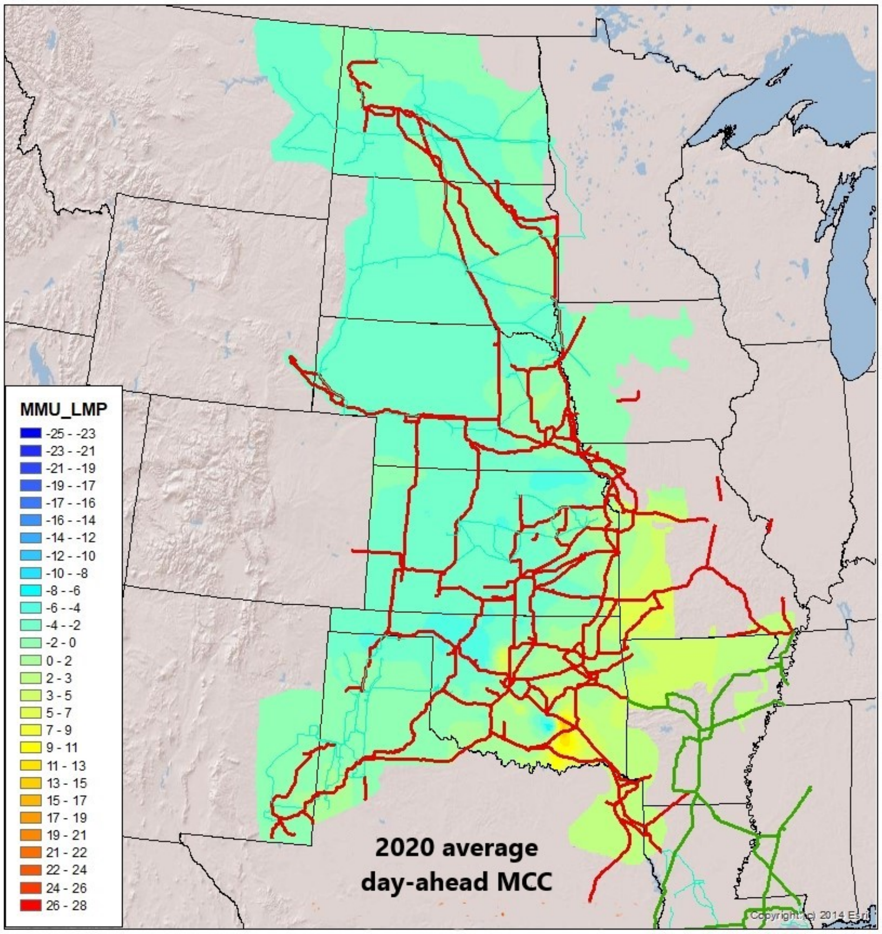
These factors combine to create a general northwest to southeast split in prices. One exception is slightly higher prices in the northern area of North Dakota along the border of Montana resulting from the growth of, and associated demand from, oil and gas exploration and production facilities. The other exception is the lower southwest area of the SPP region around

[135] FRAMIDCANCED (Franklin – Midwest 138kV for the loss of Cedar Lane – Canadian 138kV)
[136] TMP109_22593 (Stonewall Tap – Tupelo Tap 138kV for the loss of Seminole – Pittsburg 345kV) and TEMP29_23044: Stonewall Tap-Tupelo Tap 138kV (WFEC) for the loss of Pittsburg-Valliant 345kV.

Lubbock, Texas. This congestion historically extended further north into the Texas panhandle but transmission buildout and additional generation has moved congestion further south.

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 occurred in the concentrated areas around Oklahoma City and in southeast Oklahoma, at −$9/MWh. The highest marginal congestion costs lie around the congestion in southeast Oklahoma at around $16/MWh.

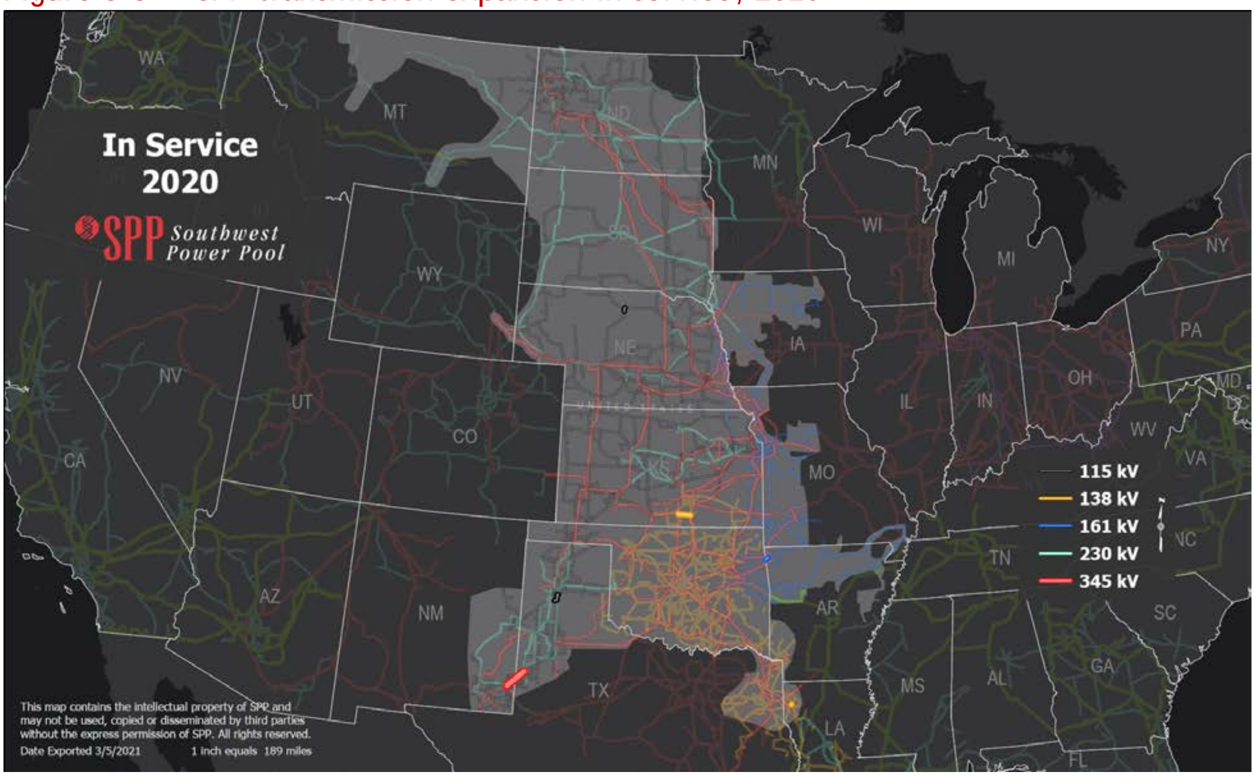
The congestion in the southwest Missouri area reduced from 2018 to 2019 but increased in 2020. Congestion remained in this area and in neighboring areas to the south, such as northwest Arkansas, Tulsa, and eastern Oklahoma. With the addition of the phase-shifting transformer at Woodward, Oklahoma in 2017 and upgrades in central Kansas in December 2018, congestion in SPP is prevalent mainly on the southeastern edge of the SPP footprint.

5.1.3 TRANSMISSION EXPANSION

A handful of major transmission projects (230kV or above) were completed during 2019 (shown on Figure 5–3 below) that will support the efficient transmission of energy across the SPP footprint[137] and promote reliability.

- Tuco – Yoakum 345kV
    - location: west Texas
    - energized: June 2020
- Eddy County – Kiowa 345kV
    - location: eastern New Mexico
    - energized: November 2020

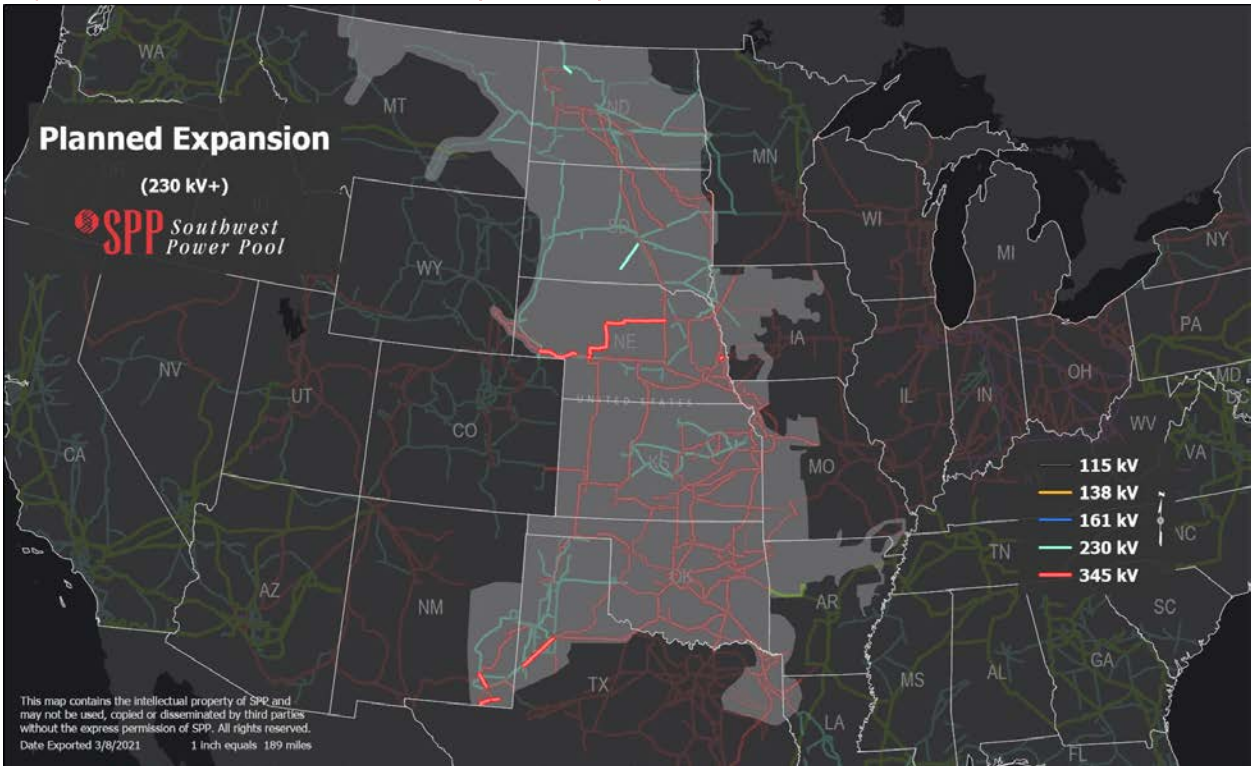
Figure 5–3 SPP transmission expansion in service, 2020



The lines depicted on the map in Figure 5–4 below are projects that will further enhance the SPP transmission grid in future years.

137 2020 SPP Transmission Expansion Plan Report.

Figure 5–4 SPP transmission expansion plan

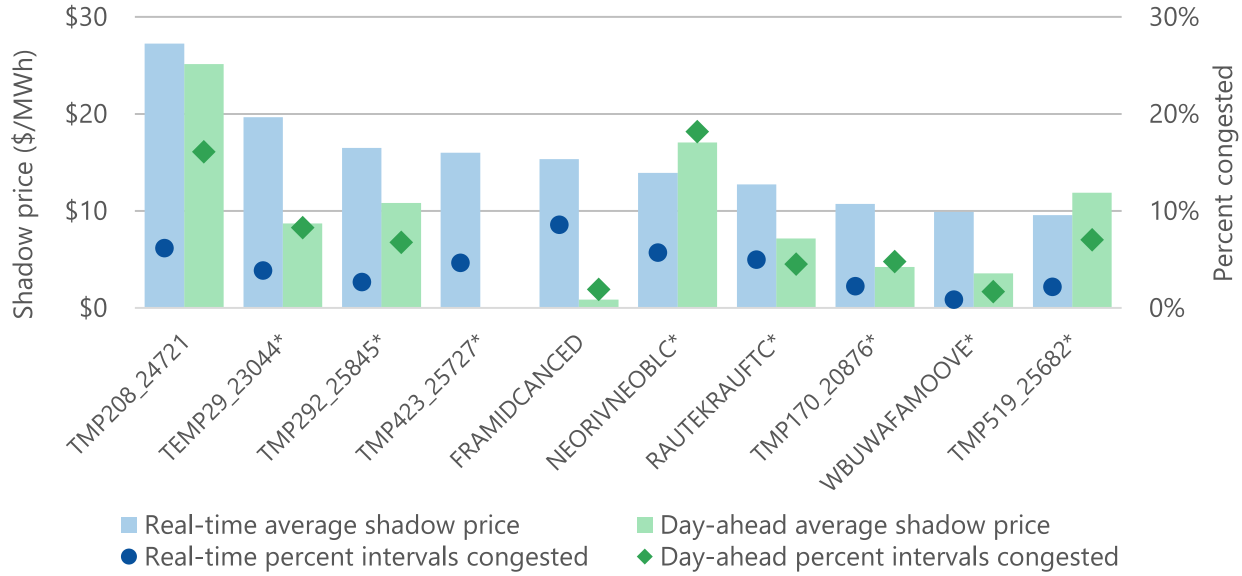


The Integrated Transmission Plan (ITP) projects shown are recommended upgrades to the extra-high-voltage backbone (345kV and above) for a 20-year horizon. The ITP process seeks to target a reasonable balance between long-term transmission investments and congestion costs to customers. The notification 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.

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 ten flowgate constraints by shadow price for 2020.

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



Flowgate name	Region	Flowgate location
TMP208_24721	Western Oklahoma	Okeene-Dover Sw. 138kV (WFEC) ftlo Waukomis-Waukomis Tap 138kV (OKGE)
TEMP29_23044*	Eastern Oklahoma	Stonewall Tap-Tupelo Tap 138kV (WFEC) ftlo Pittsburg-Valliant 345kV (CSWS)
TMP292_25845*	Kansas City	Nashua MPS-Liberty West Tap 161kV (MPS) ftlo Nashua-Hawthorn 345kV (WR)
TMP423_25727*	Northern Missouri	Maryville-Midway 161kV (MPS) ftlo Maryville-Nodaway 161kV (AECI)
FRAMIDCANCED	Central Oklahoma	Franklin-Midwest 138kV (OKGE-WFEC) ftlo Cedar Lane-Canadian 138kV (OKGE)
NEORIVNEOBLC*	SW Missouri/SE Kansas	Neosho-Riverton 161kV (EDE-WR) ftlo Neosho-Blackberry 345kV (AECI-WR)
RAUTEKRAUFTC*	Eastern Nebraska	Raun-Tekamah 161kV ftlo Raun-Fort Calhoun 345kV (OPPD-MEC)
TMP170_20876*	Northeast Kansas	Kelly-Tecumseh Hill 161kV (WR) ftlo Cooper-St. Joseph 345kV (NPPD-MPS)
WBUWAFAMOOVE*	Western Missouri	Warrensburg-Whiteman AFB 161kV (MPS) ftlo Sibley-Overton 345kV (AMRN-KCPL)
TMP519_25682*	Kansas City	Nashua-Roanridge 161kV ftlo Nashua-Hawthorn 345kV (KCPL)

* SPP Market-to-Market flowgate during all or part of 2020

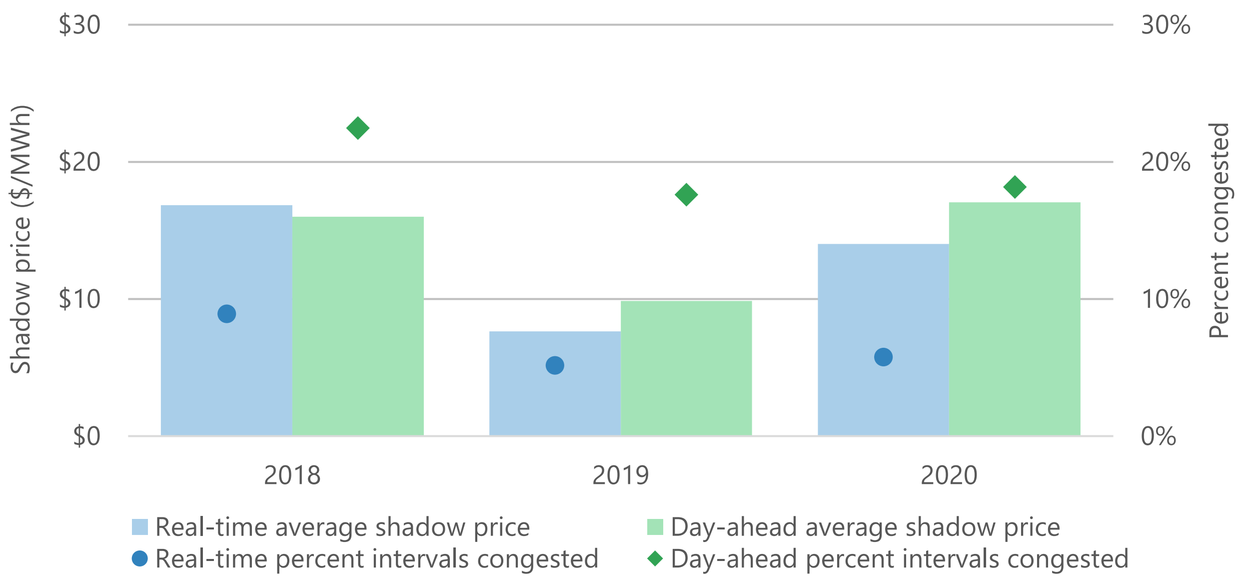
The eastern Oklahoma area continues to see consistent congestion in 2020. The most congested flowgate in this area (Stonewall Tap-Tupelo Tap for the loss of Pittsburg-Valliant) had an average real-time shadow price of around $19/MWh and was congested in four percent of real-time intervals. The flowgate with the highest congestion in 2020 (Okeene-Dover for the loss of Waukomis- Waukomis Tap) is located northwest of Oklahoma City and had an annual real-time shadow price of around $27/MWh, and was congested six percent of all real-time intervals.

Most of the congested areas in the SPP footprint are significantly impacted by inexpensive wind generation but the areas on the eastern edge of SPP are also impacted by external flows given their market-to-market designations. Projects are planned throughout the SPP footprint that may address these areas and are listed in Figure 5–10.

5.1.4.1 Southwest Missouri

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.[138] Congestion in this area dates back to prior to the start of the Integrated Marketplace. Figure 5–7 compares congestion on the Neosho – Riverton 161kV constraint since 2018.

Figure 5–6 Southwest Missouri congestion



Wind in SPP and neighboring areas contributes to the congestion in this area, but has remained lower in 2018, 2019, and 2020 when compared to 2017 (not shown) where the average real-time shadow price was $31/MWh. Congestion still remains on this and other constraints in the area but an upgrade to the limiting element of Neosho – Riverton 161kV in December 2018 has appeared to provide some relief to this area. This constraint remains a focus of seams

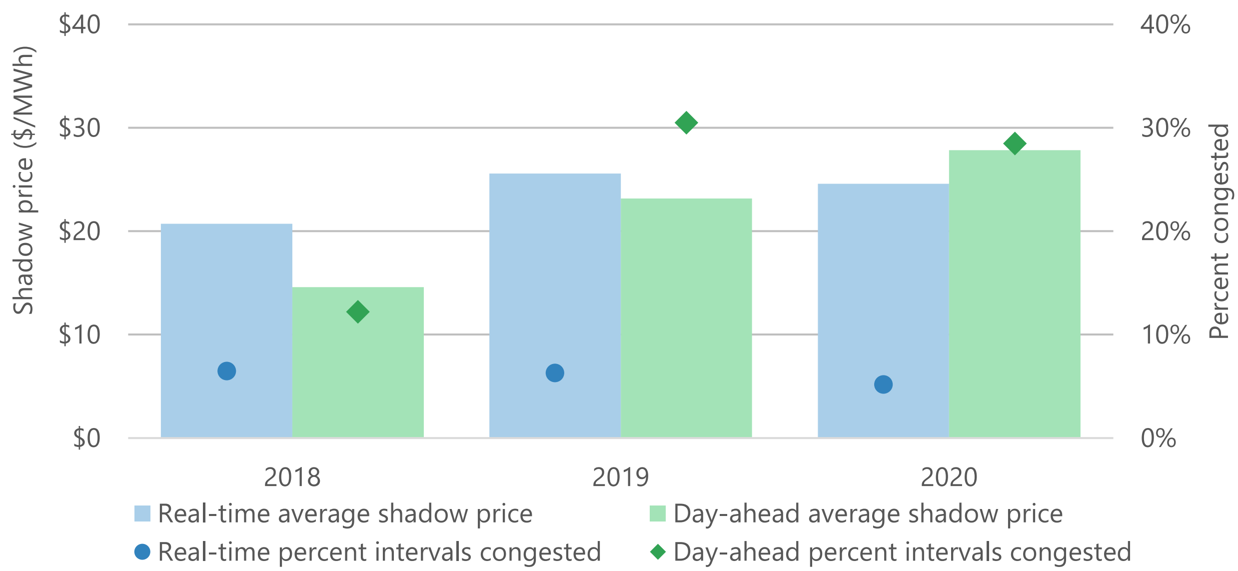
[138] Neighboring non-markets include: Tennessee Valley Authority, Associated Electric Cooperative Inc., and Southwestern Power Administration.

discussions on the amount of market-to-market payments and transmission upgrades that may benefit SPP, MISO, and other neighboring non-market entities. The market-to-market process has settled nearly $39 million in payments from MISO to SPP for the Neosho-Riverton constraint.

5.1.4.2 Eastern Oklahoma

As the southwest Missouri congestion has leveled over the past three years, the eastern Oklahoma area has increased. The eastern Oklahoma area contained the second most constrained facility in both 2019 and 2020. The TMP109_22593[139] was the second most constrained in 2019 and TEMP29_23044[140] was the second most constrained in 2020. Both constraints have the same limiting facility with differing contingent facilities. Figure 5–8 compares congestion for the TMP109_22593 and TEMP29_23044[141] flowgates since 2018.

Figure 5–7 Eastern Oklahoma congestion - TMP109_22593 and TEMP29_23044



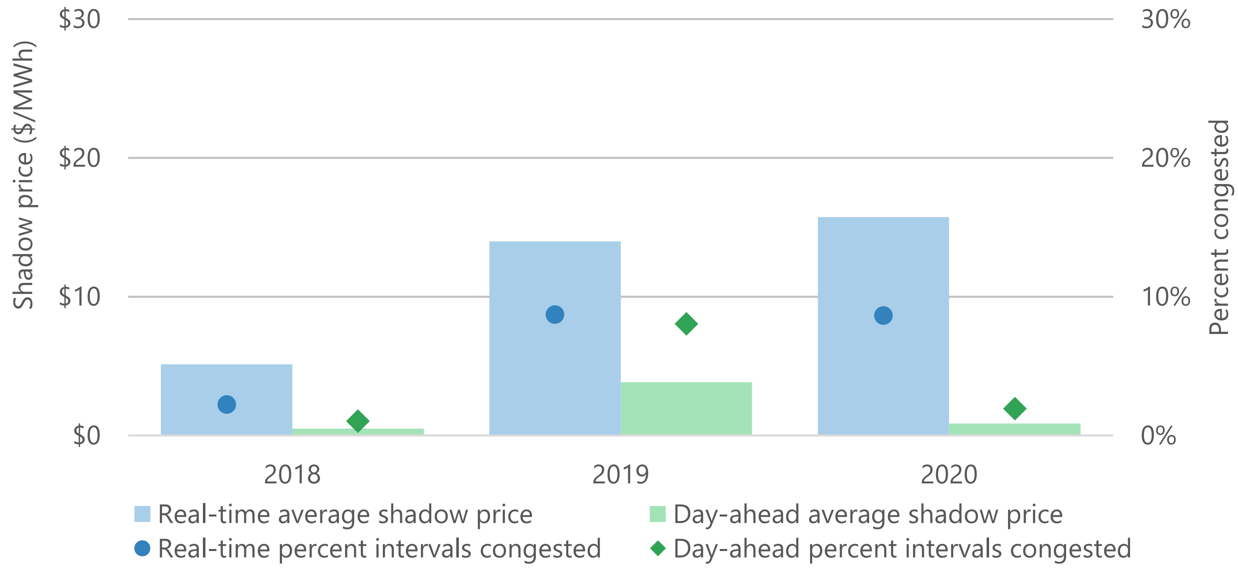
The Stonewall Tap – Tupelo 138kV constraint is a market-to-market constraint and has seen consistent congestion since 2018. This constraint experienced congestion in 28 percent of all intervals in the day-ahead market in 2020 compared to 30 percent in 2019. This constraint

[139] TMP109_22593: Stonewall Tap-Tupelo Tap 138kV (WFEC) for the loss of Seminole-Pittsburg 345kV.
[140] TEMP29_23044: Stonewall Tap-Tupelo Tap 138kV (WFEC) for the loss of Pittsburg-Valliant 345kV.
[141] Values were combined for TMP109_22593 and TEMP29_23044 since these share the same limiting element and seldom are constrained in the same interval.

experienced between five and six percent of congestion during all intervals in the real-time market.

Another area of congestion is in the Oklahoma City area where the Franklin – Midwest 138kV[142] constraint has appeared as a top congested constraint in 2019 and 2020. Figure 5–9 compares congestion for this constraint since 2018.

Figure 5–8 Oklahoma City congestion - FRAMIDCANCED



The Franklin – Midwest 138kV constraint was the fifth most congested constraint in both 2019 and 2020. This constraint is located east of Oklahoma City and has increased in real-time congestion since 2018. This constraint experiences less congestion in day-ahead when compared to real-time. Almost nine percent of all real-time intervals experienced congestion in 2020 compared to two percent of all day-ahead intervals in the same year.

5.1.5 PLANNED TRANSMISSION PROJECTS

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

[142] FRAMIDCANCED: Franklin-Midwest 138kV for the loss of Cedar Lane-Canadian 138kV.

Figure 5–9 Top ten congested flowgates with projects

Flowgate name	Region	Flowgate location	Projects that may provide relief
TMP208_24721	Western Oklahoma	Okeene-Dover Sw. 138kV (WFEC) ftlo Waukomis-Waukomis Tap 138kV (OKGE)	Dover Switch-Okeene 138 kV and Aspen-Mooreland-Pic 138 kV terminal equipment, 2020 ITP Board of Directors approved project
TEMP29_23044*	Eastern Oklahoma	Stonewall Tap-Tupelo Tap 138kV (WFEC) ftlo Pittsburg-Valliant 345kV (CSWS)	Tupelo 138 kV Terminal Upgrades (July 2021, 2017 ITP10).
TMP292_25845*	Kansas City	Nashua MPS-Liberty West Tap 161kV (MPS) ftlo Nashua-Hawthorn 345kV (WR)	None identified at this time
TMP423_25727*	Northern Missouri	Maryville-Midway 161kV (MPS) ftlo Maryville-Nodaway 161kV (AECI)	None identified at this time [Related to an economic need identified in the 2021 ITP Assessment to be completed December 2021]
FRAMIDCANCED	Central Oklahoma	Franklin-Midwest 138kV (OKGE-WFEC) ftlo Cedar Lane-Canadian 138kV (OKGE)	Pleasant Valley 345/138 kV Station, Minco-Pleasant Valley-Draper 345 kV new line, Franklin-Midwest 138 kV terminal equipment, Cimarron-Draper 345 kV terminal equipment and Pleasant Valley cut-in, 2020 ITP Board of Directors approved project [Related to an operational economic need identified in the 2021 ITP Assessment to be completed December 2021]
NEORIVNEOBLC*	SW Missouri/SE Kansas	Neosho-Riverton 161kV (EDE-WR) ftlo Neosho-Blackberry 345kV (AECI-WR)	Neosho -Riverton 161kV Rebuild (October 2023, ATSS SPP-2019-AG1-AFS-2)
RAUTEKRAUFTC*	Eastern Nebraska	Raun-Tekamah 161kV ftlo Raun-Fort Calhoun 345kV (OPPD-MEC)	None identified at this time [Related to an economic need identified in the 2021 ITP Assessment to be completed December 2021]
TMP170_20876*	Northeast Kansas	Kelly-Tecumseh Hill 161kV (WR) ftlo Cooper-St. Joseph 345kV (NPPD-MPS)	None identified at this time [Related to an economic need identified in the 2021 ITP Assessment to be completed December 2021]
WBUWAFAMOOVE*	Western Missouri	Warrensburg-Whiteman AFB 161kV (MPS) ftlo Sibley-Overton 345kV (AMRN-KCPL)	None identified at this time [Related to an economic need identified in the 2021 ITP Assessment to be completed December 2021]
TMP519_25682*	Kansas City	Nashua-Roanridge 161kV ftlo Nashua-Hawthorn 345kV (KCPL)	None identified at this time

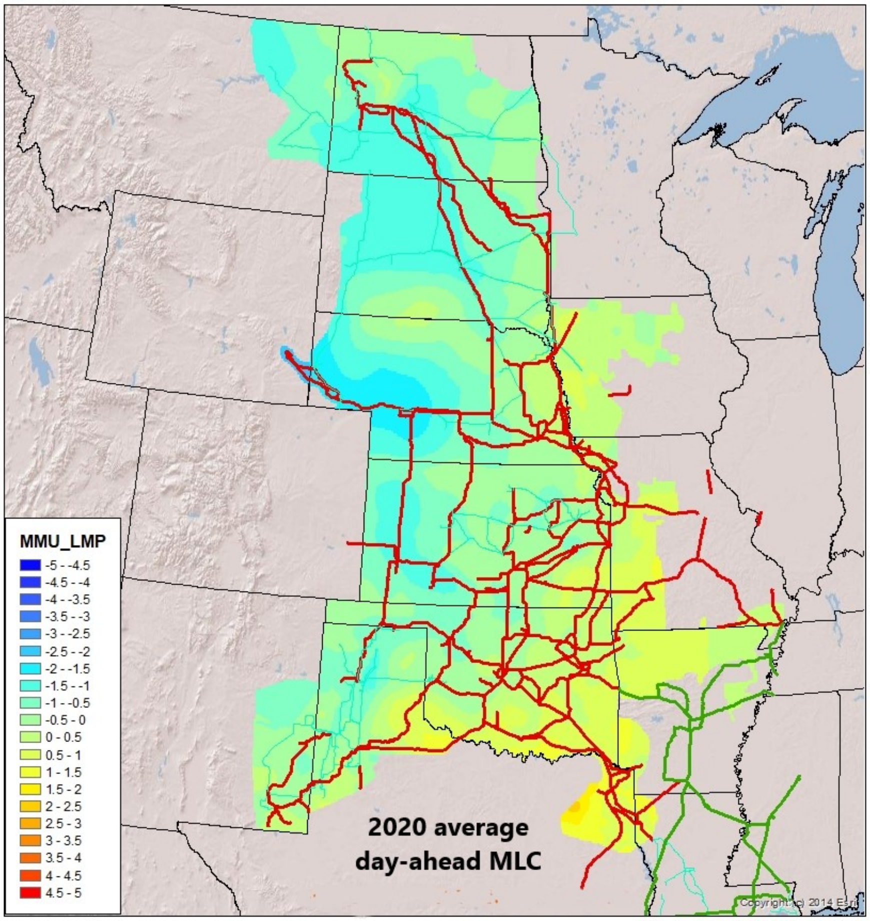
* SPP Market-to-Market flowgate during all or part of 2020

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 2020 were 2.8 percent in the day-ahead market. This is consistent with 2.8 percent in 2019 and 2018. 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 5–10 Marginal loss component map, day-ahead



The average day-ahead marginal loss component ranges from about −$2.19/MWh at the Laramie River Station in eastern Wyoming, to −$1.90/MWh near North Platte, Nebraska, to −$1.20/MWh in the Texas panhandle area, to −$0.12/MWh in the Kansas City area, and over $2.50/MWh in northeast Texas. 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. The $4.86/MWh spread between geographic prices in 2020 is less than the $5.65/MWh spread in 2019.

5.1.7 FREQUENTLY CONSTRAINED AREAS AND LOCAL MARKET POWER

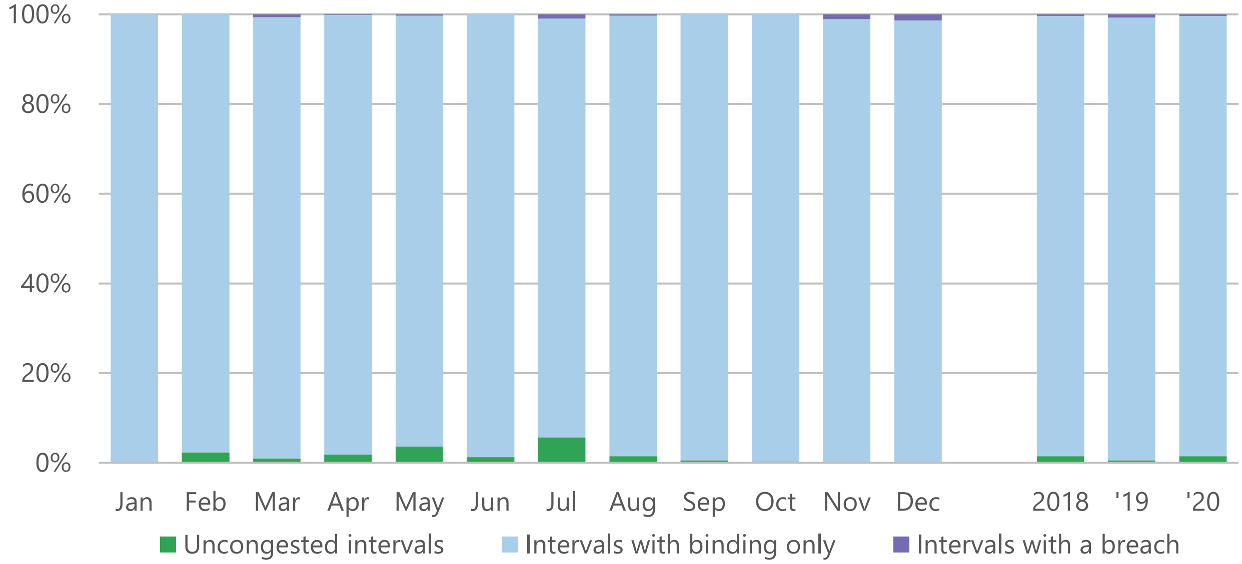
Congestion in the market creates local areas where only a limited number of suppliers can provide the energy to serve local load without overloading a constrained transmission element. Under these circumstances, the pivotal suppliers have local market power and the ability to raise prices above competitive 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 Section 7.2.2. 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 2018 results removed the Texas Panhandle (Lubbock) area and added two new areas; southwest Missouri and central Kansas. These changes were implemented February 22, 2019. The 2019 study results identified a reduction in congestion in the southwest Missouri and central Kansas areas and recommended removal of these two frequently constrained areas. No new areas were identified to be added at the time of the study, but several areas such as Tulsa, Oklahoma City, and southeast Oklahoma experienced increases in pivotal supplier hours. The removals of the southwest Missouri and central Kansas areas were implemented March 31, 2020. The latest 2020 analysis identified a similar congestion pattern to the 2019 study resulting in no areas added as frequently constrained areas.

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.

Figure 5–11 Breached and binding intervals, day-ahead market

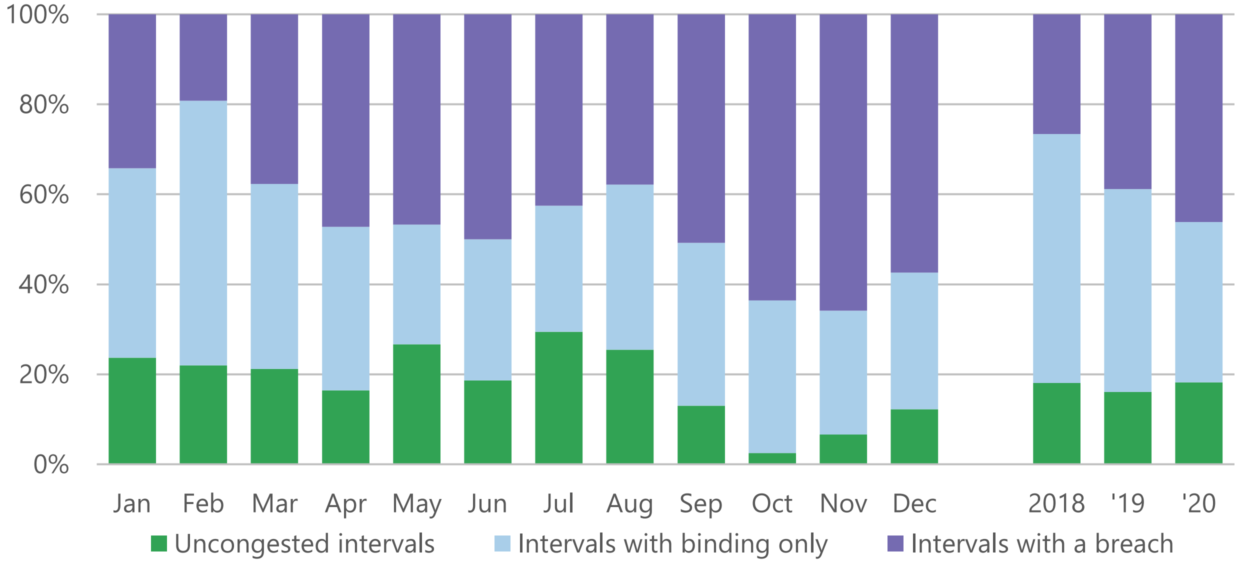


The figure shows that uncongested intervals and breached intervals are rare in day-ahead. Historically in the Integrated Marketplace, less than one percent of day-ahead market intervals incur a breached condition compared to over 25 percent for the real-time market[143] in 2018 and increasing to over 45 percent in 2020.

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.

[143] 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 5–12 Breached and binding intervals, real-time



As shown above, uncongested intervals has remained relatively the same from 2018 to 2020 with 16 percent to 18 percent of intervals with no congestion. Real-time intervals with a breached constraint increased in 2019 and again in 2020, with 39 percent of intervals with a breach in 2019, compared to 46 percent in 2020.

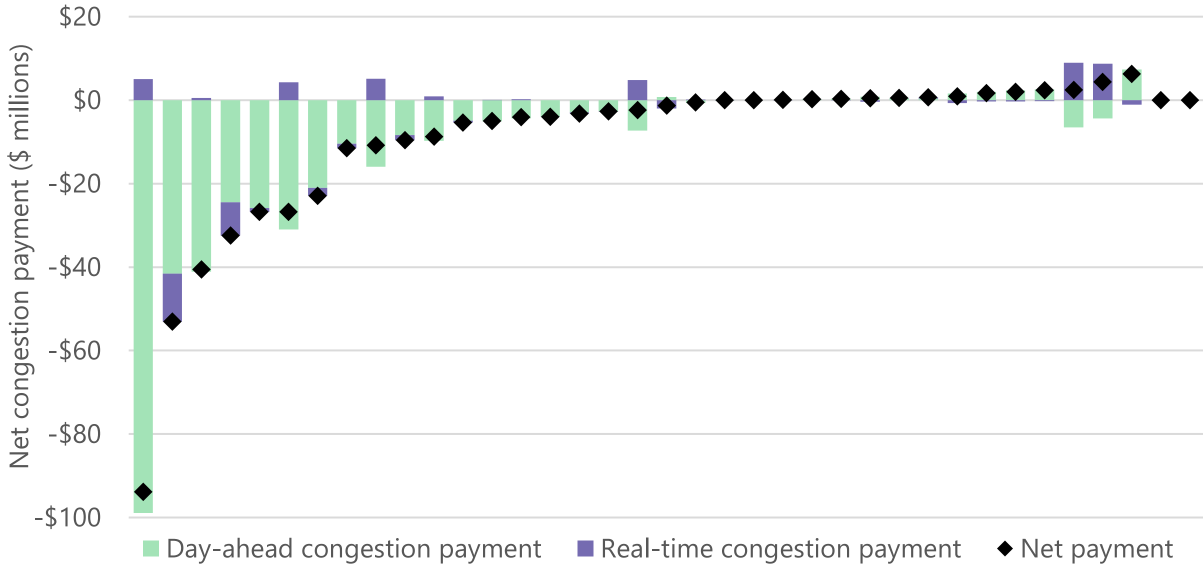
Market-to-market coordination with MISO, as discussed in Section 2.7.2, was implemented in March 2015. A market-to-market breach of a MISO constraint could be an indicator that MISO has more efficient generation than SPP to alleviate congestion on that constraint. Of the 46 percent of the real-time intervals with a breached constraint in 2020, over 85 percent of these had a breached market-to-market constraint. This is an increase compared to 74 percent in 2019 and 55 percent in 2018. This is noticeable in Figure 5–1 and Figure 5–2 showing the congestion on the eastern edge of SPP where neighboring flows are more prevalent.

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 2020.

Figure 5–13 Annual congestion payment by load-serving entity



Most load-serving entities face congestion costs, depicted as negative payments (charges) in the graph. Congestion stems from various injection and withdrawal market activities and can manifest as either a charge or credit. Day-ahead congestion payments ranked by load-serving entities ranged from about $99 million in charges to more than $7 million in payments.[144]

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, 98 percent of the SPP load-serving entities' net congestion costs stemmed from the day-ahead market.

Figure 5–15 provides the aggregate congestion costs and hedging totals for load-serving entities, non-load-serving entities and financial only entities, and the total for all entities.

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

Figure 5–14 Total congestion payments

(in $ millions)	Load-serving entities			Non-load-serving and financial only			Total		
	2018	2019	2020	2018	2019	2020	2018	2019	2020
Day-ahead congestion	$ 391	$ 362	$ 352	$ 170	$ 232	$ 225	$ 561	$ 593	$ 577
Real-time congestion	-10	-10	-9	-98	-126	-127	-108	-136	-135
Net congestion	381	352	344	72	106	98	453	457	442
Real-time congestion uplift	-81	-116	-115	-6	-10	-12	-87	-126	-127

The real-time market congestion payments result in a net benefit of $9 million for load-serving entities. Total real-time market congestion payments for non-load-serving and financial only entities also resulted in a net benefit and amounted to $127 million. On an individual basis, real-time market congestion ranged from almost $9 million in payments to over $11 million in costs for load-serving entities. Real-time market congestion ranged from $24 million in payments to $23 million in costs for 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.

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 2020, SPP allocated about 90 percent of revenue neutrality uplift charges to load-serving entities, resulting in an additional $115 million in congestion-related charges for load-serving entities.[145]

5.2 CONGESTION HEDGING MARKET

In the Integrated Marketplace, the locational marginal prices assessed to load are generally higher than the locational marginal prices assessed to generators. The largest portion of this price difference is almost always attributed to congestion. This is an expected outcome and

[145] Real-time congestion uplift is not allocated in the same proportion in which it is collected.

central to the design of nodal electricity markets. The difference between what generators are paid and what loads pay is often referred to as congestion rent. SPP remains revenue neutral in all Integrated Marketplace transactions and therefore must allocate the congestion rent back to the market participants. The congestion hedging market is the mechanism used to allocate congestion overcollections.[146]

5.2.1 MARKET DESIGN

Market participants participate in the congestion hedging market by obtaining auction revenue rights and/or transmission congestion rights. Auction revenue rights begin as entitlements associated with long-term, firm transmission service reservations. These transmission service reservations are a revenue source for transmission owners and an expense for transmission customers. More specifically, transmission owners receive revenues from transmission customers for building and maintaining the transmission lines, and transmission customers pay the transmission owners for the use of the lines by way of the charges associated with transmission service reservations.[147]

Auction revenue rights link the transmission service, which provides physical rights, to the Integrated Marketplace by converting these to financial rights. SPP verifies transmission service entitlements, which become candidate auction revenue rights. To obtain auction revenue rights, market participants nominate candidate auction revenue rights in the annual auction which awards revenue rights from June to May. If the nominations pass the allocation's simultaneous feasibility test, the candidate auction revenue rights become auction revenue rights. The simultaneous feasibility test ensures that the market's aggregate nomination of auction revenue rights does not violate thermal constraint limits under a single contingency.[148] The test incorporates information from the network model, which aids SPP in aligning the supply of auction revenue rights with the capacity of the underlying transmission system. The simultaneous feasibility test aims to ensure the revenues generated from the congestion right auction will sufficiently fund the quantity of auction revenue rights nominated. If a candidate

[146] With respect to day-ahead congestion rent only.
[147] These charges are assessed through transmission settlements and include various tariff schedules.
[148] *SPP Open Access Transmission Tariff*, Section 5.3.3, Simultaneous Feasibility

auction revenue right nomination fails the simultaneous feasibility test, this reduces the quantity of auction revenue rights successfully converted from candidate rights.[149]

Once market participants have successfully nominated their candidates into auction revenue rights, they must choose to either hold their auction revenue right or convert it into a transmission congestion right through a process known as self-conversion.[150] If a market participant holds their auction revenue right, they will receive, or pay, a stream of unchanged cash flows over the life of the product. The size and direction of the cash flow depends on the market's collective assessment of the congestion rent along the auction revenue right path as assessed by prices during the transmission congestion right auction. If a market participant believes that the auction prices will undervalue the congestion rent associated with their auction revenue right, the market participant will likely self-convert. When a market participant self-converts, their auction revenue right becomes a transmission congestion right, which means their cash flow is subject to the fluctuations in day-ahead market congestion rent.

Financial-only[151] market participants participate alongside traditional utilities in the transmission congestion right auctions to provide additional liquidity and price discovery. All participants compete for the residual network capacity, on price. The auction software attempts to maximize auction revenue without violating the simultaneous feasibility test. This test helps align the supply of transmission congestion rights with the residual capacity of the underlying transmission system. If a transmission congestion right bid fails the simultaneous feasibility test, the quantity of transmission congestion rights successfully obtained will be reduced to the point where the bid no longer violates the test. Once a market participant obtains a transmission congestion right, they can hold it through to settlement, offer it for sale in a subsequent auction, or transact on the bulletin board outside of the auction cycle. The overwhelming majority of positions are held through to settlement.

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[149] *SPP MMU State of the Market Report, Spring 2018*, page 50.
[150] *SPP Open Access Transmission Tariff,* Section 5.4.1 (2)
[151] Financial-only market participants do not generate or serve load in the SPP footprint.

5.2.2 MARKET TRANSPARENCY

5.2.2.1 Hedging effectiveness by classification

The transmission congestion right and auction revenue right net payments paid to entities in the SPP market are shown in Figure 5–16.

Figure 5–15 Total congestion and hedges

(in $ millions)	Load-serving entities			Non-load-serving and financial only			Total		
	2018	2019	2020	2018	2019	2020	2018	2019	2020
DA congestion	391	362	352	170	232	225	561	593	577
RT congestion	(10)	(10)	(9)	(98)	(126)	(127)	(108)	(136)	(135)
Net congestion	381	352	344	72	106	98	453	457	442
TCR charges	215	250	243	175	181	179	390	431	422
TCR payments	(331)	(358)	(409)	(263)	(309)	(296)	(594)	(668)	(705)
TCR uplift	26	34	55	32	51	77	58	85	132
TCR surplus *	(5)	(5)	(2)	(7)	(6)	(2)	(13)	(11)	(4)
ARR payments	(249)	(315)	(325)	(18)	(20)	(19)	(267)	(335)	(344)
ARR surplus	(113)	(89)	(72)	(10)	(7)	(6)	(123)	(96)	(78)
Net TCR/ARR	(458)	(482)	(509)	(91)	(111)	(68)	(549)	(593)	(577)

** remaining at year-end*

Payments to load-serving entities of $509 million exceeded their day-ahead congestion costs of $352 million in 2020. Additionally, real-time congestion costs aided load-serving entities by $9 million, thereby reducing total congestion cost to $344 million. This shows that overall, load-serving entities hedged their day-ahead congestion effectively, in aggregate. In 2020, non-load-serving and financial only entities collected transmission congestion right and auction revenue right net revenues of $68 million, which did not exceed their day-ahead and real-time market congestions costs of $98 million. Overall, day-ahead congestion cost decreased three percent year-to-year, from $593 million in 2019 to $577 million in 2020.

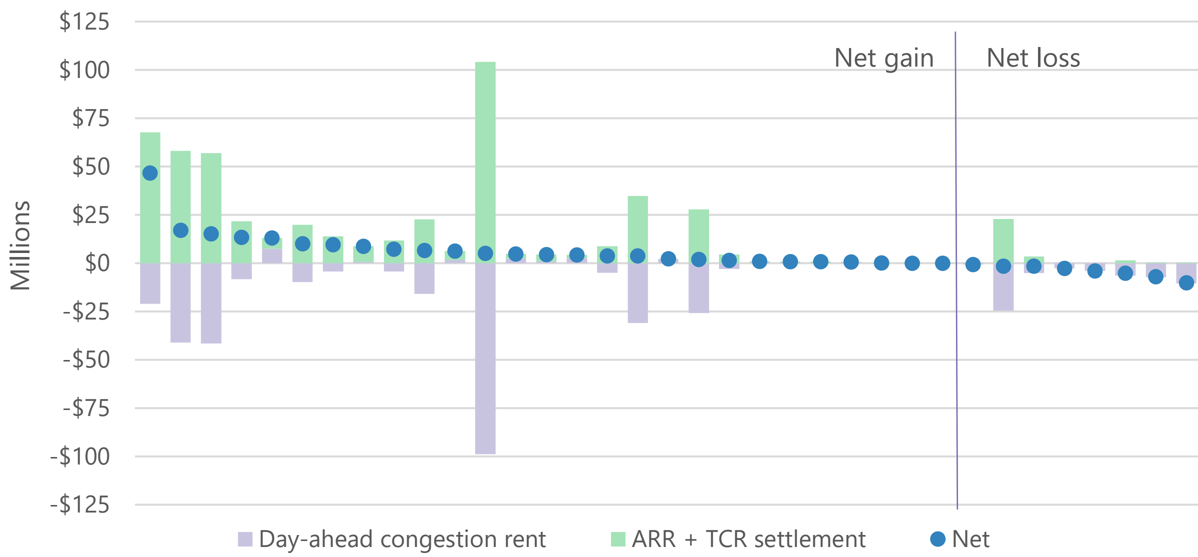
5.2.2.2 Bidding behaviors

The SPP working groups continued dialogue over the past year with respect to obtaining auction revenue rights, and by extension self-converted transmission congestion rights. The market monitor reported on this topic in the quarterly state of the market report for spring

2018,[152] and is actively engaged in efforts to improve this issue. The Holistic Integrated Tariff Team has adopted a recommendation to provide a limited amount of counterflow in order to increase the amount of prevailing flow.[153] As noted above, in aggregate, load-serving entities received more revenue from their congestion hedges than they paid in day-ahead and real-time congestion cost. However, on the individual participant level, some load-serving entities under-hedged while others over-hedged.

Figure 5–17 shows, by load-serving market participant, the day-ahead congestion exposure along with the value of auction revenue rights and transmission congestion rights as well as the net overall position.

Figure 5–16 Net congestion revenue by market participant



The figure highlights that the majority of load-serving participants received positive net revenues, while a handful of participants held portfolios that did not cover their day-ahead congestion costs. For instance, the bottom five participants paid almost $29 million more in congestion costs than was offset by their auction revenue right and transmission congestion right positions. This is less than the $36 million for the bottom five participants in the 2019 calendar year.

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152 *SPP MMU State of the Market Report, Spring 2018*, page 50.
153 *Holistic Integrated Tariff Team Report*

The range of participant outcomes is influenced by three main factors: hedging need, individual participant bidding behavior, and the market's collective bidding behavior.

With respect to hedging need, each participant experiences varying levels of congestion exposure mostly related to geographic location and type of physical interconnection. The various levels of congestion exposure lead to different hedging needs among market participants.

The bidding behavior of the individual participant affects the auction revenue rights they receive through the allocation. Participants can, and do, employ numerous strategies with varying degrees of success.

The bidding behavior of the other market participants, as a whole, affects the ability of each and every other market participant to obtain hedges through the auction revenue right allocation. More specifically, if a transaction is physically feasible with respect to transmission service, and by extension the day-ahead market, it does not necessarily mean the transaction will also be feasible in the auction revenue right allocation. The issue arises because the transmission system's capacity, represented by transmission service requests,[154] includes both prevailing flow and counter-flow transactions. However, participants often choose not to nominate their counter-flow candidate auction revenue rights in the allocation process, in part, because these positions tend to carry negative cash flows. These incentives motivate individual participants to abstain from counter-flow positions.[155] By not nominating all candidate auction revenue rights, the capacity in the allocation will not match the capacity of the physical system. Because the basis of the auction revenue right is transmission service, if the two capacities do not align, a participant's auction revenue right may not perfectly hedge their transmission service and their related day-ahead market activity.

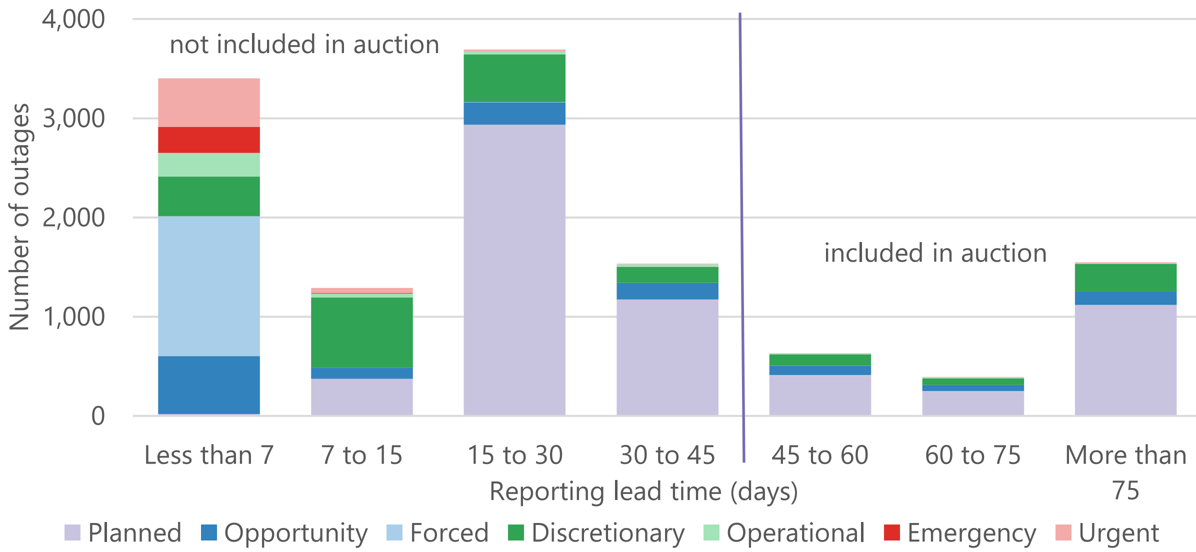
Differences between outages modeled in the auction processes and day-ahead market can also affect market participants' ability to obtain hedges. Details on outage modeling are discussed below.

[154] Long-term, firm, transmission service requests
[155] SPP MWG Meeting Materials, 1/22/2019, Item 11a, SPP MMU_ARR Observation.pdf

5.2.2.3 Transmission outage modeling

When there are outages in the day-ahead market that were not in the transmission congestion rights auction, there is a reduction in system capacity which can cause underfunding. Figure 5–18 shows transmission outages by reported lead time.

Figure 5–17 Transmission outages by reporting lead time

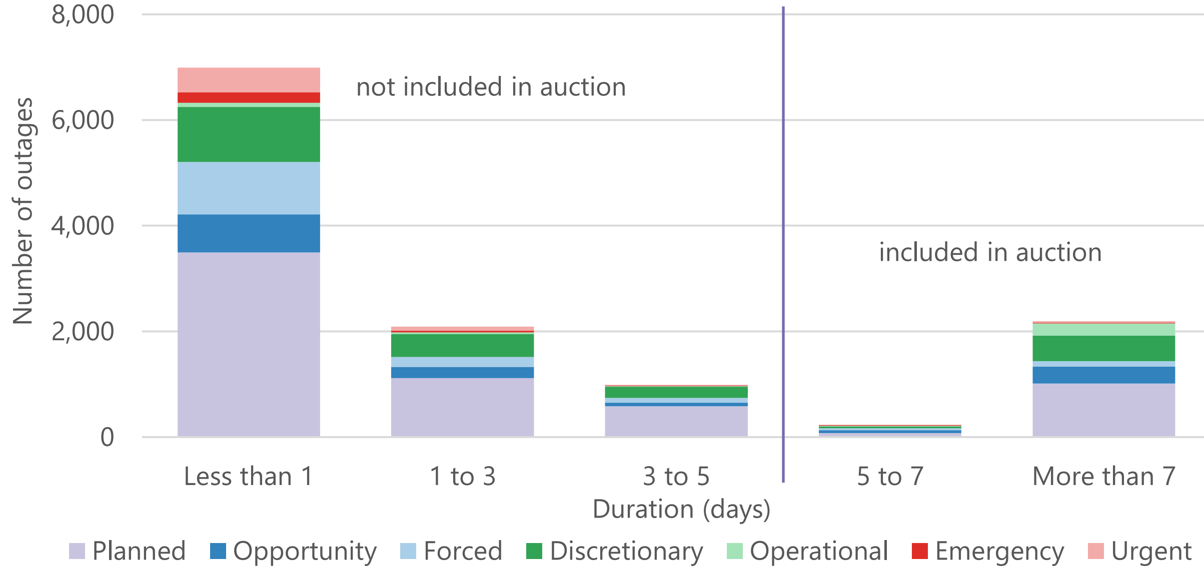


SPP models only transmission outages that were reported at least 45 days prior to the first of the month in the transmission congestion rights auction.[156] However, SPP only requires transmission owners to submit planned outages 14 days in advance.[157] The above figure shows that the majority of outages are not considered in the transmission congestion rights markets solely due to the submission lead time. Roughly 80 percent of outages are ruled out of the transmission congestion rights model by this phase alone. This is a similar level as prior years.

Figure 5–19 shows the duration in days for the different types of outages.

[156] *Integrated Marketplace Protocols*, Section 6.6
[157] *SPP Operating Criteria*, Appendix OP-2

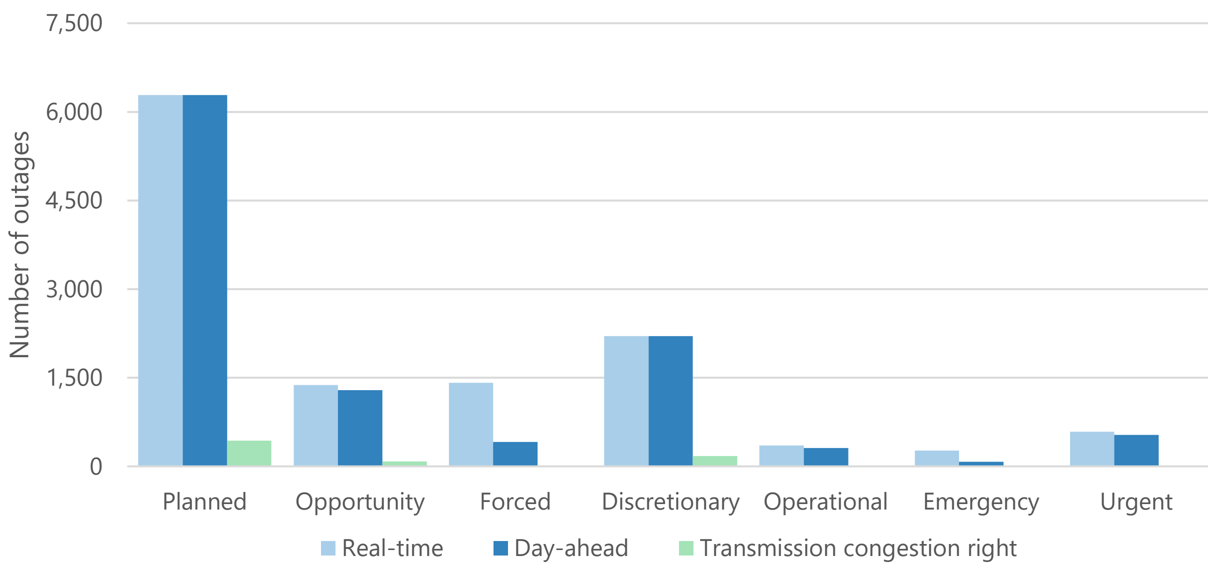
Figure 5–18 Transmission outages by duration



Outages shorter than five days are excluded from auction revenue right/transmission congestion right processes. This means the vast majority of outages (81 percent) are excluded from the transmission congestion rights models because they are less than five days or were not reported in the time allowed to be included in the transmission congestion rights models.

Figure 5–20 shows outages by real-time, day-ahead, and transmission congestion right markets.

Figure 5–19 Transmission outages by market



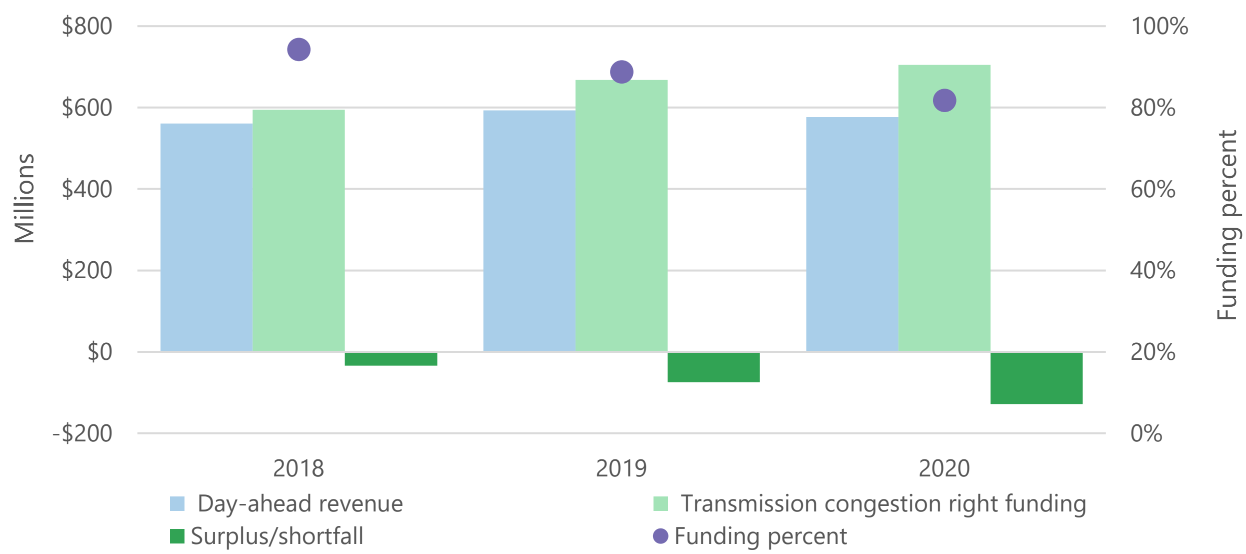
While the number of outages in the day-ahead and real-time are similar, the outages represented in the transmission congestion rights market are only a fraction of the total number of outages. The transmission congestion market only includes outages that are longer than five days, and are submitted at least 45 days in advance of the first of the month. This represented only about six percent of the 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 improving how outages are accounted for in the transmission congestion right auction process to improve the congestion hedging market results.

5.2.3 FUNDING

Funding for transmission congestion rights decreased in 2020. Additionally, funding percentage for auction revenue rights and auction revenue right closeout decreased in 2020. As mentioned in previous reports,[158] the overfunding of auction revenue rights could be cause for concern. The market monitor continues to encourage SPP to review and address the reasons for this overfunding.

Figure 5–20 Transmission congestion right funding levels, annual

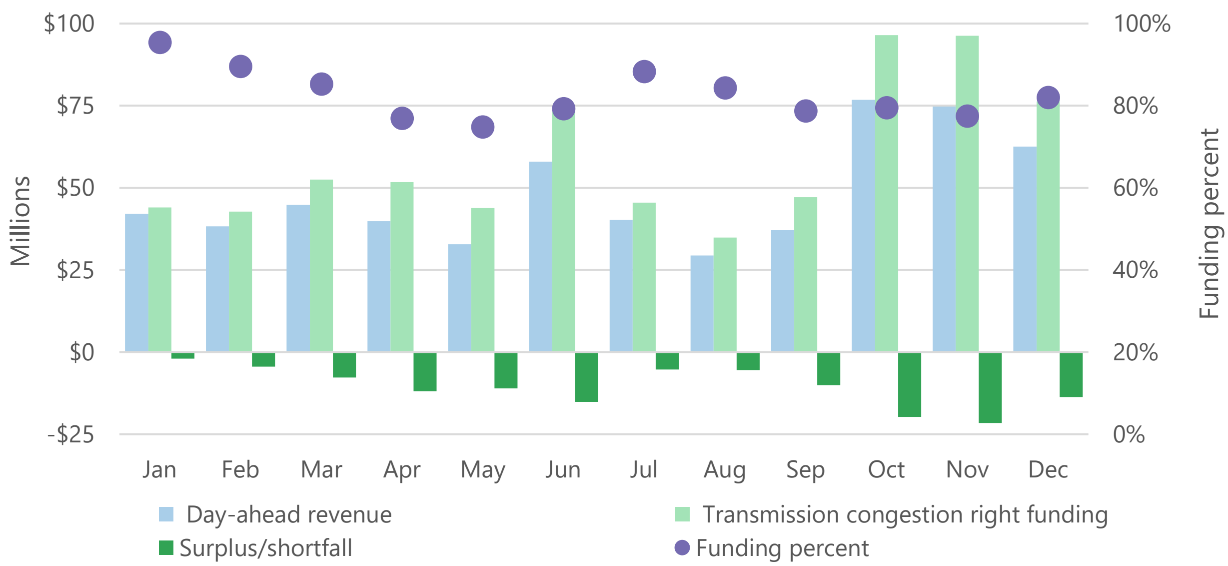


[158] SPP MMU 2017 Annual State of the Market report

The 2018 calendar year, produced 94 percent transmission congestion right funding while the following calendar years decreased to 89 percent and 82 percent respectively. The 2020 calendar year funding percentage is materially below the 90 percent target. The funding percentage declined significantly year-over-year, and the shortfall declined by more than $53 million during 2020. The cumulative funding by constraint tends to fall between −$1 and $1 million. However, during the 2020 calendar year there were thirty-three constraints with more than −$1 million underfunding. Those thirty-three constraints, roughly 2 percent of the day-ahead constraints, contributed more than 101 million to the underfunding.

Monthly transmission congestion right funding levels and revenue are shown in Figure 5–22.

Figure 5–21 Transmission congestion right funding levels, monthly

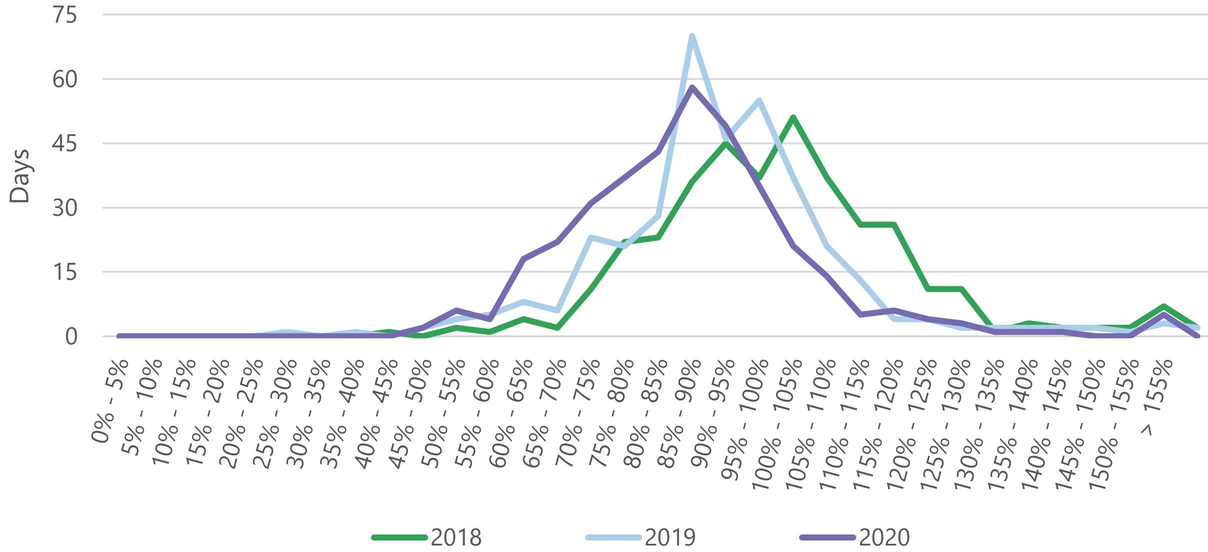


The monthly funding percentage declined from January through May; and then rose, declined, and rose again from June through December. Only two months achieved funding within the 90 to 100 percent target range. [159] The lowest funding percentage was 75 percent in May and the highest was at 95 percent in January.

Daily observations of transmission congestion right funding for the past three years are shown in Figure 5–23.

[159] *Integrated Marketplace Protocols*, Section 5.3.3 specifies a target range. "In the event the cumulative funding is at or below 90 percent or above 100 percent, MWG may approve an additional adjustment…"

Figure 5–22 Transmission congestion right funding, daily

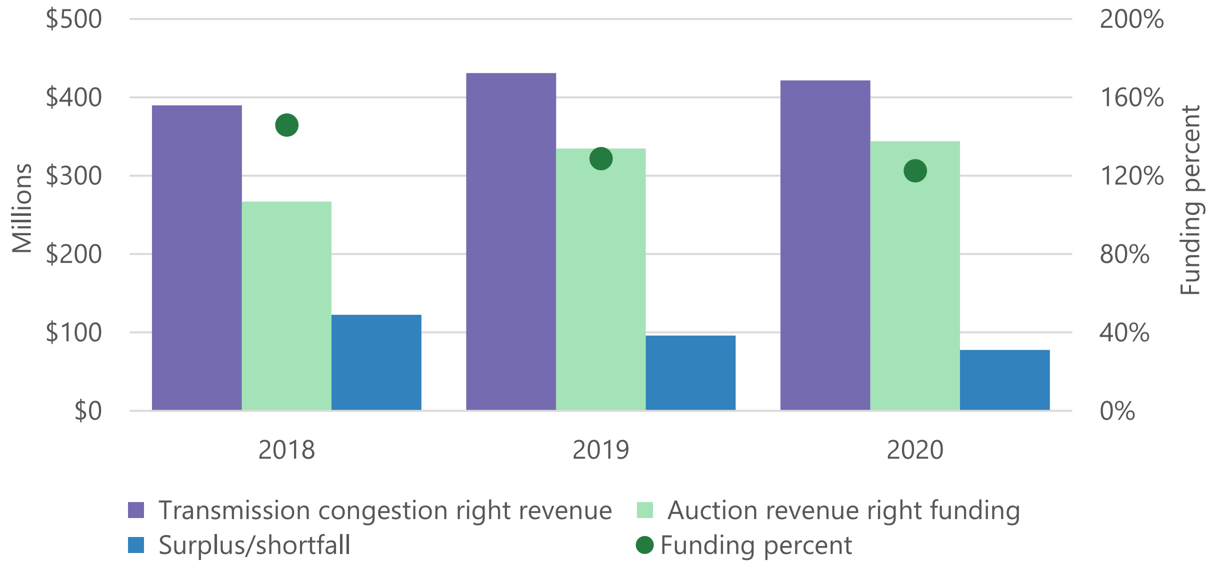


Most daily observations of transmission congestion right funding percent fall between 80 percent and 120 percent, as seen in Figure 5–23. While variation in funding can be expected as a result of factors including transmission outages and derates, the fact that the majority of funding falls in this range indicates that the overall process is generally effective. There was a decrease in funding events in excess of 150 percent, and the number funding events below 50 percent was unchanged at eight year-over-year. This data suggests that while the annual funding percentage is relatively stable year-over-year, the downside volatility in the daily observations continued to increase.

The magnitude of downside volatility also increased in 2020. Most daily funding observations fell between plus and minus $250,000 in 2020. However, the frequency of downside events outside this range continues to increase. For example, in 2018, there were 20 days where daily underfunding exceeded $1 million. In 2019, there were 29 of these events and in 2020 there were 52 events. Conversely, the frequency in overfunding events in excess of $1 million declined from two events in 2018 to zero in 2019 and 2020.

Figure 5–24 shows the auction revenue right funding percentage since 2018.

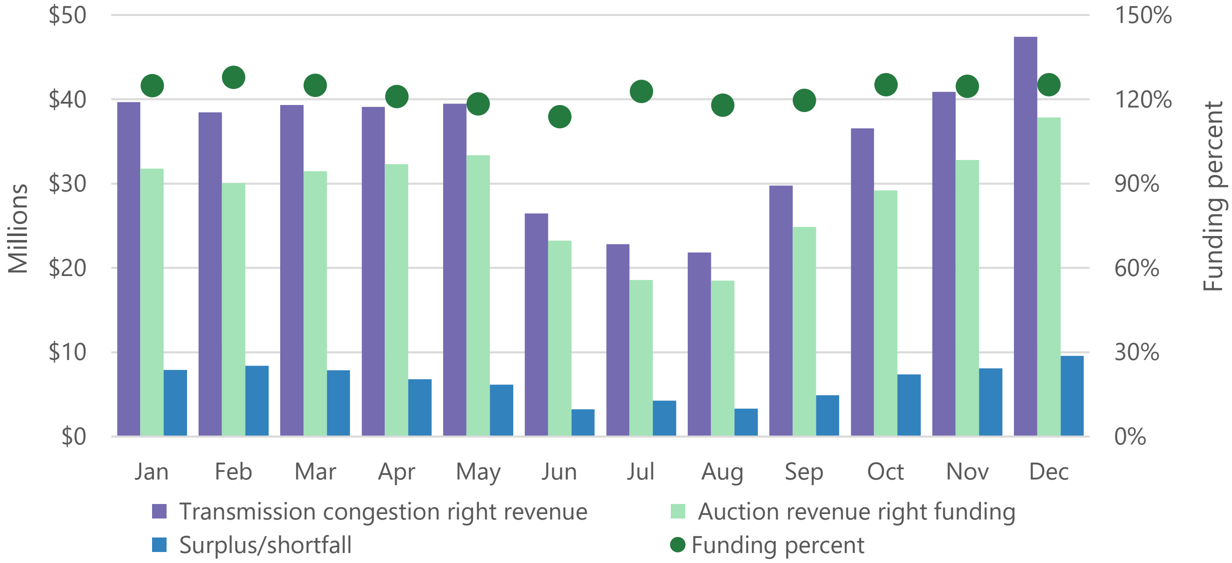
Figure 5–23 Auction revenue right funding levels, annual



Auction revenue right funding has declined over the last three calendar years. In 2018, auction revenue rights were 146 percent funded, followed by 129 percent funded in 2019, and 123 percent in 2020. Auction revenue right surpluses also declined over the last three years. In 2018, the auction revenue right surplus was $123 million, followed by $96 million in 2019, and $78 million in 2020. While the decrease in funding percentage is encouraging, the surplus is still quite substantial and presents a potential concern, as it could be an indicator of inefficiency. The market monitor urges SPP, along with the stakeholders, to determine the root cause of the overfunding, and analyze the surplus distribution methodology to ensure it is equitably allocated.

Figure 5–25 shows the 2020 monthly funding levels and revenues for auction revenue rights.

Figure 5–24 Auction revenue right funding levels, monthly



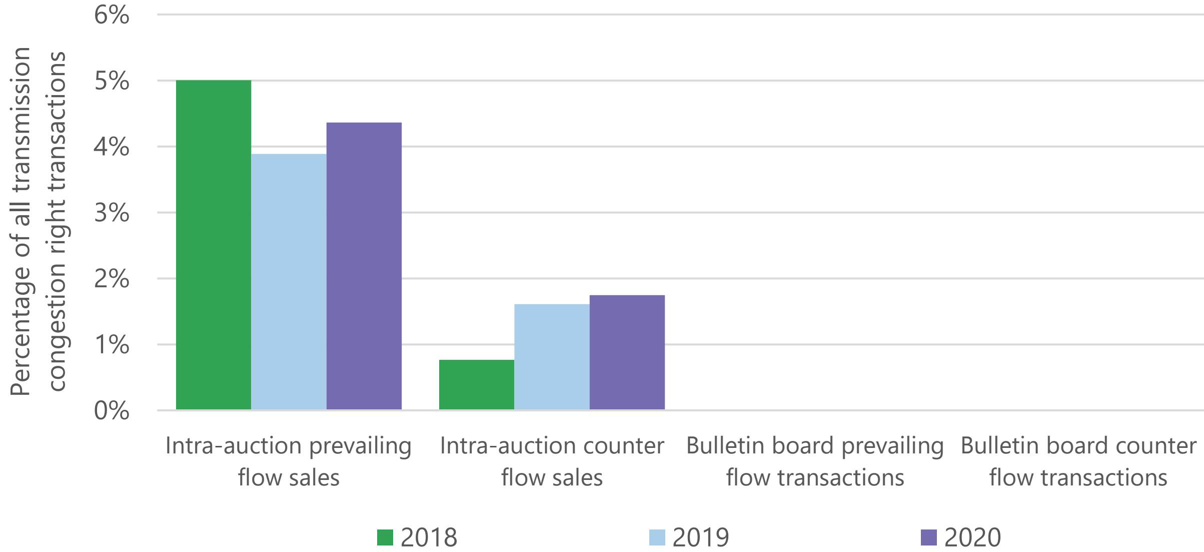
The shift in auction revenue rights funding beginning in June reflects the change in the TCR year, which runs from June to May. The figure also shows the auction revenue right funding was relatively stable though out the 2020 calendar year.

5.2.4 INTRA-AUCTION SALES AND BULLETIN BOARD TRANSACTIONS

Intra-auction sales refer to the sale of a previously acquired transmission congestion right position in a subsequent auction. Bulletin board transactions refer to trades where a market participant buys or sells a position outside of the auction cycle through the SPP bulletin board. Overall, both inter-auction sales and bulletin board transactions remain low.

Figure 5–26 shows the transaction volume by type as a percentage of all transmission congestion right purchase volume.

Figure 5–25 Intra-auction sales and bulletin board transactions



No bulletin board transactions cleared in 2018, 2019, or 2020. Additionally, intra-auction sale volume remained relatively stable around five percent of the total transmission congestion right volume.

Outside their relationship to the auction cycle, these transactions also differ from each other in another material way. Bulletin board transactions are similar to the secondary equity market, where a share of stock is offered for sale and that same share is later purchased by another market participant. As such, the bulletin board transactions do not affect total supply; they only affect ownership of the existing supply.

However, intra-auction sales can affect supply in addition to ownership. When market participants offer their prevailing flow positions for sale intra-auction, the capacity of those positions once used is available to the market again. But, the newly available system capacity can be taken up by any path, not just the path sold intra-auction. Furthermore, to sell counter-flow positions intra-auction, unclaimed prevailing flow capacity must exist for the transaction to clear.[160] This is because counter-flow intra-auction sales reduce the total capacity available. The counter-flow now offered for sale, previously facilitated other prevailing flow positions. If the counter-flow sale were to clear without considering supply, the prevailing flow once facilitated by this counter-flow would no longer be feasible. So in order for these existing prevailing flow

[160] The additional capacity could also be provided by another counter-flow intra-auction bid.

transactions to remain feasible, additional prevailing flow capacity must exist. Practically, the additional prevailing flow capacity required plays the same role once played by the counter-flow being offered for sale. These circumstances likely also incentivize market participant abstentions from counter-flow. Generally, if a market participant holds a counter-flow position, it could be very difficult to sell the position intra-auction, which is the main source of intra-marketplace liquidity.[161]

5.2.5 ISSUES, PROGRESS, AND NEXT STEPS

While the congestion hedging market is workably effective overall, the market monitor highlights the following four areas where continued progress could bring about improved market outcomes, risk reduction, and efficiency gains.

1. **Obtaining auction revenue rights**

   Market participants experience varying levels of success in obtaining auction revenue rights and by extension self-converted transmission congestion rights. This issue prompted the Holistic Integrated Tariff Team to issue the recommendation: implement congestion hedging improvements in April 2019.[162] However, after nearly a year of deliberation, the Market Working Group overwhelmingly prefers the status quo. The Strategic Planning Committee has taken the lead and hired a consultant to recommend modifications to the market design. The consultant's report is expected to be delivered to the Strategic Planning Committee in July of 2021.[163]

2. **Credit policy**

   The Credit Practices Working Group has recommended three phase one modifications to the SPP Credit policy. The modifications include establishing minimum collateral requirements for portfolios of transmission congestion rights, enhancing the credit application, and increasing the minimal capitalization required to transact transmission

[161] Intra-market refers to inside the SPP Integrated Marketplace.
[162] Holistic Integrated Tariff Team Report, Marketplace Enhancement Recommendations, Implement congestion hedging improvements: SPP should continue with a market mechanism to hedge load against congestion charges. The existing market design should include modifications to implement counter-flow optimization that is limited to excess auction revenues.
[163] Strategic Planning Committee meeting materials, January 2021, page 152.

congestion rights. The SPP board of directors has approved all three of the proposed modifications. Additionally, the filings related to minimum collateral requirements and the credit application, have been approved by the Federal Energy Regulatory Commission.[164] The proposed modifications to minimal capitalization are expected to be filed with the Commission in early 2021. Phase two changes are expected to be finalized after the Commission's credit policy technical conference scheduled for late February.

3. Secondary intra-market liquidity

Zero megawatts were transacted on SPP's bulletin board in 2020, a continuation of the observations from 2019 and 2018. Intra-auction sales continue to represent modest transaction volume. The limited liquidity associated with these products is not unique to the SPP markets; however, improved liquidity would likely prove beneficial for all market participants and enhance efficient auction price formation. The market monitor encourages SPP to adopt policies and procedures that deepen liquidity by incentivizing market participants to transact in SPP's secondary market.

4. Modeling inconsistencies

Modeling inconsistencies and outage discrepancies between the congestion hedging and day-ahead models worsened in 2020. As stated in previous reports, the process and rules surrounding the modeling of congestion hedging outages should be reviewed, and during the review SPP and its stakeholders should determine if the current practice is appropriate. The market monitor recognizes the significant challenges associated with model convergence and encourages SPP's continued focus in this area.

[164] See: ER21-79-000 and ER20-2882

6 PLANNING PROCESS

The scope of market monitoring work covers all aspects of the SPP market including activities that could impact the short-term and long-term operation of the market. The transmission planning process, which is one of the core functions of SPP, is one such activity. The planning process and its outcomes, in particular, affect congestion patterns, operational effectiveness, and costs, as well as reliability.

The MMU's capability to possess and analyze comprehensive market information positions it to be able to provide valuable input in the planning process. For this reason, starting in 2018 the MMU, in its advisory capacity, has been involved in SPP's planning process, primarily with meetings and the discussions of the Economic Studies Working Group (ESWG),[165] but also with the Transmission Working Group (TWG), Supply Adequacy Working Group (SAWG), Markets and Operations Policy Committee (MOPC), and Strategic Planning Committee (SPC), when necessary. The MMU feedback in the planning process on relevant topics has already proved beneficial by improving planning assumptions, drivers, and outcomes thereby benefitting the market as a whole.

Key highlights from this chapter include:

- The MMU engaged in scope development discussions in stakeholder meetings in 2020 providing input both for the (ten-year) 2022 Integrated Transmission Planning (ITP) and for the 20-year assessment. In doing so, the MMU first provided advice on the 20-year assessment scope by considering its strategic planning horizon and then making adjustments to derive the 2022 ITP scope to ensure consistency and completeness.

[165] The ESWG advises and assists SPP staff, various working groups, and task forces in the development and evaluation principles for economic studies. The group provides technical support for the development and application of economic studies. The group also reviews the economic planning processes for adherence to sound economic metrics methods and provides recommendations for improvement of the economic evaluations (*see* https://www.spp.org/organizational-groups/board-of-directorsmembers-committee/markets-and-operations-policy-committee/economic-studies-working-group/).

- Under this approach, the MMU's recommendations for Future 1 for both planning horizons overlapped, whereas the MMU's recommendations for Future 2 of the 2022 ITP was a combination of Futures 2 and 3 of the 20-year assessment.
- The SPP stakeholders voted for the 2022 ITP to maintain the 2021 ITP's two-scenario approach, the Reference case (Future 1) and the Emerging Technologies case (Future 2) having primarily a similar set of features of the 2021 ITP. However, the approved two futures do not reflect the assumptions and drivers as recommended by the MMU and will likely lag actual industry trends and potential outcomes as has occurred in previous ITP studies.
- SPP stakeholders approved a four-future scope for the 20-year assessment, with Future 3 and Future 4 representing *decarbonization* features. While Future 3 stayed as initially recommended by the MMU, Future 4 assumed zero hurdle rates for interchange transactions between SPP and MISO markets.
- SPP's ITP 20-year assessment is scheduled to be completed in October 2022.
- The MMU's peak available capacity metric was 36 percent in 2020, up from 31 percent in 2019.

Addressing congestion related issues requires consideration of both transmission and generation investment options from an overall market view. For instance, the current excess generation capacity relative to demand in the SPP market—even in the presence of increased outages since 2017— and its implication on market outcomes is a topic that needs to be evaluated in the planning process. For the last several years, the persistently high amount of excess generation capacity—and the large share of wind generation in that— has been a contributing factor to the relatively low market prices in the SPP market. This affects the financial viability of generators as low prices that are not supportive of the existing generation capacity or new entry make future retirements more likely. Additionally, low prices encourage generators to minimize maintenance costs, which reduces availability.

The MMU outlined its recommendations to improve planning processes in its 2017 and 2018 annual reports.[166] In 2018 and 2019, the MMU maintained its involvement in helping stakeholders develop key inputs to the ITP scope and futures case studies for the 2020 ITP and 2021 ITP, respectively. In 2020, the MMU's engagement with the planning process extended to the scope development and future cases for the 20-year assessment as well as the (ten-year) 2022 ITP.[167]

Section 6.1 of this chapter covers the resource adequacy process. The remainder of this chapter covers in more detail the transmission planning process and the input provided by the MMU.

6.1 RESOURCE ADEQUACY

6.1.1 CAPACITY ADDITIONS AND RETIREMENTS

As of the end of 2020, nearly 44 percent of SPP's fleet is more than 30 years old. In particular, nearly 87 percent of coal capacity and 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 in 2020 was 45 years.[168,169] Aside from the resources that joined SPP from Nebraska in 2009 and the Integrated System[170] in 2015, the largest source of new capacity in the SPP footprint over the last 10 years has been wind capacity.

Figure 6–1 illustrates that certain segments of the SPP generation fleet are aging. The chart highlights that about 32 GW of generation capacity is over 40 years old corresponding nearly to 34 percent of total capacity. Almost 44 percent is gas, and 39 percent is coal.

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166 SPP MMU 2017 Annual State of the Market report, pages 198-199; and 2018 Annual State of the Market report, pages 240-241.

167 *See* Sections 6.1.4 and 6.1.5 for more on these topics.

168 Through November 2020. *See* https://www.eia.gov/electricity/data/eia860M/.

169 Based on the EIA data, 9.1 GW of generating capacity is scheduled to retire in 2021 with nuclear capacity accounting 56 percent of the total followed by coal with 30 percent. EIA estimates after substantial amount of retirements of coal-fired generating capacity in the last five years, totaling 48 GW, coal retirements will slow in 2021 with 2.7 GW of scheduled retirement, coming primarily from older units. According to the same estimate, the capacity-weighted average age of retiring coal units is more than 51 years old. *See* https://www.eia.gov/todayinenergy/detail.php?id=46436.

170 Market participants added as part of the Integrated System are Western Area Power Administration – Upper Great Plains (Western), Basin Electric Power Cooperative, and Heartland Consumers Power District.

Figure 6–1 Capacity by age of resource

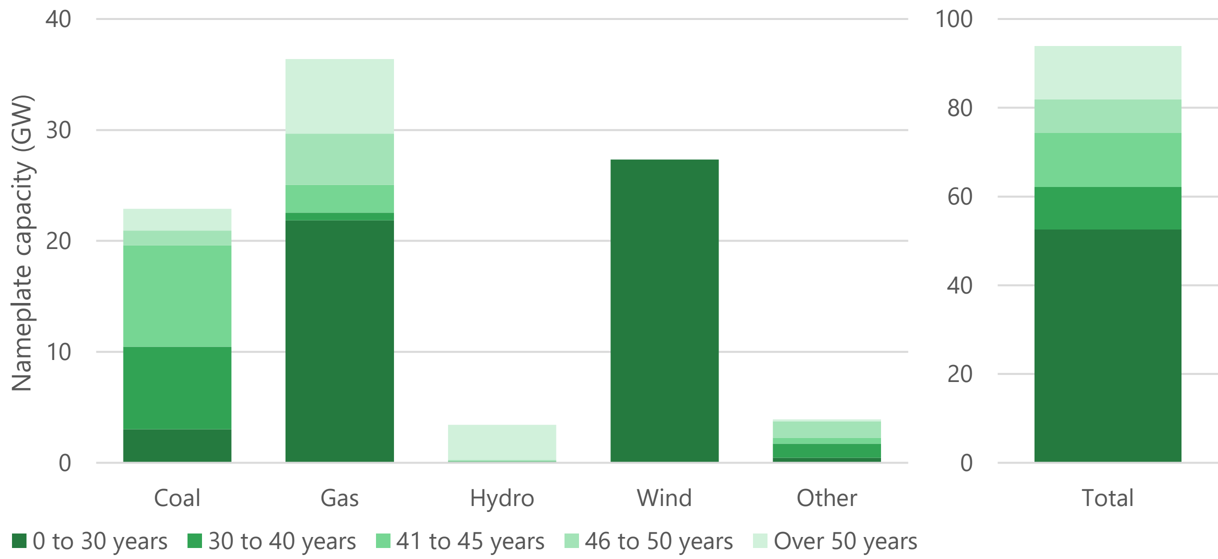
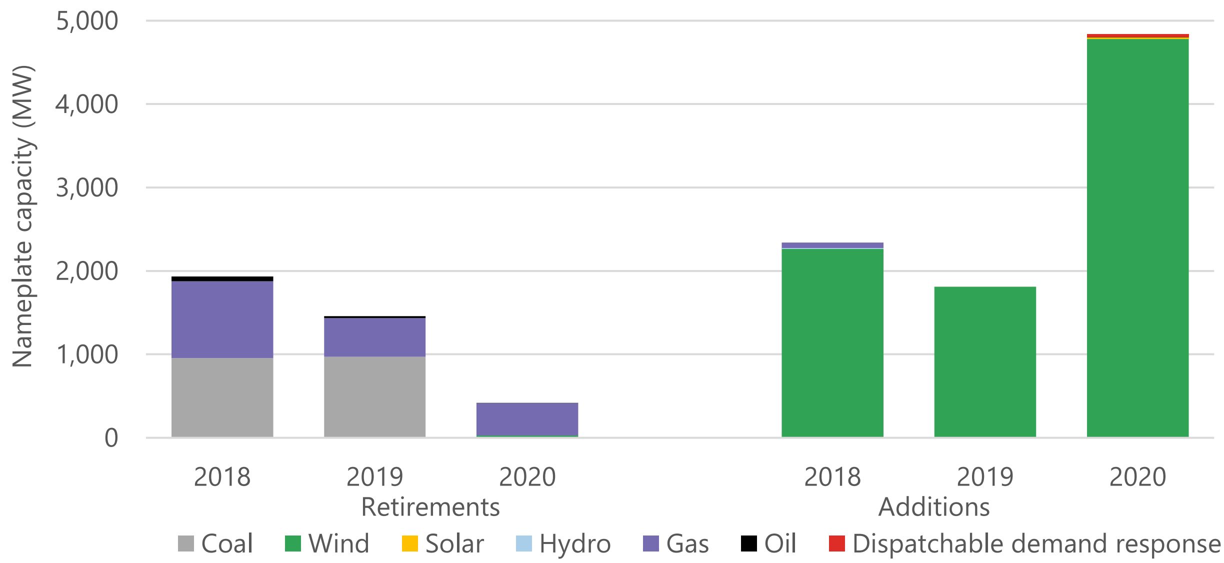


Figure 6–2 shows the annual trend of capacity additions and retirements over the past three years.

Figure 6–2 Capacity additions and retirements by year



Almost all of the coal and gas capacity retired since 2016 has been 1950s era plants. The wind units that retired were first-generation wind resources with very low capacity. Of the 417 MW of retired capacity in 2020, 388 MW belongs to gas units, 27 MW belongs to wind units and the remaining 2 MW belongs to fuel oil units.

For capacity additions, wind generation has accounted for 98.5 percent of the additions over the last three years and all of the additions in 2019. Total nameplate capacity additions were 4,836 MW in 2020. Even with the increased amount of solar generation in the generation interconnection queue, solar generation accounted for only 20 MW of the capacity additions in 2020. This brings the total solar generation in the market to 235 MW. In addition, several dispatchable demand response resources were added to the market in 2020, ranging in size from 0.1 MW to 10 MW, and bringing total to approximately 34 MW. Considering the 4,836 MW in capacity additions along with 417 MW of retirements, 4,419 MW of net generating capacity was added to the SPP market in 2020.

6.1.2 GENERATOR RETIREMENTS

The SPP market currently has a significant amount of excess generation capacity, even in the presence of increased outages since 2017. Furthermore, the substantial incoming—and projected—new capacity, primarily wind, and the projected low rates of load growth are likely to exacerbate this situation absent a significant amount of generator retirements. While the SPP Planning Criteria provides for a 12 percent capacity (reserve) margin for the footprint,[171] the MMU's calculated peak available capacity metric discussed in Section 6.1.3 points to levels well above the required level, at 36 percent.[172] Reserve margin requirements are based on long-established standards and are intended to provide for sufficient support for reliability, however, significant excess capacity imposes inefficiencies on the market. When such excess capacity exists, functioning competitive markets send signals mainly through (low) energy prices[173] incentivizing the exit of that capacity.

[171] *See* Section 6.2 under 2019 Loss of Load Expectation (LOLE) Study Report update that discusses SPP's most recent reserve margin assessment.
[172] While the 12 percent is calculated based on the non-coincident peak of the load serving entities, the MMU's 36 percent is based on the SPP coincident peak,
[173] As highlighted in Section 7.2.1, market offers are less than mitigated offers, which contribute to price formation.

A wave of generator retirements, particularly of coal-fired generation, is occurring throughout the country.[174] The SPP market is likely to follow this trend given its excess capacity and aging fleet, and the cost disadvantages of certain generation technologies in regards to prevailing market prices.

Considering these developments, the MMU remains involved with the SPP's initiative to develop a new process for evaluating generator retirement applications. The MMU has approached this primarily from market economics and market power perspectives, as a strategically motivated generator retirement particularly in a congested area could constitute physical withholding by creating a shortage that leads to sustained price spikes. The MMU is already evaluating generator retirements for reasonable technical and economic justifications, market impacts, and concerns regarding physical withholding.

The MMU has communicated with SPP staff and the market participants in regard to its proposed review process through internal meetings and presentations at the Market Working Group, and will continue to provide feedback as necessary. In December 2019, the MMU posted a data template and related instructions on SPP.org for calculating going forward costs should the MMU request a market participant to provide such data to be evaluated for physical withholding.[175] This new approach will aid the MMU in better assessing the economic justifications for retirement. Given the amount of excess capacity in the SPP market and market economics associated with it, the MMU expects these requests to apply only to only a small portion of retirements.

Meanwhile, SPP designed a new generation retirement process that went into effect in January 1, 2021. The new design introduces steps for a resource retirement study that includes resource retirement submission, screening and analysis processes.[176]

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[174] Coal unit retirements have been steady across the U.S. with 2,809 MW in 2014, 12,439 MW in 2015, 6,568 MW in 2016, 4,925 MW in 2017, 9,699 MW in 2018, 7,505 MW in 2019, and 4,459 MW in 2020 (*See* EIA 860 electric utility data as of November 2020, available at https://www.eia.gov/electricity/data/eia860M/)

[175] The documents are available at https://www.spp.org/spp-documents-filings/?id=18510.

[176] *See SPP Open Access Transmission Tariff*, Sixth Revised Volume, Attachment AB Generator Retirement Process, and Section 7800 Resource Retirement Study, *SPP OATT Business Practices* (available at https://spp.org/documents/63847/spp%20oatt%20business%20practices%2020210120.pdf#page172).

6.1.3 GENERATION CAPACITY COMPARED TO PEAK LOAD

In the 2017 annual report, the MMU introduced a new peak available capacity metric to replace the previous reserve margin metric[177] 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 and outages 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. Wind and solar resources are derated based on capacity factors during the afternoon hours in July and August. Solar resources are derated to 50 percent of nameplate capacity. For wind resources, 24 percent of nameplate capacity is included in the calculation.

The peak available capacity percent is the amount of extra system capacity available after serving system peak load, and is shown in Figure 6–3.

Figure 6–3 Peak available capacity percent

Year	Peak available capacity (MW)	Peak load (MWh)	Peak available capacity percent
2014	62,332	45,301	38%
2015[178]	62,958	45,279	39%
2016	68,839	50,622	36%
2017	67,950	51,181	33%
2018	67,475	49,926	35%
2019	66,953	51,230	31%
2020	67,586	49,569	36%

For 2020, the peak available capacity percent was 36 percent, up from 31 percent in 2019, and was more in line with 2018 levels. Peak available capacity increased by around 630 MW from 2019 to 2020. However, the decrease in peak load of 1,661 MW was the primary driver for the increase in peak available capacity percent. At 36 percent, peak available capacity is still three

[177] The previous reserve margin metric used unit registration ratings (i.e. nameplate capacity) to determine system capacity, while wind counted at only five percent of registered capacity.
[178] 2015 uses the total capacity on September 30, prior to the addition of the Integrated System.

times higher than SPP's minimum required planning reserve margin of 12 percent.[179] 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 the MMU's metric includes all system resources interconnected with the SPP grid using derate factors.

A relatively high peak available capacity percentage such as this has positive implications for both reliability and 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, increases uplift, and can burden ratepayers with additional and potentially unnecessary costs.

6.1.4 INTEGRATED TRANSMISSION PLANNING PROCESS

The SPP tariff[180] requires SPP to conduct an annual Integrated Transmission Planning (ITP) Assessment to evaluate the transmission system upgrades for a ten-year planning horizon. The planning assessment serves as a regional planning process. This process involves many aspects of transmission planning including the considerations for reliability, public policy, operational, and economic needs, and generator interconnection to develop a cost-effective transmission portfolio for a ten-year planning horizon.[181,182] The assessment employs a set of modeling assumptions that are used as the starting point for planning studies and identifies system needs from interconnection and transmission service requests within the limits of the process timelines established. The process coordinates the evaluation of transmission service needs and associated projects with those identified in the ITP assessment. This approach facilitates continuity in SPP's overall transmission expansion plan.

Each integrated transmission plan has a study scope that receives input from stakeholders in conjunction with the assumptions and parameters that are not standardized in the integrated

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[179] *SPP Planning Criteri*a, Section 4.1.9.
[180] *SPP Open Access Transmission Tariff*, Sixth Revised Vol. No. 1, Attachment O Transmission Planning Process, Section III.
[181] The latest version of the ITP manual published can be found at https://www.spp.org/engineering/transmission-planning/.
[182] SPP also performs a 20-year assessment. The first ITP 20-year assessment will be completed in October 2022. *See* Section 6.1.4 for more on this.

transmission process manual.[183] The SPP transmission planning studies coordinate the evaluation of transmission service needs—resulting from generator interconnection and transmission service requests—and associated projects with those identified in the ITP assessment to conduct an overall transmission expansion plan.

SPP, along with the ESWG and the Transmission Working Group (TWG), develops an assessment scope for each ITP assessment for items that require SPP stakeholder review and approval with each new study.[184] The study scope document[185] describes the assumptions and methodologies that need to be updated at each study cycle so that the future performance of the existing transmission system and any needed improvements can be assessed.

In 2020, the MMU participated both in the scope development discussions of the 2022 ITP and the 20-year assessment. The MMU's input included assumptions for future cases to incorporate various market developments.

6.1.5 20-YEAR ASSESSMENT SCOPE FUTURES

Overview

In addition to annual ITP assessments, SPP is also required to perform 20-year assessments at least once every five years, or more frequently if approved by the SPP Board of Directors.[186] These assessments review the system for a twenty-year planning horizon and address, at a minimum, facilities 300 kV and above needed in year 20. SPP's 20-year assessment is scheduled to be completed in October 2022.[187]

In 2020, the MMU provided feedback for the 20-year assessment scope development from which its recommended 2022 ITP assumptions, drivers and futures were derived. In doing so,

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[183] *SPP Open Access Transmission Tariff*, Sixth Revised Vol. No. 1, Attachment O Transmission Planning Process, Section III.1.c.
[184] *Ibid*. at 1-2. The assessment report requires approvals from the MOPC and the board.
[185] The most recent scope document is the "2021 Integrated Transmission Planning Assessment Scope," published on January 23, 2020. The document was approved by the SPP stakeholder process.
[186] *SPP Open Access Transmission Tariff*, Sixth Revised Vol. No. 1, Attachment O, Section IV.2.
[187] The 20-year assessment process requires input and review from the Economic Studies Working Group (ESWG), Transmission Working Group (TWG), Cost Allocation Working Group (CAWG), Strategic Planning Committee (SPC), Regional State Committee (RSC),and Markets and Operations Policy Committee (MOPC). (*See* https://www.spp.org/engineering/transmission-planning/integrated-transmission-planning/).

the MMU first advised on the development of the 20-year assessment scope by considering its strategic planning horizon then made adjustments to derive the 2022 ITP scope to ensure consistency and completeness. The modeling approach adopted by the MMU allows for the 20-year study scope to be able capture a larger timeframe and number of scenarios foreseen, as well as probable policy options. Moreover, the 20-year assessment futures are expected to influence the 10-year ITP as the current recession realties should equally apply to the 10-year and 20-year studies. Through this approach, the MMU's 20-year futures provided a feedback for those of the 2022 ITP consistent with the latter's shorter timeframe.

The modeling approach

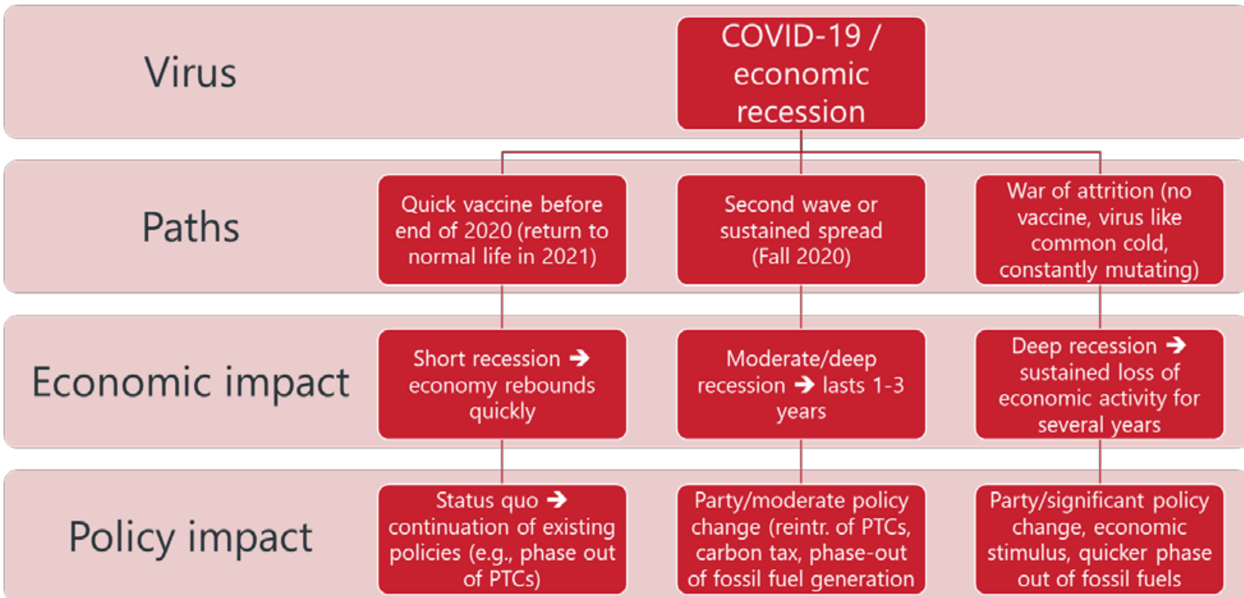
In advising on the 20-year scope development, the MMU followed a top down modeling approach establishing a link between probable virus scenarios—or *paths*—introduced by COVID-19 and macroeconomic factors. From a modeling perspective, the coexistence of these factors necessitated a top down modeling approach for future development by initially identifying probable virus paths, by which developments downstream would be felt through economic and policy impacts. Subsequently, projections were made for the likely influence of these factors on the federal government's long-term energy and environmental policies, along with the results of the November 2020 elections.

The outcomes of this approach were incorporated in three major scenarios (or futures) recommended for the 20-year assessment. The MMU's 20-year assessment study also provided feedback in two scenarios for the 2022 ITP's ten year planning horizon.[188] Under this approach, the MMU's recommendations for Future 1 for both planning horizons overlapped, whereas the MMU's recommendations for Future 2 of the 2022 ITP was a combination of Futures 2 and 3 of the 20-year assessment.

The MMU's three major scenario approach for the 20-year assessment is illustrated in Figure 6–4 below.[189]

[188] *See* MMU's August 27, 2020 presentation in ESWG August 2020 meeting materials at https://www.spp.org/spp-documents-filings/?id=19028.
[189] This section draws on the SPP MMU Summer 2020 Quarterly State of the Market report published November 2, 2020, Section 6: Special Issues ("Summer 2020 Quarterly Report, Special Issues.")

Figure 6–4 General framework for MMU recommended futures for the 20-year assessment



In this approach, each virus path determines macroeconomic performance, which in turn greatly influences federal government's policy on the energy and environment as part of a greater macroeconomic policy response. In this context, government policy would further be influenced by November 2020 election results, as a change in administration, which in turn would likely result in a change in policy.

Accordingly, the MMU considered pre-election policy announcements by both congressional and presidential candidates as important factors for futures development. From this, the MMU set out three major scenarios, incorporating probable macroeconomic recession paths and already announced policy targets,[190] as follows:

- **Future 1:** Ongoing/business as usual plans (reflecting reelection of current administration and status quo)

[190] These are: Climate Crisis Action Plan of the Select Committee of the House on the Climate Crisis which targets to reduce net U.S. greenhouse gas emissions by 37 percent below 2010 levels in 2030 and 88 percent below 2010 levels in 2050, and build a cleaner and more resilient electricity sector to achieve net-zero emissions from power generation by 2040 (*see* https://climatecrisis.house.gov/sites/climatecrisis.house.gov/files/Climate%20Crisis%20Action%20Plan.pdf) ; and policy statement by Biden-Sanders aiming to reverse current climate and environmental policies by rejoining the Paris Climate Agreement, and putting a strong emphasis and aggressive targets on clean energy generation, energy efficiency, clean transportation, and cutting carbon pollution, *see* (https://joebiden.com/wp-content/uploads/2020/07/UNITY-TASK-FORCE-RECOMMENDATIONS.pdf).

- **Future 2:** Moderate macroeconomic recession (with new administration and moderate energy and environment policy response), and
- **Future 3:** Deep macroeconomic recession (with new administration and aggressive energy and environment policy response) having two alternative sub-scenarios:
    - **Future 3a:** Assuming **lower** natural gas generating capacity
    - **Future 3b:** Assuming **higher** natural gas generating capacity

The MMU approach to developing its recommended futures began with considering what capacity would be needed to meet the forecasted peak load in year 20. Starting with that, the MMU then worked backwards to determine what the potential installed capacities for renewable and fossil fuel resources would be. The MMU considered impacts of potential policy drivers, both corporate and government, including carbon reduction targets, fossil fuel generator retirements, energy efficiency, and demand response initiatives.[191]

Future 1 (base case) inputs and analysis

Future 1 considers that the SPP interconnection queue remains dominated by wind, solar and storage with continued coal unit retirements replaced with renewable generation. Additional assumptions include continued corporate carbon reduction targets and a phase out of production tax credits (PTCs).[192]

Future 2 (moderate policy) inputs and analysis

Future 2 represents a scenario in which there are moderate policy changes initiated by a change in political party control and a moderate economic recession. This scenario considers a reintroduction of PTCs, a significant phase out of fossil fuel generation, and a limited carbon tax.

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[191] Other key factors and assumptions included: 1) Average age of generators in the SPP market as of end of 2019 (see Figure 6-2), 2) Significantly more solar and wind capacity would be needed without the addition of appropriate storage capacity, 3) Storage capacity built was linked to peak load rather than just solar built, assuming some wind would also likely pair with storage in addition to the not just solar, and 4) impact of emissions pricing policy on fossil fuel prices and generation levels. (*See* Summer 2020 Quarterly Report, Special Issues for more details.)

[192] Specifics of Future 1 include: 1) 3,300 MW of coal and 22,000 MW of natural gas-fired generation remains based on 50 and 51 year retirement age for coal and gas/oil resources, respectively, 2) Storage assumed at 20 percent of peak projected load, 3) 26 GW of solar and 50 GW of wind capacity, and 4) An estimated 56 percent reduction of carbon emissions is achieved.

In addition, Future 2 assumes a higher penetration of renewables, with an increase of storage and solar capacity, and an accelerated deployment of electric vehicles.[193]

Future 3 (aggressive policy) inputs and analysis

Future 3 represents an aggressive policy change that is initiated by a moderate to deep economic recession. These policy changes include mandated carbon cuts and a more sizable carbon tax. This scenario assumes a phase out of carbon pollution from power plants by 2035-2040 with government stimulus to accelerate transmission build for deliverability of more renewable energy, not only to support internal load but also for exports off system as well. [194]

Figure 6–1 in Section 6.1.1 shows the average age profile of generation by fuel in the SPP footprint as of the end of 2020. This is helpful in understanding age based generation retirements by 2042.[195]

Figure 6-5 below shows the MMU estimation of generation required to meet a peak-load day (with a 12 percent capacity margin) in 2042 by each future, respectively.

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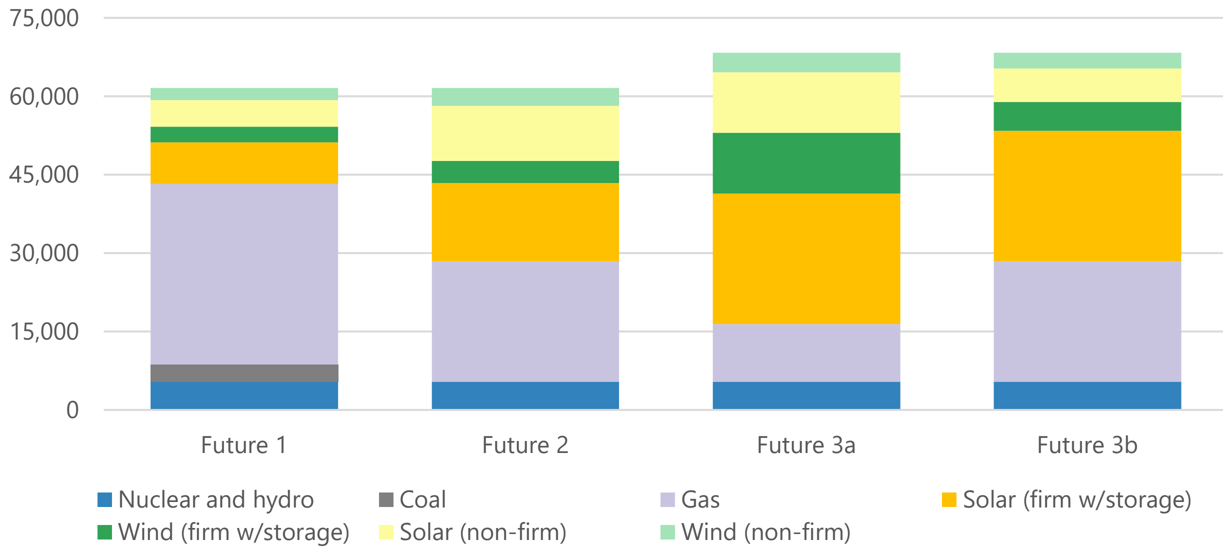
[193] Specifics of Future 2 include: 1) Complete retirement of coal generation, 2) 51 year retirement age for gas/oil resources, 3) 22,000 MW of natural gas-fired generation remains, 4) Assumes no coal generation replaced by gas, 5) Storage assumed at 35 percent of peak projected load, 6) 52.5 GW of solar and 73.3 GW of wind capacity, and 7) An estimated 82 percent reduction of carbon emissions is achieved.

[194] Specifics of Future 3 include: 1) Complete retirement of coal generation, 2) Gas capacity to not exceed 5 percent of total generation (Future 3a: 11,000 MW of gas capacity remains, Future 3b: 22,000 MW of gas capacity remains), 3) Future 3a: Storage assumed at 60 percent of peak projected load with 66.5 GW solar and 85.5 GW wind capacity, 4) Future 3b: Storage assumed at 50 percent of peak projected load with 48 GW solar and 65 GW wind capacity, 5) An estimated 93-95 percent reduction of carbon emissions is achieved depending on load growth.

[195] For instance, if coal and natural gas generation retires after 50 years, then only the dark green capacity would remain. This would represent approximately 3,300 MW for coal generation and 22,000 MW for natural gas resources.

Figure 6-5 Capacity build out by future, with 12 percent margin in 2042



6.1.6 2022 ITP ASSESSMENT SCOPE FUTURES

The MMU designed its recommendations for the (ten-year) 2022 ITP scope based on the 20-year assessment scope. Specifically, the MMU's recommendations for Future 1 of the 2022 ITP overlaps with the MMU's recommendations for Future 1 of the 20-year assessment, and the MMU's recommendations for Future 2 of the 2022 ITP overlap with a combination of Futures 2 and 3 of the 20-year assessment. For the 2022 ITP Future 2, the MMU considered the following:

- *Environmental regulations* to reflect federally funded new green energy network, mandated carbon cuts, and carbon tax;
- Higher penetration of *distributed generation* (solar) due to policy shifts and significant incentives for behind the meter installations;
- Higher levels of *energy efficiency* because of significant federal incentives;
- Year 5 and 10 *storage* figures were developed based on 1 percent and 5 percent of projected peak load, respectively, to consider exponential growth; and
- Year 5 and 10 *solar and wind* (GW) figures were developed based on ability to hit target levels in the 20-year assessment.

Based on this framework, the MMU provided the following recommendation for 2022 ITP scope futures, as shown in Figure 6-6 below.[196]

[196] The MMU initially recommended that the ESWG consider three futures for the 2022 ITP scope development however, stakeholders voted to carry over the two future approach of the 2021 ITP. Accordingly, the MMU revised its original recommendation to produce a two future approach.

Figure 6-6 ITP 2022 scope recommendation by MMU: Two futures

Key assumptions	**Future 1** ongoing plans (reelection and status quo)		**Future 2** emerging technology	
Peak demand growth	As in load forecast		As in load forecast	
Energy demand growth	As in load forecast		↑ due to ↑ electrification (electric vehicle growth)	
Natural gas prices	Current industry forecast		Prices influenced by emissions pricing policy	
Coal prices	Current industry forecast		Prices influenced by emissions pricing policy	
Emissions prices	Current industry forecast		↑ carbon prices per target of carbon reduction of 80% from 2000 levels	
Fossil fuel retirements	Coal aged-based at 50; gas/oil at 51; < 50% of coal retirement replaced by gas		Complete coal retirement driven by emission reduction targets; gas/oil retirement age-based	
Environmental regulations	Current regulations		Federally funded green energy network, mandated carbon cuts, carbon tax	
Demand response [1]	As in load forecast		↑ demand response (focus on savings rather than consumption per policy shift)	
Demand response (solar)	As in load forecast		↑ penetration (policy shift and incentives to behind the meter installation)	
Energy efficiency	As in load forecast		↑ energy efficiency > F1 (due to significant ↑ incentives)	
Storage	**Year 5** 1% of projected peak load	**Year 10** 5% of projected peak load	**Year 5** 2% of projected peak load	**Year 10** 15% of projected peak load
Solar (GW)	6	12	7	20
Wind (GW)	32	38	35	50

[1] As defined in the SPP Model Development Working Group (MDWG) Model Development Procedure Manual: MDWG Manual

Conclusion

For the 10-year 2022 ITP scope, the ESWG voted to use only two futures. These futures were based primarily on the two futures used in the 2021 ITP. Ultimately, the proposed 10-year ITP does not reflect the same range of potential outcomes as recommended by the MMU and will likely lag potential outcomes as has occurred in previous ITP studies.[197]

For the 20-year assessment, SPP staff has currently proposed a four-scenario approach accepting the MMU's 3b scenario as the fourth future. These results were discussed at the October 2020 MOPC and SPC meetings with the MMU restating its position, and ESWG receiving feedback from market participants particularly for the 20-year assessment. The MMU recommendations for the 20-year assessment stirred a considerable amount of discussion among members at both the MOPC and SPC meetings, and provides a bookend scenario for considering deep de-carbonization.

Further discussions took place in ESWG's November and December 2020 meetings to finalize the scope of the 2022 ITP and 20-year assessments. The MMU actively participated during these discussions and promoted a need to assess a wide range of potential outcomes, particularly for the 20-year assessment.

Finally, the SPP stakeholders at the January 2021 MOPC and SPC meetings approved a four-future scope for the 20-year assessment, with Future 3 and Future 4 representing *decarbonization* features. While Future 3 stayed as initially recommended by the MMU, Future 4 assumed zero hurdle rates for interchange transactions between SPP and MISO markets.

6.1.7 2022 ITP GENERATOR RETIREMENT ASSUMPTIONS

TIn 2020, stakeholders approved resource retirement assumptions for both futures of the 2022 ITP scope that were carried over from the 2021 ITP. As a result, under the Reference Case the retirement age assumed for coal generators, and gas-fired and oil generators is 56 and 50 years,

[197] For instance, stakeholder approved resource retirement assumptions for both futures were carried over from 2021 ITP. As a result, under the Reference Case Future the retirement age assumed for coal generators, and gas-fired and oil generators is 56 and 50 years, respectively. (This is also a carryover from 2020 ITP). Under the Emerging Technologies Case it is assumed coal generators, and gas-fired and oil generators to retire over the age of 52 and 48, respectively,

respectively. Note that this is also a carryover from the 2020 ITP scope. Under the Emerging Technologies Case it is assumed coal generators, and gas-fired and oil generators to retire over the age of 52 and 48, respectively,

The MMU continues to argue that its net revenue analysis indicates a new coal resource cannot recover fixed operating and maintenance (O&M) costs at current market prices (see Section 4.4 for 2020 results). In addition, the trend for coal resources' average retirement ages in 2020 remained below the various sub period EIA averages, shown in Table 6-4 below. As such, even lower retirement ages for the next 10 years could be expected given the new administration's already announced shift in federal energy and environmental policies. The MMU's argument is also supported by the announcements of several market participants over the last couple years redirecting their investment policies towards more renewable resources and less carbon intensity.[198]

[198] For instance, Omaha Public Power District (OPPD) set a long-term goal of providing at least 50 percent of its retail sales from renewable sources and reducing its carbon intensity by 20 percent from 2010 to 2030 (S&P Global Market Intelligence published on Nov., 5, 2018). Xcel Energy Inc. announced that it plans to completely decarbonize its power supply portfolio serving eight states by midcentury, first cutting carbon emission by 80 percent by 2030, from 2005 levels in its utility service territories in Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin (S&P Global Market Intelligence published on Dec., 4, 2018). On February 24, 2021, Xcel Energy updated this pledge through its 2030 Clean Energy Plan that it will reduce carbon emissions by an estimated 85 percent from 2005 levels by 2030. (https://www.xcelenergy.com/company/media_room/news_releases/xcel_energy_announces_2030_clean_energy_plan_to_reduce_carbon_emissions_85%2). AEP first announced in February 6, 2018 that it will pursue a goal to reduce its CO2 emissions of its generating units 60 percent by 2030 and 80 percent by 2050 from 2000 levels (https://www.aep.com/news/releases/read/1503/AEPs-Clean-Energy-Strategy-Will-Achieve-Significant-Future-Carbon-Dioxide-Reductions-). September 10, 2019, the company stated that it's cutting CO2 emissions faster than anticipated and revised its 2030 reduction target to 70 percent from 2000 levels (https://www.aep.com/news/releases/read/1615/AEP-Accelerates-Carbon-Dioxide-Emissions-Reduction-Target). Most recently on February 25, 2021, AEP announced that it was accelerating its transition to a clean energy future by setting a new goal of achieving an 80 percent reduction in CO2 emissions by 2030 from the company's 2000 baseline, and reach net zero emissions by 2050 (https://aep.com/news/releases/read/6026/AEP-Reports-Strong-2020-Earnings-Raises-2021-Operating-Earnings-Guidance). Meanwhile, on April 30, 2021 Evergy announced that it is advancing its goal to reduce carbon emissions 70 percent by 2030 (relative to 2005 levels) and achieve net-zero carbon emissions by 2045 (https://newsroom.evergy.com/2021-04-30-Evergy-Sets-Goal-for-Net-Zero-Carbon-Emissions-by-2045,-Interim-Carbon-Reduction-Target-of-70-percent-by-2030).

Figure 6–7 shows the data for average age of retirements for coal and natural gas-fired resources for the U.S.

Figure 6–7 Average age of retirements for coal and gas resources

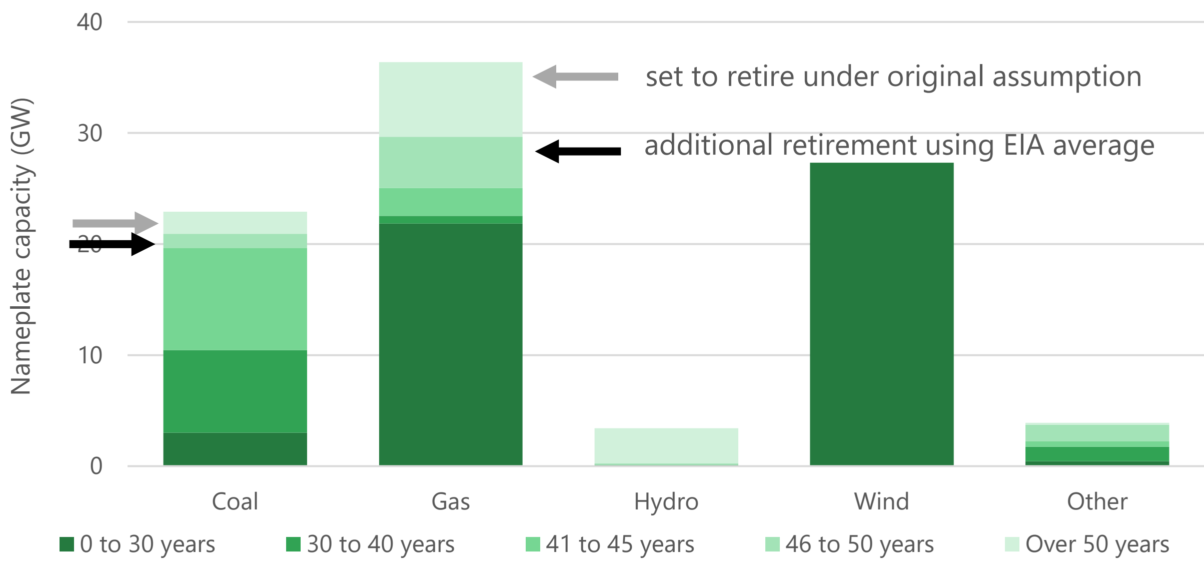
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Coal	54	64	54	54	56	58	56	56	49	50	45
Gas	43	49	48	51	52	48	46	52	46	51	54

	2002-20	2010-20	2015-20
Coal	54	55	54
Gas	48	49	48

Source: EIA-860 Electric Utility Retirements (data through November 2020).

Figure 6–8 below presents the age of all existing resources along with the original proposed retirements and with the change associated with using EIA averages.

Figure 6–8 Average age of generators in the SPP market



6.2 MMU INVOLVEMENT IN OTHER WORKING GROUPS

Effective Load Carrying Capability Method

In addition to the ESWG, the MMU follows other working group activities as necessary. In 2019, the MMU had closely followed discussions on the adoption of Effective Load Carrying Capability

(ELCC) as the method for accrediting renewable resources first in the Supply Adequacy Working Group (SAWG) and later in ESWG. In 2019, the SAWG initiated, and stakeholders approved, to adopt the ELCC method as the guiding principle for accrediting solar, wind, and storage resources to replace the current accreditation methodology found in section 7.1.6.1 (7) of the SPP Planning Criteria. Subsequently, the ESWG also approved to use the ELCC method for wind and solar accreditation in 2019.

In 2018, the SAWG had directed SPP staff to review and research industry use of the ELCC methodology for storage resources, and SPP contracted with a consulting company to examine the capacity credit of energy storage resources on the SPP system. The results were compiled in Energy Storage Accreditation Methodology White Paper that was discussed by stakeholders.[199] In July 2020, the SAWG approved both the use of the ELCC methodology for determination of the capacity credit for standalone energy storage resources, and the use of Economic Arbitrage—rather than the Preserve Reliability—approach as the method for determining capacity accreditation.[200] The MMU noted during stakeholder discussions and through written comments[201] that the ELCC is a better approach for accreditation of storage resources compared to the alternative Capacity Value method, and supported the Economic Arbitrage approach in the SPP as the underlying principle for allowing and operating storage resources,[202]

The white paper also evaluated the capacity credit of storage resources (batteries) using different sized equipment including two, four, six, and eight-hour equipment. The SPP's current Planning Criteria and Attachment AA require all resources to be able to maintain their accredited capacity for at least four hours. While the white paper did not recommend increasing the minimum battery duration to a value greater than four hours, it adopted a tiered approach to accommodate differing sized equipment for accreditation by considering four, six and eight hours, as follows:

[199] *See* Energy Storage Accreditation Methodology White Paper, SPP, January 2020, in Supply Adequacy Working Group July 14, 2020 meeting materials.
[200] *Ibid*.,, Section 3. Markets and Operations Policy Committee (MOPC) approved the white paper in its October 2020 meeting.
[201] Through written comments provided on the energy storage accreditation methodology white paper, prepared by an outside consultant.
[202] *See* Section 6.2 of Annual State of the Market 2019 for more details on this.

1. Two-hour batteries will be derated to their equivalent of four hour rating (i.e., effective nameplate rating derated to approximately 50 percent), which will be used in the annual ELCC study.

2. Four-hour batteries will be included in the ELCC study at their nameplate rating.

3. Batteries with a duration greater than four hours will be treated as a four-hour battery and included in the ELCC study at their applicable (six hour, eight hour, etc.) rating.

For capacity accreditation, SPP will perform an ELCC study for storage resources every two years on both the summer and winter seasons on a system wide basis. The white paper proposes the implementation of the ELCC methodology to begin with the 2023 summer season depending on the level of expected penetration over the next several years. Until then, storage resources with a four-hour or greater duration will be accredited based on the four-hour availability requirement with no adjustments. A two-hour duration equipment will be adjusted to 50 percent of its rating.[203]

2019 Loss of Load Expectation (LOLE) Study Report

In its June 2020 meeting, the SAWG also reviewed and approved the (updated) 2019 Loss of Load Expectation (LOLE) Study Report as modified.[204] Per Attachment AA of the SPP tariff, SPP performs a biennial (probabilistic) LOLE study to determine the adequate amount of planning reserves needed to maintain a reliability metric of one day (or less) in ten years, or 0.1 day per year while utilizing a Security Constrained Economic Dispatch. Currently, the SPP's Planning Reserve Margin (PRM) is twelve percent (12%). The results of an LOLE study in the form of a report is presented to the Supply Adequacy Working Group for approval.

The LOLE study informs stakeholders and state commissions in the SPP footprint in the process of making policy decisions regarding resource adequacy, particularly when considering adjusting the SPP PRM. SPP's PRM is applicable to each load responsible entity's resource

[203] *See* Sections 3, 4 and 5 of the white paper.
[204] *See* 2019 SPP Loss of Load Expectation Study Report, SPP Resource Adequacy Team, June 29, 2020, (available in May 2020 SAWG meeting materials) for the ensuing information.

adequacy requirement, which functions to ensure entities procure sufficient capacity for their summer season's forecasted peak demand.

The SPP's last LOLE study was the 2019 LOLE Study that analyzed the planning years of 2021 and 2024 based on the study scope approved by the SAWG. In 2020, SPP conducted a study for planning year 2021 by incorporating several modifications to the modeling assumptions of the 2019 LOLE study. SPP staff concluded that the current PRM of 12.0% does not exceed the threshold of one day in ten years for planning year 2021 and did not recommend a change in the PRM. The next such study will be the 2021 LOLE Study.

Hybrid Resources

One likely construction scenario is the co-location of a storage resource with either wind or solar; the combination is a hybrid resource. In particular, the wind or solar resource will charge the battery which will then discharge to the grid later. For hybrid resources the MMU recommended that SAWG consider and evaluate the following options separately for storage resources for both reliability and efficiency:

- When a resource operates as a standby asset charging and discharging from/into the system
- When a resource is co-located with renewable resource(s), and
- When a resource is co-located with renewable resource(s) behind the meter

As of March 2021, the discussions for hybrid resources at the SAWG are ongoing. The MMU will continue to follow working group discussions particularly with respect to specific topics that may have market efficiency implications for the SPP market.

6.3 RECOMMENDATIONS GOING FORWARD

Based on its experience with the planning process starting in 2018, the MMU recommends the planning process continue to use data gathering and analysis methods to determine robust economic modeling and needed inputs so that a more accurate assessment can be made for the SPP's system needs and conditions. Possible ways to accomplish this is to research and assemble customized data sets including EIA and other external up to date databases, keep abreast of ongoing market and regulatory developments, assess likely changes considering political and policy change prospects as well as announced corporate decision-making, and review best practices across other organized markets.

Giving primary importance to membership data in planning process has a potential to create bias. The MMU recommends planning process to follow industry trends in the footprint and elsewhere, and utilize external databases in that context. Planning studies are forward looking by nature. Therefore, building robust models by using variables and databases to reflect industry trends and (expected) policy changes can make achieving forward-looking results easier. Employing stochastic/econometric models will also be helpful in addressing the challenge of producing forward-looking results. The MMU's observation is such that SPP planning studies, to a large extent, have not so far used such tools.[205]

Another important methodological issue is the generator retirement age assumptions used in economic modeling. In addition to market participant input, substantial consideration needs to be given to the operational realities and historical trends when the assumptions for retirement ages are made. The futures used in the planning process allow for the assessment of likely deviations from the (base) reference case where the impact could be significant. For this reason, in the general modeling framework and particularly in the context of generator retirements, certain assumptions (such as retirement age for generators) should be structured through formal modeling so that every planning cycle they would be readily available as a baseline, subject to market participant data input and local adjustments. For instance, EIA data of generator retirement age can be used as a baseline to be adjusted for the SPP footprint data. Otherwise, the process would have no systematic component, fluctuating widely or staying constant over time.

[205] Meanwhile, the SPP Strategic and Creative Re-Engineering of Integrated Planning Team (SCRIPT) Decision Quality Sub-Team has focused on developing policies to be applied to SPP's transmission planning processes that result in greater decision quality. The sub-team has discussed goals and recommendations on various topics including achieving a high-level of decision quality through high-quality data and credible study assumptions, and wide-ranging solutions and comprehensive analysis, *See* Decision Quality Sub-Team, Straw Proposal for Consideration by the SCRIPT, SPP Staff and SCRIPT DQ Sub-Team, March 18, 2021, Version 4.0.

When including scenarios, the ITP scope should consider developments occurring in the power sector in general with due considerations given for probable shifts in environmental regulations, major federal policy changes, market trends, or technological advancements. In addition, the planning processes should factor in announcements with regard to major shifts in corporate policies given the evolving market trends and technologies towards more renewable generation and reduced emissions. The MMU will continue to provide feedback to the ESWG on this issue as more data becomes available.

The planning process should have the ability to assess a range of potential outcomes in transmission planning. Following market trends and the likelihood of major policy changes helped shape the MMU's thinking in terms of how to consider the future generation mix and the potential need for an additional scenario. As in the case of 2022 ITP and the 20-year assessment, the MMU believed additional scenario(s) would provide a bookend scenario for the respective analyses and proved helpful in reaching stakeholder approved results.

Finally, the MMU recommends the planning process to have a well-defined method for periodical (modeling) performance evaluation including end of planning cycle assessments. This could include seeing to what extent goals were achieved in terms of minimizing congestion through investment decisions, or assumptions and data inputs being meaningful or accurate, or off track. Assumptions and inputs are a part of modeling quality. Developing metric(s) for post-planning cycle performance evaluation would shed light on what needs to be done to further improve the process going forward.

7 COMPETITIVE ASSESSMENT

Chapter 7 of this report provides a competitive assessment of the SPP market. Key points from this chapter include:

- Structural and behavioral metrics indicate that the SPP markets have been competitive over the last several years. The market share, Herfindahl-Hirschman Index (HHI), and pivotal supplier analyses all indicate minimal to moderate potential structural market power in SPP markets outside of frequently constrained areas.
- In 66 percent of the hours in 2020, the market share of the largest on-line supplier in terms of real time energy output exceeded 20 percent, which represents a significant increase from 2018 and 2019. This trend, which coincides with the merger between Great Plains Energy and Westar Energy to form Evergy, Inc., has been observed since June 2018 and is attributable to real-time dispatch of resources owned and controlled by the merged entity.
- The HHI market concentration analysis shows that 12 percent of hours were considered moderately concentrated in 2020. However, the SPP market remained mostly unconcentrated—in 88 to 89 percent of hours from 2018 to 2020—from the addition of the Integrated System to date including the Great Plains/Westar merger.
- The results of the pivotal supplier analyses indicate that the percent of hours with a pivotal supplier is the highest in the New Mexico and West Texas region, regardless of demand level. Meanwhile, continued decrease since 2018 in the Iowa, Dakotas, Montana region in pivotal supplier frequency when demand was below the 80th percentile was reversed in 2020. It now shows nearly 100 percent pivotal supplier frequency for all demand levels.
- Both off-peak and on-peak annual average markups were at their lowest levels since the implementation of the Integrated Marketplace at around −$9.54/MWh and −$8.70/MWh, respectively, indicating significant pricing pressure.
- Incremental energy offer mitigation in 2020 was extremely low, with approximately 0.03 percent of hours mitigated in both the day-ahead and real-time markets. The combined

mitigation frequency of start-up offers for day-ahead, reliability unit commitment, and manual commitments was slightly higher than in 2019 at around 3.5 percent in 2020.

- Compared with the previous years, the output gap was slightly increased in 2020, but still remained infrequent. The results of the output gap analysis continue to show very low levels of economic output withheld in the SPP footprint—nearly 0.12 percent on annual average level. These outcomes are consistent with competitive market conduct.
- The unoffered economic capacity analysis results show that, on an annual average basis, total unoffered capacity equaled 3.2 percent in 2018, 2.9 percent in 2019, and 1.5 percent in 2020. Although the majority of the unoffered capacity was due to long-term outages for maintenance in the spring and fall shoulder months in 2018 and 2019, this pattern has changed in 2020 due to the impact of pandemic of COVID-19. From an overall market perspective, the results generally indicate reasonable levels of total unoffered economic capacity. This metric indicates that there is little market incentive for timely completion of generation maintenance.
- Participants began including major maintenance costs in mitigated start-up and no-load offers in April 2019. Following this policy change, the day-ahead mitigation frequency for start-up and no-load offers continued a downward trend when measured against the same period in previous years. Start-up mitigation only occurred in about four percent of intervals in 2020 and day-ahead mitigation accounted for 84 percent of the total start-up cost mitigation.

The SPP Integrated Marketplace provides sufficient market incentives to produce competitive market outcomes in regions and periods lacking local market power. The MMU’s competitive assessment provides evidence that in 2020, market outcomes were workably competitive, requiring only infrequent mitigation of local market power.

The market power analysis in this report considers both structural and behavioral aspects of market power concerns. Structural aspects are examined with techniques such as market share analysis, market-wide concentration indices, and pivotal supplier analysis. These structural indicators illuminate the potential for market power without regard to the actual *exercise* of market power. Behavioral analyses, on the other hand, look for the exercise of market power by assessing the actual offer or bid conduct of market participants, and the impact of that conduct on market prices. Behavioral indicators include offer price markup;[206] economic withholding analysis, addressed through automated mitigation and indicated by output gap analysis; uneconomic production; and physical withholding.[207]

This chapter evaluates the SPP market's competitive environment by establishing the level of structural market power and then examining market prices for indications of the exercise of that power. Structural market power is assessed both at the SPP footprint level through supplier concentration indices and at the local (transmission-constrained) level through pivotal supplier analysis. In the SPP markets, 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.

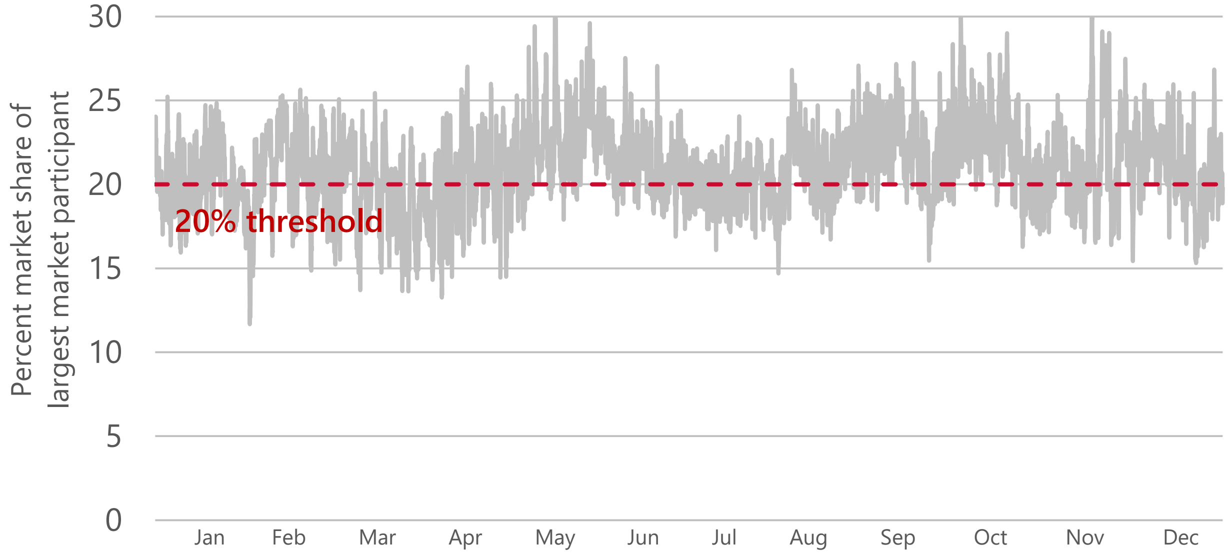
7.1 STRUCTURAL ASPECTS OF THE MARKET

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 market-wide concentration, ignoring local constraints. Pivotal supplier analysis, on the other hand, accounts for the dynamics of power markets and considers changing demand conditions and locational transmission constraints in assessing potential market power.

Figure 7–1 displays the market share of the largest on-line supplier in terms of energy dispatch in the real-time market by hour for 2020.

[206] While the SPP MMU uses offer price markup, other market monitors may use price cost markup as a behavioral indicator.
[207] The uneconomic production and physical withholding analysis are addressed through FERC referrals instead of automatic mitigation.

Figure 7–1 Market share of largest supplier



The market share ranged from 11.6 percent to 32.3 percent, exceeding the 20 percent threshold[208] in 5,834 hours (66 percent) for the year. In 2019, market shares ranged from 11.3 percent to 28 percent, with market shares exceeding the 20 percent threshold in 55 percent of intervals. The increase in intervals with a market share over 20 percent continues a pattern that began in June 2018 with the merger between Great Plains Energy (parent company of Kansas City Power & Light) and Westar Energy to form Evergy, Inc. In fact, during almost all of hours with a largest share above 20 percent, the largest on-line supplier was Evergy. Furthermore, these 5,834 hours are not evenly distributed throughout the year, mostly occurring during spring and late summer seasons. Note that although a mere increase in market share does not itself pose a threat to the structural competitiveness of the SPP market, other relevant market data including pivotal supplier hours and local market power mitigation must also be closely evaluated for competitive assessment (see below).

The Herfindahl-Hirschman Index (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:

[208] The 20 percent threshold is a historically accepted standard for identifying 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.

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

According to FERC's "Merger Policy Statement,"[209] which is similar to the Department of Justice's merger guidelines, an HHI below 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 above 1,800 indicates a highly concentrated market.

Figure 7–2 provides the number of hours for each concentration category in terms of actual generation over the last three years.[210]

Figure 7-2 Market concentration level, real-time

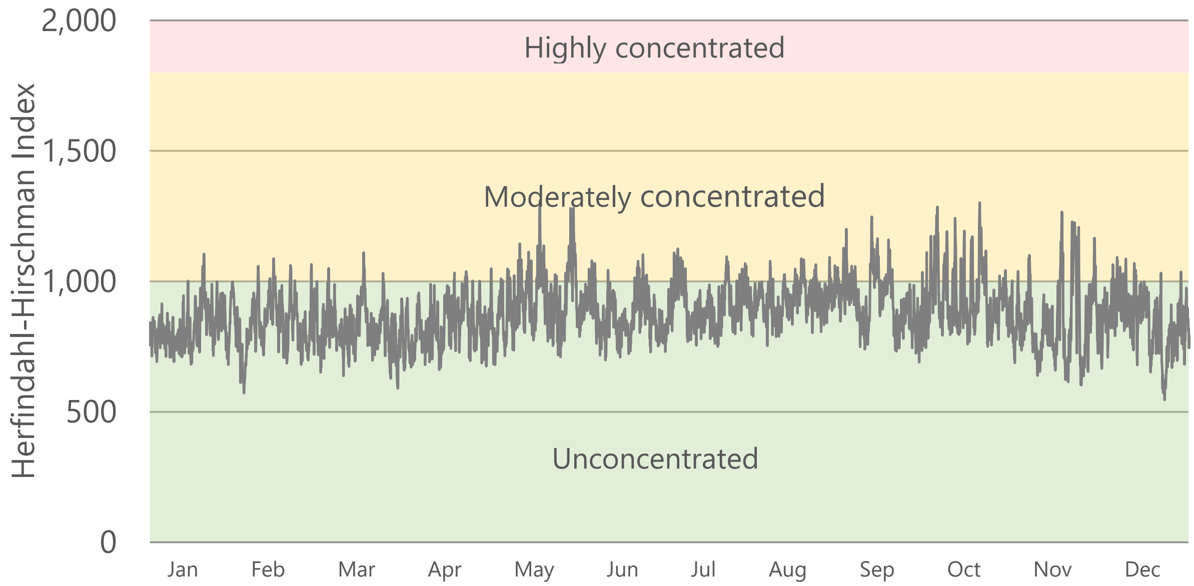
Concentration	HHI Level	2018		2019		2020	
		Hours	Percent of hours	Hours	Percent of hours	Hours	Percent of hours
Unconcentrated	Below 1,000	7,692	88%	7,768	89%	7691	88%
Moderately concentrated	1,000 to	1,067	12%	984	11%	1093	12%
Highly concentrated	Above 1,800	0	0%	0	0%	0	0%

The SPP market was unconcentrated in 88 to 89 percent of hours from 2018 to 2020. However, 11 to 12 percent of hours were considered moderately concentrated during the same period. The SPP market has never risen above the highly concentrated threshold of 1,800 since the start of the Integrated Marketplace in 2014. Figure 7–3 depicts the hourly real-time market HHI in terms of generation for 2020.

209 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).

210 The SPP MMU calculates HHI by actual generation as determined by real-time market (five-minute) dispatch solutions aggregated to the hourly level. The FERC merger guidelines uses capacity owned. Some years may reflect hour counts that, when totaled, do not constitute a full 8,760 hours. Generally, this is due to sustained real-time market system outages lasting longer than one hour. In accordance with the SPP Integrated Marketplace Protocols for pricing during system outages, if the market has not solved for a full hourly interval, it is excluded from the HHI analysis.

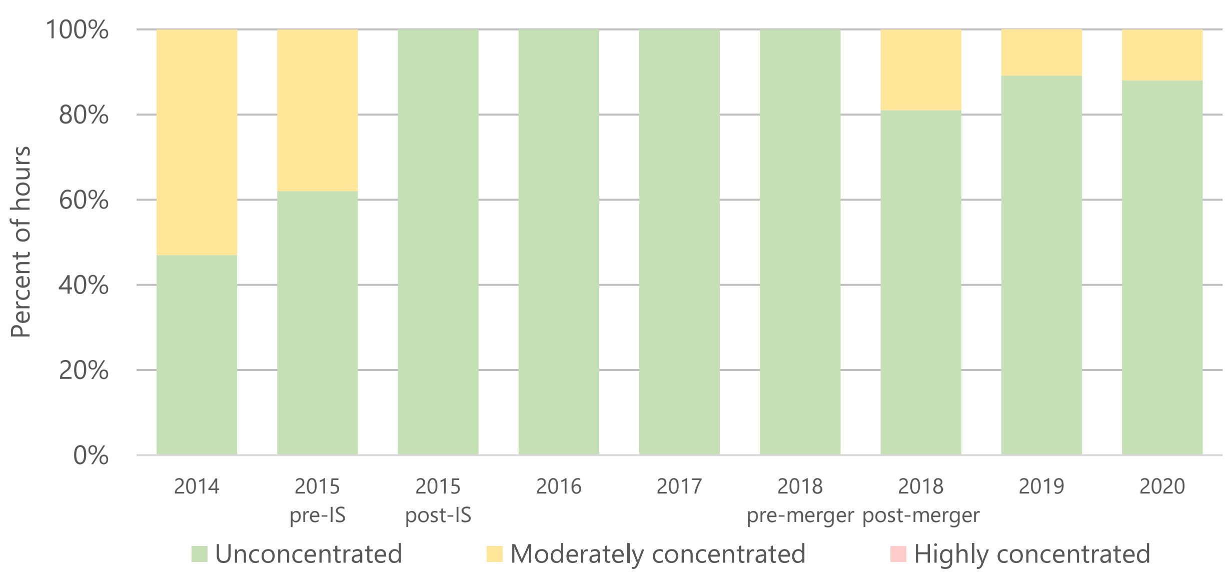
Figure 7–3 Herfindahl-Hirschman Index, 2020



Hourly HHI values ranged from 545 to 1,309 during 2020, pointing to a higher trend relative to 2019.

Figure 7–4 shows a graphical breakdown of the HHI for all hours since the start of the Integrated Marketplace in March 2014. For the years with significant events impacting the make-up of the market—2015, for the addition of the Integrated System; and 2018, with the creation of Evergy—the years are divided on the chart showing the HHI before and after the event.

Figure 7–4 Herfindahl-Hirschman Index, annual



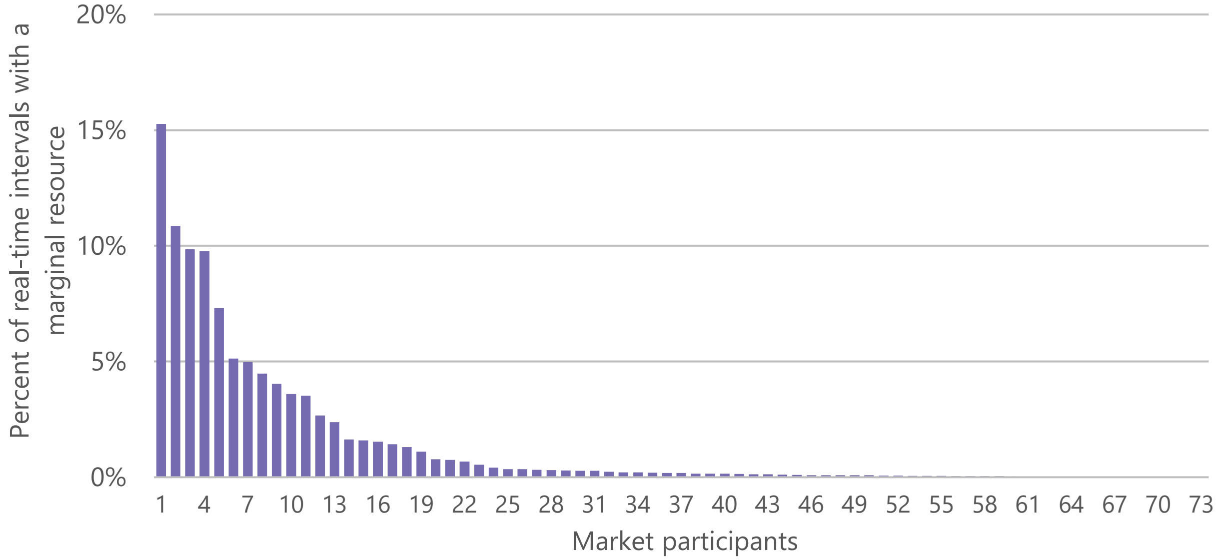
As shown above, the market remained mostly unconcentrated from the addition of the Integrated System to the date of the Great Plains/Westar merger.[211] Even though moderately concentrated hours increased following the creation of Evergy, only 11 and 12 percent of hours fell into this category in 2019 and 2020, respectively. In contrast, in 2014, just over 50 percent of hours were considered moderately concentrated, and in 2015, prior to the addition of the Integrated System, nearly 40 percent of hours were moderately concentrated.

While moderately concentrated hours increased following the creation of Evergy, it is not necessarily a cause for alarm, as they still remain below 2015 levels, prior to the Integrated System joining the market. Given the HHI results in conjunction with the elevated market shares, this report takes a closer look at market behavior by market participants in terms of the exercise of local market power.[212]

SPP market participants with large, diversified generation portfolios 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 7–5 depicts the percentage of real-time market intervals in which each market participant had a resource on the margin.[213]

[211] Note that the HHI analysis is performed at the market participant level. There may be asset owners under market participants on a contractual basis, where bidding control is not under the purview of the market participant.
[212] Section 7.2 analyzes behavioral aspect of market power.
[213] The Kansas City Power & Light and Westar Energy market participants were combined for the purpose of this analysis.

Figure 7–5 Market participants with a marginal resource, real-time



The top three market participants each set price in approximately 10 to 15 percent of all real-time market time intervals. Conversely, the majority of participants set price in less than one percent of all intervals.[214]

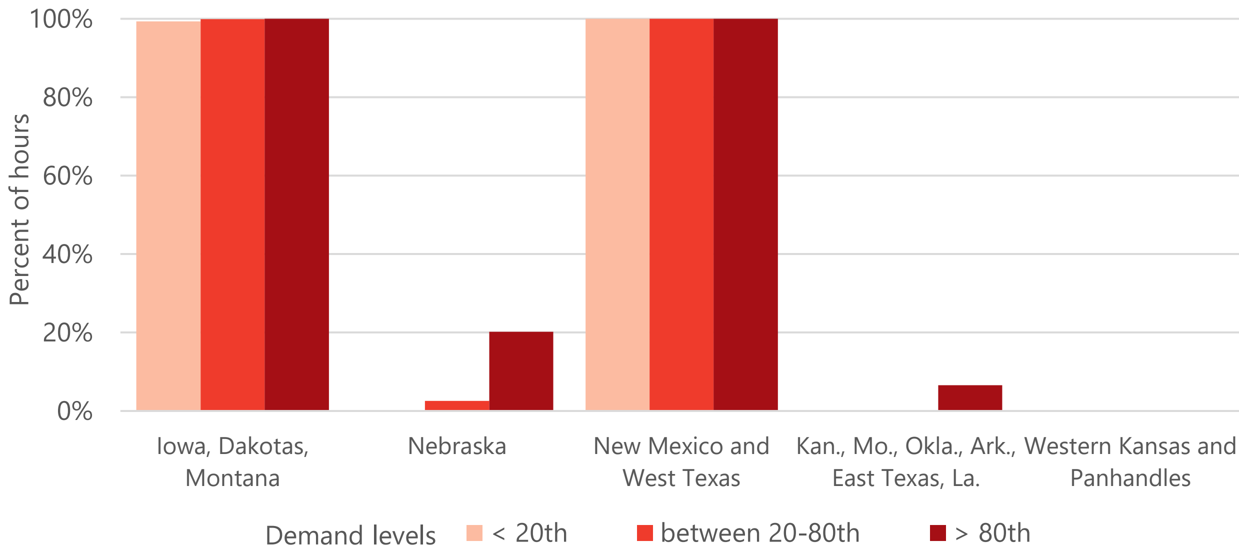
The MMU's market share analysis and HHI metrics both indicate a moderate potential for general structural market power in SPP markets outside of frequently-constrained areas. Structural market power is also assessed at a more localized level and in the context of locational transmission constraints by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

Pivotal supplier analysis takes into account the dynamic nature of the power market, particularly variable demand conditions, and evaluates the potential for market power in the presence of pivotal suppliers. A supplier is pivotal when market demand cannot be met without some or all of its generation. There may be one or more pivotal suppliers in a particular market defined by transmission constraints and load conditions, and a supplier's pivotal status may vary between time periods irrespective of its size. SPP's market clearing process automatically evaluates and—if necessary—mitigates local market power throughout the network.

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

The following metric identifies the frequency with which at least one supplier was pivotal in the five different reserve zones[215] (regions) of the SPP footprint in 2020.[216] The frequency with which a supplier is pivotal is an indication of their potential to raise prices above competitive levels. While the mere size of a supplier does not itself render the supplier pivotal, suppliers which are frequently pivotal in high-demand intervals have a greater ability to exercise market power. For this reason, the pivotal supply frequency is analyzed at various levels of demand across these five regions, as shown in Figure 7–6.

Figure 7–6 Hours with at least one pivotal supplier



The results indicate that the percent of hours with a pivotal supplier is the highest (100 percent) in the New Mexico and West Texas region, regardless of demand level. This has been the case for the last several years. This is followed by the Iowa, Dakotas, Montana region where a downward trend observed since 2017 for all demand levels with the exception of the highest

[215] 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 2020.

[216] It is important to note that reserve zones have rarely been activated in the SPP market.

demand block exhibiting 100 percent pivotal supplier frequency was reversed, showing nearly 100 percent pivotal supplier frequency for all demand levels in 2020.[217]

Compared to 2019, while the Kansas, Missouri, Oklahoma, Arkansas, East Texas, Louisiana region decreased from nearly 34 percent to 7 percent the Nebraska region increased from 10 percent to 20 percent[218] during the highest demand hours with a pivotal supplier.[219]

7.2 BEHAVIORAL ASPECTS OF THE MARKET

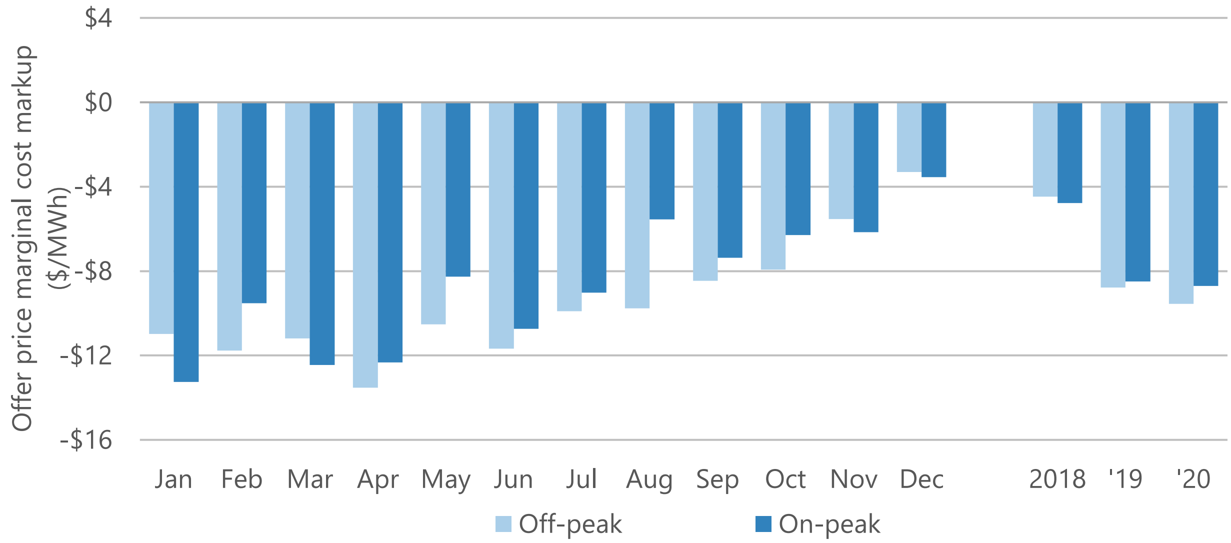
7.2.1 OFFER PRICE MARKUP

In a competitive market, prices should reflect the short-run marginal cost of producing 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 7–7 provides the average marginal resource offer price markups[220] by month for on-peak and off-peak periods. The MMU observed a growing trend of negative markups in both on-peak and off-peak periods from 2018 to 2019, which continued almost in all months in 2020 (see Figure 7–8 for annual ranges). This implies significant and increased price pressure in the SPP market.

[217] Demand in the zone "Iowa, Dakotas, Montana" in 2020 dropped slightly from 2019 but remained above 2018 levels. Near constant demand along with supply shifts caused by below average river inflows into the Missouri River Basin and new generation registered to the largest provider may explain the dramatic rise in pivotal supplier hours in this region.
[218] These numbers are slightly different from last year's reflecting a calculation correction.
[219] Note that this analysis differs from the MMU's Frequently Congested Areas (FCA) study where *impact* of congestion, as well as specific pivotal hours and transmission constraints, are taken into account when FCA designation is determined. Here, the suppliers' pivotal hours' frequency is analyzed only by considering demand levels and reserve zone/demand area assumptions.
[220] 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 markups are weighted based on megawatt to reflect each marginal resource's proportional impact on price.

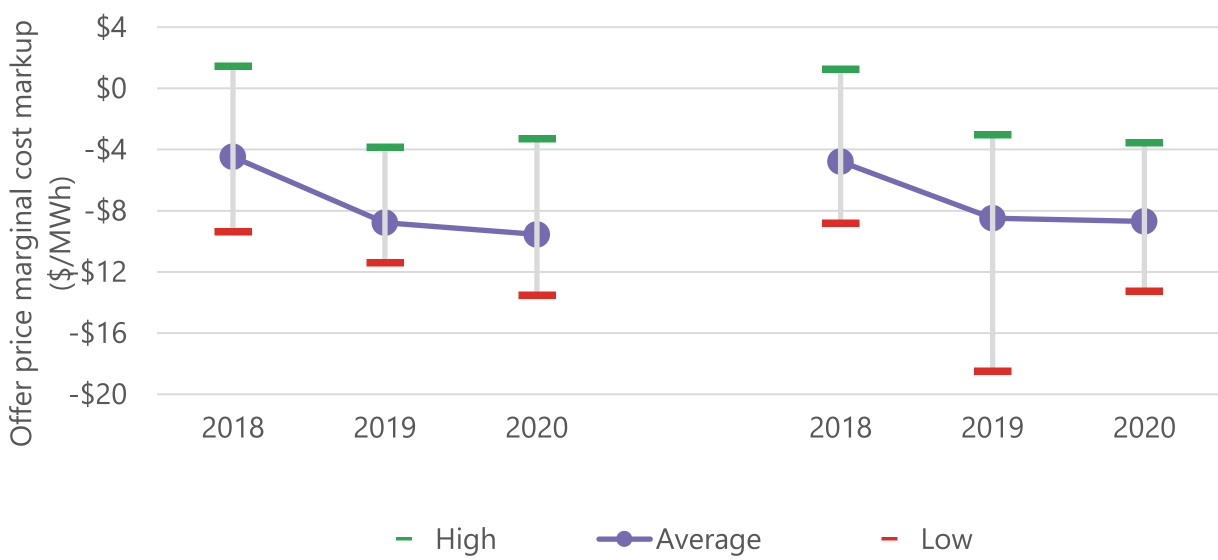
Figure 7–7 Average offer price markup of marginal resource, monthly



In 2020 average monthly markups ranged from −$13.52 to −$3.31/MWh for off-peak periods and from −$13.25 to −$3.54/MWh for on-peak periods. The lowest markups occurred in spring and winter in off-peak and on-peak hours, when wind generation was generally the highest.

Figure 7–8 below points to a continued annual low levels in off-peak and on-peak average marginal resource offer markups in 2020 somewhat leveling off relative to 2019.

Figure 7–8 Average marginal resource offer price markup, annual

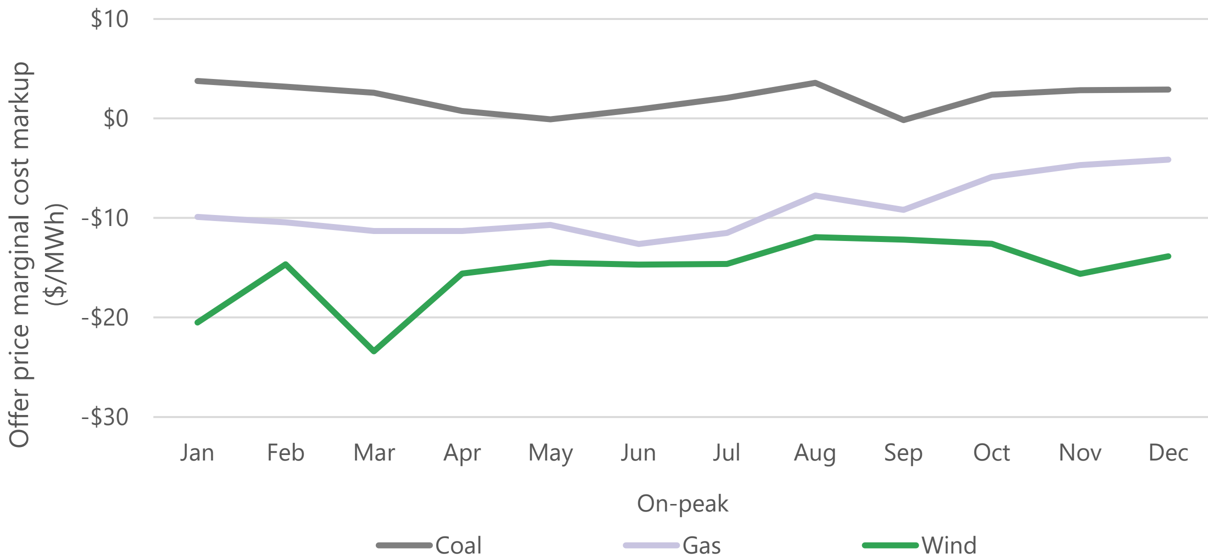


Both off-peak and on-peak average annual markups were at the lowest levels since implementation of the Integrated Marketplace at around −$9.54/MWh and −$8.70/MWh, respectively, showing significantly lower levels compared to 2019 figures. Although a lower offer price markup level in itself would indicate competitive pressure on suppliers in the SPP market, the observed continuous and deepening downward trend may raise questions about the continued commercial viability of generating units and the possibility of generation retirements, as well as inappropriate behavior.[221] Despite this trend, SPP continues to add new generation (mostly wind), and generation capacity relative to peak loads remains high (see Section 6.1.3). More renewable generation is anticipated to be added over the next few years, which is expected to outweigh planned retirements. As such the trend in negative offer-price mark ups will likely continue, further pressuring the economic viability of many generating resources. This concern is also a reason why the MMU recommended, and the Holistic Integrated Tariff Team adopted, a recommendation to study if automatic mitigation of unduly low offers should be developed. The MMU performed a study on this matter,[222] which was presented to the MWG, MOPC, and board. A recommendation to adjust the offer floor to -$100/MWh from -$500/MWh was added to the market roadmap[223]. This recommendation is also included as a recommendation in this report, see Section 8.1.

Figure 7–9 shows the average on-peak marginal resource offer price markup by fuel type for 2020.

[221]Uneconomic Production is reviewed per the Market Monitoring Plan, *SPP Open Access Transmission Tariff*, Attachment AG, Section 4.6.1.
[222] Study on Unduly Low Offers
[223] 2021 Roadmap Candidate Initiative List

Figure 7–9 Average peak offer price markup by fuel type of marginal resource, on-peak, monthly



The observed levels of negative markups indicate that many market participants' real-time market offers were below their mitigated offers.[224] This could occur where generators decide to offer below their marginal cost to:

- meet their day-ahead positions in order to avoid financial risk associated with buying back energy in real time market,
- maintain commitments or reflect temporary negative fuel prices, as in the case of natural gas units,[225] or
- ensure they run to be able to receive production tax credits (PTC), as in the case of wind resources that constitute a sizeable share in total resource portfolio

[224] Wind units may have negative mitigated offers primarily as a result of the federal production tax credit (PTC) for renewable energy.
[225] Tariff rules only allow for submitting monotonically non-decreasing offer curves by market participants, and this may result in market offers by natural gas units below their mitigated offers during negative gas prices. Additionally, real time market offers may be below mitigated offers when natural has units' mitigated offers are indexed to hub prices when in fact the cost of gas received could be below that hub price. Some SPP market participants experienced negative natural gas prices in 2019, which is a rare occurrence.

For instance, wind resources at the margin in the real time market increased from 11 percent of all resource intervals in 2017 to just over 17 percent in 2019 and 22 percent in 2020 (Figure 2–23).

7.2.2 MITIGATION PERFORMANCE AND FREQUENCY

SPP employs an automated conduct and impact mitigation process to prevent the exercise of local market power through economic withholding. The mitigation applies to resources that exercise local market power in transmission-constrained areas, resources in reserve zones experiencing shortages,[226] and resources manually committed by SPP.

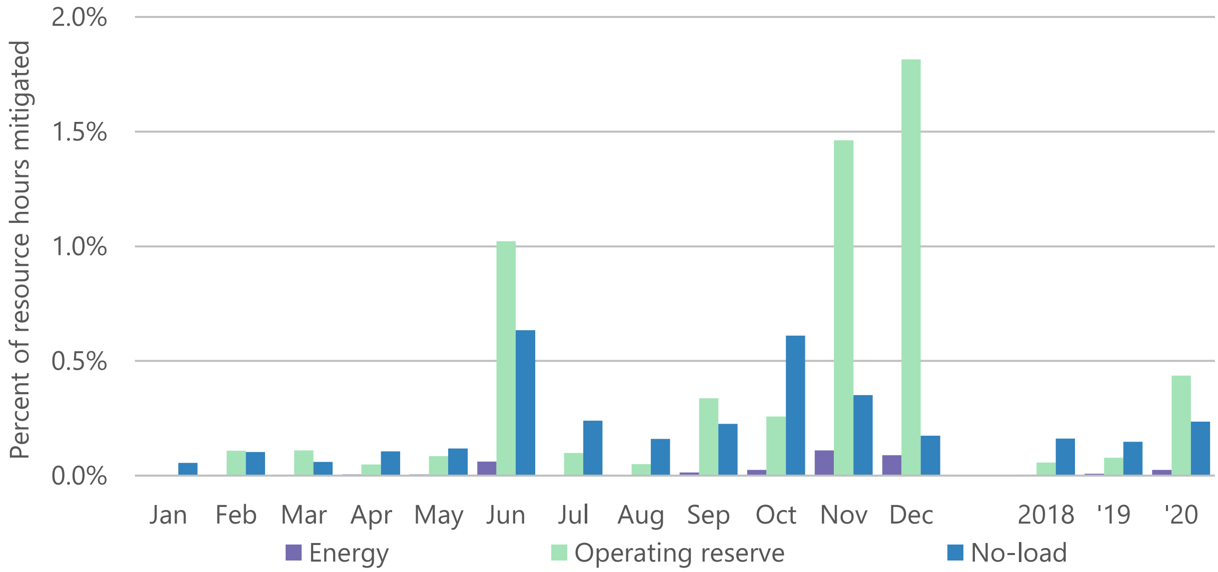
SPP resources' incremental energy, start-up, no-load, and operating reserve offers are subject to mitigation for economic withholding when the following three circumstances occur simultaneously in a market solution:

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[227] and a second offer generally referred to as a market offer, which often includes risk-based and strategy-based adjustments. An offer is considered for mitigation when the market offer exceeds the mitigated offer by more than the allowed threshold; and
3) The resource either:
    a) 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; or
    b) The application of mitigation impacts market prices or make-whole payments by more than the allowed $25/MWh threshold.

[226] No reserve zone shortages occurred in 2020.
[227] As indicated in Appendix G of SPP's *Integrated Market Protocols*.

Mitigation frequency remains very low, with some variation across products and markets. Figure 7–10 shows that the mitigation of incremental energy, operating reserve, and no-load offers was generally infrequent in the day-ahead market in 2020.

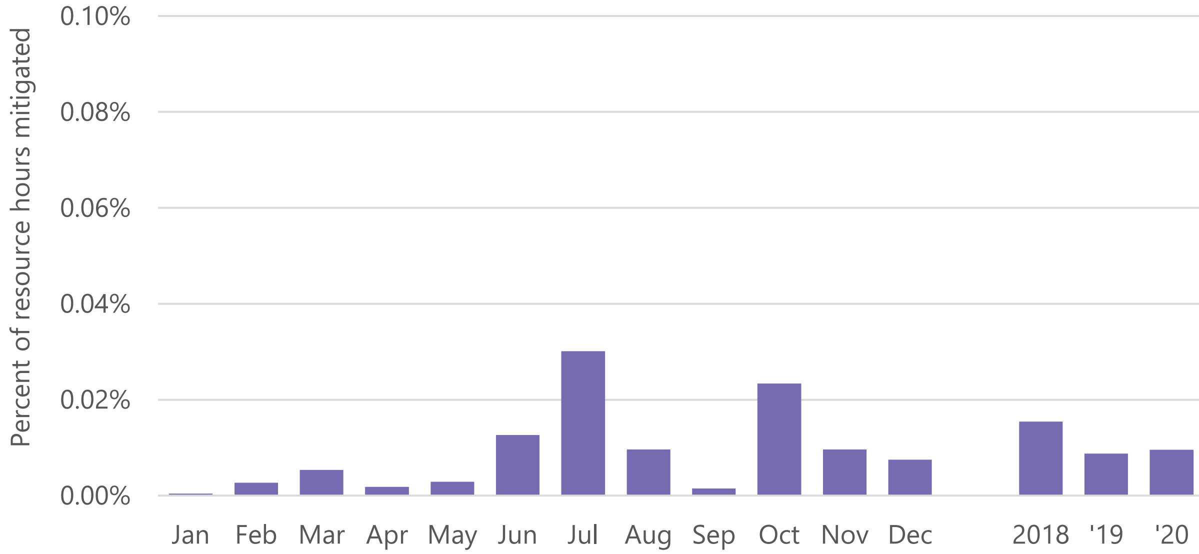
Figure 7-10 Mitigation frequency, day-ahead market



Overall levels for mitigation frequency for the three products in the day-ahead market were less than 0.5 percent since 2018, with relatively large increases in mitigation frequency for operating reserves concentrated primarily in June, November and December of 2020. In addition to June, mitigation frequency was higher slightly in October and November for no-load offers, and was higher for the three products on an annual basis than in 2019. The application of mitigation in the day-ahead market occurred at levels of 0.4 percent for operating reserves, 0.2 percent for no-load, and less than 0.03 percent for incremental energy.

Mitigation of incremental energy in the real-time market is shown in Figure 7–11 below.

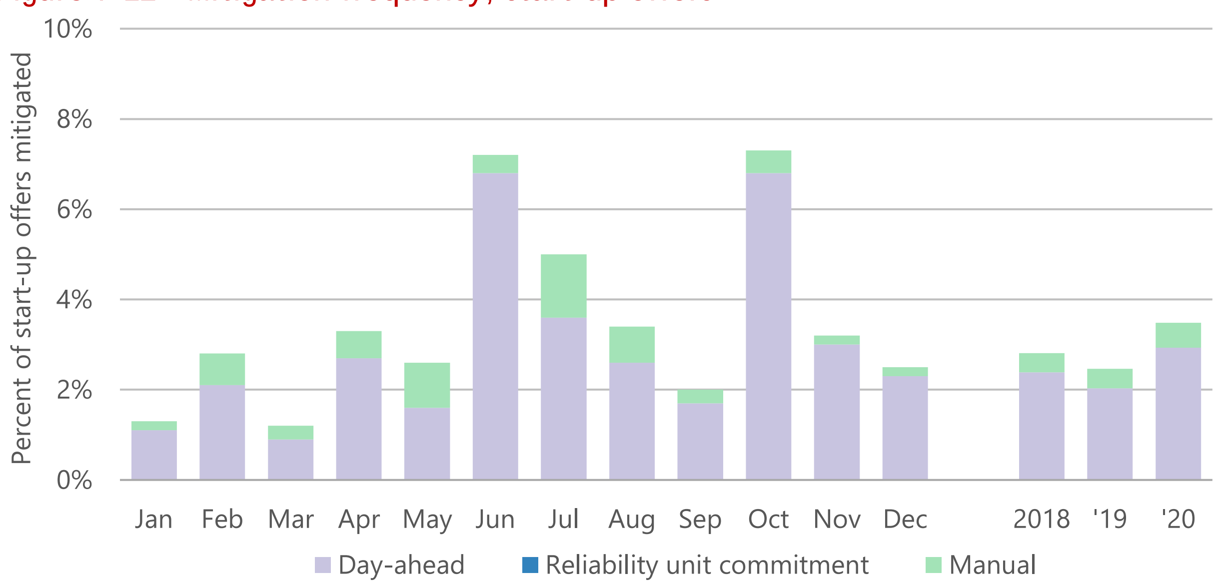
Figure 7–11 Mitigation frequency, incremental energy, real-time market



For the real-time market, the mitigation of incremental energy has remained low since the start of the market, with an annual average of 0.01 percent in 2020.

Figure 7–12 depicts the mitigation frequency for start-up offers for the various commitment types.

Figure 7–12 Mitigation frequency, start-up offers



The annual mitigation frequency of start-up offers in 2020 was slightly higher than in 2019 at under four percent. While the frequency of reliability unit commitment mitigation has been nonexistent since 2017, day-ahead and manual mitigation remained similar to 2019 levels with

2.9 and 0.6 percent, respectively. Day-ahead mitigation accounted for 84 percent of the total start-up cost mitigation. The highest levels of start-up offer mitigation occurred in June, the windiest month, and October, at 7.2 and 7.3 percent, respectively with the lowest occurring in March, at slightly higher than one percent.

7.2.3 OUTPUT GAP (MEASURE FOR POTENTIAL ECONOMIC WITHHOLDING)

Economic withholding is defined as submitting a resource offer that is artificially 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 withheld from the market through the submission of 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, similar to the one used in economic withholding mitigation. In this report, the output gap is calculated as the difference between a 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.[228]

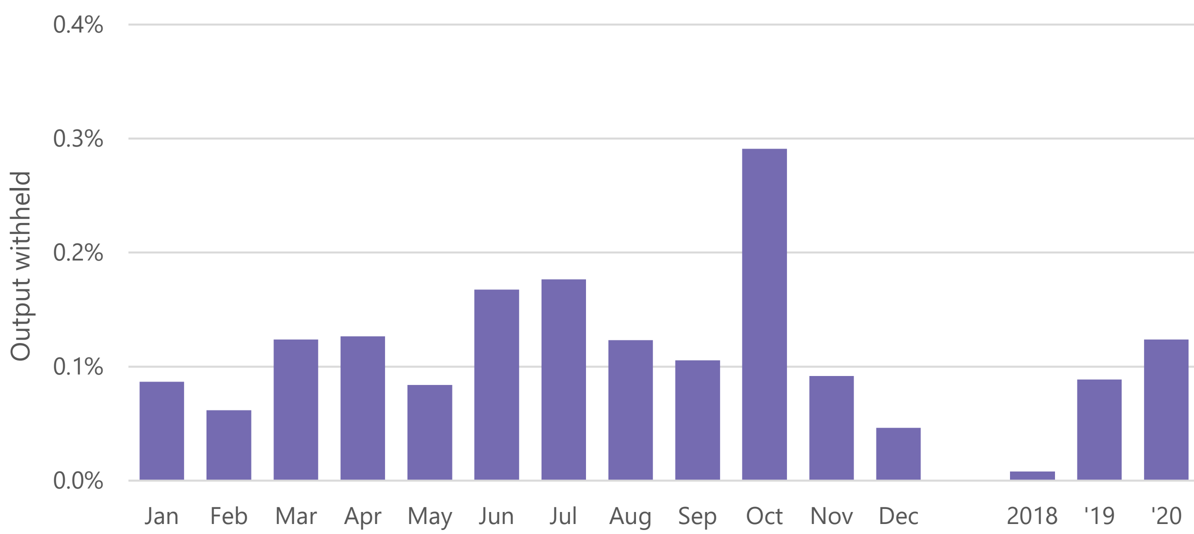
The MMU employs a 17.5 percent conduct threshold for the frequently constrained areas and a 25 percent conduct threshold for the rest of the footprint to reflect the actual thresholds used in the clearing process's automatic economic withholding mitigation.[229] In order to account for the discrepancy between a resource's offered capacity and the dispatched amount (due to 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.

[228] The MMU calculates this metric by including all resources' total (reference level) capacity when calculating output gap percentages.
[229] The frequently constrained area Central Kansas and Southwest Missouri stayed as such until March 31, 2020 after which no new frequently constrained areas in the SPP footprint. The following charts reflect this situation.

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. In addition, the output gap is calculated for the largest three suppliers (market participant portfolios) in each frequently constrained area, if so designated, comparing the levels to those of the remaining suppliers. Similar to the last year's report, [230] the annual calculations were run for all days and evaluated at varying levels of demand as a potential market condition that can affect the withholding outcome.

Figure 7–13 below shows the monthly level of the output gap across the SPP footprint from 2018 to 2020.

Figure 7–13 Output gap, monthly



Compared with the previous years, the output gap was slightly increased in 2020. Overall, it still remained at very low levels, averaging less than 0.3 percent in all months, reflecting a high level of participation in the market overall. The increase in October was mainly due to two large dual fuel resources having significantly higher market offers relative to their mitigated offer. Excluding the impact of these two resources, the output gap percentage would be below 0.2 percent.

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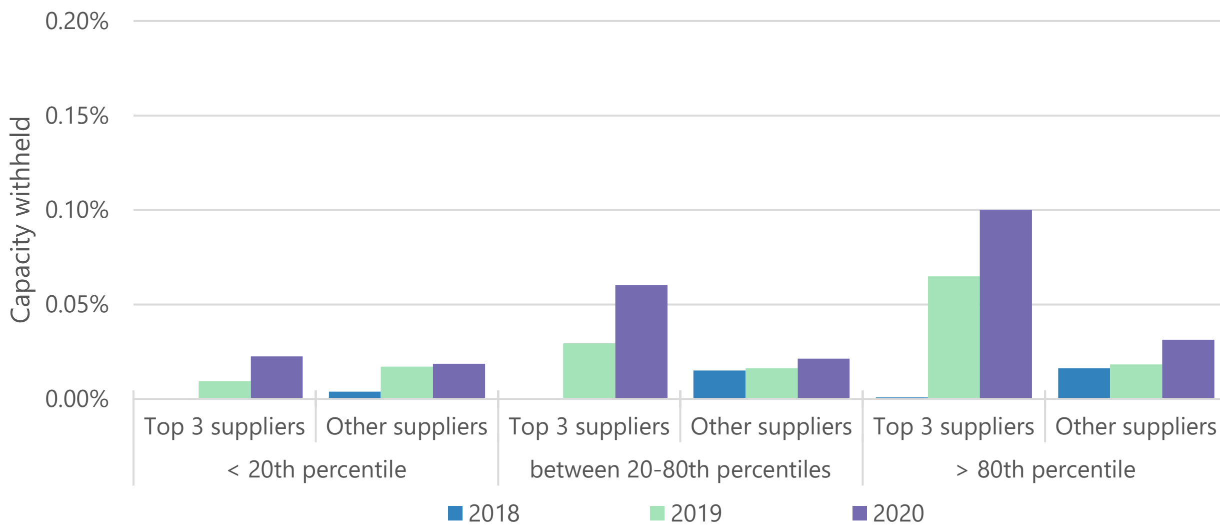
[230] See SPP MMU *2017 Annual State of the Market* report, https://www.spp.org/documents/57928/spp_mmu_asom_2017.pdf, for the output gap calculation methodology.

Figure 7–14 displays the output gap calculated by demand level and participant size for the entire SPP market footprint. No separate output gap analysis of the frequently constrained areas for 2020 was performed,[231] since the two frequently constrained areas were only active for the first three months of 2020 with insignificant impacts to the analysis. 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 7–14 Output gap, SPP footprint



Although still at low levels, the highest level of output gap (no more than 0.1 percent) was observed belonging to the top three largest suppliers and during high demand periods. In general, the results indicate a very low level of economic output withheld in the SPP footprint. These outcomes are generally consistent with expectations of competitive market conduct.

7.2.4 UNOFFERED GENERATION CAPACITY (MEASURE FOR POTENTIAL PHYSICAL WITHHOLDING)

As part of the competitive assessment, the MMU also looked into the potential physical withholding behavior by generators throughout the 2018 to 2020 period. Physical withholding refers to a conduct where a supplier derates a resource or otherwise does not offer it into the

[231] The Central Kansas and Southwest Missouri frequently constrained areas were only activated for the first three months of 2020.

market. Physical withholding may include intentionally not following dispatch instructions, declaring false derates or outages, refusing to provide offers, or providing inaccurate resource parameters such as capability limitations. Any economic generation capacity that is not made available to the market through a derate, outage, or otherwise not offered to the market is considered for this analysis.[232,233]

Total economic capacity that was derated from respective reference levels was classified by reason and duration. Derates can be reflected as planned or forced outages submitted through SPP's outage scheduling system or any undesignated unoffered capacity.[234] Any derates from reference levels 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, the 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 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, the MMU 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

[232] 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.
[233] Economic capacity is determined in a similar way as in the output gap analysis in Section 7.2.3 by comparing resource's (cost-based) mitigated offer to the prevailing locational price.
[234] The planned maintenance outages by nuclear generation and unoffered capacity by hydro, wind, and solar is excluded in this analysis.

for quick-start units. The unoffered capacity is calculated as the difference between the unit's economic capacity[235] 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 shows unoffered economic capacity as percent of total resource reference levels by month for the SPP footprint, [236] and by supplier (participant) size against varying load levels.[237]

Figure 7–15 Unoffered economic capacity

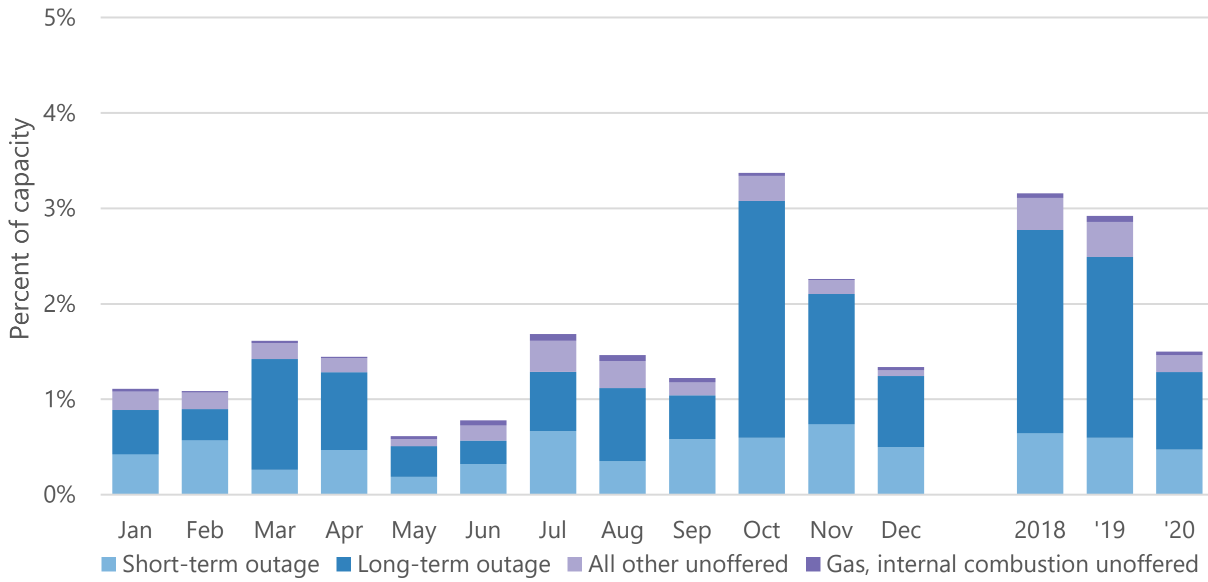


Figure 7–17 shows that on an annual average basis the total unoffered capacity equaled 3.2 percent in 2018, 2.9 percent in 2019, and 1.5 percent in 2020.

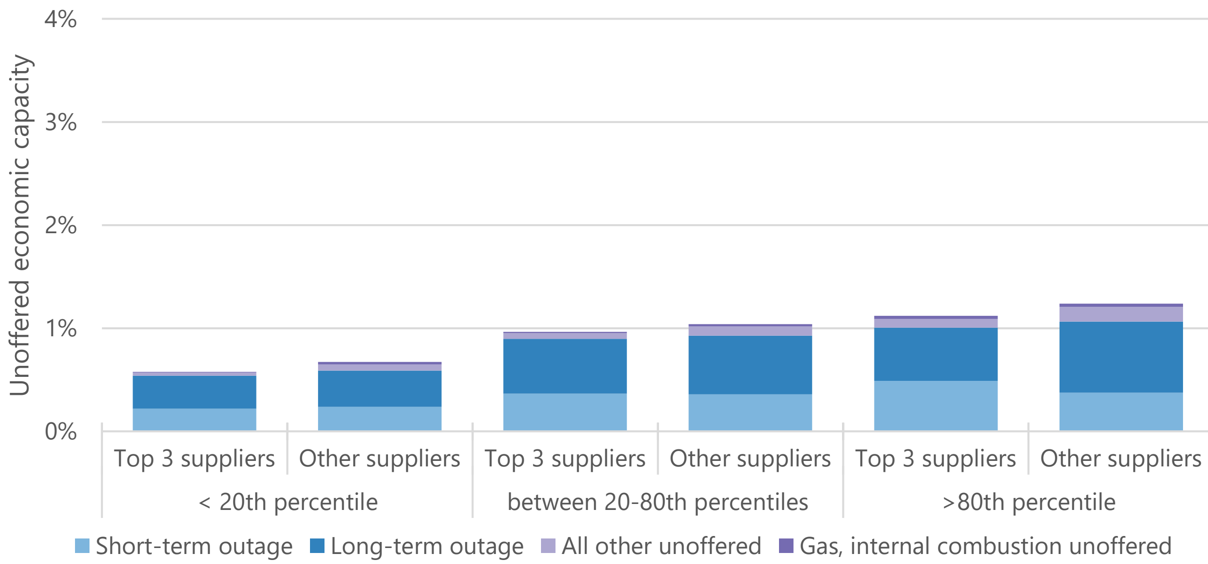
The figure shows that the majority of the outages were long-term and concentrated during the spring and fall shoulder months in 2018 and 2019. But it shows differently in 2020. Due to the pandemic of COVID-19 starting in March, many plants cancelled or postponed their regular spring maintenance so the long-term outages did not occur in the spring shoulder months, but show a higher amount in the fall shoulder months. When short and long-term outages were

[235] Bounded by a resource's reference level.
[236] The frequently constrained area analysis is excluded from this year's study, since the two frequently constrained areas were only activated for the first three months of 2020 with insignificant impacts to the analysis.
[237] Unoffered capacity percentages are calculated out of the total reference levels of the corresponding market area.

excluded from the averages, the remaining unoffered capacity amounts to 0.39 percent, 0.43 percent and 0.21 percent for 2018 through 2020, respectively. From an overall market perspective, the results generally indicate reasonable levels of total unoffered economic capacity.[238] The latter results (net of outages), 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.[239]

Figure 7–16 shows that short-term outages by either large suppliers or others slightly rise with increasing load (which correlate to increasing prices) across the SPP footprint.

Figure 7–16 Unoffered economic capacity at various load levels, SPP footprint



At the same time, unoffered economic capacity of gas (peaker) units—both by large and other suppliers—also slightly rises with increased load albeit at very low levels. Unoffered economic capacity with respect to load levels is more apparent for the remaining resource types, however, it does not exceed 1.24 percent for either of the supplier groups at any demand level.

[238] On an individual resource level, not offering economic capacity may be physical withholding depending on the facts and circumstances of the situation.

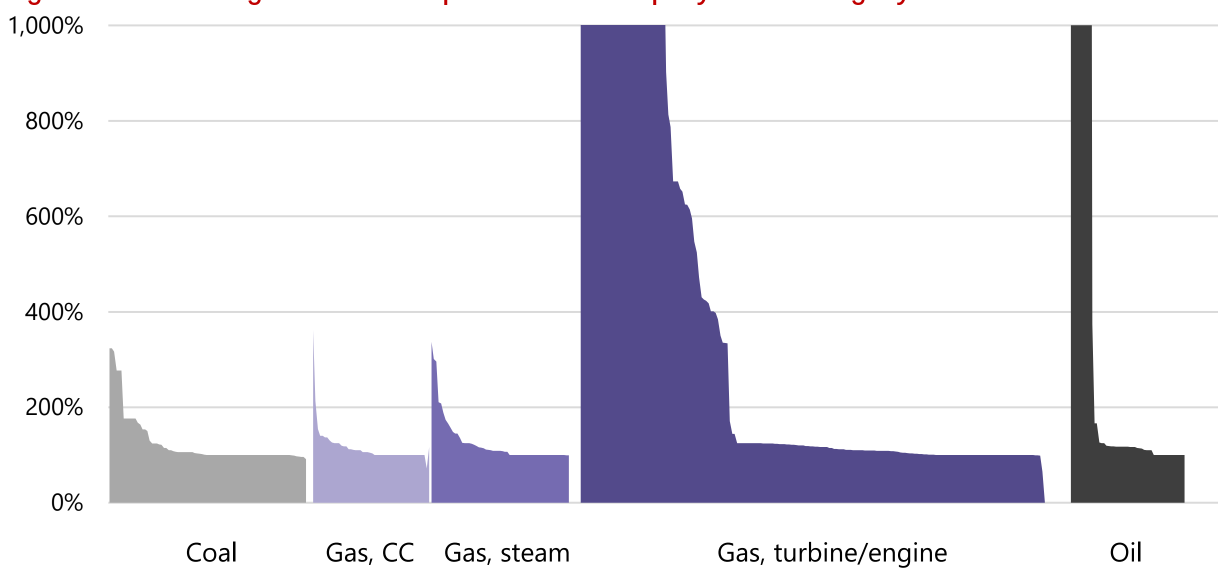
[239] Resources may prefer to offer at times even below their mitigated offers to guarantee to be scheduled or dispatched. See also the offer price markup analysis earlier in Section 7.2.1 and the negative markup results reported therein.

The SPP-wide generation outage data[240] (see Section 3.4) shows that most long-term outages were for out-of-service, maintenance outages (58 percent). Out of the short-term outages, approximately 60 percent were forced outages. Despite the fact that over 12 percent of generators are on outage at any one time, per Section 3.4, most of these generators would not be making money even if they were available. This is one reason why outages are taking longer.

7.3 START-UP AND NO-LOAD BEHAVIOR

Analysis of no-load and start-up offers showed that many market participants made start-up and no-load offers considerably above their mitigated offer levels (see Figure 7–17). Nonetheless, start-up mitigation only occurred in about four percent of intervals in 2020 and day-ahead mitigation accounted for 84 percent of the total start-up cost mitigation. These figures were very similar to results in 2019.

Figure 7–17 Mitigation start-up offer mark-up by fuel category



7.4 COMPETITIVE ASSESSMENT SUMMARY

Overall, structural and behavioral metrics indicate that the SPP markets have been competitive over the last several years. The market share, HHI, and pivotal supplier analyses all indicate

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

minimal to moderate potential structural market power in SPP markets outside of a limited number of frequently congested areas.

The market share indicators in 2020 demonstrate a significantly increased concentration from 2018 and 2019 levels that coincides with the merger of Great Plains and Westar to form Evergy, Inc. in June 2018. In 2019, the market share of the largest on-line supplier in real-time market hours exceeding the 20 percent threshold was up to 55 percent from 35 percent in 2018. This went up to 66 percent in 2020. The data show that this outcome is mostly attributable to real-time dispatch of resources owned and controlled by an Evergy-controlled resource. Meanwhile, another general measure of structural market power—the HHI calculation for supplier concentration—reveals that the percent of the hours where the SPP market was unconcentrated declined from 100 percent in 2017 to 88 to 89 percent of hours range from 2018 to 2020. The HHI market concentration analysis shows that 12 percent of hours were considered moderately concentrated in 2020. Structural market power in the SPP footprint only creates the potential for market manipulation. Although the market share indicators show increased levels, the MMU continues to believe that the existing local market power mitigation measures are sufficiently robust to moderate the impact of an *actual* exercise of that potential, should it occur. These analyses both indicate a moderate potential for general structural market power in SPP markets outside of areas that are frequently congested. The MMU will continue to evaluate structural market power concerns going forward.

Despite slightly increased HHI and significantly elevated market share metrics, there were only two frequently constrained areas in 2020, where concerns regarding potential local market power are highest.[241] MMU analysis and continued close scrutiny of these areas confirm that existing mitigation measures are effective to mitigate the exercise of local market power.

Behavioral indicators were also assessed by analyzing the conduct of market participants, and the impact of that conduct on market prices, in order to detect the exercise of market power. One such indicator—the negative offer price mark-ups—continues to show increasingly negative offer levels relative to those observed in 2017 to 2019, in both on-peak and off-peak periods. In 2020, both off-peak and on-peak annual average markups were at their lowest levels

[241] However, Central Kansas and Southwest Missouri stayed as a frequently constrained areas until March 31, 2020 after which no new frequently constrained areas were active in the SPP footprint.

since the implementation of the Integrated Marketplace at around −$9.54/MWh and −$8.70/MWh, respectively. Similar to 2019, this negative markup pattern was observed in all 12 months, with lowest markups occurring in spring and winter in off-peak and on-peak hours, when wind generation was generally the highest. This could occur when generators decide to offer below their marginal cost to meet their day-ahead positions in order to avoid financial risk associated with buying back energy in real time market or to maintain commitments or reflect temporary negative fuel prices, as in the case of natural gas units. In addition, wind units—that constitute a sizeable share in SPP's total resource portfolio—may decide to ensure their run to be able to receive production tax credits. While a low offer price markup level in itself could indicate competitive pressures on suppliers in the SPP market, the observed *continuous* and *deepening* downward trend raises questions about the long-run commercial viability of generating units and the possibility of generation retirements. The MMU's study of automatic mitigation of unduly low offers resulted in a recommendation being added to the market road map.

Similar to 2019, mitigation for economic withholding remained infrequent. In particular, incremental energy mitigation in 2020 was extremely low in both markets, with approximately 0.03 percent of hours mitigated in both the day-ahead real-time markets. The overall mitigation frequency of start-up for day-ahead, reliability unit commitment, and manual commitments was slightly higher than in 2019 at around 3.5 percent in 2020. Meanwhile, the combined frequency of no-load and operating reserve mitigation in the day-ahead market decreased from 2019 levels and remained at negligible levels.

While the system-wide monthly output gap results show slight increase in 2020, they are still low—averaging less than 0.12 percent in on annual average level. These low overall levels of withheld economic output are consistent with competitive market conduct, and reflect a high level of participation in the market.

Average unoffered economic capacity was 3.2 percent in 2018, 2.9 percent in 2019, and 1.5 percent in 2020, respectively. Although the majority of the outages responsible for unoffered capacity were long-term, and primarily the result of maintenance in the spring and fall shoulder months in 2018 and 2019, this pattern has changed in 2020 due to the pandemic of COVID-19. Starting in March 2020, many plants cancelled or postponed their regular spring maintenance so the long-term outages did not occur in the spring shoulder month. Furthermore, short-term outages by either large suppliers or others were slightly increasing with load across the SPP footprint. The increase in long-term outages from 2017 to 2020 indicates that there is little price incentive for repairing generators as quickly as possible.[242]

The very low level (0.21 percent) of unoffered capacity net of outages could indicate requirements for market participants to offer and maintain commitments given long-term obligations external to the market. The high level of self-committed supply in the market could be another factor in the low levels of unoffered capacity. From an overall market perspective, the results generally indicate reasonable levels of total unoffered economic capacity.

Overall, the SPP Integrated Marketplace provides effective market incentives and mitigation measures to produce competitive market outcomes, particularly during market intervals where the exercise of local market power is a concern. Addressing the MMU concerns discussed earlier in this report such as the role of—lack of—incentives in price formation during emergency conditions and high share of self-commitments will greatly enhance the effectiveness of the market. The competitive assessment in this report provides evidence that market results in 2020 were, to a great extent, workably competitive overall and that the market required mitigation of local market power infrequently to achieve those outcomes. Nonetheless, mitigation of economic withholding 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.

[242] See Section 3.4 for further detail.

8 RECOMMENDATIONS

One of the core functions of a market monitor is "to advise the Commission, the RTO or ISO, and other interested entities of its views regarding any needed rule and tariff changes."[243] 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 design, rules, and processes.

This section highlights new recommendations and updates recommendations made in prior reports based on 2020 market outcomes. A separate Winter Weather Report contains additional recommendations, which may also be reflected in this annual report, based on the 2021 Winter Weather events[244]. The current status of previous recommendations are also identified. Overall, SPP and its stakeholders have made significant progress on many outstanding MMU recommendations. Section 8.3 lists the status of open past and current annual report recommendations.

8.1 NEW RECOMMENDATIONS

The following recommendations are new for 2020. Updating outage requirements and developing market rules and market incentives associated with outages to better align the network models used by the transmission congestion rights auctions and the day-ahead market will help to improve the funding for the transmission congestion rights in the SPP market.

A joint study, which would evaluate the processes and mechanisms used to effectuate the market-to-market agreement between SPP and MISO, would help to identify and improve efficiencies in the market-to-market process.

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243 As defined by FERC in Order No. 719.
244 SPP MMU Report on February 2021 Winter Weather Event

Raising the floor at which resources can offer into the market will improve the efficiency of the market as these offers do not represent cost, are often costly to the offering resource, and are harmful to nearby resources. This would be a simple and cost effective solution that avoids any limitation of what costs can be included in a market offer.

2020.1 UPDATE MARKET AND OUTAGE REQUIREMENTS TO IMPROVE FUNDING FOR TRANSMISSION CONGESTION RIGHTS

The MMU has observed a continued downward trend in the overall funding of transmission congestion rights from day-ahead market congestion rents and recommends market incentives and outage requirements to improve funding. Overall funding for transmission congestion rights decreased materially from 2018 through 2020. In 2018, transmission congestion right funding by the day-ahead market was at a rate of ninety-four cents on the dollar. By 2020, the day-ahead market only funded transmission congestion rights at a rate of eighty-two cents on the dollar, a decrease of twelve cents on the dollar over a two-year period. The underfunding of transmission congestion rights lessens their usefulness as a hedge against day-ahead congestion for firm transmission and lessens their value in the transmission congestion rights auctions.

Transmission congestion rights represent the right to congestion rents from the day-ahead market on prescribed paths. Transmission congestion rights are available in seasonal and monthly auctions either through bids to purchase or through self-conversion of auction revenue right, or through the allocation of long-term congestion rights. Funding issues generally stem from a misalignment in topology or transfer capability between the auctions and the day-ahead market. When constraints differ between the network model used by the auction and the network model used by the day-ahead market, transmission congestion rights may be under or over sold in the auctions. The main reason for differences in the network model between the transmission congestion rights auctions and the day-ahead market are outages and changes in line ratings. The monthly transmission congestion rights auction includes only outages submitted at least forty-five days prior to the first of the month that have a duration of at least five days. Outages fitting that scenario represent about five percent of the total outages in the day-ahead market.

The MMU highly recommends updating outage requirements and developing market rules and market incentives associated with outages to better align the network models used by the transmission congestion rights auctions and the day-ahead market. Regulatory requirements, market rules, and market incentives should address but not be limited to the following recommendations.

A. Strengthen approval criteria for outage requests that cannot be reflected in the last transmission congestion rights auction for an operating day. Outage requests submitted after the cutoff for the last transmission congestion rights auction for an operating day, for reasons other than "forced outage", should require additional scrutiny by the RTO prior to approval. Evaluation should include impacts to both reliability and economics. Outage requests submitted after the cutoff for the last auction for an operating day, which surpass a threshold for impacts to reliability or economics, should not receive approval. Additional scrutiny of the reliability and economic impacts to the market, of non-forced outages, prior to approval will minimize the impact of outages on the funding of transmission congestion rights.
B. Develop a method to supplement the funding of transmission congestion rights through charges for outages requested after the cutoff for the last auction for an operating day. Any outage request, including forced, submitted after the cutoff date should be allocated a share of any underfunding of the transmission congestion rights from the day-ahead market for that operating day, commiserate with the impact of the outage on the market. Charging resources for impact they have on the congestion hedging market, caused by short lead-time outages, minimizes those impacts and allocates the costs to the causers.
C. Implement more frequent transmission congestion rights auctions with a shorter auction period that accommodates outages with durations less than five days. These actions will improve the alignment of the network models between the transmission congestion rights auctions and the day-ahead market, limiting the impact of outages on the congestion market and enhancing the funding of the transmission congestion rights by the day-ahead market. More frequent auctions with a shorter auction period help ensure the network models between the transmission congestion rights auctions and the day-ahead market are more closely aligned and limits the impacts of outages on the funding of transmission congestion rights.

The MMU worked with the Market Working Group to add this as an initiative[245] on the SPP Roadmap[246]. The estimated start and estimated completion date of this initiative is currently pending.

2020.2 ENHANCE MARKET-TO-MARKET EFFICIENCIES THROUGH COLLABORATION WITH MISO

Through a joint study with MISO's independent market monitor, Potomac Economics, the MMU identified inefficiencies in the processes and mechanisms that manage market-to-market congestion on the seam between the SPP and MISO regions. The market-to-market agreement with MISO allows the adjacent RTOs to manage congestion more economically through monitoring shadow prices at designated flowgates and requesting economic relief to that congestion from the neighboring RTO. The MMU recommends the processes and mechanisms used to effectuate the market-to-market agreement between SPP and MISO be evaluated through a joint study and the following inefficiencies addressed:

A. The request for relief on a binding market-to-market flowgate and the subsequent reloading of the flowgate when it is no longer binding causes power oscillations. Upon a request for relief by the monitoring RTO, both regions attempting to relieve the congestion based on a single shadow price, often resulting in overshooting the relief needed. Upon the reloading of a market-to-market constraint, by the non-monitoring RTO, when it is no longer binding often results in an increase of flows causing an exceedance of flowgate limits. The MMU recommends collaboration between SPP and MISO to develop a process for requesting relief, and a process for reloading when the relief is no longer needed, that minimizes the oscillation.
B. Differing assumptions by SPP and MISO on market-to-market constraints in the day-ahead markets cause day-ahead solutions that lead to real-time congestion and binding market-to-market constraints. The MMU recommends SPP and MISO collaborate on a standard process for data exchange to improve the consistency in modeling market-to-market

[245] SIR77 - TCR Funding

[246] The SPP Strategic Market Roadmap is a process where SPP staff and stakeholders identify, educate, rank, and approve new and existing Integrated Marketplace initiatives for development over the next two to five years. More information on this process can be found at https://www.spp.org/stakeholder-center/spp-roadmap/.

constraints between the day-ahead markets, and better align day-ahead and real-time congestion.

C. Not considering all available generation[247] when relieving constrained market-to-market flowgates limits the capability for relief. MISO has a considerable amount of generation available that has limited impact on different market-to-market flowgates. While the individual impact from a specific generator can be small, the aggregate of this generation can provide a substantial amount of relief for congestion. The MMU recommends that SPP work with MISO to include generation with limited impacts on market-to-market flowgates when providing requested relief by SPP.

D. Delays in identifying and activation of coordinated market-to-market flowgates, caused by manual processes, delays the non-monitoring RTO in providing requested relief to congestion. During this delay, the monitoring RTO has no assistance in relieving the congestion. The MMU recommends that SPP and MISO collaborate to automate the process of identifying and activating coordinated market-to-market constraints.

The MMU worked with the Market Working Group to add this as an initiative[248] on the SPP Roadmap. The estimated start and estimated completion date of this initiative is currently pending.

2020.3 RAISE OFFER FLOOR TO -$100/MWH

The MMU recommends that the energy offer floor be raised to -$100/MWh. The MMU has observed resources offering at the offer floor, -$500/MWh, and setting price. These offers do not represent cost, are often costly to the offering resource, and are harmful to nearby resources. Raising the offer floor is a simple and cost effective solution that avoids any limitation of what costs can be included in a market offer. With the raised floor, market participants can still offer such that they are the last to be dispatched while losing much less revenue when setting price. This can also reduce losses of other nearby resources that cannot be dispatched down due to a minimum or due to a start-up or shut down process. The raised

[247] Generation shift factor cutoff in MISO section in OMS-RSC Seams Study: Market-to-Market Coordination report, prepared by Potomac Economics (MISO IMM).
[248] SIR75 - Market-to-Market Improvements

offer floor will not significantly affect those offering unduly low and will improve price formation.

The MMU worked with the Market Working Group to add this as an initiative[249] on the SPP Roadmap. The estimated start and completion date of this initiative is currently pending.

8.2 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 remain outstanding recommendations. A description of each of these recommendations and their current status is outlined below.

2019.1 IMPROVE PRICE FORMATION

Price formation is the economic basis of incentivizing both short-term operational and long-term investment decisions. The MMU has identified circumstances where market prices provide neither a short-term nor a long-term economic incentive to ensure reliability. The following recommendations are two areas to improve price formation.

A. Improve price formation during emergencies

The MMU reviewed the prices during each conservative operations event as well as the Energy Emergency Alert event in 2019[250]. Prices were very low for a significant amount of time during the Energy Emergency Alert, although they were very high at the beginning of the event.[251] These very low prices do not signal that generation and imports need to be available during these events. The MMU highly recommends reviewing price formation during emergencies.

Other markets ensure the marginal energy price is not lower than the highest economic offer, typically an oil-fired unit. Alternatively, a reliability risk adder could be determined and then added to the operating reserve cost. For example, if reserves reduce the risk of a loss of load

[249] SIR76 - Mitigation of Unduly Low Offers
[250] Section 3.5 of the 2019 Annual State of the Market report
[251] Figure 3-33 of the 2019 Annual State of the Market report

event by one percent, then these reserves have a value of $150/MWh, based on a lost load value of $15,000/MWh. Developing a way to value reliability, including establishment of a regional value of lost load, helps to ensure resources are available when needed. Further, this allows the market to resolve the situation with a minimum of manual commitments.

The MMU continues to recommend that SPP and stakeholders address this as a high priority. SPP and stakeholders added this as an initiative[252] to the SPP Roadmap with final approval estimated for 2022. Setting proper prices during emergency events can signal market participants to take actions to address the underlying emergency condition, such as increasing imports. Proper prices also provide proper signals for investment in new generation or demand response resources to deal with and avoid future emergencies. Finally proper prices provide an important signal for generators planning maintenance; they will want to minimize generation outages during periods of high prices.

B. Improve price formation during scarcity

In 2019, the MMU reviewed the prices during scarcity events (Section 3.2.1) and noted that there was a significant increase in intervals where scarcity pricing was invoked.[253] This trend continued in 2020 (Figure 3-14) with total scarcity events being about 10 percent higher than 2019. While regulation and operating reserves use graduated demand curves during scarcity events, energy and spinning reserve use violation relaxation limits (VRL) which may have no effect on price.[254] As shown in Figure 3-16, the instance of shadow prices capped at the VRL during spinning reserve scarcity events decreases as the scarcity increases. Relaxing the spinning reserve requirement instead of clearing the requirement from a graduated demand curve undervalues spinning reserves when there is competition between products and does not provide a price signal that ensures generator availability.

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[252] SIR32 – Price Formation During Conservative Operations & Emergency Conditions
[253] Figure 3-13 of the 2019 Annual State of the Market report
[254] The operating reserve scarcity price is based on a requirement that is the sum of requirements for (i) regulation-up, (ii) spinning reserve, and (iii) supplemental reserve. This requirement is separate from the requirement and scarcity price for regulation-up. If cleared spinning reserve is short of the spinning reserve requirement, then additional regulation-up or supplemental reserves can count towards the operating reserve requirement. Even though the spinning reserve requirement is not met, scarcity pricing may not be invoked.

The MMU highly recommends SPP and stakeholders review price formation during scarcity events and establish graduated demand curves that incentivize proper price formation. In the short-term, scarcity prices can ensure resources are performing at their maximum limits and that energy imports are incentivized. Even when no more capacity is physically available and imports are exhausted, improved price formation may not result in more product availability during a scarcity event, but will produce a price signal that will incentivize future availability.

2019.2 INCENTIVIZE CAPACITY PERFORMANCE

The MMU observed that the capacity adequacy requirements did not have any actual performance requirements. Other RTOs use methods to compensate resources that are available more often than the average or by adjusting the next year's capacity accreditation based on availability during a certain timeframe. Another option is to develop time estimates of forced outages and maintenance outages during high-demand periods and prorate the available MW for capacity accreditation. A true-up of available capacity at the end of the year would be required to determine whether a market participant met their capacity requirement. This helps to ensure that capacity is actually available during the most important days of the year, and helps to reduce the number of conservative operations events. The Supply Adequacy Working Group, an SPP stakeholder group, has formed a Generator Testing Task Force to address capacity performance among other matters. We highly recommend that this task force work to incentivize capacity performance.

2019.3 UPDATE AND IMPROVE OUTAGE COORDINATION METHODOLOGY

During a review of outages in 2019, MMU observations identified the need to update and improve the outage coordination methodology. The MMU also recommends updating the outage coordination methodology in order to have SPP approve all reserve shutdown outages. Additionally, SPP and stakeholders should also consider if the outage threshold of 25 MW should be lowered to the registration threshold of 10 MW.

The MMU highly recommends that outage coordination methodology be updated to cover reserve shutdown outages and to consider a lower threshold. At a minimum, all market participants should review their outage procedures to ensure they are compliant with SPP's

Outage Coordination Methodology, in particular, with requirements to accurately report outage reasons and times. These recommendations would have also helped with the 2021 Cold Weather event. These revisions are pending at the Operating Reliability Working Group.

2018.1 LIMIT THE EXERCISE OF MARKET POWER OF PARAMETER CHANGES

The market is currently vulnerable to the exercise of market power by the manipulation of a resources' non-dollar based parameters. Where there is no market power, a seller cannot control price because other sellers are competing for revenue. Market power is a market participant's ability to manipulate price by manipulating either supply, demand, or both through either dollar or non-dollar based offers. Where a seller has market power, the seller can control price.

When market power is present, market participants can exercise market power by manipulating a resource's non-dollar-based parameters. For instance, a resource can manipulate energy price by reducing its maximum operating limit from its actual limitation so that it reduces the supply of energy, shifts the supply curve to the left, and raises the price. Non-dollar-based parameters should not be manipulated for the purpose of affecting market clearing. Although SPP's tariff and market protocols have well-defined expectations and precise limitations for the basis of dollar-based offer components in the presence of local market power, the expectations for the basis of non-dollar-based offer components are much less clearly defined and the limitations are much less precise. Additionally, resources who have adjusted their parameters to increase congestion on the loading side of a constraint are not subject to mitigation, which is a problem in light of increasing negative prices.

The MMU recommends that SPP strengthen the language regarding non-dollar-based parameters so that the expectation for the basis of these values is clear and the potential exercise of market power is much more limited. The expectations for the basis of the parameters should be clear and well-defined. Changes to these parameters should be limited to actual capability and should be verified, at a minimum, in the presence of market power. One option would be to require parameters to always reflect actual limitations. Actual limitations could include physical and environmental limitations and potentially other true and verifiable limitations. Another option could be to automatically apply parameter mitigation in the presence of market power, and congesting a transmission line, similar to the automatic mitigation of dollar-based offer components. SPP and stakeholders added this initiative[255] to the SPP Roadmap with final approval estimated for 2021.

2018.2 ENHANCE CREDIT RULES TO ACCOUNT FOR KNOWN INFORMATION IN ASSESSMENTS

In 2018, GreenHat Energy, a financial-only market participant in PJM, defaulted on its portfolio of congestion hedging products in the PJM markets. The current estimate of the default exposure exceeds $160 million.[256] GreenHat Energy acquired its portfolio in compliance with the PJM credit policy, which due to its design, required GreenHat Energy to post less than $1 million in financial security. The disconnect between the projected loss and the required financial security stems largely from PJM's credit policy's assessment of the historic congestion patterns associated with GreenHat Energy's positions. Planned transmission expansion changed the historic congestion patterns in the PJM markets, which caused GreenHat Energy's congestion hedging portfolio to become unprofitable. Ultimately, GreenHat Energy defaulted and has forced the rest of the PJM market to absorb the costs.

While the SPP market is different from the PJM market, SPP's credit policy is similar to PJM's in some respects. For instance, SPP's financial security requirements for transmission congestion rights are based only on historic congestion patterns, even when significant transmission upgrades are planned or have occurred. As noted in the 2017 Annual State of the Market report, congestion patterns in SPP shifted significantly after installation of the phase shifting transformer at the Woodward substation, which changed congestion patterns throughout the footprint.[257] This known event was not factored into SPP's financial security requirements for transmission congestion rights even though it was expected to have a significant effect on outcomes. Furthermore, the congestion pattern was so noticeably shifted that after only a few months the MMU recommended eliminating a frequently constrained area as a result of the

[255] SIR 22 - Limit Market Power Through Physical Parameters
[256] https://insidelines.pjm.com/pjm-intervenors-reach-settlement-on-disposition-of-defaulted-ftrs/
[257] https://www.spp.org/documents/57928/spp_mmu_asom_2017.pdf, page 141.

expansion.[258] However, SPP's financial security requirements only factored in the historic data.[259]

The MMU has engaged SPP's Credit Practice Working Group and has contributed to the dialogue about next steps. SPP and its stakeholders generally agree that updating the SPP credit policy to protect from exposure such as that experienced in PJM is a priority. SPP stakeholders have proposed a two-phase approach to mitigate SPP's exposure. The first phase, which is essentially complete, and includes both quantitative and qualitative enhancements, such as position collateral minimums, know-your-customer best practices, and stronger capitalization requirements. The second phase, scheduled for the second half of 2021, will incorporate forward-looking information into financial security requirements. The MMU recommends that SPP continue to move forward with both phases of credit policy development, as the second phase directly addresses one of the major sources of risk that GreenHat had in PJM.

2018.3 DEVELOP COMPENSATION MECHANISM TO PAY FOR CAPACITY TO COVER UNCERTAINTIES

Because of unexpected variations in wind output, SPP operators often manually commit resources (often in excess of 50 units) in order to meet instantaneous load capacity requirements. Often, however, these resources do not earn enough revenue to cover their offered costs[260] which contributed to an increase in real-time make-whole payments.[261] Moreover, resources providing this reliability service are not compensated specifically for the need. Even when resources are needed so much that they are committed for capacity, the supplemental reserve price is still very low. While the MMU recognizes that SPP operators may need to commit units to account for unforeseen circumstances, manual capacity commitments occur often enough that systematic solutions should be developed. The design of the ramping product should allow for many of the capacity and stagger needs to be met with the compensated ramping product instead of the uncompensated headroom. However, the large

[258] https://www.spp.org/documents/56330/fca%202017%20report%20-%20final.pdf
[259] Per *SPP Open Access Transmission Tariff*, Attachment X, Section 5A.2.
[260] Offered costs included their incremental energy, no load, start-up and reserve offers. When mitigated, the resource offers are replaced with the mitigated offers.
[261] See Section 4.2.

number of manual capacity commitments may indicate that there is a need for a new uncertainty product beyond just a short-term ramping product that might better address problems in the one-hour to three-hour timeframe.[262] Developing products to reduce the need for the large number of manual capacity commitments would help ensure appropriate compensation is being provided for the reliability services provided.

The Market Working Group added the initiative[263] to implement an uncertainty market product as part of the SPP Roadmap and has been actively engaged in developing an uncertainty product for the market. The MMU has been engaged in the Market Working Group activities and fully supports these efforts to compensate capacity used to cover uncertainty of generation and load. SPP stakeholders approved the design at the April 2020 Market Working Group meeting.

2018.4 ENHANCE ABILITY TO ASSESS A RANGE OF OUTCOMES IN TRANSMISSION PLANNING

SPP's transmission planning process develops an annual look-ahead plan. This plan evaluates transmission needs over a 5-year and 10-year time horizon. The plan typically evaluates two scenarios.[264] The first case is a base case, and the second case is an emerging technology case. The process could consider a third scenario. In 2019, the MMU and stakeholders requested that SPP staff consider an additional case. The third case would have considered a shift in environmental regulations—such as a carbon tax or adder—and a change in technologies/market trends including accelerated deployment of storage devices or electric vehicles, higher levels of generation retirement, and higher penetration of renewables.[265]

MMU staff follows market trends to keep abreast of developments, including corporate announcements on carbon reduction and renewable energy targets. Following these trends helped shape the MMU's thinking in terms of how to consider the future generation mix and the

[262] The exact time periods of potential uncertainty products should be determined through the technical expertise of the stakeholder process.
[263] SIR 19 - HITT R4: Implement Uncertainty Market Product
[264] These scenarios are also known as futures cases.
[265] This scenario was similar to a scenario used in the MISO transmission plan. https://cdn.misoenergy.org/MTEP19%20Futures%20Summary291183.pdf.

potential need for an additional scenario. The MMU believed that a third scenario would provide a bookend scenario for the 2021 analysis and supported inclusion of the scenario as part of the 2021 Integrated Transmission Plan. Ultimately, stakeholders passed the third scenario at the Economic Studies Working Group, but rejected it at the Market Operations and Policy Committee and at the Strategic Planning Committee.

While the transmission planning process theoretically can include a third scenario, in practice it does not have the flexibility to include one given that cost of including a third scenario was not unique to the 2021 planning process. This appears to be a significant shortcoming in the planning process as the study process is limited to only two potential scenarios in its 10-year look ahead. This limits the range of potential outcomes that SPP could study.[266] The MMU recommends that SPP enhance their study process to allow the ability to study a range of potential outcomes. If such range of potential outcomes are not captured in a third case study, the MMU recommends to factor them into either an existing case study or potentially as part of the 20-year assessment. The wider the range of possibilities studied, the more robust the results will be.

In the 2020-2021 timeframe, the SPP stakeholders voted for the 2022 ITP to maintain the 2021 ITP's two-scenario approach, having primarily a similar set of features of the 2021 ITP. (The MMU initially recommended that the ESWG consider three futures for the 2022 ITP scope development. However, stakeholders voted to carry over the two future approach of the 2021 ITP. Accordingly, the MMU revised its original recommendation to produce a two future approach).

Meanwhile, the SPP stakeholders approved a four-future scope for the 20-year assessment, Future 3 and Future 4 representing *decarbonization* features. While Future 3 stayed as initially recommended by the MMU, Future 4 assumed zero hurdle rates for interchange transactions between SPP and MISO markets. Therefore, the MMU's above mentioned recommendation was fulfilled in the 20-year assessment.

[266] The MISO transmission planning process studies four cases.

2018.5 IMPROVE REGULATION MILEAGE PRICE FORMATION

In addition to regulation capacity payments, resources that are deployed for regulation also receive payments for costs incurred when moving from one set point instruction to another. These mileage payments are paid directly through regulation-up and regulation-down payments in the day-ahead market. 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, the position must be bought back.

The MMU has identified a mileage price inefficiency. Mileage prices are not set by the marginal cost of mileage like other products. Instead, units are cleared for regulation based on what are known as regulation service offers. These service offers are calculated by taking the competitive offer for regulation and adding the mileage offer to it after discounting the mileage offer by the mileage factor.

The MMU has observed instances where resources cleared with regulation-down competitive offers of $0 and mileage offers just under $50. These units consistently cleared with this offer strategy because the service offer was near $10.50 (e.g. 21 percent * $50) which was lower than the services offers of other resources offering in higher competitive offers. For instance, another resource may offer in a $12 competitive offer and $0 mileage offer. This would make that resource's service offer $12 (($12 + $0) * 21 percent). In this circumstance, the resource with the highest service offer will set the regulation-down price at $12, but the mileage offer will be $50, which would set the mileage clearing price.

The MMU is also concerned that the mileage clearing price does not correctly reflect price formation of mileage given that this price does not represent the expected or realized mileage deployment. Furthermore, the MMU is concerned that participants with resources frequently deployed for regulation will have an incentive to inflate the mileage prices by offering in $0 regulation offers and high mileage offers. The MMU also identified systematic overpayment of regulation mileage in the day-ahead market, which appears to be the result of the mileage factor being set consistently too high relative to actual mileage deployed.

The MMU discussed our concerns with the Market Working Group at its August 2018 meeting. While an action item was developed requesting SPP staff and the MMU to review the effectiveness of the regulation mileage pricing process and present further options, no additional work has been done since that time. We recommend that SPP staff review the performance of regulation mileage, and develop potential approaches to improve regulation mileage price formation. Furthermore, we recommend that SPP staff consider adjusting the mileage factor. We believe that SPP staff and stakeholders should include these items as part of its analysis and change development processes for moving forward. SPP and stakeholders included this initiative[267] on the SPP Roadmap with final approval estimated for 2022.

2017.1 DEVELOP A RAMPING PRODUCT

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

Today, the SPP real-time 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. Without properly valuing ramp, this leads to quick-ramping resources being economically dispatched to their maximum limits for energy, leaving the market vulnerable to a ramp shortage resulting in scarcity pricing. This is not a reflection of a lack of rampable generation being on-line, but rather a lack of rampable capacity available for a given dispatch interval. A ramping product will compensate resources for holding back rampable capability in one interval for use as energy in a future interval. This will reduce the frequency of scarcity events and provide an economic incentive to resources providing rampable capability.

SPP, stakeholders, and the MMU worked together to complete a ramping product design in April 2019 which was approved by the Market Operations and Policy Committee in October 2019. This design was approved by FERC in July 2020.[268]

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[267] SIR 20 - Improved Economic Incentive of Regulation Mileage
[268] *Order Accepting Tariff Revisions,* Docket No. ER20-1617, https://elibrary.ferc.gov/eLibrary/filelist?document_id=14877340&optimized=false.

The MMU will continue to monitor price increases due to capacity shortages and true ramp shortages through and after implementation. Implementation is currently scheduled for early 2022.

2017.2 ENHANCE COMMITMENT OF RESOURCES TO INCREASE RAMPING FLEXIBILITY

Increasing ramping flexibility is becoming increasingly important to integrate higher levels of renewable generation.[269] For instance, one way to address ramping flexibility is to ensure sufficient ramping resources are on-line to meet changing conditions. Over-commitment of resources in real-time can reduce market flexibility, suppress prices, and lead 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. In 2017, the MMU recommended that SPP and its stakeholders address this issue by modifying its market rules to enhance the commitment of resources and increase ramping flexibility. At that time, the MMU described the issue as enhancing the decommitment of resources. However in 2018, having explored the issue further, it was updated to not just be about decommitment of resources, but also included improving how resources are committed.

For instance, the market software frequently commits resources well in advance of when they are actually required to start. This commitment is based on the known assumptions and information available at the time the market engine clears the market. However, conditions change over time. For example, 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 conditions change, the resource may no longer be profitable, however, resources continue to start-up and to run as the commitment. This is due, in part, to the current tariff language that only allows the decommitment of day-ahead market committed resources to prevent anticipated excess supply conditions or other emergency conditions.

[269] SPP MMU 2017 *Annual State of the Market* report, https://www.spp.org/documents/57928/spp_mmu_asom_2017.pdf, page 193.

The MMU evaluated a day in June 2018 where wind output increased by several thousand megawatts.[270] Several quick-start and other short lead time resources were identified that had day-ahead schedules that ran in real-time.[271] Real-time system marginal energy costs were about $35/MWh less than day-ahead costs during the peak hours. Similar days occurred several times in 2020 as well. Other markets have different commitment rules that would help increase market flexibility. For instance, PJM and California ISO delay the commitment of short start resources and quick-start resources until the real-time market, making the day-ahead commitment instruction advisory. Furthermore, the California ISO can also decommit resources after a resource's minimum run time has been met, ignoring the day-ahead commitment period. These commitment rules can help increase the flexibility of resources in the SPP markets and help improve pricing outcomes.

The MMU recommends that SPP and stakeholders explore options, such as those noted above, to enhance commitment of resources and increase flexibility. The MMU views this as a high priority item and the initiative[272] has been added to the SPP Roadmap with final approval estimated for the 2022-2023 timeframe.

2017.3 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 due to the increased frequency of negative prices, as discussed in Section 4.1.4. 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 was developed.

[270] The MMU evaluated June 12, 2018. Wind was approximately 4,000 MW higher in real-time than expected in the day-ahead market.
[271] The day-ahead market committed 25 quick start resources that could be started within 10 minutes or less and an additional 18 resources with start-up times less than four hours.
[272] SIR 9 - Enhanced Commitment

FERC issued Order No. 841 in February 2018 to reduce barriers to participation and to develop a participation model for electric storage resources.[273] Over the course of 2018, SPP, stakeholders, and the MMU worked on changes that would comply with FERC Order No. 841. These changes passed the October 2018 SPP Board meeting and SPP filed the changes with FERC in December 2018. The MMU filed supportive comments shortly after. These changes were approved by FERC on October 17, 2019. In the MMU comments, multiple areas of further work were identified. These areas include further enhancements to electric storage integration include addressing the potential for storage resources to exercise downward market power, the potential for market storage resources (MSR) to manipulate the transmission market, possible market design gaps regarding major maintenance and quick-start resource requirements, and the inefficient commitment of non-continuously dispatchable resource requirements in relation to market storage resources.[274] In December 2019, SPP made a subsequent filing with FERC requesting to defer the effective date for the implementation of the revisions to comply with Order No. 841 to August 2021, which was accepted[275] by FERC on February 27, 2020.

The MMU views integration of storage resources in the SPP markets as an ongoing high priority as several outstanding items beyond compliance with FERC Order No. 841 need to be addressed in order to fully integrate electric storage resources in the SPP markets. An initiative[276] has been added to the SPP Roadmap that plans for additional design on storage with final approval estimated for the 2021-2022 timeframe.

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

[274] Some market storage resources have a non-dispatchable range between their charging range and discharging range. The dispatch calculation for this type of non-continuous dispatch range is much more complicated than the typical linear dispatch calculation. SPP's current proposal is to commit this type of market storage resource for either charging or discharging. This type of commitment is inefficient because it does not make the whole dispatch range available. For more detail, see *Motion to Intervene and Comments of the Southwest Power Pool Market Monitoring Unit*, Section I.B.5, Docket No. ER19-460, December 7, 2018.

[275] https://www.spp.org/documents/61704/20200227_order%20on%20effective%20date%20-%20order%20no.%20841%20compliance%20filing_er19-460-004.pdf

[276] SIR30 - Energy Storage Resources & ESR Phase 2

2017.4 ADDRESS INEFFICIENCY CAUSED BY SELF-COMMITTED RESOURCES

Market participants have noted several reasons for self-commitment including 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, environmental testing, cold weather operations, hydro flow requirements, desire to sell wind energy, 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 incentives to self-commit. The previously cited major maintenance costs should no longer be a concern as those costs could start being included based after April 2019.

The MMU conducted an in depth study of self-commitment practices and associated inefficiencies in 2019.[277] As confirmed in the simulation study, long lead-time and long run-time resources are often self-committed and contribute to depressing prices in the SPP market. The current market structure is limited in its ability to commit these resources, and thus market participants often commit them during uneconomic periods. The current clearing engine logic does not provide 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.[278] A multi-day market was also adopted as a Holistic Integrated Tariff Team recommendation.[279]

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 will stay on until its minimum run-time is met even if it is uneconomic. As such, many resources that have multi-day minimum run times avoid the market clearing

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[277] *Self-committing in SPP markets: Overview, impacts, and recommendations*, https://spp.org/documents/61118/spp%20mmu%20self-commit%20whitepaper.pdf
[278] This would be different from the current multi-day reliability unit commitment process.
[279] *Holistic Integrated Tariff Team Report*, https://www.spp.org/documents/60323/hitt%20report.pdf

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.

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 solution. Further, we recommend, based on its analysis, that SPP and stakeholders consider adding an additional day to the optimization process, as this will best balance forecast accuracy with the ability to commit long lead time and high start-up cost resources. The MMU continues to view reducing self-commitment of generation as a high priority for SPP and its stakeholders as this will enhance market efficiency and improve price signals.

The Holistic Integrated Tariff Team adopted a recommendation to move towards a multi-day market.[280] An initiative[281] was added to the SPP Roadmap to implement these enhancements with final approval estimated for 2022.

2017.5 ADDRESS INEFFICIENCY WHEN FORECASTED RESOURCES UNDER-SCHEDULE DAY-AHEAD

Systematic under-scheduling of wind resources in the day-ahead market can contribute to distorted price signals, suppressing real-time prices and affecting revenue adequacy for all resources. Variable energy resources are generally able to produce close to a forecasted amount. Therefore, the MMU continues to recommend that SPP and its stakeholders address this issue through market incentives and rule changes that focus on market inefficiencies associated with under-scheduling of variable energy resources in the day-ahead market based on forecasted supply.

[280] *Holistic Integrated Tariff Team Report*, https://www.spp.org/documents/60323/hitt%20report.pdf, page 16.
[281] SIR 18 - HITT R3c: Implement Marketplace Enhancements: Multi-Day Market

At November 2020 Market Working Group, SPP staff presented on analysis regarding offer requirements for variable energy resources in the day-ahead as part of a recommendation from SPP's Holistic Integrated Tariff Team.[282] As a result of the SPP and MMU analysis, the MMU proposed an initiative[283] to be added to the SPP Roadmap to address the negative impacts of variable energy resources being underscheduled in the day-ahead market. As part of the initiative, the MMU noted that the issue should be addressed through multiple avenues included 1) incentivizing more variable energy resource participation in the day-ahead market 2) incentivizing more virtual energy participation in the day-ahead market and 3) allocating measurable costs to causers. Prioritization and estimated start date of this initiative is still pending.

2014.1 IMPROVE QUICK-START LOGIC

The MMU recommended that quick-start logic be improved after implementation of the Integrated Marketplace.[284] SPP and stakeholders developed a proposal to enhance the quick-start logic several years ago.[285] However, before the proposal was filed, FERC began a 206 process that identified that the treatment of fast-start generators was unjust and unreasonable.[286] In June 2019, FERC issued an order[287] directing SPP to make a compliance filing addressing pricing practices related to fast-start generators. SPP submitted a compliance filing[288] on December 19, 2019 addressing the six issues outlined in the FERC order. The MMU filed comments[289] offering a limited protest to SPP's proposed tariff revisions to comply with the FERC order.

[282] *Holistic Integrated Tariff Team Report*, https://www.spp.org/documents/60323/hitt%20report.pdf.
[283] SIR 74 - DAMKT VER Participation
[284] SPP MMU *2014 Annual State of the Market* report, https://www.spp.org/Documents/29399/2014%20State%20of%20the%20Market%20Report.pdf , Recommendation 1, page 57.
[285] MPRR116, https://www.spp.org/Documents/30429/rr116.zip
[286] 161 FERC ¶ 61,296, https://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=14782160
[287] FERC ¶ 61,217, https://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=15269476
[288] Docket No. ER20-644-000 SPP compliance filing, https://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=15428342
[289] Docket No. ER20-644-000, MMU comments, https://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=15446258

FERC approved SPP's compliance filing on October 27, 2020 that has an effective date of May 18, 2022.

Additional enhancements to the fast-start design, which were outside the scope of the FERC order, were approved through the stakeholder process and are scheduled to be implemented in conjunction with the previously FERC approved enhancements.[290] The approved revision request makes changes to the intra-day reliability unit commitment (IDRUC) process in order to commit fast-start resources in a more timely and economic manner. The MMU supports improvements to the real-time commitment process to increase market flexibility and improve market efficiency.

2014.3 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 implementation of the 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, 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 SPP board passed a proposal[291] at the July 2018 meeting that would limit make-whole payments for any resource with multi-day minimum run times to the lower of the market offer or the mitigated offer. This limitation only applies for offers falling in hours not accessed by one of the security constrained unit commitment (SCUC) processes and the resource bid at or above their mitigated offer on the first day. The MMU supported the proposal. Subsequent to board approval of the proposal, SPP legal staff identified internally inconsistent tariff language that the revisions revealed but did not address. An associated additional tariff modification was

[290] Revision Request 402, HITT R3 (Fast-Start Resources) - Enhanced Intra-Day Reliability Unit Commitment, https://www.spp.org/search?q=RR402&t=Documents
[291] Revision Request 306, 2014 ASOM MWP MMU Recommendation (3-Day Minimum Run Time)

approved by the stakeholder process. SPP filed these changes with FERC on May 7, 2020[292] and the MMU filed comments in support of the Tariff changes on June 12, 2020.[293] The SPP filing did not note a specific effective date, but rather a first quarter 2022 goal.

2014.4 ADDRESS ISSUES WITH DAY-AHEAD MUST OFFER

In 2017, 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.

The MMU remains concerned with the design weaknesses of the current limited day-ahead must offer requirement. We recommend that SPP and stakeholders eliminate the limited day-ahead must-offer provision and revise the physical withholding rules to include a penalty for non-compliance, or address the design weaknesses. The MMU has continued to monitor and track market performance concerns and has identified a marked increase in generator outages, as discussed in Chapter 3, that are not prevented by the current limited must offer requirement and have contributed to the 35 days of conservative operations in the SPP region during 2019. In light of the increased reliability concerns exacerbated by conservative operations events, the MMU recommends the priority of this issue be elevated to high. The MMU submitted this recommendation as an initiative[294] on the SPP Roadmap. The Market Working Group prioritized this initiative to begin work in 2022 with an estimated final approval in 2023.

8.3 RECOMMENDATIONS UPDATE

The table below lists the status of Annual State of the Market recommendations included in previous reports and those that are new to this report. 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 review earlier reports. All previous annual reports can be found at https://www.spp.org/spp-documents-filings/?id=18512.

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[292] Docket No. ER20-1782, Revisions Regarding Make Whole Payments and Minimum Run Time, https://elibrary.ferc.gov/eLibrary/filelist?document_id=14858744&optimized=false
[293] Docket No. ER20-1782, MMU Comments, https://elibrary.ferc.gov/eLibrary/filelist?document_id=14861491&optimized=false
[294] SIR6 – DA Must Offer and Physical Withholding

Figure 8–1 Annual State of the Market recommendations update

	Recommendation	Report year	Current status
2020.1	Improve price formation during emergencies	2020	SPP Roadmap initiative
2020.2	Incentivize capacity performance	2020	SPP Roadmap initiative
2020.3	Update and improve outage coordination methodology	2020	SPP Roadmap initiative
2019.1	Improve price formation (two issues)	2019	Issue A: SPP Roadmap initiative Issue B: Engaging stakeholders
2019.2	Incentivize capacity performance	2019	Stakeholder discussions in progress
2019.3	Update and improve outage coordination methodology	2019	Awaiting stakeholder approval
2018.1	Limit market power by backstopping parameter changes	2018	SPP Roadmap initiative
2018.2	Enhance credit process to account for known	2018	Second phase scheduled for completion end of 2021
2018.3	Develop compensation or product for capacity used for uncertainties	2018	SPP Roadmap initiative; awaiting MOPC approval
2018.4	Enhance ability for transmission planning to cover range of outcomes	2018	Included sensitivities as part of 2021 ITP process
2018.5	Improve regulation mileage price formation	2018	SPP Roadmap initiative
2017.1	Develop ramping product	2017	Awaiting implementation
2017.2	Enhance unit commitment logic	2017	SPP Roadmap initiative
2017.3	Enhance energy storage design	2017	SPP Roadmap initiative
2017.4	Reduce self-scheduling in market	2017	SPP Roadmap initiative

Recommendation		Report year	Current status
2017.5	Address under-scheduling of wind	2017	SPP Roadmap initiative
2015.1	Non-dispatchable variable energy resource transition to dispatchable variable energy resource status	2015	FERC accepted filing in April 2019, Deadline for certain resources was January 1, 2021
2014.1	Improved quick-start logic	2014	Awaiting implementation
2014.3	Manipulation of make-whole payment provisions	2014	Awaiting implementation
2014.4	Day-ahead must offer requirement and physical withholding	2014	SPP Roadmap initiative

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