EXHIBIT DG-1

Devi Glick, Senior Associate

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Senior Associate*, April 2019 – Present, *Associate*, January 2018 – March 2019

Conducts research and provides expert witness and consulting services on energy sector issues. Examples include:

- Modeling for resource planning using PLEXOS and Encompass utility planning software to evaluate the reasonableness of utility IRP modeling.
- Modeling for resource planning to explore alternative, lower-cost and lower-emission resource portfolio options.
- Serving as an expert witness on avoided cost of distributed solar PV, and submitting direct and surrebuttal testimony regarding the appropriate calculation of benefit categories associated with the value of solar calculations.
- Writing expert testimony on the prudence of continued investment in, and operation of, coal plants relative to retirement.
- Reviewing and assessing the reasonableness of methodologies and assumptions relied on in utility IRPs and other long-term planning documents in Kentucky, South Africa, New Mexico, Florida, South Carolina, and North Carolina for expert reports.
- Contributing to the evaluation of the economics of utility plant operation and capacity planning decisions relative to market prices and alternative resource costs.
- Co-authoring public comments on the adequacy of utility coal ash disposal plans, and federal coal ash disposal rules and amendments.
- Analyzing system-level cost impacts of energy efficiency at the state and national level.

Rocky Mountain Institute, Basalt, CO. August 2012 – September 2017

Senior Associate

- Led technical analysis, modeling, training and capacity building work for utilities and governments in Sub-Saharan Africa around integrated resource planning for the central electricity grid energy. Identified over one billion dollars in savings based on improved resource-planning processes.
- Represented RMI as a content expert and presented materials on electricity pricing and rate design at conferences and events.
- Led a project to research and evaluate utility resource planning and spending processes, focusing specifically on integrated resource planning, to highlight systematic overspending on conventional resources and underinvestment and underutilization of distributed energy resources as a least-cost alternative.

Associate

- Led modeling analysis in collaboration with NextGen Climate America which identified a CO2 loophole in the Clean Power Plan of 250 million tons, or 41 percent of EPA projected abatement. Analysis was submitted as an official federal comment which led to a modification to address the loophole in the final rule.
- Led financial and economic modeling in collaboration with a major U.S. utility to quantify the impact that solar PV would have on their sales, and helped identify alternative business models which would allow them to recapture a significant portion of this at-risk value.
- Supported the planning, content development, facilitation, and execution of numerous events and workshops with participants from across the electricity sector for RMI's Electricity Innovation Lab (eLab) initiative.
- Co-authored two studies reviewing valuation methodologies for solar PV and laying out new principles and recommendations around pricing and rate design for a distributed energy future in the United States. These studies have been highly cited by the industry and submitted as evidence in numerous Public Utility Commission rate cases.

The University of Michigan, Ann Arbor, MI. *Graduate Student Instructor*, September 2011 – July 2012

The Virginia Sea Grant at the Virginia Institute of Marine Science, Gloucester Point, VA. *Policy Intern*, Summer 2011

Managed a communication network analysis study of coastal resource management stakeholders on the Eastern Shore of the Delmarva Peninsula.

The Commission for Environmental Cooperation (NAFTA), Montreal, QC. *Short Term Educational Program/Intern*, Summer 2010

Researched energy and climate issues relevant to the NAFTA parties to assist the executive director in conducting a GAP analysis of emission monitoring, reporting, and verification systems in North America.

Congressman Tom Allen, Portland, ME. *Technology Systems and Outreach Coordinator*, August 2007 – December 2008

Directed Congressman Allen's technology operation, responded to constituent requests, and represented the Congressman at events throughout southern Maine.

EDUCATION

The University of Michigan, Ann Arbor, MI
Master of Public Policy, Gerald R. Ford School of Public Policy, 2012
Master of Science, School of Natural Resources and the Environment, 2012
Masters Project: *Climate Change Adaptation Planning in U.S. Cities*

Middlebury College, Middlebury, VT

Bachelor of Arts, 2007
Environmental Studies, Policy Focus; Minor in Spanish
Thesis: *Environmental Security in a Changing National Security Environment: Reconciling Divergent Policy Interests, Cold War to Present*

PUBLICATIONS

Glick, D, D. Bhandari, C. Roberto, T. Woolf. 2020. *Review of benefit-cost analysis for the EPA's proposed revisions to the 2015 Steam Electric Effluent Limitations Guidelines.* Synapse Energy Economics for Earthjustice and Environmental Integrity Project.

Camp, E, B. Fagan, J. Frost, N. Garner, D. Glick, A. Hopkins, A. Napoleon, K. Takahashi, D. White, M. Whited, R. Wilson. 2019. *Phase 2 Report on Muskrat Falls Project Rate Mitigation, Revision 1 – September 25, 2019.* Synapse Energy Economics for the Board of Commissioners of Public Utilities, Province of Newfoundland and Labrador.

Glick, D., B. Fagan, J. Frost, D. White. 2019. *Big Bend Analysis: Cleaner, Lower-Cost Alternatives to TECO's Billion-Dollar Gas Project*. Synapse Energy Economics for Sierra Club.

Glick, D., F. Ackerman, J. Frost. 2019. *Assessment of Duke Energy's Coal Ash Basin Closure Options Analysis in North Carolina.* Synapse Energy Economics for the Southern Environmental Law Center.

Glick, D., N. Peluso, R. Fagan. 2019. *San Juan Replacement Study: An alternative clean energy resource portfolio to meet Public Service Company of New Mexico's energy, capacity, and flexibility needs after the retirement of the San Juan Generating Station*. Synapse Energy Economics for Sierra Club.

Suphachalasai, S., M. Touati, F. Ackerman, P. Knight, D. Glick, A. Horowitz, J.A. Rogers, T. Amegroud. 2018. *Morocco – Energy Policy MRV: Emission Reductions from Energy Subsidies Reform and Renewable Energy Policy.* Prepared for the World Bank Group.

Camp, E., B. Fagan, J. Frost, D. Glick, A. Hopkins, A. Napoleon, N. Peluso, K. Takahashi, D. White, R. Wilson, T. Woolf. 2018. *Phase 1 Findings on Muskrat Falls Project Rate Mitigation.* Synapse Energy Economics for Board of Commissioners of Public Utilities, Province of Newfoundland and Labrador.

Allison, A., R. Wilson, D. Glick, J. Frost. 2018. *Comments on South Africa 2018 Integrated Resource Plan.* Synapse Energy Economics for Centre for Environmental Rights.

Hopkins, A. S., K. Takahashi, D. Glick, M. Whited. 2018. *Decarbonization of Heating Energy Use in California Buildings: Technology, Markets, Impacts, and Policy Solutions*. Synapse Energy Economics for the Natural Resources Defense Council.

Knight, P., E. Camp, D. Glick, M. Chang. 2018. *Analysis of the Avoided Costs of Compliance of the Massachusetts Global Warming Solutions Act*. Supplement to 2018 AESC Study. Synapse Energy Economics for Massachusetts Department of Energy Resources and Massachusetts Department of Environmental Protection.

Fagan, B., R. Wilson, S. Fields, D. Glick, D. White. 2018. *Nova Scotia Power Inc. Thermal Generation Utilization and Optimization: Economic Analysis of Retention of Fossil-Fueled Thermal Fleet To and Beyond 2030 – M08059*. Prepared for Board Counsel to the Nova Scotia Utility Review Board.

Ackerman, F., D. Glick, T. Vitolo. 2018. *Report on CCR proposed rule*. Prepared for Earthjustice.

Lashof, D. A., D. Weiskopf, D. Glick. 2014. *Potential Emission Leakage Under the Clean Power Plan and a Proposed Solution: A Comment to the US EP*A. NextGen Climate America.

Smith, O., M. Lehrman, D. Glick. 2014. *Rate Design for the Distribution Edge*. Rocky Mountain Institute.

Hansen, L., V. Lacy, D. Glick. 2013. *A Review of Solar PV Benefit & Cost Studies*. Rocky Mountain Institute.

TESTIMONY

Texas Public Utility Commission (PUC Docket No. 49831): Direct Testimony of Devi Glick in the application of Southwestern Public Service Company for authority to change rates. On behalf of Sierra Club. February 10, 2020.

New Mexico Public Regulation Commission (Case No. 19-00170-UT): Testimony of Devi Glick in Support of Uncontested Comprehensive Stipulation. On behalf of Sierra Club. January 21, 2020.

Nova Scotia Utility and Review Board (Matter M09420): Expert Evidence of Fagan, B, D. Glick reviewing Nova Scotia Power's Application for Extra Large Industrial Active Demand Control Tariff for Port Hawkesbury Paper. Prepared for Nova Scotia Utility and Review Board Counsel. December 3, 2019.

New Mexico Public Regulation Commission (Case No. 19-00170-UT): Direct testimony of Devi Glick regarding Southwestern Public Service Company's application for revision of its retail rates and authorization and approval to shorten the service life and abandon its Tolk generation station units. On behalf of Sierra Club. November 22, 2019.

North Carolina Utilities Commission (Docket No. E-100, Sub 158): Responsive testimony of Devi Glick regarding battery storage and PURPA avoided cost rates. On behalf of Southern Alliance for Clean Energy. July 3, 2019.

State Corporation Commission of Virginia (Case No. PUR-2018-00195): Direct testimony of Devi Glick regarding the economic performance of four of Virginia Electric and Power Company's coal-fired units and the Company's petitioned to recover costs incurred to company with state and federal environmental regulations. On behalf of Sierra Club. April 23, 2019.

Connecticut Siting Council (Docket No. 470B): Joint testimony of Robert Fagan and Devi Glick regarding NTE Connecticut's application for a Certificate of Environmental Compatibility and Public Need for the Killingly generating facility. On behalf of Not Another Power Plant and Sierra Club. April 11, 2019.

Public Service Commission of South Carolina (Docket No. 2018-3-E): Surrebuttal testimony of Devi Glick regarding annual review of base rates of fuel costs for Duke Energy Carolinas. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. August 31, 2018.

Public Service Commission of South Carolina (Docket No. 2018-3-E): Direct testimony of Devi Glick regarding the annual review of base rates of fuel costs for Duke Energy Carolinas. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. August 17, 2018.

Public Service Commission of South Carolina (Docket No. 2018-1-E): Surrebuttal testimony of Devi Glick regarding Duke Energy Progress' net energy metering methodology for valuing distributed energy resources system within South Carolina. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. June 4, 2018.

Public Service Commission of South Carolina (Docket No. 2018-1-E): Direct testimony of Devi Glick regarding Duke Energy Progress' net energy metering methodology for valuing distributed energy resources system within South Carolina. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. May 22, 2018.

Public Service Commission of South Carolina (Docket No. 2018-2-E): Direct testimony of Devi Glick on avoided cost calculations and the costs and benefits of solar net energy metering for South Carolina Electric and Gas Company. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. April 12, 2018.

Public Service Commission of South Carolina (Docket No. 2018-2-E): Surrebuttal testimony of Devi Glick on avoided cost calculations and the costs and benefits of solar net energy metering for South Carolina Electric and Gas Company. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. April 4, 2018.

Resume updated February 2020

EXHIBIT DG-2

SIERRA CLUB SET 1

Sierra Club
IURC Cause No. 38707-FAC123
Data Request Set No. 1
Received: February 4, 2020

Sierra Club 1.1

Request:

For each of the Company's coal electric generating units, please provide the following hourly information for September through November 2019, inclusive. If not available at an hourly scale, explain why not and provide at the most temporally granular scale available.

a. Price ($/MWh) of offers submitted into the MISO Marketplace.
b. Quantity (MW) of offers submitted into the MISO Marketplace.
c. For each offer, whether that offer was accepted by MISO.
d. Whether the hourly decision to dispatch a unit was made by Duke or through the MISO Central Market.
e. Day-ahead dispatch status, including "economic," "self-scheduled," or other recorded purposes.
f. Real-time dispatch status, including "economic," "self-scheduled," or other recorded purposes.
g. Day-ahead unit commitment status, including "economic," "must-run," "emergency," "outage," or other recorded purpose.
h. Real-time unit commitment status, including "economic," "must-run," "emergency," "outage," or other recorded purpose.
i. Accounting fuel costs ($/MWh)
j. Marginal (variable) fuel costs ($/MWh)
k. Accounting variable costs of production ($/MWh), including fuel, variable O&M, and any other variable operating costs.
l. Marginal variable costs of production ($/MWh), including fuel, variable O&M, and any other variable operating costs.
m. Net generation (MWh)
n. Locational marginal price received ($/MWh)
o. Energy market revenues ($)
p. Ancillary market revenues ($)
q. Congestion revenues ($)
r. Heat rate (Btu/kWh)
s. Economic minimum level (MW)

Objection:

Duke Energy Indiana objects to this request on the basis that it is vague, ambiguous, overly broad and unduly burdensome as to hourly information for September through November 2019. Duke Energy Indiana further objects as the request to explain why information is not kept in the granular detail requested.

Response:

Subject to and without waiving or limiting its objections, Duke Energy Indiana responds as follows:

a. See Confidential Attachment SC 1.1-A.

b. See Confidential Attachment SC 1.1-B.

c. See Confidential Attachment SC 1.1-C. For purposes of this response, the information provided represents the offer status awarded to the Company by MISO for the given time period.

d. In general, MISO controls hourly dispatch decisions. There are times, such as when a generating unit is testing, performing hourly maintenance or other similar operational constraints when the Company determines the hourly decision and output level to dispatch a unit. Please see Confidential Attachments SC 1.1-D and E for information on how the Company dispatches these types of instances.

e. The Company uses a Day Ahead Dispatch status of Economic at all times. If a generating unit needs to perform testing, maintenance or other similar operations the Company will set the minimum economic limit to the maximum economic limit in order to signal to MISO the necessary loading of a generating unit. See Confidential Attachment SC 1.1-D.

f. The Company uses a Real Time Dispatch status of Economic at all times. If a generating unit needs to perform testing, maintenance or other similar operations the Company will set the minimum economic limit to the maximum economic limit in order to signal to MISO the necessary loading of a generating unit. See Confidential Attachment SC 1.1-E

g. See Confidential Attachment SC 1.1-F.

h. See Confidential Attachment SC 1.1-G.

i. See Confidential Attachment SC 1.1-H.

j. See Confidential Attachment SC 1.1-I. For purposes of this response, Marginal (variable) fuel costs ($/ MWh) provided represents the marginal cost at full load of the applicable generating unit. For purposes of determining costs for offering the Company's

Sierra Club
IURC Cause No. 38707-FAC123
Data Request Set No. 1
Received: February 4, 2020

Sierra Club 1.3

Request:

Regarding Duke's unit commitment decision process for the Company's coal electric generating units:

a. Describe Duke's process for determining whether to self-commit the Company's coal electric generation units and operate them up to at least their minimum operation levels.
b. Describe Duke's process for determining whether to self-schedule the Company's coal electric generating units at generating levels above their minimum operation levels.
c. Does Duke perform economic analyses to inform its unit commitment decisions for the Company's steam electric generation units (i.e., decisions regarding whether to designate these units as must run or take them offline for economic reasons)?
    i. If not, explain why not.
    ii. If so, provide all such analyses conducted since 2018 in native, machine readable format.
    iii. If so, identify each category of cost and revenue accounted for in such analyses
    iv. If so, identify whether such analyses are conducted differently for periods immediately preceding or following unit outages, and explain any differences.

Objection:

Duke Energy Indiana objects to this request as vague and ambiguous, particularly the references to "unit commitment," "dispatch" and "self-schedule." Duke Energy Indiana also objects to this request as overbroad and unduly burdensome, particularly subpart (d)'s request for "all such analyses conducted since 2018."

Response:

Subject to and without waiving or limiting its objections and assuming that the reference to "commitment" means the decision to start a generator that is offline or maintain output from a generator that is already online, "dispatch" means the decision to operate a committed generator at a level other than minimum stable load, and "self-schedule" infers operation outside of the economic dispatch signal received from MISO’s central dispatch function, Duke Energy Indiana responds as follows:

a. The Company performs an economic review each business day to inform the commitment status decision for each coal unit. The planning process is designed to minimize the total customer cost by maximizing the unit’s economic value. This review projects expected operating margins (revenues minus variable costs) from operation of each coal unit for the next 7-14 days based on unit operating parameters and expected market prices. Generally speaking, if a unit is expected to have a positive margin or is “in the money,” meaning that the revenues received are projected to be greater than the variable production costs, the unit may be self-committed with an offer status of Must-Run. This analysis also considers factors such as uneconomic cycling of generating units across lower priced energy periods such as weekends, for unit testing, or to address other operational requirements, all in which a generation unit status of Must-Run may be utilized. Used properly, as we do, the use of a Must-Run offer reduces the overall cost to supply energy to our customers by reducing the additional costs and risk associated with the unnecessary and uneconomic cycling of longer lead time generating units.

b. Duke Energy Indiana predominantly follows MISO dispatch signals and does not strategically self-schedule its generation resources. Self-scheduling a generating unit above its minimum load is typically only done under circumstances that are required for safety, testing, plant operational requirements, or reliability reasons. For example, environmental tests such as a stack tests require the operation of the unit at a specific output for a period of time, periods when the unit must operate at a higher output to supply steam for another unit in startup or shutdown, or times when a unit is manually or uneconomically re-dispatched as directed by MISO due to a transmission or other constraints. In addition, see Duke Energy Indiana’s response to Sierra Club 1.1 parts d and f.

c. Duke Energy Indiana performs an economic review each business day to inform the commitment status decision for each steam unit. The planning process is designed to minimize the total customer cost by maximizing unit economic value. This review projects expected operating margins from operation of each steam unit for the next 7-14 days based on unit operating parameters and expected market prices. This review is not a complete economic analysis as it only considers expected revenue received and variable costs incurred from operation. It does not consider other operational or reliability considerations.

    i. N/A.
    ii. See objection. These files are voluminous. Due to the number of spreadsheets, Duke Energy Indiana will make the files for September through November 2019 available for confidential viewing on-site at Duke Energy Indiana’s Plainfield offices upon reasonable notice and advanced arrangements made with Duke Energy Indiana’s counsel, subject to an appropriate non-disclosure agreement.

iii. See objection.
iv. See objection.

OUCC 3.8-D

OUCC
IURC Cause No. 38707-FAC123
Data Request Set No. 3
Received: February 7, 2020

OUCC 3.8

Request:

Please provide the Company's DA offers (including commitment status, minimum output, maximum output, and station coding), for all of its units, for the following days: September 11, 2019; October 15, 2019; and November 15, 2019. Additionally, please provide the work papers, calculations and inputs that were utilized to determine DA offer for its units for each of these three days.

Response:

See Confidential Attachments OUCC 3.8-A, 3.8-B, and 3.8-C for the units Day-Ahead offers.

Calculations and inputs for Day-Ahead unit offers are contained in the Company's Energy Cost Manual. Due to the competitively sensitive nature of the Energy Cost Manual, Duke Energy Indiana will make it available for on-site review at its Plainfield, Indiana offices upon reasonable notice and advanced arrangements made with Duke Energy Indiana's counsel. Such review will be subject to the standing non-disclosure agreement with the OUCC.

Duke Energy Indiana performs an economic review each business day to inform the commitment status decision for each coal and combined cycle unit. The planning process is designed to minimize the total customer cost by maximizing unit economic value. This review projects expected operating margins from operation of each coal unit for the next 7-14 days based on unit operating parameters and expected market prices. This review is not a complete economic analysis as it only considers expected revenue received and variable costs incurred from operation. It does not consider other operational or reliability considerations.

See Confidential Attachment OUCC 3.8-D Economic Analysis.

EXHIBIT DG-4

Exhibit DG-4

Southwest Power Pool

MARKET MONITORING UNIT

STATE OF THE MARKET

2018

published

May 15, 2019

1 EXECUTIVE SUMMARY

The Southwest Power Pool (SPP) Market Monitoring Unit's (MMU) Annual State of the Market report for 2018 presents an overview of market design and market outcomes, assesses market performance, and provides recommendations for improvement. The purpose of this report is to provide SPP market stakeholders with reliable and useful analysis and information to use in making market-related decisions. The MMU emphasizes that economics and reliability are inseparable and that an efficient wholesale electricity market provides the greatest benefit to the end user both presently and in the years to come.

1.1 MARKET HIGHLIGHTS

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

- SPP market results were workably competitive, with infrequent mitigation of offers and high resource participation levels.
- Total wholesale market costs—including energy, operating reserve, and uplift payments—averaged around $28/MWh in 2018, which was about 15 percent higher than in 2017.
- Day-ahead and real-time prices both averaged around $25/MWh for the year, up from $23/MWh in 2017.
- While the annual peak load of 49,926 MW was two percent lower this year compared to last year, total electricity consumption was up about six percent.
- The incidence of negative prices in 2018, 3.5 percent of intervals, was about half of the 2017 level of seven percent.
- While natural gas-fired resources frequently set prices in the SPP market, other factors such as load increases, had a large impact on market prices. Natural gas prices decreased about two percent in 2018 compared to 2017.
- When system prices are controlled for changes in fuel prices, they averaged about 13 percent higher in 2018 compared to 2017.

- In 2018, there were 167 intervals with operating-reserve scarcity. This was roughly five times as many intervals of operating reserve scarcity as was seen in 2017.

- Day-ahead and real-time congestion costs totaled over $450 million in 2018, a four percent decrease from 2017.

- Wind generation peaked at 16.3 GW and peak wind penetration was almost 64 percent of load in December. Wind capacity increased to almost 20.6 GW in 2017, up about 17 percent from 2017.

- Wind generation totaled 24 percent of all generation in 2018, up slightly from 23 percent in 2017. Coal generation fell from 46 percent in 2017 to 42 percent in 2018.

- New capacity additions were just over 2,300 MW at nameplate capacity, with wind representing 97 percent of the new capacity. Capacity retirements increased to just under 2,000 MW in 2018, split about evenly between coal and gas resources.

- The generator interconnection process includes just over 84 GW of additional resources, of which 99 percent are renewable or storage.

- SPP continues to have significant excess capacity at peak loads. The MMU estimates that capacity at peak is 35 percent higher than the peak demand level in 2018.

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

- Market uplifts remained low at about $73 million in 2018, which was up slightly from 2017 levels.

- Combined ancillary reserve costs totaled $76 million last year, a decrease of three percent from 2017.

- Auction revenue rights were funded at 145 percent in 2018, down from just over 160 percent in 2017.

- Transmission congestion rights funding was virtually unchanged from 2017 to 2018, at 94 percent.

1.2 OVERVIEW

Overall, the SPP market produced highly competitive market results with total market costs around $28/MWh. As with previous years, the largest component of total wholesale costs remains energy costs, which represented almost 98 percent of total costs in 2018. While total costs increased by 15 percent in 2018 compared to 2017, a main driver for the increase in energy costs was an increase in load, as well as several other factors. When adjusted for fuel prices, average SPP marginal energy prices increased by 13 percent.

While the annual peak load of 49,926 MW was two percent lower this year compared to last year, total electricity consumption was up about six percent. Over 97 percent of the 2,300 MW increase in nameplate generation capacity last year was from wind resources. This continues a pattern that has occurred over the past several years. Wind generation as a percent of total generation continued to increase as it represented 24 percent of system generation, up from 23 percent in 2017 and 18 percent in 2016. Conversely, coal generation continued to decline, representing around 42 percent of total generation last year, down from 46 percent in 2017 and 49 percent in 2016. Prior to 2016, coal represented 55 percent or more of generation in SPP.

Significant market events in 2018 included:

- A second circuit from Woodward to Mathewson was added.[1] Our analysis shows that this transmission addition helped shift power further east in the SPP footprint and reduce the frequency of negative prices.
- Market participants continued to express concerns with the effectiveness of the auction revenue rights process to allow participants to receive sufficient hedges for congestion.[2] We observe that while many participants were able to manage congestion, a handful of participants did not have sufficient hedges. There were multiple reasons for this, including the nature of congestion patterns, outages, and market participant strategies.

[1] See Section 5.1.3 for further discussion.
[2] Auction revenue rights and transmission congestion rights are covered in Section 5.2.

- SPP launched the Holistic Integrated Tariff Team effort. This group comprised members, Board of Directors, Regional State Committee members, and supported by SPP staff, focused on developing problem statements, reviewing analysis, and proposing solutions to related areas of concern including transmission cost allocation, auction revenue right allocation, market enhancements, and load integration. The findings of the group are anticipated to be presented to the April 2019 Board meeting.

1.3 DAY-AHEAD AND REAL-TIME MARKET PERFORMANCE

Overall, energy prices were about $2/MWh higher in 2018 compared to 2017. This can primarily be attributed to several factors, including increased loads, increased exports, transmission expansion, lower wind capacity factors, and increased generator outages. These offset other factors that would typically lower prices, including lower gas prices and a large and increasing reserve margin. Historically, day-ahead prices have been higher than real-time prices. However, in 2017 real-time prices were higher than day-ahead prices in nine months primarily because of higher real-time price volatility. This trend reversed in 2018 as eight out of twelve months had higher day-ahead average prices.

While load participation in the day-ahead market continued to be strong in 2018, generation participation, particularly from wind resources was substantially less in the day-market market compared to the real-time market. 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, we found that on average for the year, wind generation was over 1,000 MW higher in the real-time market compared to the amount scheduled in the day-ahead market on an hourly basis. This represents an increasing challenge to the market as wind generation has continued to increase substantially over the past few years.

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 500 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. However, total profits decreased in 2018 to about $44 million, down from $54 million in 2017. When transaction fees are included, net profit for virtual transactions was $18 million in 2018. Net virtual profits were highest in January ($4.9 million) and October ($4.0 million) when wind generation is typically high and loads are low.

Self-commitment of generation continues to be a concern because it does not allow the market software to determine the most economic market solution. Furthermore, it can contribute to market uplifts and low prices. Some of the reasons for self-committing may include contract terms for coal plants, low gas prices that reduce the opportunity for coal units to be economically cleared in the day-ahead market, long startup times, and a risk-averse business practice approach. Generation offers in the day-ahead market averaged almost 53 percent as "market" commitment status followed by "self-commit" status at 30 percent of the total capacity commitments for 2018.[3] These levels almost exactly match those in 2017, however the overall trend is still downward, as 2016 had 48 percent as "market" commitment status, and 35 percent as "self-commit" status. While the overall increase in market commitments and decrease in self-commitments highlights an improvement, self-commitments still represent over 30 percent of generation, a trend that has existed since the Integrated Marketplace began in 2014. In order to improve market commitment in the SPP market, we recommend that SPP and stakeholders look to find ways to address this issue.

Scarcity events in 2018 were generally in line with 2017 levels, with the exception of October. October 2018 experienced significant wind volatility, which among other factors, led to an uptick in operating reserve scarcity events. Additionally, looking at the intervals where scarcity occurs each hour shows that 30 percent of all scarcity events, and two-thirds of regulation-down scarcity events, in 2018 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. Our analysis shows that accounting for ramping needs would greatly assist in preparing and compensating generation for both anticipated

[3] Other resource commitment statuses are "reliability", "not participating", and "outage" at two percent, three percent, and 11 percent, respectively.

and unanticipated ramping needs. As such, we continue to recommend, as discussed below, that SPP and stakeholders complete design for a ramping product in 2019.

1.4 TRANSMISSION CONGESTION AND HEDGING

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

Areas that experienced the highest congestion costs in 2018 were in central Kansas, southeastern Oklahoma, and southwest Missouri. Western Nebraska experienced the lowest congestion costs for the year. The frequently constrained area study for 2018 saw the addition of the central Kansas and southwest Missouri frequently constrained areas, while the Texas panhandle frequently constrained area was removed.

In total, congestion costs were just over $450 million in 2018. This was down slightly from $465 million in 2017. 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. In 2018, the total of all transmission congestion right and auction revenue right net payments to load-serving entities of $458 million was more than the total day-ahead and real-time markets congestion costs of $381 million. However, on an individual basis, some participants were over-hedged, whereas others were under-hedged. The largest amount over-hedged was by just over $16 million, while the largest amount under-hedged was just under $10 million.

1.5 UPLIFT COSTS

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

In 2018, total make-whole payments were approximately $73 million, up slightly from $68 million in 2017. Make-whole payments averaged about $0.26/MWh in 2018, which was nearly the same as in 2017. In comparison to other RTO/ISO markets, SPP's make-whole payments were in the range of uplift costs, which varied from $0.08/MWh to $0.29/MWh in 2017 and 2018.[4]

Day-ahead make-whole payments constituted about 38 percent of the total make-whole payments in 2018. SPP pays about 80 percent of all make-whole payments to gas-fired resources.

In December 2017, FERC found SPP's quick-start pricing practice may be unjust and unreasonable, and argued that pricing enhancements would reduce uplift payments.[5] Our analysis shows that uplift payments remain fairly low. Furthermore, our assessment of FERC's proposal suggests that, if anything, FERC's proposal would transfer, if not increase, uplifts.[6] FERC has yet to rule on SPP's quick-start pricing practices.

1.6 COMPETITIVENESS ASSESSMENT

The SPP market provides effective incentives and mitigation measures to produce competitive market outcomes even during periods when the potential for the exercise of local market power could be a concern. The MMU's competitive assessment using structural and behavioral metrics indicate that market results in 2018 were workably competitive 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. With the merger of Great Plains Energy and Westar, creating Evergy, Inc., the percent market share of the largest supplier saw an increase, with 35 percent of hours for the year exceeding the 20 percent threshold

[4] 2017 ISO NE State of Market Report https://www.potomaceconomics.com/wp-content/uploads/2018/06/ISO-NE-2017-EMM-SOM-Report_6-17-2018_Final.pdf, page 39; 2018 State of the Market Report for PJM http://www.monitoringanalytics.com/reports/Presentations/2019/IMM_MC_SOM_20190321.pdf, page 9.

[5] Order Instituting Section 206 Proceeding and Commencing Hearing Procedures and Establishing Refund Effective Date, 161 FERC ¶ 61,296 (2017).

[6] Southwest Power Pool Market Monitoring Unit Reply Brief, Docket No. EL18-35-000, March 13, 2018.

that indicates potential market power, with a high value of 29 percent. 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 2018 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 15, up until the creation of Evergy in June 2018. Prior to the addition of the Integrated System, approximately 45 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.

For the two frequently constrained areas, where potential for concerns of local market power is the highest, existing mitigation measures serve well to prevent pivotal suppliers from unilaterally raising prices.

Behavioral indicators—which assess the actual exercise of market power—show low levels of mitigation frequency. Mitigation of day-ahead energy, operating reserve, and no-load offers each occurred less than 0.2 percent of the time and real-time mitigation occurred about 0.015 percent of the time. The overall mitigation frequency of start-up offers was the lowest since the market began in 2014, as it decreased in 2018 relative to 2016 levels to just under three percent.

The decline in mitigation may be the result of declining offer price mark-ups. Both off-peak and on-peak average offer markups were at the lowest levels since implementation of the Integrated Marketplace at around −$2.05/MWh and −$2.41/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—which measures economic withholding—shows very low levels of economic withholding in all months in 2018. Specifically, there was miniscule amounts of measurable output withheld in the frequently constrained areas. 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 2.0 percent in 2016, 1.9 percent in 2017, and 3.1 percent in 2018. When short and long-term outages are removed, the remaining unoffered capacity was 0.22 percent, 0.23 percent, and 0.39 percent, respectively. The majority of the outages were long-term outages due to maintenance during the shoulder fall and spring months. From a competitive market perspective, the results indicate reasonable levels of total unoffered economic capacity and are consistent with the results in other RTO/ISO markets.

1.7 STRUCTURAL ISSUES

Installed generation capacity in the SPP market has grown rapidly over the past several years. This has contributed to high levels of capacity at peak loads. Specifically, the MMU estimates that capacity was 35 percent higher than the peak load in 2018. SPP's current annual planning capacity requirement is 12 percent.

Wind capacity has more than doubled from 8.6 GW in 2014 to 20.6 GW in 2018. 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 24 percent in 2018. Furthermore, the interconnection process includes just over 84 GW of additional resources, of which 99 percent are renewable resources.

The shift in generation mix towards renewable resources is a significant development and carries both market and operational challenges. Furthermore, these challenges are further exacerbated by the fact that currently 29 percent of the total wind capacity is non-dispatchable.

A recent wave of generator retirements, particularly of coal-fired generation, has been widely observed throughout the country. The SPP market should be 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 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.

1.8 RECOMMENDATIONS

One of the primary responsibilities of a market monitoring unit is to evaluate market rules and market design features for market efficiency and effectiveness. When we identify issues with the market, one of the ways to correct them is to make recommendations on market enhancements. These recommendations are highlighted in detail in Chapter 8. Below is a summary of our 2018 recommendations.

1.8.1 NEW RECOMMENDATIONS FOR 2018

- **Limit the exercise of market power by creating a backstop for parameter changes** – The market is currently vulnerable to the exercise of market power by the manipulation of resources' non-dollar based parameters. Non-dollar-based parameters should not be manipulated to affect market clearing. Although SPP's tariff and 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.

  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 exercise of market power is limited.

- **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. Current estimates of the default exposure exceed $400 million.[7] 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.

The MMU recommends that changes to the SPP credit policy be developed to protect stakeholders from risks of default, particularly with respect to information that is known such as transmission expansion.

- **Develop compensation mechanism or product to pay for capacity to cover uncertainties** – Because of unexpected variations in wind output, SPP operations often needs to manually commit resources (often in excess of 50 units) in order to meet instantaneous load capacity requirements. Often, however, these resources receive real-time wake whole payments and are not compensated specifically for the need. 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 large number of manual capacity commitments may indicate that there is a need for a new uncertainty product that might better address problems in the 30-minute to 3-hour time frame.[8]

  The MMU recommends and supports developing products to reduce the need for the large number of manual capacity commitments to ensure appropriate compensation is being provided for the reliability services provided.

- **Enhance ability to assess a range of potential outcomes in transmission planning** – SPP's transmission planning process develops an annual look-ahead plan. This plan evaluates transmission needs over a 5- and 10-year time horizon. The plan typically

[7] https://pjm.com/-/media/committees-groups/committees/mic/20190206/20190206-item-01a-informational-update-ferc-order-denying-waiver-request.ashx.
[8] The exact time periods of potential uncertainty products should be determined through the stakeholder process.

evaluates two scenarios.[9] The first case is a base case, and the second case is an emerging technology case. The process could consider a third scenario. In 2018, 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.[10]

We recommend 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 that they be factored into either an existing case study, as part of the 20-year assessment, or other assessment.

- **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 payments, known as mileage, are paid directly through regulation-up and regulation down payments in the day-ahead market. The MMU is 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.

  We recommend that SPP staff review the performance of regulation mileage, and develop potential approaches to improve regulation mileage price formation.

[9] These scenarios are also known as futures cases.
[10] This scenario was similar to a scenario used in the MISO transmission plan, see https://cdn.misoenergy.org/MTEP19%20Futures%20Summary291183.pdf.

1.8.2 CLARIFICATION OF PREVIOUS RECOMMENDATIONS

The MMU has provided recommendations to improve market design in our previous annual reports. The following are clarifications made to those recommendations from the prior report.

- **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. With regards to the development of multi-day forecasting of prices or schedules or a multi-day unit commitment process, the MMU supports these as attempts to reduce self-commitment of generation, but we will carefully weigh the benefits and costs before we support any specific proposal especially in light of the accuracy of forecasted information and the potential changing generation mix. We continue, however, 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.

- **Enhance commitment of resources to increase ramping flexibility** – As noted in last year's annual report, ramping flexibility is becoming increasingly important to integrate higher levels of renewable generation.[11] Over-commitment of resources in real-time reduces flexibility, suppresses prices, and leads to increased make-whole payments. This can be caused by changing conditions between the time a resource is locked into a commitment by the market software and the time the resource actually comes on-line. The MMU recommends that SPP and its stakeholders address this issue by enhancing its markets rules to enhance the commitment of resources to increase resource flexibility. Last year, the MMU described this as enhancing decommitment of resources. However, having explored this issue further, the issue is not just about decommitment of resources, but is also about improving how and when resources are committed.

- **Further enhance alignment of planning processes with operation conditions** – Enhancing the accuracy of planning processes with operational realities enables SPP and its members to more effectively plan for future system needs and

[11] 2017 Market Monitoring Unit Annual State of the Market Report, https://www.spp.org/documents/57928/spp_mmu_asom_2017.pdf , page 194.

conditions. Many of the challenges outlined in this report—including congestion, negative prices, and low generator net revenues—as well as improvements—such as transmission additions—are, in part, a reflection of planning decisions. The more the planning process can learn from and incorporate operational information, the more planning can identify and address concerns in advance of market operations. SPP and stakeholders over the past few years have worked to improve and align the planning and operational processes.

Based on our experience in this process over the last year, we recommend that SPP staff continue to collaborate with the MMU to build upon the work in 2018, by reviewing data and best practices in other markets, factoring in market conditions and trends in decision-making process, and performing analysis to support and inform assumptions. Doing so will help to improve assumptions and ultimately study results.

1.8.3 OUTSTANDING RECOMMENDATIONS

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

- **Develop a ramping product** – A ramping product that incents actual, deliverable flexibility can send appropriate price signals to value resource flexibility. This resource flexibility can help prepare the system for fluctuations in both demand and supply that result in transient short-term positive and negative price spikes. This is a high priority initiative in the SPP stakeholder process. We concur and continue to recommend that a ramping product design be completed in 2019.

- **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. Stored energy resources have the potential to address both the need for flexibility and reduce the incidence of negative prices. 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.

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

- **Convert non-dispatchable variable energy resources to dispatchable –** Non-dispatchable variable energy resources exacerbate congestion, reduce prices for other resources, increase the magnitude of negative prices, cause the need for market-to-market payments, and force manual commitments of resources that can increase uplifts. Going forward, resource flexibility is essential to integrate an increasing volume of wind generation in the SPP market. While the MMU's preferred solution did not pass the SPP stakeholder process, an acceptable amended solution passed the board and was submitted to FERC in late 2018. FERC approved the filing in April 2019.

- **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[12] at the July 2018 meeting. However, subsequent to board approval of the proposal, SPP legal staff identified internally inconsistent tariff language that was revealed by but not addressed in the revisions. The MMU strongly recommends that SPP and its stakeholders clean up the tariff language

[12] Revision request 306 (2014 ASOM MWP MMU Recommendation [3-Day Minimum Run Time])

necessary to implement the changes to address the gaming issue and provide an anticipated implementation date for the system changes. Addressing this matter in a timely manner is a high priority for the MMU.

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

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

EXHIBIT DG-5

Southwest Power Pool
MARKET MONITORING UNIT

Self-committing in SPP markets: Overview, impacts, and recommendations

Published December 2019

Exhibit DG-5

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1 OVERVIEW AND RECOMMENDATIONS

In this report, we examine self-commitment offer behavior in SPP's Integrated Marketplace, and describe how self-commitment can affect market participants and market outcomes.

Towards that end, we conducted an empirical study analyzing offer behavior over the period of March 2014 to August 2019, and ran two simulation series of a week per month from September 2018 to August 2019 where we re-solved past market cases. The simulations included the following assumptions: (1) all generation is offered in market status, and (2) all generation offered in market status can be started economically by the day-ahead market.

Key takeaways from our analysis include:

- The volume of self-committed megawatts has declined over time, but remains nearly half of the total megawatt volume generated from March 2014 through August 2019.
- Prices and production costs were systematically lower when at least one self-committed unit was marginal.
- In almost all cases, self-committed generators had lower revenues because of negative congestion prices; whereas, market-committed generators typically had a more balanced congestion profile.
- Resources with long lead times and/or high start-up costs tend to be self-committed instead of market-committed.
- Units that are self-committed generally have much higher capacity factors than those that are market-committed. However, these results differ substantially by fuel type.

Key takeaways from the simulations include:

- When the market made unit commitment decisions, and lead times remained unchanged, both market-wide production costs and market clearing prices for energy increased.

- When the market made unit commitment decisions and lead times were modified to allow the day-ahead market to commit the resources with long lead times, market-wide production costs were essentially unchanged and market clearing prices for energy increased.
  - System prices increased by about $2/MWh (seven percent) on average.
  - Congestion prices changed by about –$1/MWh to $1/MWh on average.
- To optimize long-lead time resources' participation in the market, the economic commitment process would need to solve over a longer market window (e.g., over a two-day period rather than just one day).

1.1 RECOMMENDATIONS

- In order to improve price formation and market efficiency, we recommend SPP and stakeholders work to reduce the incidence of self-commitments.
- We recommend modifying SPP's market design by adding one additional day to the market optimization period.[1]

1.2 OUTLINE

The paper is organized as follows. In chapter 2, we cover the mechanics of self-commitment in the SPP market, how this impacts the supply curve, and identify reasons participants may choose to self-commit their generation. Chapter 3 covers the theoretical underpinnings of the market and efficient price formation. Chapter 4 presents empirical observations over the study period comparing market and self-commitment behavior. Chapter 5 covers self-commitment behavior and price formation. Chapter 6 presents two simulation scenarios estimating how market results

[1] SPP has found in its multi-day forecasting study, the accuracy of forecasts (load and wind) remain at acceptable levels for a second day but decline sharply afterwards.

would change if participants market-committed versus self-committed. Chapter 7 highlights our conclusions.

The empirical study period spans from March 2014 through August 2019 and covers all resources and fuel types. However, in our presentation of offer and generation related metrics, we exclude nuclear resources because of the limited number of resources with this fuel type.[2]

Readers of this report may note that the analysis of self-commitment differs from what we have presented in our previous reports. In our annual and quarterly state of the markets reports, we have presented self-commitment information in the form of offers and unit starts. In this report, we focus instead on the megawatts produced from self-committed units.

The re-run (simulations) study period covers the first week of each month from September 2018 through August 2019.[3] We believe that this provides a significant enough sample of re-runs to capture seasonality in the market.

[2] Many of the charts and analysis that follows presents offer behavior by fuel type. As there are a limited number of nuclear resources, any charts that show this as a fuel type could potentially expose specific market offer data. All other resources have a sufficient number of resources to mask any specific offer behavior.

[3] Additional information regarding the sample set can be found in chapter 6.

2 SELF-COMMITMENT MECHANICS

In the broadest terms, and similar to other auction-based electricity markets, the Integrated Marketplace attempts to minimize the cost to serve load[4] subject to transmission and generator constraints. The day-ahead market does this by using two main tools: centralized unit commitment[5] and economic dispatch.[6]

Centralized unit commitment sorts the available generators from least expensive to most expensive and then selects the least expensive units that can achieve the objective without violating the constraints of the optimization.

Economic dispatch then uses the results of the unit commitment process as inputs to its own separate optimization. The results of which produce two key, time-based outputs: the megawatts each generator should produce at the corresponding locational prices.

Centralized unit commitment and economic dispatch processes are designed to work together to make the market more efficient. For instance, FERC stated that "…the unit commitment process an essential part of least-cost operation" when discussing price formation in organized wholesale electricity markets.[7]

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

[4] The cost to serve load is also referred to as production cost.

[5] The Integrated Marketplace Protocols define Security Constrained Unit Commitment as an algorithm capable of committing Resources to supply Energy and/or Operating Reserve on a co-optimized basis that minimizes commitment costs while enforcing multiple security constraints. Integrated Marketplace Protocols, Section 1 Glossary

[6] The Integrated Marketplace Protocols define Security Constrained Economic Dispatch as an algorithm capable of clearing, dispatching, and pricing Energy and Operating Reserve on a co-optimized basis that minimizes overall cost while enforcing multiple security constraints. Integrated Marketplace Protocols, Section 1 Glossary

[7] Price Formation in Organized Wholesale Electricity Markets, Docket No. AD14-14-000

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 (see Section 2.2 below), the practice can distort prices and investment signals.

2.1 TYPES OF COMMITMENT STATUS

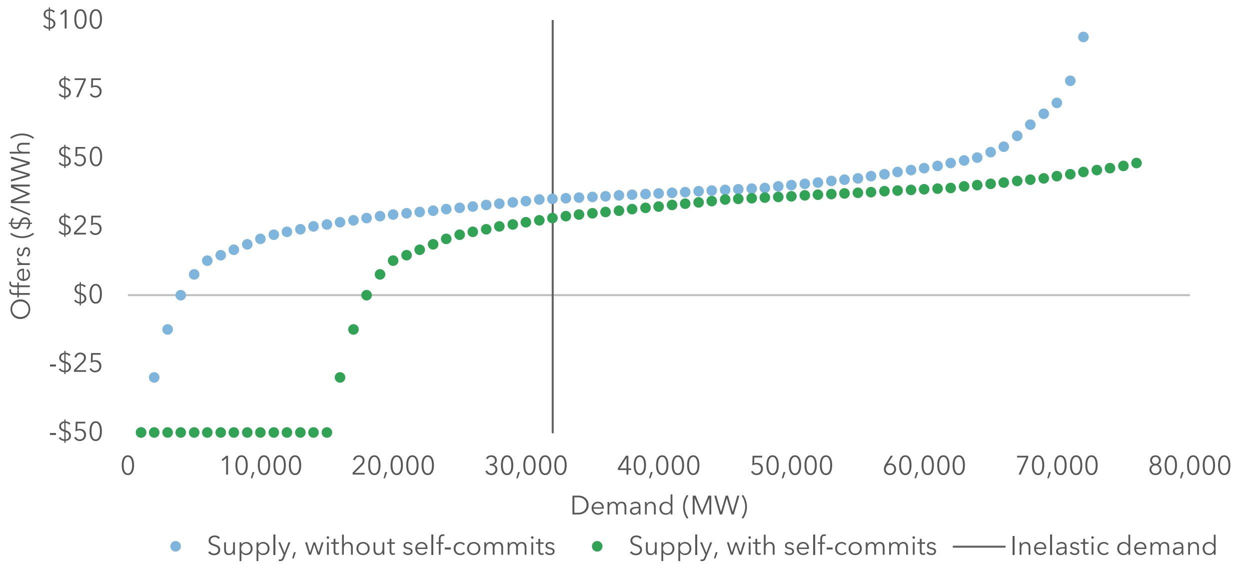
Including self-commitment, the Integrated Marketplace permits five different commitment statuses. The statuses convey information to the centralized unit commitment process. Each status and its accompanying description can be found below:

1. Market – the resource is available for centralized unit commitment through its price sensitive (merit-based) price quantity offers.
2. Self – the market participant is committing the resource through price insensitive offers outside of centralized unit commitment.
3. Reliability – the resource is off-line and is only available for centralized unit commitment if there is an anticipated reliability issue.
4. Outage – the resource is unavailable due to a planned, forced, maintenance, or other approved outage.
5. Not participating – the resource is otherwise available but has elected not to participate in the day-ahead market.

Because the day-ahead market cannot dispatch resources with commitment statuses of outage and not participating, we included market, self, and reliability commitment statuses in our empirical study. However, due to the extremely low megawatt volumes[8] dispatched from reliability-committed units, we present and discuss only market and self statuses in the report.

Mechanically, self-commitment can affect the construction of supply curves by altering the generators selected to serve the demand. Self-commitment shifts the merit order of the supply curve by treating the self-committed generators as price insensitive, which shifts the supply curve to the right.[9] This relationship is shown in Figure 2–1.

Figure 2–1 Rightward shift in market supply curve



The blue supply curve represents supply without self-committed megawatts, whereas the green supply curve represents supply including self-committed megawatts. When participants self-commit resources, the commitment algorithm does not make the decision to commit those units based on their cost. Participants make their own commitment decisions without regard to the optimization of total costs. Said another way, these resources effectively move themselves to the bottom of the cost curve. The result of a rightward shift in supply, all else equal, likely

[8] Over the study period, less than 0.004 percent of dispatched megawatts sourced from units committed in reliability status.

[9] Moreover, the supply curve itself can be reordered as resources whose commitment costs are high can also change the order of dispatch of incremental energy.

reduces the market's marginal clearing price.[10] In addition to shifting the supply curve to the right, the slope of the supply curve also changes when generators self-commit. The change in slope reflects the re-ordering of suppliers in least cost merit order for market dispatch based on the set of resources from the commitment process.[11]

Along with shifting and reordering the supply curve, when participants self-commit resources, their economic minimums essentially create a resource specific dispatch megawatt floor. These floors in turn, create additional constraints to which the economic dispatch optimization must solve around. Self-committed resources also carry the lowest curtailment priority, which means they are generally the last producers instructed to reduce output.[12] Because these self-committed units are deemed "must run", the dispatch engine cannot take them off-line for economic reasons.[13]

2.2 REASONS FOR SELF-COMMITMENT

We have worked with market participants to understand the reasons that participants self-commit generators. Market participants have stated the following reasons for self-commitment:

- Testing – NERC requirement
- Public Utilities Regulatory Policy Act (PURPA)
- Federal service exemptions
- Started by a different market
- Weather
- Long lead times

[10] This is also known as the system marginal price.

[11] Under certain circumstances, this type of reordering could cause a price increase, but this has not been observed. Typically, the reordering has resulted in price declines.

[12] Integrated Marketplace Protocols, Section 4.3.2.2 Day-Ahead RUC Execution

[13] Integrated Marketplace Protocols, Section 4.4.2.5 Out-of-Merit Energy (OOME) Dispatch

- Fuel contracts
- Other contracts
- Long minimum run times
- Commitment bridging
- Desire to reduce thermal damage to the unit due to starts and stops
- High startup costs

Some of these reasons are unavoidable and can require the resource to be offered in self-status. Testing the output of a plant, as periodically required by regulatory agencies, is a frequent justification. A few generators in SPP are classified as qualifying facilities under the Public Utilities Regulatory Policy Act, and the commitment of those resources cannot be separated from other uses, such as cogeneration processes. Additionally, a small group of SPP resources qualifies for Federal service exemptions. Finally, a participant may need to self-commit a resource during very cold weather for reliability reasons.

Some of the reasons, such as high start-up costs, fuel contracts, or commitment bridging are economic in nature and can be handled within the market offer through dollar-based offer parameters. Thermal damage due to start-ups and shut-downs and resulting major maintenance could be included in mitigated offers starting in April 2019.[14] As we show later in the report, we have seen a general decline in self-committed generation over time and it is possible that perceptions of economic justifications have changed over time.

To the extent that a long lead time[15] is reflective of operating or environmental limitations, there may be a software limitation. To the extent that there are limitations to the software, these can be addressed through market design changes.

[14] Revision Request 245.

[15] Based on August 2019 offers, 7 percent of resources (or MWs) had lead times longer than 32 hours and 10 percent had between 24 and 32 hours.

3 MARKET FEEDBACK LOOP

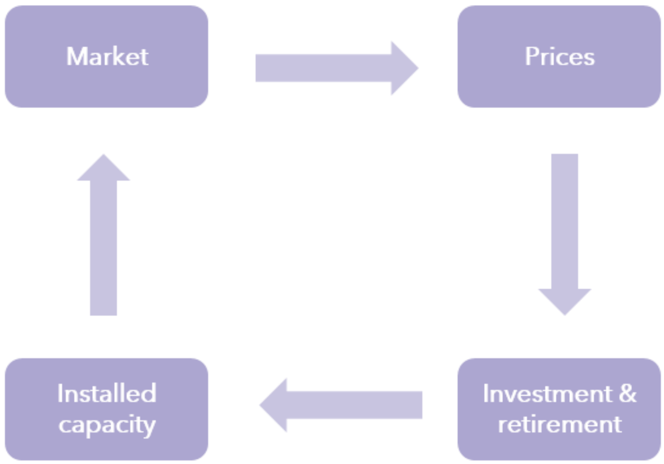
As we showed in the previous section, self-commitment of generation can put downward pressure on the marginal clearing price of energy. In this section, we discuss how the marginal clearing price drives the market feedback loop to bring about equilibrium and efficiency.

A central theory in economics is that competition leads to efficiency.[16] If the market design effectively fosters competition, a competitive equilibrium is possible, and by extension, efficiency may be gained. In electricity markets, a primary source of efficiency gain stems from the minimization of system production cost through centralized clearing. When this occurs, resulting prices are based on marginal costs and the level of production and consumption is optimal – the result is an efficient market at competitive equilibrium.

Market equilibrium generally has two time dimensions: the short-run and the long-run. In the short-run, market participants profit maximize by asking themselves, "What is the best we can do with our current set of resources?" They submit their best answers in the form of market offers. The market provides feedback in the form of commitment, dispatch, and prices. Market participants then use this information to adjust their short-run profit maximizing behavior. Concurrently, participants ask themselves, "What is the best we could do if we had something different?" This question relates to long-run market equilibrium and decision-making to include investment (or retirement) in installed capacity. The search for short-run and long-run equilibriums creates the market feedback loop. In the following sections, we will examine how self-commitment can affect this process and, by extension, market efficiency.

[16] Perfectly competitive markets attain both *productive efficiency*—where output is produced at the least possible cost—and *allocative efficiency*—where output produced is the one that consumers value most.

Figure 3–1 The market feedback loop



3.1 THE MARKET

For competition to flourish, several conditions must exist including having the lack of market power by market participants,[17] the necessary cost information,[18] and non-convex operating costs.[19] Good market design, along with effective regulation and monitoring, helps bring about the first two requirements. The third requirement, however, is unlike the first two. Convexity or lack thereof, is inherent to the characteristics of the resources that participate in the market. Non-convex costs occur when it is cheaper to produce two units than to produce one. Generator start-up and no-load operating costs have this property and are non-convex. As such, when non-convex cost elements exist, designing a competitive market with an efficient pricing mechanism is difficult. However, when suppliers lack market power and have necessary cost information, the improved, if not perfect, level of competition can still bring about efficiency improvements.

[17] A lack of market power implies being a price taker.

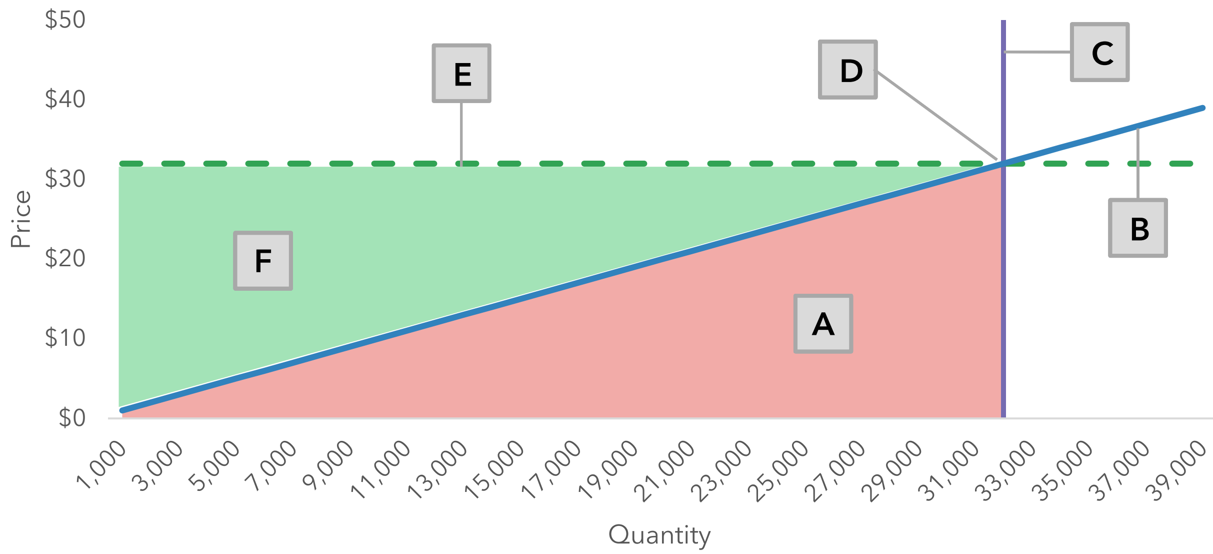
[18] All production costs are known.

[19] The shape of the cost curve is a critical input to the supply function. Classical economics assumes that costs are convex. In practice, some costs are nonconvex.

3.2 LINKING THE MARKET TO PRICES

Economics has concepts that are very precise and have specific meanings. For example, accountants and economists both use the term profit. However, the idea each intends to convey can differ materially.[20] For this reason, we provide the following simplified figure[21] and associated terms to help convey the appropriate intention.

Figure 3–2 Market supply and demand



A. The red shaded region is the production cost,[22] more specifically the energy portion of total production cost.[23] This region is also referred to as the area under the supply (or marginal cost) curve, which gives *total* variable cost, or *total* marginal cost.

B. The supply curve is the blue line. In electricity markets, the supply curve is created by summing the offers of market participants. These offers are submitted in price/quantity

[20] For instance, the IRS expects income tax even when economic profit is zero.

[21] In order to facilitate illustration we use a linearized approximation (of a stepwise line) under a continuous function assumption.

[22] Corresponding to "mitigated offers" in SPP tariff terms.

[23] Production cost is generally presented as the sum of energy, start-up, no-load, and ancillary service costs.

pairs each indicating minimum price levels the supplier is willing to offer for the corresponding quantity. The price the supplier wants to be paid is plotted on the y-axis, and the quantity the supplier is willing to produce for that price is plotted on the x-axis.

C. The demand curve is the purple vertical line.[24] The demand curve shows price/quantity pairs each indicating maximum price levels the consumer is willing to demand for the corresponding quantity. Electricity is mostly a non-storable product and must be supplied instantly upon demand. Further, when there is no competition at the retail end, price elasticity is very low. As such, we represent demand as a vertical line.

D. The market-clearing price is the point where the supply meets the demand. When this occurs, all buyer orders have been filled and the market is said to have cleared. In an organized wholesale electricity market setting, the market clearing price is also called the spot price.

E. The dark green dotted line reflects the price each supplier is paid and is equivalent to the market-clearing price. This equilibrium price multiplied by the total quantity produced is the revenue received by all suppliers.

F. The light green shaded region is the producer surplus. Generally, when economists refer to profit, they are referring to the producer surplus. Short-run profits for individual producers can be calculated by subtracting variable costs from revenue where revenue equals market clearing price multiplied by the quantity produced.[25]

[24] This represents perfectly inelastic demand. Under that assumption, demand is not responsive to price. In practice, the line may not be vertical, having a certain degree of downward slope depending on the degree of price responsiveness in the market, particularly in the day-ahead market.

[25] In electricity markets, start-up and no load costs, in addition to incremental energy costs, need to be included in the short-run profit calculation.

3.3 PRODUCTION COST MINIMIZED, NOT PRICE

The objective function of the market clearing software, stated generally, is to minimize production cost, not the marginal clearing price.[26] Broadly, production cost is the sum of energy,[27] ancillary services,[28] start-up,[29] and no-load[30] costs. Efficiency occurs by serving the same level of demand, while at the same time minimizing the sum of these costs. The clearing price is an output of the optimization and a component of the total production cost. Because the clearing price only relates to a component of the production cost (i.e., the incremental energy component), there is no guarantee that an increase in energy prices will translate to an increase in total production cost.

3.4 PRICE TO INVESTMENT SIGNALS

In the long run producers are incented to invest in projects that minimize their costs.[31] When current prices reflect the true marginal cost of the current set of producers at the margin, participants can better determine the cost structure of the market. When participants have better information, they will likely better optimize their existing generation portfolio. However, in the long run some market participants may not be able to use their existing fleet to achieve their desired level of profitability or recover their cost of capital. When participants find themselves in this situation, they consider entry and exit decisions. Typically, this means

[26] In this cost minimization problem, prices are discovered by identifying the marginal cost of serving the next increment of load during a specific interval and location.

[27] Energy is a power flow for a time period.

[28] Ancillary services are needed to maintain reliability of the system, often by forgoing the opportunity to sell energy.

[29] Start-up is the cost associated with preparing a generator to produce (and stop producing) energy or ancillary services.

[30] No-load is the theoretical cost of running a generator while producing no output.

[31] In a competitive market, the market price is given to individual suppliers and all they can do is to adjust their production amount that minimizes cost.

generators whose long run costs exceed projected revenues retire.[32] Then suppliers either permanently exit the market, focus on reducing maintenance costs, place the unit in reserve shutdown (i.e., mothball),[33] or invest in new lower cost generators.

3.5 INVESTMENT SIGNALS TO INSTALLED CAPACITY

Spot prices are an input to forward price projections and bilateral contract prices. Therefore, a spot price that does not reflect the true cost structure of the market can send an incorrect entry and exit signal. In addition to potentially sending distorted investment signals, generators that self-commit may displace other generators who would have otherwise been committed and earned energy market revenue. This could cause generators that should have earned profits to mount losses. These losses may subsequently incent more generators to self-commit, or cause a generator to retire who would have otherwise been profitable—either case results in a distorted investment signal. In short, sending the right price signal is critical, but so too is ensuring those who warrant the revenue—receive it.

[32] Projected revenues would be based on estimated forward prices.

[33] Mothballed generators are not used to produce electricity currently but could produce electricity in the future. Additionally, generators can be made available for reliability only.

4 UNIT COMMITMENT AND DISPATCH PROCESSES: EMPIRICAL FINDINGS

This section includes information and analysis regarding the pervasiveness of self-commitment, and then discusses generator start-up parameters and capacity factors.

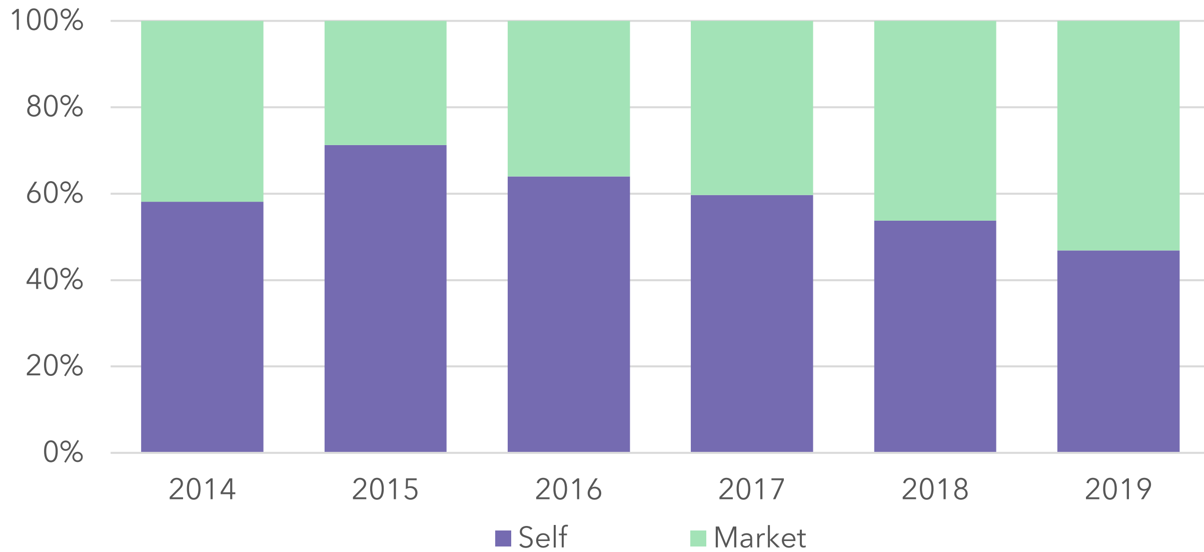
Key takeaways from this section include:

- The volume of self-committed megawatts declined over the study period, but remains nearly half of the total megawatt volume produced in the day-ahead market.
- Resources with long lead times and/or high start-up costs tend to self-commit instead of market-commit.
- Units that self-commit generally have much higher capacity-factors than those who market-commit. However, capacity factors by commitment status differ substantially by fuel type.

4.1 UNIT COMMITMENT – COMMITMENT STATUS

Figure 4–1 shows the percentage of day-ahead economic dispatch megawatts by commitment type over the study period.

Figure 4–1 Percentage of megawatts dispatched by commitment status



The volume of self-committed megawatts has declined over the last several years, but remains nearly half of the total dispatch megawatt volumes. In other words, nearly half of the energy produced was from a resource that was not selected by the day-ahead market's centralized unit commitment process.

While a relatively small percentage[34] of the self-committed megawatts were block-loaded,[35] many self-committed resources have operating parameters that include non-zero economic minimums.[36]

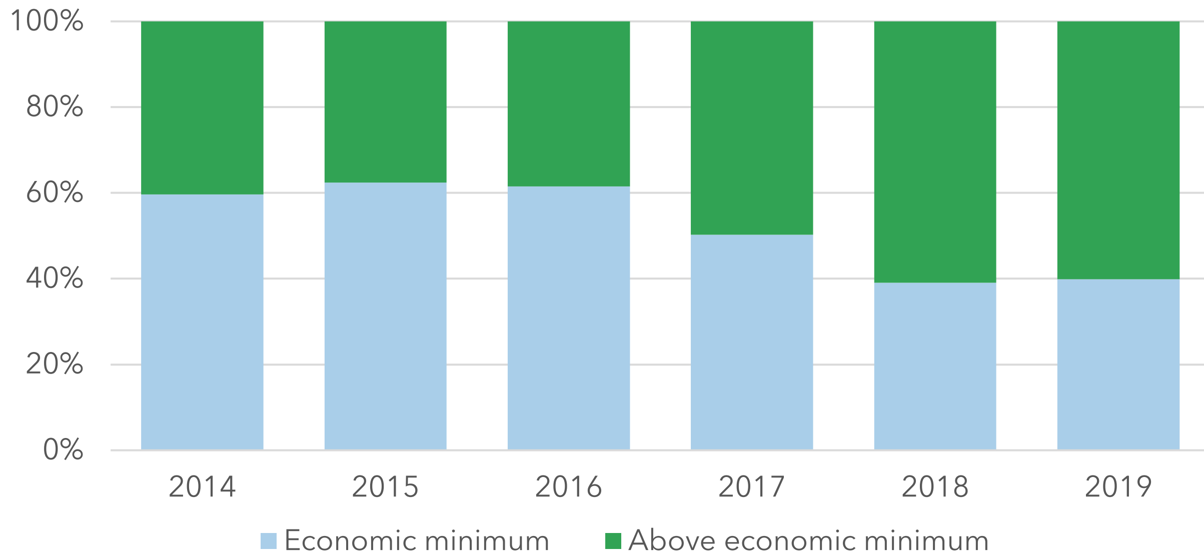
Even though resources are self-committed in the market, there also tends to be economic capacity above minimum that the market can dispatch. Figure 4–2 shows the percentage of self-committed dispatch megawatts above economic minimums.

[34] Over the study period, block loaded self-committed resources averaged about six percent of total self-committed volume.

[35] Block-loaded resources self-schedule by submitting one point offer curves, where economic dispatch range is zero, i.e. where economic minimum and economic maximum values are identical.

[36] Integrated Marketplace Protocols, Exhibit 4-6: Resource Limit Relationships, "Minimum Economic Capacity Operating Limit"

Figure 4–2 Percentage of self-committed megawatts dispatched above economic minimum



While the trend is decreasing, economic minimums amount to roughly forty percent of all self-committed dispatch megawatts.

4.2 UNIT COMMITMENT – FUEL TYPE

Resource fuel type is a useful classification of resources. Generally, the operating parameters and economics tend to be similar among units of the same fuel type. Operating parameters tend to be physical or time-based and include items like ramp rate, minimum run time, and lead time. Economic parameters include operating cost. In auction based ISO/RTO markets, the capital/fixed cost[37] portion is generally recovered through market revenues and public service commission rate cases, whereas allowable fuel and short-term maintenance cost[38] is incorporated directly into energy market offers.

In the absence of market power, the centralized unit commitment optimization uses the suite of unmitigated offers when it chooses the lowest cost generators. In general, a low (operating)

[37] Capital cost is also referred to as fixed cost (there is also fixed overhead & maintenance).

[38] Operating cost is also referred to as variable cost.

cost position on the supply curve comes at the expense of high fixed costs. Because fossil fuel generators tend to be quite levered to the price of fuel, the tradeoff between capital cost and operating cost can change if fuel prices decline significantly. This means that each generator's cost position can change, perhaps dramatically, based on fuel prices.

Figure 4–3 shows the percentage of self-committed dispatch megawatts by fuel type by year. Over the study period, the largest portion of self-committed dispatch megawatts sourced from coal units. Coal self-committed megawatts generally exceed the size of the second largest fuel type by a factor of more than four to one.

Figure 4–3 Percentage of self-committed megawatts by fuel type

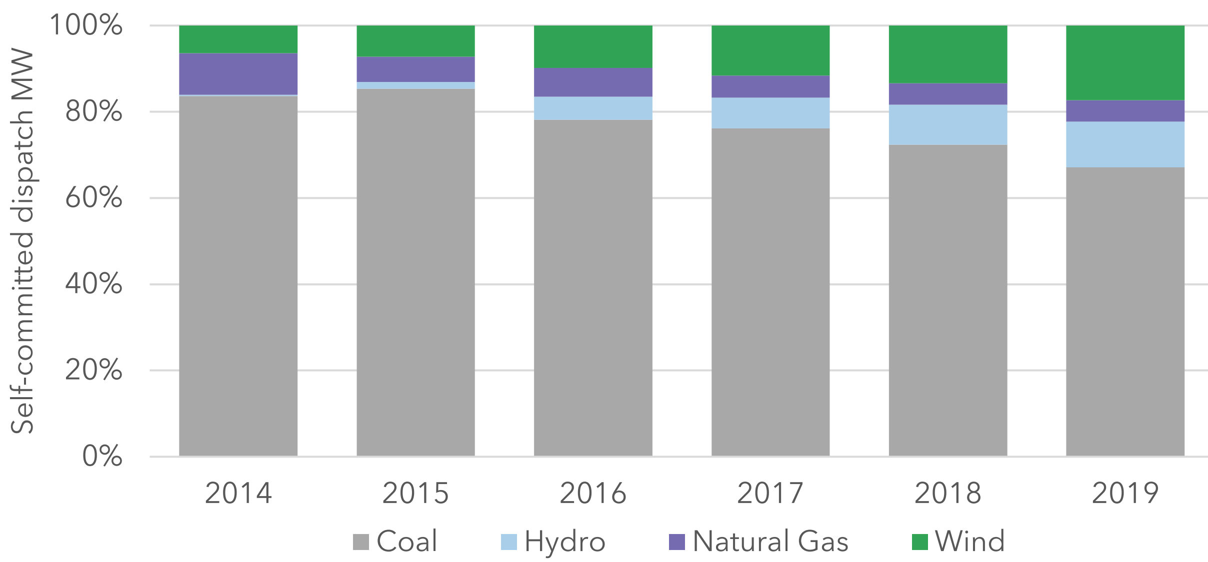


Figure 4–4 shows the percentage of market-committed dispatch megawatts by fuel type by year. Over the study period, the largest portion of market-committed dispatch megawatts sourced from natural gas units. However during the first year of market operation, coal units made up the largest share of market-committed megawatts.

Figure 4–4 Percentage of market-committed megawatts by fuel type

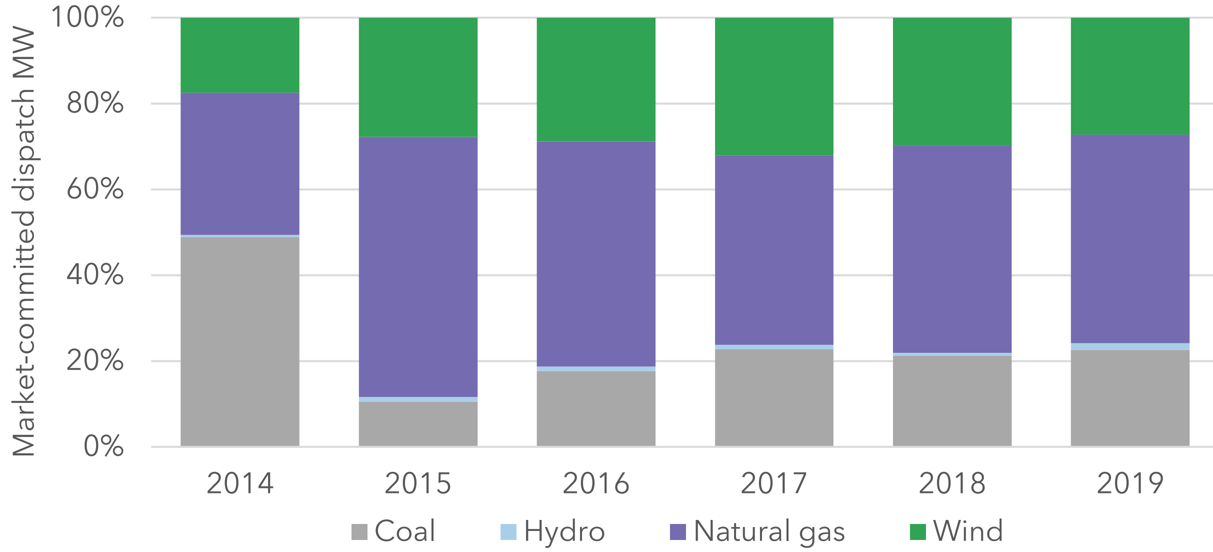
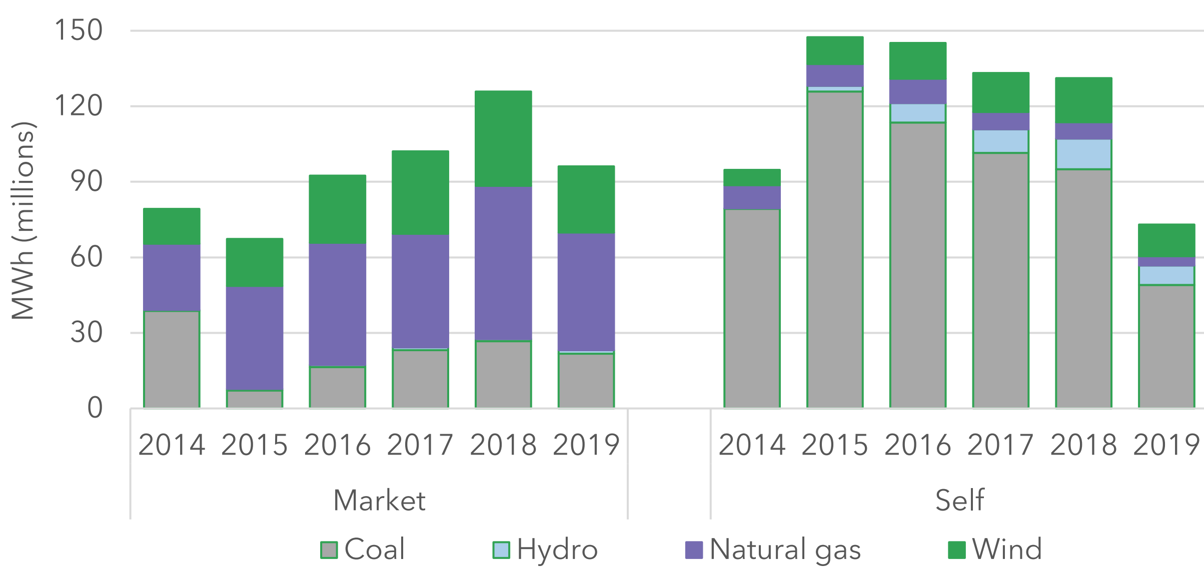


Figure 4–5 shows dispatch megawatts by fuel type by commitment type for each year of the study period.

Figure 4–5 Dispatch megawatt hours by fuel type by commitment type



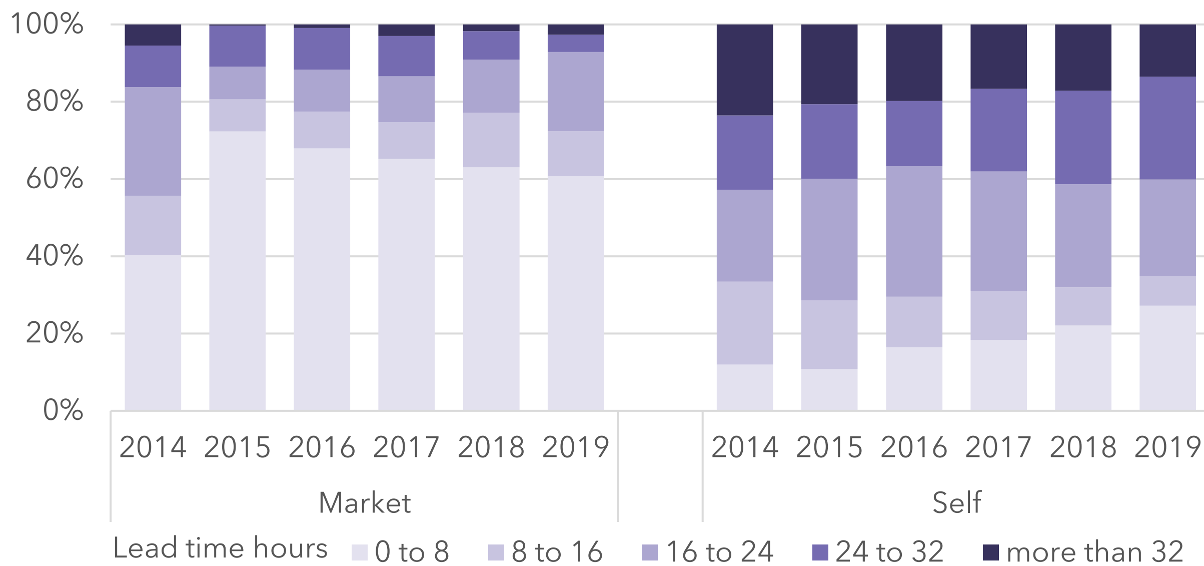
For the total period of March 2014 to August 2019, the magnitude of coal self-committed dispatch megawatts essentially equaled the total dispatch megawatts from all market-committed resources over the same period. In 2015 and 2016, self-committed coal greatly exceeded market commitments. However, as seen in 2019, self-committed coal megawatt hours, while still quite large, do not exceed market committed megawatt hours.

4.3 UNIT COMMITMENT – START-UP TIME

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, we examine lead times by commitment status and fuel type.

Figure 4–6 shows the relationship between commitment status and start-up time.

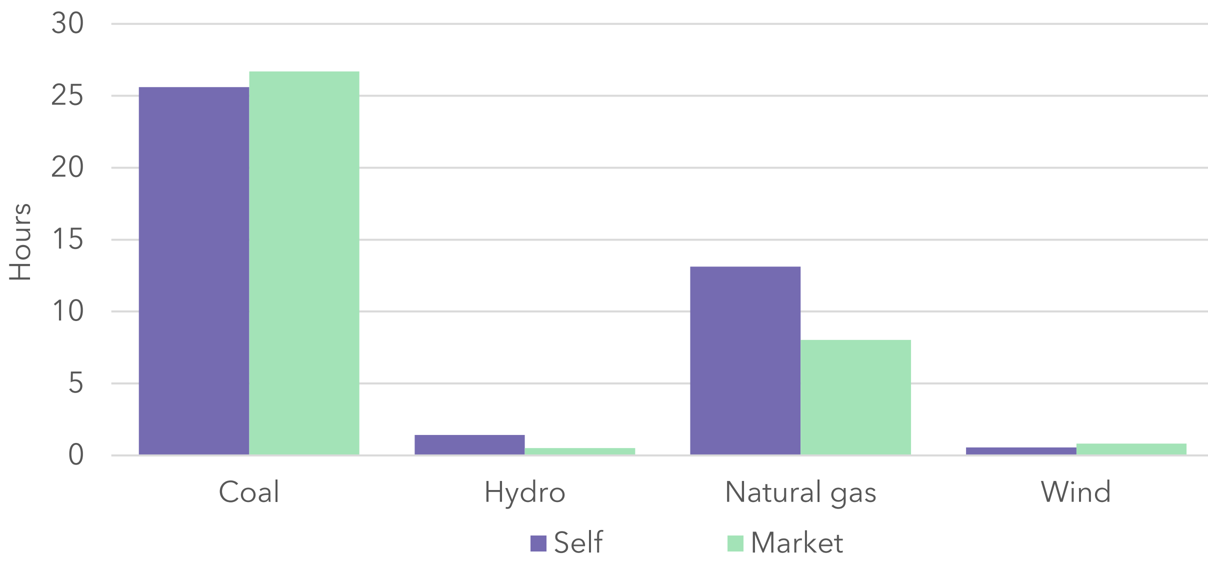
Figure 4–6 Lead time hours by commitment status



Self-committed resources tend to have longer lead times than market-committed resources. Because centralized unit commitment must observe constraints other than cost, it may not select a unit even if that unit's offer falls below the marginal resource.

Coal units have the longest cold start-up time, followed by natural gas. Figure 4–7 shows the dispatch megawatt weighted cold start-up time by fuel type by commitment type

Figure 4–7 Dispatch megawatt weighted lead time by fuel type by commitment status



Natural gas generators have the largest difference in start-up times between self-committed and market committed resources compared to other resources. Coal resources show relatively little deviation in their cold start-up time.

4.4 UNIT COMMITMENT – START-UP COST

Start-up cost is submitted in terms of dollars per start.[39] These parameters also vary widely by fuel type. Like start-up time, resources can submit three different start-up costs: cold, intermediate, and hot. Thermal resources generally have more expensive start-up costs when they are cold, as opposed to when they are hot. Additionally, start-up costs are non-convex which makes it hard for the market clearing algorithm to achieve an optimum solution.[40] However, when price taking behavior combines with good information, the market's efficiency can be improved.[41] In the following section, we examine start-up cost by commitment status and fuel type.

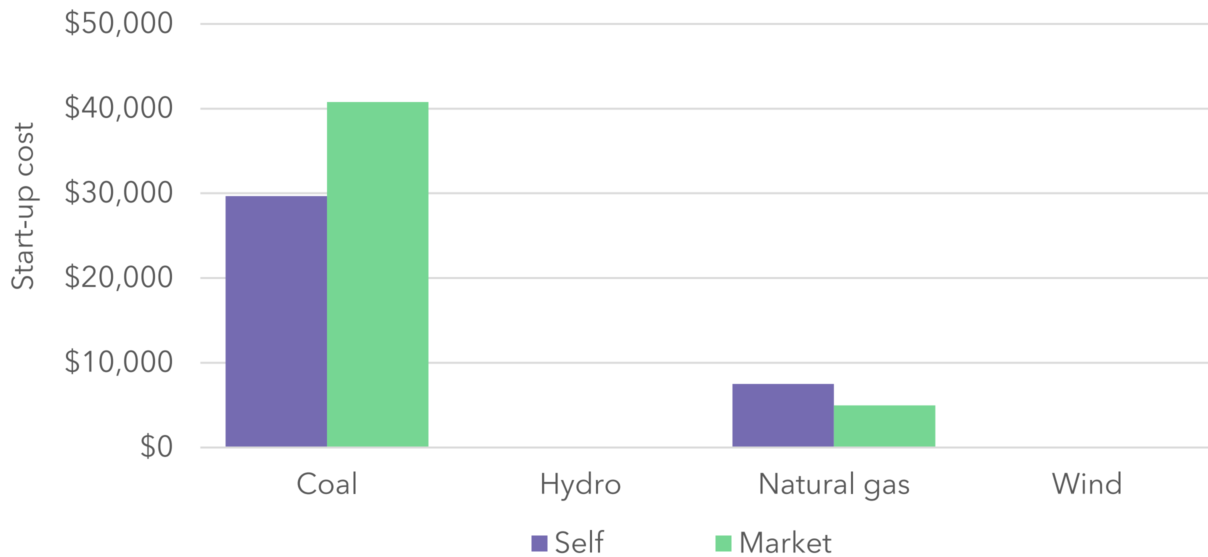
[39] Integrated Marketplace protocols, G.2.6.1 Start- Up Offer Definitions

[40] https://www.ferc.gov/legal/staff-reports/2014/AD14-14-operator-actions.pdf

[41] Steven Stoft, Power System Economics, p.55

Coal units have the highest cold start-up cost by more than a factor of five over the next highest start-up cost fuel type as seen in Figure 4–8. Coal start-up costs and gas start-up costs correlate strongly with gas prices.[42]

Figure 4–8 Dispatch megawatt weighted start-up cost by fuel type by commit status



Unlike start-up time, start-up cost differs materially for both coal and natural gas resources by commitment type. The difference between the market-committed cold start-up cost of coal and natural gas is even more significant than the relationship called out in Figure 4—7. Interestingly, market status based coal start-up costs exceed the start-up costs of self-committed resources. In market status, the cold start-up cost of coal exceeds that of natural gas by a factor of more than eight to one.

4.5 UNIT COMMITMENT – START-UP OFFERS

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.

[42] Over the study period, the correlation between natural gas start-up costs and Henry Hub gas prices is 78 percent, whereas the correlation between coal start-up costs and Henry Hub gas prices is 65 percent.

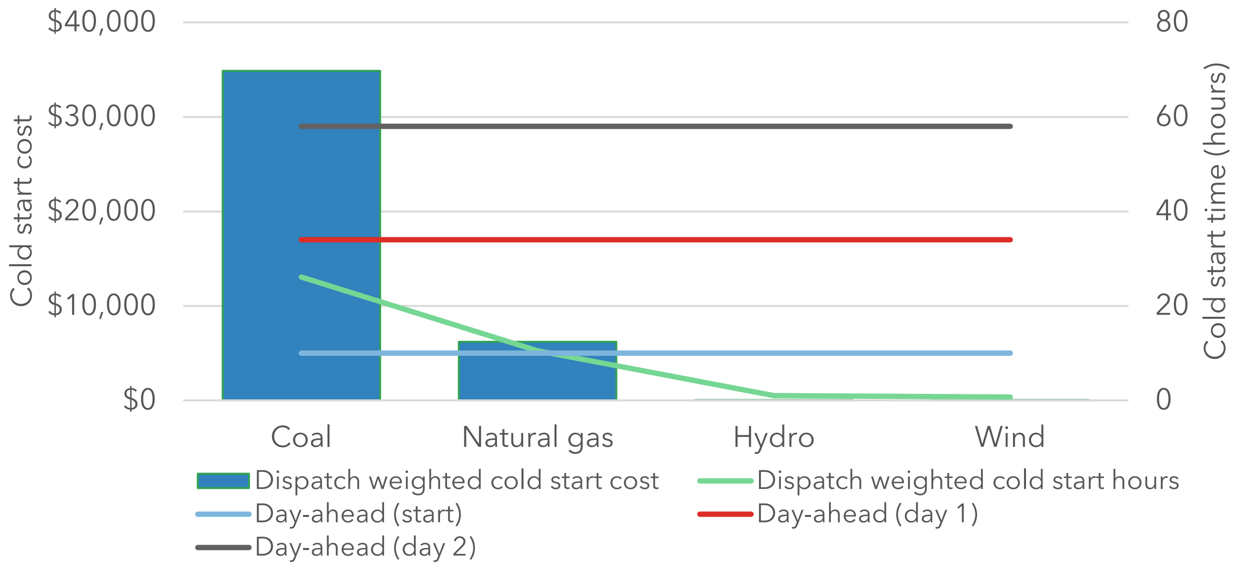
However, the optimization evaluates the offer in dollars per start per hour. The start-up cost is optimized and later amortized over the lesser of the resource's minimum run time or the number of hours from start time through the end of the day-ahead market window.[43]

While the financially binding day-ahead market covers only one operating day, the day-ahead market optimizes over a two-day window – the operating day and the next operating day. However, only the results from day one of the unit commitment solution feed forward to the economic dispatch algorithm. The results from the second day of the optimization are non-binding and are not used for commitment purposes. The two-day optimization helps prepare for the following day's morning ramp and attempts to prevent any unnecessary starting and stopping of units from one day to the next.

Figure 4–9 compares cold start time and cold start cost (y-axes) by resource fuel type (x-axis). The horizontal reference lines (blue, red, black) call out various periods in the day-ahead market window. Hour 10 represents the time from the posting of day-ahead market results to the beginning of the day-ahead market day. The second line at hour 34 represents the end of the first day-ahead market day and the beginning of the second day-ahead market day. The third line at hour 58 represents the end of the second day-ahead market day. The blue bars relate to the left axis and the lines relate to the right axis. These two inputs are used in the construction of the start-up offer.

[43] The day-ahead market window covers two days.

Figure 4–9 Cold start time and cold start cost by resource fuel type



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.

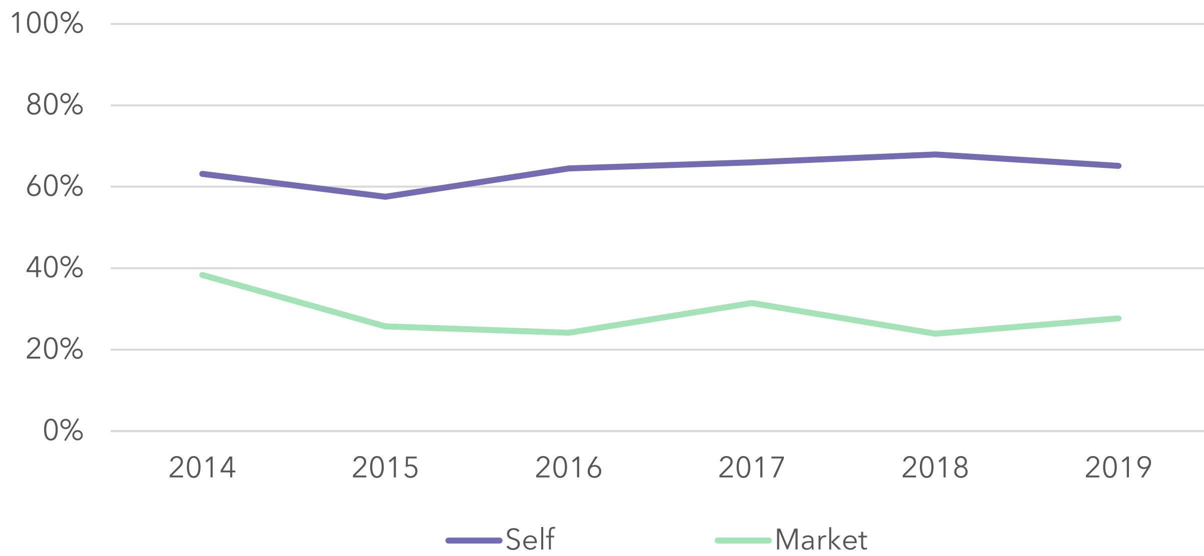
4.6 UNIT COMMITMENT – THE CAPACITY FACTOR

Because of the relationship between fixed cost and variable cost inherent in power generation, capacity factors are a central input when calculating a generator's long run average cost and by extension their long run economic viability.

A capacity factor is the ratio of energy output for a given period (usually a year) to the maximum possible energy output over the same period. The more energy a resource produces, the lower its fixed cost per unit of production. The relationship between fixed cost and marginal cost is often referred in other industries as operating leverage. If fixed costs are significantly larger than variable costs, a firm will exhibit high operating leverage.

The higher the operating leverage the more profit earned from an incremental sale and the more lost from a lost sale. The capacity factor is effectively the ratio of sales to potential sales for power plants.

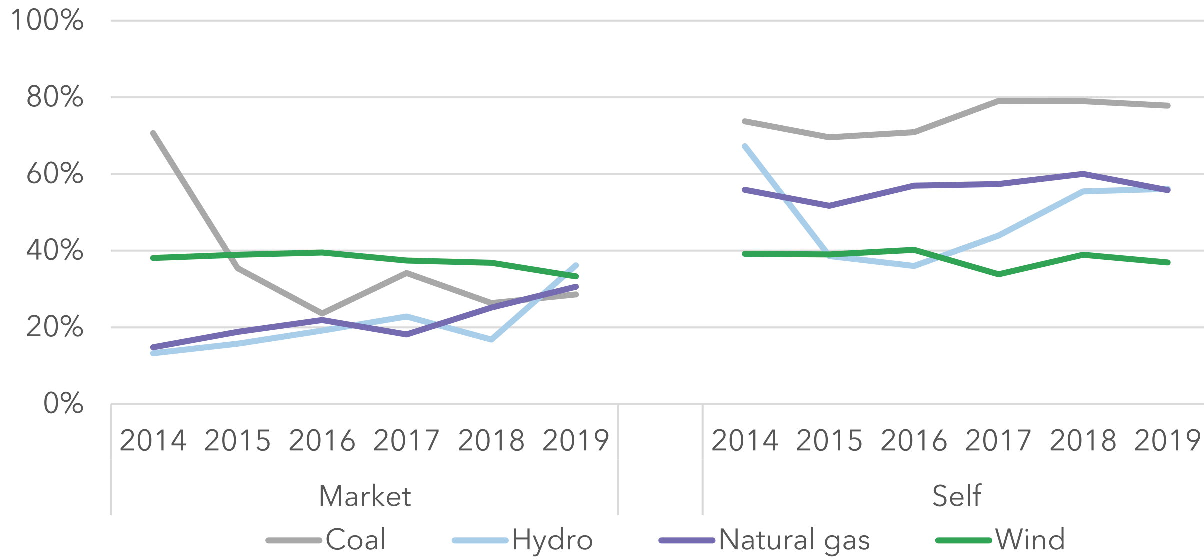
Figure 4–10 Capacity factors by commitment type



Over all resource fuel types, capacity factors roughly double when resources offer in self-status, as opposed to market-status.

Figure 4–11 shows the capacity factors by commitment type by fuel type. This figure shows that some fuel types (such as wind) have comparatively similar capacity factors irrespective of their offer status. However, some fuel types (such as coal and natural gas) have vastly different capacity factors when they are committed in market or self.

Figure 4–11 Capacity factors by fuel type by commitment type



Similar to capacity factors by fuel type, some turbine types have quite similar capacity factors when they are committed in market or self-status.

5 PRICE FORMATION

In this section, we build upon the price portion of the market feedback loop discussed earlier. Specifically, we provide empirical information and analysis reflecting the prices and production costs over the study period.

Key points from this section include:

- Over the study period, at least one self-committed unit was marginal in roughly 75 percent of the day-ahead market hours.[44]
- Over the study period, prices were systematically lower when at least one self-committed unit was marginal.
- In almost all cases, self-committed generators had lower revenues than market-committed generators because of negative congestion prices.
- In SPP's case, consumers and producers are not necessarily two distinct, organically separated groups.[45] This dynamic makes the impact of price levels and production costs less clear.

5.1 IMPACT OF SELF-COMMITMENT ON PRICE FORMATION

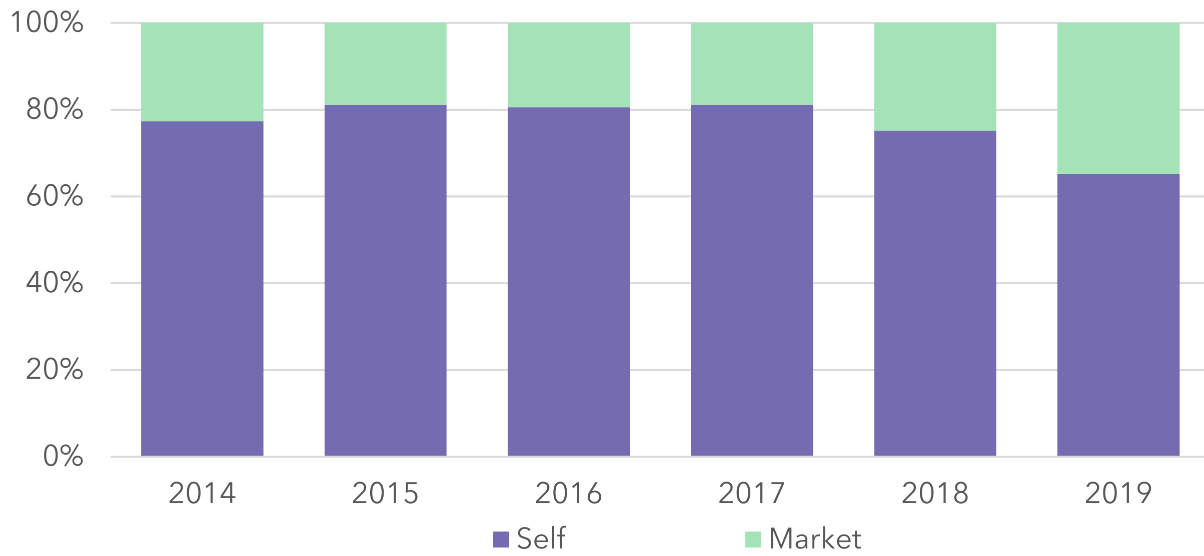
To quantify the impact of self-commitment on prices and price formation, we evaluate the frequency and magnitude of self-commitment in addition to the time it sets price. Self-committed resources can set price as many self-committed generators offer their incremental

[44] More than one resource can be marginal during a given period.

[45] The participants—primarily the investor owned utilities—who serve load may also own or control both generation and transmission assets. In fact, in 2018 investor owned utilities owned 53 percent of the total nameplate generation capacity in the SPP market.

energy into the market. Self-dispatched resources are resources that do not allow the market to choose their incremental energy output.[46]

Figure 5–1 Percentage of day-ahead hours by marginal resource by commitment type



Over the study period, at least one self-committed resource was marginal in substantially more than half of the day-ahead market hours. For the purposes of Figure 5–1, if during an hour, a single marginal generator was self-committed, that hour is classified as self. If only market committed generators were marginal during the hour, that hour is classified as market.

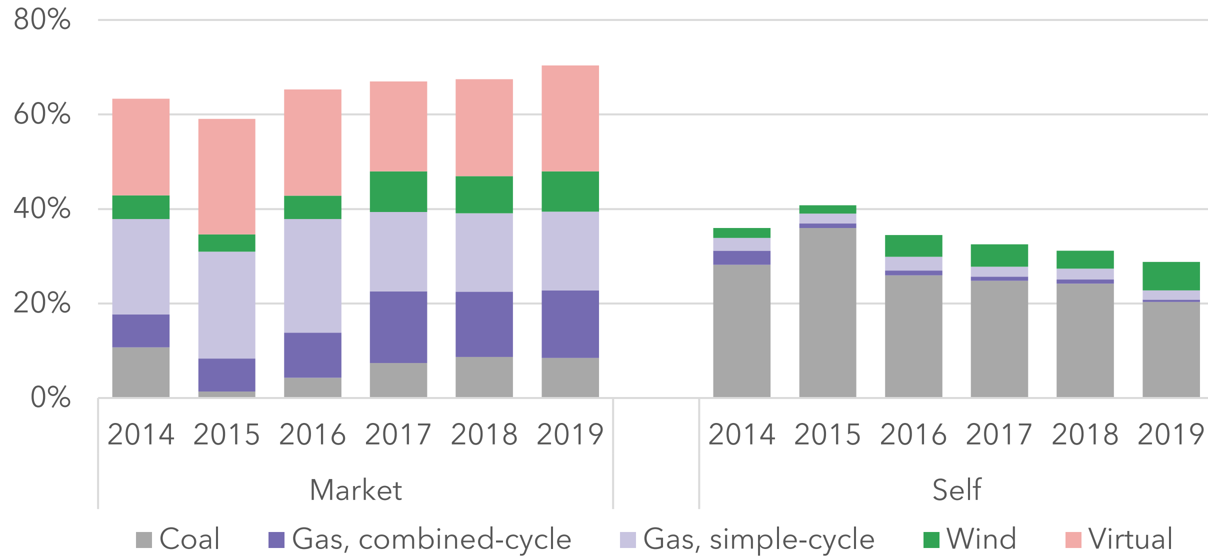
Even though self-committed generators are treated as price insensitive suppliers in the unit commitment process, these same generators can set the marginal clearing price if they provide the marginal unit of supply when dispatched above their economic minimum. These units may not have been committed by the centralized unit commitment had they been offered in market-status, and by extension, may not have otherwise been marginal. This is one of the reasons market participant's unit commitment decisions can affect price formation.

However, in any given hour, there is likely to be more than one marginal price setting resource because of the effects of transmission congestion. Figure 5–2 captures this effect. It looks at all

[46] For example, non-dispatchable variable energy resources (NDVERs) are self-scheduled as opposed to self-committed. However, for the purposes of this analysis, we have including NDVER as self-committed.

the marginal resources in the market and finds that over the study period, market-committed resources[47] were on the margin setting prices during roughly two-thirds of all instances in the day-ahead market whereas self-committed resources set prices during roughly one-third of all instances day-ahead.

Figure 5–2 Percentage of marginal hours by fuel type

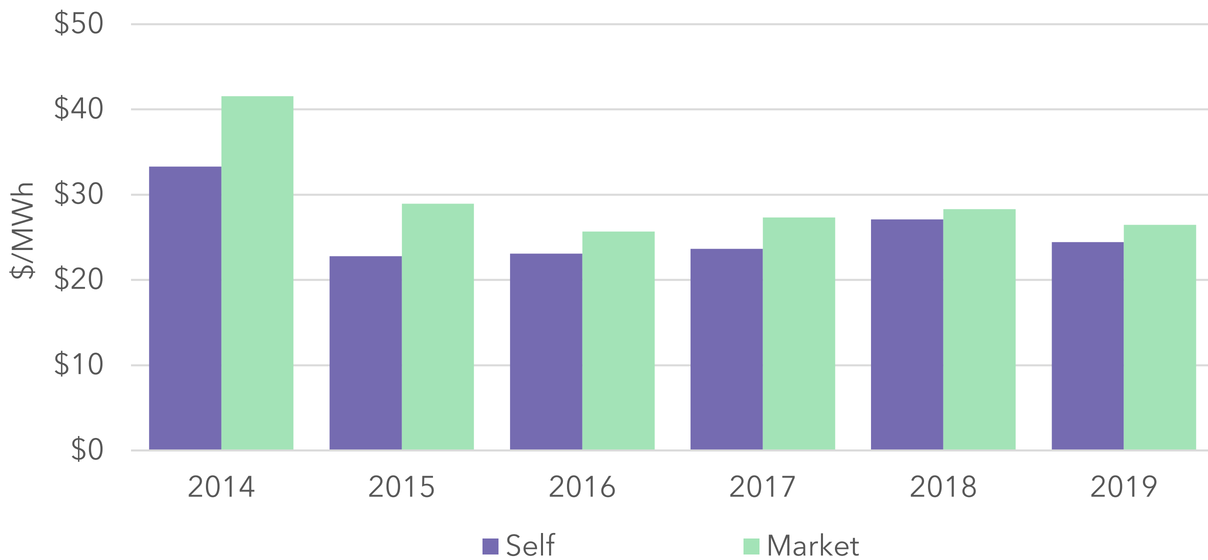


Of the market committed-units, wind, virtual, and combined-cycle gas resource types have increased their time setting prices on the margin, while simple-cycle gas and coal generators have decreased their time setting prices on the margin.

Of the self committed-units, coal dominates the time on the margin compared to all other fuel types. Wind on the margin continues to grow, whereas the frequency of coal on the margin, while still quite large, continues to decline.

[47] We have classified virtual transactions as market committed for the purpose of this analysis.

Figure 5–3 Average day-ahead system marginal prices by marginal unit commitment type



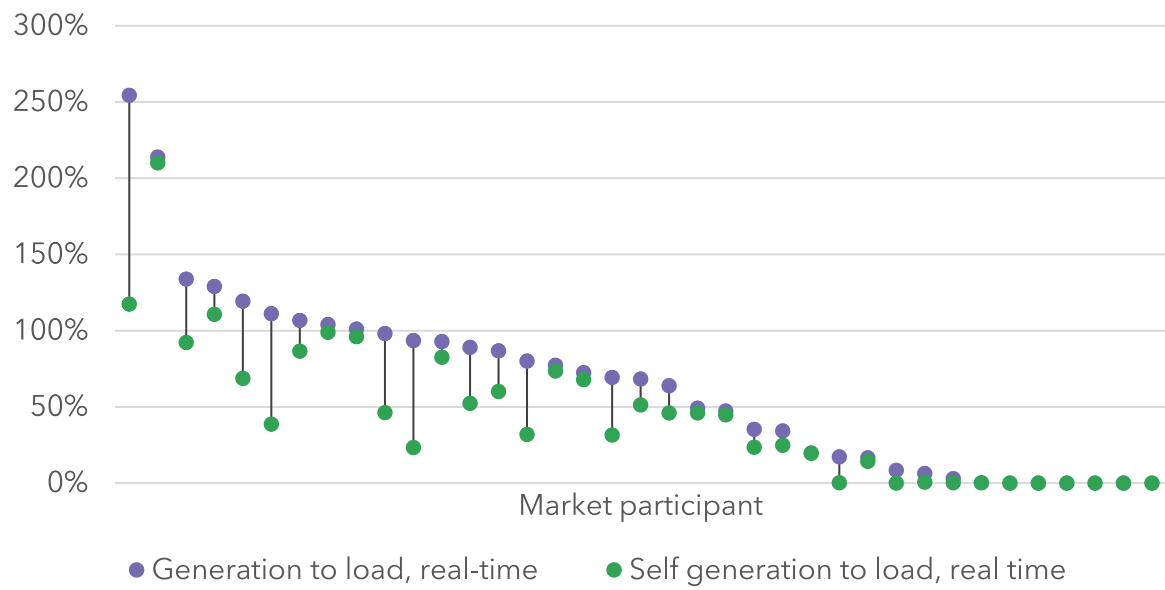
Over the study period, prices were systematically lower when at least one self-committed unit was marginal.

5.2 WHO PAYS?

SPP market participants have indicated in stakeholder meetings, that in a cost-of-service regulated market, when participants are vertically integrated, the load ultimately pays and therefore will benefit from lower prices and production costs. However, when participants are vertically integrated, the load is also the generation in terms of integrated ownership. Low prices do indeed benefit load, but they do not benefit generation. Because these entities are not distinct, and must carry generation capacity to meet their capacity obligation, the "who benefits" question with respect to the level of prices is nuanced.

Figure 5–4 highlights two things. First, it shows the level of generation produced by a participant relative to its load. Second, the figure shows the level of self-committed generation relative to its load.

Figure 5–4 Generation megawatts to load megawatts by commitment type



The purple dots above 100 percent line denote a market participant who produced energy in excess of its real-time load obligation. The inverse indicates a market participant who produced less than their real-time load. In a competitive market, it would be expected that some would produce more than their load and some would produce less, as lower cost resources would displace higher cost resources.

The green dots show the self-committed generation relative to load. The green dots above the 100 percent line denote a market participant whose self-committed energy production exceeded their corresponding real-time load. The inverse indicates a market participant whose self-committed units produced less than their real-time load.

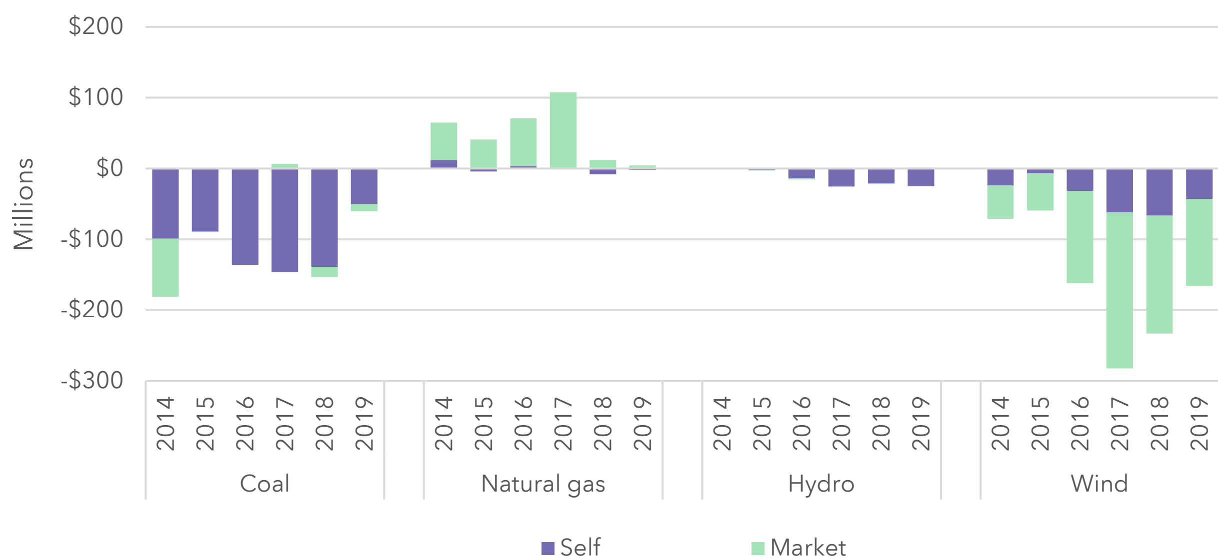
The figure shows that there are three participants that self-committed more generation than their load. In this case, the participant would be selling self-committed generation to the market. Furthermore, the chart shows that some participants self-committed almost all of their generation (purple and green dot the same or very close) and that the majority of participants self-committed some generation. This highlights how difficult it is to determine who benefits from higher or lower prices.

5.3 CONGESTION

Congestion price signals incentivize the behavior of market participants. When locational marginal prices are elevated, generators in that particular pricing node earn more. Because every node in the system includes the system marginal price, the difference in locational marginal prices stems mostly from the marginal congestion component of the locational marginal price.

Congestion affects all resources. However, in the SPP market, it tends to affect resources differently as seen in Figure 5–5. Natural gas resources tend to have higher prices as a result of congestion, while coal and wind resources tend to have dramatically lower prices. The congestion profile is more balanced for units that market-commit. Some market generators earn more than the system marginal price and some earn less, whereas generators who self-commit almost always earn less than the system marginal price.

Figure 5–5 Congestion dollars by fuel type, by commitment status



Additionally, Figure 5–5 brings to light an additional price signal. Congestion prices, similar to energy prices, provide feedback to market participants. When congestion reduces generator revenues, the market's general message is twofold: generators are incented to do less of what they are doing in the short-run and generators are incented not to build additional generation in the long run. The market also uses congestion to convey information to transmission owners.

In this case, if participant behavior does not change, transmission owners will likely be incented to build additional transmission infrastructure. When generator congestion is positive, the market generally conveys the opposite information to market participants. As an extension of our message in Section 3, self-commitment also blurs the congestion price signal.

In Figure 5–5, the green bars represent the market commitments and is more desirable than the purple bars because the unit commitment process committed that resource, not the market participant. What we do not know, however, is if the market-committed unit earned its commitment to offset a constraint created or enhanced by a self-committed unit. The purple bars below zero might also represent the market software attempting to incent different commitment behavior.

Both generators and loads are assessed congestion costs. Generators pay congestion through reductions in the locational marginal price. Loads pay congestion through increases in the locational marginal price. On balance, we observe that generation has been assessed more congestion than load in the Integrated Marketplace.[48]

Because self-commitment affects congestion, it also affects SPP's congestion hedging market. One way of scaling this impact is to compare average transmission congestion right (TCR) profitability by marginal unit commitment type by hour, which is the same classification methodology used in Figure 5–1.

[48] MMU Quarterly State of the Market Report, Spring 2019, Special Issues

Figure 5–6 Transmission congestion right revenue per megawatt by marginal unit commitment status

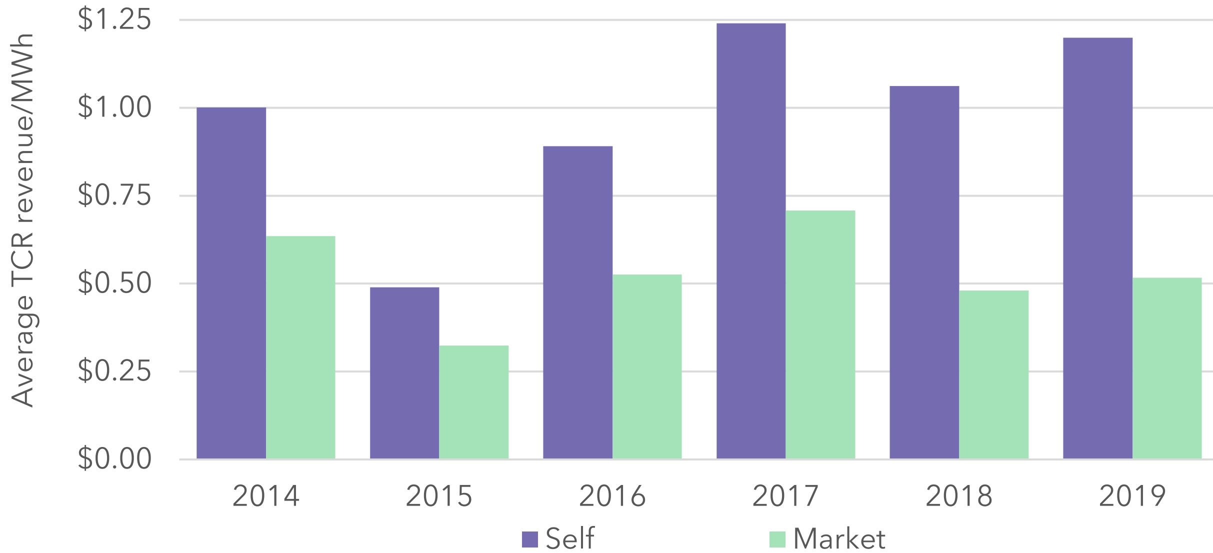


Figure 5–6 shows the revenue per megawatt of transmission congestion rights[49] was significantly higher when at least one self-committed unit was marginal. Our general takeaway is that in hours when at least one self-commit unit is marginal the system is more congested when compared to hours where only market-committed units are marginal. By extension, the congestion revenues from congestion hedges increase during hours where at least one self-committed unit is marginal.

[49] Figure 5—6 includes self-converted transmission congestion rights, long-term transmission congestion rights, and the positions purchased and sold in the various auctions.

6 SELF-COMMITMENT SIMULATIONS

In this section, we perform three simulations to study the effect of market committing resources that participants currently self-commit in the day ahead market.

6.1 OVERVIEW

To study the impact of self-commitment on market results, we re-solved the Integrated Marketplace's day-ahead market. In our study, we executed three scenarios using the effective version of the actual Integrated Marketplace software associated with each operating day. In each of the scenarios, we simulated the centralized unit commitment and economic dispatch optimizations.

In our first scenario, we validated our process by rerunning the original day-ahead market and compared the validation results to the original results. The validation cases were then used as the base inputs to scenarios two and three.

In scenario two, we changed the offer status from self to market for all resources that originally elected self-status. We also turned off all resources, so the market could make all unit commitment and dispatch decisions without optimizing the generators already producing power. Scenario three builds on scenario two, and includes the same input modifications in addition to reducing lead times to simulate extending the day-ahead market optimization window.

Findings from the simulations include:

- The key to reducing self-commitment while not increasing costs is multi-day economic unit commitment.[50]

[50] Our position supports the findings of The Holistic Integrated Tariff Team's Reliability Recommendation #3 – Implement Marketplace enhancements. Specifically, Multi-day market.

- Increasing the optimization window by another 24 hours allows the market to more effectively optimize resources with long start-up times. This enhancement combined with a reduction in self-commitment, would likely benefit ratepayers by reducing production costs in addition to sending more clear investment signals.
- If the optimization window is not lengthened, and self-commitment is eliminated, investment signals would be more clear, but production costs would likely increase.

6.2 STUDY DETAILS

6.2.1 SCENARIO 1 – VALIDATION SCENARIO

The purpose of the validation scenario is to determine the legitimacy of our testing framework. As with many electricity markets, SPP's software uses a mixed-integer optimization program that solves for optimal commitment and dispatch. Because of the nature of this type of software, it is not always possible to reproduce the original results even with identical inputs. For this reason, we rejected several market days from our study where the hourly production costs fell outside our tolerance when compared to the original market solution.[51]

Because of simulation run-time constraints, the study period includes one week of each month from September 2018 through August 2019. In addition to the data being readily available, this period also includes the different annual seasons and a wide variety of market conditions. The testing criteria, sample size, and results of our validation scenario gives us confidence in our process.

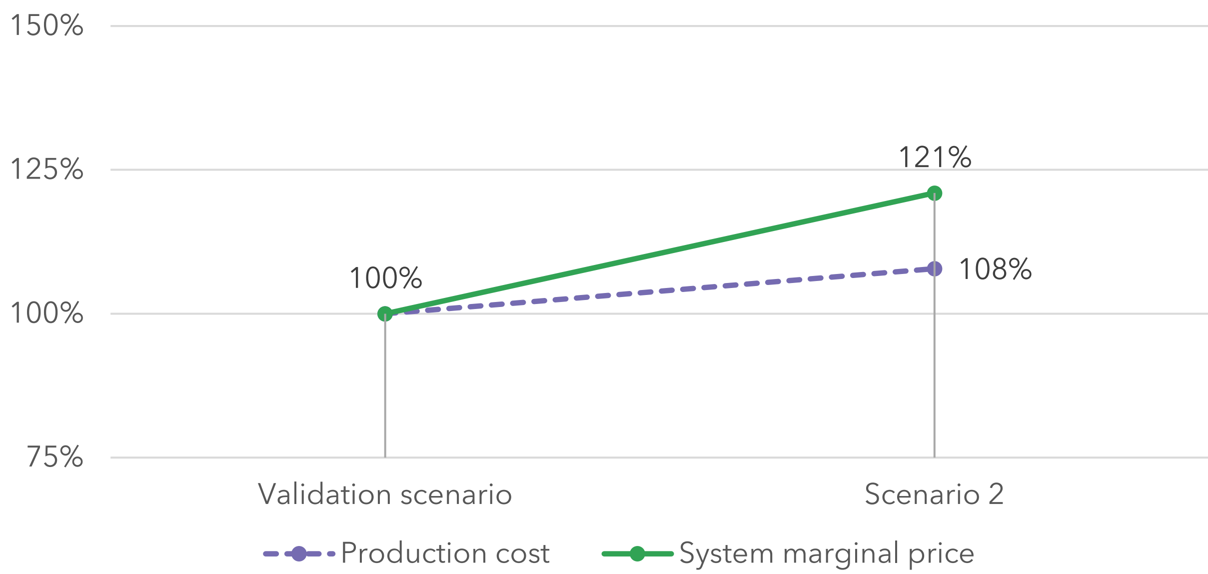
[51] We discarded market days for which the coefficient of determination of hourly production costs between the original market solution and the validation solution were less than 95 percent, representing about eight percent of market periods simulated. The remaining days averaged 99.5 percent coefficient of determination between the original solution and the validation solution. When simulating a market day, small differences in the calculation of hourly commitment or dispatch levels can compound in subsequent hourly solutions, leaving the final solution set for a day significantly different from the original market solutions.

6.2.2 SCENARIO 2 – UNITS CHOOSE "MARKET"

A number of changes were made to the validation data set prior to executing scenario two. Resources that were originally offered to the day-ahead market in self-status were set to market-status, de-committed at the start of each study period, and treated as having met their minimum down time before each continuous study period to allow for immediate commitment by the market engine.

Figure 6–1 shows the results of scenario two in terms of change in prices and production cost relative to the validation scenario.

Figure 6–1 Scenario 1 vs Scenario 2, system marginal price and production cost



In scenario two, marginal energy prices increased in excess of twenty percent, which was more than $6/MWh. Also in scenario two, production costs increased roughly eight percent, or more than $22,000 per hour. The results suggest that the current market software cannot more efficiently commit and dispatch all available units in the absence of self-commitment. As we discussed earlier in this report, the length of the optimization period is one of the software's limitations. As such, scenario two represents the market software's optimal solution given the current market structure if all resources did not self-commit.

6.2.3 SCENARIO 3 – UNITS CHOOSE "MARKET" AND OPTIMIZE LONG LEAD TIMES

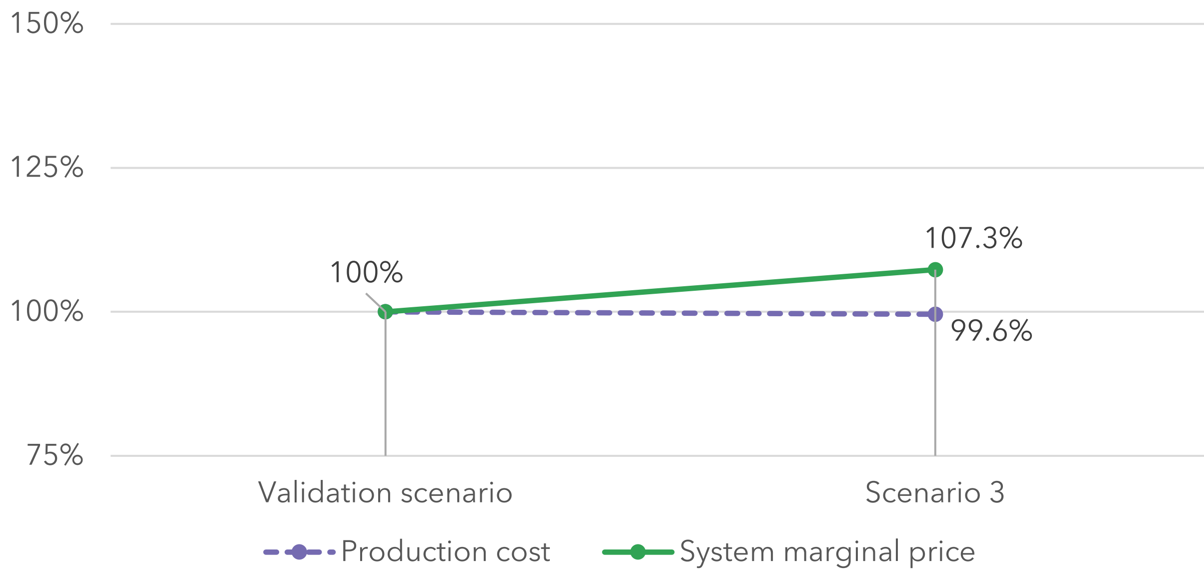
Scenario three expands on scenario two by simulating the lengthening of the optimization period of the day-ahead market. Effectively, this scenario attempted to create a multi-day economic unit commitment. This enhancement directly addresses one of the current limitations of the market software – optimizing long-lead time resources. As we mentioned in the unit-commitment section, long-lead time resources, especially those with high start-up costs, tend to be uncompetitive, in part, because of the duration of the current market optimization window.

Lengthening the optimization window includes long-lead resources that would otherwise be excluded from the optimization and decreases the hourly-amortized start-up amount, making these resources more competitive. Lengthening the optimization window by an additional day resolves the majority of these cases.

The length of the optimization window is not configurable in the current software. Therefore, to simulate an increased optimization window, we decreased the start-up times of resources with startup times greater than 23 hours to 12 hours. This change allows the current day-ahead market software to commit the resource in a manner which simulates the presence of a lengthened economic commitment mechanism.

Figure 6–2 shows that in this scenario prices increased, but production cost decreased when compared to the validation scenario.

Figure 6–2 Scenario 1 vs Scenario 3, system marginal price and production cost

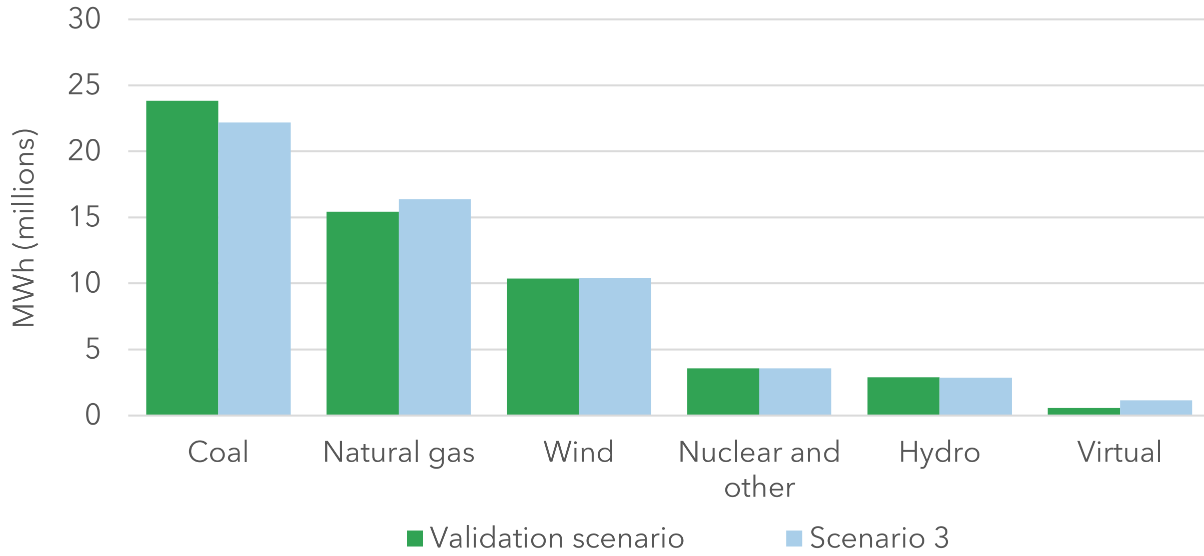


On average in every hour of the study period, system marginal prices were higher when all units market-committed. This is the same directional result as in scenario two and a predicted result based on the change in the supply curve as discussed in section two. The average system marginal price over all hours increased more than seven percent, about $2/MWh on average. The average production cost change over all hours decreased roughly one-half of one percent, or $1,750 per hour.

These results suggest that a purely economic commitment model, if able to consider and commit long lead-time resources, would lead to somewhat higher market prices and potentially more accurate investment signals while potentially reducing production costs. Given this result, we would prefer scenario three to scenario two.

Not only did the optimization change prices, it also changed dispatch quantities. Figure 6–3 shows the change in dispatch megawatts between scenario three and the validation scenario.

Figure 6–3 Scenario 1 vs Scenario 3, dispatch megawatts by fuel type



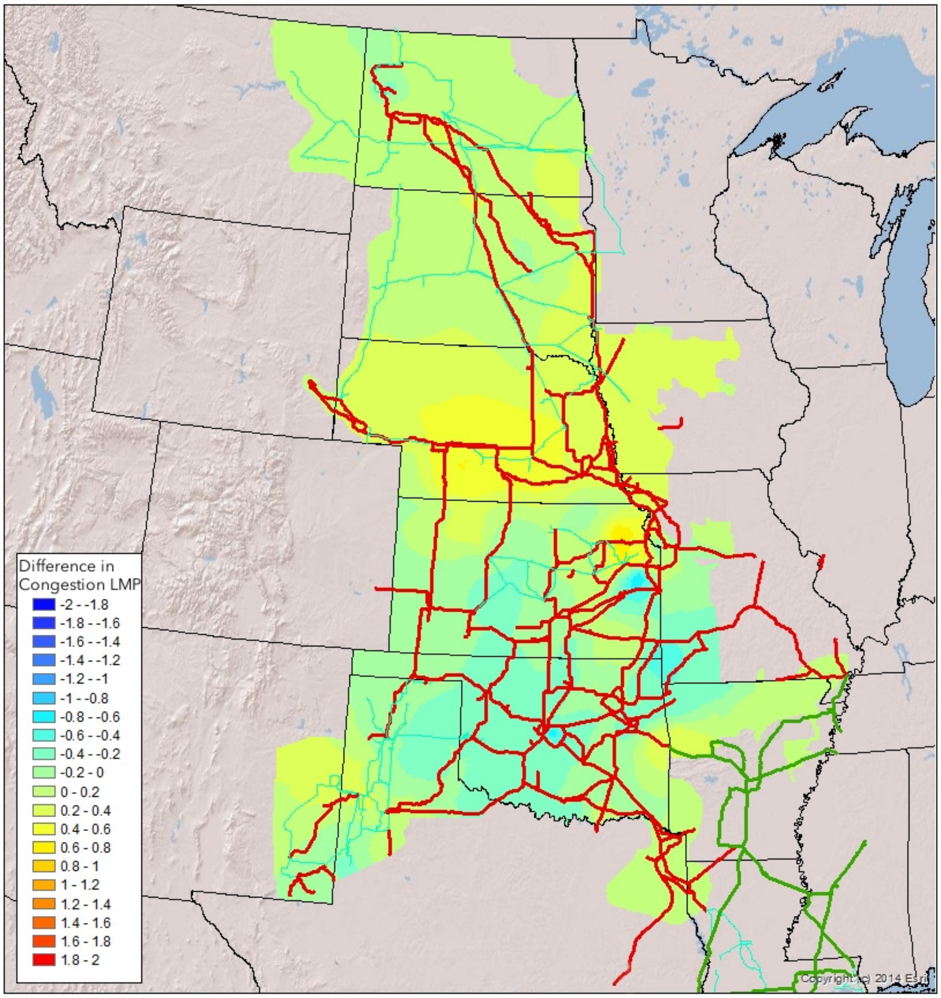
In scenario three, coal energy awards decreased seven percent, when compared against the validation scenario. Natural gas and virtual supply replaced the majority of the reduction in coal. Because changes in self-commitment affect prices, and virtual participation is based on projected prices, we expect virtual trading behavior would also change. However, we are unable to simulate how virtual participants might change their behavior in this analysis.

Any structural change to the SPP markets would likely cause a redistribution of marginal generation that can have far-reaching impacts on congestion, local pricing, and congestion hedging products. In order to visualize the net congestion differences between the original market solution and this scenario, we graphed the difference in the marginal congestion component (MCC) of the locational marginal price over the study period.

Generally, congestion reflects supply and demand relationships between producers and consumers in a given area. When an area is oversupplied with generation, congestion prices tend to be lower. Likewise, an area undersupplied with generation will tend to have higher congestion prices. This framework translates into the figure below.

Figure 6–4 shows the change in congestion between scenario three and the validation scenario. Higher congestion prices (yellow and orange) indicate increase in prices from the validation scenario to scenario three, and lower prices (green and blue) reflect price reductions in scenario three relative to the validation scenario. Ultimately, changes in congestion prices ranged between a decrease of approximately $1/MWh and an increase of approximately $1/MWh over the study period.

Figure 6–4 Scenario 1 and Scenario 3 comparison, difference in congestion costs



The majority of the supply reductions are in the coal-dominated regions of the footprint, which leads to a slight increase in congestion pricing in those areas. Accordingly, much of the replacement energy committed and dispatched to serve the day-ahead demand comes from gas-fired generation in the southern portion of the footprint, leading to a slight reduction in congestion pricing around those units.

7 CONCLUSION

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 profit maximization. Enhanced profit maximization combined with effective regulation and monitoring will likely lead to ratepayer benefits in the form of cost reduction.

While we have seen gradual reductions in self-commitments over the last few years, generation from self-committed generators still represent about half of the generation in the SPP market. Given our results, we recommend that the SPP and its stakeholders continue to find ways to further reduce self-commitments. Many resources have switched from self-commitment to market status over the past few years, and it is possible that many more could switch without any market enhancements.

However, as we presented in our simulations, simply eliminating self-commitment without any additional changes could result in an increase in total production costs. This would not necessarily be an improvement when compared to today's results. However, when lead times were shortened to reflect an additional day in the market optimization and self-commitment was eliminated, producers were paid more and production costs declined.

The efficiency gain stems largely from an improvement in the optimization of nonconvex costs, specifically start-up costs. In the current construct, units with long lead times, high start-up costs, and long minimum run times may be uneconomic over a single day, but economic over a longer period. Extending the optimization period helps bridge this gap. However, as the optimization period lengthens, it must solve for variables further into the future where there is more uncertainty. However, empirical evidence suggests that the accuracy of wind and load forecasts remain acceptable over a two-day optimization window.[52]

For these reasons, and others covered throughout this report, we support the HITT recommendation of evaluating a multi-day optimization,[53] and see this as an enhancement that can improve market efficiency and help further reduce the incidence of self-commitment. Specifically, we recommend that SPP and its stakeholders consider a multi-day commitment period of two days to allow units to commit long lead time resources.

[52] Market Working Group Meeting Materials – February 2019 – 10.b.i.MultiDay Forecast_021919

[53] See footnote 50.