State of Electricity in Kansas

Recommendations to Lower Costs for All Customers

Neil Chatterjee

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Kansas Electric Issues

In this paper, Neil Chatterjee reports on the scope of regulatory and market factors driving high retail electric rates in Kansas and evaluates and provides suggestions for potential mitigation strategies to address those rates.

The report will include consideration of Kansas regulatory and legislative drivers affecting rates, historical rate treatment, regional transmission operator wholesale market and tariff issues affecting rates, impacts on and from municipal utilities and rural electric cooperatives, and Federal Energy Regulatory Commission ("FERC") regulatory drivers affecting retail rates.

It also will evaluate the merits and potential impacts of retail electric market deregulation.

About the author

Neil Chatterjee is a former Commissioner and Chairman of the Federal Energy Regulatory Commission (FERC), and has deep ties in Washington and across the industry, with extensive experience across the energy landscape both domestically and internationally. He is respected for his ability to strike compromise and work with a wide variety of stakeholders.

In his time on the Hill and at FERC, Neil built a reputation as a bipartisan operator who builds alliances and cuts through red tape with an eye on always promoting innovation. Neil's significant knowledge and experience is derived from operating at the highest levels of government and as such, is able to provide clients valuable insights and counsel when navigating the highly regulated energy industry.

While at FERC, Neil championed several strategic initiatives, including streamlining and improving FERC's liquified natural gas application review and approval process, bolstering power grid reliability and resilience, and boosting renewable resources' ability to compete in regional power markets and for the reduction of carbon emissions.

Neil is a policy reformer who broke down market barriers for the entrance of new technologies, particularly for low-carbon technologies. He has been an advocate for harnessing technology to mitigate physical and cyber threats to critical energy infrastructure.

Prior to his time at the Commission, Neil served as an advisor to Sen. Mitch McConnell (R-KY) where he aided in the passage of major energy, highway, and agriculture legislation. Neil also has experience working as a principal in government relations for the National Rural Electric Cooperative Association. He began his career as a staff member on the House Committee on Ways and Means.

I. Overview of Kansas Electric Market

Based on the data for the most recently available year (2020), utilities in the state of Kansas sold 39,483,946 megawatt-hours of electricity to retail customers.[1] This represents a decrease from each of the prior four years, in which total sales exceeded 40 million megawatt-hours (with a high of 42,036,979 megawatt-hours in 2018). Approximately 34 percent of such sales were to residential customers, approximately 38 percent to commercial customers, and approximately 28 percent to industrial customers. The overall average rate for sales was 10.38 cents/kWh, with average rates per load classification of 12.85 cents/kWh to residential customers, 10.40 cents/kWh to commercial customers, and 7.30 cents/kWh to industrial customers. Kansas electric rates for 2020 were slightly higher than in 2019 and slightly lower than in 2018 and 2017. The four investor-owned utilities made 63.4 percent of all sales,[2] at an average rate of 10.49 cents/kWh. The 117 public (municipal) utilities made 17.5 percent of all sales, at an average rate of 9.45 cents/kWh. The 28 electric cooperatives made 19.1 percent of sales, at an average rate of 10.84 cents/kWh.

Generators in Kansas produced 54,541,831 megawatt-hours of electricity in 2020. Approximately 59 percent of this production was from utility-owned generation and the remaining 41 percent was from independent power producers. The bulk of this generation was used for direct sales to load in Kansas (39,483,946 megawatt-hours) and net electricity exports out of state (12,739,343 megawatt-hours). The net out-of-state exports of electricity exceeded the highest prior year exports (8,131,983 megawatt-hours in 2017) by over 50 percent.

Kansas has approximately 25 megawatts of installed photovoltaic generation (14.4 MW at residential customer locations and 10.6 MW at commercial customer locations) and 2.2 MW of installed wind generation (.27 MW at residential locations and 1.94 MW at commercial locations) used for net metering programs. In addition, there are only 0.424 MW of distributed generation installed in Kansas.

II. Scope of current Kansas regulatory regime

The rates and various other business activities of investor-owned utilities in Kansas are regulated by the Kansas Corporation Commission ("KCC"). This section summarizes the scope of and key issues resulting from such regulation.

1. Regulatory Structure for Retail Rates

Ratemaking Principles and Rate Case Process

Pursuant to K.S.A. 66-101b, all Kansas utilities are required to provide "reasonably efficient and sufficient service and facilities" and establish "just and reasonable rates". The Kansas Supreme Court has determined that in establishing just and reasonable rates, the Commission must consider and balance the interests of the following: (i) the utility's investors against the ratepayers; (ii) the present ratepayers against the future ratepayers; and (iii) the public interest. *See* December 2018 Rate Study of Kansas City Power & Light and Westar Energy for the years 2008 to 2018 (pp. 12-14) ("December 2018 Rate Study").

[1] All data in this section are from the United States Energy Information Administration Kansas Electricity Profile, found at https://www.eia.gov/electricity/state/kansas/ .

[2] The three affiliated Evergy utilities (Evergy Kansas Central, Evergy Kansas South and Evergy Metro) account for over 99 percent of these investor-owned sales. Every thus represents over 60 percent of the load-serving responsibility in Kansas.

According to Part 1 of the January 2020 Study of Retail Rates of Kansas Electric Public Utilities (p. 51) ("January 2020 Study of Retail Rates"), broadly accepted principles of ratemaking can be categorized into six groups, and the relevant Kansas statutes closely align with these principles:

1. **Economic efficiency and performance**: Provide funding to maintain reliability consistent with customer expectations while recognizing such preferences are increasingly varied.

2. **Customer focus and bill impacts**: Encourages the pursuit of opportunities for better cost containment.

3. **Stability of the sector**: Investment signals must be proportional to associated risk, and market returns and remuneration should take into account the impact on debt service coverage ratios and associated parameters for maintaining an efficient capital structure. Also, stranded costs should be identified, quantified, and recovered in a fair manner.

4. **Cost causation and avoidance of cross-subsidies**: Customer that causes a cost to be incurred should pay that cost.

5. **Evolving utility structure to facilitate innovation**: Framework must balance incumbent opportunities against market participation, reducing barriers to the third-party providers of services. This also includes the elimination of capex, ownership, and technology biases and emphasizes the focus on a long-run least-cost approach that values optionality for determining solutions to identified system and customer needs.

6. **Regulatory simplicity**: Ratemaking must balance appropriate oversight with administrative simplicity to avoid an overly burdensome process for all parties. Moreover, the framework must have built-in decision criteria and evaluation to increase accountability and advance strong stakeholder support.

The rate case process is 240 days by statute, and proceeds as follows:

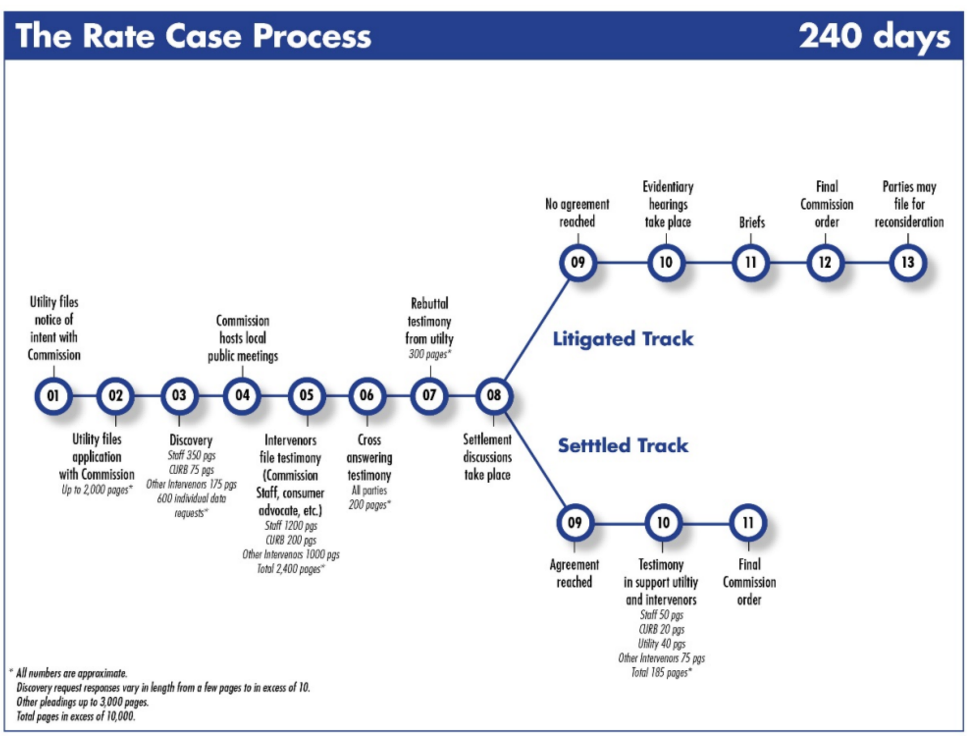

**Chart taken from the December 2018 Rate Study of Kansas City Power & Light and Westar Energy for the years 2008 to 2018 (p. 21).*

Revenue Requirements and Rate Base

The revenue requirement identifies the expected amount of revenue a utility requires to cover its cost of service, allowed return to its investors, and operating costs. Revenue requirements have three key components: (i) the rate base; (ii) the Rate of Return ("ROR"); and (iii) operating costs. The revenue requirement is determined by multiplying the rate base by an appropriate ROR and then adding the operating costs. There are also pass-through charges (e.g. fuel cost adjustment riders), as discussed below. *See* Part 1 of the January 2020 Study of Retail Rates (p. 56).

When beginning to analyze a given utility's revenue requirement, the KCC staff selects a historical test year as a baseline for examining the given utility's actual revenues and expenses. The rate base is comprised of utility investments (e.g. utility-owned generation facilities, buildings, transformers, computers, etc.). The rate base is the investment base to which an ROR is applied to arrive at the allowed return to investors. Material increases in the rate base, due to additional capital investment, can result in a significant increase in the utility's overall revenue requirement.

The formula to calculate rate base is:

Net Book Value Assets + Capital Expenditure – Depreciation + Working Capital

Rate Design

The final stage of the ratemaking process is creation of the rate structure, which involves translating the utility's revenue requirement into customer rates that will recover the revenue requirement. Rate structure creation is a two-step process: (1) allocating the revenue requirement among rate classes; and (2) developing customer rates for each class.

To translate the revenue requirement into retail customer rates, the following two components are needed:

1. **Billing Determinants**: These consist of all data necessary to generate existing and proposed revenue from customers. This includes the number of customers by season and class, the energy used in each rate block by season and class, customer demand for each demand block by season and class, and the customer rates by block, season, and class.

    a. Multiplying the number of customers, energy used, and customer demand by the appropriate customer rates, will provide the revenue the customer rates can generate, which is the proof of revenue.

    b. The proof of revenue: (i) demonstrates the company's revenue requirement can be recovered under the proposed rate structure; and (ii) allows for comparing the change in revenue caused by moving from existing to proposed rates.

2. **Class Cost of Service ("CCOS")**: This constitutes full allocation of the utility's cost to serve customers allocated among all customer classes. It's based on the concept that the cost causer should be the cost payer. The purpose of a CCOS study is to allocate a utility's costs to serve customers among the different customer classes—which can be used as a guide for class allocation of the revenue requirement.

a. The allocation process used to develop a CCOS follows a standard method outlined in the NARUC manual titled *Electric Utility Cost Allocation Manual*.
b. The five basic steps to the CCOS process are:

    i. Direct assignment of costs where possible.
        When direct assignment is not possible, joint and common costs are instead assigned by:
    ii. Functionalizing costs
    iii. Classifying costs
    iv. Allocating costs across classes
        After all the costs have been allocated across customer classes, then the question of whether cross-subsidization exists in the current rate design can be investigated using:

    v. Rate of return analysis

See December 2018 Rate Study of Kansas City Power & Light and Westar Energy for the years 2008 to 2018 (pp. 28-30). Also see the response below for allocation of costs between industrial, residential, and commercial customers.

Cost Recovery Mechanisms

In addition to recovering costs through base rate changes, the KCC permits utilities to recover specific cost categories through commission-authorized adjustment riders and legislatively mandated adjustment clauses, as follows:

- **Energy Cost Adjustment ("ECA")**: Authorized by the Commission, an ECA is a "formula-based rate" that utilities use to recover costs such as those related to fuel costs, purchased power costs, and transmission related expenses. Applications are filed with the KCC on an annual basis for each year-end.

- **Environmental Cost Recovery Rider ("ECRR")**: The ECRR tariff, authorized by the Commission in 2005, permitted Westar Energy to recover costs associated with "mandatory environmental upgrades through a monthly surcharge rather than adding these costs to base rates after the projects are completed." This was upheld by the Kansas Court of Appeals.

- **Transmission Delivery Charge ("TDC")**: The TDC is used to recover transmission-related costs resulting from "any order of a regulatory authority having legal jurisdiction over transmission matters, including orders setting rates on a subject-to-refund basis." Accordingly, utilities use TDCs to recover Southwest Power Pool ("SPP") costs associated with retail transmission services. The TDC is allowed within the framework of K.S.A. 66-1237 and enables utilities to recover transmission-related costs through a charge on customer bills.

- **Ad Valorem Tax Rider**: These are used to recover costs incurred due to annual changes (an increase or decrease) in ad valorem property taxes as charged in the "books and records of the utility." Regulated pursuant to K.S.A. 66-1179(f).

- **Energy Efficiency Rider**: This is used to recover costs associated with utility energy efficiency programs. Regulated pursuant to K.S.A. 66-1283.

See Part 1 of the January 2020 Study of Retail Rates (pp. 67-74).

2. **FREQUENCY OF FILED RATE CASES AND SETTLEMENTS**

Frequency of Filings

Major utilities in Kansas have generally filed rate cases every year or two on average, with fluctuations.

For example, from 2007-2018, Kansas City Power & Light ("KCP&L") filed 8 rate cases, as follows: in May 2007 (rates effective January 2008), September 2008 (effective August 2009), December 2008 (effective December 2010), April 2012 (effective December 2012), December 2013 (effective August 2014), January 2015 (effective August 2015), November 2016 (effective July 2017), and May 2018 (effective December 2018).

Westar Energy from 2007-2018 filed 7 rate cases, as follows: May 2008 (rates effective January 2009), June 2009 (effective February 2010), August 2011 (effective April 2012), April 2013 (effective December 2013), March 2015 (effective October 2015), October 2016 (effective June 2017), and February 2018 (effective September 2018).

See December 2018 Rate Study (pp. 80-94).

Settlements

The majority of rate cases under KCC jurisdiction are settled. "Fully litigated [rate] cases are a minority of the total large investor-owned rate cases to appear before the Commission." Fully-litigated cases usually occur when there is disagreement by the parties "over a number of adjustments that have a large dollar value associated with them." *See* December 2018 Rate Study (pp. 51-52).

Driving the point home, the Commission has noted "[i]t is an elemental rule that the law favors compromise and settlement of disputes." Order Approving Non-Unanimous Stipulation and Agreement, p. 22, Docket No. 18-WSEE-328-RTS (Sept. 27, 2018), citing In the Matter of Thompson's Estates, 226 Kan. at 440.

The Commission has a five-factor test to determine the reasonableness of settlements, as follows:

1. Was there an opportunity for the opposing party to be heard on the reasons for opposition to the Stipulation and Agreement?
2. Is the Stipulation and Agreement supported by substantial competent evidence in the record as a whole?
3. Does the Stipulation and Agreement conform with applicable law?
4. Does the Stipulation and Agreement result in just and reasonable rates?
5. Are the results of the Stipulation and Agreement in the public interest, including the interest of customers represented by any party not consenting to the Agreement?

Order Approving Non-Unanimous Stipulation and Agreement, p. 12, Docket No. 18-WSEE-328-RTS (Sept. 27, 2018).

3. Allocation of Costs between Industrial, Residential, and Commercial

As described above, rate design starts with calculating the total annual revenue requirement of a utility, using the Cost-of-Service ("COS") mechanism. The cost components are then allocated to different customer classes after KCC Staff and other parties conduct a Class COS ("CCOS") study—to determine the relationship between the revenue recovered from each customer class and the cost caused by each customer class, and aids in categorizing and allocating total utility costs to various rate classes. KCC Staff propose a revenue requirement allocation based on the cost to serve each of the rate classes.

The CCOS is used to link the revenue recovered from each customer class (i.e. industrial, residential, commercial) to the costs caused by each customer class, respectively. At center is the tenet that the cost causer should be the cost payer, but other policy and equity factors may also be considered.

The next step is rate design—the final step in the revenue allocation process. The KCC must determine how best to collect that revenue from the customers in each class, by developing a specific rate design for each class. *See* the response above for more information on this step.

See The Utility Ratemaking Process, KCC website; Part 1 of the January 2020 Study of Retail Rates (pp. 65-7).

4. Mechanism for Special Contracts

Special Mechanism

Economic Development Riders ("EDRs") offer a discounted rate to eligible customers to incentivize business development. The economic theory behind EDRs is that generation of additional power sales would eventually lower rates for all customers because utilities' fixed costs are spread over a larger base of customers. *See* Part 2 of the January 2020 Study of Retail Rates (p. 134).

In Kansas, EDRs are limited to industrial and commercial customers that are not providing goods and services directly to the general public (i.e. no retail activity) and would otherwise not maintain or establish operations in Kansas. Eligibility is further determined by meeting minimum load requirements and establishing permanent jobs within the service area. General EDR rates as well as the terms of special contracts that affect tariffs are subject to approval by the KCC. *See* Part 2 of the January 2020 Study of Retail Rates (p. 134).

Comparison to Peer States

The discount rates offered by Kansas IOUs fall within the range of discounts offered by comparable utilities in nine peer states, although each utility has different criteria for load requirements, duration of contract, and additional stipulations of eligibility. On average, Kansas EDRs have lower load requirements and lower discounts than other peer-state utilities. *See* Part 2 of the January 2020 Study of Retail Rates (p. 134-5).

Some Implications

Special contracts result in cost shifts to other customers. Per Part 2 of the January 2020 Study of Retail Rates (p. 136), Evergy Metro since 2015 has had the highest average annual rate across its customer classes. The rise in average electric rate corresponds to the high rate of entry for EDRs beginning in 2015. Theoretically, the analyzed utility should see a subsequent drop in electric rates relative to their peers as contracts expire and fixed costs are distributed among more customers, assuming other conditions remain the same.

The EDRs in Kansas may bridge the competitiveness gap for the first five years of business development or expansion compared to the average annual rate for the region. The discounted rates available through EDRs result in average discounts ranging from 15% to 20% depending on the specific location, effectively neutralizing Kansas' higher electric rates. Additionally, utilities in the peer states also offer EDRs, and some of their discounts are larger than those offered by IOUs in Kansas. Discounts are valid for five years, and this short timeframe might not be sufficient to entice business development in Kansas over the peer states due to nonenergy related factors. In leveraging available data, it appears that the average annual rate for all customers in the service area with the most EDRs did increase and rise above those of other geographies since 2015. *See* Part 2 of the January 2020 Study of Retail Rates (p. 136).

5. Electric Cooperatives and Municipal Utilities

Municipal utilities ("munis") and electric cooperatives ("co-ops") are *not* under the jurisdiction of the KCC. These include generation and transmission utilities, transmission and distribution utilities, and distribution-only utilities. As of early 2020, there were 32 co-ops and 118 munis in Kansas. In contrast, investor-owned utilities ("IOUs") are vertically integrated and regulated by the KCC. There are two traditional IOUs in Kansas—Evergy and Empire District Electric.

There is no retail competition in Kansas, and all utilities have exclusive franchise over the retail customers within their service territory.

See Part 1 of the January 2020 Study of Retail Rates (p. 13).

6. Statutory Framework for Certification of New Facilities

The KCC relies on the primary objective standards noted in K.S.A. 66-128 et seq. and K.S.A. 66-1239 to determine whether a proposed investment by a utility is justified or not. In accordance with the "used and useful principle," which requires that utility investments should be used by and useful to ratepayers before they are paid for, the KCC utilizes traditional means to evaluate new investments, including "(1) pre-construction to determine the construction bid process (lowest reasonable cost) and the analysis for need (used and required to be used), (2) during construction to monitor costs, change orders, and recordkeeping, and (3) post-construction to determine how well the project was managed, whether there were cost overruns that were justified or unjustified, and determination of whether any prudence issues exist." Vetting can be conducted through a predetermination proceeding, a regulatory plan filing, or through a specific docket or rate case. *See* Part 1 of the January 2020 Study of Retail Rates (p. 93).

The KCC recently issued an order on April 28, 2022 to curb participation of ratepayers represented through Kansas Industrial Consumers Group ("KIC") in the NextEra Energy Transmission Southwest, LLC ("NextEra") project (Docket No. 22-NETE-419-COC). This project aims to build 89 miles of transmission line from the Wolf Creek nuclear power plant into Southwest Missouri, paid entirely by retail electric ratepayers. Instead of granting KIC full intervention rights as is custom, the KCC made the rather unprecedented decision to provide limited rights, restricting KIC to interacting exclusively on retail rate impact issues and prohibiting it from offering input or seeking information on vital issues such as eminent domain and capacity requirements. The majority stated in part: "While KIC has made broad statements about other interests that should be protected or evaluated, it has not identified how it, a collection of private commercial and industrial utility customers, has standing to represent those interests."

There is little or no recent precedent for such an action, particularly given that all other intervenors in the docket—including the seven utility intervenors—have been granted full intervention rights, and the KIC has a history of full intervention in these types of proceedings. KCC Chair Dwight Keen gave a strong dissent to this limitation (his first dissent in his 4.5 years as a KCC commissioner). Further still, the KCC set a very abbreviated schedule for interventions on April 29, 2022—providing only until May 6, 2022. This type of unprecedented and irregular action provides further fuel supporting reform of the KCC.

NextEra, KCC Staff, Evergy, SPP, the Citizens' Utility Ratepayer Board ("CURB"), and several other parties subsequently reached a settlement agreement. Only KIC and affected landowners have opposed the settlement. In post-hearing briefs, some of the central active parties have made the following arguments regarding the settlement:

NextEra – The settlement is in the public interest and results in just and reasonable rates, and the Commission should grant the requested certificate. The project will benefit Kansas customers and result in a net decrease in energy costs in Kansas. They specifically reject the KIC claims that the project would move wind and nuclear power out of state.

Evergy – They support approval of the certificate application and argue that the project will provide economic benefits to Kansas and to the entire SPP region, including enhanced reliability and "reduction in upward pressure on rates." They explain that the costs of the project will be accolated across the SPP region. They note that their initial concerns about the application have been alleviated through the settlement process, including the NextEra commitments to include cost caps and conditions in its FERC formula rate and to file quarterly construction reports.

KCC Staff – They argue that granting the requested certificate is in the public interest and support the settlement. They conclude that the settlement results in a reduction of congestion on the Kansas electric grid transmission system and an increase in reliability for Kansas ratepayers and that it results in just and reasonable rates, noting that the evidence shows that only 16.5% of the total revenue required for this project will be paid by Kansas customers.

CURB – CURB, the entity charged with protecting ratepayer interests in Kansas, concludes that the record contains substantial evidence to support approving the settlement and granting the certificate. They argue that the settlement will result in just and reasonable rates and that a substantial amount of the project's benefits will be realized by Kansas customers.

KIC – As noted, KIC opposes the settlement. They argue that the record does not contain evidence of Kansas-specific costs and benefits (a claim disputed by the settling parties), and that the project will raise prices in Western Kansas. They further argue that the KCC process does not adequately consider the prudence of a project such as this one.

While there is consensus among the settling parties, including CURB, that Kansas ratepayers will benefit from the project, KIC remains opposed. It is likely, based on the record and arguments of the settling parties, that the KCC will grant the NextEra's application. The major significant concern is that the KCC may continue to deny the ability of customer interests to participate directly in future proceeding.

7. Integrated Resource Plans

Most utilities in Kansas are not required to go through a regular Integrated Resource Plan ("IRP") process except for selected utilities, such as the Kansas City Board of Public Utilities ("BPU"). BPU states that it "is required by law to file an IRP with Western Area Power Administration, an agency of the US Department of Energy, and update the plan every five years. As part of this requirement, BPU must also submit annual progress reports and the status of its IRP."

However, at the time of publication of the 2020 Rate Study, Westar Energy, Kansas City Power & Light Company, Empire District Electric Company, Kansas Power Pool, Kansas Municipal Energy Agency, Kansas Electric Power Cooperative Inc., Midwest Energy, Sunflower Electric Power Corporation, MidKansas Electric Company, and Kansas City Board of Public Utilities were all required to file annual generation capacity needs, system peak capacity needs, and renewable generation needs (now voluntary in Kansas) to the KCC. *See* KCC Docket 13-GIME-256-CPL. These filings share some similarities to IRP filings but do not include the level of detail that would be required for an IRP.

See Part 1 of the January 2020 Study of Retail Rates (pp. 14, 132).

Evergy was formed in 2018 by the merger of Westar Energy, Inc. and Kansas City Power and Light Company. The KCC approved the merger by order issued May 24, 2018, approving a non-unanimous settlement agreement that called for a Capital Plan reporting Docket in which Evergy would file its five-year capital expenditure projections annually. In 2020, the KCC approved the Capital Plan framework to provide the KCC with visibility into Evergy's new investment forecast and plans for replacing existing infrastructure. The Capital Plan is to be based on Every's five-year budgeting process and practices and will include generation, transmission, distribution and general plant investment plans.

Evergy submitted its most recent Capital Plan on February 28, 2022 in KCC Docket No. 19-KCPE-096-CPL.[3] The plan calls for combined capital expenditures of $6.782 billion for the years 2022 through 2026 for Evergy Kansas Central and Evergy Kansas Metro. This total is approximately 21.82 percent larger than the capital expenditures projected for 2020 through 2024. Evergy projects that the increased spending will result in a rate increase of just over 1 percent for both Evergy Kansas Central and Evergy Kansas Metro, although they claim (without substantiation) that operating and maintenance savings will reduce such rate increases to just below 1 percent.

The plan included $1.111 billion for new renewable generation, $912 million for other generation, $2.239 billion for transmission investment, $1.777 for distribution investment, and $742 million for IT and other plant investment.

On July 8, 2022, KCC Staff filed its report and recommendation on the Evergy Capital Investment Plan filing. Staff states that the increases in Evergy's capital expenditure projecstions are "highly concerning" to Staff but concludes that "Evergy's capital expenditure projections remain comparable to other publicly-traded electric utilities and its regional peers." Staff recommends that Evergy slow the pace of transmission investment and shift some of that planned investment to distribution modernization, citing the potential reliability benefits of such investment. Staff's overall recommendation is that the KCC accept the Capital Plan as compliant with the Capital Planning framework.

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[3] Found at https://estar.kcc.ks.gov/estar/ViewFile.aspx/S20220228151015717.pdf?Id=a1790824-29dc-42f9-9e27-cb397b80379e .

This lack of an IRP requirement makes if far more difficult for the KCC to monitor and require that jurisdictional utilities plan their systems in the most cost-effective manner. While the Capital Plan framework addresses some of these concerns for Evergy; it is designed for identification of plans, and not for evaluation of the reasonableness of those plans. Those issues are left for certification proceedings and rate cases. A beefed up Capital Planning framework that considers the reasonable of such plans would help to transform such proceedings into a more traditional IRP review.

8. Comparison of Similar States to Kansas

Areas of Difference. Key areas in which Kansas is somewhat unique when compared to similar states include:

- **Integrated Resource Plans.** Kansas does not have a mandated Integrated Resource Plan ("IRP") process, one of the few states in which this is the case. Arkansas, Colorado, Missouri, North Dakota (only one utility in the state is required to file IRPs), Oklahoma, and South Dakota are examples of comparable states with varying IRP requirements. Iowa (but different filing requirements) and Texas are comparable states to Kansas that also have no such requirement.

- **Renewable Portfolio Standard.** Kansas also does not have a mandatory Renewable Portfolio Standard ("RPS") target.

Areas of Similarity. Areas in which Kansas is similar to other comparable states include: (1) a similar institutional framework with exclusive franchises for electric supply; (2) a single state regulator with a broad rate-setting jurisdiction; and (3) a combination of member-owned, municipal-owned, and investor-owned utilities.

ISO Participation. Kansas has SPP, while states like Colorado and Iowa do not. Kansas does not have MISO, while states like Arkansas, Iowa, Missouri, the Dakotas do have it. Oklahoma—similar to Kansas, has SPP but not MISO.

Following is a chart of key electric profile statistics taken from Part 1 of the January 2020 Study of Retail Rates (p. 14):

Figure 2. Key statistics across selected states

Jurisdiction	Installed capacity (MW, 2017)	Demand (TWh, 2017)	Area (sq.km)	Population (2018)	Population density (2018, ppl/sq km)	ISO Participation
Arkansas	14,642	46	137,732	3,013,825	22	Yes (MISO & SPP)
Colorado	16,017	55	269,601	5,695,564	21	No
Iowa	17,671	49	145,746	3,156,145	22	Yes (MISO)
Kansas	16,138	40	213,100	2,911,505	14	Yes (SPP)
Missouri	21,809	76	180,540	6,126,452	34	Yes (MISO & SPP)
North Dakota	8,234	20	183,108	760,077	4	Yes (MISO & SPP)
Oklahoma	26,691	60	181,037	3,943,079	22	Yes (SPP)
South Dakota	4,129	12	199,729	882,235	4	Yes (MISO & SPP)
Texas	123,512	402	695,662	28,701,845	41	Yes (ERCOT)

Source: Energy Information Administration, *State Electricity Profiles*. January 2019; US Census Bureau. *Population Estimate (As of July 1)*. 2018.

As explained in the January 2020 study, retail rates in Kansas are the highest of any of these comparable states. However, at the same time, average ROE's for Kansas utilities are the second lowest among these states, which suggests that the amount of capital expenses is one of the key drivers resulting in the higher Kansas rates. This could be a direct consequence of a lack of an IRP requirement that results in system additions that are not comprehensively planned to be lowest cost.

In addition, the January 2020 study shows that a higher percentage of Kansas retail rate cases settle than in all but one of the comparable states. This push to settle these cases could also be a contributing factor in the higher retail rates in Kansas. The threat of potentially having to fully litigate the costs of new system additions could potentially put additional pressure on utilities to ensure that their capital expenses are cost effective.

III. Southwest Power Pool and Kansas Overview

This section summarizes the key elements of the Southwest Power Pool ("SPP") Open Access Transmission Tariff ("Tariff") currently on file with the Federal Energy Regulatory Commission ("FERC"), along with SPP's bylaws, and recent FERC Orders approving revisions to the Tariff. It addresses the role and functions of SPP and who its members are, how transmission projects are selected, how costs are recovered under the Tariff, and the withdrawal process from SPP membership including exit fees.

1. Role of SPP and SPP Members

The Southwest Power Pool ("SPP") is a not-for-profit Regional Transmission Operator ("RTO") mandated by FERC to manage reliability coordination, wholesale markets, and transmission services using its members' transmission systems. SPP established a real-time energy market in 2007 and moved to an integrated day-ahead and ancillary services energy market in March 2014, referred to as the "IM". The IM provides a centralized unit commitment process, and a market co-optimization process to all market participants in the footprint.

The role of SPP is to ensure the reliable supply of power, adequate transmission infrastructure, and competitive wholesale electricity prices for a 575,000-square-mile region including more than 70,000 miles of high-voltage transmission lines. Activities outside of the SPP's responsibility are transmission siting, generation planning/siting, transmission and generation construction, permitting, and credit/allowance trading oversight. SPP's services are independently provided on a regional basis, focused on electric reliability, cost-effectiveness and bringing value to SPP members and their customers.

SPP is based in Little Rock, Arkansas, and serves 94 members in 14 states of a geographic area of over 575,000 square miles, including all or portions of Arkansas, Kansas, Louisiana, Missouri, Nebraska, New Mexico, Oklahoma, Texas, Iowa, Minnesota, Montana, North Dakota, South Dakota, and Wyoming. This footprint comprises over 800 generating plants and over 60,000 miles of transmission lines. All major utilities in Kansas are members of the SPP.

- **SPP in Kansas**

All Kansas utilities are members of SPP, meaning they have transferred functional control of their transmission assets to SPP. As participating members of SPP, Kansas utilities receive transmission services from SPP, including Network Integration Transmission Services, and Point-to-Point service, and are assessed a service fee by SPP. The SPP fee was at 39.4¢/MWh for service in 2019 – this fee is capped at 43¢/MWh. Kansas utilities represent approximately 18% of the total load in SPP, referred to as its "load ratio share."

Major SPP members in Kansas include the following (this list is not exhaustive):

- Kansas Electric Power Cooperative, Inc. (Cooperative) - They also provides transmission services for all members through SPP as part of their Network Integrated Transmission Service. Sixteen of their members are in Evergy's transmission zone, while seven are in the Mid-Kansas Electric Company zone, and one is in the Midwest Energy zone.
- Sunflower Electric Power Corporation
- Evergy (Investor-Owned)
    - Evergy Kansas Central, Inc.
    - Evergy Kansas South, Inc.
    - Evergy Metro, Inc.
    - Evergy Missouri West, Inc.
- Board of Public Utilities of Kansas City, Kansas (Municipal)
- Kansas Municipal Energy Agency
- Kansas Power Pool (KPP)
- Evergy Kansas Central, Inc. (Market Participant)
- Kansas City Board of Public Utilities
- Kansas Electric Power Cooperative
- Kansas Ethanol, LLC
- Kansas Municipal Energy Agency
- Kansas Power Pool

1. Approving Transmission Projects

Every year SPP works with its members to determine the region's new transmission needs. These projects benefit the region by connecting new generators and demand sources to the transmission system, ensuring low-cost electricity is delivered to consumers and solving power grid issues that, if not addressed, could impact the reliable delivery of electricity. Determining who should pay for transmission upgrades is a highly debated public policy issue. SPP is challenged to better align its transmission planning processes, Integrated Marketplace and transmission cost allocation methodologies. It is important to address the cost responsibility of loads and generators as well as cost allocation among loads.

A. Transmission Planning Overview

As a FERC-designated RTO, one of SPP's responsibilities is to create regional transmission expansion plans. With its members, regulators, and stakeholders, SPP creates planning models and studies that determine what new transmission is needed to meet the region's long- and near-term needs and create a cost-effective, flexible and robust transmission network. SPP does not own or build transmission, though its Tariff contains rules that govern transmission planning.

Under the Tariff, transmission planning is an open process. New and proposed transmission facilities can come from the following processes in this Tariff: 1) Transmission Service Requests; 2) Generator Interconnection Requests; 3) the Integrated Transmission Planning Assessment; 4) the Balanced Portfolio process; 5) the High Priority Study process; 6) requests for Sponsored Upgrades; 7) the 20-Year Assessment; 8) the evaluation of proposed Interregional Projects; and 9) the Generator Retirement Process.

B. Transmission Owner Selection Process

FERC Order 1000 required the removal of federal right of first refusal ("ROFR") for certain transmission projects under the SPP Tariff. To comply with this requirement, SPP developed the Transmission Owner Selection Process

("TOSP") to competitively solicit proposals for projects that no longer have ROFR. Transmission Facilities that meet the criteria contained in the SPP Tariff and are approved for construction or endorsed by the SPP Board of Directors after Jan. 1, 2015 are known as Competitive Upgrades.

SPP will solicit proposals for Competitive Upgrades from Qualified RFP Participants ("QRPs") utilizing the TOSP. A QRP is an entity that wants to participate in the TOSP. Each entity must submit a QRP application and supporting materials to demonstrate that it satisfies the qualification criteria in the Tariff. All QRP applications must be received no later than June 30 of the year prior to the calendar year in which the applicant wishes to begin participation in the TOSP. Only approved QRPs can participate in the TOSP.

All project proposal submissions will be reviewed and evaluated by an Industry Expert Panel ("IEP"). After completing an evaluation, the IEP will recommend a proposal for each Competitive Upgrade to the SPP Board.

If the Competitive Upgrade was submitted as a Detailed Project Proposal ("DPP") during the Integrated Transmission Planning ("ITP") study process as outlined the Tariff, the submitting QRP may be eligible to receive incentive points pursuant to the eligibility requirements described the Tariff.

During the ITP process — once the applicable ITP study scope has been approved and the needs assessment performed — SPP shall notify stakeholders of the identified transmission needs and provide a transmission-planning response window of 30 calendar days. During this time, any stakeholder may submit a DPP and the information must be sufficient to allow SPP to evaluate the project described by the DPP in accordance the SPP Tariff. All DPPs will be kept confidential.

The Economic Planning department performs economic studies for SPP Engineering. This includes economic analysis and development of proposed transmission upgrades through the Integrated Transmission Planning, Balance Portfolio process, high priority study process, Sponsored Upgrades and Interregional Projects. This department also analyzes benefit metrics for the Regional Cost Allocation Review ("RCAR") and performs other ad hoc planning studies requiring economic analysis.

The idea for Priority Projects was developed by the Synergistic Planning Project Team ("SPPT"), a high-level policy team consisting of state regulators and SPP member representatives that was created in January 2009. The SPPT focused on recommendations for creating a robust, flexible and cost-effective transmission system for the region, large enough in both scale and geography to meet SPP's future needs.

Development of Priority Projects was one major recommendation of the SPPT; the others were to develop an Integrated Transmission Planning process that improves and integrates SPP's existing transmission planning processes and to implement a new Highway/Byway cost allocation methodology to pay for new transmission in the region.

C. Overview of Transmission Owner Designation Process (SPP Tariff Attachment Y)

The Transmission Provider shall designate a Transmission Owner for transmission facilities approved for construction by the Transmission Provider after January 1, 2015 that meet all of the following criteria:

- Transmission facilities are ITP Upgrades, high priority upgrades, Generator Retirement Upgrades, or Interregional Projects;
- Transmission facilities with a nominal operating voltage of greater than 100 kV;

- Transmission facilities that are not a Rebuild of an existing facility;
- Transmission facilities that do not alter a Transmission Owner's use and control of its existing right of way under relevant laws or regulations;
- Transmission facilities located where the selection of a Transmission Owner does not violate relevant law where the transmission facility is to be built;
- Transmission projects that do not require both a Rebuild of existing facilities and new transmission facilities; and
- Transmission facilities that are not a Local Transmission Facility.

For transmission projects involving both a Rebuild of existing facilities and the construction of new transmission facilities, the Transmission Provider shall designate the Transmission Owner(s) as follows:

- If 80% or more of the total cost of a project consists of the Rebuild of existing facilities, then the Transmission Provider shall designate the Transmission Owner(s) for the project; or
- Otherwise, the Transmission Provider shall divide the project into two or more segments based upon whether that portion of the project is a Rebuild of existing facilities or new facilities. For those segments that are Rebuilds of existing facilities, the Transmission Provider shall designate the Transmission Owner(s).

Transmission Provider may designate the Transmission Owner(s) if such upgrade is required to be in service within 3 years or less to address an identified reliability violation ("Short-Term Reliability Project"). To have a transmission project approved as a Short-Term Reliability Project, the Transmission Provider shall:

- Separately identify and post an explanation of the reliability violations and system conditions for which there is a time-sensitive need, in sufficient detail to allow stakeholders to understand the need and why it is time sensitive.
- Provide to stakeholders and post on its website a full and supported written description explaining:
    - The decision to designate the Transmission Owner, including an explanation of other transmission or non-transmission options that the Transmission Provider considered but concluded would not sufficiently address the immediate reliability need; and
    - The circumstances that generated the immediate reliability need and an explanation of why that immediate reliability need was not identified earlier.
- Permit stakeholders thirty (30) days to provide comments in response to the description required under Section I.3.b of this Attachment Y and make such comments publicly available.
- Maintain and post a list of prior year designations of Short-Term Reliability Projects. The list must include the Short-Term Reliability Project's need date and the date that the DTO actually energized the project. Such list must be filed with the Commission as an informational filing in January of each calendar year covering the designations of the prior calendar year.
- Obtain approval by the SPP Board of Directors.

D. Transmission Owner Selection Process Deposit and Cost Calculation

Each Proposal shall pay its share of the Transmission Provider's total cost incurred to administer the Transmission Owner Selection Process for each Competitive Upgrade, as calculated pursuant to the Tariff. At the time of submission of each Proposal, each Respondent (or for a Joint Proposal) shall submit a Transmission Owner Selection Process deposit for each Proposal, which shall be determined as follows (based on the value of the Competitive Upgrade as identified in the SPP Transmission Expansion Plan approved by the SPP Board of Directors):

- Small Project (less than $10 million): $10,000 deposit
- Medium Project (between $10 million and $100 million): $25,000 deposit
- Large Project (greater than $100 million): $50,000 deposit

The Transmission Provider shall determine the actual Transmission Owner Selection Process costs at the completion of the process, and all Respondents will make additional payments or obtain refunds based on the reconciliation of Transmission Owner Selection Process deposits collected and actual Transmission Owner Selection Process costs. The Transmission Owner Selection Process costs shall include the Transmission Provider's staff and administrative costs associated with administering the Transmission Owner Selection Process for the Competitive Upgrade and all costs associated with administering the IEP process for the Competitive Upgrade, including the identification, recruiting, hiring, and retention of industry experts to serve on the IEP(s). The costs shall be allocated to each Proposal on a pro-rata share basis, calculated by taking the total Transmission Owner Selection Process costs for each Competitive Upgrade and dividing by the number of Proposals submitted for that Competitive Upgrade. The Transmission Provider shall refund any unused deposit amounts with interest earned on such deposits.

2. Cost Allocation Methodology Overview

SPP is responsible for assessing and evaluating the transmission revenue requirements for utilities in its RTO, including Kansas. Put another way, SPP acts as an agent for and of the transmission owners, i.e., the utilities in Kansas.

The process of determining the revenue requirements starts with the utilities determining their annual transmission revenue requirement ("ATRR"), according to the Tariff. Utilities will determine their ATRR using a FERC-approved Transmission Formula Rate ("TFR") and submit them to SPP as well as to FERC as an informational filing. SPP will then post this ATRR information to its Revenue Requirements and Rates ("RRR") file that is made publicly available for all transmission owners in the SPP footprint and is used to establish SPP's rates for transmission service.

SPP's footprint is separated into multiple transmission pricing zones, and transmission service rates are based on a zonal ATRR that is based on the sum of the ATRR from each utility or transmission owner in a specific zone. Once this ATRR is determined, the Kansas utilities' revenue requirement is based on its load ratio share ("LRS") within SPP.

SPP determines two types of service, Network and Point-to-Point, and charges for service over transmission owner facilities. These revenues collected for the use of the transmission owners' facilities are provided back to transmission owners, with SPP collecting a fee.

a. Highway/Byway

In terms of financial impact, the most significant change to SPP's cost allocation to date has been the development of the Highway/Byway ("HWBW") cost allocation methodology.[4]

[4] Since 2018, stakeholders expressed frustration with SPP's current Highway/Byway cost allocation methodology. Stakeholders recommended that transmission costs instead be fairly allocated between those who sell and use the exported energy, such as

SPP is responsible for cost allocation for new transmission lines, and typically the framework used is referred to as the Highway/Byway methodology. This methodology was developed by the SPP RSC which regroups regulators from all states with member utilities in SPP. The approach seeks to spread the costs of new transmission lines depending on the size and scope of the project, i.e., the larger the project, the greater the contribution from regional utilities.

Pursuant to the HWBW cost allocation methodology,[5] SPP allocates the costs for reliability and economic projects identified in SPP's transmission planning processes among individual SPP pricing zones and to the entire SPP region based on the voltage level and location of the specific facility, as provided in Table A below.

Table A: Highway Byway Cost Allocation Methodology

Voltage	SPP Region Pays Based on Member Utilities' Load Ratio Share	Local Zone Where the Transmission Facility is Located Pays
300 kV and above	100%	0%
above 100 kV and below 300 kV	33%	67%
100 kV and below	0%	100%

i. Exemption for wind

The HWBW cost allocation methodology includes an exception for Base Plan Upgrades that operate at less than 300 kV and are associated with a wind generation Designated Resource that serves load in a zone where the necessary Base Plan Upgrade(s) is not located. This provision was created to help ensure that the costs for Byway line upgrades in areas anticipated to have substantial wind development but that were being designated as Network resources by load in other zones would not be assigned to the zones where the upgrades were constructed. However, the HWBW cost allocation methodology continues to apply to: (1) Base Plan Upgrades that are located within the same zone as the transmission customer's Point of Delivery; and (2) Base Plan Upgrades that operate at 300kV and above.

ii. Allocation by project size

With respect to the new build transmission projects, SPP's HWBW allocation methodology spreads the costs of the transmission line depending on the size and scope of the project. Highway projects are typically above 300 kV, and their costs are spread across the entire SPP footprint on a postage stamp basis, i.e., a single rate across all SPP members. Lower voltage projects (between 100 kV and 300 kV) are split between the SPP region and the local footprint at a ratio of one-third to two-thirds. Projects below 100 kV are borne by the local zone, known as Byway projects.

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through the creation of a unique export pricing mechanism. Additionally, stakeholders discussed the administrative burden required to engage Kansans impacted by proposed regional transmission investments and reach unanimous approval for the project, concluding that the costs necessary to facilitate this process can further impact rates.

[5] On June 17, 2010, the FERC approved the HWBW cost allocation methodology for all Base Plan Upgrades for which SPP issues a Notification to Construct (NTC), with an effective date on or after June 19, 2010. The HWBW methodology does not apply to upgrades identified in SPP's generator interconnection process or the portion of cost of service upgrades identified through SPP's Aggregate Transmission Service Study (ATSS) process that does not qualify as Base Plan Upgrade costs eligible for cost allocation. Furthermore, HWBW only applies to NTCs issued on or after the effective date of HWBW, June 19, 2010.

Costs for region-wide transmission projects are recovered through FERC-approved TFRs, FERC-approved stated rates, or in some cases, state-approved TFR. In 2018, the total ATRR for Kansas represented approximately 17% of the total for the SPP region, which was $110 million, allocated to Kansas ratepayers.

Approved SPP transmission rates consist of the zonal rates, a regional rate and MW-mile rate under the Base Plan Funding mechanism; a postage-stamp rate for the Balanced Portfolio projects, and the possibility of another cost allocation method for an EHV Overlay system. <u>SPP members and staff have expressed concern that these cost recovery methods are fragmented, confusing, and difficult to administer as it requires a complex system to track costs by project over the life of the project</u>. According to SPP 2019 Expansion Report, "[t]he SPPT recommended expanding and including a comprehensive review of all cost allocation methodologies for possible consolidation under a unified system using the recommended 'highway-byway' approach."
To address concerns with cost allocation, among other issues, across the SPP footprint, in 2019, SPP commissioned the HITT to assess and recommend actions. The HITT report recommended a byway facility cost allocation review process, whereby specific projects between 100 kV and 300 kV can be allocated on a highway basis. Under this recommendation, additional consideration would be given to regional benefits that result from these transmission projects, "including energy exports from the transmission pricing zone where each project is located." This recommendation was implemented.

SPP stated that for Base Plan Upgrades associated with Designated Resources that are wind generation resources where the upgrade is located in a different zone than the point of delivery, the HWBW method will only apply if the facility operates at 300 kV and above. In such case, 100 percent of the costs will be allocated regionally. However, if the upgrade operates at less than 300 kV (including those operating at or below 100 kV), 67 percent of the costs of the upgrade will be allocated regionally, with the remaining 33 percent allocated to the transmission customer.

b. Impact of Uptick in Renewables on Highway/Byway

There has been a significant increase in renewable generation, predominantly wind, throughout the SPP region. While most zones have seen some wind generation additions, a few zones have been disproportionately affected, primarily because of the high quality of wind resources in those zones. Unlike traditional generation sources, renewable generation is not located close to the load it serves, but rather, is remotely located where the renewable energy resource is abundant. This has resulted in some generation-rich zones having nameplate generation capacity in excess of 500% of the peak demand for load inside the zone. There is evidence that this can contribute to increased loading on both highway and byway facilities inside these zones. In addition, the IM, launched in 2014, coupled with abundant wind resources, attracted a significant amount of wind generation investment in SPP.

A significant number of these resources have not been designated as network resources under network transmission service nor in the alternative affiliated Point-to-Point Transmission Service. Historically, the ITP process generated much larger amounts of new transmission than the other two processes especially in zones with high renewable resources penetration. Zones with an abundance of generation in comparison to that which is needed to serve load can have a significant risk of this misalignment of costs and benefits. In some generation-rich zones, byway facilities have been identified as needed through the ITP even though native load within these zones has remained stable or decreased. In the ITP, 67% of the byway facility cost is allocated to the local zone. This cost allocation percentage is intended to be roughly commensurate to the benefit of these upgrades to that zone. However, in some zones with high levels of generation as compared to load, upgrades identified in the ITP are being used regularly on a more regional basis. In such cases, allocating 67 percent of the cost of an upgrade may not be roughly commensurate with the benefits received and thus it may be more appropriate that such lines be regionally cost allocated.

Kansas customer interests should consider whether to argue that SPP should evaluate creating a narrow process through which costs for specific projects between 100 kV and 300 kV can be fully allocated prospectively on a region-wide basis. The process should take into consideration regional benefits resulting from the facilities, including energy exports from the transmission pricing zone where each project is located. Under this approach, costs for a byway-funded transmission upgrade could be funded using a region-wide allocation after meeting certain criteria under a narrow review process. Projects eligible for this narrow process must be base plan upgrade costs eligible for cost allocation under the SPP tariff. This could include new or existing Schedule 11 facilities and costs that are directly assigned shall not be eligible for this review. This process could be administered through a request for waiver of the cost allocation that otherwise would be applicable. Information concerning the specific upgrade(s) must be submitted to SPP for such costs to be considered for full regionwide allocation. The process for review and approval of the requests could conceptually follow the current processes for addressing waiver requests related to upgrades for transmission service and for transformers.

c. General Pass Through and Cost Recovery Mechanisms

All Transmission Customers are required to purchase two services from the Transmission Provider based on the charges in Schedules 1 and 2. Each Transmission Owner must maintain a schedule showing the charges for such services. Any amounts charged the Transmission Provider by a Transmission Owner for such service shall be passed through to the Transmission Customer without mark-up.

Schedule 1A charges are assessed by SPP directly to the transmission customers and are retained by SPP. Schedule 12 revenues associated with Transmission Service are collected by SPP and remitted to FERC by SPP. Any Schedule 1A or Schedule 12 revenues collected by Empire on behalf of Zonal customers are simply passed through to SPP.

The Cost Allocation Working Group determined in 2019 that the current cost allocation methodology and/or rate recovery mechanism in zones with a high proportion of generation relative to zonal load is not reflective of cost causation principles.

Separately, the RSC’s Balanced Portfolio methodology allows for 100% of the revenue requirement for the Balanced Portfolio (including revenue requirements for economic upgrades in the portfolio and any revenue requirements associated with reliability upgrades included in the portfolio to achieve balance) to be recovered through SPP’s postage-stamp based region-wide charge. The region-wide postage-stamp charge will be assessed to all load, including resident load and transmission customers taking point-to-point transmission service under SPP’s Tariff.

i. Basic Cost Allocation and Recovery Mechanisms

- License plate: each utility recovers the costs of its own transmission investments (usually located within its footprint).
- Beneficiary pays: various formulas that allocate costs of transmission investments to individual Transmission Owners (TOs) that benefit from a project, even if the project is not owned by the beneficiaries. TOs then recover allocated costs in their License Plate tariffs from own customers.

- Postage stamp: transmission costs are recovered uniformly from all loads in a defined market area (e.g., RTO-wide in ERCOT and CAISO). In some cases (e.g., SPP, MISO, PJM) cost of certain project types are allocated uniformly to TOs, who then recover these allocated costs in their License Plate tariffs.
- Direct assignment: transmission costs associated with generation interconnection or other transmission service requests are fully or partially assigned to requesting entity. Innovative variance: Tehachapi LCRI (up-front shared funding, later charged back to generators)
- Merchant cost recovery: the project sponsors recover the cost of the investment outside regulated tariffs (e.g., via negotiated rates with specific customers); largely applies to DC lines where transmission use can be controlled.
- Co-ownership: benefitting transmission owners co-own the facility (each recovering costs through rate base treatment); one operator; shared transmission rights (often used in WECC)

ii. Who Pays for Transmission Projects

- Sponsored: Project owner builds and receives credit for use of transmission lines
- Directly assigned: Project owner builds and is responsible for cost recovery and receives credit for use of transmission lines
- Highway/Byway: Most SPP projects paid for under this methodology

Voltage	Region Pays	Local Zone Pays
300 kV and above	100%	0%
Above 100 kV and below 300 kV	33%	67%
100 kV and below	0%	100%

Evergy's Capital Investment Plan discussed above does not break down the budgeted transmission investment for 2022 through 2026 by voltage level, but they provided estimates in their December 2020 Sustainability Transformation Plan. In that plan, for specifically identified facility investment for 2020 through 2024, they estimated approximately 35 percent would be for facilities 100 kV and below (for which Evergy local zone customers would be 100% responsible), approximately 60 percent for facilities above 100 kV and below 300 kV (for which Evergy zone load would pay 67 percent) and the remaining 5 percent above 300 kV.

It is not a direct comparison, but among all network transmission upgrades completed in SPP in 2021 (which generally does not include 100 kV and lower voltage upgrades, which are not included in the SPP transmission expansion plan), approximately 45 percent of the costs of such upgrades were for highway (above 300 kV) upgrades.[6] Thus, it appears that Evergy's transmission plans include a significantly higher percentage of costs allocated to local zonal load than for SPP as a whole.

iii. Stranded Cost Recovery

The Tariff does not affect the right of any Transmission Owner to seek and receive stranded cost recovery or the right of anyone to oppose such stranded cost recovery. Thus, the Transmission Owner(s) may seek to recover

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[6] See https://www.spp.org/documents/56611/2022%20spp%20transmission%20expansion%20plan%20report.pdf .

stranded costs from the User(s) in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However, Transmission Owner(s) must separately file any specific proposed stranded cost charge under Section 205 of the Federal Power Act. If the Commission approves stranded cost charges to be recovered through schedules to be implemented by the Transmission Provider, the Transmission Provider as agent for the Transmission Owner(s) shall charge and collect the appropriate charge(s) from the relevant User(s) and distribute the appropriate amounts directly to the relevant Transmission Owner(s).

iv. Review of Base Plan Allocation Methodology

The Transmission Provider shall review the reasonableness of the regional allocation methodology and factors (X% and Y%) and the zonal allocation methodology at least once every six years. The Transmission Provider and/or the Regional State Committee may initiate such review at any time. Any change in the regional allocation methodology and factors or the zonal allocation methodology shall be filed with the Commission. Transmission Provider shall determine the cost allocation impacts of the Base Plan Upgrades approved for construction after June 19, 2010 to each pricing Zone within the SPP Region. The Transmission Provider in collaboration with the Regional State Committee shall determine the cost allocation impacts and the results produced by the analytical methods.

3. SPP Membership Requirements and Withdrawal Rights

a. Membership Fees and Withdrawal Process Under SPP Bylaws

- Annual Membership Fee. All SPP Members will be subject to an annual membership fee in the amount of $6,000, or other amount established by the Board of Directors. Membership fees are not subject to refund. The Board of Directors shall determine the annual membership fee for the upcoming year in advance of the last meeting. Legitimate public interest groups (e.g. consumer advocates, environmental groups, or citizen participation groups) may seek a waiver of the annual membership fee.

- Existing Financial Obligations (set forth in the Bylaws):
    - Member’s unpaid annual membership fee,
    - Member’s unpaid dues, assessments, and other amounts charged under Section 3.8 of this Agreement, Section 8.4 of the Bylaws, or otherwise under the Bylaws, plus the Member’s share of costs SPP customarily includes in such dues, assessments or other charges, but which as of the Termination Date SPP had not included in such dues assessments or other charges.
    - Any costs, expenses or liabilities incurred by SPP directly due to the Termination, regardless of when incurred or payable.
    - A Transmission Owner Member’s Existing Obligations shall also include:
    - the Member’s share of all interest that will become due for payment with respect to all interest bearing Financial Obligations after the Termination Date and until the maturity of all Financial Oblations in accordance with their respective terms (“Future Interest”). In the event that a Financial Obligation carries a variable interest rate, the interest rate in effect at the Termination Date shall be used to calculate the applicable Future Interest. In determining the Member’s share of Future Interest, SPP shall take into account any reduction of Financial Obligations.

- Notice of Voluntary Withdrawal and Deposit. A Member submitting a written notice of its intent to withdraw must simultaneously submit a cash withdrawal deposit to SPP. Load serving entities must pay $ 150,000 and Non-Load Serving Entity $ 50,000.

- SPP will not accept a notice of intent to withdraw without a withdrawal deposit. SPP will treat the withdrawal deposit as a pre-payment of a portion of the costs SPP incurs to process the Member's withdrawal from SPP or the costs associated with reintegrating the Member into SPP if the Member subsequently rescinds its notice of intent to withdraw and SPP incurs costs to reintegrate the Member.

- If the cost of processing the Member's withdrawal exceeds the withdrawal deposit, the additional amount shall be included in the invoice SPP provides to the Member. If the Member rescinds its notice of intent to withdraw and the cost of processing the Member's withdrawal and subsequent reintegration into SPP exceeds the withdrawal deposit, SPP shall invoice the Member for the amount of the cost that exceeds the deposit. If the withdrawal deposit exceeds the costs of processing the Member's withdrawal and/or reintegration, SPP shall refund the difference to the Member.

- Monthly Assessments Costs. SPP will assess certain Members on a monthly basis all costs not otherwise collected. Costs recovered under the assessment will include but are not limited to all operating costs, financing costs, debt repayment, and capital expenditures associated with the performance of SPP's functions.

    - Significant among these are costs associated with regional reliability coordination and the provision of transmission service. SPP shall determine the assessment rate based on its annual budgeted net expenditures divided by estimated annual Schedule 1 billing units for service sold under SPP's Tariff and Member load. The monthly assessment shall be assessed on each Member for the portion of their Member load eligible for service but not currently taking Network Integration Transmission Service or Point-To-Point Transmission Service under the SPP Tariff. The intent is that each Member be obligated to pay, at a minimum, the amount due under its monthly assessment as calculated above.

- Financial Obligation of Withdrawing Members. Computation of a Transmission Owner Member's Existing Obligations For purposes of computing the Existing Obligations of any withdrawing or terminated Transmission Owner, such "Member's share" is a percentage calculated as follows:

    A = 100 [0.25(1/N) + 0.75(B/C)]
    Where: A = Member's share (expressed as a percentage)
    N = Total number of Transmission Owner Members that are subject to Sections 4.3.2(b)-(f) of the Membership Agreement
    B = The previous year Net Energy for Load connected to transmission facilities of Transmission Owner Member, including any such load of other load serving entities
    C = Total of factor B for all Transmission Owner Members that are subject to Sections 4.3.2(b)-(f) of the Membership Agreement

    - The Finance Committee shall have the discretion to reduce the Existing Obligations of any withdrawing or Terminated Member or of any Member submitting a notification of Partial Termination to reflect any SPP costs or expenses that may be mitigated in connection with such Member's withdrawal, termination, or Partial Termination. In the event of consolidation of affiliate memberships or the transfer of membership from one corporate entity to another, whereby one entity remains a member of SPP, the withdrawal obligation for the departing company(ies) may be waived at SPP's sole discretion.

- Financial Obligations for Transmission Facilities. A Terminated Member and a Member submitting a notice of Partial Termination shall remain financially responsible for all financial obligations incurred and costs allocated to its load for transmission facilities approved prior to the Termination Date.

- Penalty Costs. A Terminated Member and a Member submitting a notice of Partial shall remain liable for its share of costs associated with penalties assessed against SPP by FERC, the FERC-approved Electric Reliability Organization, any Electric Reliability Organization-approved Regional Entity, or any other governmental or regulatory authority with jurisdiction over SPP that SPP incurs as a result of events that occurred prior to Member's Termination Date but that SPP is unable to recover under the SPP Tariff.

- Termination Procedures and Effective Dates. A Member may withdraw voluntarily from their Agreement, provided that it has given written notice to the President of its intent to withdraw. Notice of intent to withdraw must state a proposed date for the withdrawal and be delivered to the President no less than twenty-four (24) months prior to such date. In order to assure that there is no more than one proposed termination date with respect to a Member, a withdrawal notice shall be deemed to supersede any prior withdrawal notice given by the Member, except that a Member may not submit a withdrawal notice less than twenty-four (24) months prior to the termination date proposed in the Member's previous notice of intent to withdraw. Voluntary withdrawal is a Termination and creates the same obligations as a Termination for any other reason. Upon receiving a notice of intent to withdraw, SPP shall account for such notice of intent to withdraw in the SPP planning process, unless the Member plans to continue to take transmission service from SPP after the termination date.

    - If the withdrawing Member is a Transmission Owner subject to FERC jurisdiction, the Termination Date shall be the later of (i) the proposed date specified in the withdrawal notice or otherwise agreed by SPP, (ii) the effective date, if any, set by the FERC order approving the withdrawal; or (iii) the date that such FERC order is no longer subject to review by a court of competent jurisdiction.

4. Areas for Possible Rate Mitigation

- Certain recovery. According to the 2019 retail rate studies conducted by the KCC and the Evergy utilities, utilities and KCC staff cited increased transmission investments resulting from SPP-directed transmission expenditure as a driver for increased rates. Also, the transmission delivery charge ("TDC") is a charge passed on to customers to recover SPP-assessed service for the utility's retail load. The TDC is based on the SPP ATRR, and KCC staff have noted that it includes a higher return on equity ("ROE") than those allowed by the regulator.

    - According to the 2019 studies, the impact of key factors driving the rise in rates was quantified. For example, KCC staff analysis indicated that 60% of Westar's rate increases were driven by environmental retrofits and transmission investments. For KCP&L, environmental retrofits, transmission charges, and increased power production costs were responsible for 62% of rate increases.

- As of 2019, Kansas contains the SPP transmission zones with both the highest and lowest ATRR per member of the service population. The difference in revenue requirements by zone correlates to the service population densities through the SPP region. The general trend indicates that more populous urban zones benefit from economies of scale in the provisions of transmission infrastructure to their service area.

  - For both Kansas and non-Kansas SPP zones, the ATRR grew from 2010 to 2019 but the average transmission investment per member grew at a slower rate in the Kansas SPP zones than in the non-Kansas SPP zones. This does not explain the high electric rate in Kansas compared to the regional average.

- Highway/byway. Many stakeholders expressed frustration with SPP's current Highway/Byway cost allocation methodology. Stakeholders recommended that transmission costs instead be fairly allocated between those who sell and use the exported energy, such as through the creation of a unique export pricing mechanism. Additionally, stakeholders discussed the administrative burden required to engage Kansans impacted by proposed regional transmission investments and reach unanimous approval for the project, concluding that the costs necessary to facilitate this process can further impact rates.

- Further division with wind. Transmission investments in Kansas have been roughly equal to those of the entire SPP transmission service area when estimated by service population membership. However, transmission infrastructure for exports cannot easily be isolated from transmission infrastructure for intrastate transmission because capital investments anywhere in the grid can carry electricity to and from interconnected nodes. The same lines that carry electricity from a wind farm to an urban area in Kansas can also be used to export to or import from another state.

IV. FERC Matters Affecting Kansas Retail Rates

1. FERC

FERC has exclusive jurisdiction over interstate transmission rates and the terms of service contained in the SPP Tariff. States are preempted from modifying transmission rates approved by FERC and Kansas utilities are thus permitted to pass through their FERC-jurisdictional transmission charges. Given that transmission costs are one of the primary drivers of increases in retail rates in Kansas, this highlights the importance of customer interests taking a more active role in FERC rate and tariff matters.

Aside from general rate and tariff regulation, FERC has undertaken several recent matters that could have a material impact on Kansas rates. Those matters are discussed below.

2. FERC Notice of Proposed Rulemaking on Transmission Planning and Cost Allocation Methodology Changes

a. Overview

On April 21, 2022, FERC issued a Notice of Proposed Rulemaking ("NOPR") to improve regional transmission planning and cost allocation of certain types of transmission.[7] The NOPR builds upon prior FERC Order 888 from 1996, Order 890 from 2007 and Order 1000 from 2011, and is intended to remedy observed deficiencies in the FERC's existing regional transmission planning and cost allocation requirements.

[7] Notice of Proposed Rulemaking, titled "Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection" under Docket No. RM21-17-000 (April 21, 2022) (hereinafter "NOPR").

Since issuing Order No. 1000 more than ten years ago, FERC is now proposing new rules for regional transmission planning and cost allocation after "mounting evidence" that existing planning processes are inadequate to meet transmission needs of the future.[8] In the NOPR, FERC proposed a series of reforms to build on its existing body of landmark transmission rulemaking.

The Commission believes that the current regional transmission planning process is not optimized to coordinate the interconnection and transmission of energy from renewable generation that is anticipated to be connected to the grid at an increasing rate over the coming years.[9] Due to the lack of regional transmission planning and cost allocation, the grid is currently being expanded on a more localized level through interconnection-related network upgrades resulting from one-off generator interconnection requests.[10]

The NOPR proposes to remedy these possible shortcomings by requiring transmission providers to participate in a regional transmission planning process that includes "Long-Term Regional Transmission Planning." FERC describes this as regional planning on a sufficiently long-term, forward-looking basis that would include the identification of transmission needs driven by changes in resource mix and demand, and the evaluation and selection of projects to meet those needs.[11] FERC's vision for Long-Term Regional Planning involves a multi-pronged set of reforms.

Further, FERC states in the NOPR that reforms to public utility transmission providers' regional cost allocation methods are necessary to ensure that Commission-jurisdictional rates are just and reasonable and not unduly discriminatory or preferential. However, the most readily recognizable impediment to the build out of regional transmission facilities is identifying and implementing a cost allocation methodology that is recognized as just and reasonable and may encompass several states. As a result, the NOPR contains proposed cost allocation modifications.

b. Proposed Changes to Regional Transmission Cost Allocation

A. State involvement. The regional transmission cost allocation section of the NOPR emphasizes state involvement. Specifically, the NOPR proposes to require public utility transmission providers to seek agreement regarding cost allocation methods from relevant state entities within the applicable transmission planning region.

According to the NOPR, each transmission provider would be required to do the following:

1. Seek the agreement of relevant state entities within the transmission planning region regarding the cost allocation for transmission facilities selected as part of long-term regional transmission planning.

2. Establish a cost allocation method for transmission facilities selected as part of long-term regional transmission planning that is an ex ante cost allocation method, State Agreement process by which one or more relevant state entities may voluntarily agree to a cost allocation method, or a combination thereof.

[8] *Id.* at P 24.

[9] *Id*. at P 13, 24, 29.

[10] *See generally* NOPR; *see also id.* at 22.

[11] *Id.* at 24.

3. Establish a cost allocation method for transmission facilities selected as part of long-term regional transmission planning that complies with the existing six Order No. 1000 regional cost allocation principles.

In developing and obtaining state agreement on the cost allocation methodology, the providers would revise their Open Access Transmission Tariffs ("OATTs") to include agreed upon methods such as:

1. A long-term regional transmission cost allocation method, i.e., an *ex-ante* cost allocation method that would be included in the OATT and utilized by the developer of a long-term regional transmission facility;
2. A State Agreement Process, which FERC proposes to define as an *ex-post* cost allocation process that would be included in the OATT which could be followed to establish a cost allocation method for a particular facility, if agreement can be reached;
3. Or some combination thereof, so long as either cost allocation methodology complies with the six existing Order No. 1000 cost allocation principles.[12]

Once regional transmission providers and states come to an agreement on which of the three options to use, the NOPR proposes to have transmission providers file state-agreed cost allocations for specific projects with FERC under Section 205 of the Federal Power Act ("FPA").[13]

B. Alternative method and OATT revisions. The NOPR further proposes to require public utility transmission providers in each transmission planning region to establish a process detailed in their OATTs to add a time period for states to negotiate an alternate cost allocation method for a transmission facility selected in the regional transmission plan for purposes of cost allocation that is different from any *ex ante* regional cost allocation method that would otherwise apply. If the state(s) can agree upon an alternate cost allocation methodology during the relevant time period (e.g., 90 days), then the public utility transmission provider may elect to file the agreement with the Commission for consideration under Section 205 of the FPA.[14]

c. Proposed Changes to Transmission Planning

The transmission planning section of the NOPR includes timeframe, identification of needs, evaluation of facility benefits, and increased transparency. Generally, transmission providers would be required to identify transmission needs based on changes in resource mix and demand via long-term scenarios that meet the requirements set forth in the NOPR. They would further be required to assess the benefits of regional transmission facilities to meet the identified needs over a minimum timeframe of 20 years from the in-service date of the given facilities. The NOPR also proposes to mandate the establishment of transparent and not unduly discriminatory criteria to select transmission facilities and further coordination between regional and local transmission planning to identify "right-size" replacement transmission facilities.[15] Certain technologies such as dynamic line ratings and advanced power flow control devices would also need to be considered.[16]

[12] *Id.* at P 32, n.509.
[13] *Id.* at P 319.
[14] *Id.* at P 320.
[15] *Id.* at P 3.
[16] *See generally id.* at Section VIII.

A. Timing and needs. According to the NOPR, transmission providers would be required to:

- Conduct regional transmission planning on a sufficiently long-term, forward-looking basis to meet transmission needs driven by changes in the resource mix and demand;
- Identify transmission needs through multiple long-term scenarios that incorporate a minimum set of factors, such as federal, state and local laws and regulations that affect the future resource mix and demand, trends in technology and fuel costs, resource retirements, generator interconnection requests and withdrawals, and extreme weather events;
- Consider a proposed list of broader set of benefits of regional transmission facilities to meet these long-term transmission needs for the purposes of selection and cost allocation;
- Establish transparent and not unduly discriminatory or preferential criteria which seeks to maximize benefits to consumers over time without over-building transmission facilities to select transmission facilities in the regional plan for purposes of cost allocation that address these long-term transmission needs; and
- Consider dynamic transmission ratings and more modern flow-control technology and practices in formulating their transmission plans.

B. Evaluating benefits*:* Under FERC's proposed framework, once a public utility transmission provider in a transmission planning region identifies the region's transmission needs driven by changes in the resource mix and demand, it will need to evaluate the benefits of those regional facilities for purposes of selection and cost allocation. FERC is proposing requiring transmission providers to clearly identify the benefits considered for that evaluation and how they are calculated. To that end, FERC proposed a broad set of benefits transmission providers could consider and may give transmission providers the option to evaluate benefits based on a portfolio of facilities as opposed to on a facility-by-facility basis.

d. Proposed Amendments to Order No. 1000: Right of First Refusal

The NOPR proposes to amend Order No. 1000 to permit the exercise of a federal rights of first refusal for transmission facilities selected in a regional transmission plan for purposes of cost allocation, conditioned on the incumbent transmission provider establishing joint ownership of those facilities.[17]

Transmission development and planning are fundamentally long-term activities, especially where local disapproval exists. Thousands of megawatts of renewables—both offshore and onshore—are "queued" for interconnection, some of the organized market entities that FERC regulates have experienced extraordinary delays in processing interconnection applications and several states (e.g., New York and New Jersey) are proceeding with their own significant transmission development efforts. The NOPR does not explicitly address the significant interconnection backlog. Until FERC recognizes the backlog, it may be difficult to bring increased capacity and efficiency to the grid needed to improve reliability and resiliency of the bulk power system. This could be an area where Kansas consumer interests should consider submitting comments on the NOPR (which are initially due July 5, 2022, and reply comments are due August 4, 2022).

2. FERC Demand Response and Distributed Generation Initiatives

FERC has undertaken two initiatives in wholesale power markets that aim to reduce barriers to entry to non-traditional types of resources, which makes the markets more competitive and ideally lowers wholesale

[17] *Id.* at Section VII.

prices. A reduction in wholesale prices would result in lower retail prices to customers as well. The two initiatives involve allowing non-traditional types of resources – demand response and distributed energy resources ("DER") and DER aggregations - to compete in the organized energy markets administered by ISOs and RTOs. In order to allow demand response resources to provide market benefits, FERC Order No. 745 required regional grid operators to compensate demand response providers for reducing electricity load at the same rates as if they met that demand with generated electricity.[18] In order to remove the barriers for DERs to compete in the organized capacity, energy and ancillary services markets, FERC issued Order No. 2222 which requires regional grid operators to revise their tariffs to establish DER aggregations as a category of market participant.[19]

a. Order No. 745

FERC enacted Order No. 745 in order to ensure the competitiveness of the wholesale energy markets, remove barriers to the participation of demand response resources, and ensure just and reasonable wholesale rates. Demand response is the reduction in the consumption of electric energy by customers for their expected consumption in response to an increase in the price of electric energy or incentive payments designed to lower consumption of electric energy; a demand response resource means a resource capable of providing demand response.

Order No. 745 required RTOs to pay demand response resources the locational marginal price ("LMP") for energy when: (1) the demand response resource has the capability to balance supply and demand as an alternative to a generation resource; and (2) dispatch of the demand response resource is cost-effective as determined by a net benefits test outlined in the order.[20] The net benefits test, which determines the point at which compensating a demand response resource at the market price is cost effective, requires each RTO to determine the price level at which the dispatch of the demand response resources lowers the LMP sufficiently to offset the additional cost to load of compensating the resource at full market price.[21]

i. Implementation in SPP

SPP filed a compliance filing with Order No. 745's net benefits test and cost allocation requirements for SPP's Energy Imbalance Service ("EIS") Market, and it was accepted by FERC in a letter order on December 13, 2013.[22]

However, the implementation of Order No. 745 by SPP was complicated due to the fact that while the compliance filing was pending, SPP proposed revisions to its Tariff to transition from its Real-Time EIS Market to the SPP Integrated Marketplace. In a series of orders, FERC directed SPP to incorporate into its Integrated

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[18] *Demand Response Compensation in Organized Wholesale Energy Markets*, Order No. 745, 2008–2013 FERC Stats. & Regs., Regs. Preambles ¶ 31,322, *order on reh'g & clarification*, Order No. 745-A, 137 FERC ¶ 61,215 (2011), *reh'g denied*, Order No. 745-B, 138 FERC ¶ 61,148 (2012), *vacated*, *Elec. Power Supply Ass'n v. FERC*, 753 F.3d 216 (D.C. Cir. 2014), *rev'd & remanded*, 136 S. Ct. 760 (2016).

[19] *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 2222, 172 FERC ¶ 61,247 (2020), *order on reh'g*, Order No. 2222-A, 174 FERC ¶ 61,197, *order on reh'g and clarification*, Order No. 2222-B, 175 FERC ¶ 61,227 (2021).

[20] Order No. 745 at PP 2, 47-48.

[21] Id. at PP 3-4, 79-80.

[22] *Sw. Power Pool, Inc.*, Letter Order, Docket No. ER11-4105-001 (Dec. 20, 2013).

marketplace Tariff any provisions that would be appropriate in light of the requirements of Order No. 745. In a 2014 compliance filing, SPP proposed cost allocation and net benefits test methodologies similar to those accepted by FERC for the EIS Market. SPP noted that the methodology would have to be adjusted once SPP had access to a full year of Integrated Marketplace data and proposed the use of the EIS Market methodology as a transitional measure.[23] The Integrated Marketplace commenced operation on March 1, 2014.

A further series of FERC orders and compliance filings were made, and FERC ultimately ordered SPP to change the net benefits test methodology to use all available offer data and include non-peak hour data in the construction of supply curves, and that the calculation should first average the supply curves and then smooth the average curve. On July 3, 2018, SPP ultimately filed revisions to Section 3.9 of Attachment AE of its Tariff to incorporate two design changes required by FERC: (1) adjust its net benefits test methodology to use all available offer data and include non-peak hour data in the construction of supply curves, and (2) first average the supply curves and then smooth the resulting average curve when performing the net benefits test.

In 2018, SPP represented to FERC that it had not experienced load-reduction demand response activity in the Integrated Marketplace. It appears that demand response resources have not had much of an impact on the SPP markets; however, there is the potential for these resources to be utilized to a greater extent, especially in light of the fact that in late 2019 a demand response aggregator of retail customers, Voltus, entered SPP's integrated market.

b. Order No. 2222

In September 2020, FERC issued Order No. 2222 after determining that current market rules in ISOs and RTOs designed for traditional resources can create barriers to entry for emerging technologies. FERC deemed these barriers unjust and unreasonable due to the fact that may restrict efficient deployment of resources and the competitiveness of wholesale markets. Order No. 2222 requires RTOs and ISOs to allow DER[24] aggregations to participate directly in wholesale markets. It requires RTO and ISO tariffs to be amended to include a number of provisions, including provisions to: allow DER aggregations to participate directly in markets and establish DER Aggregators as a type of Market Participant; allow DER Aggregators to register DER aggregations under one or more participation models that can accommodate the physical and operational characteristics of the DER aggregation; establish minimum size requirements for DER aggregations that does not exceed 100 kW; and address coordination between the ISO/RTO, the DER Aggregator, the distribution utility, and the relevant electric retail regulatory authority.

i. Implementation in SPP

On April 28, 2022, SPP filed its Order No. 2222 Compliance Filing in FERC Docket No. ER22-1697-000. SPP requested that FERC issue a final order by December 31, 2022 in order for it to develop the processes necessary to implement the changes with a target date of the third quarter of 2025 for implementation. SPP stated that it would provide a specific date not less than six months prior to implementation.

[23] Submission of Tariff Revisions to Implement Order No. 745 in the SPP Integrated Marketplace of Southwest Power Pool, Inc., Docket No. ER12-1179-016 (submitted Jan. 22, 2014).

[24] FERC defined a "distributed energy resource" as "any resource located on the distribution system, any subsystem thereof or behind a customer meter. These resources may include, but are not limited to, electric storage resources, distributed generation, demand response, energy efficiency, thermal storage, and electric vehicles and their supply equipment." Order No. 2222, 172 FERC ¶ 61,247, 62,722, fn. 1 (2020).

The implementation of Order No. 2222 will not occur in SPP several years; however, at that time, there may be opportunities for cost savings because DERs and DER aggregators could potentially add competitive alternatives to the market, bringing down the costs of wholesale transmission.

4. FERC, NERC and SPP Enforcement Activity

Overview

In 2006, FERC approved the North American Electric Reliability Corporation ("NERC") as the Electric Reliability Organization under section 215(e)(4) of the FPA. NERC oversees and enforces Reliability Standards; monitors the Bulk-Power System; assesses adequacy annually via a 10-year forecast; audits owners, operators and users for preparedness; and educates and trains industry personnel. NERC delegates its authority to monitor and enforce compliance of Reliability Standards to Regional Entities ("RE") established across North America, since each geographic segment of the U.S. maintains a different electric footprint.

The Southwest Power Pool Regional Entity ("SPP RE") was an independent and separate division of SPP, Inc. – the RTO – that assessed regional reliability and monitored and enforced compliance with Reliability Standards for the region that included Kansas.

In 2018, federal regulators approved a joint petition to dissolve SPP RE and to transfer the registered entities and Members within the SPP RE footprint to the Midwest Reliability Organization ("MRO") and SERC Reliability Corporation, though MRO is the entity covering Kansas. SPP and NERC mutually agreed on this termination to reflect the organizations' changing geographic footprints. Today, SPP is just an RTO and not a RE, and MRO is required to monitor and ensure SPP Members and the electric entities in Kansas maintain compliance with both NERC and FERC's Reliability Standards.

Below is a summary of the roles and responsibilities across each agency and the REs, the enforcement process, whether penalty fines associated with compliance and enforcement are passed through to RTO/ISO Members, and recent enforcement or compliance examples. In sum, RTOs/ISOs may be responsible for the costs of penalties for violating Reliability Standards, if the participating Members cannot be connected to the alleged violation and if FERC denies an RTO/ISO request to allocate the penalty costs.

1) Roles and Responsibilities

FERC. FERC is an independent agency that regulates interstate transmission of natural gas, oil, and electricity and natural gas and hydropower projects. FERC oversees NERC via authority provided by the 2005 Energy Policy Act.

In 2007, FERC Order No. 693 approved "version 0" Reliability Standards, which became enforceable in June 2007. Since then, FERC has approved new and revised standards. Enforcement of these standards forms the foundation of NERC's and FERC's efforts to maintain and improve Bulk Electric System ("BES") reliability.

NERC. NERC is the regulatory authority that evaluates and improves BES reliability. NERC does this by: 1) developing and enforcing reliability standards; 2) assessing seasonal and long-term reliability; 3) monitoring BES through system awareness; and 4) training and certifying industry personnel. NERC delegates oversight and enforcement authority to six Regional Entities.

Regional Entities and Registration. NERC delegates compliance and enforcement authority to six Regional Entities ("REs") , although some load serving entities participate in one RE and their associated transmission owner/operators in another.

REs are authorized to find violations and levy NERC penalties against the entities they monitor for non-compliance, including the RTO/ISO directly or its Members depending on the facts of the violation.

Approximately 120 entities were registered with SPP RE. After performing a transmission corridor analysis and considering the functional relationships between registered entities, NERC transferred 109 SPP RE Registered Entities to MRO (including all of SPP's Kansas Members) and 14 to SERC, with one entity to be registered in both MRO and SERC.

2) RE Compliance and Enforcement

Generally, the RE monitors compliance with the Reliability Standards through a variety of methods such as self-reporting, self-certifications, audits, spot checks, data submittals, complaints, and investigations. Potential noncompliance issues are primarily discovered through audits, spot checks, self-certification, and self-reports.

The RE may impose a penalty on a user, owner or operator of the Bulk-Power System for a violation of a Reliability Standard if the RE, after public notice and opportunity for hearing, finds that the user, owner or operator has violated a Reliability Standard and files notice with the Commission. *See* Final Rule, Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards, Docket No. RM05-30-000; Order No. 672 (2006) ("Order No. 672").

In Order No. 672, FERC directs NERC, through the REs, to propose a formula or method of funding payments for violations that addresses cost allocation and cost responsibility, along with a proposed mechanism for revenue collection for Commission consideration. *Id.* And as discussed below, those facing the Notice of Violation may propose their own method of penalty allocation, which FERC will review.

3) Allocation of Costs Associated with NERC Reliability Penalty Assessments

As non-profit, revenue-neutral entities, RTOs/ISOs do not generally maintain the reserves to pay monetary penalties assessed for violations of Reliability Standards. However, the Commission will look to certain factors to determine if penalty costs are assigned to the RTO/ISO directly or allocated across different Members and will make this determination on a case by case basis. *See* Reliability Standard Compliance and Enforcement in Regions with Regional Transmission Organizations or Independent System Operators, 122 FERC ¶ 61,247, at PP 16, 21-27 (2008) ("Guidance Order"); *Southwest Power Pool, Inc.*, Docket No. ER19-2362-000 Reliability Penalty Cost Recovery and Request for Confidential Treatment at PP 4-5 (filed July 9, 2019) ("SPP Penalty Cost Recovery Filing").

Therefore, all or some Members may be responsible for all or partial penalty costs assessed against the RTO/ISO if it is determined that the Members are responsible, directly contributed, or are tangentially affiliated with the confirmed violation of any NERC Reliability Standard. *See* NERC Rules of Procedure, Appendices 4B "Sanction Guidelines" and 4C "Uniform Compliance Monitoring and Enforcement Program" at Section 5.11.

While all Members may potentially be responsible for all or partial reliability penalty costs assessed in the event that the Member's conduct or omission contributed to the violation(s) for which a monetary penalty was assessed to RTO/ISO, the Commission has rejected RTO/ISO requests for blanket cost recovery mechanisms. *See* SPP Penalty Cost Recovery Filing at p 3 (citing Order No. 672 at PP 634-35; Order No. 672-A at PP 55-58).

This example of penalty cost allocation demonstrates how SPP may take responsibility for penalty costs itself rather than assigning costs to its Members, which benefits Kansas utilities. Cost allocation proposals such as SPP's are evaluated on a case by case basis, but this case does show that there are protections for Members and their customers that do not contribute to Reliability Standard violations. Furthermore, the fact that FERC rejected RTO/ISO requests for blanket recovery of penalty costs affords a level of protection for state level entities and Members.

V. Retail Competition

Kansas has not approved retail competition for electric power supplies. States that have adopted retail competition have generally seen reductions in rates, but any determination of the specific impacts of retail competition would require a detailed analysis of the Kansas customer and generation profile. Note that retail competition only affects the generation portion of a customer's bill. Even customers that shop for alternative supplies must pay the host utility's transmission and distribution charges. Retail competition would not help with increases in transmission costs. Moreover, retail competition can have significant adverse cost consequences if customers are charged market prices. For example, in the February 2020 Texas freeze, some retail customers were charged rates several hundred times higher than their typical rates, due to wholesale price spikes caused by supply limitations. Any retail competitor study should very carefully consider a structure that effectively protects retail customers from such market spikes.

As noted in the January 2020 rate study, the transition to any form of retail competition can be expected to take up to ten years to implement and must be very carefully structured to avoid some of the problems that developed in Texas and California. The first step in this process would be a detailed study to determine whether and in what form retail competition makes sense for Kansas.

Among the issues to be considered in any such study are:

- Whether to introduce competition for all customers or to limit it to only commercial and industrial customers;
- The role of the incumbent utilities as providers of last resort;
- The scope and recovery mechanisms for stranded costs of the incumbent utilities; and
- Whether to adopt a pure competition model (such as Texas) a hybrid model (such as many Northeastern states), or a mass aggregation model (such as Illinois).

VI. Recommendations and mitigation strategies

Based on our analysis of the Kansas retail market and rates, we recommend the following considerations as potential approaches to mitigate the impacts of high retail rates:

Areas for legislative and regulatory reform

Kansas consumer interests should consider lobbying the Kansas legislature for the following:

- Undertake a detailed study of the costs and benefits of retail competition in the electric sector. Such a study should analyze the impacts on rates and costs of service if the state were to permit all or certain classes of

customers to shop for alternative power suppliers and should address possible cost shifts among customer classes if the state were to consider retail competition for only certain customer classes.
- Require the KCC to implement pilot programs for distributed generation and demand response. These programs provide opportunities for significant cost savings for large customers, but development and implementation of these programs in Kansas have been extremely limited. A KCC requirement that utilities develop pilot programs to promote the participation of customers in such areas could provide an effective jump start to these types of savings opportunities.
- Adopt an IRP requirement for all utilities that will require the development and KCC approval of system plans that identify facility needs and the identification of the most cost-effective means of satisfying these needs (including consideration of options to new construction, such as demand response and energy efficiency programs).
- Undertake a study to consider the costs and benefits of continued participation in SPP. Such a study would have to consider the costs of withdrawal from SPP and the loss of SPP-specific benefits, compared with the cost savings resulting from a more Kansas-specific focus on transmission and system planning.
- Consider whether an expanded, directly elected KCC could better represent consumer interests.
- Also consider whether increases in KCC funding and staffing could reduce incentives to settle every rate case.

Each of these items could separately be pursued at the KCC as well, but it is likely that legislative fixes will be faster and more effective.

In addition, Kansas consumer interests should consider taking a more active role in the SPP Stakeholder process and in FERC proceedings involving the SPP. As noted, transmission costs are one of the primary drivers of increased rates in Kansas, and the transmission expansion cost allocation decisions are made at the SPP and FERC.