**BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS**

In the Matter of a General Investigation Regarding the Rate Study and Assessment of Expenses Resulting from Substitute for Senate Bill No. 69.	))))	Docket No. 20-GIME-068-GIE

NOTICE OF FILING OF RATE STUDY

Staff of the State Corporation Commission of the State of Kansas (Staff and Commission, respectively) hereby files the second part of the study of electric rates ordered in Substitute for Senate Bill No. 69. Among other things, Substitute for Senate Bill No. 69 directed the Kansas Legislative Coordinating Council to authorize a study of retail rates of Kansas electric public utilities, and directed the Commission to make the second part of the study available on the Commission's website by July 1, 2020. Staff received a public and confidential version of the Study on July 2, 2020, and filed the public version in this docket, and made it available on the Commission's website.

Over the course of the next several months, AECOM worked to address the confidential designations within the study to provide the Commission with a new public version containing less redactions, the result of which is attached hereto. Due to the sensitive nature of some of the fuel pricing information, a small portion of the study continues to be redacted, but such redactions are consistent with past Commission treatment of such information. A confidential designation sheet has been provided to identify those areas of the study that are redacted and the justification for such redaction.

WHEREFORE, Staff respectfully submits the rate study directed by Substitute for Senate Bill No. 69, and recommends the Commission make available on its website the rate study and corresponding confidential designation sheet.

Respectfully submitted,

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STUDY OF CONSEQUENTIAL ISSUES MATERIALLY AFFECTING KANSAS ELECTRICITY RATES

PUBLIC VERSION

SEPTEMBER 2020

This report was prepared by AECOM, in partnership with subconsultant Energeia USA, in accordance with a contract issued by the Legislative Coordinating Council of the State of Kansas and the State Corporation Commission of the State of Kansas

Pursuant to the Protective and Discovery Order entered in KCC Docket No. 20-GIME-068-GIE, information designated as confidential by the utilities was redacted in the Public Version of this document

The September 2020 version of this document reveals certain information that was previously deemed confidential by the utilities.

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ACRONYMS

$/MMBtu	Price ($) per Million British Thermal Unit
AES	Advanced Energy Solutions
ATRR	Annual Transmission Revenue Requirements
BCR	Benefit-cost Ratio
BOO	Build, Own, and Operate
BTM	Behind-the-Meter
CAGR	Compound Annual Growth Rate
CCN	Clean Charge Network
CCOS	Class Cost of Service
CIP	Critical Infrastructure Protection
CIPC	Critical Infrastructure Protection Committee
CNN	Clean Charge Network
CoS	Cost of Service
CP1	Annual Coincident Peak
CP12	Monthly Coincident Peak
CP4	Quarterly Coincident Peak
CURB	Citizens' Utility Ratepayer Board
CWP	Construction Work Plan
DCFC	DC Fast Charging
DER	Distributed Energy Resources
DR	Demand Response
DSIRE	Database of State Incentives for Renewables & Efficiency
DSM	Demand-Side Resources
ECA	Energy Cost Adjustment
ECRR	Environmental Cost Recovery Rider
EDE	Empire District Electric Company
EDR	Economic Development Rates
EERS	Energy Efficiency Resource Standards
EIA	U.S. Energy Information Administration
ELCC	Electricity Load Carrying Capability
EPMP	Energy Planning and Management Program
ERO	Electric Reliability Organization
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
FiT	Feed in Tariff
G&T	Generation and Transmission
GDP	Gross Domestic Product
GIS	Geographic Information Systems
GRP	Gross Regional Product
GWh	Gigawatt Hours
HB	House Bill
HECO	Hawaiian Electric Company
IBT	Inclining Block Tariff
ICE	Internal Combustion Engine

IOU	Investor Owned Utility
IPP	Independent Power Producers
IRP	Integrated Resource Plan or Integrated Resource Planning
ISO	Independent System Operator
ITC	Investment Tax Credit
KC BPU	Kansas City Board of Public Utilities
KCC	Kansas Corporation Commission
KCP&L	Kansas City Power & Light
KEC	Kansas Electric Cooperatives, Inc
KEPCo	Kansas Electric Power Cooperative, Inc.
KIC	Kansas Industrial Consumer's Group
KMEA	Kansas Municipal Energy Agency
KMU	Kansas Municipal Utilities
KPP	Kansas Power Pool
kVA	Kilovolt Amperes
kW	Kilowatts
kWh	Kilowatt-hours
L2	Level 2 EV Charging Stations
L3	Level 3 EV Charging Stations
LADWP	Los Angeles Department of Water and Power
LCC	Legislative Coordinating Council
LEI	London Economics International, LLC
LMP	Locational Marginal Price
LQ	Location Quotient: measure of relative concentration between a selected geography and a base geography
MG	Microgrid
MIDW	Midwest Energy Inc Transmission Zone
MIKEC	Mid-Kansas Electric Company Transmission Zone
MOU	Municipally Owned Utility
MWh	Megawatt Hours
NAICS	North American Industrial Classification System
NARUC	National Association of Utility Commissioners
NCP	Non-coincident peak
NDA	Non-disclosure Agreement
NEG	Net Excess Generation
NEM	Net Energy Metering
NERC	North American Electric Reliability Corporation

NITS	Network Integrated Transmission Service
NREL	National Renewable Energy Laboratory
PG&E	Pacific Gas and Electric
PRB	Powder River Basin
PUC	Public Utility Commission
PV	Photovoltaic
RAP	Regulatory Assistance Project
RAPS	Remote Area Power Systems
RFI	Request for Information
RMI	Rocky Mountain Institute
RPS	Renewable Portfolio Standards
RTO	Regional Transmission Organization
RTP	Real Time Pricing
SAPS	Stand-Alone Power System
SB	Senate Bill
SCADA	Supervisory Control And Data Acquisition
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric
SMUD	Sacramento Municipal Utility District
SPP	Southwest Power Pool
SUNC	Sunflower Electric Cooperative Inc Transmission Zone
T&D	Transmission and Distribution
TCR	Total Cost Ratio
TDC	Transmission Delivery Charge
TE	Transactive Energy
ToU	Time of Use
U.S.	United States
UMZ	Upper Missouri Zone
VWA	Volume Weighted Average
WACC	Weighted Average Cost of Capital
WAPA	Western Area Power Administration
WFEC	Western Farmers Electric Cooperative
WTI	West Texas Intermediate

EXECUTIVE SUMMARY

INTRODUCTION

Kansas Legislature passed the Substitute for Senate Bill 69, calling for a study of retail electricity rates of Kansas electric public utilities. To address this task, a two-part Study will inform future legislative and regulatory efforts to establish policies that support regionally competitive electric rates and reliable service. Part 1 of the Study, which was completed by London Economics International, LLC in January of 2020, assessed the effectiveness of current Kansas ratemaking practices and explored possible approaches for the Kansas Legislature and Kansas Corporation Commission to make retail electricity prices regionally competitive. Part 2 of Study, addressed in this document, addresses 13 matters with topics including the regional economy, regional planning processes, regional electricity market, transmission investments, impacts of advanced energy solutions, and physical and cyber security processes. Kansas public utilities included in the Study include investor owned utilities, three municipally owned utilities, and 26 electric cooperatives.

SCOPE AND APPROACH

To address the 13 matters in Part 2 of the Study, the project team took a two-phase approach which included (1) Information Gathering and (2) Review and Assessment.

Information Gathering consisted of a request for information process, stakeholder engagement, and independent research. The request for information was used to solicit information from Kansas utilities while the stakeholder engagement process was used to solicit information from non-utility entities. The Review and Assessment phase included three workstreams through which the project team analyzed and addressed the matters of the Study. The workstreams included economics, technology, and electricity market areas of focus. Through the economics workstream, the project team reviewed and assessed key economics-related topics that covered cost of service, electricity rate design, and integrated resource planning. Through the technology workstream, the project team explored the potential benefits of advanced energy solutions, cyber and physical security, and transmission investments. Through the electricity market workstream, the project team studied and analyzed Kansas' regional economy and competitiveness, regional electricity markets, and electric vehicle charging services market trends. The project team analyzed information and trends between each of the workstreams, enabling a thorough and holistic approach to addressing each of the 13 matters.

INFORMATION GATHERING

The information gathering processes for the Study consisted of three stages: Request for Information (RFI), Stakeholder Engagement, and Independent Research. Each stage informed each of the 13 matters. The RFI (**see APPENDIX A Request for Information** for the full RFI) included 61 questions and was sent to all utilities included in the Study. Information requested through the RFI included qualitative and quantitative data focused on the following categories:

- EV Charging
- Advanced Energy Solutions
- Transmission
- Rates
- Economic Development
- Cost Causation
- Security
- Resource Planning
- Fuel

RFI responses were accepted for about 13 weeks from the delivery of the RFI. The project team offered technical assistance for utilities seeking help completing the data request through teleconferences, individual phone calls, and e-mail correspondence. Non-disclosure agreements were offered to utilities who requested to protect confidential data. Complete cost of service data sets were unavailable from many utilities, leading to small sample sizes in certain utility classes. In the case of the Cooperatives, Midwest Energy was the only Coop able to provide all necessary components to analyze cost of service within the time frame necessary for the project team to model. Where insufficient data was gathered, the project team took the appropriate approach to fill information gaps with other data provided through the RFI or with data found through independent research.

Thirty-three stakeholders who represented 24 non-utility entities **(see Appendix: Non-Utility Stakeholders for stakeholder organizations)** were involved the stakeholder engagement process, representing a broad spectrum of interests related to retail electricity rates and programs. The stakeholder engagement process entailed two virtual teleconferences where stakeholders engaged in facilitated discussions focused on each of the 13 matters. Additional teleconferences were held on an as needed basis for stakeholders who wished to provide additional comments or were not able to attend the group teleconferences. Stakeholders were also welcomed to provide additional comments following teleconferences.

Following the initial release of the Study, in which analysis based upon material marked confidential by the utilities was redacted, the KCC entered an order instructing KCC staff and the project team to work with the utilities to release all possible previously redacted material. Through this process, the utilities agreed to allow the release of most of the previously redacted information. Additionally, Midwest requested that previously redacted analysis based solely upon their cost of service information be labeled as such to more accurately reflect the information portrayed. The Study now reflects these changes.

KEY FINDINGS AND RECOMMENDATIONS

1. Electric Vehicle Charging Services Cost Recovery

Whether any costs incurred by Kansas electric public utilities to build and operate electric vehicle charging stations, including any necessary upgrades to distribution infrastructure, are recovered from ratepayers not using electric vehicle charging services.

SCOPE AND APPROACH

Utilities across the nation are preparing their electric vehicle (EV) infrastructure and distribution systems to meet the needs of the growing population of EV drivers. Ratepayers who do not drive EVs may be impacted by cost recovery mechanisms to implement utility system upgrades for EV infrastructure. To determine if costs incurred by Kansas electric public utilities for these upgrades are recovered from ratepayers who do not use EV charging services, information was collected from Kansas utilities related to cost allocation policies and public charging infrastructure cost causation data. Information related to key issues, inputs, and assumptions were solicited from stakeholders. This information was then analyzed to determine if costs relating to EV charging services are recovered from other ratepayers.

INFORMATION GATHERING

REQUEST FOR INFORMATION RESPONSES

To address this matter, the project team collected Kansas utility EV infrastructure data such as the amount of utility-operated public EV charging stations. Spending data and cost recovery mechanism data was also collected for capital and operating expenses allocated to EV charging services and distribution system upgrades needed to support EV infrastructure. Utilities were also sent additional information requests related to distribution system and customer hourly load and cost of service models.

One out of the 32 utilities included in the study reported that it owned and operated public charging infrastructure, and that it was not recovering capital investments or operating costs by all customers in the same class. The remaining utilities did not own or operate public charging infrastructure. In the absence of distribution system or customer hourly load data, the project team used utility system coincident peak demand data to fill this information gap for the analysis.

STAKEHOLDER FEEDBACK

Consumer advocates noted that the KCC approved a tariff allowing Evergy to charge only EV charging customers for their use of the network. Members from both stakeholder groups opposed EV charging related cost recovery from all customers. Reasons given for their opposition included low EV uptake and the possibility of providing unfair advantage in a potentially competitive marketplace.

KEY FINDINGS AND CONCLUSIONS

Based on utility responses to the RFI, Kansas public utilities are unlikely to be recovering public charging infrastructure costs from ratepayers. Furthermore, IOU and Midwest Energy rates applied to public charging stations are over-recovering their marginal cost of service, leading the project team to conclude that electricity system costs are being over-recovered from EV drivers. On the other hand, Munis appear to be under-recovering electricity system costs from EV drivers.

2. Electric Vehicle Charging Services Rate Design

How rates for electric vehicle charging services should be designed to ensure such rates are just and reasonable and not subsidized by other utility customers.

SCOPE AND APPROACH

Given the findings in Matter 1, the project team explored how EV rates should be designed to ensure that they are not subsidized by other utility customers. To determine how just and reasonable rates should be designed in Kansas, the project team gathered information about each utility's public charging rate design and reviewed Kansas rate design legislation, case law, and regulatory proceedings. The collected information was analyzed to determine a best practice approach for fair and just rate design that fits Kansas' regulatory landscape.

INFORMATION GATHERING RESULTS

REQUEST FOR INFORMATION RESPONSES

The RFI processes solicited information from Kansas utilities regarding their electric vehicle cost recovery strategies and their protocol to ensure that their cost recovery strategies are just and reasonable. The RFI included additional data requests related to distribution network, system, customer, and public charging hourly load and cost of service models. None of the utilities reported having a public charging EV rate for use by third party public charging service operators or plans to implement such a rate.

STAKEHOLDER INFORMATION

The majority of stakeholders were in favor of EV charging rates that did not result in cross-subsidies, especially for low-income ratepayers. A small group of stakeholders were not concerned with cross-subsidization in rates and were in favor of increased EV adoption that would provide various social benefits, such as reduced air pollution. Rates based on use cases that define location, vehicle type, charging technology, and charging behavior of customers were proposed.

KEY FINDINGS AND CONCLUSIONS

The project team concluded that just and reasonable public charging rates should be broken into their own rate class in order to enable appropriate allocation of costs. Specifically, public charging rates should have a hybrid rate design with fixed, peak period, off-peak period, or annual maximum charges. Charges in the hybrid design should be cost reflective, meaning the charge should depend on the cost driver.

3. Potential Effects of Deregulating Electric Vehicle Charging Services

The potential effects of deregulating electric vehicle charging services in Kansas, including whether deregulation would ensure that electric vehicle charging services are not subsidized by public utility ratepayers not using electric vehicle charging services.

SCOPE AND APPROACH

As originally introduced during the 2020 legislative session, House Bill (HB) 2585 would have allowed non-utilities to operate EV charging services unregulated by the KCC, while still complying with other state restrictions (sales tax, etc.). During the legislative process, the Bill was amended to no longer include the provisions relating to EV charging services and was then passed and signed into law.

Deregulation of EV charging services may be considered for inclusion in future legislation. Project team research into this matter involved interviewing utilities and other stakeholders to understand their perception towards deregulating EV charging services, researching the current landscape of EV charging deregulation across the U.S., and analyzing the potential impact on utility level of service, cost of service, and potential cross-subsidies.

INFORMATION GATHERING RESULTS

REQUEST FOR INFORMATION RESPONSES

The RFI was issued with requests pertaining to the expected costs and benefits of deregulating EV charging services. The utility which currently offers a public charging service provided a response regarding the potential impacts of deregulation. Their insights were largely positive and focused on the potential for service subsidies and increased level of innovation within the industry.

STAKEHOLDER INFORMATION

Non-utility stakeholders expressed support for deregulation during the engagement process, as they believe this would lead to eliminating cross-subsidies and reducing charging costs through market forces. Stakeholders also pointed to KCC's deregulation of compressed natural gas for use as vehicle fuel as precedent for EV charging station deregulation.

KEY FINDINGS AND CONCLUSIONS

CHARGER AVAILABILITY

Kansas offers Level 2 and Level 3 public charging stations at rates comparable to most of the other states; the relative level of public charging stations in Kansas is remarkable given the service only currently covers about half of the population. Because of this relatively high level of availability, service congestion is unlikely to become an issue.

SUPPORTING SERVICES

Increased offerings in a deregulated public charging service market may result in the introduction of supporting services not currently available in Kansas, such as the ability to charge from any public station using the same account, scheduling services, concierge services, and load management services. These services are not widely offered in other states either.

KEY EFFECTS OF COMPETITION

Competition will lead to the introduction of the cost saving factors, such as lower service costs because of market entry by larger firms with lower purchase, operational, and fixed costs per unit due to economies of scale; and potentially lower electricity costs due to incorporation of solar PV, storage, and/or other advanced energy solutions to help minimize service costs. Additionally, new firms entering the market as a result of deregulation may offer subsidized charging services to attract customers to their primary businesses, as has been seen in other markets. Finally, while competition is not expected to impact the level of public charging direct cost cross-subsidies, it is expected to increase the level of electricity rate cross-subsidies to the degree it increases the rate of EV adoption.

4. Benefits to Kansans Consumers of Improved Access to Advanced Energy Solutions

Whether Kansas consumers could benefit from improved access to advanced energy solutions, including microgrids, electric vehicles, charging stations, customer generation, battery storage and transactive energy.

SCOPE AND APPROACH

Advanced energy solutions (AES) offer potential benefits such as lower energy bills, higher reliability, and access to cleaner power and transportation options. However, systems needed to support AES can potentially raise electric system costs and introduce cross-subsidies. To understand the net benefit of AES for Kansas customers, the project team gathered information on the underlying cost trajectory of AES, their impact on other areas of the electricity system and interested parties (utility shareholders, ratepayers and the public), and the role of rate design in allocating any costs and benefits between those adopting AES and other ratepayers. The project team included similar types of information for competitive alternatives to AES in the analysis of this matter.

INFORMATION GATHERING RESULTS

REQUEST FOR INFORMATION RESPONSES

Through the RFI, Kansas utilities were asked to provide information related to their existing AES inventory and AES program portfolio and performance data, such as participation and energy usage data. Information related to planned AES programs and completed AES adoption feasibility studies was also requested. Information on tariffs, riders, and other cost recovery mechanisms for AES technology was also requested. The RFI included additional data requests related to distribution network, system, and customer hourly load and cost of service models.

The utilities provided aggregated customer generation data with AES solutions over time. In the absence of certain customer AES adoption information, the project team used a model-based approach using actual hourly customer or customer class load data to estimate the impact on utility cost of service and the bill impacts of customers who adopt AES.

STAKEHOLDER INFORMATION

Nearly all stakeholders largely supported improved access to multiple advanced energy solutions, noting the opportunities for electric rate savings resulting from new system efficiencies, as well as improved reliability, grid resilience, public health, and comfort. One stakeholder provided an opposing viewpoint, suggesting that because Kansas has already spent more money in this area than many other states, it should not invest more money in renewables.

KEY FINDINGS AND CONCLUSIONS

The analysis showed the following key findings regarding benefits of various types of AES:

CUSTOMER GENERATION

Solar PV generation will increasingly benefit Kansas ratepayers; these benefits could be improved through rate reform. In terms of technology accessibility, Kansas utilities were found to offer programs comparable to peer state and best practice utilities.

ELECTRIC VEHICLES AND CHARGING STATIONS

EVs are not currently economical for Kansas customers due to the leasing premium. They are expected to achieve a positive net benefit as EVs approach pricing parity with internal combustion engine vehicles by 2026. Furthermore, current electricity rate design may be charging EV drivers more than their incremental cost of service.

If there are cross-subsidies in current rates that disadvantage EV drivers, reforming them under the approach recommended in **Section 5.2** would increase the net benefits of EVs by around $100 to $250 per year for the average home-charging EV driver and $100 to $150 per year for the average workplace-charging EV driver.

BATTERY STORAGE

Improved access to behind-the-meter (BTM) storage would not currently benefit Kansas ratepayers but, provided that the program would be coordinated by the utility, could be expected to within the next ten years. Additionally, the programs currently offered in Kansas are less accessible than those offered by best practice regional and national utilities, as no Kansas utilities currently offer BTM programs or pilots.

MICROGRIDS

Increased access to microgrid solutions could improve grid resiliency, especially for customers in wildfire prone areas or on a utility's worst performing feeder, and would thus benefit Kansas ratepayers.

TRANSACTIVE ENERGY

All transactive energy (TE) markets identified by the project team are in the pilot phase, mainly focused on developing and testing TE products with prosumers, their agents, and the utility. TE could deliver benefits to Kansas ratepayers in the future, once TE markets and technology are more mature.

5. Impacts of Transmission Investments on Kansas Retail Electricity Rates

The extent to which transmission investments by Kansas electric public utilities have impacted retail rates, including any incremental regional transmission costs incurred by Kansas ratepayers for transmission investments in other states, and whether such costs have been fully offset by financial benefits such as improved access to low-cost renewable energy and wholesale energy markets.

SCOPE AND APPROACH

Part 1 of the Study identified[1] changes in electricity production costs as one of the key drivers of rate increases in Kansas over the past ten years, based on the findings of the cost of service study completed by the KCC. In addition to changing environmental regulation and generation costs, the predominant factor influencing rates has been transmission investments. To inform whether rates appeared to be materially impacted by regional transmission investment, transmission investment data was compared against electricity rate, and job and population growth data across the SPP region, and then to locational marginal prices (LMPs).

1 London Economics International, LLC (2020). Study of Retail Rates of Kansas Electric Public Utilities, page 48. Kansas Corporation Commission. Retrieved from: https://estar.kcc.ks.gov/estar/ViewFile.aspx/S20200108144309.pdf?Id=1a3a31e5-e38d-4445-aada-1cd0170a7b85

INFORMATION GATHERING RESULTS

REQUEST FOR INFORMATION RESPONSES

The majority of the analysis was conducted with publicly available data. SPP Annual Transmission Revenue Requirement (ATRR) data provided in Open Access Transmission Tariff Reports was used to assess the costs incurred by transmission owners and resulting impact on ratepayers; to normalize these impacts on different population centers across the region, demographic and employment data was acquired. Finally, LMP data allowed the project team to weigh the cost of transmission investments against the resulting benefits associated with reduced transmission congestion and line losses.

STAKEHOLDER INFORMATION

Rising transmission investments were a priority concern of the majority of stakeholders consulted over the course of the Study. While stakeholders unilaterally recognized that these investments have led to reduced wholesale generation prices, they were conflicted about the degree to which these savings have offset transmission investment impacts on retail rates. Stakeholders also provided conflicting information about the current state of how transmission costs are allocated between power producers and ratepayers.

KEY FINDINGS AND CONCLUSIONS

TRANSMISSION INVESTMENT COST ALLOCATION

For all three customer classes, the cost allocated to transmission (between 2.6-3.8%) was far less than both generation and distribution, although allocation varied significantly between utility types. Transmission costs' contributions to retail price range from $1/MWh for IOUs to $10/MWh for Midwest Energy. This indicates a variation in the percentage of total cost from approximately 1.3% for IOUs to 12% for Munis, for which transmission costs represent the greatest proportion of retail cost among utility types.

ANNUAL TRANSMISSION REVENUE REQUIREMENT ANALYSIS

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 strongly to the service population densities throughout the SPP region. The general trend indicates that more populous urban zones benefit from economies of scale in the provision of transmission infrastructure to their service areas.

For both the Kansas and Non-Kansas SPP zones, the ATRR grew at a substantial rate from 2010 to 2019, but the average transmission investment per member of the service population grew at a slower rate in the Kansas SPP zones than in the Non-Kansas SPP zones. So, while this uptick corresponds to the most significant increase in electricity rates for industrial, commercial, and residential ratepayers, these costs alone cannot explain the relatively high electric rates in Kansas as compared to the regional average.

GENERATION COSTS

While transmission investments grew year-over-year per member of the service population, these costs were largely offset by lower generation costs.

6. Costs and Benefits of Transmission Investments Used to Import and Export Electricity

The costs and benefits incurred by Kansas ratepayers for transmission investments in Kansas, used to export energy out of Kansas.

SCOPE AND APPROACH

To conduct the analysis, the project team sought information regarding transmission assets utilized to export or import electricity, the net export of electricity by Kansas and other peer states. Economic data regarding transmission investment in Kansas was utilized to analyze the costs and benefits of transmission investment to Kansas ratepayers.

INFORMATION GATHERING RESULTS

REQUEST FOR INFORMATION RESPONSES

A key gap in the information resulted from the utilities' inability to track electricity flowing across state lines by transmission asset. To work around this gap, the project team attempted to use additional information obtained from the SPP but was unable to link utility provided mapping and SPP data with any degree of confidence due to lack of mapping specificity or alignment with SPP data. As a result, there was insufficient information to determine which transmission investments have been specifically used to export electricity, so the analysis is based on the project team's assumption that the proportion of Kansas transmission investment allocated to exports is equivalent to the proportion of total generated power exported to the region.

STAKEHOLDER INFORMATION

Many stakeholders engaged 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.

KEY FINDINGS AND CONCLUSIONS

Kansas' share of transmission costs potentially attributed to electricity exports have been increasing since 2013. The value of transmission investments used for the export of electricity in 2018 is estimated at approximately $64.5 million.

A variety of benefits, both direct and indirect, can result from transmission investment. These benefits include those that can be quantified and others that are not readily quantifiable. The analysis indicates that for the period analyzed the total transmission investment (not that proportion used for export/import) has resulted in the creation of up to 1,940 jobs, $127 million in earnings and $58 million in tax revenue.

During the time period analyzed, the localized marginal price, a measure of how much it costs to generate and move electricity, has been decreasing in Kansas, underscoring the benefit of a regional electricity market.

7. Impact of Rising Costs of Kansas Investor Owned Utilities on Electric Cooperatives and Municipal Utilities

How rate increases, or the associated rising costs of Kansas investor-owned electric public utilities, impact the retail electric rates of Kansas electric cooperatives and municipal utilities.

SCOPE AND APPROACH

Rising IOU costs may directly impact Munis and Coop electric rates when generation or transmission services are provided, or indirectly through the impact of their generation and transmission costs on SPP market prices and transmission zone costs. The project team's approach to evaluating the magnitude of these direct and indirect impacts involved gathering data pertaining to IOU generation, transmission, and SPP costs, analyzing trends in these costs and how they are passed on to other utilities and their ratepayers, and finally, understanding stakeholder perception of these trends.

INFORMATION GATHERING RESULTS

REQUEST FOR INFORMATION RESPONSES

An RFI was issued with requests for generation and SPP cost recovery, and for Munis and IOUs, other costs passed on from IOUs to ratepayers. Few utilities provided data in response to these requests, though generation capital and operating expenses, as well as transmission delivery charge data, were recovered through other requests and research. Additionally, SPP data was provided by pricing node, along with information regarding how SPP settlement operated. Utility-specific data was not provided due to confidentiality restrictions.

In the absence of the exact data requested, a proxy-based approach was developed to answer the matter at hand. Changes in overall IOU generation and transmission costs were estimated and applied to Munis and Coops with wholesale supply contracts. Changes in SPP impacted nodes were estimated and applied to the other Munis and Coops based on their estimated average share of the final bill.

STAKEHOLDER INFORMATION

Few participating stakeholders had direct experience with this matter, though several referred the project team to the fact that some Kansas Munis and Coops purchase power from Evergy and expected that their rates may be impacted to the extent those costs have changed.

KEY FINDINGS AND CONCLUSIONS

The impact of IOU cost increases on Muni and Coops for which IOUs provide generation and transmission (G&T) services could be as high as 48% if the terms of their wholesale contracts allowed costs to be fully passed onto the purchaser. However, given that IOUs' share in the Muni and Coop G&T market peaked at 0.36% in 2011 and was estimated to be 0.01% in 2018, the overall impact on the Muni and Coop sectors is limited..

The impact of key IOU G&T cost increases on Muni and Coops for which IOUs do not G&T services is difficult to determine due to the 40-45% reduction in SPP pool prices over the 2013 to 2019 period, despite the increase in G&T cost drivers. The $0.02/kWh SPP price reduction outweighs the estimated $0.003/kWh increase in regional transmission costs.

8. The Impacts of Retail Electric Rates on Kansas Economic Development

Whether retail electric rates in Kansas are a material barrier to economic development in Kansas.

SCOPE AND APPROACH

To analyze whether retail electric rates in Kansas are a material barrier to economic development, the project team: compared the economic health of Kansas generally to nine peer states[2] and U.S. average, identified industries most sensitive to retail electric rates, and compared the economic health of these industries to those in peer states.

INFORMATION GATHERING RESULTS

REQUEST FOR INFORMATION RESPONSES

Utilities provided data related to economic development rates. In light of certain information gaps, the methodology was adapted to align with publicly available industry data from EMSI and focused on gauging electricity-related industries' sensitivity to utility rates in Kansas relative to its peer states.

STAKEHOLDER INFORMATION

Feedback from stakeholder meetings provided anecdotal evidence of companies leaving Kansas or choosing not to locate in Kansas due to higher retail electric rates. It underscored the impact that rates seem to be having on clean energy sector development related to additional demand charges on solar customers. This feedback drove exploration into specific data considerations.

KEY FINDINGS AND CONCLUSIONS

The results of this analysis highlight the complex environment in which electricity-dependent industries make economic development decisions. While the economic health data does suggest that Kansas may be less economically competitive overall than its peers, the data does not signal that electricity rates are the sole explanatory factor.

Stakeholder input identified anecdotal examples of large industrial companies who chose to not locate in Kansas due to electricity rates. These discrete examples are supported by quantitative evidence that some industrial sectors have experienced less growth than in peer states and the U.S. average. Under-performing sectors include wholesale trade and real estate/leasing services, which use more electricity as a share of inputs than the average sector. Top line economic growth in Kansas has been slower than in all nine peer states included in this analysis since 2010. It appears that electricity rates in Kansas likely contribute to such under-performing economic development, including business attraction and retention. However, these findings are not conclusive that retail electric rates are the only barrier to economic development in Kansas, but insinuate they are one correlate with negative economic outcomes in some cases.

To allow for a better understanding of specific industries, **Appendix 5.8b (Industry Summaries)** provides information relating to the economic health and energy sensitivity for multiple industries and how each compares to peer states.

2 For purposes of this section, peer states are those in the region including Arkansas, Colorado, Iowa, Missouri, Nebraska, North Dakota, Oklahoma, South Dakota and Nebraska.

9. Impact of Contract and Economic Development Rates on Other Customer Classes

The impact of contract rates with commercial and industrial customers and economic development rates on other customer classes, including whether expanded utilization of such approaches can benefit all customers over time.

SCOPE AND APPROACH

To conduct this analysis, the project team sought available data for customer load and economic development rates (EDRs) for Kansas utilities. In light of a key data gap, the project team was not able to estimate the impact of EDRs on other customer classes. Instead a limited analysis of the impact and efficacy of EDRs on the average ratepayer for a selected utility sample was conducted. Additionally, research was performed to identify industry best practices utilized to attract capital investment, as well as create and maintain jobs, through EDRs and activities of utilities nationwide.

INFORMATION GATHERING RESULTS

REQUEST FOR INFORMATION RESPONSES

Information was provided related to certain EDRs offered by utilities and was supplemented by publicly available sources; however, a key gap in the requested information was the lack of detailed cost of service and customer load profile and billing data, as well as customer asset mapping information. Without these inputs, the project team was unable to estimate the impact of EDRs on other customer classes.

STAKEHOLDER FEEDBACK

Stakeholders engaged throughout the project suggested that while economic development rate contracts may impact residential customer classes, the benefits associated with increasing electricity sales while maintaining generation loads may outweigh the costs of potential cross-subsidies (especially if rates were to be restructured to encourage peak shedding). Additionally, stakeholders pointed to the ripple effects of economic development rates, that not only do they encourage economic regeneration on behalf of the contract holders, but also their suppliers.

KEY FINDINGS AND CONCLUSIONS

Data indicates the discounts provided by EDRs may bridge the competitiveness gap for the first five years of business development or expansion compared to the average annual rate for the region. However, there are two further considerations. The first is that utilities in the peer states also offer EDRs, and some of their discounts are larger than those offered by IOUs in Kansas. The second is that 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 non-energy related factors. Given available data, it appears that the average annual rate for customers in the sample service area did increase and rise above those of other geographies during the period measured.

10. Cost Recovery on the Basis of Causation

Whether Kansas electric public utilities recover their costs of serving customers from each customer class on the basis of cost causation.

SCOPE AND APPROACH

Rising retail prices have caused customers and their advocates to question whether electricity generation, transmission, and distribution costs are being allocated on a cost causation basis, or if a subset of customer classes are subsidizing others. There is particular concern that a growing increase in residential and commercial rates, as compared to flattening industrial rates, is indicative of costs not being allocated on a cost causation basis. Determining the extent of the misalignment between utility cost to serve and cost allocation, and ultimately the level of cost causation, involved gathering holistic stakeholder perspectives of cost causation's impact on rates, analyzing utility data regarding cost allocation policies, and developing an independent estimate of cost causation to compare to outcomes of these allocation policies.

INFORMATION GATHERING RESULTS

REQUEST FOR INFORMATION RESPONSES

Through the RFI, information was requested regarding utility cost of service, cost allocation, and rate design practices, as well as customer class load profiles. While there was sufficient data to model differences in cost of service and cost allocation for generation services at the residential and non-residential level, there were gaps in the data provided for transmission and distribution services and the data necessary to analyze cost causation for commercial and industrial customer classes, specifically. Additional data was found to estimate transmission cost causation, but the lack of data with respect to distribution network load profiles made it impossible for the project team to independently estimate the contribution of each customer class to distribution cost causation.

STAKEHOLDER FEEDBACK

Stakeholders recommended that utilities should modify their approach to cost allocation, given that the current practices are not the "most reasonable or beneficial for the ratepayers." They suggested the project team reference Class Cost of Service Studies (CCOSS) as guidance for the analysis.

More specifically, one consumer advocate stated that oil rig rates should be lower than other rates (they currently are the same or higher), because "oil load is the base load for the utilities" and has a less variable load than its counterparts.

KEY FINDINGS AND CONCLUSIONS

Kansas utilities are recovering their transmission and generation costs on the basis of cost-causation. However, due to the age of some utilities' cost of service models, the basis may be out of date, and is likely to become more inaccurate over time due to changes in customer load shapes and cost factors. To mitigate these risks, it is recommended that cost of service study updates be conducted periodically, depending on the rate of change of cost causation factors.

Analysis conducted by the project team suggested significant variation between some utility cost allocation outcomes and our independent estimate of cost causation factors using 2019 data.

11. The Impact of Cyber and Physical Security and Grid Stabilization Efforts on Rates

How cyber and physical security and grid stabilization efforts have affected, or are projected to affect, electric public utility rates.

SCOPE AND APPROACH

As security threats against major energy infrastructure systems become increasingly sophisticated, the systems required to maintain grid stability and service reliability have similarly grown in their complexity. Utilities must balance their security expenditures to ensure they are sufficiently protected, but not placing undue financial burden on their ratepayers.

The project team's approach to determining the rates impact of such spending in Kansas included analyzing utility data obtained through a formal RFI, understanding projected trends in utility security spending, and conducting research into cost-saving mechanisms Kansas and peer state utilities are employing to manage security expenditures and mitigate the burden on ratepayers.

INFORMATION GATHERING RESULTS

REQUEST FOR INFORMATION RESPONSES

At the beginning of the Study, the project team issued a request for utility data surrounding physical security, cybersecurity, and grid stabilization spending and documentation resulting from internal reviews of security and grid stabilization programs. The degree of detail in utility responses were highly variable.

STAKEHOLDER FEEDBACK

All utilities and stakeholders engaged throughout he Study agreed that security spending is expected to increase. Furthermore, utilities noted that, especially with respect to cybersecurity protections, spending has significantly shifted from capital to operating expenditures. Stakeholders also provided background and information relating to various KCC proceedings regarding security.

KEY FINDINGS AND CONCLUSIONS

Based on the available data, physical security and cybersecurity appear to, at most, account for less 1.5% of residential and commercial rates, and a fraction of a percent of commercial rates. Because of the broader implications of grid stabilization, these costs have higher rate impact on all customer classes, accounting for, at most, 9% of residential rates, and closer to 4% for both commercial and industrial rates.

These results indicate that, for the utilities included in the model, physical security and cybersecurity expenditures may not currently have a significant impact on rates. However, with the expected upward trend in spending, the State may wish to proactively consider instituting a state-wide recovery mechanism to provide formal guidance as to what efficient security spending may entail and more frequent oversight into the prudency of security spending. This mechanism could take the form of a grid security cost tracker, which is currently employed by Evergy to manage unforeseen increases in security spending, or a single-issue rider, as is used by peer utilities in Texas to more effectively recover security costs.

To evaluate the feasibility of either of these mechanisms, the State may consider adopting security data reporting standards. With this data, the State can better anticipate how each of these mechanisms may capture benefits aligned with the State's objectives, as well as reduce the cost burden passed onto Kansas ratepayers.

12. The Value of an Integrated Resource Planning Process Requiring State Regulatory Approval

The value of a utility integrated resource planning process that requires state regulatory approval.

SCOPE AND APPROACH

In Part 1 of the Study, LEI recommended instituting a state-regulated IRP process in Kansas.[3] The project team's research builds off LEI's analysis and works to further evaluate the viability of an IRP's potential benefits, assess the anticipated costs to utilities in adhering to the guidelines of a state-wide IRP process, and ultimately recommend a course of action for the State Legislature and KCC.

INFORMATION GATHERING

BACKGROUND RESEARCH

The project team's preliminary background research identified typical components of an IRP and how these components may be addressed in state-defined guidelines. Current IRP activities required of Kansas utilities were categorized by component type.

In addition to generation capacity planning filings with the KCC, nearly all Kansas utilities already conduct some form of integrated resource planning. IOUs submit IRPs to the regulatory authorities in the other states in which they operate. Evergy, as a stipulation of its merger, will also begin submitting IRP documentation to KCC later this year. Finally, all of the Munis within the scope of this study, and all but one Coop, submit IRPs for federal review.

REQUEST FOR INFORMATION RESPONSES AND STAKEHOLDER FEEDBACK

Utilities were asked to provide information regarding the cost of their current resource planning activities, projected added costs should a state-wide IRP requirement be introduced, and the benefits of such a requirement. Estimates of current resource planning costs ranged from $100,000 to $3 million, depending on the breadth of activities; the associated additional cost of introducing a state-regulated IRP process was less significant for utilities already undertaking extensive resource planning activities.

The RFI responses also illuminated several potential benefits of a state-regulated IRP process, many of which were reiterated by stakeholders during feedback sessions. The benefits determined to be of highest priority to all stakeholders were capital investment deferment, distributed energy resource integration, energy efficiency integration, progress toward state level policy objectives, and added transparency.

ANALYTICAL APPROACH AND KEY FINDINGS

The IRP processes defined by oversight authorities at the state and federal level vary greatly in detail required and flexibility. These differences not only impact the level of cost imposed on utilities to fulfill their IRP requirements, but also the extent to which they can leverage the benefits of an IRP.

A benchmarking framework was developed and used to evaluate the different levels of prescriptiveness of the resource planning guidelines currently followed by Kansas utilities, as well as other regional best practice guidelines. Using these results, suggestions were made with respect to the optimal level of IRP guideline prescription; in other words, the requirements that best allow utilities to leverage IRP benefits while also minimizing the associated costs. The following approaches were found most likely to yield a favorable return on investment: weighing several definitions of "least cost", considering a wide array of resources, screening preliminary resource plans with a comprehensive list of externalities in mind, and ultimately selecting the resource plan that takes these externalities, industry-recognized best practice, and consumer preference into account.

3 London Economics International, LLC (2020). Study of Retail Rates of Kansas Electric Public Utilities. Kansas Corporation Commission. Retrieved from: https://estar.kcc.ks.gov/estar/ViewFile.aspx/S20200108144309.pdf?Id=1a3a31e5-e38d-4445-aada-1cd0170a7b85

The fundamental value of a state-regulated IRP process is dependent on its scale of impact, or the suite of utilities for which the requirement would apply. IRP processes examined almost universally required IOUs to participate in state-regulated IRP processes. In a few instances, Coops and Munis are also required to submit an IRP for state review. As a result, the expected marginal cost of introducing an IRP state-regulated IRP requirement would be lowest for IOUs, followed by G&T Coops, and then distribution Coops and Munis.

It is recommended that, as a result of this research, the State first determine the outcomes it wishes to achieve in introducing a state-regulated IRP requirement. Then, the KCC may begin to design a set of guidelines that optimize the level of prescription with respect to each component of an IRP to maximize these outcomes, and finally, characterize the appropriate scale for which these guidelines will be enforced.

13. Economic Analysis of Generation Fuel Price Fluctuations on the Cost of Electricity

Economic analysis of the price fluctuations of generation fuels on the cost of electricity.

SCOPE AND APPROACH

Part 1 of the Study identified[4] changes in electricity production costs as one of the key drivers of rate increases in Kansas over the past 10 years, based on the findings of the cost of service study completed by the KCC. In addition to changing environmental regulation and rising transmission costs, the predominant factor influencing rates has been generation costs, of which fuels are a major cost component. In analyzing the relationship between generation fuel and electricity costs, the following steps were taken: gathering holistic stakeholder perspectives regarding this matter, analyzing utility and SPP fuel pricing and settlement data, and creating a statistical model to quantify the relationship between fuel, generation, and electricity prices.

INFORMATION GATHERING

REQUEST FOR INFORMATION RESPONSES

Information was requested regarding historical and forecasted fuel prices, fuel procurement contracts, and fuel price hedging policies. Given certain gaps in the data provided, it was not possible to provide insight into how fuel prices are passed through to generation prices.

Data was also requested from the SPP, which provided pricing information by node, along with information regarding how SPP settlement operated. Due to confidentiality restrictions, utility-specific load data could not be provided by the SPP within the timeframe needed. This represented the most significant gap in data, as utility-specific prices could not be directly determined. To work around this gap, a simple averaging of all settlement nodes for a given utility was performed to estimate SPP prices.

STAKEHOLDER FEEDBACK

Stakeholders stated that high electricity rates in the state are due to coal plants being overpriced and underutilized from hold-over utility contracts established 20 years ago, when coal was cheaper than gas – and that these plants can no longer compete with emerging technologies. In a written response, one stakeholder cited a Rocky Mountain Institute study that determined that energy portfolios incorporating renewable energy sources and demand-side management show lower risk and better prices than gas-fired plants.

4 London Economics International, LLC (2020). Study of Retail Rates of Kansas Electric Public Utilities, page 48. Kansas Corporation Commission. Retrieved from: https://estar.kcc.ks.gov/estar/ViewFile.aspx/S20200108144309.pdf?Id=1a3a31e5-e38d-4445-aada-1cd0170a7b85

KEY FINDINGS AND CONCLUSIONS

GENERATION UTILITY FUEL PRICES

[redacted]

G&T UTILITY WEIGHTED ELECTRICITY PRICES

The utilities for which there was enough data to include in the model have experienced similar SPP prices and therefore generation costs per MWh. Muni costs have increased more over time relative to other utility types, while Coop costs have fallen by comparison. IOU costs sit about midway in between.

FUEL PRICE IMPACTS ON GENERATION COSTS

For the data modeled, fuel price variations accounted for 79-96% of utility generation costs from 2014 to 2016. Data limitations and workarounds employed by the project team limit the extent to which these results can be generalized.

GENERATION COST IMPACTS ON RETAIL AND ELECTRICITY COSTS

Based on this analysis, the project team has reached the conclusion that fuel price variations account for 50-70% of electricity cost variations over the period from 2014 to 2018, depending on the type of utility.

INTRODUCTION

2. INTRODUCTION

The Kansas Legislature passed the Substitute for Senate Bill 69 (SB 69) which, after being signed into law by the Governor, was codified as K.S.A. 66-1287. The legislation authorized a study (Study) of retail electricity rates of Kansas electric public utilities in order to provide information that may assist future legislative and regulatory efforts to craft forward-looking electric policy that leads to regionally competitive electric rates and reliable electric service.[1]

Kansas public utilities, for the purposes of the Study, include electric public utilities defined in K.S.A. 66-101a, electric cooperative utilities exempt from Kansas Corporation (KCC) jurisdiction, and the three largest, by customer count, municipally owned or operated electric utilities.[2] The utilities under the jurisdiction of the Study are shown in the **TABLE 1. Utilities Included in the Study**.

1 K.S.A.§ 66-1287a

2 Id.

TABLE 1. Utilities Included in the Study

INVESTOR OWNED UTILITIES IOUs	MUNICIPALLY OWNED OR OPERATED UTILITIES Munis	ELECTRIC COOPERATIVES Coops
Evergy [3] Liberty Utilities, Empire District (Liberty)[4] Southern Pioneer[5]	Kansas City Board of Public Utilities (KC BPU) Garden City Electric Department (Garden City) Gardner Utilities Department (Gardner)	4 Rivers Electric Cooperative, Inc. Ark Valley Electric Cooperative Assn., Inc. Bluestem Electric Cooperative, Inc. Brown-Atchison Electric Cooperative Assn., Inc. Butler Electric Cooperative Assn., Inc. Caney Valley Electric Cooperative Assn., Inc. CMS Electric Cooperative, Inc. Doniphan Electric Cooperative Assn., Inc, (Doniphan) DS&O Electric Cooperative, Inc. Flint Hills Rural Electric Cooperative Assn., Inc. FreeState Electric Cooperative, Inc. Heartland Rural Electric Cooperative, Inc. Kansas Electric Power Cooperative, Inc.[6] Lane-Scott Electric Cooperative, Inc. (KEPCo) Midwest Energy, Inc. (Midwest)[7] Nemaha-Marshall Electric Cooperative Assn., Inc. (Nemaha-Marshall) Ninnescah Electric Cooperative Assn., Inc. Pioneer Electric cooperative, Inc. Prairie Land Electric Cooperative, Inc. Sedgwick County Electric Cooperative Assn., Inc. Sumner-Cowley Electric Cooperative, Inc. Sunflower Electric Power Corporation (Sunflower)[8] Twin Valley Electric Cooperative, Inc. Victory Electric Cooperative Assn., Inc. Western Cooperative Electric Assn., Inc. Wheatland Electric Cooperative, Inc.

The legislation divided the Study into two parts. The first phase (Part 1 of the Study or Part 1) addressed the effectiveness of Kansas ratemaking practices[9] and "options available to the state corporation commission and the Kansas legislature to affect retail electricity prices to become regionally competitive with the best practicable combination of price, quality and service."[10] It was completed by London Economics International, LLC (LEI) and submitted on January 8, 2020.

This report addresses the second phase of the Study, titled Other Consequential Issues Materially Affecting Kansas Electricity Rates (Part 2 of the Study or Part 2). SB 69 set forth 13 matters to be addressed by Part 2 of the Study, which was submitted on July 1, 2020.[11] **TABLE 2. Matters Addressed in the Study** sets forth the matters to be addressed in Part 2 of the Study and the general subject of each.

3 Evergy is the largest electric utility in Kansas serving approximately 970,000 customers or roughly 64% of all Kansas electricity customers. In 2018, Evergy was created through a merger of Westar Energy (Westar) and Kansas City Power & Light (KCP&L), a subsidiary of Great Plains Energy. The utility operates two service territories in the state of Kansas, Kansas Central, which is the historical footprint of Westar, and Kansas Metro, the historic footprint of KCP&L. Depending on how data was received, the analysis encompassed in this study may interchangeably refer to Evergy's current service areas by the name of their legacy utilities.

4 Liberty Utilities/Empire District serves approximately 10,000 customers in southwest Kansas. According to EIA data, it also operates in Arkansas, Missouri, and Oklahoma, serving approximately 168,000 customers.

5 Southern Pioneer primarily operates as an IOU and is regulated as such; however, it is owned by Pioneer Electric Cooperative.

6 KEPCo is a generation and transmission Coop supplying electricity to its 18 member distribution Coops. Its member Coops include 4 Rivers, Ark Valley, Bluestem, Brown-Atchison, Butler, Caney Valley, CMS, DS&P, Flint Hills, Free State, Heartland, Ninnescah, Prairie Land, Rolling Hills, Sedgwick County, Sumner-Cowley, Twin Valley and Victory Electric. Members collectively have approximately 110,000 customers.

7 Midwest Energy is unique amongst Kansas Coops in that it is a vertically integrated utility providing generation, transmission, and distribution services to its members.

8 Sunflower is a generation and transmission Coop providing services to its six member distribution Coops. Those members include Lane-Scott, Pioneer, Prairie Land, Southern Pioneer, Victory, Western and Wheatland which collectively serve approximately 200,000 customers.

9 K.S.A. § 66-1287c1

10 K.S.A. § 66-1287c2

11 K.S.A. § 66-1287b4

TABLE 2. Matters Addressed in the Study

Electric Vehicle Charging	1	Whether any costs incurred by Kansas electric public utilities to build and operate electric vehicle charging stations, including any necessary upgrades to distribution infrastructure, are recovered from ratepayers not using electric vehicle charging services.
	2	How rates for electric vehicle charging services should be designed to ensure such rates are just and reasonable and not subsidized by other utility customers.
	3	The potential effects of deregulating electric vehicle charging services in Kansas, including whether deregulation would ensure that electric vehicle charging services are not subsidized by public utility ratepayers not using electric vehicle charging services.
Advanced Energy Solutions	4	Whether Kansas consumers could benefit from improved access to advanced energy solutions, including micro grids, electric vehicles, charging stations, customer generation, battery storage and transactive energy.
Transmission	5	The extent to which transmission investments by Kansas electric public utilities have impacted retail rates, including any incremental regional transmission costs incurred by Kansas ratepayers for transmission investments in other states, and whether such costs have been fully offset by financial benefits such as improved access to low-cost renewable energy and wholesale energy markets.
	6	The costs and benefits incurred by Kansas ratepayers for transmission investments in Kansas, used to export energy out of Kansas.
Rates	7	How rate increases, or the associated rising costs of Kansas investor-owned electric public utilities, impact the retail electric rates of Kansas electric cooperatives and municipal utilities.
Economic Development	8	Whether retail electric rates in Kansas are a material barrier to economic development in Kansas.
	9	The impact of contract rates with commercial and industrial customers and economic development rates on other customer classes, including whether expanded utilization of such approaches can benefit all customers over time.
Cost Causation	10	Whether Kansas electric public utilities recover their costs of serving customers from each customer class on the basis of cost causation.
Security	11	How cyber and physical security and grid stabilization efforts have affected, or are projected to affect, electric public utility rates.
Resource Planning	12	The value of a utility integrated resource planning process that requires state regulatory approval.
Fuels	13	Economic analysis of the price fluctuations of generation fuels on the cost of electricity.[12]

12 K.S.A. § 66-1287c3

Within this report, research findings related to each matter are detailed, as is the project team's approach and information gathering methodologies that supported exploration into the 13 matters outlined in SB 69 to be addressed.

SCOPE AND APPROACH

3. SCOPE AND APPROACH

The scope of work required by SB 69 covers a wide range of topics, including the regional economy, regional planning, the regional electricity market, transmission investments, the impact of advanced energy solutions such as electric vehicles (EVs), and physical and cyber security.

To address the 13 specific matters set forth in SB 69, the project team approached the analysis in two phases: (1) Information Gathering and (2) Review and Assessment.

3.1 Information Gathering

As described in more detail in the following section, a Request for Information (RFI) was developed to solicit specific data and information from each public utility. The RFI process, including follow-up related to data submitted or other matters, was managed through a single point of contact within the utility or their representative association. Extensive follow-up with each utility was performed, through teleconferences and e-mail, to explain the requests, close data gaps, and seek alternative data sources. To obtain additional data, impacts and views, non-utility stakeholders were engaged through a series of group and individual teleconferences. Information from publicly available sources was also obtained.

3.2 Review and Assessment

To analyze and address the 13 matters set forth in SB 69, the project team completed three distinct workstreams, each with specific functional areas. The workstreams collaborated to provide the inputs, modeling, and analysis necessary for completion of Part 2 of the Study.

The economics workstream focused on key economics-related topics covering cost of service, electricity rate design and integrated resource planning.

- The electricity cost of service function reviewed utility cost of service by cost category and the allocation of these costs to customer classes and rates. This was accomplished by developing a flexible cost of service model that allowed changes to be made to key cost allocation and customer classification assumptions. With these models, and other tools, assessments were made to determine:
  - Whether costs for EV charging services are being allocated to those who do not use the service;
  - Whether costs for regional transmission projects being allocated to Kansas ratepayers exceed the benefits of lower wholesale power costs;
  - The impact of higher IOU costs on cooperatives and municipal utilities;
  - Whether customer class cost allocation is based on customer class cost causation;
  - The impact of physical and cyber security on utility cost to serve; and
  - The impact of wholesale cost variability on the cost of electricity.
- The electricity rates review function reviewed current utility rate designs and cost recovery mechanisms to assess:
  - Whether current EV charging service rate designs are just and reasonable;
  - Whether EV charging service rate designs recover costs on the basis of causation;
  - If rates were not cost reflective and/or lead to cross-subsidies, how EV charging service rates should be designed to be just and reasonable and not subsidized by other customers; and

- Whether utilities recover their cost of service for customers from each customer class on the basis of cost causation.

- The integrated resource planning review function reviewed current resource planning activities of Kansas utilities and other regional states to determine and identify:
  - The costs and benefits of a utility integrated resource planning process that requires state regulatory approval; and
  - Policy and other changes that could improve the value of the Kansas integrated resource planning process.

The technology workstream addressed technology related topics covering the potential benefits of advanced energy solutions, cyber and physical security, and transmission investments.

- The advanced energy solutions function reviewed Kansas advanced energy programs against the best practices of other utilities with respect to availability, cost, enrollment, and impact; developed a model of the impact of improved access to advanced energy solutions; and estimated the economically optimal level of alternative energy solutions to be included in integrated resource plans based on relative costs and benefits to address:
  - The advanced energy solutions that will benefit Kansas, the net benefits they could provide and how, and whether they are currently being offered by utilities in Kansas.
- The cyber and physical security function reviewed utility programs and costs related to physical and cyber security, as well as grid stabilization, and best practices of peer states. The function also reviewed cost treatment in cost of service to address how these programs and costs are projected to impact utility rates. The outputs of this function include:
  - The level of costs that cyber and physical security and grid stabilization efforts have contributed to electric public utility rates; and
  - Changes to policies that could minimize the cost of cyber and physical security for Kansas ratepayers.
- The transmission investment review function examined transmission investments and their cost assignment to ratepayers and rates, assessed the impacts of investment on wholesale prices and renewable energy costs for ratepayers, and reviewed constraints within the regional transmission system negatively impacting Kansas electricity rates to address:
  - The benefits or costs to Kansas ratepayers from regional transmission investments;
  - The wholesale market and renewable energy benefits or costs to Kansas ratepayers from regional transmission investment; and
  - The costs and benefits incurred by Kansas ratepayers for transmission investment in Kansas used to export energy.

The markets workstream addressed key market related topics covering Kansas' regional economy and competitiveness, its regional electricity markets, and the future market for EV charging services.

- The EV markets assessment function reviewed current utility costs of providing EV charging services, the cost recovery relative to costs, and whether costs are being recovered from customers not using EV charging services. The function also reviewed benefits to non-EV drivers and whether they are being shared between customer classes, and best practices for deregulating EV charging services to maximize the benefits to ratepayers, EV drivers, and the wider community. This information was used to provide information regarding:
  - Whether deregulation would ensure EV charging services are not subsidized by public utility ratepayers not using EV charging services; and
  - Key options and approaches for deregulating EV charging services, emerging best practices in the area, and key recommendations to maximize the net benefits across ratepayers, EV drivers, and the community.

- The regional power market costs and benefits function integrated the impacts from a number of other workstreams on regional wholesale power market processes, and fed information to other areas' analyses regarding the impact of those changes on wholesale market costs and benefits. The activities included:
  - Analysis of the historical relationship between regional wholesale prices and transmission investment, regional exports, and fuel prices; and
  - Estimation of the impacts of transmission investments, regional exports, and fuel prices on regional wholesale prices paid by Kansas consumers.
- The regional cost competitiveness review function identified industries in Kansas most sensitive to retail electricity rates and their economic and job contributions, benchmarked Kansas' electricity rates by customer class as compared to state peers, reviewed economic development rates, and estimated the impact of economic development rates on ratepayers in order to determine:
  - Whether rates are a material barrier to economic development to economic development; and
  - Whether economic development rates address competitiveness gaps.

INFORMATION GATHERING

4. INFORMATION GATHERING

Information gathering for Part 2 of the Study was conducted in three stages. First, a Request for Information (RFI) was issued to the utilities, seeking specific data sets and other information. Then, stakeholders were engaged to gather additional viewpoints, information and data. Finally, the publicly accessible data and other available materials were used to fill data gaps, provide benchmarking information, and inform the analysis.

4.1 Request for Information

An RFI was developed to collect the utility data needed to model cost causation and allocation by customer class, specific programs, and certain investments. The RFI also asked for other information relevant to each of the 13 matters to be addressed by Part 2 of the Study. In total, the RFI, attached as **APPENDIX A: Request For Information,** contained 61 individual questions asking for information relating to the following:

- **EV Charging:** current and projected EV charging activities, their costs, and allocation; existing EV charging service rates and structure; and the potential costs and impacts of deregulating EV charging services.
- **Advanced Energy Solutions:** anonymized data on customers enrolled in advanced energy solution programs and information on all residential customers, including loads, rates, and charges; the number, megawatts, and annual megawatt hours of advanced energy solutions on the utility's network; and a description of current and planned advanced energy solution programs, feasibility studies, and rates or tariffs relating to those programs.
- **Transmission:** transmission investments, operating costs, allocation of costs, cost recovery, and transmission asset locations and flows; additional information specific to assets utilized to import and export electricity; costs, cost allocation, and revenues associated with the import and export of electricity; and transmission feasibility and cost-benefit studies.
- **Rates:** generation cost and recovery data, SPP costs, and, for Muni and Coops, costs from IOUs that were passed onto ratepayers.
- **Economic Development:** non-residential customer data, including loads, rates (economic development and contract rates, and others), charges, usage, location, and the reduction in rates from economic development or contract rates; feasibility studies relating to economic development or contract rates; and cost of service and revenue recovery treatment methodologies.
- **Cost Causation:** cost of service, cost allocation, and rate design models and reports; and load profiles for all customers.
- **Security:** historical and planned capital and operational costs relating to physical security, cyber security, and grid stabilization efforts; and studies relating thereto.
- **Resource Planning:** current resource plans, policies, and costs; and estimates of costs and benefits of moving to a state regulated planning process.
- **Fuel:** fuel prices/costs, procurement contracts, and hedging policies.

After the draft RFI was developed, its contents were reviewed during the project kick-off meeting, which was attended by the project team and staff from the Legislative Coordinating Council (LCC), KCC, Legislative Research, and Revisor of Statutes. Opinions regarding the sufficiency of the request, availability of data, breadth and manner of distribution, time necessary for response, and secure data sharing platforms were solicited during the meeting.

The final RFI was distributed by staff of the LCC directly to Evergy, Liberty Utilities, Midwest Energy, Sunflower Electric Cooperative, and KEPCo. LCC staff also sent the RFI to Kansas Electric Cooperatives, Inc. (KEC) and Kansas Municipal Utilities (KMU) to distribute to their members under the study's jurisdiction.[1] Utilities were asked to respond within two weeks in accordance with provisions of SB 69.[2]

Just days after the release of the RFI, many businesses in Kansas began closing or telling their employees to work from home due to the spread of COVID-19. Within a week, most, if not all, of the utilities and their representative associations were staffing office operations remotely. Given the additional challenges posed by the pandemic, a number of the utilities asked for, and were granted, a two-week extension to respond to the RFI.

Shortly after distribution of the RFI, the project team began having teleconferences with utilities and their representative associations to walk through the RFI, explain why the data was needed, and identify data gaps and alternatives if data was not available. As responses were received, follow-up teleconferences were held to clarify data issues, address missing information, and ask other questions to inform the analysis. Eighteen teleconferences with utilities were held to discuss data needed for the study. Additionally, multiple individual phone calls and e-mails were exchanged to discuss the data received and request additional information.

As the utilities began gathering data, the non-disclosure agreements (NDAs) were prepared for the protection of confidential data. Draft NDAs were forwarded to each utility and/or their representative association. After negotiation, a standard agreement was finalized, and the project team ultimately entered into an NDA with most of the utilities providing data to inform the study.

Data submittals started three weeks after the RFI was issued and the final responses were accepted for approximately 13 weeks, which was 2 weeks before the Part 2 of the Study was due. A large proportion of the data requested was not available due to a variety of reasons, most often because the utility did not have the data to provide. Such information was generally unavailable because the program was not offered, as was the case for EV charging services, or because the utility's metering system or databases did not record or store the information requested. In other instances, such as transmission and resource planning, smaller electric cooperatives rely on generation and transmission cooperatives to provide those services and, as such, had no independent information to provide in those areas. Finally, in some instances, confidentiality agreements with third parties, federal prohibitions, and security were cited as reasons the information was not provided. Given the number and type (e.g. IOU, Muni, or Coop) of utilities in the study, it is normal and anticipated that there would be differences in data management practices, labeling, applications, and systems. These differences create additional complexity when making comparisons and analyzing impacts in a statewide study.

Four key pieces of information were needed to model utility cost of service. While many utilities provided some at least some information, few provided all four key components. In some utility classes, this led to a small sample which could be analyzed. Such was the case with respect to the Cooperatives. Midwest Energy was the only Cooperative able to provide all necessary components to analyze cost of service for that utility class within the time frame necessary for use in the Study.

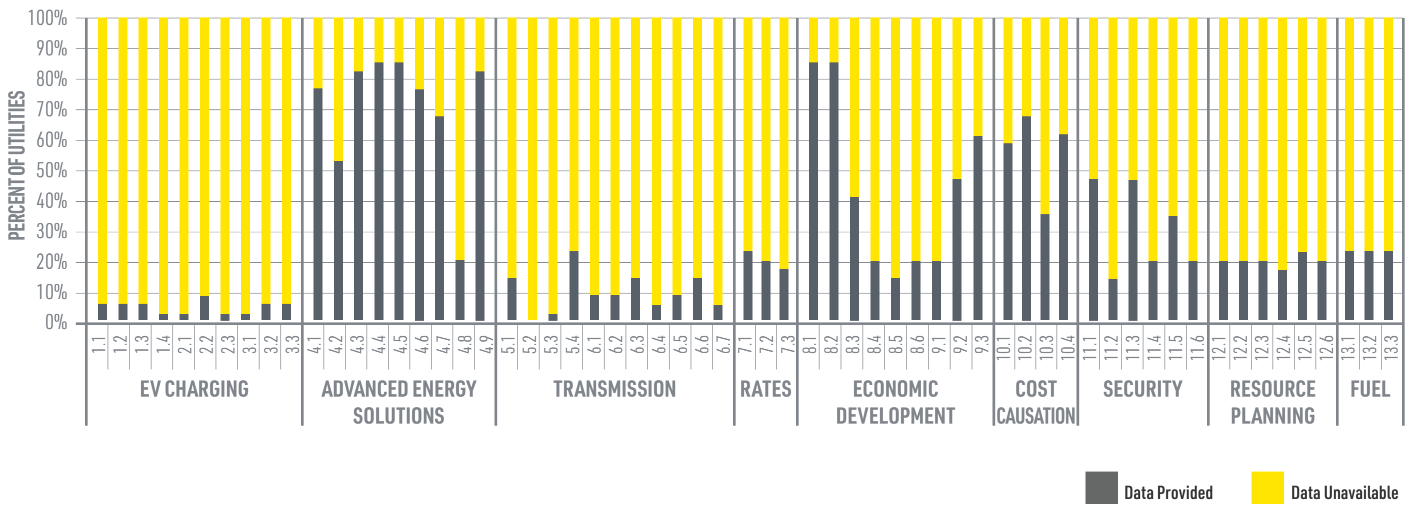
Following the initial release of the Study, in which analysis based upon material marked confidential by the utilities was redacted, the KCC entered an order instructing KCC staff and AECOM to work with the utilities to release all possible previously redacted material. Through this process, the utilities agreed to allow the release of most of the previously redacted information. Additionally, Midwest requested that previously redacted analysis based solely upon their cost of service information be labeled as such to more accurately reflect the information portrayed. The Study now reflects these changes.

1 KEC is the service organization representing Kansas electric cooperatives, including those under the jurisdiction of the study. KMU is the association representing public and non-profit entities which own and operate municipal utilities. All three Munis involved in the study are members of KMU. KEC and KMU coordinated much of the RFI dissemination to their members. They also provided their members with assistance during the information gathering process

2 K.S.A. § 66-1287b2

FIGURE 1. RFI Response Rate shows the areas in which data was not provided or available. The X-axis shows each RFI question number and its general subject area. The Y-axis represents the percent of utilities that provided data in response to the question.

FIGURE 1. RFI Response Rate



4.2 Stakeholder Engagement

Non-utility stakeholders were engaged to solicit additional information relevant to and provide their views on each matter to be addressed by Part 2 of the Study. Based upon an initial list provided by the LCC staff, stakeholders were identified that represented a broad spectrum of interests concerned with retail electricity rates and programs offered by Kansas utilities.

Given COVID-19 restrictions, two group stakeholder teleconferences were held in place of in-person discussions. Prior to the meetings, the 13 matters to be addressed in Part 2 of the Study were sent to stakeholders to help them prepare and promote informed discussion during the teleconference. A facilitated discussion was held around each area of the Study. Stakeholders were also encouraged to provide additional information following the teleconferences. Staff from the LCC, KCC, Legislative Research, and the Revisor of Statutes participated in each teleconference as observers without offering comment. Additional teleconferences were held with individual stakeholders who were not in attendance at the group meeting and, as needed, for additional follow up.

Thirty-three individuals, representing 24 non-utility entities, attended group or individual stakeholder conferences. **Appendix: Non-Utility Stakeholders** contains a list of the stakeholder organizations engaged. Stakeholders also submitted approximately 45 individual items to the project team. Items received included written responses to one or more of the 13 matters to be addressed in Part 2 of the Study, articles, studies, presentations, data files, and other materials.

Stakeholder feedback was invaluable for providing added context to both utility-specific policies and the broader state and regional legislative environment and representing ratepayer concerns about how these policies may impact utility rates and service. The areas of highest priority to stakeholders include balancing the impact of cross-subsidies resulting from increased uptake of emerging technologies and pursuit of economic development contracts with the benefits stemming from the associated growth in energy demand, as well as the increasing burden of security costs, underutilized coal generation, and regional transmission investments. Stakeholders offered recommendations for each of the matters studied by the project team, such as adopting EV charging rates based on location, vehicle type, charging technology, or customer charging behavior; deregulating public charging services; creating a new transmission export pricing mechanism; and using integrated resource planning frameworks to determine the optimal level of local market penetration for advanced energy solutions.

5. FINDINGS AND RECOMMENDATIONS

5.1 Electric Vehicle Charging Services Cost Recovery

Whether any costs incurred by Kansas electric public utilities to build and operate electric vehicle charging stations, including any necessary upgrades to distribution infrastructure, are recovered from ratepayers not using electric vehicle charging services.

5.1.1 BACKGROUND

In 2015 Kansas City Power & Light Co. (KCP&L) announced their plans to install 1,000 public chargers at a cost of $20 million as part of their Clean Charge Network (CCN). The utility requested the KCC to rate base $5.3 million of the investment and $250,000 per annum in operational costs in 2016, which the KCC rejected, in part because they could not tell what the level of demand for them might be.[1] Since then, KCP&L has deployed a total of 1,200 public chargers in its network, the vast majority of which are Level 2 charging stations.

Other Kansas utilities are investigating public charging infrastructure deployment, including public utilities. How costs for public charging infrastructure will be recovered and from whom is therefore of interest to Kansas electricity ratepayers, almost none of whom drive an EV, and many of whom may not see themselves ever driving an EV given their current shortcomings in comparison to internal combustion engine (ICE) vehicles, including cost premiums, driving range, and recharging rates.

5.1.2 SCOPE AND APPROACH

Answering the question posed by this matter of the Study involved the following steps:

- Obtaining information regarding cost allocation policies from Kansas utilities via the RFI;
- Obtaining information regarding key issues, inputs, and assumptions from the stakeholder engagement process;
- Analyzing public charging infrastructure's cost causation using hourly[2] public charging load, Southwest Power Pool (SPP) pricing, transmission system and utility system data; and
- Comparing the project team's assessment of cost causation against utility cost allocation policies and rate impacts to inform our conclusions with respect to the question posed.

5.1.3 INFORMATION GATHERING

The RFI was issued with the following information requests related to this matter:

1.1: How many public EV charging stations do you operate or plan to operate in the future?

1.2: What is your calculated current or forecast capital and operating expenses (including replacement costs) needed to fund EV charging services?

1.3: How much of these costs are passed on to ratepayers not using EV charging services?

1 KCC (2016). Order Denying KCP&L's Application for Approval of its Clean Charge Network Project and Electric Vehicle Charging Station Tariff. Retrieved from: https://estar.kcc.ks.gov/estar/ViewFile.aspx/20160913110134.pdf?Id=4b0556f3-425d-4469-8eb1-a105109511ec

2 Annual hourly load data is often referred to as '8760' data.

1.4: What is your calculated current or forecast capital and operating expenses by type (including replacement costs) relating to upgrades to distribution & transmission infrastructure necessitated to fund EV charging services not provided above?

In other portions of the RFI, additional related information was requested for use in assessing overall public charging load cost causation in comparison to that of each customer class, including:

- System hourly load data;
- Distribution network hourly load data by voltage (e.g. SCADA data);
- Cost of service models, including key inputs, assumptions, and outputs; and
- Customer hourly load, or if unavailable, hourly load by customer class.

5.1.3.1 SUMMARY OF RFI RESPONSES

Only one utility reported owning and operating public charging infrastructure. It confirmed that it was not recovering capital investment or operating costs associated with the direct costs of their public charging infrastructure in their regulated rates.

All other utilities, except one, confirmed that they were not, at this stage, planning to invest in public charging infrastructure. One utility reported being in the process of developing their plan, but that it was not sufficiently developed to provide answers to the RFI questions.

RFI GAPS AND WORKAROUNDS

Distribution system hourly load data was not received, nor was customer load data and a mapping table to enable rolling up hourly data to each level of the distribution network, as was requested by the project team. This information would have informed a detailed cost causation analysis of the impact of public charging infrastructure on the electricity distribution network.

Distribution networks are built to handle the highest forecasted (i.e. peak) load at each asset. The timing and level of maximum load can vary by voltage level and location, due to the different mix of residential, commercial, and industrial loads connected to the different voltage levels in the network. Hourly load data for each voltage level in the network is therefore key to measuring a given load's contribution to distribution cost causation.

In the absence of hourly load data by voltage level, annual utility system coincident peak (CP1) demand was used to determine public charging load's contribution to distribution costs. Quarterly (CP4) and monthly (CP12) coincident peak demand were also considered as potential cost causation factors but were rejected based on the project team's experience that distribution assets are more likely to peak on an annually correlated basis.[3]

5.1.3.2 STAKEHOLDER FEEDBACK

Consumer advocates noted that the KCC approved a tariff allowing Evergy to charge only EV charging customers for their use of the network. Stakeholders uniformly opposed EV charging related cost recovery from all customers. Reasons given for their opposition included low EV uptake and the possibility of providing unfair advantage in a potentially competitive marketplace.

5.1.4 KEY FINDINGS AND CONCLUSIONS

Determining whether any costs incurred by Kansas electric public utilities to build and operate electric vehicle charging stations, including any necessary upgrades to distribution infrastructure, are recovered from ratepayers not using electric vehicle charging services requires assessing the public charging and distribution infrastructure costs incurred versus the costs recovered.

3 Distribution systems tend to be summer or winter peaking, depending on the climate.

5.1.4.1 PUBLIC CHARGING INFRASTRUCTURE

None of the utilities that responded to the RFI reported recovering any public charging costs from ratepayers via their standard rates. While it is possible that Evergy's public charging infrastructure costs are being recovered in their rate base, utilities generally have strong policies, processes, and systems in place to guard against the inappropriate allocation of costs to a regulated cost account.

Based on the above information, it was concluded that utilities are unlikely to be recovering public charging infrastructure costs from ratepayers.

A discussion surrounding whether or not they are recovering the costs for any associated upgrades to distribution infrastructure is covered in the following section.

5.1.4.2 DISTRIBUTION INFRASTRUCTURE

Determining whether there is a cross-subsidy between EV drivers using public charging infrastructure and other ratepayers requires comparing the utility's marginal cost to serve public charging infrastructure to the marginal revenues recovered through electric bills.

The project team calculated the impact of public charging load on a utility's cost to serve is based on its contribution to:

- Generation settlement costs in the SPP;
- NITS[4] transmission charges based on its transmission zone CP12 contribution; and
- Estimated distribution cost to serve based on its distribution system CP1 contribution.

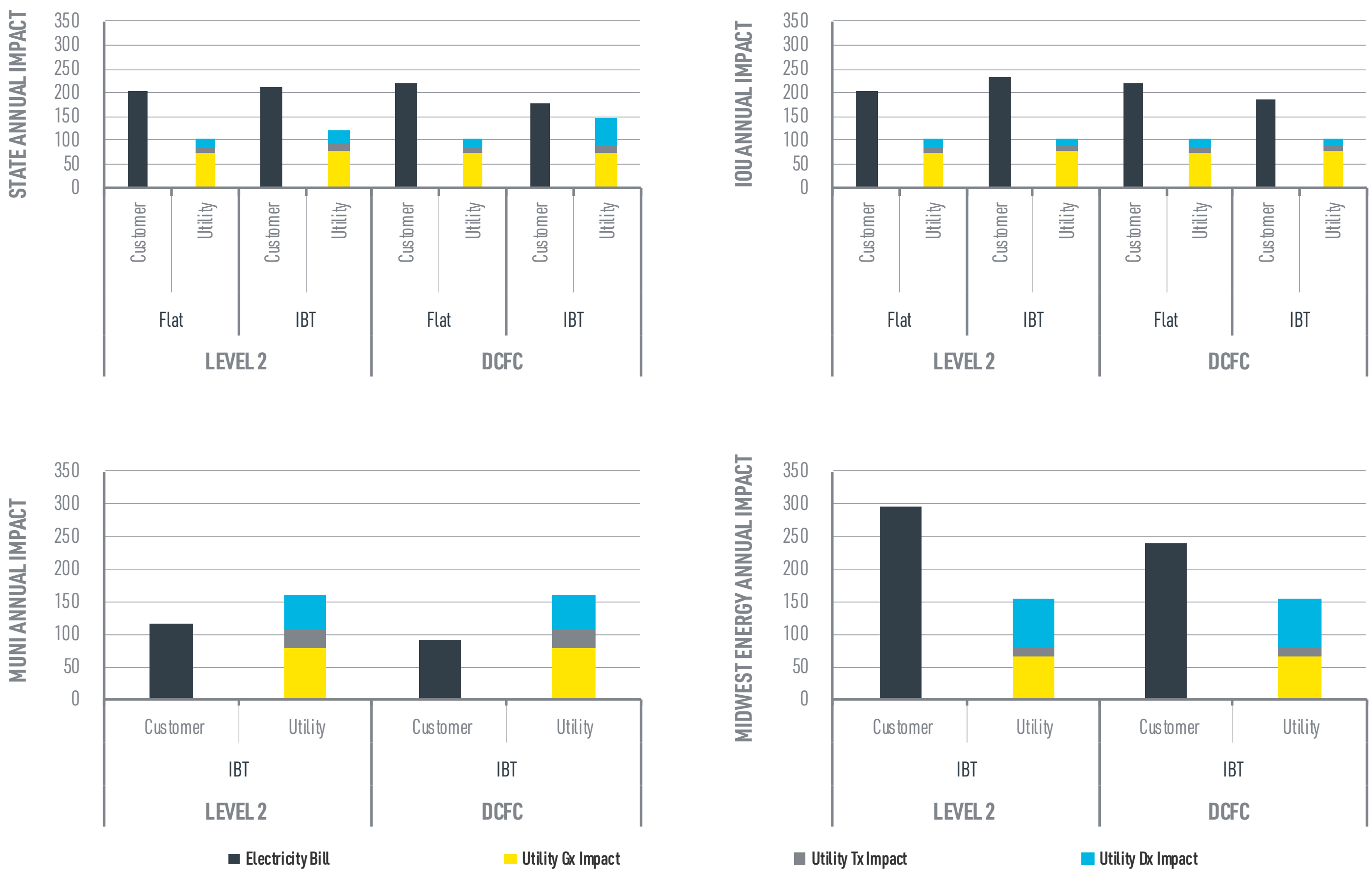
The impact of public charging load on revenue recovery was calculated based on an estimated public charging profile per registered EV driver and was applied to each rate and customer class. This profile used in the analysis was based on the one provided by Evergy.

FIGURE 2. Estimated Utility Cost to Serve vs. EV Driver Bill Impacts (Public Charging) shows the change in utility cost to serve compared to the change in EV driver bill. The analysis suggests that retail electricity rates are over-recovering the marginal cost of serving public charging infrastructure load across IOUs and Midwest Energy. This is likely due to the inclusion of sunk[5] costs in retail rates, which are higher marginal costs. Muni rates, on the other hand, appear to be under-recovering costs given estimated public charging load impacts.

4 NITS stands for Network Integration Transmission Service.

5 Sunk costs reflect historical costs, marginal costs reflect forward looking costs for an incremental unit of demand.

FIGURE 2. Estimated Utility Cost to Serve vs. EV Driver Bill Impacts (Public Charging)



Source: Energeia (2020)

Based on the analytical methodology, inputs, assumptions and outcomes reported above, utility rates applied to public charging stations are over-recovering their marginal cost of service, except in the case of Munis, leading the project team to conclude that electricity system costs are being over-recovered from EV drivers by IOUs and Midwest Energy.[6]

5.2 Electric Vehicle Charging Services Rate Design

How rates for electric vehicle charging services should be designed to ensure such rates are just and reasonable and not subsidized by other utility customers.

5.2.1 BACKGROUND

Deregulation of EV charging services would allow public charging service providers to purchase their electricity supply from the local utility and then charge whatever price they choose. The Kansas Legislature has recently considered

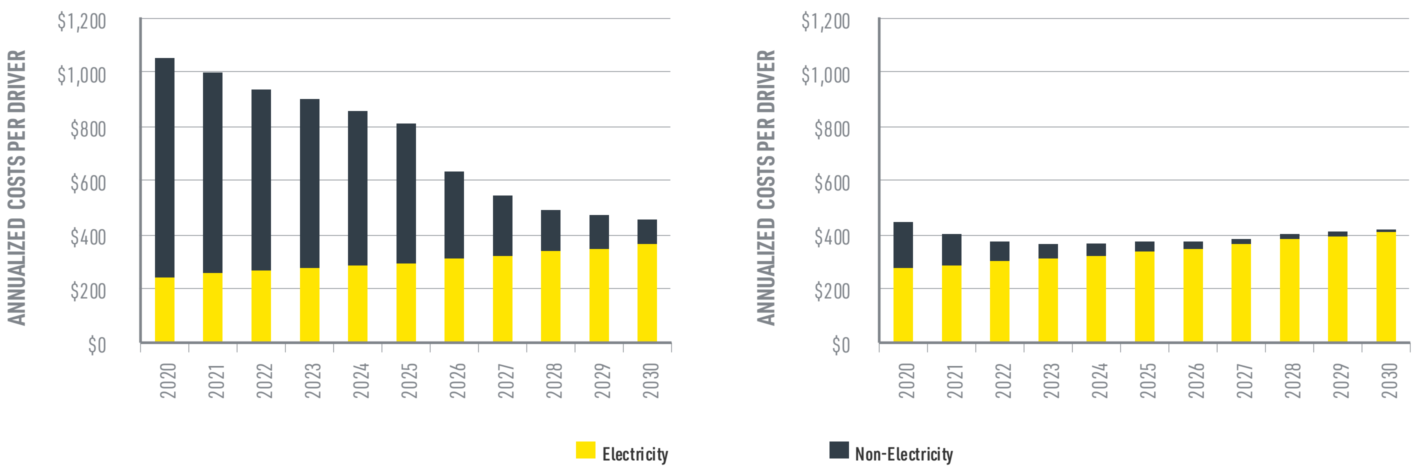
6 Section 5.2.6 presents our recommended rate design approach for mitigating these cross-subsidies

deregulating EV charging services, although the measure did not pass.[7] As a regulated service, rate design of EV charging services should strive to be just and reasonable and avoid cross-subsidization.

Given the significant role that electricity supply costs are forecast to play in the operational and maintenance costs of a public charging station, illustrated in **FIGURE 3. Forecasted Level 2 (Left) and Level 3 (Right) Public Charging Costs per Driver by Cost Type**, it is important that these costs be set on a cost causation basis to meet the requirements of state law and good industry practice.

Electricity plays a greater role in the forecast for Level 2 chargers because these chargers are more likely than a Level 3 to be underutilized, particularly in the near-term, before EVs become more common.[8] As the number of drivers increases per charging station, the annualized fixed costs decrease.

FIGURE 3. Forecasted Level 2 (Left) and Level 3 (Right) Public Charging Costs per Driver by Cost Type



Census Data (2017), ICCT (2019), Energeia

Analysis completed in **Section 5.1** identified that current electricity rates appear to result in some cost shifting between EV drivers and other ratepayers, the extent of which varies by utility type The question then becomes whether EV rates should be designed to ensure they are just and reasonable, meaning they not subsidized by other utility customers, and if so, how.

5.2.1.2 THE PURPOSE OF RATE DESIGN

According to the National Association of Regulatory Utility Commissioners (NARUC):

The basic purpose of rate design is to implement a set of rates for each rate class—residential, commercial, and industrial—that produces the revenues necessary to recover the cost of serving that rate class. In practice, rates are not based on an individual customer's cost to serve; rather, similar customers are accumulated into rate classes. In this way, the total cost incurred to provide service to the entire rate class can be determined through detailed studies using cost-causation principles. This total cost is then allocated across all the customers in that rate class.[9]

7 Kansas State Legislature (2020). HB 2585 Bill History. Retrieved from: http://www.kslegislature.org/li/b2019_20/measures/hb2585/

8 The model assumes one driver per Level 2 charging station and 15 drivers per Level 3 charging station, a likely scenario for the near future.

9 NARUC (2016). NARUC Manual on Distributed Energy Resources and Rate Design and Compensation. Retrieved from: https://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0

In addition to the common base-set of customer classes called out above, most utilities define additional classes depending on their circumstances, such as irrigation or heating loads. Both of these loads also compete for demand with other fuels (e.g. diesel and natural gas).

Whether or not public charging should be subject to existing customer class rates, or receive their own rate similar to irrigation, is a key question to be answered. The answer normally depends upon whether the load is significantly different to other loads in terms of its contribution to cost to serve and its ability to respond to prices.[10]

5.2.1.3 RATE DESIGN POLICY AND REGULATION

Retail electric utility rates in the U.S. are typically regulated by Public Utility Commissions (PUCs)[11] , with transmission rates regulated by the Federal Energy Regulatory Commission (FERC). EV charging rates are considered retail rates.

NARUC has published a best practice handbook[12] to inform and support its member regulators in implementing industry best practices related to the design of rates involving Distributed Energy Resources (DER), including EVs. However, it does not specifically address rates for public charging.

In Kansas, legislation requires[13] that prices be determined in a just and reasonable manner, which has been interpreted by the Kansas courts as falling within the reasonable space between investor, customer, and community costs and benefits.[14]

In practice, this means rates are to be designed on a cost causation basis, meaning that costs should be paid by the causer. The causer is most often defined at the customer class level, which is in turn defined as a group of customers with similar costs to serve and price elasticity of demand.[15]

Designing cost-effective rates is not without its challenges, especially in considering the complexity and opaqueness of electric utility costs. Although cost reporting and analytical methods have improved over the past decade, significant challenges remain in effectively merging the data and methodology. The KCC acknowledged these challenges in their recent comments on the difficulties in developing truly cost-reflective rates and estimating cross-subsidies due to the 'subjective and complex' nature of the cost of service models currently used to determine customer class revenue requirements.[16]

5.2.1.4 PUBLIC CHARGING RATE DESIGN OPTIONS

FIGURE 4. Types of Charging and Key Rate Options diagrams common types of EV charging, outlining the potential EV charging applications and typical rate structures that could be applied to each case, and highlighting that some types of public charging are not suitable for load management due to a need to immediately recharge. Other types of charging, though, such as where a car may be left overnight, can be more flexible.

10 This is typically referred to as the price elasticity of demand by economists, which is discussed further below.

11 The Kansas Corporation Commission (KCC) regulates IOU retail rates in Kansas. Muni and Coop retail rates are unregulated.

12 NARUC (2016). NARUC Manual on Distributed Energy Resources and Rate Design and Compensation. Retrieved from: https://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0

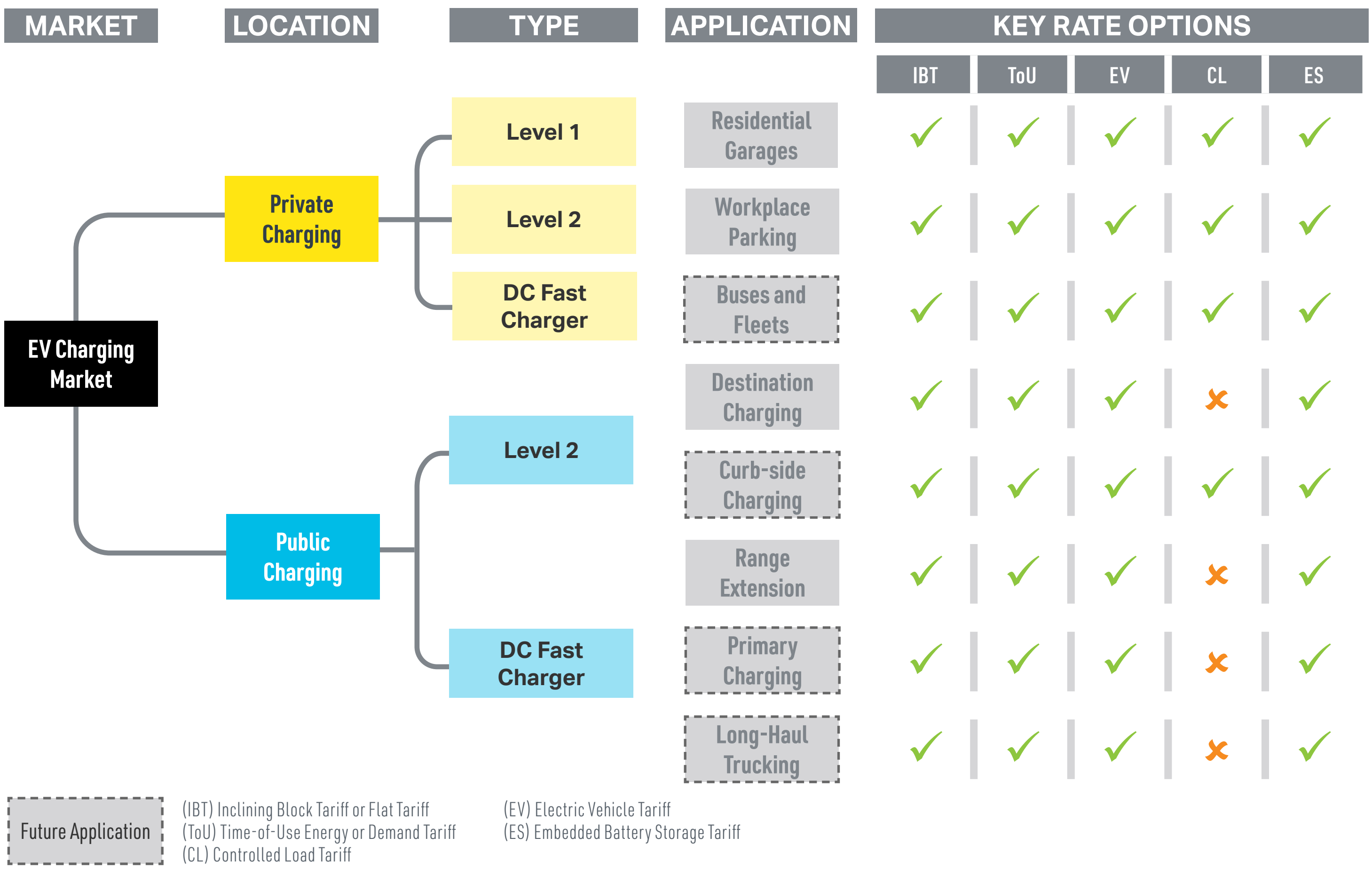
13 K.S.A. § 66-101b

14 KCC (2018). Rate Study of Kansas City Power & Light and Westar Energy for the Years 2008 to 2018. Retrieved from: https://kcc.ks.gov/images/PDFs/electric/Rate-Study-Final-1-13-2018.pdf

15 Price elasticity of demand is defined as the unit change in demand for a unit change in price.

16 KCC (2018). Rate Study of Kansas City Power & Light and Westar Energy for the Years 2008 to 2018. Retrieved from: https://kcc.ks.gov/images/PDFs/electric/Rate-Study-Final-1-13-2018.pdf

FIGURE 4. Types of Charging and Key Rate Options



Source: Energeia (2020)

With so many distinct alternatives and potential combinations of public charging applications, whether and how electricity for public charging infrastructure should be charged in Kansas is therefore a topical question of interest to Kansas electricity ratepayers and other stakeholders.

5.2.2 SCOPE AND APPROACH

The project team's approach to answering the question involved the following steps:

- Obtaining information regarding each utility's approach to designing their public charging infrastructure rate to identify the basis of current approaches;
- Reviewing Kansas legislation, case law, and regulatory proceedings related to rate design to identify the key design requirements in Kansas;
- Reviewing the economic and industry literature and examples of public charging rates design in the public domain to identify U.S. best practice; and
- Developing a best practice approach that is consistent with Kansas statutes, case law, and regulatory proceedings, as well as economic theory and industry best practice.

5.2.3 INFORMATION GATHERING

Information to answer this question was gathered via the RFI process, meetings with key stakeholders as outlined in **Section 4.2** and research to identify Kansas statutory, case law, and regulatory requirements, as well as economic theory and U.S. best practice.

5.2.3.1 SUMMARY OF RFI REQUESTS , GAPS, AND WORKAROUNDS

The RFI was issued with the following information requests related to this matter:

2.1: How do you recover the costs of EV charging services (e.g. monthly fixed fee, flat kWh, Time of Use kWh, etc.)?

2.2: How do you or will you ensure that EV charging services are just and reasonable and not subsidized by other utility customers?

2.3: Provide copies of tariffs, riders, or other cost recovery mechanisms associated with EV charging services.

In other portions of the RFI, additional related information was requested for use as a basis for assessing cost causation:

- System hourly load data;
- Distribution network hourly load data by voltage (i.e. SCADA data);
- Cost of service models, including key inputs, assumptions, and outputs;
- Customer hourly load, or if unavailable, hourly load by customer class; and
- Public charging hourly loads, or if unavailable, an aggregated hourly load.

None of the utilities reported having a public charging EV rate for use by third party public charging service operators or plans to implement such a rate. Given that only utilities have been able to offer public charging services to date, this is expected.

One of the utilities reported that it would set prices for public charging on the basis of cost of service.

5.2.3.2 STAKEHOLDER FEEDBACK

Stakeholder feedback predominantly focused on how rates could be better designed to eliminate potential cross-subsidies, especially with respect to lower-income ratepayers and use of public chargers by EV drivers outside of the utility's service territory. A smaller subset of stakeholders did not take issue with cross-subsidization in rates, though, as increased EV uptake (and rates that would encourage this) would act to reduce the cost of electricity for all ratepayers, not just EV drivers, and provide other social benefits, such as reduced air pollution.

Rates based on use cases that define location, vehicle type, charging technology, and charging behavior of customers were proposed. One stakeholder also recommended separately metered TOU rates in order to create effective and efficient price signals for energy consumers, minimize long-term grid impacts from increased EV adoption, and maximize fuel cost savings for EV owners.

5.2.4 KANSAS STATUTES, CASE LAW AND REGULATORY REQUIREMENTS

Research into the definition, interpretation and application of *Just and Reasonable* rates and *Subsidy-Free* rates identified the following key statutes, legal cases and regulatory proceedings.

5.2.4.1 STATUTORY REQUIREMENTS

Kansas state law empowers the KCC to regulate IOU retail electricity rates.

> *The commission shall have the power, after notice and hearing in accordance with the provisions of the Kansas administrative procedure act, to require all electric public utilities governed by this act to establish and maintain just and reasonable rates when the same are reasonably necessary in order to maintain reasonably sufficient and efficient service from such electric public utilities.*[17]

17 K.S.A. § 66-101b

KCC decisions regarding retail price setting are subject to appeal via the court system.

Retail price setting for customers served by Munis falls under the statutes covering city-provided utility services:

> *Upon the recommendation of said board of commissioners, the governing body shall by ordinance fix such rates for water, fuel, power or light as are recommended by said board, provide for such employees as may be necessary to operate said plant or plants, define their duties, and fix their salaries; and when such employees are once appointed, they shall not be removed from service except for inefficiency or neglect of duty.*[18]

City commission or council decisions regarding municipal rates are subject to legal challenge, as well as democratic action at the ballot box influencing the appointment of commissioners or removal of elected officials.

Rural electric Coops set their own prices, which are not governed by statute. Coop prices are regulated by their membership.

5.2.4.2 LEGAL PRECEDENT

Legal challenges to KCC decisions regarding rates design are played out in Kansas' state court, with the judgements setting precedent and thus informing legal framework over time. The following decisions provide key background and insight into the interpretation and application of just and reasonable rates:

- **Kansas Gas Electric Co. v. KCC (1986):** In its decision, the Kansas Supreme Court (Court) stated that "The Kansas Corporation Commission, in setting the rates for an electrical utility, should have as its goal the fixing of the rates, within a zone of reasonableness after balancing the interests of the utility's investors, the ratepayers, and the public." The Court also declared that there is no legal basis under which a utility is guaranteed a return on capital irrespective of the interest of the ratepayer, and that the KCC is not tied to particular formulae in valuing the utility's property.[19]
- **Farmland Industries v. KCC (1997):** In this case the Court stated that, "given the complexity and the nature of the commission's role, it would uphold the its [KCC rate] decision unless it was found "unlawful, not supported by substantial competent evidence, is without foundation in fact, or is otherwise unreasonable, arbitrary, or capricious."" The Court also added that the KCC must "weigh competing policies in determining the recovery of appropriate rate expenses."[20]
- **In the Matter of the Joint Application of Westar Energy, Inc. (2020):** On April 2020, the Court published an opinion, disagreeing with the joint application by Westar and Kansas Gas and Electric. In the application, the utilities argued that demand charges levied against distributed generation customers, and resulting rate increases, were allowed under a K.S.A. 66-1265, which stated the utilities had the option to change the rate structures of customer-generators. The utilities argued this new law superseded 1980 legislature which protected customer-generators from rate hikes. The Court disagreed, finding that the two directives were not in competition with each other, and that it was possible to change rate structures without imposing rate increases.[21]

The KCC's own interpretation of 1986 and 1997 legal precedent was summarized in their recent rate study:

As a specialized decision-making body, the statutory authorization to establish "just and reasonable" rates implies flexibility in exercising our complicated regulatory function. That same statutory authorization was not intended to confine the boundary of our regulatory discretion to an absolute or mathematical formula, but rather it was intended to confer power to make and apply policy concerning the appropriate prices charged to utility customers and returns on capital to utility investors in accord with constitutional protections applicable to both interests. Thus, the Kansas courts have always held that our goal is to fix rates within a "zone of reasonableness," after we balance the interests of the utility's investors, ratepayers, and the public.

18 K.S.A. § 12-829

19 Kansas Gas Electric Co. v. Kansas Corporation Comm'n, 239 Kan. 483, 720 P.2d 1063 (Kan. 1986).

20 Farmland Industries v. Kansas Corp. Comm'n, 943 P.2d 470, 24 Kan. App. 2d 172, 24 Kan. App. 2 (Kan. Ct. App. 1997).

21 In re Westar Energy, Inc., No. 120,436 2020 WL 1646814 (Kan. Apr. 3, 2020)

5.2.5 U.S. BEST PRACTICE

Research was undertaken to identify industry best practices with respect to the design of public charging infrastructure rates.

5.2.5.1 INDUSTRY LITERATURE

The following sections summarize the key insights that were found from authoritative and/or recently published reports relevant to the design of public charging rates, which include:

- Establishing EV load as a separate rate class;
- Designing new tailored rate structures that reflect marginal rather than embedded costs;
- Avoiding rate elements that rely on customer maximum demand; and
- Including explicit prices signals for load management and demand response.

NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS (NARUC)

The main resource used by regulated rate managers and utility regulators in the U.S. to evaluate local utility activities against industry best practice methods is the NARUC rate design manual, which was updated in 2016 to address issues raised by DER.

The following excerpt summarizes key thinking from this report relevant to public charging rate design:

> *Distributed Energy Resources (DER), as new technologies, challenge traditional network structure (large, central generation), regulatory framework and incentives…Rate design guidelines need to be flexible, to address these changes. For example, initially, rate structures should account for the need for incentives in the initial stage, which should be phased out over time…Rate design to reach fair revenue and cost recovery for both the utility and ratepayers, will depend on the structure and DER integration stage of each individual utility. Rate design options explored by NARUC, to address economic issues resulting from DER integration such as cost-shifting, include* ***changing existing rate structures, creating new customer classes, and tailored and explicit price signals****.[22] (emphasis added)*

ROCKY MOUNTAIN INSTITUTE (RMI)

In its 2017 report, the Rocky Mountain Institute (RMI) recommended time-varying volumetric rates, such as Time of Use (ToU) energy ($/kWh) rates, combined with low fixed charges and moving away from demand charges. They also recommended rates that vary by location to incentivize public charging in underutilized parts of the grid. Finally, the researchers recommend recovering some of the costs from the general rate base, arguing that EV charging stations provide an added value in terms of social goods.[23]

BRATTLE GROUP

In its report exploring EV fast charging rate options published in 2019, Brattle recommends designing new rates for a separate rate class targeting Level 3 charging load. Possible rate structures range from volumetric and demand charges to more complex, alternative rate structures. Other rate design recommendations include limited demand-related charges and more detailed price signals.[24]

SYNAPSE ENERGY ECONOMICS

Synapse recommends a series of principles in its 2020 report for designing EV rates in order to make them cost-reflective and to enable utility access to EV load as a flexible resource. This leads to recommendations including favoring time-varying volumetric charges over demand charges, particularly non-coincident peak demand charges. The

22 NARUC (2016). NARUC Manual on Distributed Energy Resources Rate Design and Compensation. Retrieved from: https://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0

23 Fitzgerald, F. and Nelder, C. (2017). EVGo Fleet and Tariff Analysis. Rocky Mountain Institute. Retrieved from: https://rmi.org/wp-content/uploads/2017/04/eLab_EVgo_Fleet_and_Tariff_Analysis_2017.pdf

24 Hledik, R. and Weiss, J. (2019). Increasing Electric Vehicle Fast Charging Deployment. The Brattle Group. Retrieved from: http://files.brattle.com/files/15077_increasing_ev_fast_charging_deployment_-_final.pdf

report also states that it may be appropriate to set rates to recover marginal costs rather than embedded costs to avoid cross-subsidies.[25]

5.2.5.2 INDUSTRY BEST PRACTICE

Finally, actual industry practice with respect to public charging rates was researched. The research found that electric utilities across the U.S. are developing new rates to better serve EV loads. However, not every utility is designing a new rate for EVs; many are requiring public charging infrastructure users to pay the same rate as any other load.

The results of this independent research regarding public charging infrastructure rates design for selected utilities with mature EV programs is summarized in **TABLE 3. Specific EV Rates Availability as of 2019**.

TABLE 3. Specific EV Rates Availability as of 2019

Jurisdiction	Utility	Tariff Type						EV Incentives - Tariff and Non-Tariff*					
		IBT/Flat		ToU		EV Charging		Energy Rate ($/kWh)**		Controlled Load***		Structural Changes****	
		Res	Com	Res	Com	Res	Com	Res	Com	Res	Com	Res	Com
California	PG&E	✓	✓	✓	✓	✓	×	×	N/A	×	N/A	✓	N/A
	LADWP	✓	✓	✓	✓	✓	✓	✓	✓	×	×	×	✓
	SDG&E	✓	✓	✓	✓	✓	✓ ****	✓	?	×	×	×	✓
	SCE	✓	✓	✓	✓	✓	✓	✓	✓	×	×	×	✓
Hawaii	HECO	✓	✓	✓	✓	✓	×	×	N/A	×	N/A	✓	N/A
New York	Con Ed	✓	✓	✓	✓	✓	×	✓	N/A	×	N/A	×	N/A
Minnesota	Xcel	✓	✓	✓	✓	✓	×	×	N/A	×	N/A	×	N/A
Texas	Austin Energy	✓	✓	✓	✓	✓	×	×	N/A	×	N/A	✓	N/A

*EV Incentives are comparing the EV Charging tariffs to the Time of Use (ToU) tariff (if unavailable, then the Inclining Block Tariff (IBT)/Flat tariff

**Whether there is a discount to the energy rates

***Whether the tariff includes a direct load control

****Whether there are changes to the structure of the tariff

***** SDG&E's EV Charging Tariff is only available through an ongoing pilot and is not an implemented tariff.

Source: Energeia

Key findings from this research include:

- There is not yet an industry consensus among utilities as to whether or not public charging is a stand-alone customer class in its own right;
- There is not yet an industry consensus as to the most appropriate rate design for Level 2 or Level 3 charging, however, the approaches are similar to comparable loads; and
- Those that are designing new rates are doing so to address perceived barriers in the existing rate structures, especially annual maximum charges.

25 Whited, M., Frost, J., and Havumaki, B. (2020). Best Practices for Commercial and Industrial EV Rates. Synapse Energy Economics. Retrieved from: https://www.synapse-energy.com/sites/default/files/Best-Practices-Commercial-Industrial-EV-Rates_18-122.pdf

5.2.6 KEY FINDINGS AND CONCLUSIONS

Determining how rates for electric vehicle charging services should be designed to ensure such rates are just and reasonable and not subsidized by other utility customers required understanding the definition of just and reasonable, as well as the cost of service and efficient rate design principles consistent with industry best practice.

JUST AND REASONABLE RATES

Based on the foregoing research and analysis, 'just and reasonable' rates are understood to fall within a 'zone of reasonableness' after balancing the interests of the utility's investors, the ratepayers, and the general public. Furthermore, the rates must be lawful, supported by substantial competent evidence, and not be unreasonable, arbitrary, or capricious.

Determining whether rates are just and reasonable therefore requires an understanding of the various concerns and priorities of interested parties, which are summarized below:

- **Shareholder** interests are to earn the highest possible, risk-adjusted, total rate of return, including dividends and share price increases;[26]
- **Ratepayer** interests are to pay the lowest possible price given acceptable standards of safety, reliability, and security; and
- **Public** interests include ensuring the electricity system supports the community's economic growth, health, and other social objectives.

With this understanding of the values of interested parties, the project team has interpreted the definition of "just and reasonable" to mean that public charging rates must reasonably reflect the efficient cost of service, and potentially any demonstrable benefits that public charging may afford to the public, as allowed by state law.

Additionally, findings regarding industry best practice, that the rate design should strive for cost reflectivity at the rate component level, and not just at the class or bill level. This leads to the avoidance of non-coincident peak (NCP) demand charges, except in certain[27] situations. Rates should also reflect marginal (forward-thinking) rather than embedded (backward-thinking) costs.

SUBSIDY FREE

Just and reasonable rates would also, generally, be subsidy free because all the costs associated with provision of the service would be recovered via the rate design; no more, no less.

COST OF SERVICE

Public charging's electricity system marginal cost of service is comprised of the following main functional areas, as per any electrical load:

- **SPP generation settlement costs:** charged based on the hourly load of public charging stations;
- **SPP transmission charges:** charged based on the contribution of public charging station load to the 12 coincident peaks (CP12);
- **Distribution costs:** charged based on the contribution of public charging load to distribution peaks across substations and feeders, which may vary by location and voltage level; and
- **Retailing costs:** typically driven by customer numbers and not by load patterns or levels; for example, metering, billing, and customer service.

Different types of cost are triggered at different times of the day and days of the year. It is essential the rate period setting be determined based on forecasted one-in-ten year peak demand. Developing forward-looking time periods is challenging but essential to provide the correct economic signals.

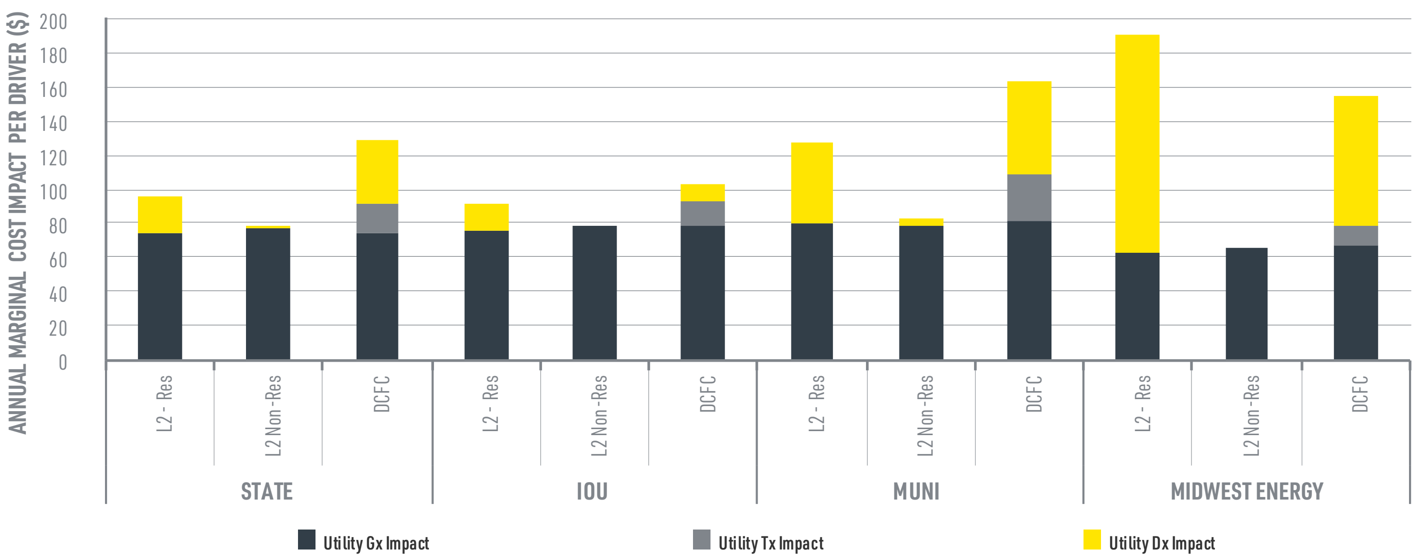
26 Muni customers and electric Coop members are generally understood to be more closely aligned with those of ratepayers and the public than are IOU shareholders

27 For example, to recover costs for dedicated connection assets, whose cost is driven by premises annual NCP.

The project team's analysis[28] of a typical public charging user's electricity system marginal cost to serve by utility type and component is shown in the **FIGURE 5. Estimated Public Charging Annual Cost to Serve per EV Driver**. This analysis shows that Level 3 charging stations cost more per customer per year than Level 2 charging stations, mainly due to higher distribution system impacts. The exception to this rule is Midwest Energy, where residential Level 2 chargers cost the most to serve.

Variations between public charging applications and utility categories are mainly due to differences in SPP settlement costs and the timing of the utility's peak demand, which is the key driver for estimating distribution system impacts. Assumptions about load management for Level 2 chargers is therefore critical to the cost of service estimates; this analysis assumed there was no load management.

FIGURE 5. Estimated Public Charging Annual Cost to Serve per EV Driver



Source: Energeia (2020)

With this cost of service in hand, the next step is the classification of the load and design of the revenue recovery instrument itself, i.e. the rate, including the selection of charging components and their associated periods of congestion.

CLASSIFICATION

Load classification leads to grouping new types of load, such as public charging, with other existing load classifications[29] or creating a new load class, as is sometimes done for irrigation or electric heating loads.

Whether or not to classify public charging load apart from other customer classes typically depends upon whether there is a justifiable reason for doing so such as:

- **Differences in the cost to serve**, for example, if public charging used different asset classes and/or relatively more or less demand during CP12 or CP1 events compared to other customer classes;
- **Differences in price responsiveness**, due to differences in the ability modify demand (e.g. charge later) or to substitute demand (e.g. by buying an ICE vehicle); and
- **Differences in public benefits**, such as differences in the impact of the load on public health by reducing tailpipe emissions or access to low cost heating in winter.

28 Information regarding the modelling approach and key assumptions can be found in Appendix X: Modeling Methodology, Key Inputs, and Assumptions.

29 Residential, commercial or industrial classifications

Establishing public charging as a new rate class will incur higher operating costs due to the associated costs for managing the respective cost of service studies and rates design over time, so the benefits of doing so should outweigh the costs.

UTILITY TRENDS AND BENCHMARKS

The project team's review of current U.S. utility practices reported in **Section 5.2.5** found that utilities take several different approaches to classifying EV charging, with some setting up separate charges, some setting up separate riders (normally discounts), and others doing neither.

With no clear best practice approach, the project team reviewed the reasons for and against classifying public charging load as part of or separate to existing rate classes.

COST TO SERVE ANALYSIS

The results of the project team's analysis of EV charges in comparison to their marginal cost to serve completed in **Section 5.1** found that using existing rates would lead to significantly higher EV charging costs than establishing new rates based on marginal cost to serve analysis. In other words, if EV rates are not broken out from standard rates, EV drivers are likely to be paying a subsidy to non-EV drivers.

PRICE SENSITIVITY ANALYSIS

Regarding price sensitivity, while EV drivers needing to recharge will exhibit a relatively lower price elasticity of demand, the decision to purchase an EV over an ICE vehicle is cost sensitive, so relatively higher rates will lead to relatively lower demand for EV charging over time.

Based on this analysis, the project team believes that public charging should be separated from other rates to allocate a different level of sunk costs than are allocated to the main customer classes. This would better balance the interests of other stakeholders, including ratepayers and the public interest.

COST RECOVERY

Rates typically include a fixed charge to recover retailing and other costs that do not vary with demand, and one or more volumetric charge, to recover demand related costs.

The main types of rates include:

- **Flat:** Charges are based on a single $/kWh price. This is the simplest rate design, but also the least cost reflective, as the cost of supply varies widely by time-of-use.
- **Inclining or declining block:** Charges are based on total consumption over a given period (e.g. month or season), with higher volumes incurring higher (inclining) or lower (declining) prices.
- **Time-of-Use (ToU) energy (kWh):** $/kWh charges vary by the period or time of use. Rates are typically set according to two or three periods but can be more complex when seasonally and diurnally set.
- **ToU maximum demand (kW or kVA):** Similar to ToU energy rates but use maximum demand during the period (not energy) to set charges.
- **Critical peak price:** Similar to other ToU rates, but the peak period is set dynamically, and not subject to a fixed schedule. It is relatively cost reflective, but also relatively complex.
- **Real-time pricing (RTP):** Prices are set based on market and infrastructure conditions in real-time or near-time. This rate design is highly cost reflective, but also highly complex.
- **Hybrid:** Hybrid prices mix any of these rate types and are most common for larger and more sophisticated commercial and industrial customers.

It is important to note that these rate designs may require additional costs to implement, such as upgrading the metering and/or billing systems, and for consumers or their agents to invest in the software and hardware necessary to receive, analyze and respond to the pricing data.

Any rate can be crafted to recover 100% of target revenues. Other important considerations of interest to stakeholders when choosing among different rate design options include:

- **Simplicity:** A simpler design should be selected over a more complex design, all else being equal. Simpler rates are also easier for customers to understand and respond to.[30]
- **Usability:** A rate that is tailored to a customer's ability to understand and respond to it is better than one which is not.
- **Fairness:** A rate that benefits customers equally and minimizes cross-subsidies is preferable to a rate that does not.
- **Stability:** A rate that is stable is better than one that changes suddenly, significantly, or both. Unsustainable rate designs are unstable.
- **Efficiency:** A rates with prices set equal to marginal costs is better than one that does not because they reduce cross-subsidies and increase allocative efficiency.[31]
- **Implementation Cost:** A rate that are lower cost to implement should be preferred over rates that are higher cost to implement, all else being equal.

A JUST AND REASONABLE RATE DESIGN

Based upon the foregoing analysis, the project team recommends that just and reasonable public charging rates be:

- Broken into their own rate class to enable appropriate allocation of sunk costs, given competition with ICE vehicles and the impacts of EVs on electricity prices and public health; and
- Based on the following hybrid rate design, which matches each cost driver to a cost reflective rate component:
  - **Fixed charge:** recovers retailing and other charges driven by customer volume and not load patterns or levels.
  - **Peak period charge:** recovers the cost of generation, transmission, and distribution costs, with the peak period set based on expected CP1 and CP12 windows.
  - **Off-peak period charge:** recovers the cost of generation outside of the peak period; may be broken into multiple periods where there is significant variation in pricing levels.
  - **Annual maximum demand charge (where appropriate):** recovers the cost of assets whose peak demand is driven by this class of customers (e.g. any dedicated substation or feeder).

While this structure is more complex than some alternatives, it is less complex than critical peak or real-time pricing. Increasing automation of load management also means that expert systems, rather than humans, will be engaging with the rate, reducing the cost of complexity in favor of efficiency.

Additionally, this design is expected to be relatively stable, as the cost reflectivity of the design will help ensure that it is sustainable over time. However, changes in cost factors or demand will be passed through to public charging users more directly than other rate design options.

In the project team's view, the use of cost reflective charging components is essential for making the public charging rate as fair and efficient as possible, without moving to the much more complex and costly to implement critical peak or real-time pricing approaches, which we do not think strike the fair and efficient balance between stakeholder interests.

30 As technology enabled demand response increases, the need for human understanding is expected to fall.

31 Allocative efficiency occurs where marginal costs are equal to marginal prices, ensuring efficient demand.

5.3 Potential Effects of Deregulating Electric Vehicle Charging Services

The potential effects of deregulating electric vehicle charging services in Kansas, including whether deregulation would ensure that electric vehicle charging services are not subsidized by public utility ratepayers not using electric vehicle charging services.

5.3.1 BACKGROUND

Following the 2016 decision by KCP&L to install, own and operate a public charging infrastructure, and subsequent denial of rate basing these costs by the KCC, the Kansas Legislature's Committee on Energy, Utilities and Telecommunications held hearings in 2020 to discuss deregulation of public charging services.[32]

Testimonies from representatives of ChargePoint and Citizens Utility Ratepayer Board (CURB) were among those that presented arguments in favor of deregulation of EV charging services.[33] Reasons put forward included:

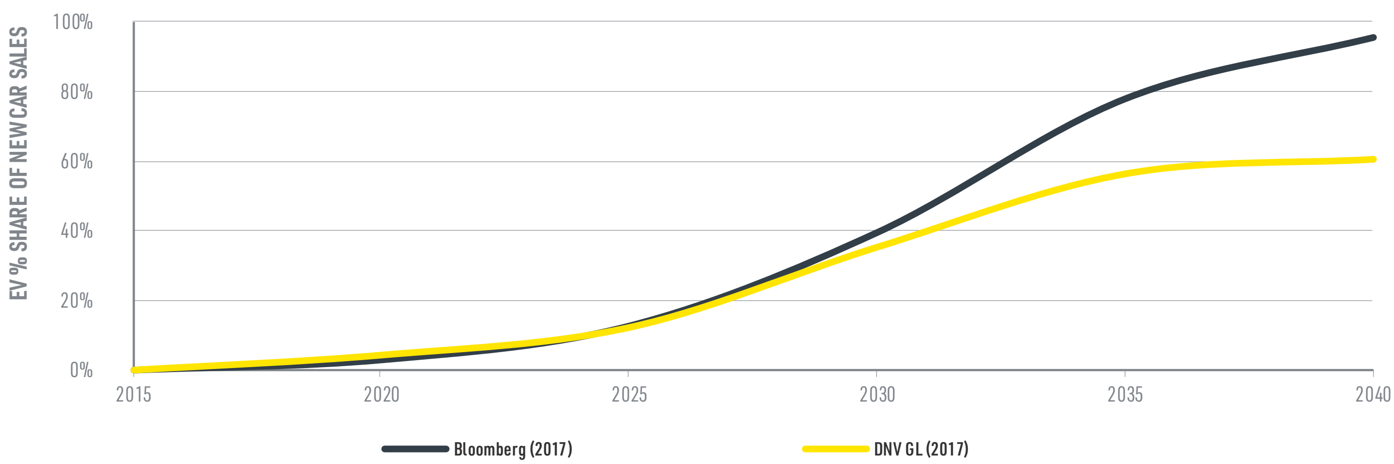
- Deregulation would enable charging station investment, location, pricing, and service levels be directed by a competitive marketplace; and
- Installation costs could be shifted away from other ratepayers that do not use the public charging network.

As originally introduced during the 2020 legislative session, HB 2585 would have allowed non-utilities to operate EV charging services unregulated by the KCC, while still complying with other state restrictions (sales tax, etc.). Under the Bill, public charging service providers would have been regulated by the Department of Agriculture's Weights and Measurements Division, which regulates gas stations. During the legislative process, the Bill was amended to no longer include the provisions relating to EV charging services and was then passed and signed into law.[34]

5.3.1.1 PUBLIC CHARGING INFRASTRUCTURE AND SERVICES

Transportation electrification is a worldwide trend, with experts anticipating most passenger cars in the U.S. to be electrified within the next 20 years, as shown in **FIGURE 6. Projected EV New Car Sales in the U.S. by Study**.

FIGURE 6. Projected EV New Car Sales in the U.S. by Study



Source: Bloomberg New Energy Finance, DNV GL

32 Kansas Legislature (2020). HB 2585 Committee Minutes and Testimony. Retrieved from: http://www.kslegislature.org/li/b2019_20/measures/hb2585/

33 Justin Wilson, Director of Public Policy at ChargePoint and Joseph R. Astrab, attorney with the Citizens' Utility Rate Board testified in support of HB 2585. Their testimonies may be found here: http://www.kslegislature.org/li/b2019_20/measures/HB2585/testimony

34 Kansas House Bill 2585 (2019-2020 legislative session)

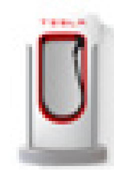
While drivers with dedicated overnight parking and multiple cars[35] can use an EV without worrying about where they can charge them, drivers without access to a private charger, either due to travel or the lack of a private overnight parking spot, will need public charging infrastructure to use an EV. Examples of such drivers include:

- **Renters:** Renters may not be able to obtain landlord approval to install a Level 2 charger and has a lesser incentive to invest in one as they will lose their investment when they move.
- **Multicar Households:** Households with more than one vehicle are more likely to park their second and third vehicles on the street due to a shortage of dedicated parking spaces in a shared garage or lack of room in a typical single-family home's garage.
- **Long-distance Trips:** Vehicles with dedicated overnight parking still require public charging when on long-distance trips of over 150-200 miles given current vehicle range performance (e.g. the Model 3 or Chevy Bolt).

In the absence of public charging infrastructure, these drivers would be unable to drive an EV, limiting their access to expected EV benefits, especially significantly lower refueling costs. The key to efficient and timely infrastructure deployment is anticipating the optimal mix and location of public charging stations over time.

TABLE 4. Summary of Main Types of Public Charging Station summarizes the two main types of public charging stations. Level 2 charges can be located on curbsides near residential or business districts, anywhere people are likely to park for 3-4 hours per day to recharge their cars on average. Level 3, or DC Fast Charging (DCFC) chargers can recharge a vehicle battery by 80% capacity in around 20 to 40 minutes and are mostly used for long-distance recharging.

TABLE 4. Summary of Main Types of Public Charging Station

Type	Voltage	Rating	Connectors	Examples
L2 CHARGING (AC)	**240 V**	**3.7 kW to 17.2kW**		
DC FAST CHARGING (DCFC/L3)	**480 V**	**22 kW to 350 kW**		

Source: Energeia

In terms of the optimal number and mix, it depends on the expected mix of EV drivers needing public charging infrastructure, as some types of drivers, for example retirees and students, may not be able to use a Level 2 charger in a business parking lot to meet their needs. **TABLE 5. Mapping Public Charging Options to Public Charging Customers** maps different public charging customer segments to charging solutions.

35 EV drivers could take their internal combustion engine vehicle for long-distance trips.

TABLE 5. Mapping Public Charging Options to Public Charging Customers

	Level 2									DCFC	
Driver Segment	BUSINESS					RESIDENTIAL		COMMUNITY			
	College	Workplace	Curbside	Hotel/Motel	Parking Lot	Multifamily	Curbside	Community Centers	Parks	Gas Station	Retail Center
Full-time College	✓					✓	✓			✓	✓
Retired, Not-Full Time						✓	✓			✓	✓
Full-time Work Locally		✓	✓		✓	✓	✓			✓	✓
Full-time Commuters						✓	✓			✓	✓
Visitors				✓					✓	✓	✓

Source: Energeia

In anticipation of the need for public charging infrastructure, utilities across the U.S. are preparing their systems to be able to connect and recharge EVs. These preparations may include building, owning, and operating EV charging infrastructure, enabling it to be connected via 'make ready' services or direct incentives to third parties:

- **Direct** – Incentives paid by utilities to customers for investments made in public charging infrastructure often in exchange for data and/or load management opportunities. Costs are typically recovered from all ratepayers.
- **Make Ready** – The utility invests in service connections and electrical infrastructure up to the charging equipment's point of supply. Costs are typically covered from all ratepayers.
- **Build, Own, and Operate (BOO)** – The utility deploys infrastructure and recovers costs on a regulated or unregulated basis, depending on the jurisdiction

KCP&L's Clean Charge Network (CCN) is an example of a BOO approach. Even if public charging is deregulated, there may still be a need for utilities to support it via make ready services, as takes place in other jurisdictions.

5.3.2 SCOPE AND APPROACH

Answering the question posed by this matter of the Study involved the following steps:

- Gathering information regarding each utility's and stakeholder's view on the question and related issues via the RFI and stakeholder engagement processes, respectively;
- Undertaking additional background research to benchmark the current situation with respect to public charging infrastructure services, including level of service, cost of service, and cross-subsidies as compared to peer and best practice utilities; and
- Analyzing the potential impact of deregulation on the level of service, cost of service, and level of cross-subsidies.

5.3.3 INFORMATION GATHERING

Information to answer this question was gathered through the RFI process, meetings with key stakeholders as outlined in **Section 4.2**, and additional background research.

5.3.3.1 SUMMARY OF RFI REQUESTS, RESPONSES, GAPS AND WORKAROUNDS

The RFI was issued with the following information requests related to this matter:

3.1: What costs (e.g. inspection, compliance, market development and market support costs) do you expect to incur if EV charging services are deregulated in Kansas?

3.2: What benefits do you expect your ratepayers will forego (e.g. higher asset utilization, lower cost of capital) if EV charging services are deregulated?

3.3: What benefits do you expect your ratepayers to receive (e.g. more competitive pricing, greater choice, more innovation) if EV charging services are deregulated?

In other portions of the RFI, additional related information was requested for use as a basis for assessing cost causation:

- System hourly load data;
- Distribution network hourly load data by voltage (e.g. SCADA data);
- Cost of service models, including key inputs, assumptions, and outputs;
- Customer hourly load, or if unavailable, hourly load by customer class; and
- Public charging hourly loads, or if unavailable, an aggregated hourly load.

Only two utilities reported offering a public charging service. One utility reported that it was in the planning stage of developing a public charging service, but that it had not yet developed its plan sufficiently to provide a response regarding its rate design approach or result.

The utility offering a public charging service reported that their view regarding the potential effects of competition in public charging services, and particularly its impact on potential service subsidies, was positive, mainly focusing on the benefits from:

- A more competitive market for charging services;
- Increased levels of innovation; and
- Choice of service providers.

None of the other utilities provided any information regarding the potential effects of competition in public charging services, including its anticipated impact on cross-subsidies.

5.3.3.2 STAKEHOLDER FEEDBACK

Non-utility stakeholders expressed support for deregulation of EV charging services during the engagement process, as they believe this would lead to eliminate cross-subsidies and reduce charging costs through market forces. Stakeholders also pointed to KCC's deregulation of compressed natural gas for use as vehicle fuel as precedent for EV charging station deregulation (as codified in K.S.A. § 104(d)).

5.3.4 KEY FINDINGS AND CONCLUSIONS

Determining the effects of deregulating electric vehicle charging services in Kansas, including whether deregulation would ensure that electric vehicle charging services are not subsidized by public utility ratepayers not using electric vehicle charging services requires understanding the potential impacts that deregulation might have on service levels, cost of service, and cross-subsidies.

5.3.4.1 SERVICE LEVEL IMPACTS

A public charging service may be defined as the supply of recharging stations where and when they are needed (i.e. charger availability), with supporting services. Supporting services may include software to let drivers know where and when chargers are available, when their vehicles will finish charging; charging slot scheduling[36] and vehicle charging concierge[37] services.

The following sections discuss findings with the respect to the current level of service availability relative to forecast requirements, and the expected effects of deregulation on service levels.

36 A scheduling service enables drivers to book in charging times as needed, enabling efficient station utilization.

37 A concierge charging service will charge a car and then park it, enabling efficient use of charging stations.

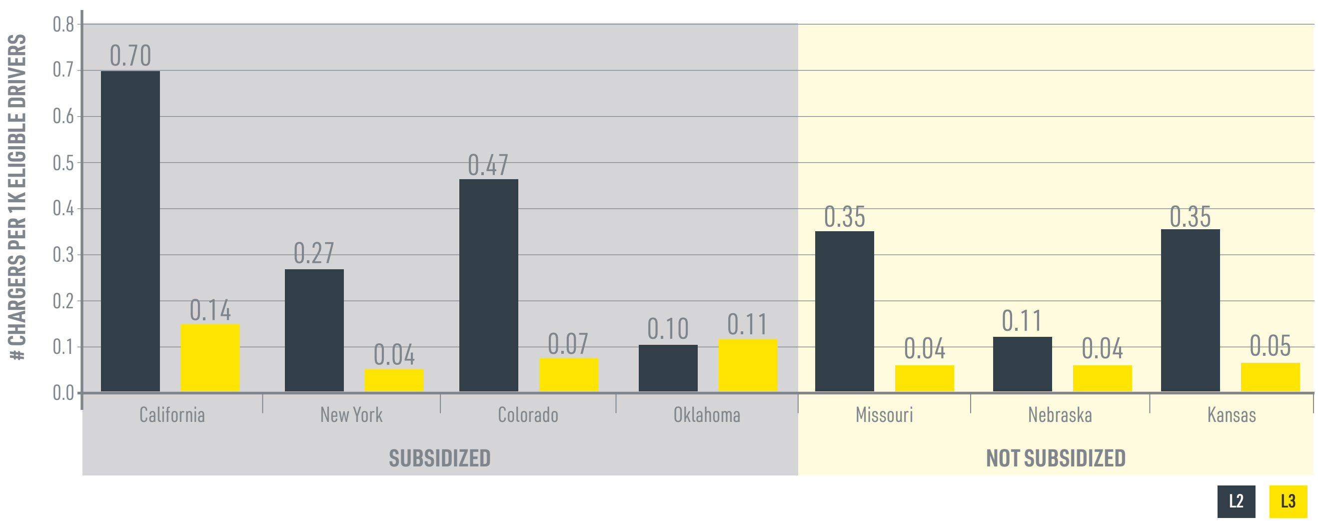
CHARGER AVAILABILITY

Key findings from the project team's research of public charging availability best practices include:

- Level 2 charging stations (L2) should be located where drivers can recharge two to three hours every day, based on typical driving patterns and relative density; and
- Level 3 chargers (50-150kW) (L3) require 20 to 40 minutes to recharge 80% of the battery capacity, and are best placed on major transportation corridors and other amenities for rapid range extension.

In terms of the level and mix of public charging infrastructure available, **FIGURE 7. Public Chargers per Driver by Selected State, Charger Technology, and Whether Subsidized** shows the reported number of L2 and L3 chargers per driver in several states.[38] This analysis shows Kansas offers L2 and L3 public charging stations at rates comparable to most of the other states: slightly higher than New York, about half of California, but more than double than Oklahoma and Nebraska. The relative level of public charging stations in Kansas is remarkable given the service only currently covers about half of the population. While half of the population does not have any access to chargers, the other half has access to public charging infrastructure at a comparable rate to Californians, which is where the greatest levels of EV adoption have occurred thus far in the U.S.

FIGURE 7. Public Chargers per Driver by Selected State, Charger Technology, and Whether Subsidized



SourceAFDC (2018), Census Data (2020)

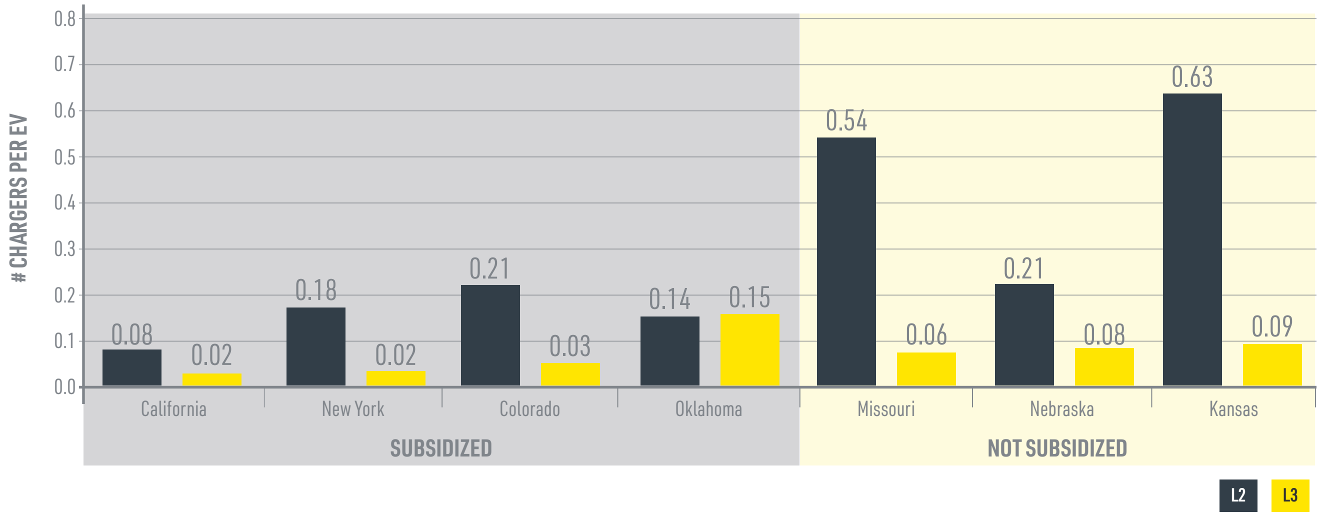
In terms of congestion,[39] the project team was unable to identify the level of station utilization in Kansas due to data limitations.[40] However, given the levels of public charger availability per EV driver in Kansas shown in the **FIGURE 8. Public Chargers per EV Driver by Selected State and Charger Technology**, the project team concludes that service congestion is unlikely to be an issue.

38 Per capita, or all eligible drivers, is shown rather per EV drivers because the number of EV drivers relying on public charging infrastructure is not reflected in the number of current EV drivers.

39 Congestion measures the expected wait time a customer can anticipate, on average.

40 No charger level hourly load data was provided in response to the RFI.

FIGURE 8. Public Chargers per EV Driver by Selected State and Charger Technology



Source: AFDC (2018), Census Data (2020)

SUPPORTING SERVICES

Secondary services include the ability to charge from any public station using the same account, similarly to how toll road billing services work, and less commonly, scheduling services to guarantee recharging when needed, concierge services to ensure congested charging stations are used efficiently, and load management services to optimize the charging profile of this highly flexible load.

Although KCP&L's CCN does not yet offer any of the supporting services mentioned above, they are not yet widely offered in other states either. Concierge services are the most common supporting service, and are typically employed in busy shopping centers, congested airport parking lots, etc. in a similar fashion as how car detailing services are offered in these locations.

KEY EFFECTS OF COMPETITION

Assuming opening public charging to competition will lead to market entry and private investment levels comparable with other similar[41] jurisdictions, increased service levels of public charging infrastructure in terms of chargers per driver, technology mix, location, congestion levels, and support services are expected.

Importantly, the private sector is likely to focus on the market segments that deliver the best long-term shareholder value. In practice, this means installing in areas with the highest expected driver density. Lower density areas, including rural areas, are likely to be under-served, at least initially.

Gas stations provide refueling across the country and have been strategically located to deliver refueling efficiently in rural and remote areas since the automobile was invented. It is therefore likely that the private sector can provide a similar EV charging service.

5.3.4.2 COST OF SERVICE

The key potential cost of service effects, as related to deregulation of public charging services, include impacts on:

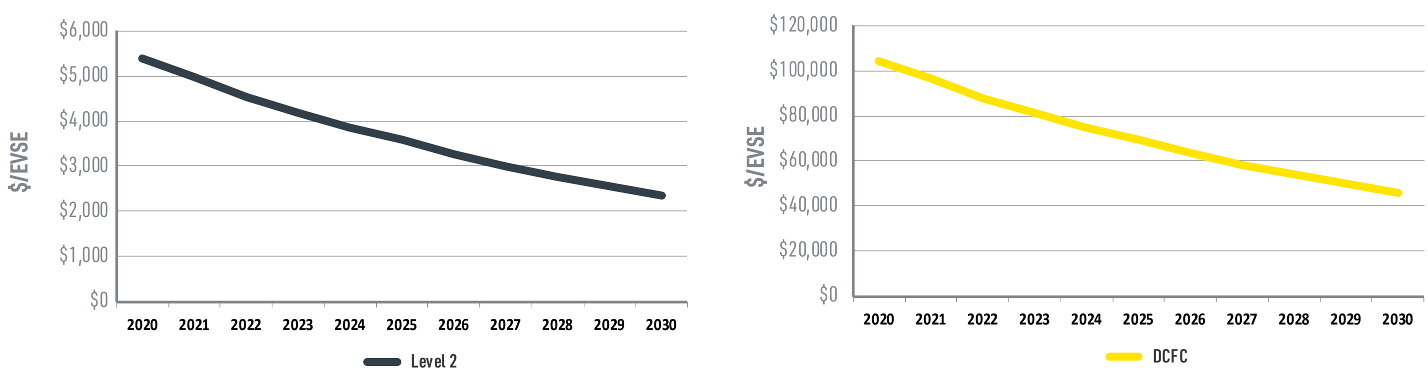
- Lower public charging infrastructure associated investment, operating, and maintenance costs;
- Electricity supply costs; and
- Regulation and compliance costs associated with third party public charging providers.

41 Similar in terms of the level of forecasted EV adoption. New Hampshire, Maine, Florida, Minnesota, North Carolina, Indiana, Pennsylvania and New Mexico all had adoption rates between 0.81% and 1.16%. Kansas' was 0.96% in 2018.

PUBLIC CHARGING INFRASTRUCTURE AND SUPPORT COSTS

The capital and operational costs of public charging infrastructure are not widely reported at the utility level, and it is therefore not possible to compare Kansas costs with peer utilities directly. **FIGURE 9. Forecast $/EV Charger by Cost Type** provides forecasts of L2 and L3 costs from a recently released study.

FIGURE 9. Forecast $/EV Charger by Cost Type



Source: ICCT (2019)

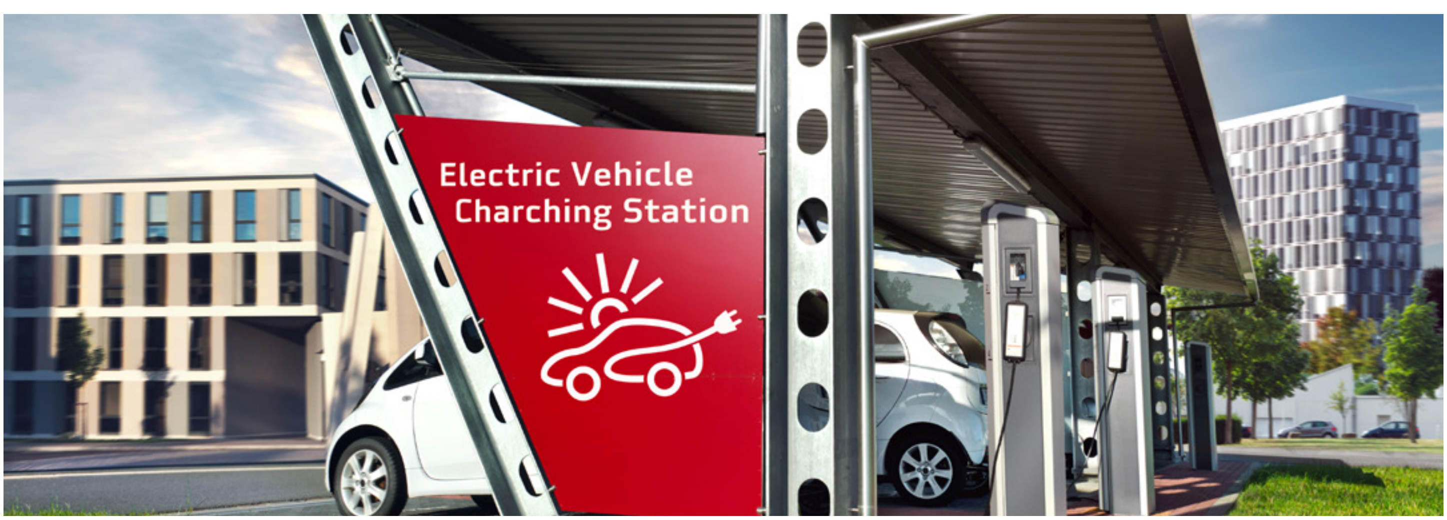
The competitive market would be expected to deliver installed costs comparable to these forecasts. The corresponding benefits for Kansas EV drivers would depend upon how much higher or lower utility delivered services would otherwise be.

ELECTRICITY SYSTEM COSTS

The cost of providing electricity for public charging depends upon the public charging load shape and its contribution to key utility cost drivers including generation, transmission, and distribution costs.[42] While public charging loads can be relatively inflexible, particularly for higher power, for shorter duration L3 charging, it is still possible to modify the load using advanced energy solutions, like battery storage.

The project team's review of best practice public charging approaches found that public charging stations are being co-located with solar PV and/or storage to modify their loads, helping to reduce the cost of service. Examples of solar PV co-located public charging stations are shown in **FIGURE 10. Example of Collocating Advanced Energy Solutions Including PV to Minimize Electricity Supply Costs**.

FIGURE 10. Example of Collocating Advanced Energy Solutions Including PV to Minimize Electricity Supply Costs



42 A detailed assessment of public charging costs is presented in Section 5.1

The project team's research also identified examples of solar PV and storage-bundled services being offered by both utilities and specialist public charging providers.[43] Based on the results of the RFI, stakeholder engagement, and additional background research, public charging stations in Kansas are believed to be stand alone at the current time and not co-located with solar PV or storage.

REGULATION AND COMPLIANCE COSTS

In terms of the utility or other costs of regulating a competitive public charging service, data is not available to benchmark these costs in other jurisdictions. However, it is expected that they would be comparable to regulating gas station pump accuracy, due to their similar functionality.

KEY EFFECTS OF COMPETITION

Based on the analysis of key cost drivers, it is concluded that the key effects of competition with respect to key cost drivers include:

- Lower service costs (e.g. equipment and labor) due to market entry by larger firms with lower purchase, operational, and fixed costs per unit due to economies of scale;
- Potentially lower electricity costs due to incorporation of solar PV, storage and/or other advanced energy solutions to help minimize service costs; and
- No material additional utility costs due to regulation of third-party public charging services, as service wire and metering inspections would be as per any normal load.

The above findings are based on the assumption that competition will lead to the introduction of the cost saving factors discussed above. As is the case with the service level impacts, they are likely to impact metropolitan and suburban areas well before rural areas.

5.3.4.3 SUBSIDIES

The project team's analysis of cross-subsidies presented in **Section 5.1** found that the direct costs of utility public charging services are not being charged to ratepayers not using the service. However, the analysis did identify cross-subsidies embedded in the electricity rate design.

Additionally, the project team's research found that deregulation could lead to private businesses subsidizing public charging in order to attract more customers to their primary business. For example:

- Free charging at a winery or other tourist destination to attract EV drivers; and/or
- Free charging for the life of the car as in the case, until recently, of Tesla.

However, the cost of this amenity to the private business increases as the number of drivers increases. Tesla's policy change may signal the start of a wider trend away from offering 100% free charging to a co-funding model, where EV drivers increasingly pay a portion of the cost.

KEY EFFECTS OF COMPETITION

Based on this analysis, key findings and conclusions related to the impact of competition on the level of subsidies paid by ratepayers include:

- Competition is not expected to impact the level of public charging direct cost cross-subsidies, as the utility provided service is not being subsidized by ratepayers;
- Competition is expected to increase the level of electricity supply cross-subsidies to the degree it increases the rate of EV adoption;[44] and
- Some firms may offer subsidized charging services to attract customers to their primary business, as has been seen in other markets.

43 The Los Angeles Department of Water and Power is one such example; however, their solar PV and storage bundled rate has been initially limited to public transportation operators.

44 Our recommended approach to mitigating this risk is set out in **Section 5.2**.

5.4 Advanced Energy Solutions

Whether Kansas consumers could benefit from improved access to advanced energy solutions, including micro grids, electric vehicles, charging stations, customer generation, battery storage and transactive energy.

5.4.1 BACKGROUND TO THE QUESTION

Commonly understood benefits of advanced energy solutions (AES) include lower household and transportation energy bills, emission free electricity and transportation, and higher electric service reliability. However, these benefits come at the potential cost of higher electricity system costs to accommodate them, and the potential for cross-subsidies due to rate design limitations, among other factors.

The potential net benefits from AES, and in particular, rooftop solar PV, are debated each time the KCC considers changes to rates impacted on rooftop solar PV customers,[45] periodically in the state legislature,[46] and even in the Kansas Supreme Court, which recently decided that solar PV customers could not be price discriminated against.[47]

Getting to the bottom of whether and when AES is likely to deliver net benefits to Kansas consumers requires understanding AES' underlying cost trajectory (as well as that of competing alternatives), their impact on other areas of the electricity system and stakeholders, and the role of rate design in allocating the associated costs and benefits between those adopting AES and other ratepayers.

5.4.1.1 TECHNOLOGY COST DECLINES

AES – including microgrids, EVs, charging stations, customer generation (especially rooftop solar PV), battery storage, and transactive energy – are growing in popularity as their respective costs decrease, mainly driven by decreases in solar PV and lithium battery costs.

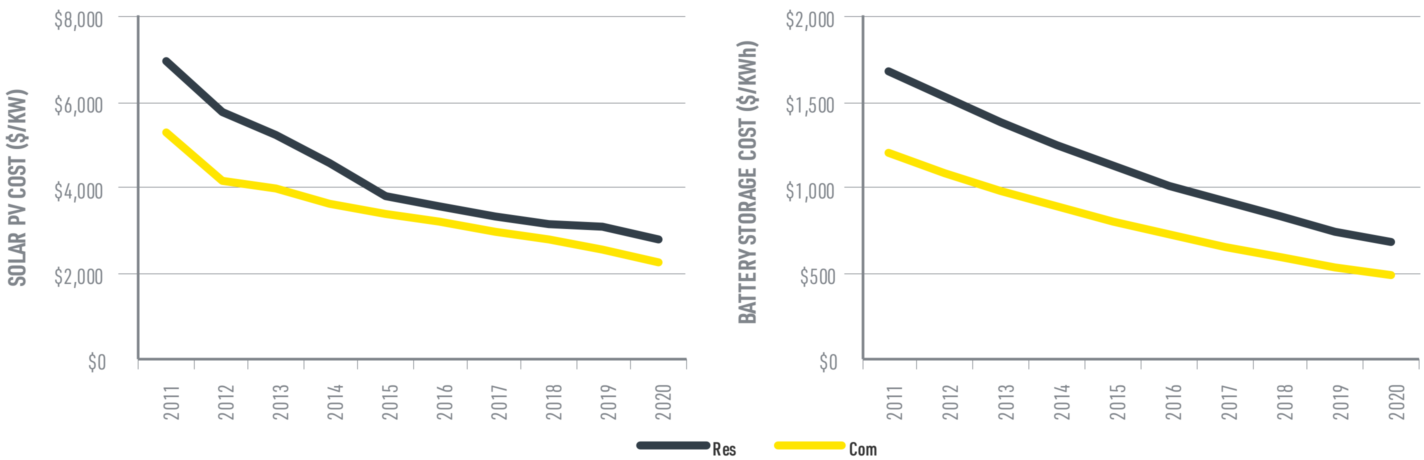
FIGURE 11. Historical Costs of Rooftop Solar PV (left) and Lithium Battery Storage (right) reports the average rooftop solar PV system cost per kW and lithium battery module cost per kWh over the past ten years in the U.S.

45 Climate and Energy Project (2017). KCC Ruling Could Drive Competition for Solar Out of State. Retrieved from: http://climateandenergy.org/blog.1050367.kcc-ruling-could-drive-competition-for-solar-out-of-the-state?act=view

46 Kansas Legislature (2020). Written Proponent Testimony.

47 Driscoll, W. (2020). Victory for solar as Kansas Supreme Court blocks fixed fee for distributed power. PV Magazine. Retrieved from: https://pv-magazine-usa.com/2020/04/06/victory-for-solar-as-kansas-supreme-court-blocks-fixed-fee-for-distributed-power/

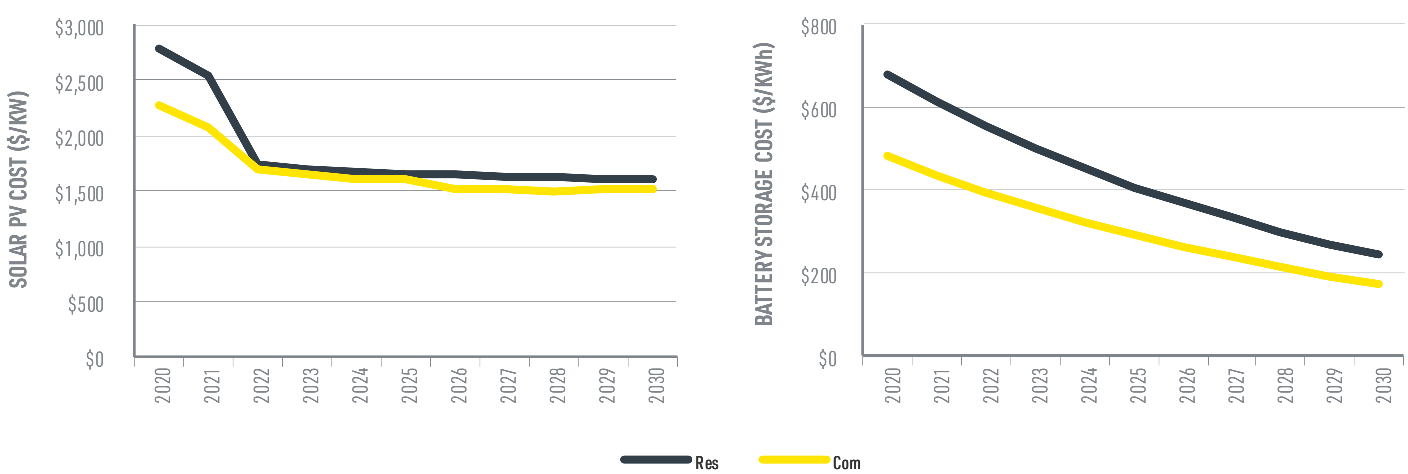
FIGURE 11. Historical Costs of Rooftop Solar PV (left) and Lithium Battery Storage (right)



Energeia (2019)

With solar PV and lithium battery costs anticipated[48] to continue falling over the next ten to 20 years, as shown in **FIGURE 12. Forecasted Costs of Rooftop Solar PV (left) and Lithium Battery Storage (right)**, the expected benefits of adopting AES, especially solar PV and lithium battery related technologies, are expected to rise, assuming electricity prices remain constant or increase.

FIGURE 12. Forecasted Costs of Rooftop Solar PV (left) and Lithium Battery Storage (right)



Energeia (2019)

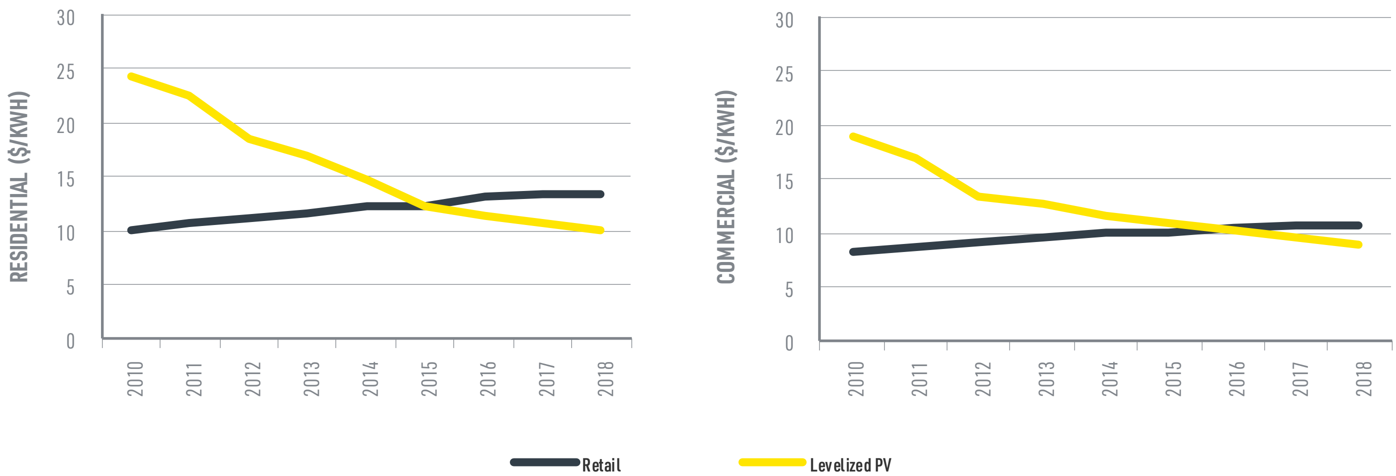
5.4.1.2 COST COMPETITIVENESS INCLUDING FULL UTILITY SYSTEM INTEGRATION COSTS

While the costs of AES technologies have declined significantly over the past ten years, electricity prices in Kansas have risen, as shown in **FIGURE 13. Historical Levelized Cost of PV Solar vs. Retail Electricity Prices for Residential (Left) and Commercial & Industrial (Right)**, increasing the relative cost competitiveness of AES solutions on a levelized basis. It is important to note that levelized costs,[49] while a common measure, is not equivalent to the retail price – unless it includes the full cost of supplying the customer, as it would for a microgrid.

48 The drop in 2022 is driven by the reduction in the federal Investment Tax Credit (ITC) offered to renewable developers, which is intended to keep PV competitive.

49 Levelized costs divide the full cost of a technology by its lifetime kWhs.

FIGURE 13. Historical Levelized Cost of PV Solar vs. Retail Electricity Prices for Residential (Left) and Commercial & Industrial (Right)



Source: EIA (2019), NREL (2020), Energeia

These levelized cost comparisons may make it seem like greater access to rooftop solar PV could help reduce electricity prices in Kansas, though if they actually will in practice depends upon on the cost of associated electricity system impacts, which may include:

- Higher reserve and ancillary services costs to counteract potentially increased generation ramp-rates, uncertainty, and volatility; and
- Higher distribution costs to counteract potential impacts to voltage regulation, protection, and under-frequency load shedding arrangements.

Although not yet as cost competitive as rooftop solar PV, EV costs are also falling and expected to eventually become lower cost[50] than current ICE-based technology. Behind-the-meter (BTM) storage and microgrids are even further away from competing with grid alternatives, except in niche areas.

5.4.1.3 BENEFIT ALLOCATION AND CROSS-SUBSIDIES

In considering the net benefits of AES, it is essential that their full system costs, including those imposed elsewhere in the system, and not just the savings in one area, is taken into consideration.

A key driver of the realized benefits of AES, along with the cost of the technology itself, is the applicable rate design. In the case of rooftop solar PV, there are primarily two types of rates offered:

- **Net Energy Metering (NEM):** Customers with solar PV systems can offset their consumption used for billing, with exports back to the system carried forward or cashed out at a set price.
- **Parallel Generation (Feed-in Tariffs, or FiT):** Customers are paid a set rate for the generation from their systems, which are metered separately from the premise.

NEM rates, which value exported kWh to the grid at the same price as kWh imported from the grid, is the most common rate design for customers in the U.S. with a rooftop solar PV system. A number of states have introduced changes to their NEM designs in response to stakeholder concerns regarding cross-subsidies, particularly of transmission and distribution costs. The main changes include:

- **Settlement and cash-out terms:** initial NEM rates typically allowed generation credits to roll forward indefinitely, however, more recent designs have settled on a shorter basis, including monthly. This tends to reduce the value of

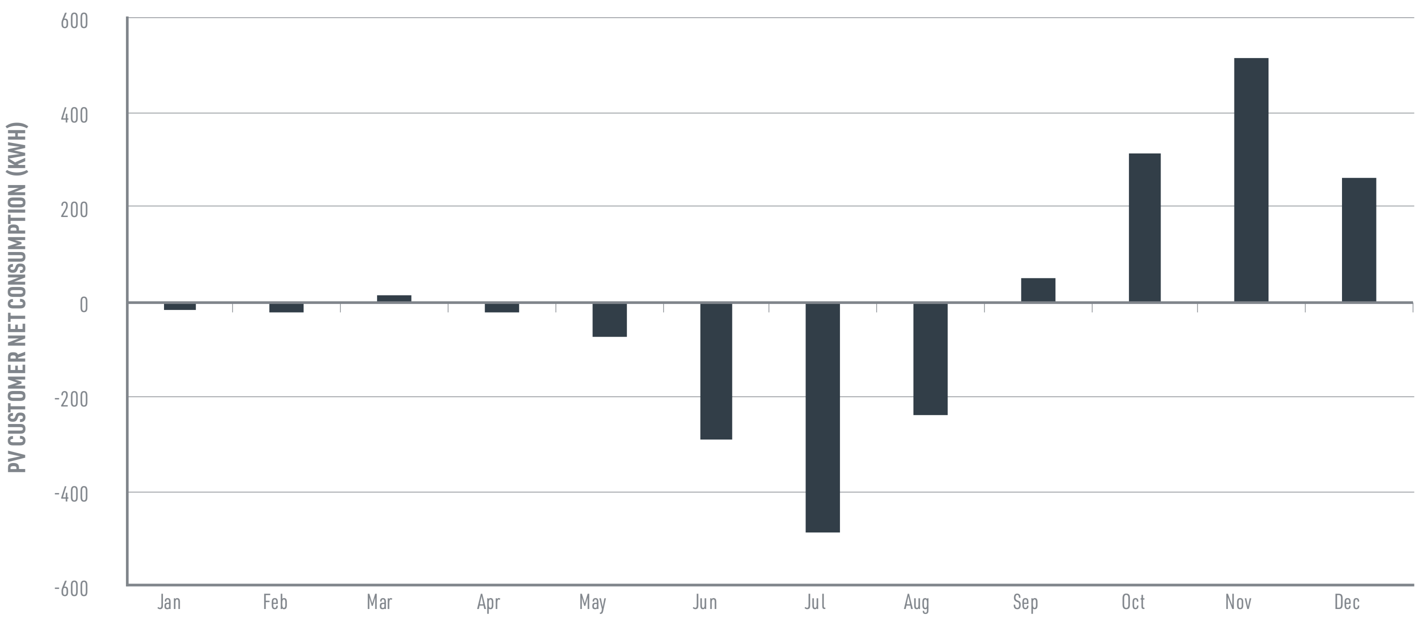
50 EV economics and cost-competitiveness timing are discussed in **Section 5.4.4**.

solar PV generation, due to its strongly seasonal generation pattern. Even where the system matches the premise consumption over the year, it will be over producing during the summer and under-producing during the winter.

- **Minimum or demand charges:** the first generation of NEM rates allowed solar PV generation to offset the entire bill, which was viewed as cross-subsidizing customers. Second generation and new NEM designs increasingly impose charges aimed at clawing back the cost of transmission and distribution infrastructure costs by limiting the solar PV benefit paid to the adopting consumer to avoided wholesale purchase costs only.

FIGURE 14. Example Residential Solar PV Customer Net Imports and Exports by Month illustrates how a solar PV system aligns with a consumer's annual consumption on a monthly basis, resulting in over- or under-generation. Depending on grid congestion and market prices, this may impose additional costs on the grid. Excess monthly generation is often paid the cash-out value of solar PV generation in the wholesale market, which is a fraction of the full retail price it was allocated under first generation NEM rates (up to the customer's total annual consumption).

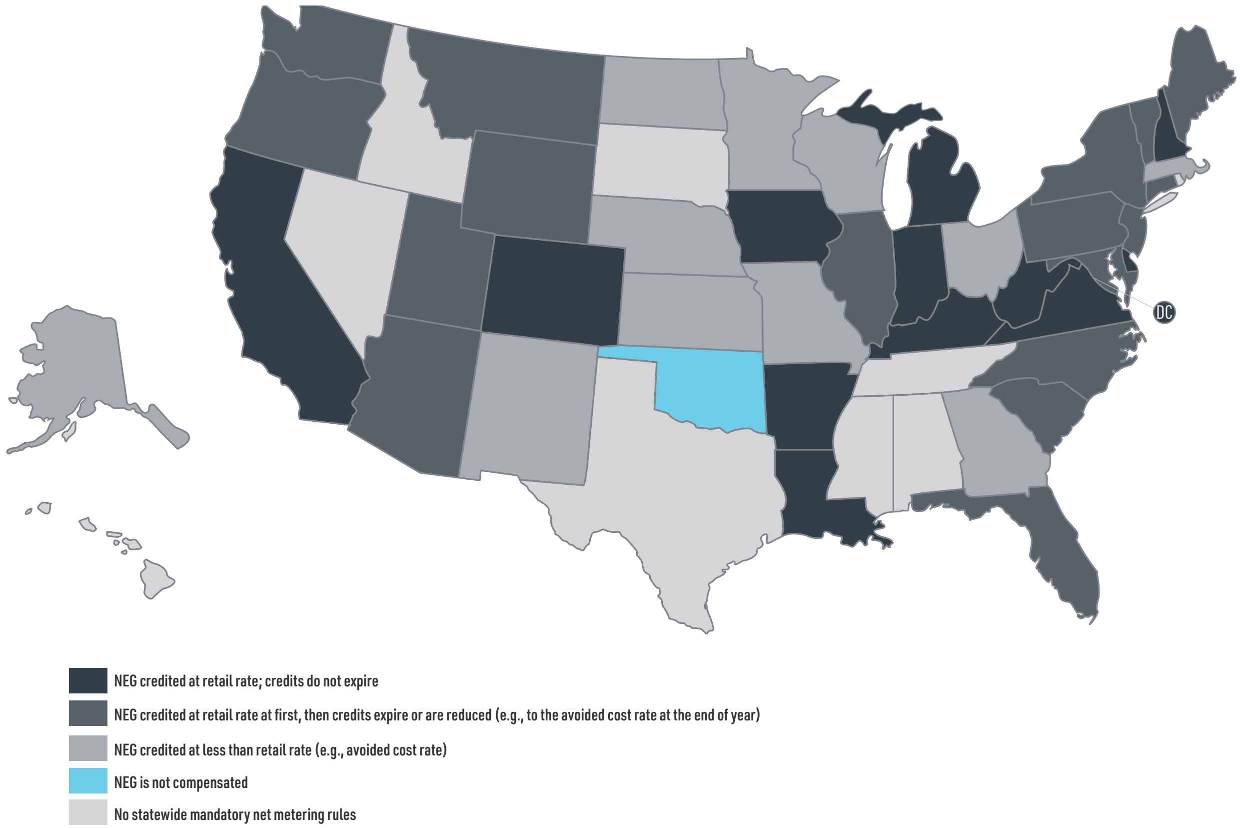
FIGURE 14. Example Residential Solar PV Customer Net Imports and Exports by Month



Source: Energeia (2020)

The net impact of the above changes is to reduce the level of cross-subsidy to the extent that the original rate designs were reducing solar PV customers rates more than their solar PV generation was reducing utility costs. However, where solar PV is reducing the transmission and distribution costs of the utility the new, wholesale-cost focused NEM rate designs may be leading to cross-subsidy of other rate payers at the expense of solar PV customers.

FIGURE 15. US Map of NEM Rules



Note: The map shows NEG credits under statewide policies for IOUs; other utilities may offer different NEG credit amounts. IOUs in HI, NV, MS, and GA have other policies for compensating self-generators. Some IOUs in TX and ID offer net metering, but there is no statewide policy. IOUs in WI differ in their treatment of NEG.

Source: DSIRE (2016)

In Kansas, NEM rates have been revised over time, and are not the same across all of the state's utilities, as summarized in **TABLE 6. Key NEM and FiT Rate Terms for Major Kansas Utilities**. Key differences in the rates offered include how and when exported energy is priced and settled, and how the level of minimum charge, if any, is applied to the bill.

TABLE 6. Key NEM and FiT Rate Terms for Major Kansas Utilities

	IOUs			Muni	Coop
	Westar	KCPL	Liberty	Kansas City BPU	Midwest Energy
Programs					
Solar PV Net Metering					
Net consumption charged at standard rate	✓	✓	✓	✓	✓
Credits applied to the next billing period	×	×	×	×	×
Credits paid at cost	✓	✓	✓	✓	×
Minimum charges apply	✓	✓	✓	✓	✓
Solar PV Feed-in Rates					
Credited higher than cost	✓	✓	✓	✓	✓
Added charges	×	×	×	×	×

Source: RFI, Energeia Research

While this review focuses on the rate design issues related to rooftop solar PV, rate design is a key determinant of the extent to which the associated costs, benefits and/or cross-subsidies of other AES, including EVs[51] and transactive energy platforms, are passed through.

5.4.2 SCOPE AND APPROACH

Answering the question posed by this matter of the Study involved the following steps:

- Gathering information regarding each utility's current level of access to AES via the RFI process, as well as the impact of AES on current cost of service, and customer rates;
- Gathering stakeholder views and materials related to the matter and related issues;
- Undertaking additional background research to benchmark levels of access, solution costs, and bill impacts in Kansas as compared to peer state and best practice utilities; and
- Analyzing the potential impact of AES on utility cost of service and customer bills, and the associated cross-subsidy levels.

5.4.3 INFORMATION GATHERING

Information to answer this question was gathered through the RFI process, via meetings with key stakeholders, and desktop research.

5.4.3.1 SUMMARY OF RFI REQUESTS, RESPONSES, GAPS AND WORKAROUNDS

The RFI was issued with the following information requests related to this matter:

4.1: Please send us a table of customer advanced energy solution program enrollment that includes customer ID, premise ID, program ID, start date, solution sizing / configuration, etc. which can be used to generate #s, MWs, and MWhs of each program by year for the last five years.

4.2: Please send us the last five years of 8760 profiles of residential customers (including sub-loads where available) including meter ID to map to customer data.

4.3: Please send information regarding residential customers including transformer ID, customer ID, premise ID, meter ID, address, XY, Parcel ID, customer type, rate code, economic development contract, annual consumption, annual charges.

4.4: Please send the number of microgrids, EVs, charging stations, customer generation (solar PV, cogeneration, backup gensets), battery storage and/or transactive energy sites on your network by customer class by year for the last five years.

4.5: Please send the MWs of microgrids, EVs, charging stations, customer generation (solar PV, cogeneration, backup gensets), battery storage and/or transactive energy sites on your network by customer class by year for the last five years.

4.6: Please send the annual MWhs of microgrids, EVs, charging stations, customer generation (solar PV, cogeneration, backup gensets), battery storage and/or transactive energy sites on your network by customer class by year for the last five years.

4.7: What programs do you currently or plan to offer related to microgrids, EVs, charging stations, customer generation, battery storage and/or transactive energy by customer class?

4.8: Please provide copies of all feasibility studies (economic, technical, etc.) relating to the types of programs described above which were prepared and/or utilized by your utility during the last five years, regardless of whether the program was implemented.

4.9: Please provide copies of tariffs, riders or other cost recovery mechanisms associated with the programs described above.

51 Rate design issues and best practice is covered in **Section 5.2**.

In other portions of the RFI, additional related information was requested for use as a basis for assessing cost causation:

- System hourly load data;
- Distribution network hourly load data by voltage (e.g. SCADA data);
- Cost of service models, including key inputs, assumptions, and outputs; and
- Customer hourly load, or if unavailable, hourly load by customer class.

Overall, utility responses to these requests were among the most complete relative to the other portions of the RFI. Most utilities were able to provide aggregated data regarding customer generation (mainly solar PV), EV, battery storage, microgrid, and transactive energy services over time.

Some utilities provided the requested AES adoption data at the customer level. It was only possible to analyze actual costs and benefits of each type of AES with data at this level of disaggregation. Some the utilities also provided customer-level hourly load profiles, or customer class-level profiles.

Based on the level of information received, the project team's original approach was modified from using actual utility and customer bill impacts to a model-based approach using actual hourly customer or customer class load data to estimate the impact on utility cost of service, and the flow of these impacts to the adopting customer class via the bill impact.

5.4.3.2 STAKEHOLDER FEEDBACK

Nearly all stakeholders largely supported improved access to multiple advanced energy solutions, noting the opportunities for electric rate savings resulting from new system efficiencies, as well as improved reliability, grid resilience, public health, and comfort. One stakeholder provided an opposing viewpoint, suggesting that because Kansas has already spent more money in this area than many other states, it should not invest more money in renewables.

5.4.4 KEY FINDINGS AND CONCLUSIONS

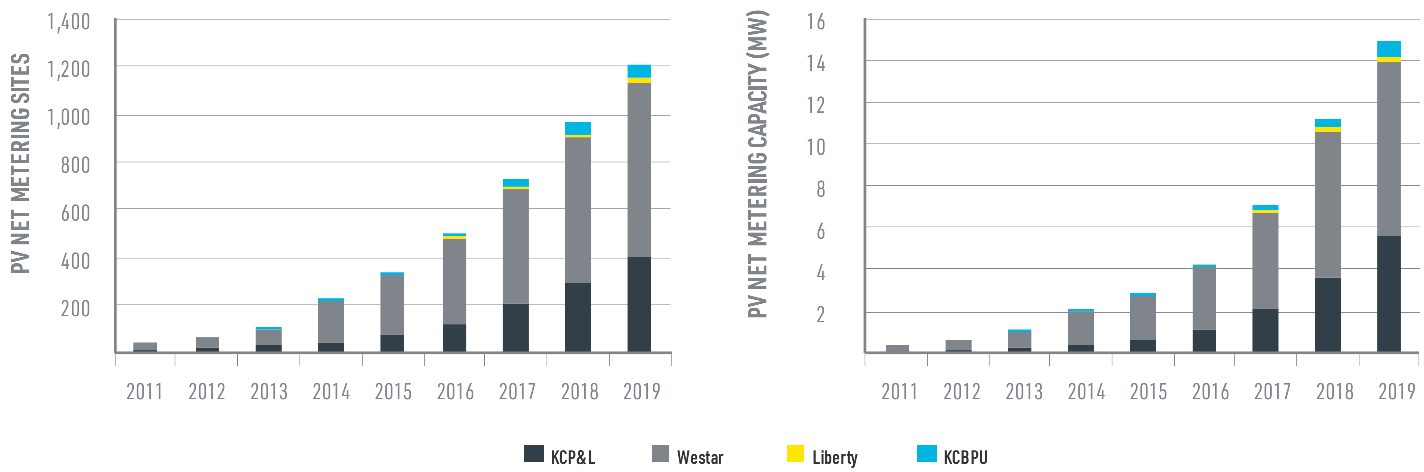
Determining whether Kansas consumers could benefit from improved access to advanced energy solutions, including microgrids, electric vehicles, charging stations, customer generation, battery storage and transactive energy requires understanding the potential impacts that improved access might have on ratepayer costs and cross-subsidies, whether or not there are barriers to accessing AES.

The following sections summarize our key findings, analysis, and conclusions regarding relevant industry benchmarks, costs, and benefits by consumer category.

5.4.4.1 CUSTOMER GENERATION

Customer generation typically covers distributed thermal generation used on a stand-alone or cogeneration-basis (combined with heating applications), or onsite solar PV generation. Utilities have not reported any thermal generation programs and reported a low rate of solar PV system adoption. **FIGURE 16. PV Net Metering Sites (Left) and Capacity in MW (Right)** reports on customer generation trends in Kansas over time for select utilities.

FIGURE 16. PV Net Metering Sites (Left) and Capacity in MW (Right)



Source: EIA (2020)

Given the increasingly poor economics of customer thermal generation (for most applications except cogeneration or backup) as compared to solar PV generation, the project team's analysis focused on the potential benefits of solar PV.

While those adopting solar PV benefit from lower bills and the knowledge of using more emissions free electricity, utilities can also realize a range of benefits. A summary of best practices for capturing utility and public benefits is presented in **TABLE 7. Best Practice Potential Utility Benefits Valuation Framework**. The degree to which a given solar PV system will generate these benefits depends on the specific context of the electricity system in which it operates, which can vary significantly from utility to utility. For example, the magnitude of transmission or distribution benefits captured depends on the degree to which periods of congestion overlap with periods of high solar PV output.

TABLE 7. Best Practice Potential Utility Benefits Valuation Framework

Value Component	Benefit/Cost	Description
Generation		
Energy	Benefit	Avoided purchase of energy that would otherwise be needed, for renewable or carbon emissions requirements
	Cost	Integration cost
	Cost	Higher marginal cost of emissions due to intermittent resources
Generation Capacity	Benefit	Provides Resource Adequacy
	Cost	Increases need to intra-hour flexibility
Financial Risk	Benefit	Reduces Fuel Price Risk
	Neutral	Increases energy price volatility
	Neutral	Assigned criteria pollutant Emission Reduction Credits are sunk cost (no financial impact)
Variable Operating Cost	Benefit	Decreased thermal power plant operations will decrease variable operating costs (i.e., water, waste, etc.)
	Cost	Increased power plant standby/station power costs and higher operations and maintenance (O&M) costs due to cycling

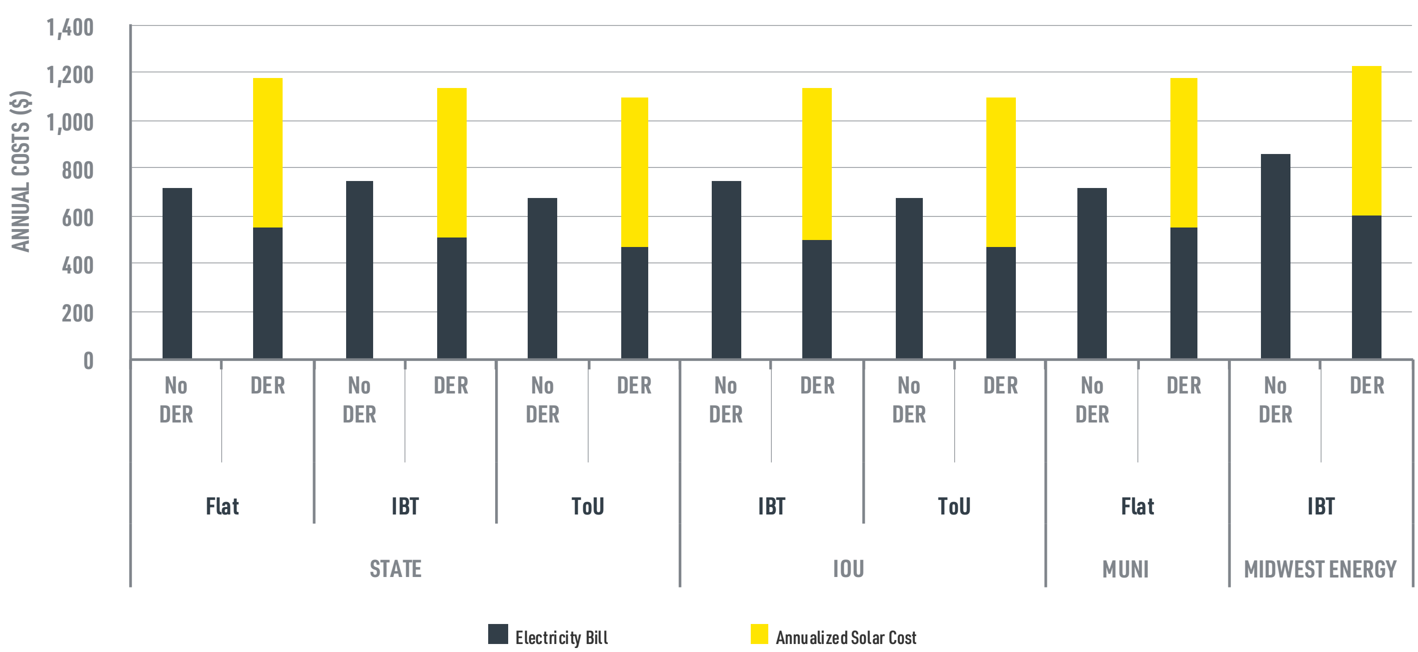
Environmental		
Criteria Emission Reductions	Benefit	Overall decreased emissions contribute to societal benefits
Carbon Emission Reductions	Benefit	Benefits of reducing carbon emissions beyond those achieved in support of SMUD's compliance with California cap and trade system (Recommendation #1)
Land and Water Use	Benefit	Use of the built environment, water use reductions
Societal		
Equity	Benefit	Reduced energy burden for low income customers who have solar/storage
Resilience	Benefit	Customer can meet critical needs during outage if the system is configured to function during grid outages
Transmission		
Transmission Capacity	Benefit	Reduces daytime demand and may reduce traditional upgrades
Transmission Line Losses	Benefit	Local generation reduces losses on transmission grid

Source: Sacramento Municipal Utility District (2019)

Importantly, where the change in a solar PV adopter's bill varies from the change in the utility cost of service, a cross-subsidy will arise. When solar PV adopters are being subsidized by other ratepayers, adoption can be beneficial for the solar adopter, but be financially harmful for other ratepayers, or vice-versa when solar PV adopters subsidize ratepayers. Therefore, an economic benefits assessment needs to account for these distributional effects.

FIGURE 17. Residential Solar PV Customer Bill Savings vs. Annualized Solar PV System Costs to FIGURE 19. Industrial Solar PV Customer Bill Savings vs. Annualized Solar PV System Costs report on the apparent benefits of solar PV to Kansas consumers based on the annualized[52] costs of a solar PV system versus annual electricity bill savings. This analysis illustrates current customers' experience with NEM rates without accounting for actual utility costs or benefits. The results show that a typical residential and commercial customer would not be financially better off investing in a solar PV system, as it would increase their overall costs.

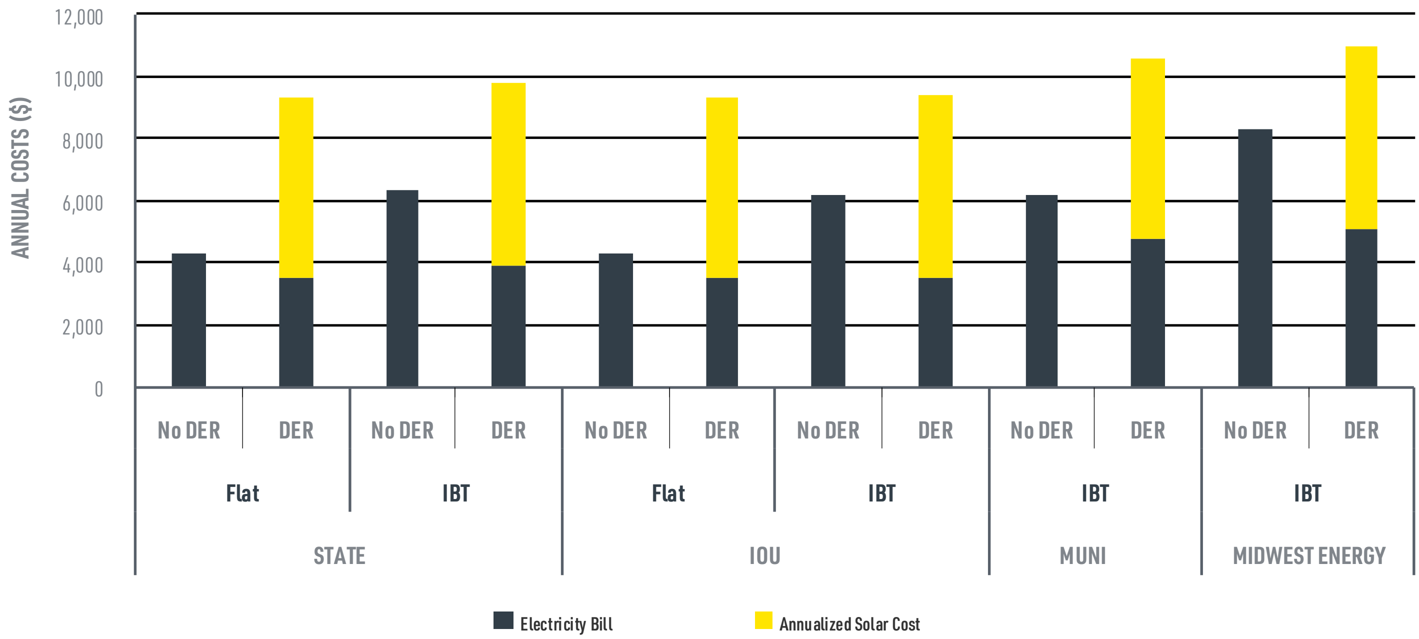
FIGURE 17. Residential Solar PV Customer Bill Savings vs. Annualized Solar PV System Costs



Source: Energeia (2020)

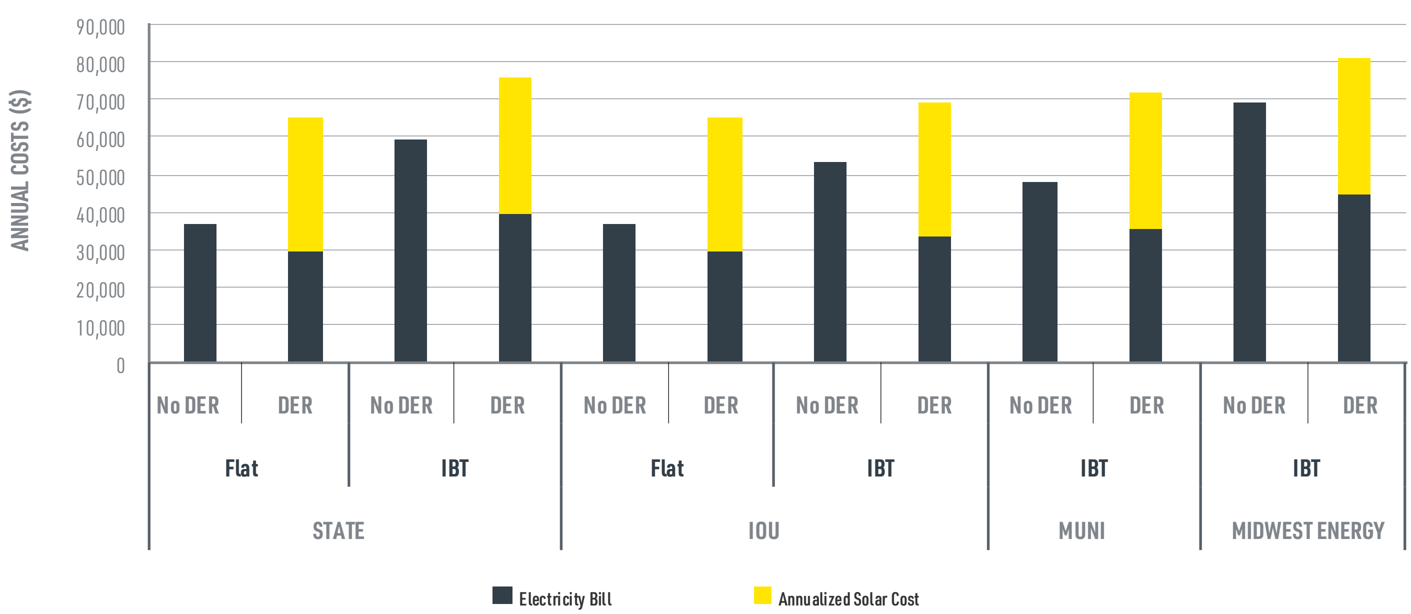
52 Annualized spreads the investment costs into equal payments over a number of years, like a mortgage.

FIGURE 18. **Commercial Solar PV Customer Bill Savings vs. Annualized Solar PV System Costs**



Source: Energeia

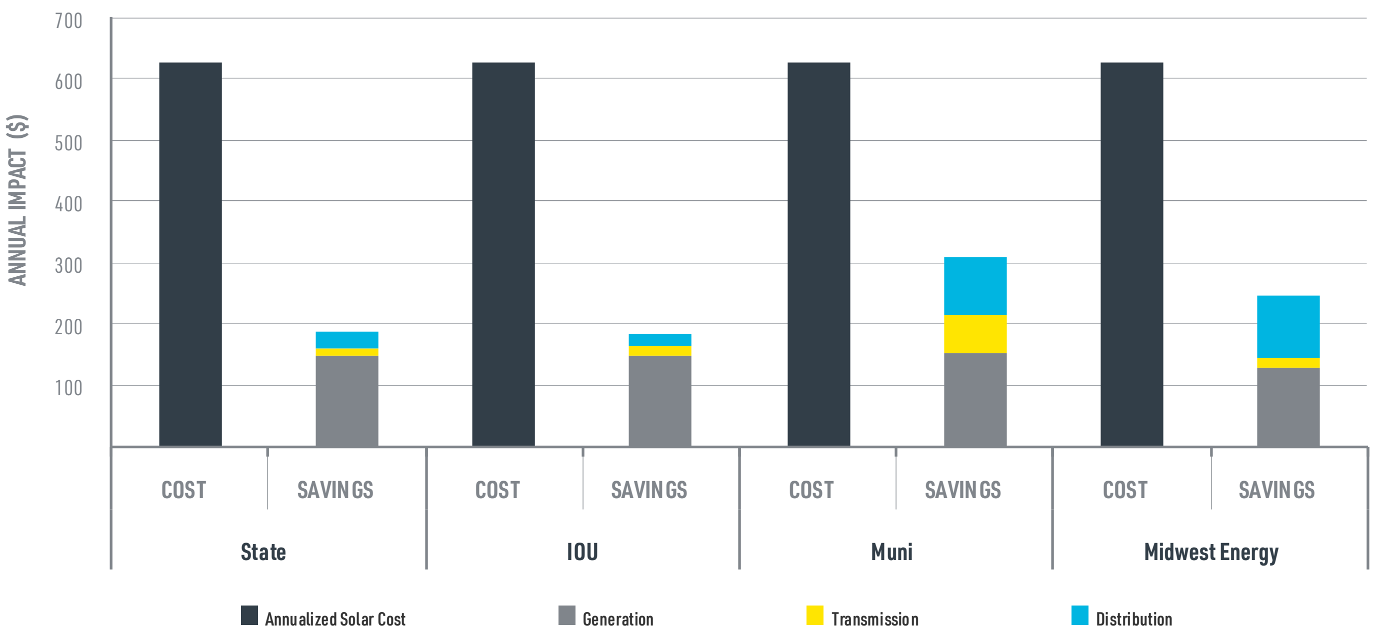
FIGURE 19. **Industrial Solar PV Customer Bill Savings vs. Annualized Solar PV System Costs**



Source: Energeia (2020)

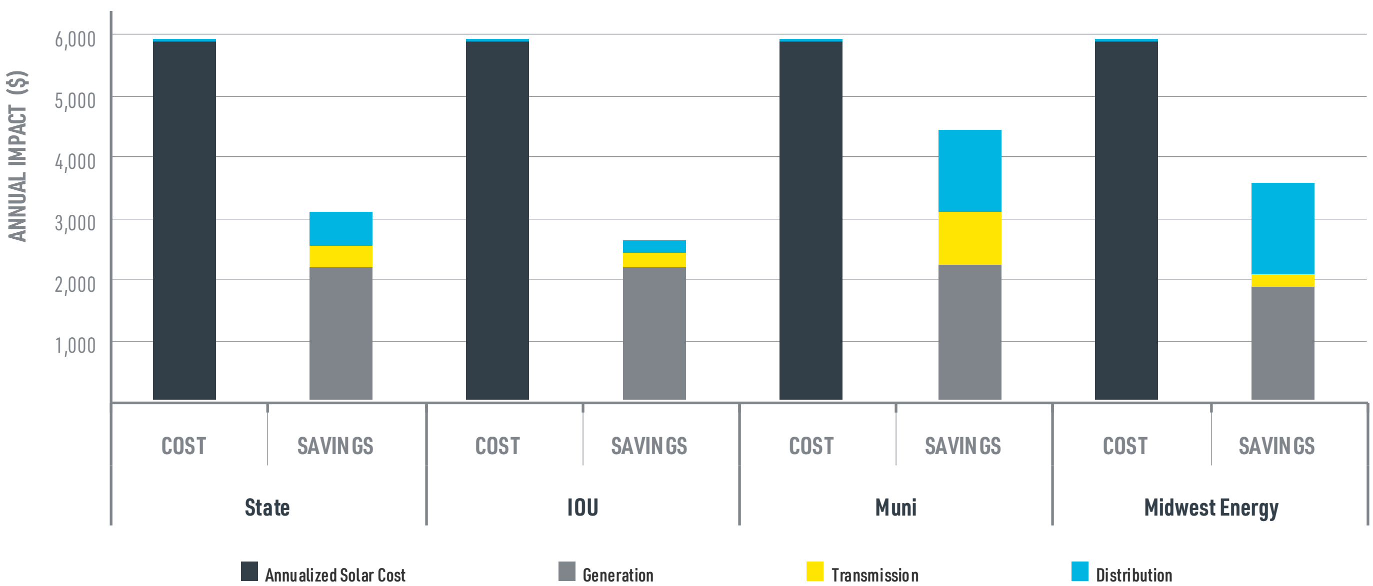
The results of the project team's model of utility cost to serve savings from rooftop solar PV versus its annualized costs are reported by utility and rate class in **FIGURE 20. Economic Utility Impacts of Solar PV vs. Residential Solar PV Costs to FIGURE 22. Economic Utility Impacts of Solar PV vs. Industrial Solar PV Costs**. The analysis shows that rooftop solar PV costs, even including federal tax subsidies, are higher than current utility costs for residential systems, are about the same for commercial systems, and are lowest for the largest industrial systems.

FIGURE 20. Estimated Utility Cost of Service Impacts of Solar PV vs. Residential Solar PV Costs



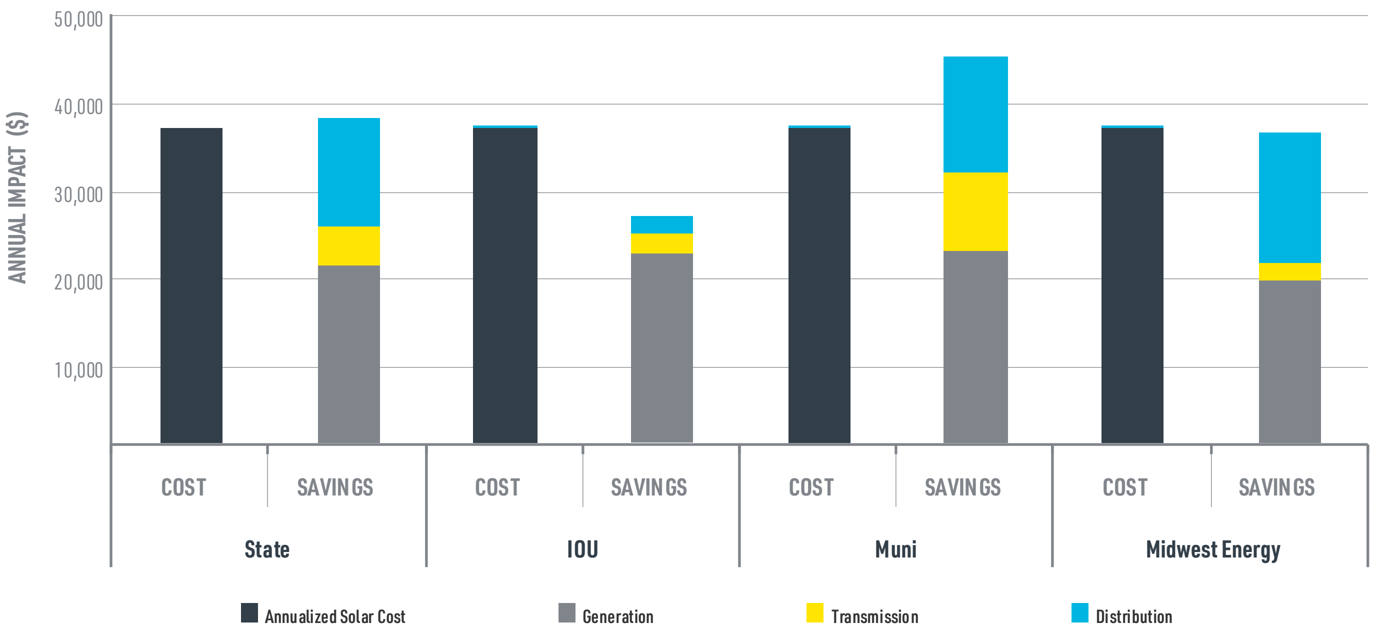
Source: Energeia (2020)

FIGURE 21. Estimated Utility Cost of Service Impacts of Solar PV vs. Commercial Solar PV Costs



Source: Energeia (2020)

FIGURE 22. Estimated Utility Cost of Service Impacts of Solar PV vs. Industrial Solar PV Costs



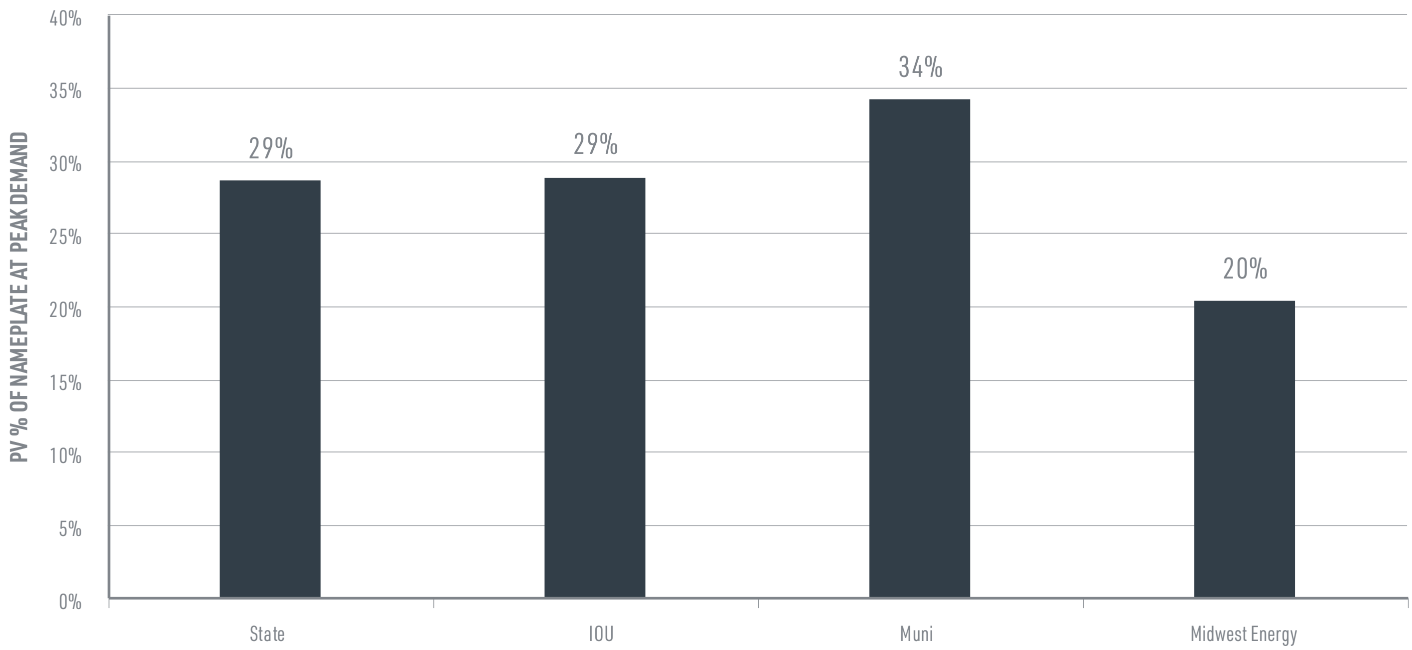
Source: Energeia (2020)

It is important to note that this analysis takes both the actual 2019 impacts on transmission CP12 values and the utility CP1 value into consideration. In lieu of detailed network load profile data, the utility CP1 value is used as a proxy for the impact of solar PV on distribution peak demand. This simplification could result in an over- or under-estimation of the true solar PV impacts on distribution cost to serve. Additional, more accurate analysis using detailed solar PV generation and network loading data follows.

FIGURE 23. Solar PV CP1 Impact Comparison by Utility Category (Confidential) and FIGURE 24. Solar PV Output during Top 3% of Summer Hours vs. Nameplate Capacity by Confidence Factor show the estimated solar PV generation outputs compared to their nameplate[53] capacity during the time of system peak demand in selected Kansas utilities' service territories in 2019. The model results show solar PV output per nameplate kW reduces the utility system peak demand, which may then reduce infrastructure investment costs, depending on how reliable this output is considered by utility planners.

53 Nameplate refers to the rated capacity of the system; actual output varies based on solar insulation levels.

FIGURE 23.Solar PV CP1 Impact Comparison by Utility Category



Source: PVWatts (2020), Energeia (2020)

A key assumption in this analysis is the level of solar PV that can be relied upon for the purpose of utility planning. Thermal generation, except in the case of a forced outage, can be counted on to generate whenever it is needed to meet peak demand, and can then be delivered through transmission and distribution circuits. Solar PV generation varies by insolation levels, which may be impacted by cloud cover. Thus, how solar PV output is factored into utility reliability planning has a large impact on its assumed value to a utility.

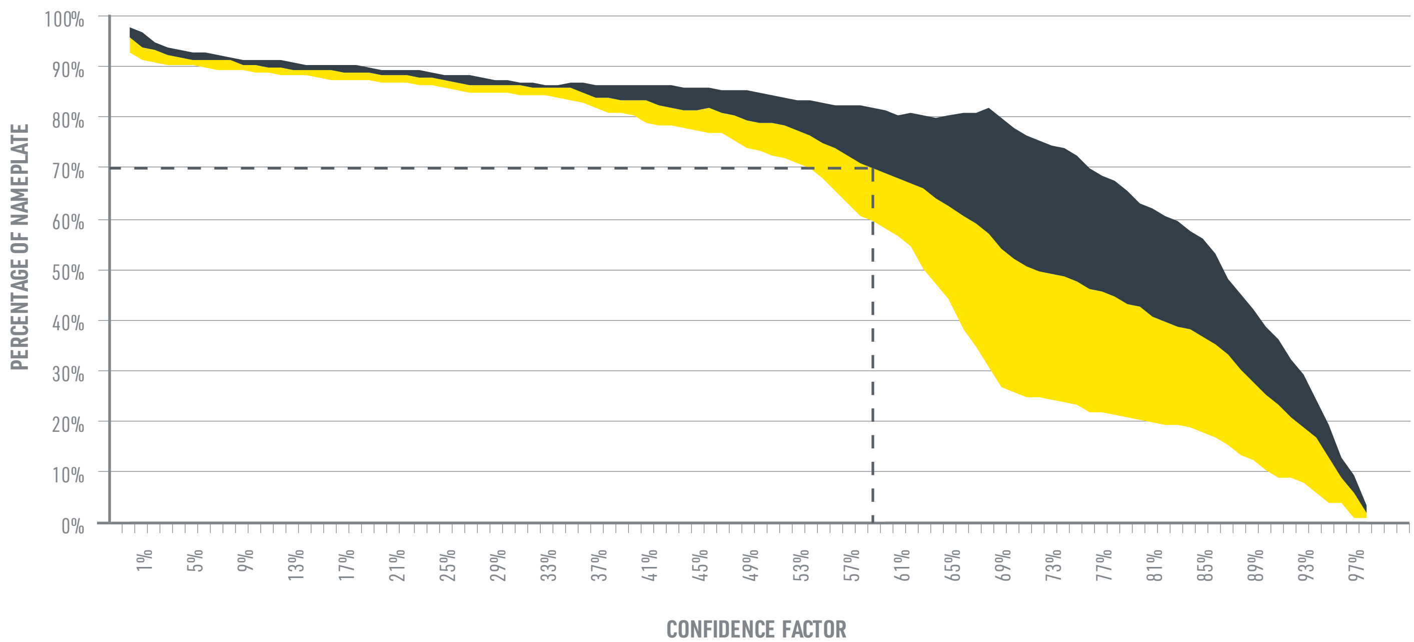
For the purpose of transmission planning, the SPP credits solar PV generation based on its historical output during the top 3% of system hours with a 60% confidence interval.[54] The SPP is currently reviewing[55] their solar PV accreditation methodology to more accurately account for the value of solar PV resources using the increasingly accepted Effective Load Carrying Capability (ELCC) approach.

FIGURE 24. Solar PV Output during Top 3% of Summer Hours vs. Nameplate Capacity by Confidence Factor shows the SPP-calculated value of solar PV for transmission planning purposes under their current approach. The different colors indicate how much solar PV systems varied across confidence levels, particularly as they passed the 60% threshold. Using this approach, the value of solar PV is assumed to reduce transmission peak demand by around 70% of its nameplate value.

54 This means the value that is higher than 60% of all values during the top 3% of hours.

55 Southwest Power Pool (2019). Solar and Wind ELCC Accreditation. Retrieved from: https://www.spp.org/documents/61025/elcc%20solar%20and%20wind%20accreditation.pdf

FIGURE 24. **Solar PV Output during Top 3% of Summer Hours vs. Nameplate Capacity by Confidence Factor**

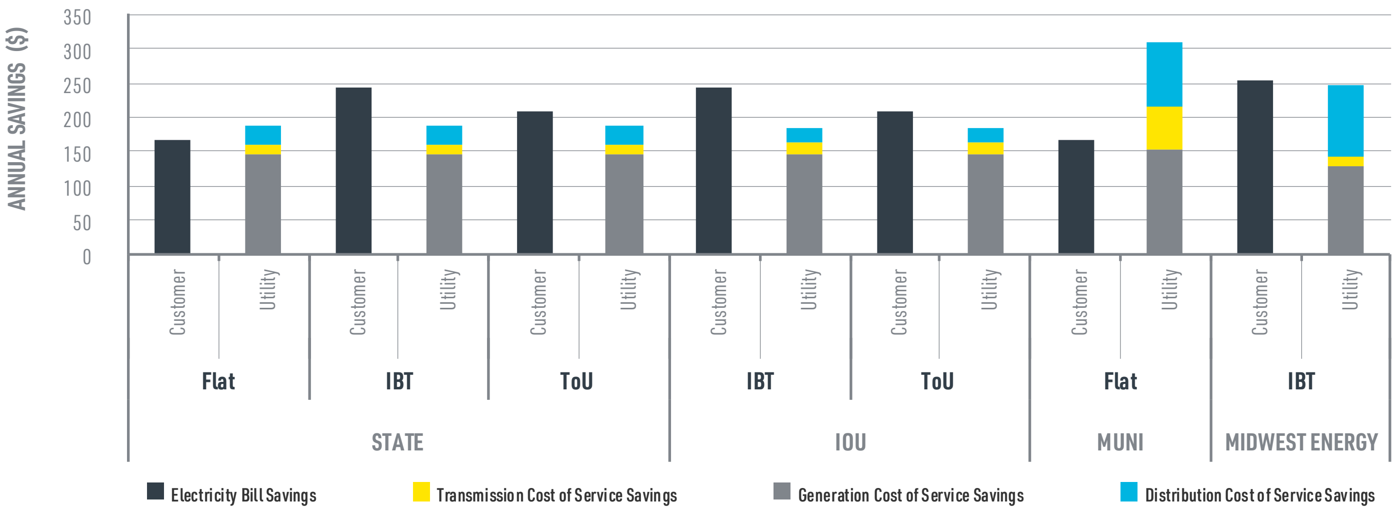


Source: SPP (2017)

At the distribution level, it is common utility practice to assume solar PV generation will be zero during the peak period, however, there are alternative approaches emerging (such as ELCC) that use data-driven statistical analysis to determine an expected level at a specified level of precision and confidence. For example, the expected level would be +/- 5% for 95% of the time.

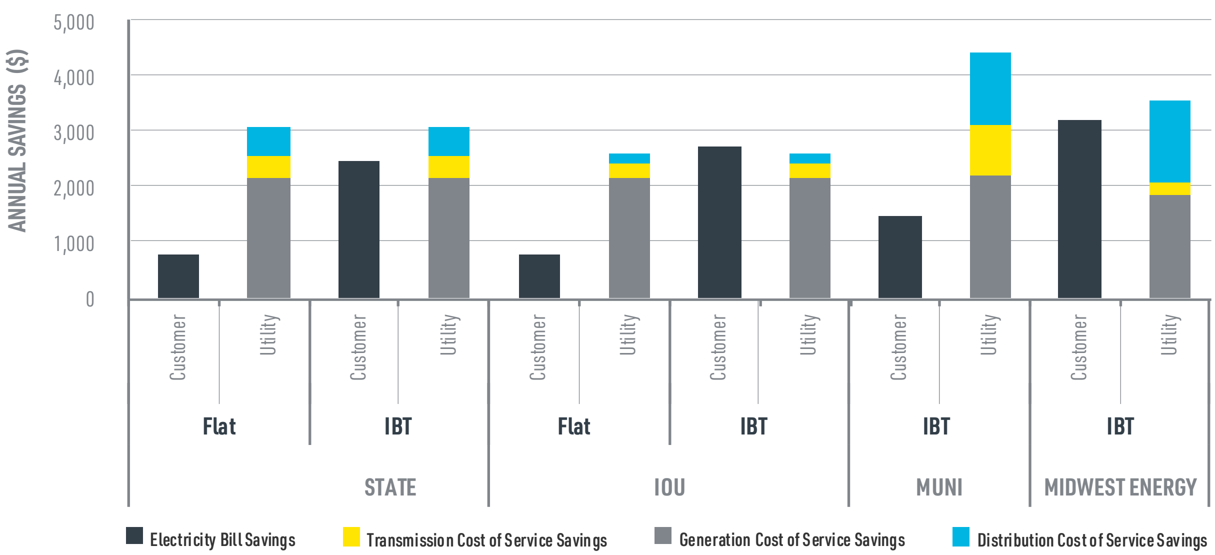
The results of the project team's model of how rooftop solar PV's net benefits are distributed between adopters and other ratepayers is reported in **Figures 25-27** by utility and rate type. The model suggests that current NEM rates may have resulted in solar PV adopters cross-subsidizing other ratepayers, particularly in the case of commercial and industrial customers. However, this largely depends on how distribution benefits are valued.

FIGURE 25. **Estimated Residential Solar PV Customer Bill Savings vs. Utility Cost Savings**



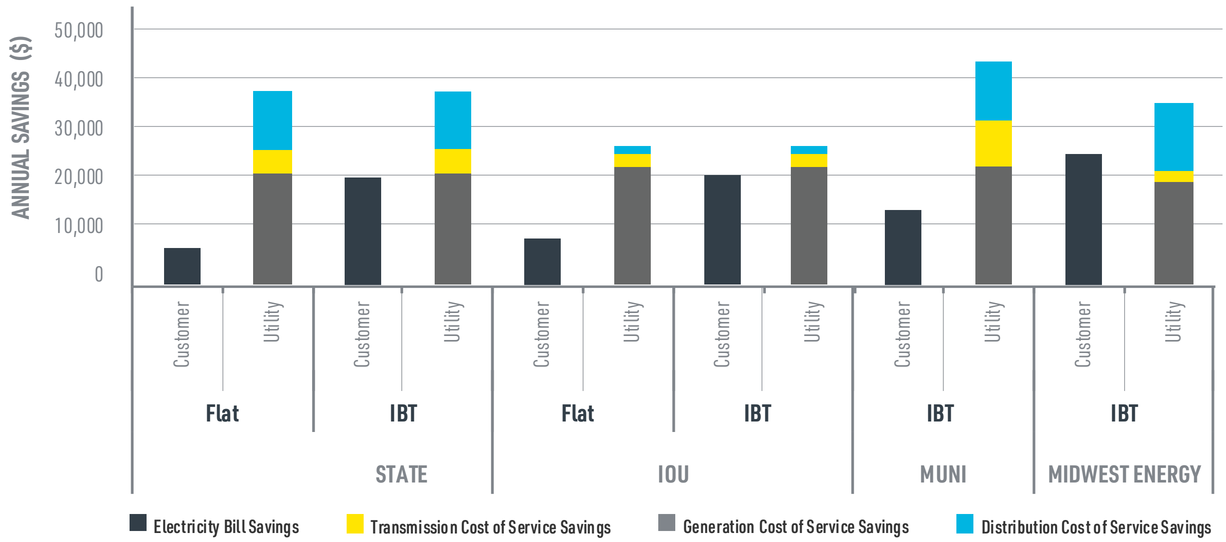
Source: Energeia (2020)

FIGURE 26. **Estimated Commercial Solar PV Customer Bill Savings vs. Utility Cost Savings**



Source: Energeia (2020)

FIGURE 27. Estimated Industrial Solar PV Customer Bill Savings vs. Utility Cost Savings



Source: Energeia (2020)

These models show that equity between solar PV adopters and other ratepayers may be increased if rates were redesigned to better allocate utility benefits. Increasing their financial attractiveness would encourage higher solar PV adoption. As the cost of solar PV declines, the cost to all ratepayers could decline, subject to utility integration costs. Key measures of access include the range of programs and their pricing, and whether levels are above or below peer and best practice levels.

Kansas utilities that responded to the RFI related to this matter reported offering three main options for accessing solar PV benefits: NEM, feed-in rate, and PV subscriptions.[56] **TABLE 8. Solar PV Programs Offered by Utility Type** reports on the percentage of utilities offering each of these types of solar PV programs by category. It shows that Kansas IOUs are, on average, offering more choices than Munis and Coops, which tend to have fewer customers and therefore fewer resources to implement a wider range of solar PV programs.

TABLE 8. Solar PV Programs Offered by Utility Type

Program	IOUs	Munis	Coops
Net Energy Metering (NEM)	100%	100%	89%
Feed-in Rate	100%	67%	54%
PV Subscriptions	0%	0%	0%

Source: RFI Responses

The only solar PV related program that was not identified as being currently implemented in Kansas was virtual net metering, which enables ratepayers in multifamily dwellings (e.g. apartments) to access a fractional share of solar PV installed on the building, or from another building via a "virtual" meter. That being said, subscriptions to utility- or community-scale PV provide a similar benefit.

Information in response to the request for program cost-benefit assessments was not provided. Such assessments could have provided detailed information regarding program cost to serve and its relationship to program pricing, which is particularly relevant for feed-in and PV subscription programs. NEM programs focus on ensuring net benefits are passed back, as has been previously discussed in this section.

56 PV subscriptions allow consumers to purchase a portion of the energy generated by a utility or community scale PV project

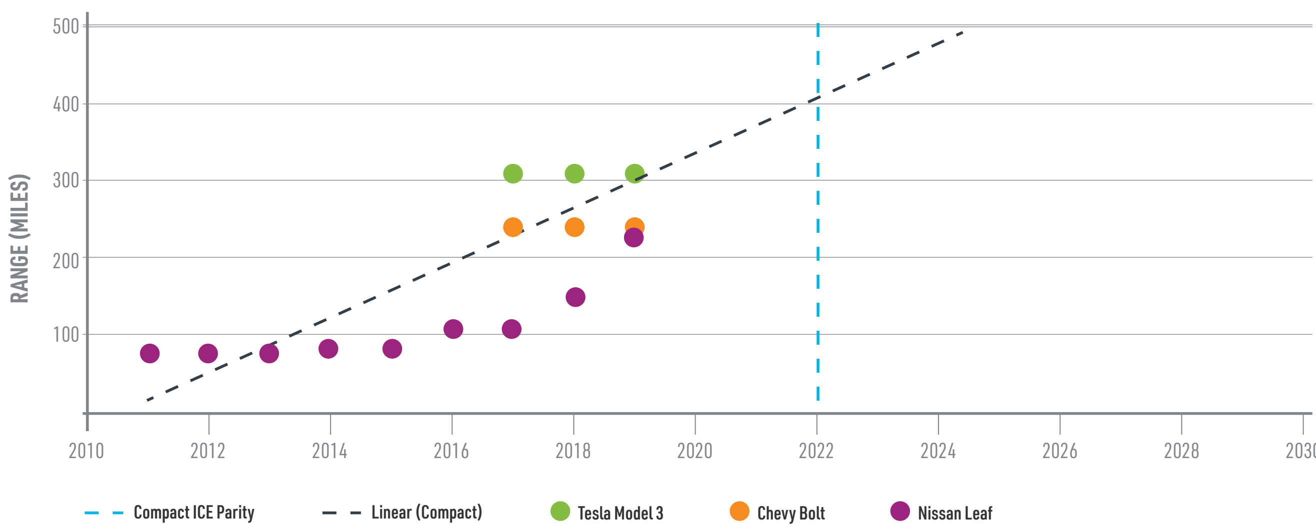
Based on this analysis, the project team has reached the conclusion that solar PV generation will increasingly benefit Kansas ratepayers, and that these benefits could be improved through rate reform. In terms of access, it was found that utilities offer programs comparable to peer state and best practice utilities.

5.4.4.2 ELECTRIC VEHICLES AND CHARGING STATIONS

EVs[57] currently offer lower operating and maintenance costs compared to equivalent ICE vehicles, though require a higher upfront purchase cost and have a more limited driving range. However, the market climate is rapidly changing in favor of EV technology.

Typical EV driving ranges are rapidly increasing, as depicted in **FIGURE 28. EV Driving Range Based on Battery Energy Capacity**. If the trend depicted in this Figure continues, EVs could be expected to reach ICE equivalent ranges in the next 2-3 years, as the cost of batteries continues to fall, which was previously highlighted by **FIGURE 12. Forecasted Costs of Rooftop Solar PV (left) and Lithium Battery Storage (right)**.

FIGURE 28.EV Driving Range Based on Battery Energy Capacity

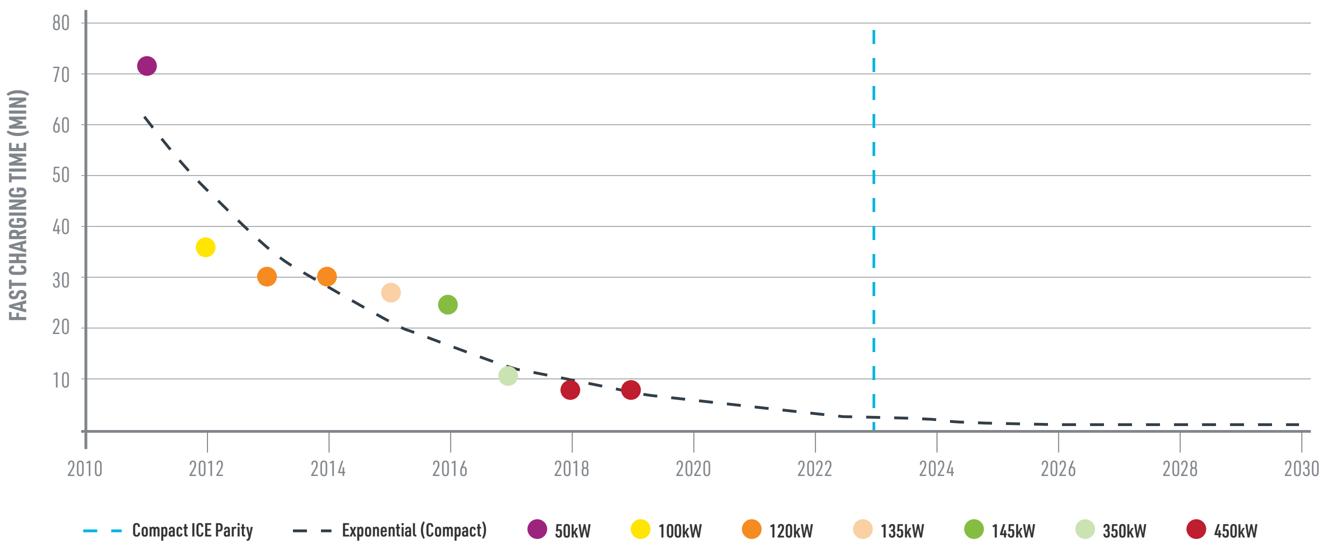


Source: OEM Websites and Energeia (2019)

EV recharging times are also decreasing rapidly, as shown in **FIGURE 29. EV Driving Range Based on Direct Current Fast Charging (DCFC)**. Projecting this trend forward, EVs may reach the average ICE vehicle's required refueling time within the next three to four years, though this is only applicable to the EVs that are manufactured with the more sophisticated technology produced at that point in time. Ensuring access to the latest charging technology would therefore be beneficial to Kansas EV drivers.

57 This report focused on passenger vehicles which are expected to be the most beneficial segment in the next five years.

FIGURE 29. EV Driving Range Based on Direct Current Fast Charging (DCFC)



Source: OEM Websites and Energeia (2019)

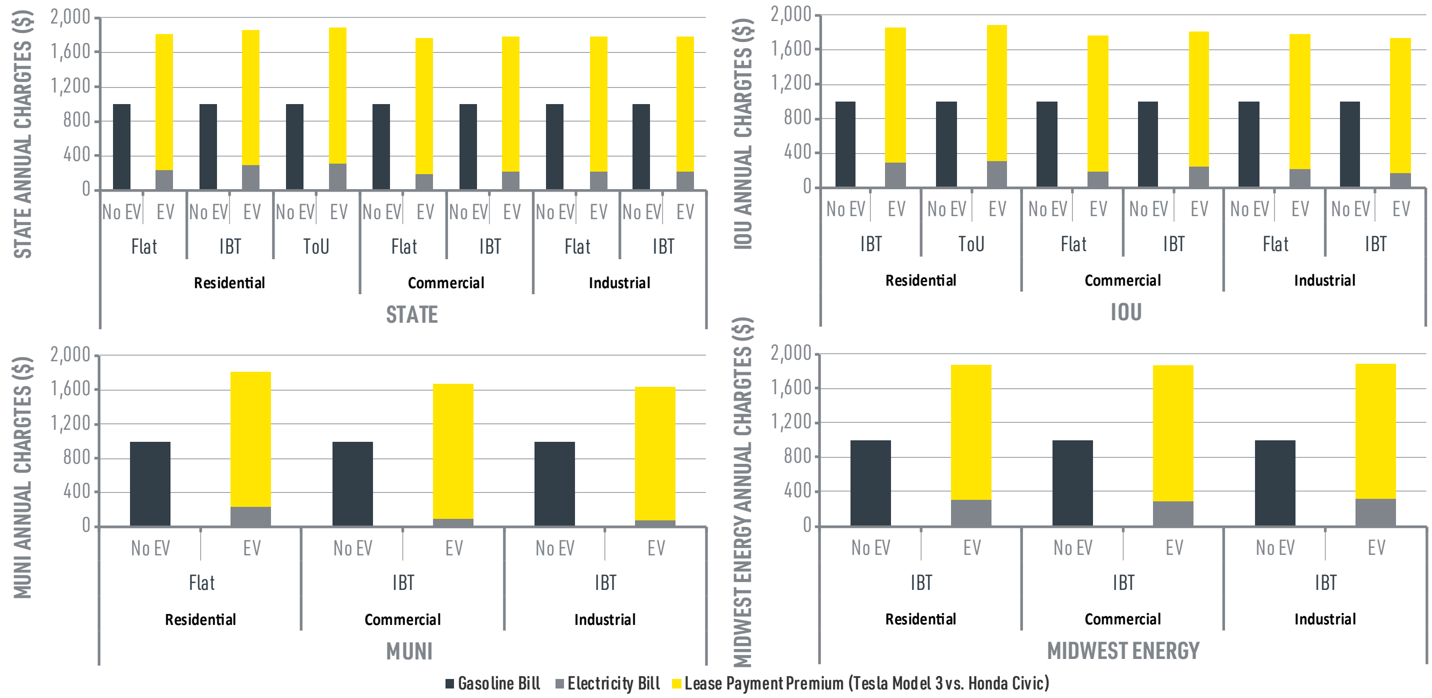
TRANSPORTATION COST REDUCTION BENEFITS

The federal government and some other jurisdictions have subsidized the upfront purchase of an EV, and often the associated charging stations, offsetting the purchase premium. However, the rapid decline in lithium battery technology prices, combined with lower raw material costs, is leading experts to forecast EV pricing parity by 2026, even without subsidies.

The key questions then are whether EV technology and their associated charging stations are, or will be, beneficial to Kansas EV drivers, whether access to them could be improved, and if so, how.

The results of the project team's analysis of current EV net benefits for Kansas consumers are presented in **FIGURE 30. EV Operating Costs Compared to Internal Combustion Vehicles (Private Charging)**, based on a comparison of a Tesla Model 3 and Honda Civic, assuming typical driving mileage and fueling profiles. The analysis shows that the leasing premium make EVs financially unattractive despite significant annual savings in fuel costs.

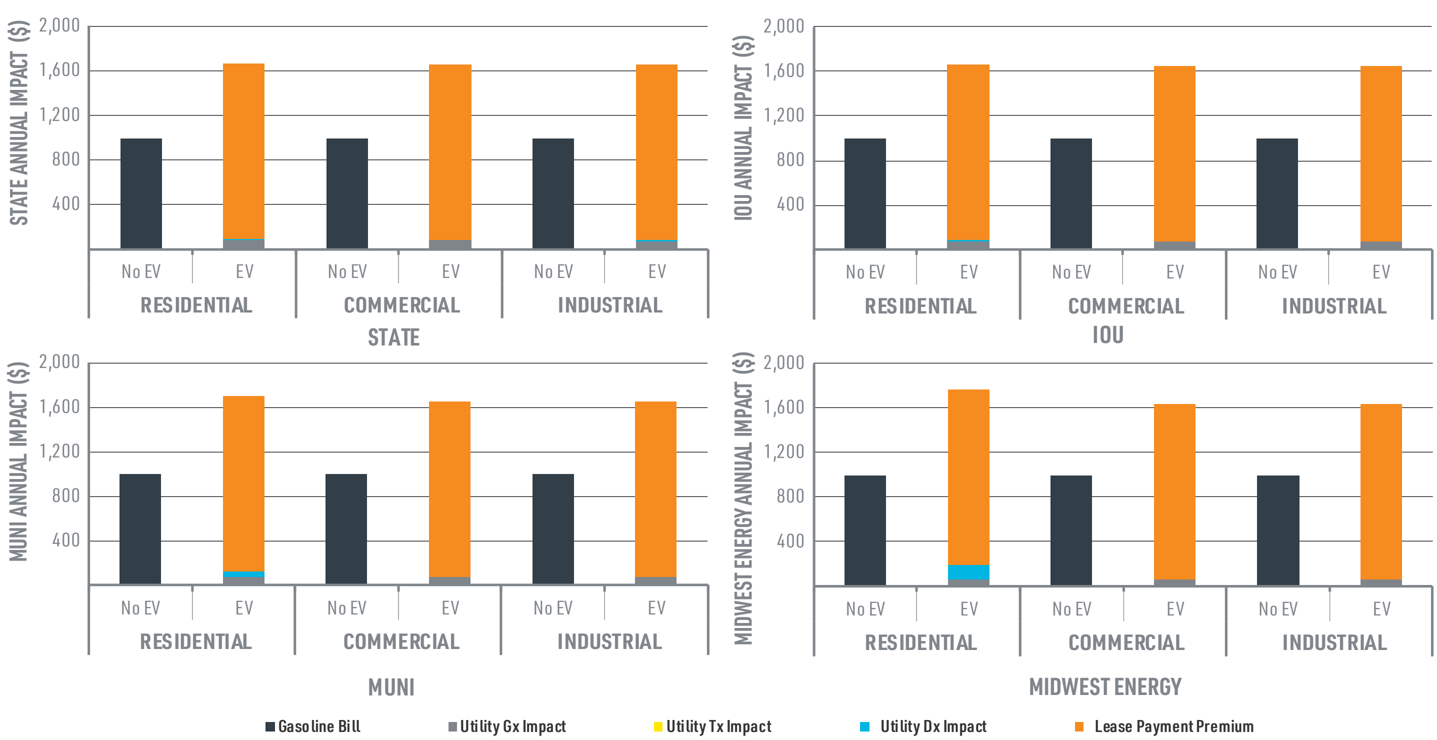
FIGURE 30. EV Operating Costs Compared to Internal Combustion Vehicles (Private Charging)



Source: Energeia (2020)

This analysis assumes current retail prices and may reflect cross-subsidies rather than true net benefits. Therefore, an economic analysis of the impacts of EV charging on utility cost to serve is necessary, as is comparing these impacts to annual changes in EV driver fuel and leasing payments. The results of these analyses are shown in **FIGURE 31. Estimated Utility Cost to Serve vs. Customer Bill Changes due to an EV**. EVs do not currently deliver an economic benefit but could be expected to at any point before 2026, when the price of an EV is forecasted to be the same as an equivalent ICE vehicle.

FIGURE 31. Estimated Utility Cost to Serve vs. Customer Bill Changes due to an EV



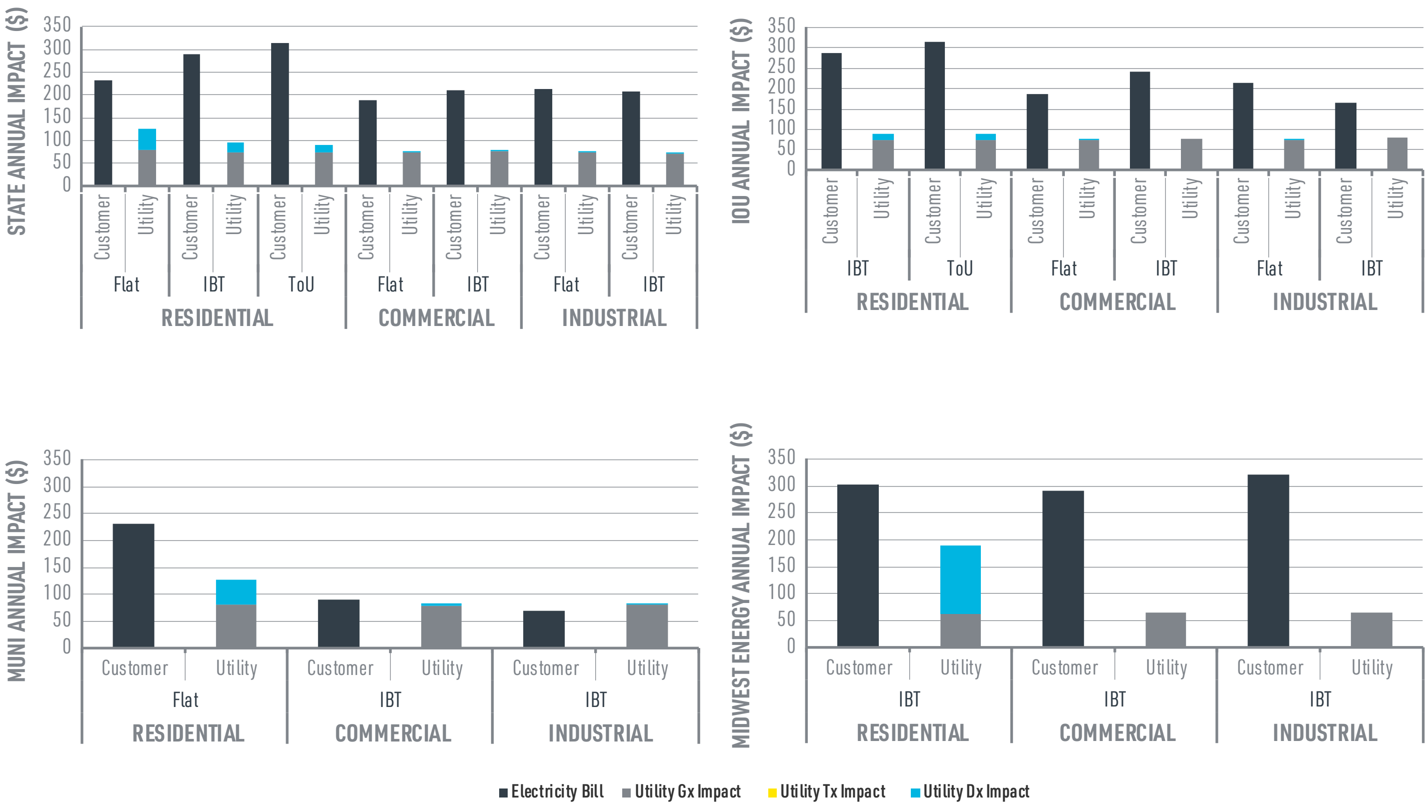
Source: Energeia (2020)

It is important to note that this above cost of service analysis is based on marginal cost of service measures, including SPP settlement prices, SPP transmission rates, and distribution cost of service; and does not account for sunk costs, which may be embedded in existing retail rates. If sunk costs were included in the cost of service estimate, the estimates above would increase accordingly.[58]

FIGURE 32. Estimated Utility Cost to Serve vs. EV Driver Bill Impacts (Private Charging) shows the estimated difference between utility cost to serve and customer electricity bill impacts, which is an indicator of the level and direction of cross-subsidies in current retail electricity rates, by utility type, rate type, and customer class. This analysis suggests that EV drivers may be paying more than the cost of EV impact on the electricity system. This result is consistent across utility type, rate type, and customer class.

58 In the case where the consumer is already paying their fair share of stranded costs, the project team does not believe sunk costs should be included in considering incremental consumption.

FIGURE 32.Estimated Utility Cost to Serve vs. EV Driver Bill Impacts (Private Charging)



Source: Energeia (2020)

Based on the above analysis, the project team has reached the conclusion that EVs are not currently economical for Kansas customers due to the leasing premium. They are expected to achieve a positive net benefit as EVs approach pricing parity with ICE vehicles by 2026. Furthermore, current electricity rates may be charging EV drivers more than their incremental cost of service.

If there are cross-subsidies in current rates that disadvantage EV drivers, reforming them under the approach recommended in **Section 5.2** would increase the net benefits of EVs by around $100 to $250 per year for the average home-charging EV driver and $100 to $150 per year for the average workplace-charging EV driver.

5.4.4.3 BATTERY STORAGE

TABLE 9. Potential Storage Benefits below lists a wide range of potential benefits to ratepayers from BTM battery storage, of which some of the most prominent are:

- Higher levels of reliability;[59]
- The ability to use more of their own solar directly and reduce their reliance on the grid; and
- Lower utility bills.

There are additional potential benefits of BTM storage for utilities, also reported in **TABLE 9. Potential Storage Benefits**. As is the case for solar PV, actualizing these benefits is depends upon local network conditions and the utility's familiarity with coordinating battery operation, which require additional expenditure.

TABLE 9. Potential Storage Benefits

Stakeholder Category	Stakeholder Group	Behind the Meter	Distribution	Transmission
Customer Services	Backup Power	✓		
	Increased PV Self-Consumption	✓		
	Demand Charge Reduction	✓		
	Time-of-Use Bill Management	✓		
ISO/RTO Services	Energy Arbitrage	✓	✓	✓
	Spin/Non-Spin Reserve	✓	✓	✓
	Frequency Regulation	✓	✓	✓
	Voltage Support	✓	✓	✓
	Black Start	✓	✓	✓
Utility Services	Distribution Deferral	✓	✓	
	Transmission Deferral	✓	✓	✓
	Transmission Congestion Relief	✓	✓	✓
	Resource Adequacy	✓	✓	✓

Source: RMI

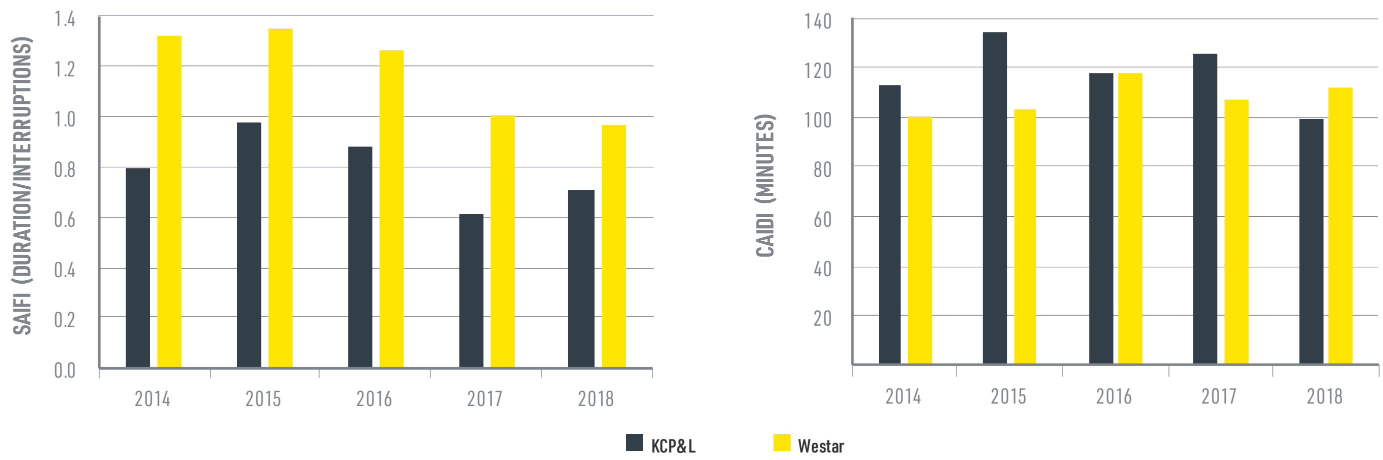
A cross-subsidy will arise when the change to a BTM storage system adopter's bill is different than the change in the utility cost of service. Therefore, a complete benefits assessment needs to account for distributional effects – and not just overall economic impacts.

BACKUP POWER

FIGURE 33. IOU Reported Outage Levels (SAIFI and CAIDI) shows the average level of IOU service reliability over the past few years in terms of average number of outages per year and the average duration of these outages at the customer level. Taken together, IOU customers can expect less than one outage per year, lasting around 100 minutes.

59 The residual benefits of higher reliability were not analyzed but are expected to be relatively minimal.

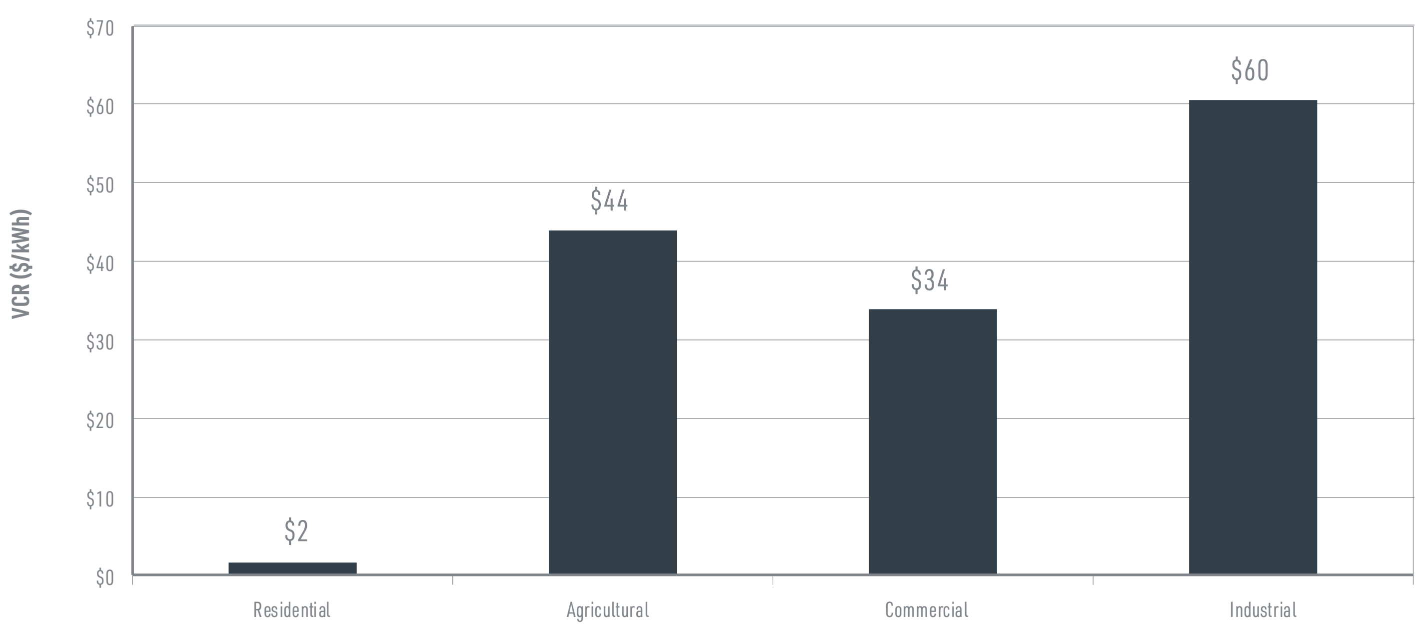
FIGURE 33. IOU Reported Outage Levels (SAIFI and CAIDI)



Source: LEI (2019)

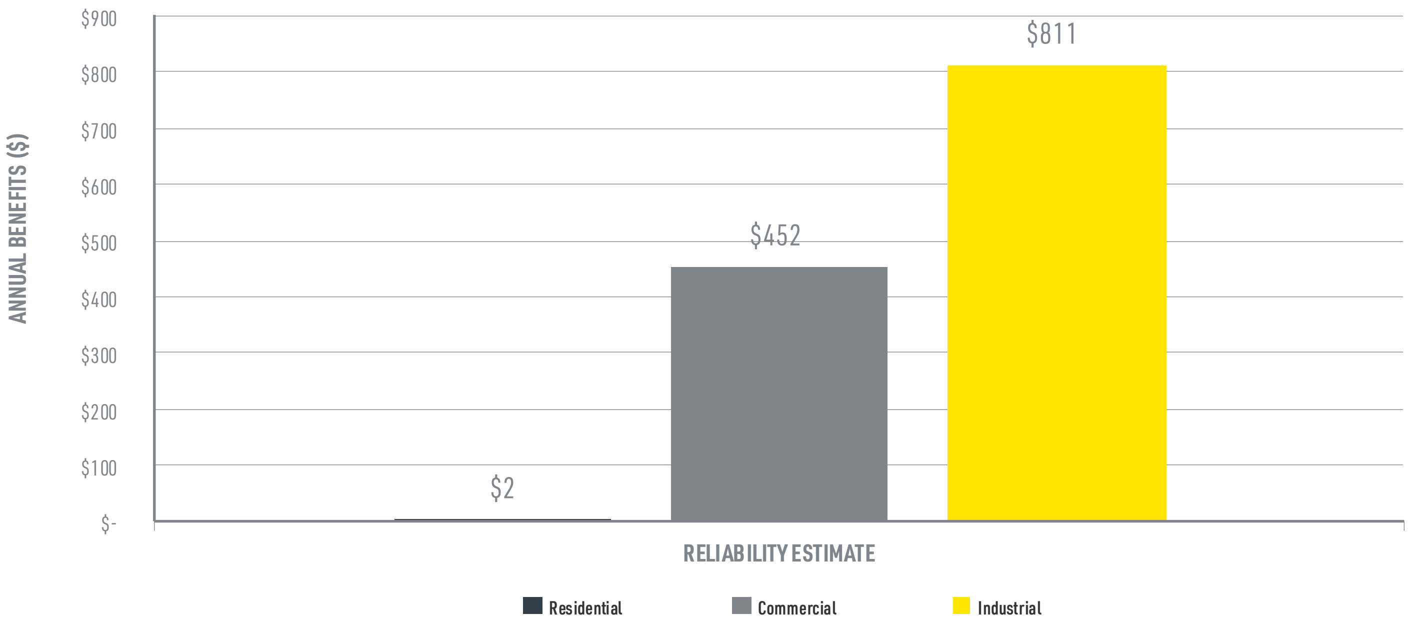
The estimated value of avoiding this outage, often referred to as the value of lost load, is shown in **FIGURE 34. Estimated Value of Lost Load by Customer Type (U.S. Midwest)** by customer type.

FIGURE 34. Estimated Value of Lost Load by Customer Type (U.S. Midwest)



Source:LEI (2013)

FIGURE 35. Estimated Annual Benefits from Avoided Outages



Source: Energeia (2020)

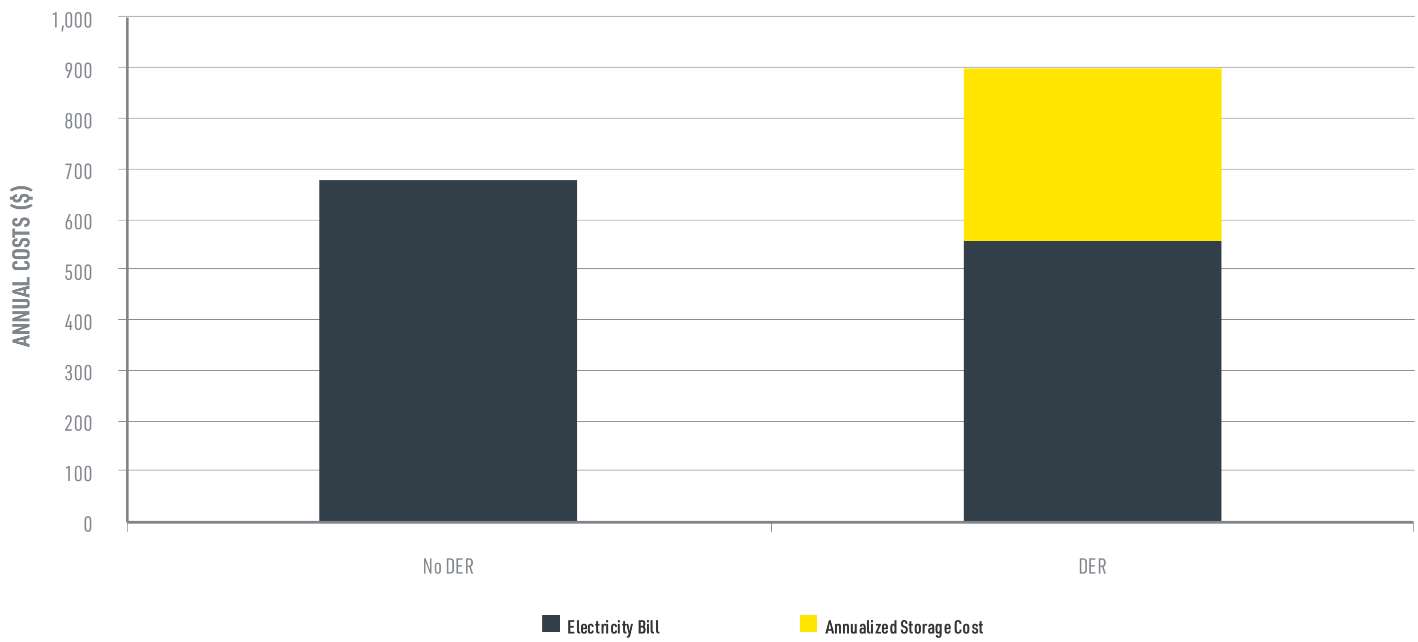
Although these benefits fall below the annualized cost of storage, whether or not BTM storage delivers an overall positive net benefit for Kansas ratepayers ultimately depends on the results of the following financial analysis.

COST REDUCTION BENEFITS

The value capture of current net benefits of BTM storage for adopting customers is reported in Figure **FIGURE 36. Estimated Impact of BTM Storage Adoption on a Residential Customer's Total Costs**.[60] Assuming the battery would only be used to shift the consumer's peak period consumption, the analysis shows that while the consumer's bill would be reduced, it does not offset the annualized cost of the battery.

60 Details regarding the modelling methodology and key inputs and assumptions are provided in **see APPENDIX C Cost of Service Modelling Methodology**.

FIGURE 36. Estimated Impact of BTM Storage Adoption on a Residential Customer's Total Costs



Source: Energeia

As is the case with solar PV, the net benefits for adopting customers are expected to increase as lithium battery costs drop, as shown in **FIGURE 12. Forecasted Costs of Rooftop Solar PV (left) and Lithium Battery Storage (right)**. Assuming BTM storage programs were effectively coordinated by the utility to address utility generation, transmission and distribution cost drivers, modelling suggests such a storage system could deliver net positive benefits to ratepayers by 2030.

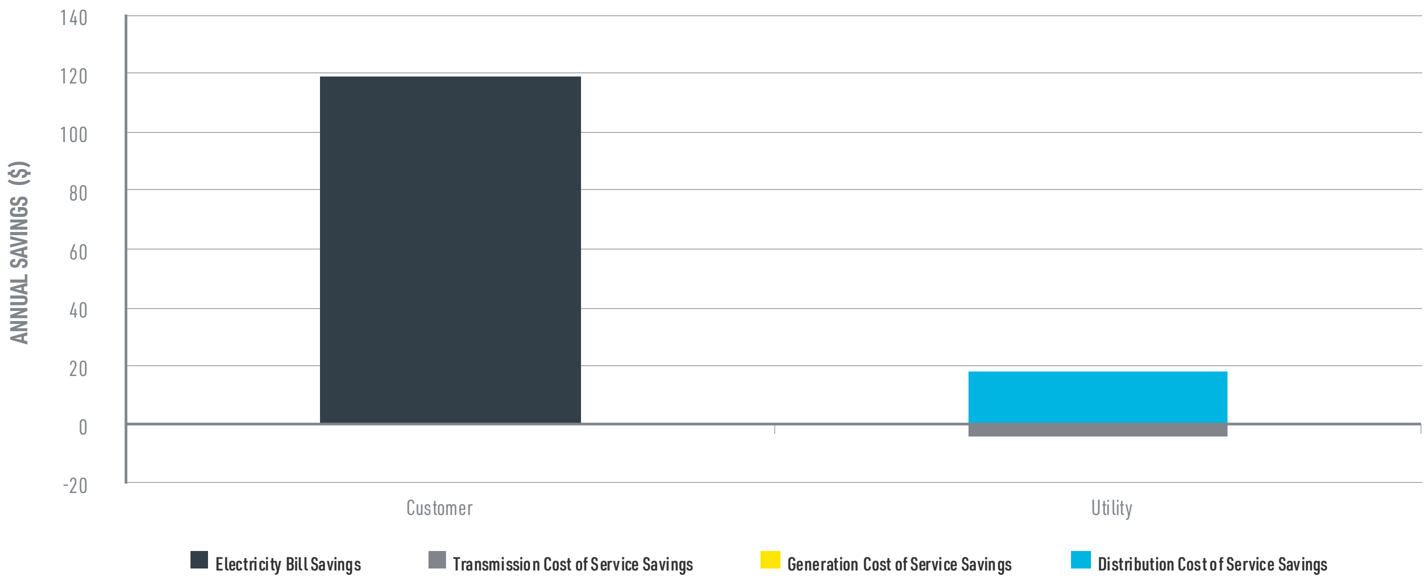
Implementing successful BTM storage programs that maximize benefits will require changes to rate design, and incentive levels and structures. Utilities should also consider their capability to manage storage integration technologies (and other AES, as they emerge) to ensure their benefits are harnessed.

CROSS-SUBSIDIES

The differences between the impact of BTM storage on adopting customers' bills and the utility's cost of service , assuming no utility coordination, is shown in **FIGURE 37. BTM Storage Residential Customer Bill vs. Utility Cost of Service Impacts.** [61] The model indicates that current residential ToU rates may lead to a BTM storage cross-subsidy as a result of the difference in how much customers adopting BTM storage save relative to what they are expected to save the utility.

61 Flat and inclining block rates were excluded as there is no incentive to time shift usage using the battery.

FIGURE 37. BTM Storage Residential Customer Bill vs. Utility Cost of Service Impacts



Source: Energeia (2020)

Based on this analysis, the project team has reached the conclusion that customer coordinated BTM storage does not deliver a financial benefit to either those adopting it or other ratepayers. However, based on forecasted technology prices, BTM storage could deliver net benefits to adopters within the next 10 years; rate reform and utility coordination would be required to avoid inflicting negative impacts on ratepayers.

ACCESS TO BENEFITS

The range and price of storage programs currently offered by Kansas utilities were studied and benchmarked against or below peer state and best practice utility offerings.

None of the utilities that responded to the RFI currently offer a BTM storage program – or plan to offer one in the near future. Peer state and best practice utilities offer the following types of programs:

- **BTM storage solutions:** The utility offers to install a BTM storage solution for a fee, and then the system is operated by the customer to maximize their own benefits.
- **Virtual power plant solutions:** The utility offers to install a BTM storage solution and coordinates the operation of the system so as to better unlock utility benefits.
- **Community and virtual solutions:** The utility offers to apply virtual storage to a customer's bill, typically when they have a solar PV system or want to reduce their bill with a ToU rate.[62]

Based on the above analysis, the project team concludes that improved access to BTM storage would not benefit Kansas ratepayers currently but could be expected to within the next 10 years, provided that it was coordinated with utility cost drivers. From the standpoint of access, the project team concludes that current levels of access are behind best practice utilities due to the lack of any BTM storage programs or pilots.

5.4.4.4 MICROGRIDS

Microgrids (MGs) are typically used for one of two primary applications, with a third application emerging:

- **Powering remote premises**, either remote area power systems (RAPS) or stand-alone power systems (SAPS), which are too far from a grid source of supply to make it cost effective to connect;

62 This type of program is similar to virtual net metering and community solar PV programs but focused on storage.

- **Providing higher reliability** than is possible from the grid, typically for critical infrastructure like military or police facilities, or very high value commercial premises, like stock exchanges; or
- **Providing a lower cost alternative to upgrading the grid**, typically used in high cost to serve pockets of the network, such as wildfire prone areas, to avoid rolling blackouts.

REMOTE AREA POWER SYSTEMS AND STAND-ALONE POWER SYSTEMS

A RAPS is typically a community of premises, while a SAPS is a single premise in an area, remote from the grid.

Until the recent fall in the price of solar and battery storage, RAPS were historically powered by diesel generators for the most part. Now solar PV with thermal generation and potentially BTM storage (solar-storage-diesel MGs) is a more common configuration for connecting new and replacing existing systems.

None of the Kansas utilities reported having any microgrid customers. This is not surprising for the metro, urban and suburban utilities. Some rural and remote utilities in other states offer RAPS, mainly to support remote communities, rather than individual premises.

Based on this analysis, the project team has reached the conclusion that Kansas electricity consumers in remote locations could benefit from connecting to solar-storage-diesel MGs, provided they are accessible from either the market or the utility (though utilities do not yet offer MG solutions).

HIGH RELIABILITY SITES

Premises requiring better than average grid reliability typically install multiple points of connection, backup generators, and increasingly, solar PV and storage systems. While these sites are not set up to normally operate on an isolated or MG-basis, they can do during grid outages. The scope of the site and level of reliability required impacts how the solution is sized and configured.

While falling solar PV and storage costs are bringing down the cost of solar-storage-diesel microgrids, these are less well suited to this microgrid segment, at least not in metro, urban or even suburban locations, due to the amount of space needed for the solar PV systems. Rural areas with ample room are best placed to potentially benefit from solar-storage-diesel systems, compared to diesel only.

As is the case with the off-grid market segment for microgrids, the grid connected, high reliability market is being served by the private sector, as evidenced by the wide range of solution offers serving Kansas able to be identified via an internet search.

HIGH COST TO SERVE, LOW RELIABILITY SITES

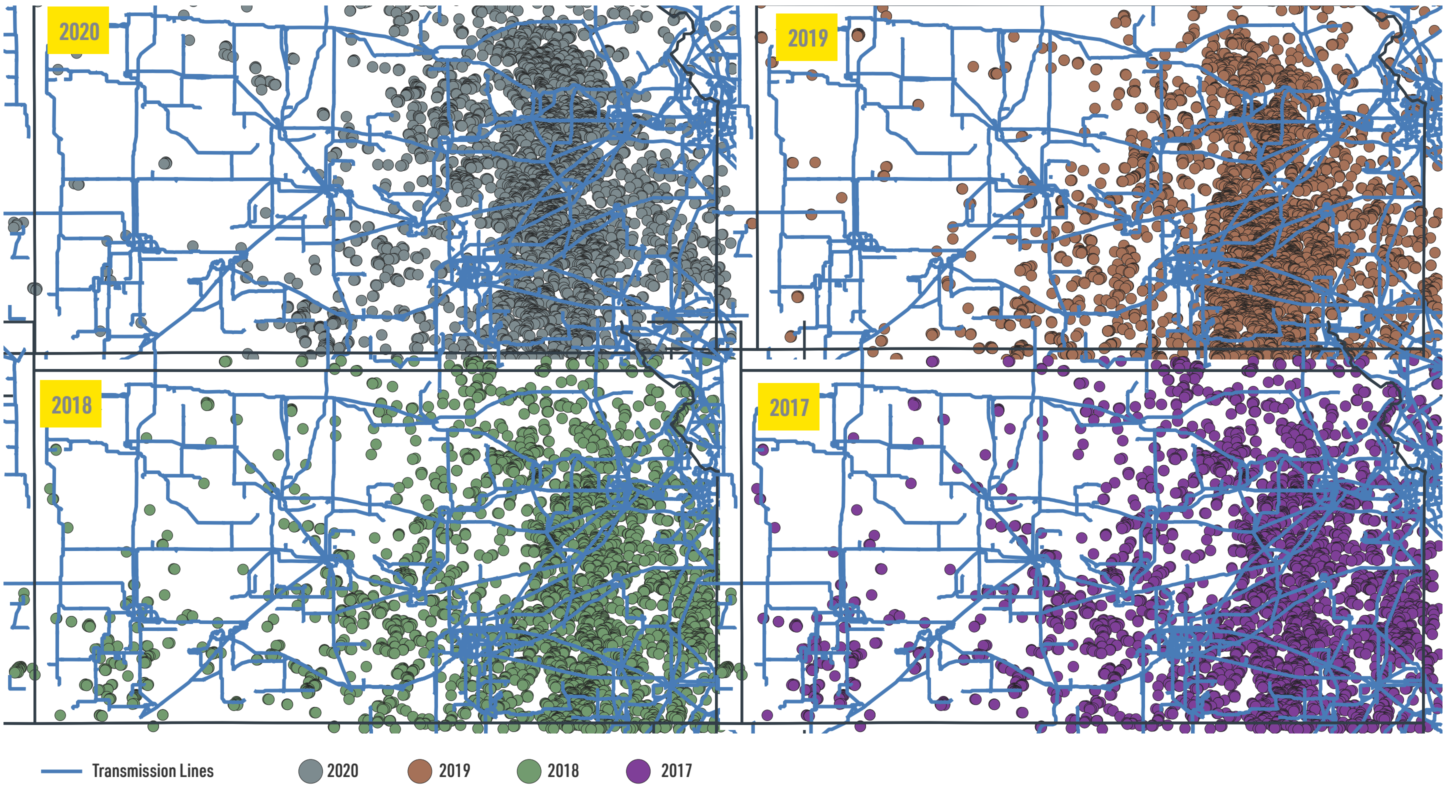
Utilities typically track performance of their worst performing feeders and develop plans for improving reliability up to some minimum threshold, often at a very high cost.

An emerging application for MGs is serving premises in high cost to serve areas with low levels of grid reliability, typically where there is a lot of vegetation or other environmental conditions that make it difficult to maintain target levels of reliability.

Wildfire-prone areas, for example, have emerging demand for utility-developed microgrids as a reliability solution – especially in California, where the IOUs have disconnected tens of thousands of people at a time to mitigate the risk of fire-related deaths.

FIGURE 38. Map of Historical Wildfire Activity in Kansas depicts the areas of seasonable wildfire activity in Kansas, overlaid with electrical infrastructure.

FIGURE 38.Map of Historical Wildfire Activity in Kansas



Source: Kansas Forest Service (2020)

While not currently a major concern, wildfire-related outages may become less tolerated as advocates become familiar with MG solutions being implemented in other states to mitigate the need for such outages.

Kansas utilities reported examples of using or piloting MGs to target their worst performing feeders or to provide a reliability solution in wildfire-prone areas. Based on other states' experiences, the project team has reached the conclusion that solar-storage-diesel MG technology may provide a greater benefit than other available alternatives to this customer segment due to its lower cost to serve.

Additionally, as the cost of MGs continue, they will become even more cost effective, and therefore will become a more common tool for Kansas utilities to improve the reliability on their worse performing feeders. Implementation of these systems will likely improve grid reliability for rural customers, who are most likely to experience relatively low levels of reliability.

Based on this analysis, the project team has reached the conclusion that increased access to MG solutions could improve grid resiliency, especially for customers in wildfire prone areas or on a utility's worst performing feeder, and would thus benefit Kansas ratepayers.

5.4.4.5 TRANSACTIVE ENERGY

Transactive Energy (TE) is an industry term that without an industry-standard definition. According to the Smart Electric Power Alliance (SEPA), TE:

> *Allows customers, either as individuals or in aggregate, to actively engage in energy markets by negotiating and responding to "value signals," based on demand, price, time of day or other considerations.*[63]

The ability of prosumers[64] or their agents to buy and sell TE products among themselves and with distribution and transmission utilities across a range of time horizons is expected to increase economic efficiency, competition, and consumer choice.[65]

A key precondition of TE is the availability of TE products to buy and sell, and the existence of a TE marketplace within which to buy and sell these products. A number of TE marketplace providers have emerged nationally, including TeMix and GreenSync, to provide the product specifications, market matching, clearing, and settlement services required of any commodity marketplace.

All TE markets identified by the project team are in the pilot phase, mainly focused on developing and testing TE products with prosumers, their agents, and the utility. Initial results from these pilots show that they can be used to coordinate DER across a group of prosumers to achieve lower cost and more efficient outcomes.[66]

Among the key challenges reportedly being faced by TE is standardizing physical delivery of products due to the generally complex nature of distribution grids and power systems. However, physical delivery issues are faced by ISOs/RTOs, who may provide a workable framework for TE.

Depending on the TE definition, the role of the utility may be as a market facilitator similar to the role of an ISO/RTO in bulk energy markets like the SPP.[67] Other TE visions see a more decentralized coordination model, similar to the internet.

Although most of the pilots identified by the project team have been based in California or New York, Ameren, based in Missouri, is currently testing TE marketplace software. None of the Kansas utilities reported offering or planning to offer transactive energy services in their RFI responses.

Based on this research and analysis of the key benefits of and barriers to accessing TE, the project team has reached the conclusion that TE could deliver benefits to Kansas ratepayers in the future, once TE markets and technology are more mature.

63 Hardin, K. and Kaufman, K. (2017). Transactive Energy 101: DERs drive real-time market dynamics to the distribution system-are we ready? Smart Electric Power Alliance. Retrieved from: https://sepapower.org/knowledge/transactive-energy-101/

64 A prosumer is generally understood to be a buyer and seller of electricity, typically via a rooftop solar PV system

65 NIST (n.d.). Transactive Energy: An Overview. Retrieved from: https://www.nist.gov/engineering-laboratory/smart-grid/hot-topics/transactive-energy-overview

66 do Prado, J., Qiao, W., Qu, L., and Aguero, J. (2019). The Next-Generation Retail Electricity Market in the Context of Distributed Energy Resources: Vision and Integrating Framework. Energies, 12 (3), 491. Retrieved from: https://www.mdpi.com/1996-1073/12/3/491

67 Hino, K-I. (2017). Transactive Energy: The next step for the digital grid? Cleantech Group. Retrieved from: https://www.cleantech.com/transactive-energy-the-next-step-for-the-digital-grid/

5.5 Impacts of Transmission Investments on Kansas Electricity Rates

The extent to which transmission investments by Kansas electric public utilities have impacted retail rates, including any incremental regional transmission costs incurred by Kansas ratepayers for transmission investments in other states, and whether such costs have been fully offset by financial benefits such as improved access to low-cost renewable energy and wholesale energy markets.

5.5.1 BACKGROUND TO THE QUESTION

Part 1 of the Study identified[68] changes in transmission investment costs as one of the key drivers of rate increases in Kansas[69] over the past 10 years, based on the findings of the cost of service study completed by the KCC. The other two predominant factors contributing to rate increases were environmental regulations and rising electricity production costs, which when taken into consideration with transmission investments, explained 60-62% of total cost increases over the period.[70] This section examines the impacts of transmission investments on retail electricity rates and whether such costs have been offset by financial benefits.

5.5.2 SCOPE AND APPROACH

In order to answer the question posed by this matter in the Study, a quantitative analysis was conducted by the project team, which was then reinforced by stakeholder data. The analysis involved the following steps:

- Collecting transmission investment data for each SPP transmission zone from the annual transmission revenue requirements (ATRR) data provided in open access transmission tariff reports;
- Using GIS software to extract demographic and employment data for the relevant geographies that correspond to SPP transmission zones for each year of the analysis period (2010 to 2019);
- Comparing transmission investment, electricity rate, job and population growth data by SPP transmission zone and state based on a normalized service population;
- Aligning electricity rate data with transmission investment data to identify potential benefits and costs to the Kansas ratepayer associated with electricity rates;
- Comparing locational marginal prices (LMP) for SPP transmission zones to analyze impact of transmission investments on generation costs, congestion costs, and load reliability; and
- Analyzing state-wide generation and net exports for Kansas and its nine peer states to compare transmission investments to electricity exports over time.

Findings from this analysis were used to inform whether retail electricity rates in Kansas appeared to be materially impacted by regional transmission investment, and more specifically, answer the following questions:

- How do electricity rates in Kansas compare to peer states by customer class?
- What are the net benefits or costs of regional transmission investmets on the Kansas ratepayer?

Additional information regarding the impact of electricity exports is addressed in **Section 5.6**.

68 London Economics International, LLC (2020). Study of Retail Rates of Kansas Electric Public Utilities, page 48. Kansas Corporation Commission. Retrieved from: https://estar.kcc.ks.gov/estar/ViewFile.aspx/S20200108144309.pdf?Id=1a3a31e5-e38d-4445-aada-1cd0170a7b85

69 State and utility pricing trends by customer class are reported in Section 5.10.1.

70 London Economics International, LLC (2020). Study of Retail Rates of Kansas Electric Public Utilities, page 48. Kansas Corporation Commission. Retrieved from: https://estar.kcc.ks.gov/estar/ViewFile.aspx/S20200108144309.pdf?Id=1a3a31e5-e38d-4445-aada-1cd0170a7b85

5.5.3 INFORMATION GATHERING

The RFI was issued with the following information request related to this question:

5.1: Please send your transmission investment and associated operating expenses over the last ten years in Kansas and in other states by year.

5.2: Please send us the economic feasibility analysis completed and accepted by the SPP related to each of the above investments.

5.3: Please send us any economic feasibility analysis completed within the past ten years (whether or not accepted by the SPP) with regard to transmission investments.

5.4: Please send transmission costs recovered from your consumers over the last ten years by rate and year.

5.5.3.1 SUMMARY OF RFI RESPONSES

Limited information was gathered from the utilities in this area, in part due to the predominance of distribution-only entities. To workaround this data gap, the majority of the analysis was conducted with publicly available data. SPP ATRR data provided in Open Access Transmission Tariff reports was used to assess the costs incurred by transmission owners and resulting impact on ratepayers; to normalize these impacts on different population centers across the region, demographic and employment data was acquired. Finally, LMP data allowed the project team to weigh the cost of transmission investments against the resulting benefits associated with reduced transmission congestion and line losses.

5.5.3.2 STAKEHOLDER FEEDBACK

Rising transmission investments were a priority concern of the majority of stakeholders consulted over the course of the Study. While stakeholders unilaterally recognized that these investments have led to reduced wholesale generation prices, they were conflicted about the degree to which these savings have offset transmission investment impacts on retail rates. One stakeholder provided data about the growth of one utility's transmission delivery charge (TDC): overall, the TDC had increased by 304% between when it had first been implemented and the present day. For a typical residential customer in the utility's service territory, this has a resulted in over a $10 increase on their monthly bill over this timeframe, and for an average large-volume customer, over a $215,000 monthly increase. Stakeholders also provided conflicting information about the current state of how transmission costs are allocated between power producers and ratepayers. Transmission investments required to connect new wind generation to the grid, for example, are supposed to be entirely paid by the developer. One stakeholder suggested that, as a result, these transmission investments made little to no impact on retail rates. Another stakeholder advised the project team that while this would be true for wind projects that are directly assigned by FERC, projects are often left unassigned.

Finally, stakeholders recommended that the project team consider the economic development impacts of transmission investments, specifically pointing to the job growth and agricultural opportunities resulting from construction of wind farms across the SPP region.

5.5.4 KEY FINDINGS AND CONCLUSIONS

To determine the costs and benefits to Kansas ratepayers from regional transmission investments, the project team analyzed the relative growth in electric rates for Kansas and nine peer states[71] to understand the potential impact of these investments on the average rates. In 2019, Kansas customers were paying higher electricity rates in the industrial, commercial, and residential classes. Additionally, electricity rates grew more slowly than the regional average in Kansas from 2001 to 2007, and subsequently faster than the regional average from 2010 to 2019 for the three customer classes examined. **TABLE 10. Average Annual Electricity Rates** shows the 2019 rates and compound annual growth rates (CAGR) for two periods of analysis: 2001 to 2007 and 2010 to 2019.

71 For this analysis, electricity rates in Kansas were compared to Arkansas, Colorado, Iowa, Missouri, Nebraska, North Dakota, Oklahoma, South Dakota, and Texas.

TABLE 10. Average Annual Electricity Rates

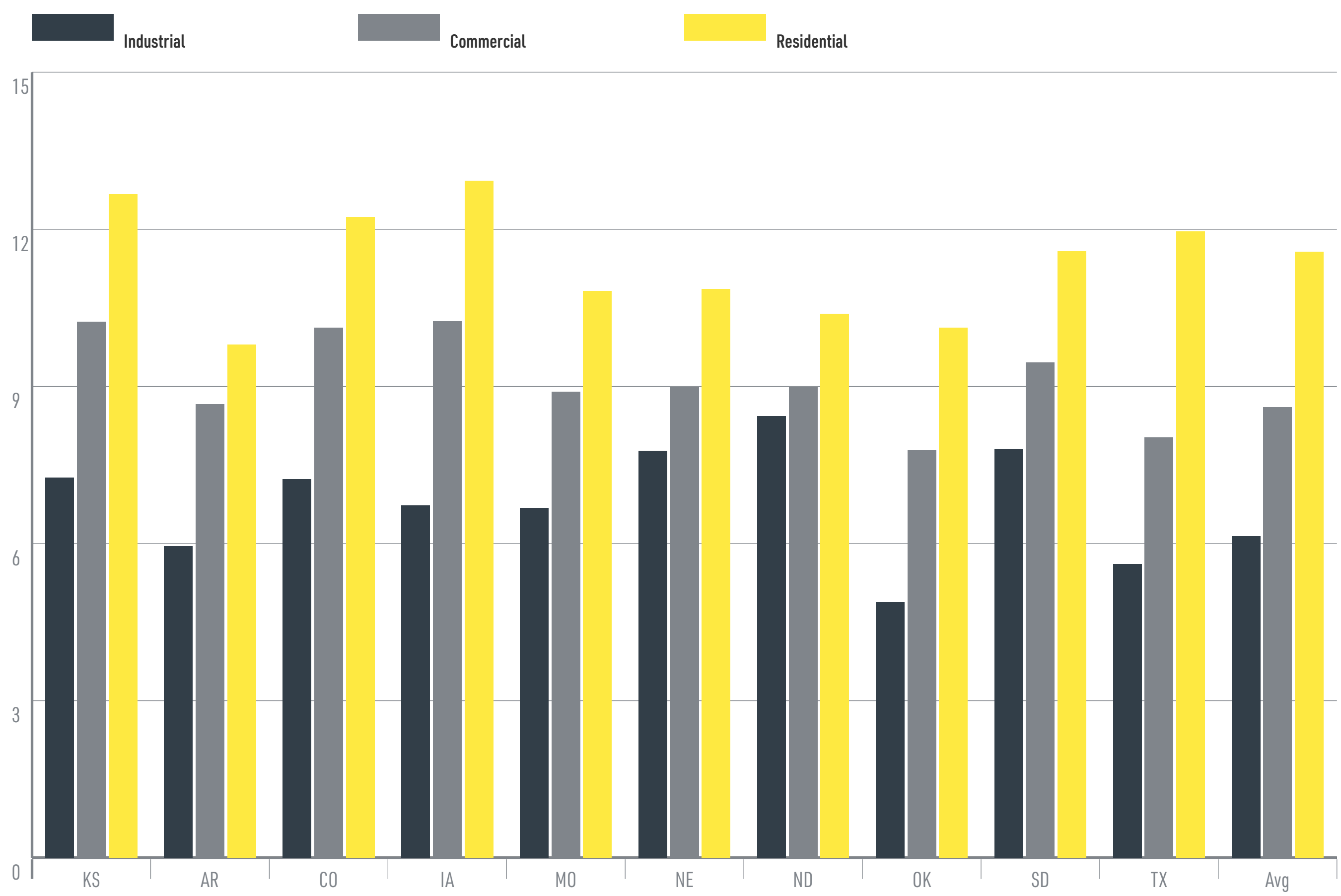
		2019 Rate (cents/kwh)	CAGR 2001-2007	CAGR 2010-2019
Industrial	**Kansas**	7.26	2.02%	1.95%
	Regional Average*	6.14	5.06%	-0.02%
Commercial	**Kansas**	10.23	1.62%	2.95%
	Regional Average*	8.60	3.91%	0.16%
Residential	**Kansas**	12.67	1.12%	3.21%
	Regional Average*	11.57	4.01%	0.92%

* Weighted average of Kansas, Arkansas, Colorado, Iowa, Missouri, Nebraska, North Dakota, Oklahoma, South Dakota, and Texas

Source: EIA (2019), AECOM (2020)

In 2019, customers in Kansas experienced electricity rates that were among the highest in the region. Industrial rates in Kansas were surpassed only by South Dakota, North Dakota, and Iowa, while commercial and residential rates were the second highest in the region, with only customers in Iowa paying higher rates. Yet, because of the proportion of ratepayers in each customer class, Kansas had the highest average rate for its overall ratepayer base. **FIGURE 39. Electricity Rates by State: Average Annual Electricity Rate (cents/kwh) (2019)** shows the annual average electricity rates for the three customer classes for Kansas, its peer states, and the regional average.

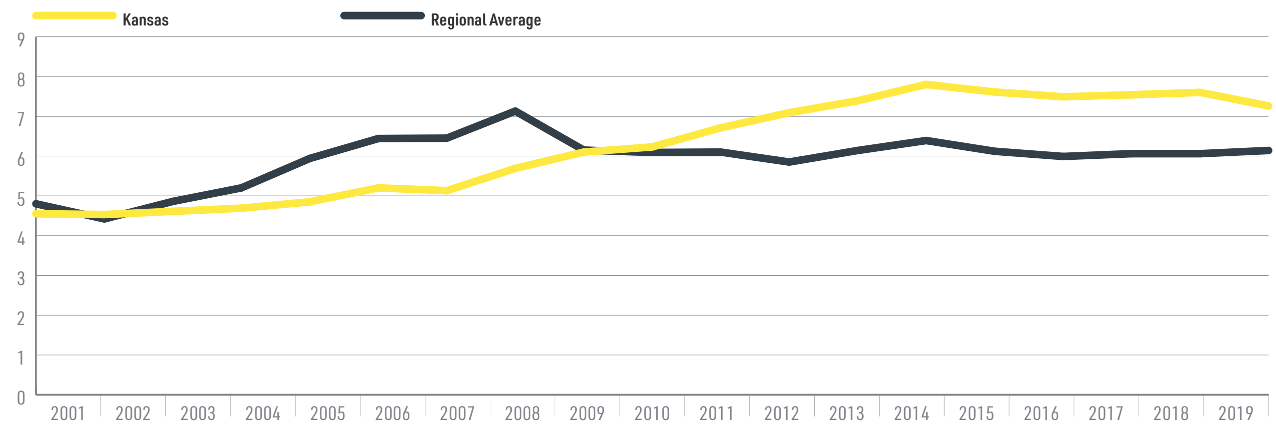
FIGURE 39. Electricity Rates by State: Average Annual Electricity Rate (cents/kwh) (2019)



Source: EIA

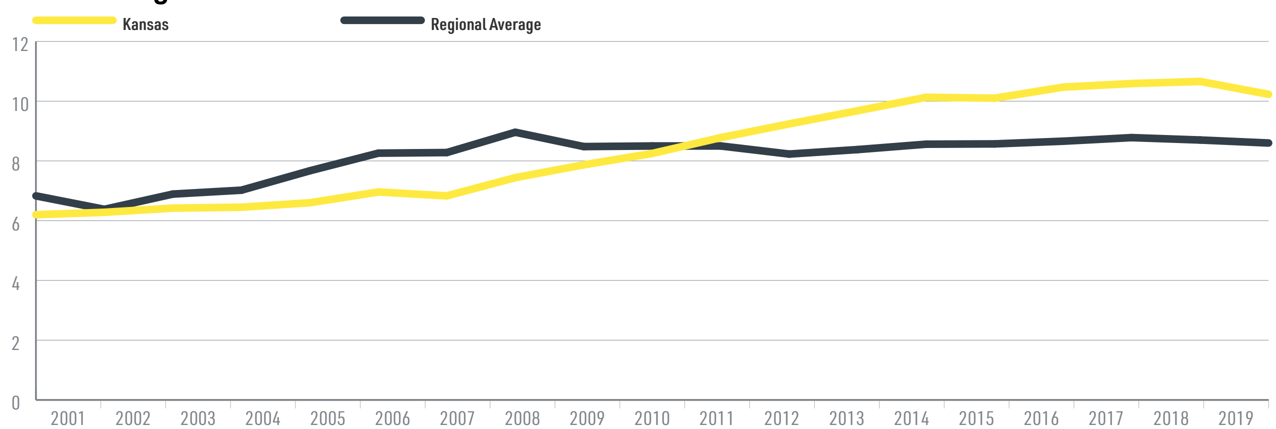
The following timeseries graphs (**FIGURE 40. Average Annual Industrial Rates, FIGURE 41. Average Annual Commercial Rates and FIGURE 42. Average Annual Residential Rates**) show the historical rates across the region for the three customer classes. The average annual industrial rate in Kansas surpassed the regional average in 2010, and both the commercial and residential rates surpassed the average in 2011. Thus, Kansas electricity rates were lower and grew more slowly than the regional average during the first period of observation (2000 to 2007) but were then higher and grew more quickly during the second period (2010 to 2019).

FIGURE 40. Average Annual Industrial Rates



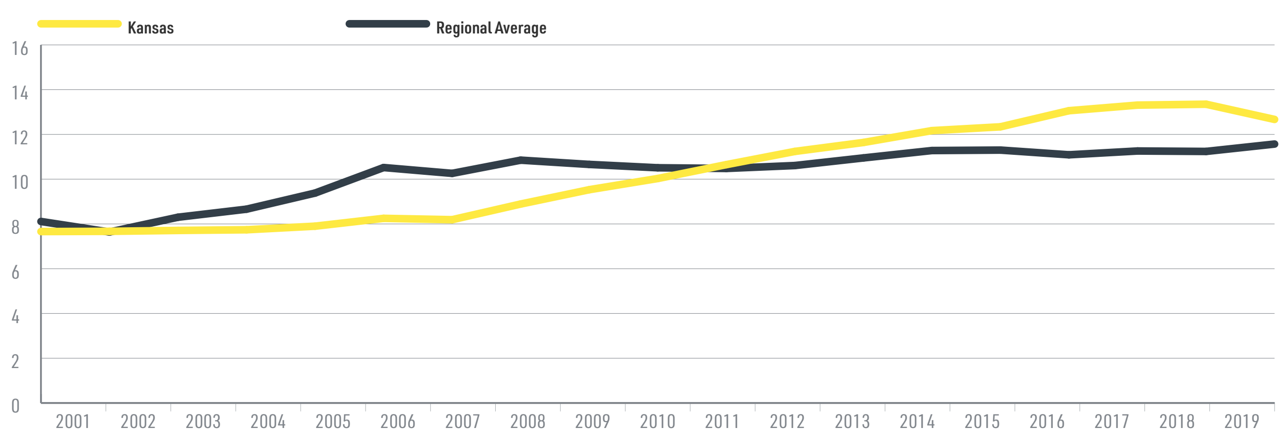
Source: EIA

FIGURE 41. Average Annual Commercial Rates



Source: EIA

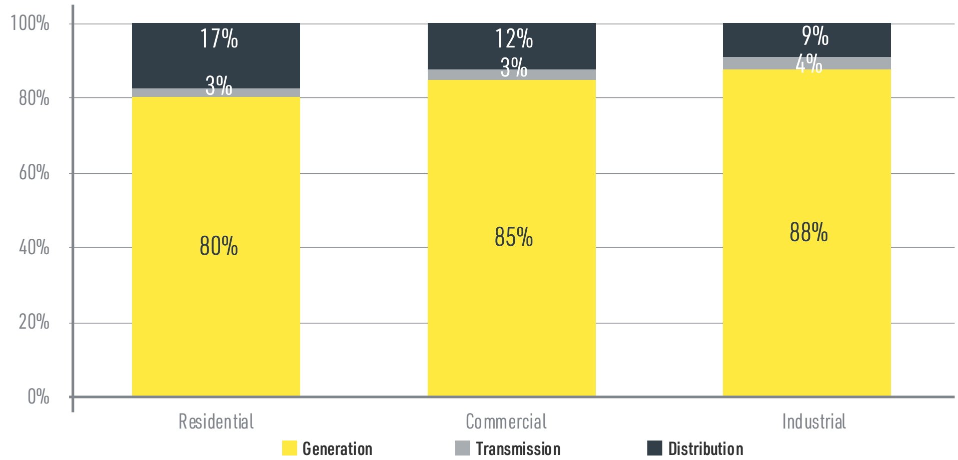
FIGURE 42. Average Annual Residential Rates



Source: EIA

As described in more detail in **Section 5.10**, **FIGURE 43. Retail Price Cost Allocation by Customer Class (2019)** shows the total cost allocation of the retail electricity price for the residential, commercial, and industrial customer classes in Kansas by utility type. For all three classes, the cost allocated to transmission (between 2.6-3.8%) was far less than both generation and distribution.

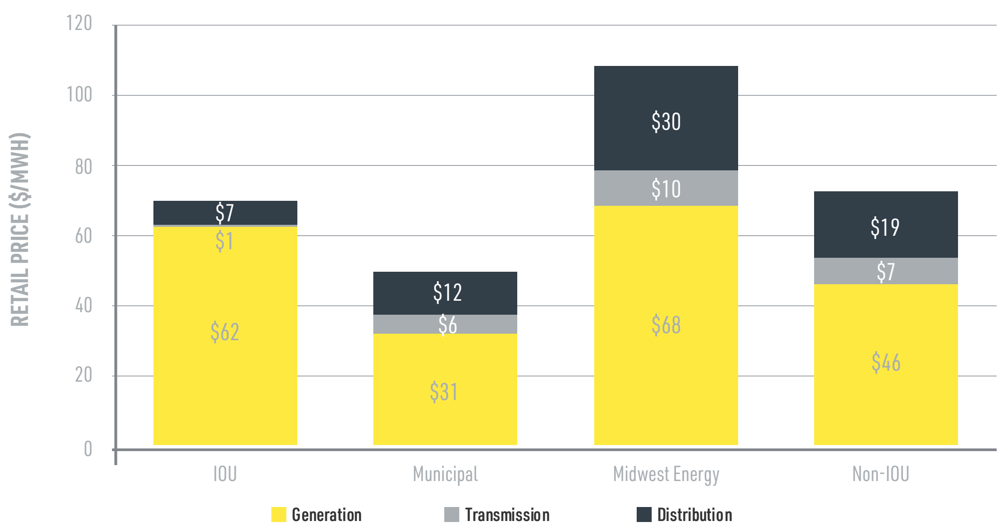
FIGURE 43.Retail Price Cost Allocation by Customer Class (2019)



Source: EIA, Kansas Utilities, Energeia

While transmission costs ranged from 2.6-3.8% of state-wide average annual retail rates for the three customer classes, retail prices and their cost allocations varied significantly between utility types, **FIGURE 44. Retail Electricity Price Cost Allocation by Utility Type (2019)** shows the approximate average annual retail price and cost allocation for generation, transmission, and distribution services in 2019 for IOUs, Munis, and Coops based on EIA data.

FIGURE 44.Retail Electricity Price Cost Allocation by Utility Type (2019)



Source: EIA, Kansas Utilities, Energeia

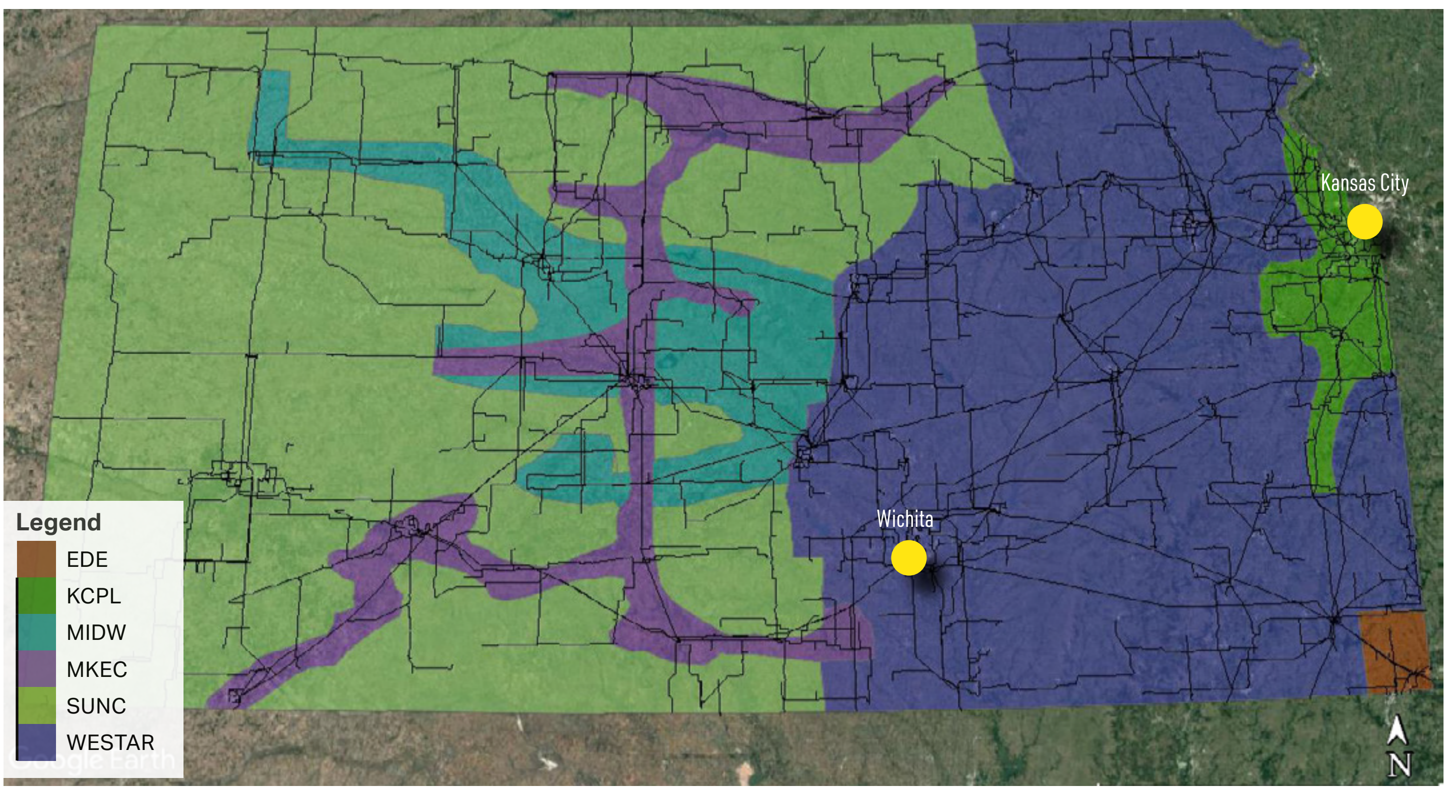
Transmission costs' contributions to retail price range from $1/MWh for IOUs to $10/MWh for Midwest Energy. This indicates a variation in the percentage of total cost from approximately 1.3% for IOUs to 12% for Munis, for which transmission costs represent the greatest proportion of retail cost among utility types. Some utilities and ratepayers experience much greater transmission costs and would thus be highly sensitive to transmission investments that impose increased cost burdens on their retail rates. The following section analyzes transmission costs throughout the region and shows how transmission costs vary significantly between rural and urban areas in the state.

ANNUAL TRANSMISSION REVENUE REQUIREMENT ANALYSIS

To estimate the net benefits and costs to Kansas rate payers from regional transmission investments by Kansas electric public utilities, the ATRR of the 18 SPP transmission zones were analyzed. All Kansas utilities are members of the SPP and have transferred control of their transmission assets to this organization in exchange for an established fee schedule. The cost allocation of transmission investments in each transmission zone are reflected in the ATRR that utilities must charge to recoup their assigned cost of transmission projects. This includes all costs of construction, capital, and financing associated with the development and operation of transmission infrastructure, regulated by a revenue requirement formula approved by FERC.

The ATRR of the 18 transmission zones from Attachment H of the SPP Tariff Schedule were analyzed to trace the allocation of costs from transmission investments to ratepayers in Kansas and nine peer states from 2010 to 2019.[72] There are six transmission zones that serve Kansas, three entirely within the state boundary and three that also serve Missouri. The zones that serve ratepayers in Kansas are Empire District Electric Company (EDE), Kansas City Power & Light (KCPL), Midwest Energy Inc (MIDW), Mid-Kansas Electric Company (MKEC), Sunflower Electric Cooperative Inc (SUNC), and Westar Energy Inc (WESTAR).[73] **FIGURE 45. Kansas SPP Transmission Zones** shows the areas in Kansas covered by these six transmission zones. While EDE provides transmission services to the southeast corner of Kansas, this area represents less than 3% of the total service population[74] in the zone. As such, this zone will not be included in analysis of areas in Kansas. On the other hand, KCPL is more balanced between the two states with approximately 60% of its service population in Kansas. As such, it will be included in the analysis of areas in Kansas.

FIGURE 45. Kansas SPP Transmission Zones



Source: SPP, KCC, Google Earth, AECOM

72 Regional peer states include Arkansas, Colorado, Iowa, Missouri, Nebraska, North Dakota, Oklahoma, South Dakota, and Texas.

73 The naming convention for these transmission zones are out-of-date. Empire has since been acquired by Liberty Utilities and operates under this name. KCP&L and Westar have merged into Evergy, and now operate as Evergy Kansas Metro and Evergy Kansas Central, respectively. Finally, Mid-Kansas no longer operates as an independent utility; it has merged with Sunflower.

74 Service population = total population + total jobs

The six zones vary significantly in the both the land area and service populations they serve. To normalize the transmission investment for a relevant cross-sectional comparison of transmission zones both in Kansas and throughout the SPP region, the service population of each zone was calculated by adding total population and total employment. Because both households and jobs generate demand for electricity, the investment per capita for members of the service population provides an estimate of the benefits and costs of transmission investments to Kansas ratepayers over time. **TABLE 11. Service Population by Kansas Transmission Zone (2019)** shows the service population calculations by SPP zone for Kansas.

TABLE 11. Service Population by Kansas Transmission Zone (2019)

SPP Zone	Population	Jobs	Service Population*	
			Total	CAGR 2010-2019
KCPL	1,521,287	787,568	2,058,855	1.07%
MIDW	72,870	34,411	107,281	0.64%
MKEC	139,895	72,708	212,603	0.07%
SUNC	188,075	88,143	276,218	0.54%
WESTAR	1,645,912	855,509	2,501,421	0.92%
Total	**3,568,039**	**1,968,339**	**5,536,378**	**1.72%**

* Service Population = Total Population + Total Jobs

Source: US Census Bureau, ESRI, LEHD, SPP, AECOM

KCPL and WESTAR represent the largest and fastest growing zones in Kansas, with service populations of 2 million and 2.5 million, respectively.[75] They contain the largest urban areas in the state with the fastest growing employment clusters.

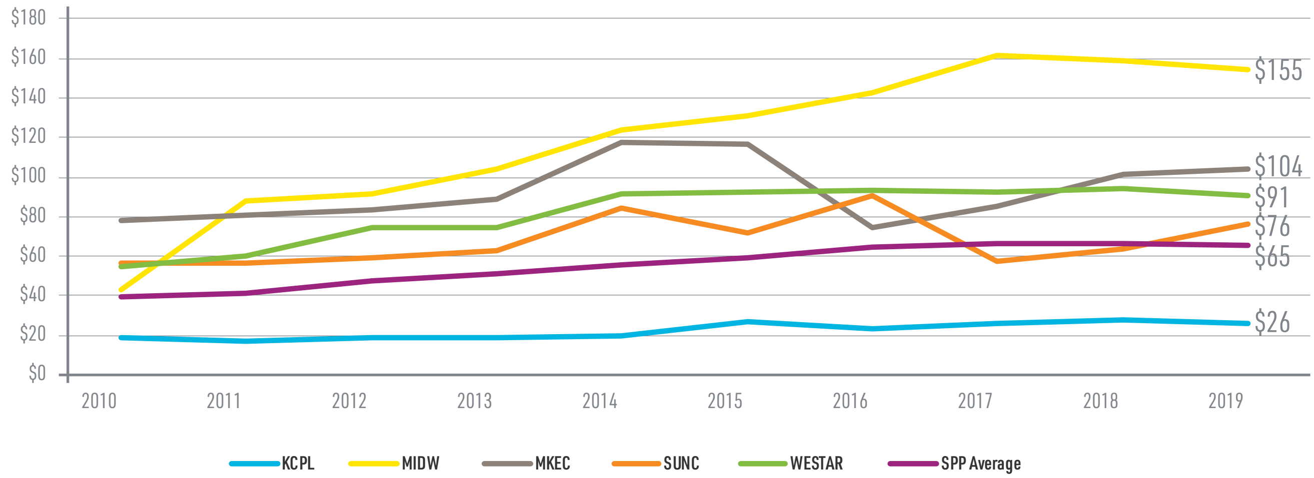
To estimate the impact of transmission investments on Kansas ratepayers, the project team analyzed the ATRR of SPP's 18 transmission zones. These revenue requirements cover all costs incurred by transmission owners in the development and maintenance of transmission services that eventually service Kansas ratepayers. The aggregate ATRRs include:

- **Zonal ATRR:** annual requirements of transmission owners for facilities owned prior to joining SPP, facilities constructed under their own initiative, and repair/rebuild of said facilities.
- **Base Plan Zonal ATRR:** annual requirements allocated to each transmission zone under cost allocation agreement for facilities directed by SPP for construction before June 19, 2010.
- **Base Plan Zonal ATRR:** annual requirements allocated to each transmission zone under cost allocation agreement for facilities directed by SPP for construction after June 19, 2010.
- **ATRR Reallocated to Balanced Portfolio Region-Wide ATRR:** annual requirements transferred from each transmission zone to regional facilities according to a cost allocation agreement with SPP.
- **Base Plan Zonal ATRR to Pay Upgrade Sponsors:** annual requirements used to fund reimbursement for non-transmission owners that fund construction of transmission infrastructure.

The ATRR of the five transmission zones serving Kansans also varies substantially, with the more populous urban zones requiring less transmission investment per member of the service population relative to the less populous, rural zones. **FIGURE 46. ATRR by Service Population for Kansas SPP Zones** shows the ATRR per member of the service population from 2010 to 2019 for the five zones analyzed for Kansas and the SPP average.

75 Approximately 60% of KCPL's population and jobs are in Kansas, with the remainder in Missouri.

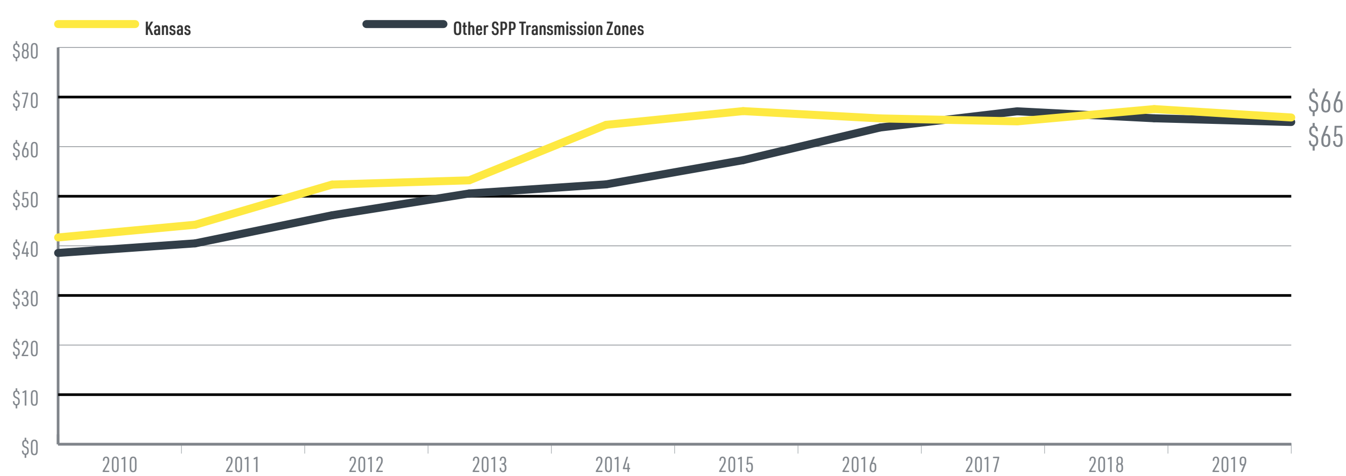
FIGURE 46. ATRR by Service Population for Kansas SPP Zones



Source: US Census Bureau, ESRI, LEHD, SPP, AECOM

As of 2019, Kansas contains the transmission zones with both the highest and lowest ATRR per member of the service population of all 18 zones. At $155, MIDW has the highest transmission investment per member of the service population, while KCPL has the lowest at $26. The difference in revenue requirements by zone correlates strongly to the service population densities throughout the SPP region. The general trend indicates that more populous urban zones benefit from economies of scale in the provision of transmission infrastructure to their service areas. Although KCPL was the only Kansas zone with below average ATRR by service population in 2019, the average for all Kansas zones is roughly on par with the average of non-Kansas zones in the SPP region. **FIGURE 47. Transmission Investment by Service Population: Kansas and SPP Region** shows the ATRR per member of the service population for the weighted averages of Kansas and the 13 remaining zones spanning from Montana to Louisiana.

FIGURE 47. Transmission Investment by Service Population: Kansas and SPP Region



Source: US Census Bureau, ESRI, LEHD, SPP, AECOM

In 2019, the average per capita ATRR for the entire service population of Kansas was approximately $66, while the non-Kansas SPP areas saw an average of $65 per member of the service population. With the exception of the Oklahoma Gas and Electric Zone, all transmission zones in the SPP region experienced faster growth of ATRR than growth of their service populations. **TABLE 12. Transmission Investment and Service Population Growth** compares the 2019 totals and CAGR from 2010-2019 for the aggregate ATRR and service populations for all Kansas and non-Kansas SPP transmission zones.

TABLE 12. Transmission Investment and Service Population Growth

		Total ATRR	Service Population*	Per Capita Investment**
Kansas SPP Zones	2019 Estimate	$339,713,486	5,156,378	$66
	CAGR 2010-2019	6.18%	0.92%	5.22%
Non-Kanas SPP Zones	2019 Estimate	$1,336,407,167	20,571,380	$65
	CAGR 2010-2019	9.95%	3.76%	5.96%

*Service Population = Total Population + Total Jobs

**ATRR / Service Population

Source: US Census Bureau, ESRI, LEHD, SPP, AECOM

For both the Kansas and non-Kansas transmission zones, the ATRR grew at a substantial rate from 2010 to 2019. Much of this growth in transmission investment comes from the inclusion of new geographical areas as well as from natural population and job growth. For example, the Upper Missouri Zone (UMZ) that encompasses much of Iowa, Montana, North Dakota, and South Dakota joined the SPP after 2014. As such, the per capita investment offers a normalized estimate to compare costs over time. The per capita investment for both Kansas and non-Kansas transmission zones has also grown at a CAGR of 5.22% and 5.96%, respectively. This indicates a substantial and sustained level of growth from 2010 to 2019. For Kansas, the ATRR per member of the service population grew from approximately $42 in 2010 to approximately $64 in 2014, after which it has been relatively stable year after year. This uptick in transmission investment per member of the service population corresponds to the most significant increase in electricity rates for industrial, commercial, and residential ratepayers.

The average transmission investment per member of the service population grew at a slower rate in the Kansas SPP zones than in the non-Kansas SPP zones. Thus, while large and growing transmission investments contribute to the retail price of Kanas ratepayers, these costs alone cannot explain the relatively high electric rates across the three customer classes in Kansas compared to the regional average.

Because the total SPP Transmission area covers regions in 14 different states, this raises the possibility that transmission investments in one state affect the price of electricity in another, and ratepayers incur costs that do not benefit them directly. To understand whether Kansas ratepayers were bearing the burden of investments in other states, the project team further analyzed the pattern of electricity prices and transmission investments presented above.

As discussed in **Section 5.6**, net exports of electricity account for approximately 19% of electricity generation in Kansas, resulting in the export of approximately 9.7 million MWh in 2019. However, Kansas is not an exception in the region, as all but two of the nine peer states are also net exporters of electricity. As such, there appears to be significant interstate transmission among the many utilities and customers throughout the SPP Region.

Transmission costs per member of the service population are highest in more rural areas with lower population and workforce concentrations. MIDW and MKEC had the highest and third highest per capita ATRR of all the SPP transmission zones. The second highest was SPS, which services the region from Oklahoma's panhandle to eastern New Mexico (large and rural zone). In general, the per capita costs of transmission investment are proportional to the population densities of the regions. How these costs are allocated among ratepayers differs by region and utility type, but if the proportion of investments in Kansas were significantly different than its corresponding service population, then costs of investment could also be disproportionate to its benefits. From 2010 to 2019, the proportion of all SPP transmission investments in Kansas was roughly equivalent to the proportion of the state's service population (20-26% depending on the year). This indicates that on the aggregate state level, Kansas ratepayers are not unduly paying for transmission investments in other states.

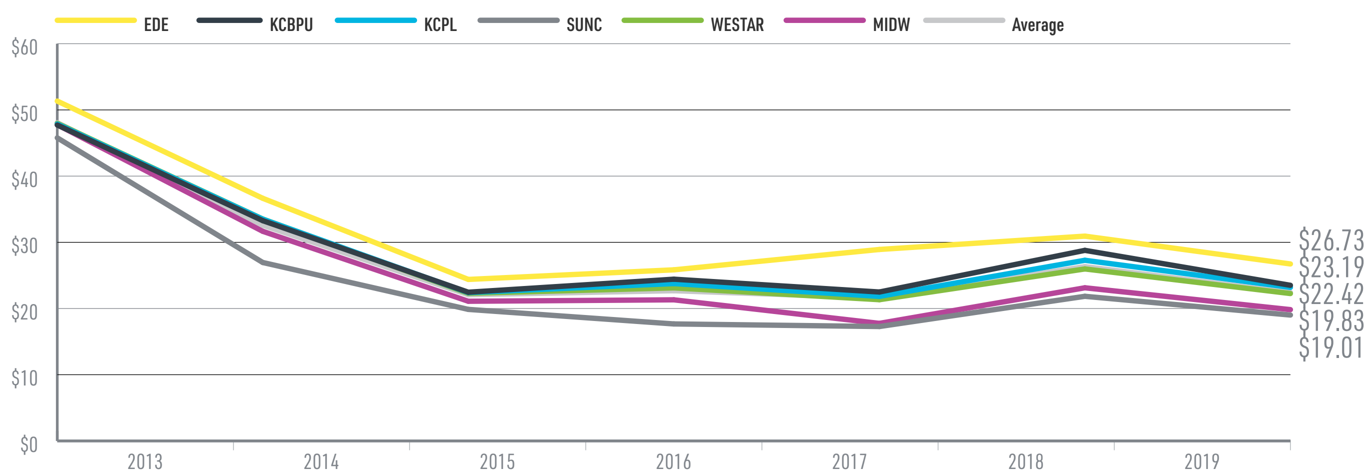
Furthermore, anecdotal evidence from stakeholders revealed that certain Kansas Coops imported electricity from generation and transmission utilities outside the state, when and where the opportunity to do so provided their ratepayers with cheaper, more efficient electricity. As such, it could be sustained that Kansas ratepayers benefit from transmission investments in other states that allow access to lower generation and congestion costs. Further analysis of investment and export patterns between utilities will be needed to determine a more thorough cost-benefit analysis of this interstate interconnectivity.

GENERATION COSTS

While transmission investments affect the average retail electricity price through the revenue requirements of the various transmission zones, they also provide benefits to ratepayers by lowering transmission congestion and line losses throughout the system. This creates benefits for the end-users through access to more reliable and more efficient electric generation. Thus, transmission capital costs can offset generation capital costs and connect ratepayers to more affordable power.

To estimate the impact of transmission investments on Kansas ratepayers, LMP of electricity within the SPP transmission zone wholesale markets was analyzed from 2013 to 2019. The LMP represents the system energy price, as well as transmission congestion and line loss costs, at various nodes within the SPP transmission network. Benefits of investments accrued by the ratepayers should be reflected in lower average LMP over time. **FIGURE 48. Average LMP by Kansas Transmission Zone ($/MWh)** shows the average LMP for the SPP transmission zones in Kansas from 2013 to 2019.

FIGURE 48.Average LMP by Kansas Transmission Zone ($/MWh)



Source: SPP

The average LMP for the Kansas SPP transmission zones experienced an average CAGR of -12% from 2013 to 2019. This represents a drop from approximately $48 to $22 per MWh on average for the Zones over this period. The precipitous drop in average LMP coincides with increased transmission investments, which saw ATRR grow at a CAGR of 4.7% from 2013 to 2019. Thus, while transmission investments grew year-to-year per member of the service population, these costs were largely offset by lower generation costs. From 2013 to 2019, the average annual electricity rates in Kansas for the industrial, commercial, and residential customer classes grew at CAGRs of -0.30%, 0.92%, and 1.42%, respectively.

5.6 Costs and Benefits of Transmission Investments Used to Import and Export Electricity

The costs and benefits incurred by Kansas ratepayers for transmission investments in Kansas, used to export energy out of Kansas.

5.6.1 INTRODUCTION

To analyze the costs and benefits incurred by Kansas ratepayers for transmission investments in Kansas used to export energy out of Kansas, the following questions were researched by the project team:

- What share of transmission investment costs are attributed to infrastructure that supports exports?
- What benefits are Kansas ratepayers realizing based on these export-supporting investments?

It is important to recognize that on a regional grid, system investments are not easily distinguishable between export and non-export-related infrastructure because capital investments anywhere in the grid can carry electricity to and from interconnected nodes. Instead, the proxy analyses were used to attempt to illustrate the costs potentially attributable to exports and the benefits incurred by Kansans.

5.6.2 BACKGROUND

As the demand for renewable energy resources has increased, development of renewable generation facilities has occurred in areas where the resources are available. In the case of wind, the areas with the most potential for generation are often distant from population centers and areas where traditional larger generation facilities are located. Such is the case with a large proportion of the wind resources in Kansas. Transmission facilities become necessary to move the electricity from where it is generated to where it will be used.

Kansas utilities, officials, and ratepayers have expressed concern over the SPP's Highway/Byway allocation of transmission costs, described in **TABLE 13. Allocation of Costs Under the Highway/Byway Methodology**, and its impacts on Kansas ratepayers. Specifically, there is concern that local zones (those in which the generation and transmission assets are located) are paying for a disproportionate share of the transmission assets, which are utilized to export electricity to other areas, while receiving limited benefits.

TABLE 13. Allocation of Costs Under the Highway/Byway Methodology

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

Source: Wind Rich Zones Presentation, Sunflower Electric System

5.6.3 SCOPE AND APPROACH

To conduct this analysis, a process involving the following steps was planned:

- Obtaining information regarding transmission assets utilized to export or import electricity, including maps, load, revenues and costs, both operating and capital;
- Obtaining information to determine the net export of electricity out of Kansas, as well as that of other states in the SPP;

- Obtaining economic data regarding transmission investment in Kansas; and
- Analyzing the costs and benefits of transmission investment to Kansas ratepayers.

Sufficient data, as described in **Section 5.6.4**, was not available to carry out the study as described in these steps. Therefore, the analysis methodology was adjusted to describe the information received, determine the total electricity exports for the state, discuss potential costs and benefits, and estimate the general economic impact of transmission.

5.6.4 INFORMATION GATHERING

The RFI was issued with the following information requests related to this matter:

6.1: Please send us a GIS map of your transmission system, including voltages, ratings, etc.

6.2: Please send us 8760 data (and meter IDs to relate to asset and network data) on flows over the lines used to export power over the past ten years

6.3: Please send us total transmission imports and exports (GWhs) by transmission asset and year for the last ten years

6.4: Please send total revenue received for transmission service for imports and exports over the past 10 years by asset, year and type of service

6.5: Please send us the total capital and operating costs by type (e.g. construction, operations, maintenance, etc.) of each transmission line used to export power from Kansas over last ten years by year.

6.6: Please send us the allocation of transmission costs to each customer class over the past ten years by year.

6.7: Please send us the cost-benefit studies used to justify the transmission investments over the past ten years or note if any such studies were provided in response to previous requests.

5.6.4.1 RFI GAPS AND WORKAROUNDS

Approximately 10% of utilities responded to the requests made in this section of the RFI, which was expected given the high number of distribution-only entities. A key gap in the information resulted from the utilities' inability to track electricity flowing across state lines by transmission asset. To work around this gap, the project team attempted to use additional information obtained from the SPP but was unable to link utility provided mapping and SPP data with any degree of confidence due to lack of mapping specificity or alignment with SPP data.

As a result, the project team was unable to determine which transmission investments have been specifically used to export electricity. Therefore, the project team's analytical approach was shifted as described in **Section 5.6.3**.

5.6.4.2 STAKEHOLDER FEEDBACK

Many of the stakeholders engaged over the course of the Study expressed frustration with SPP's current Highway/Byway cost allocation methodology. One stakeholder pointed the project team towards SPP's 2017 Strategic Plan documentation, in which they stated that this method "does not (and was not intended to) fairly recover the cost of transmission built and used solely to export renewable resources to markets outside of the SPP."[76] Given that there is significant wind generation activity in Kansas, this places a heavy burden on Kansas ratepayers. 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.

Stakeholders also 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.

76 Southwest Power Pool (2017). 2017 Strategic Plan Revised Initiatives, page 3. Retrieved from: https://www.spp.org/documents/55101/2017%20strategic%20plan%20-%20revised%20initiatives.pdf

Arkansas, Colorado, Iowa, Missouri, Nebraska, North Dakota, Oklahoma, South Dakota, and Texas

5.6.5 KEY FINDINGS

5.6.5.1 KANSAS EXPORTS

To assess the costs and benefits for transmission investments in Kansas used to export energy out of Kansas, the net electricity exports of Kansas and its nine peer states first need to be understood. This data was analyzed for the 2013 to 2018 time period. **TABLE 14. Annual Generation and Net Exports** shows annual electrical generation and net export data for Kansas and the peer states.

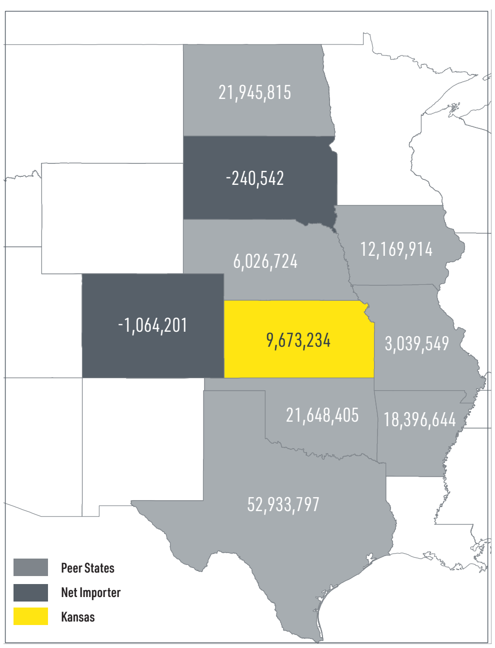
TABLE 14. Annual Generation and Net Exports

	2018				
	Generation (MWH)	Net Exports (MWH)	Exports % of Generation	Generation CAGR 2013-18	Exports CAGR 2013-2018
Kansas	51,710,213	9,673,234	19%	1.30%	2.32%
Arkansas	67,999,352	18,396,644	27%	2.42%	6.17%
Colorado	55,386,279	-1,064,201	-2%	0.91%	N/A
Iowa	63,380,569	12,169,914	19%	2.26%	4.08%
Missouri	85,095,384	3,039,549	4%	-1.47%	-18.05%
Nebraska	36,966,216	6,026,724	16%	-0.07%	-1.21%
North Dakota	42,615,321	21,945,815	51%	4.00%	2.94%
Oklahoma	86,223,721	21,648,405	25%	3.20%	9.51%
South Dakota	12,616,396	-240,542	-2%	4.53%	N/A
Texas	477,352,425	52,933,797	11%	1.95%	-0.60%

Source: EIA (2020) , AECOM (2020)

Of all the states in the region, only Colorado and South Dakota are net importers of electricity, and only marginally so. While Kansas is an energy-rich state, so too are all of its peer states, many of which also have the current capacity to generate cheap and abundant electricity. Nonetheless, approximately 19% of the electricity generated in Kansas is exported, and net exports grew faster (CAGR of 2.3%) than generation (CAGR of 1.3%) from 2013 to 2018. **FIGURE 49. Net Annual Electricity Export by State (MWh)** shows the regional map and net exports by state for 2018.

FIGURE 49. Net Annual Electricity Export by State (MWh)



EIA, ESRI, AECOM (2020)

While Kansas has been a net exporter of electricity since at least 1996, nearly the entire region bears the same distinction. As previously noted, Kansas had the highest annual average retail electricity rate in the region. Based on EIA data, the average retail price growth rate and net export growth rate from 2013 to 2018 are uncorrelated.

5.6.5.2 KANSAS TRANSMISSION COSTS

As discussed in **Section 5.5**, transmission investments in Kansas have been roughly equal to those of the entire SPP transmission service area when estimated by service population membership.[77] 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. Despite growth in transmission investments and net electricity exports in Kansas, exports as a percentage of generation were roughly the same in 2013 and 2018, although growth in exports slightly outpaced growth in generation. To determine if Kansas ratepayers experience a net benefit or a net cost from transmission investments for export, the share of transmission costs for export needs to be understood. Using the proportion of Kansas' electrical generation used for export, it is possible to estimate the potential proportion of transmission investments allocated to the export of electricity, based on the assumption that transmission infrastructure benefits all regions to which it connects. **TABLE 15. Proportion of Transmission Investments for Export in Kansas** shows total transmission investments in Kansas and those allocated to the export of electricity based on the percent of electricity exported.

TABLE 15. Proportion of Transmission Investments for Export in Kansas

	2013	2014	2015	2016	2017	2018	CAGR 2013-2018
Generation (MWh)	48,472,581	49,728,363	45,527,124	47,599,991	50,933,305	51,710,213	1.3%
Exports (MWh)	8,625,184	9,166,757	5,677,997	6,789,817	10,645,518	9,673,234	2.3%
Exports and % of Generation	18%	18%	12%	14%	21%	19%	N/A
Total Transmission Investments	$259,655,789	$317,132,496	$333,797,237	$329,482,008	$329,525,136	$345,236,269	5.8%
Export Transmission Investments*	$46,2003,006	$58,459,124	$41,630,122	$46,998,382	$68,873,712	$64,582,043	6.9%

*Assumes proportion of generation exported is equivalent to investments in export infrastructure

Source: EIA, SPP, AECOM (2020)

From 2013 to 2018, transmission investments grew at a CAGR of 5.8%, while electricity exports grew at a CAGR of 2.3%. The percentage of Kansas electricity generation exported varied between 12% and 21% over the same time period, but only marginally changed from 2013 to 2018. Nonetheless, the proportion of transmission investments used for the export of electricity can be estimated at approximately $64.5 million in 2018, having grown at a CAGR of 6.9% over the period in question. This signals that the share of transmissions investments for export has potentially been increasing. To determine if these added costs incurred by Kansas ratepayers is beneficial, the potential benefits realized from the new transmission must be analyzed.

5.6.5.3 BENEFITS OF TRANSMISSION INVESTMENTS

Transmission investment can create both direct costs (e.g., capital and operational expenditures) and benefits (e.g., lowered generation costs, created jobs and investments) for Kansas ratepayers. Potential benefits of transmission investments include:[78]

77 The service population was calculated by adding total population and total employment. Because both households and jobs generate demand for electricity, the investment per capita for members of the service population provides an estimate of the benefits and costs of transmission investments to Kansas ratepayers over time.

78 Southwest Power Pool (2016). The Value of Transmission. Retrieved from: https://spp.org/documents/35297/the%20value%20of%20transmission%20report.pdf

- Economic Impact (e.g., job creation, local market development);
- Increased competition;
- Increased market liquidity;
- Storm hardening;
- System flexibility;
- Fuel diversity;
- Reducing costs of future transmission needs;
- Increased wheeling revenues;
- Reduced emissions of air pollutants;
- Improved utilization of transmission corridors; and
- Optimal wind generation development.

The majority of these benefits are not readily quantifiable. To better understand the potential benefits, the total transmission investment cost paid out in Kansas was reviewed and used this to derive economic impacts from the spending. Additionally, qualitative research of SPP documents was performed to understand additional soft benefits that can be realized from transmission investment. Ideally, the geographically precise projects would have been obtained, with indications of whether the projects were used for export or not. Due to data limitations described above, this approach was not possible.

To gauge the indirect benefits of transmission investment, the economic multipliers obtained through EMSI and used to determine the jobs, earnings, and taxes generated by investments in electricity transmission. The Electric Bulk Power Transmission and Control industry was chosen as the industry to receive transmission investments for the impact scenario. The analysis indicates that 1,940 jobs in Kansas are created through the $340 million transmission investments in 2019 (or in other words, approximately 1,900 jobs in Kansas are created through transmission investments at the 2019 magnitude). Additionally, $127 million in earnings and $58 million in tax revenue is generated from this investment. **TABLE 16. Transmission Investment Economic Impact*** depicts the economic impact of transmission investment. Note that this is not a complete picture of the benefits of the transmission investments and drawing a direct comparison to the transmission investment costs to determine net costs/benefits is not recommended without quantifying other benefits. This analysis aims to demonstrate one component of benefits to enable further discussion and analysis.

TABLE 16. Transmission Investment Economic Impact

Impact Type	Total Impact*
Change in Jobs	1,943
Change in Earnings	$127,200,000
Taxes on Production	$57,900,000

* Dollar figures rounded to the nearest $100,000

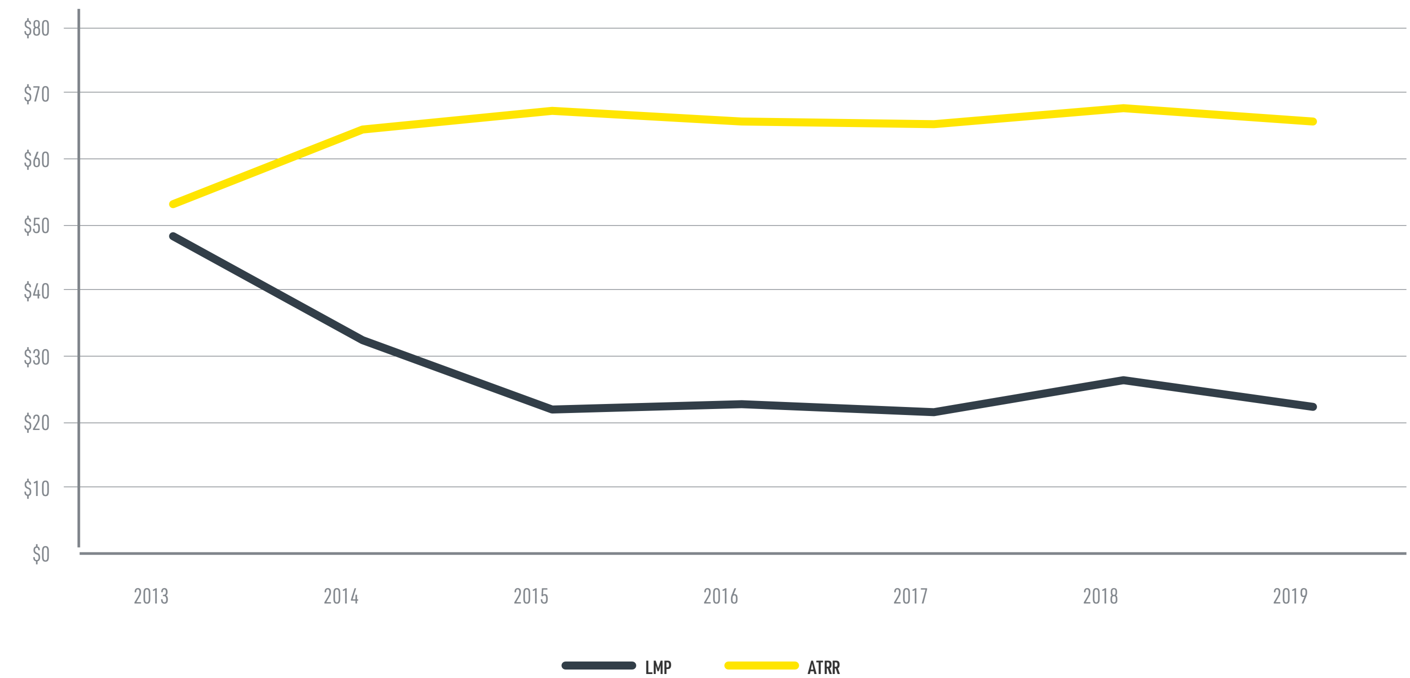
Source: EMSI and SPP

Another approach taken to illustrate potential benefits is a comparison of average transmission investments and generation costs. Hypothetically, the costs of transmission investment (both for interstate transmission and export) should be offset by access to more efficient and affordable electric generation. **FIGURE 50. Kansas Transmission Zones Average ATRR per Service Population and LMP ($/MWh)** shows the negative correlation between the average transmission investments (ATRR) and locational marginal price (LMP)[79] for Kansas from 2013 to 2019. While the drop in generation costs could also have been the result of other factors, including fuel prices as discussed in **Section 5.13**, this correlation between transmission and generation indicates an additional benefit of regional transmission investments, even those that are for exports. While ATRR per service member grew at a CAGR of approximately 4%, LMP fell by a CAGR of approximately 12%. Transmission investments used for exports could also provide a benefit to Kansas

79 The LMP represents the system energy price, transmission congestion, and line loss costs at various nodes within the SPP Transmission network.

ratepayers by sharing fixed costs with a larger customer base or allowing for imports of electricity when and where it is most efficient.

FIGURE 50. Kansas Transmission Zones Average ATRR per Service Population and LMP ($/MWh)



Source: US Census Bureau (2020), ESRI (2020), LEHD (2020), SPP (2020), AECOM (2020)

5.6.6 CONCLUSION

Kansas' share of transmission costs potentially attributed to electricity exports have been increasing since 2013. At the same time, LMP, a measure of how much it costs to generate and move electricity, has been decreasing in Kansas, underscoring the benefit of a regional electricity market. Due to data limitations, a complete cost-benefit analysis was not feasible. Future analysis of specific transmissions investments could provide additional insights into the costs and benefits that are being realized at a local level.

5.7 Impact of Rising Costs of Kansas Investor Owned Utilities on Electric Cooperatives and Municipal Utilities

How rate increases, or the associated rising costs of Kansas investor-owned electric public utilities, impact the retail electric rates of Kansas electric cooperatives and municipal utilities.

5.7.1 BACKGROUND

Part 1 of the Study found IOU rates and costs had increased by approximately 20% between 2013 and 2018, largely as a result of generation, environmental compliance, and transmission costs, which were found[80] to explain 60-62% of total cost increases over this period.

However, neither Munis nor Coops pay IOU electric rates, and IOU rate increases therefore do not impact on Muni or Coop electric rates, at least not directly.

Rising IOU costs can, however, impact Muni and Coop electric rates where they are providing generation or transmission services, and indirectly, via the impact of their generation and transmission costs on SPP market prices and SPP transmission zone costs.

5.7.1.1 DIRECT IMPACTS

Kansas Muni and Coop electric rates are driven by their cost of generation, transmission, and distribution services, as well as other customer-related costs (e.g. metering, contact center, etc.). All Munis and Coops own and operate their distribution networks and provide their own customer services. However, most currently source their generation and transmission (G&T) services from one of the G&T providers listed in **TABLE 17. G&T Provider Statistics**.

TABLE 17. G&T Provider Statistics

G&T Provider	Major Customers	End Customers	MWh	Revenues ($'000s)
KEPCo	17	157,042	3,217,371	$407,548
KMEA	25	86,367	2,632,832	$243,913
KPP	2	5,434	87,134	$10,898
Self	3	12,499	1,076,891	$67,392
Sunflower	4	67,251	2,145,465	$222,518
WFEC	1	953	29,605	$2,770
Multiple	5	103,448	3,248,047	$350,851
Total	**57**	**432,994**	**12,437,345**	**$1,305,890**

Source: EIA (2018), Energeia (2020)

5.7.1.2 GENERATION COSTS

As set out in the Part 1 of the Study,[81] IOU generation costs are driven by the rate base, the regulator-allowed investment (less depreciation) multiplied by the allowed cost of capital, and operational expenditures (including fuel costs).

80 London Economics International, LLC (2020). Study of Retail Rates of Kansas Electric Public Utilities, page 47. Kansas Corporation Commission. Retrieved from: https://estar.kcc.ks.gov/estar/ViewFile.aspx/S20200108144309.pdf?Id=1a3a31e5-e38d-4445-aada-1cd0170a7b85

81 London Economics International, LLC (2020). Study of Retail Rates of Kansas Electric Public Utilities, page 56. Kansas Corporation Commission. Retrieved from: https://estar.kcc.ks.gov/estar/ViewFile.aspx/S20200108144309.pdf?Id=1a3a31e5-e38d-4445-aada-1cd0170a7b85

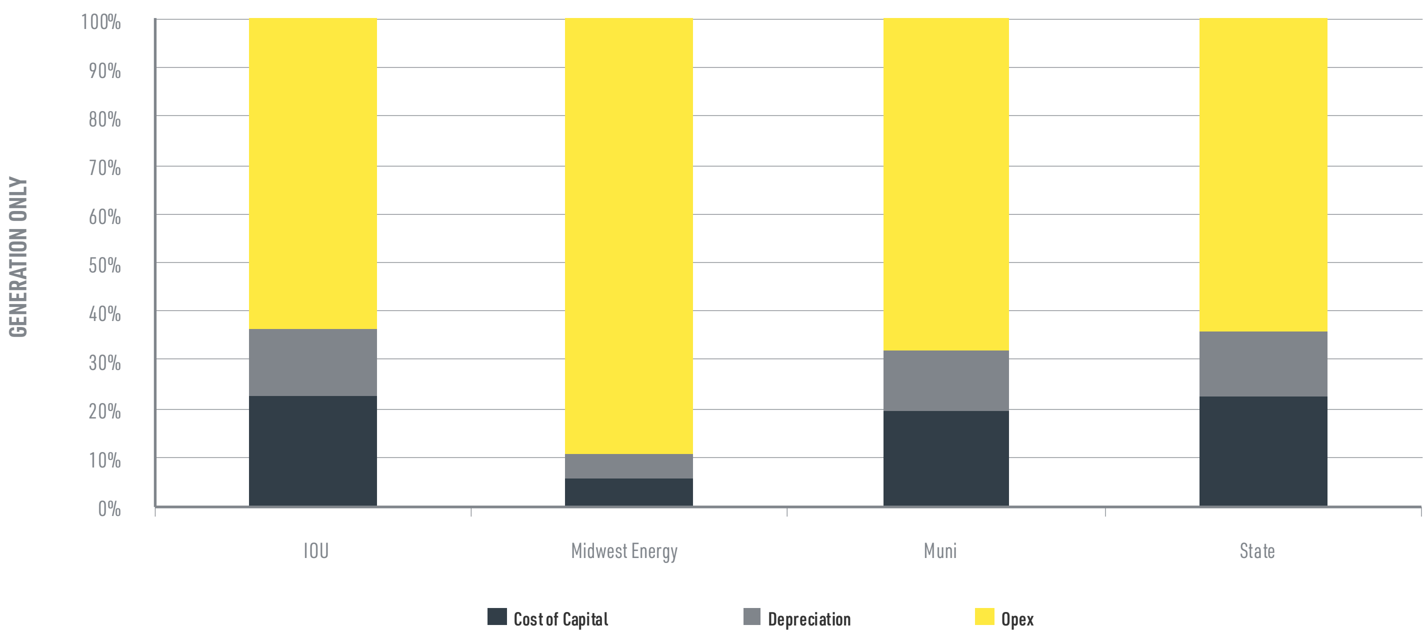
The KCC reported IOU generation costs have mainly increased over the 2013 to 2018 due to investments in wind generation, coal station retrofits with environmental mitigation equipment (these investments were paid off by 2015), obsolete plant shut downs, and changes in fuel costs.

FIGURE 51. Generation Cost Components (%) shows the contribution of each of the following key generation cost drivers on utilities' annual revenue requirements:

- **Cost of capital:** driven by the level of investment in the rate base and the weighted cost of capital (WACC), which includes interest expenses and return on equity.
- **Depreciation:** driven by the level of investment in the rate base and rate of depreciation.
- **Operation expenditure:** driven by the number of customers and assets, as well as the cost of key inputs, including labor, materials, and services.

This analysis shows that investment, cost of capital, and depreciation drive 38% of the customer's final bill, on average, while operational expenditures are responsible for the remaining 68%. The proportion for Munis is similar, while Midwest Energy sees a much higher share of operating expenditures in their generation costs.

FIGURE 51. Generation Cost Components (%) (Confidential)



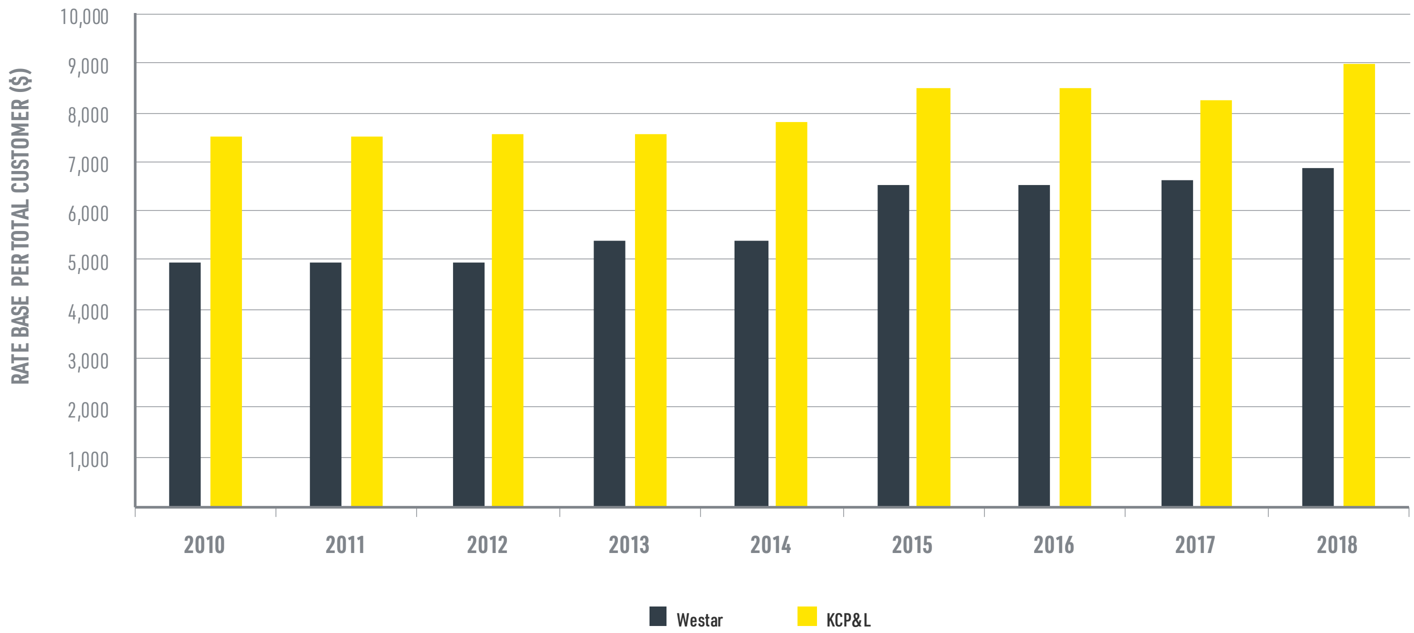
Source: Requests for Information, Energeia (2020) , EIA (2020)

FIGURE 52. Selected IOU Rate Bases by Year and Utility shows the 2-4% increase in the rate base over 2010 to 2018 for the two largest IOUs, as reported by the Part 1 of the Study,[82] which stated that these increases were mainly due to investments in wind generation, and the expiration of wholesale agreements.[83]

82 London Economics International, LLC (2020). Study of Retail Rates of Kansas Electric Public Utilities, pages 56-57. Kansas Corporation Commission. Retrieved from: https://estar.kcc.ks.gov/estar/ViewFile.aspx/S20200108144309.pdf?Id=1a3a31e5-e38d-4445-aada-1cd0170a7b85

83 Westar Environmental Cost Recovery Rider (ECRR)

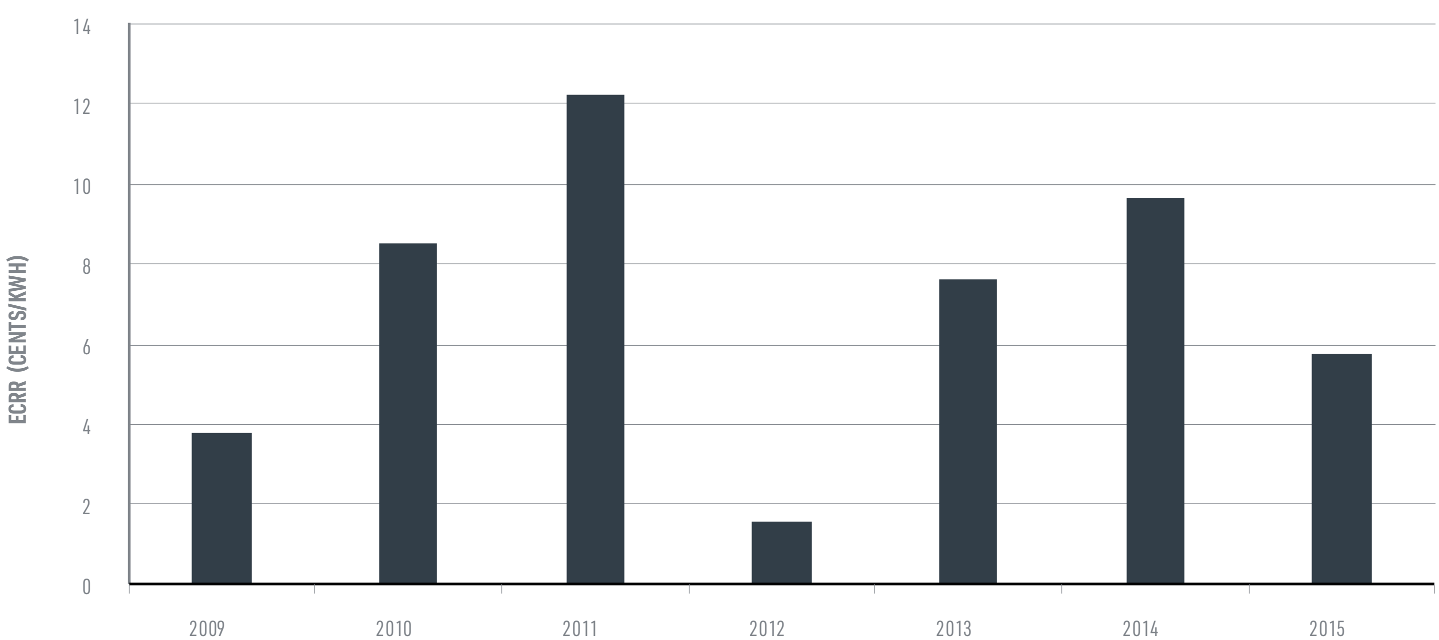
FIGURE 52.Selected IOU Rate Bases by Year and Utility



Source: LEI (2020), Utilities, Energeia

FIGURE 53. Westar Environmental Cost Recovery Rider (ECRR) shows the cost of environmental compliance for Westar, as reported in Part 1 of the Study.[84] These compliance expenses ended in 2015 and would have been passed on to Muni and Coop customers served by Westar at the time.

FIGURE 53.Westar Environmental Cost Recovery Rider (ECRR)



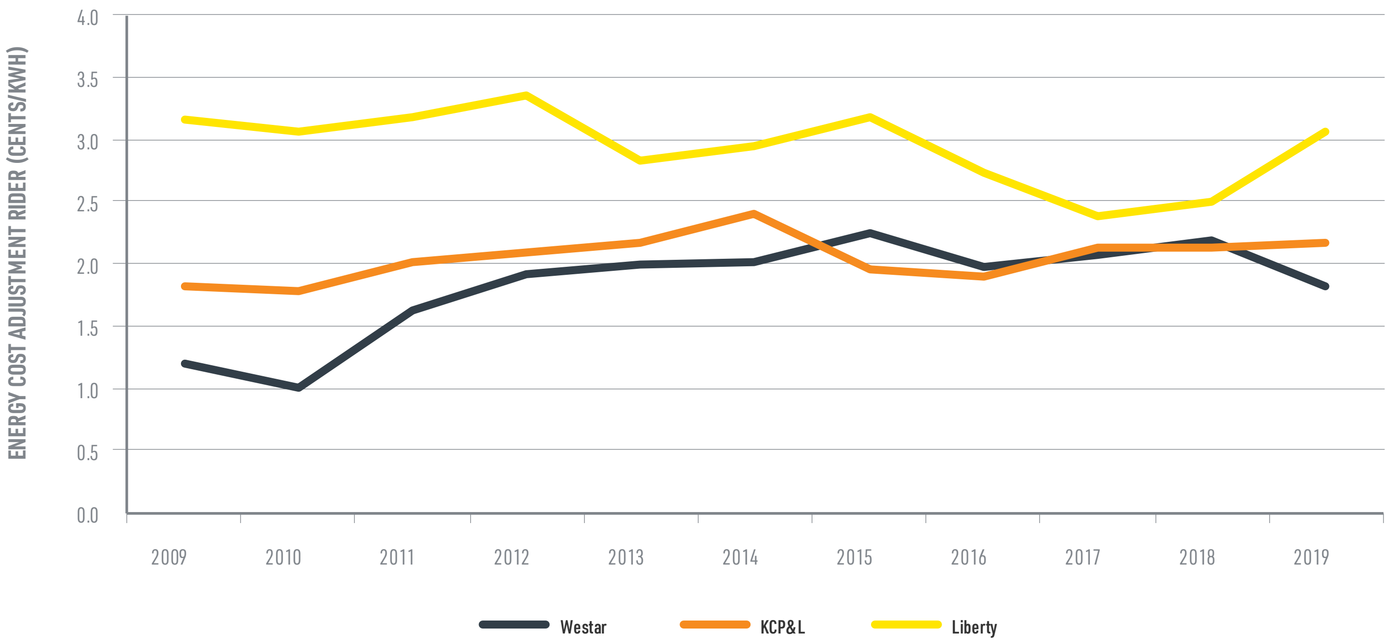
Source: LEI (2020)

84 Evergy disputed the accuracy of these figures.

The other major generation-related cost driver, other than capital investment in environmental compliance and the corresponding rate of return, which Part 1 of the Study found to be relatively static over the period, is operational expenditure.

Most operational costs associated with generation are passed through to IOU ratepayers through the energy cost adjustment (ECA)[85] rider, the costs for which are reported in **FIGURE 54. Energy Cost Adjustment (ECA) by Utility** over the 2009 to 2019 period according to Part 1 of the Study.[86] The Figure shows that Liberty's relatively high costs fall closer to those of Evergy's legacy utilities, which are relatively harmonized by 2012.

FIGURE 54. Energy Cost Adjustment (ECA) by Utility



Source: LEI (2020)

It is worth noting that generation costs can be reduced to the degree that IOUs can sell excess generated power at a profit.

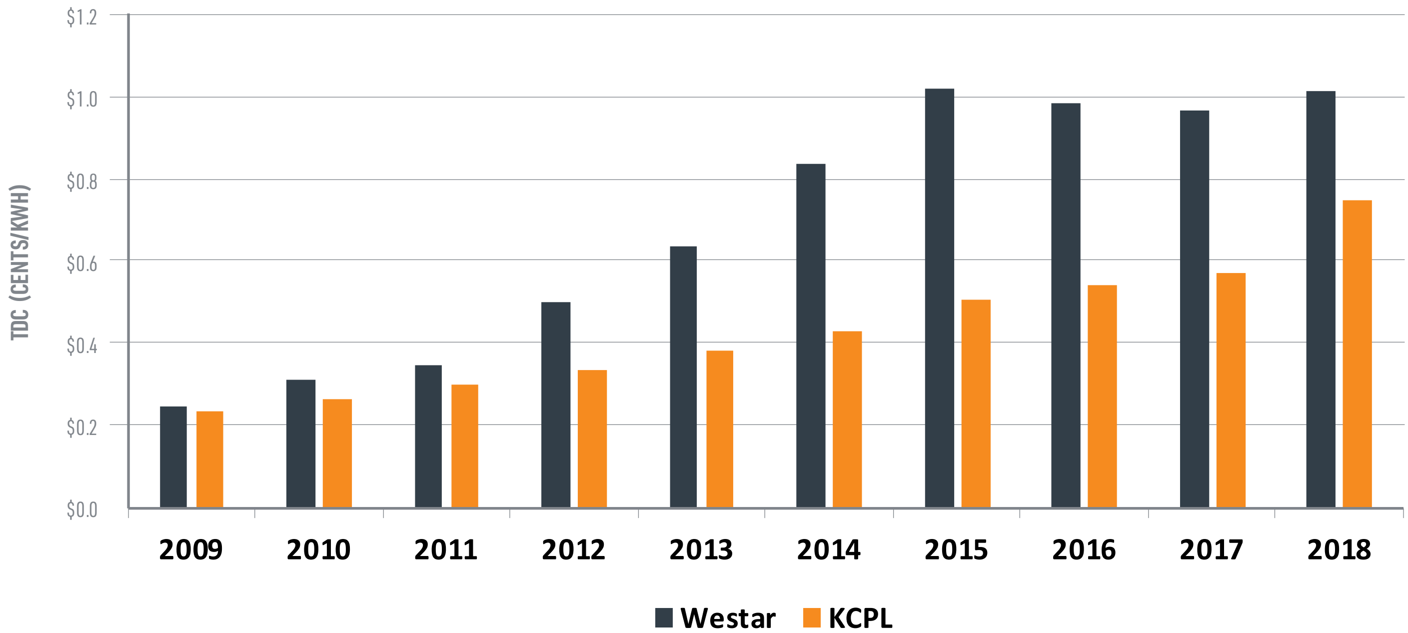
5.7.1.3 TRANSMISSION COSTS

IOU transmission cost increases per kWh were quantified in Part 1 of the Study and are shown in **FIGURE 55. Transmission Delivery Charge (TDC) by Utility**. This Figure captures the cost of transmission investment in each utility's franchise area, including costs allocated on the basis of regional investment (per FERC's cost allocation methodology).

85 The ECA rider predominantly passes changes in generation fuel costs through to ratepayers.

86 London Economics International, LLC (2020). Study of Retail Rates of Kansas Electric Public Utilities, page 69. Kansas Corporation Commission. Retrieved from: https://estar.kcc.ks.gov/estar/ViewFile.aspx/S20200108144309.pdf?Id=1a3a31e5-e38d-4445-aada-1cd0170a7b85

FIGURE 55. Transmission Delivery Charge (TDC) by Utility



Source: LEI (2020)

The degree to which Munis and Coops are exposed to these averaged costs per kWh depends upon their respective service contracts with the IOUs.

5.7.1.4 INDIRECT IMPACTS

Munis and Coops receiving generation from one of the G&T service providers can also be impacted by rising IOU costs where they flow through to SPP market prices used to settle their loads, and where IOU transmission investments are recovered from regional rather than local transmission customers.

5.7.2 SCOPE AND APPROACH

The project team's approach to answering the question involved the following steps:

- Gathering and analyzing information regarding each utility's generation, transmission and SPP costs, and any other IOU charge;
- Gathering stakeholder views and materials related to the question and related issues via stakeholder engagement processes; and
- Analyzing IOU generation and transmission cost trends, cost pass-throughs, IOU impacted SPP market prices, and their respective roles in Muni and Coop electric rates.

5.7.3 INFORMATION GATHERING RESULTS

Information to answer this question was gathered via the RFI process, via meetings with key stakeholders as outlined in **Section 4.2**, and independent research.

5.7.3.1 SUMMARY OF RFI REQUESTS, RESPONSES, GAPS AND WORKAROUNDS

The RFI was issued with the following information requests related to this matter:

7.1: Please send generation costs recovered from your consumers over the last ten years by rate, year and type of charge.

7.2: Please send SPP costs other than generation and transmission recovered from your consumers over the last ten years by rate, year and type of charge.

7.3: If a Muni or Coop, please send any other costs from IOUs passed on to consumers over the last ten years by year, rate and type of charge.

In other portions of the RFI, additional related information was requested for use as a basis for assessing the impact of IOU rates on Muni and Coop rates:

- SPP pricing data by utility
- SPP load data by utility

Most of the IOUs provided detailed information regarding the amount of generation revenues they recovered from Coops and Munis. Additional information about such cost recovery was not received from Munis and Coops.

SPP data was provided by pricing node, along with information regarding how SPP settlement operated. Utility-specific data was not provided due to confidentiality restrictions.

The biggest data gap was the lack of specific reporting regarding annual generation and transmission cost recovery over the requested period, including any SPP related generation and/or transmission settlement costs.

In the absence of exact information regarding generation, transmission and other costs charged by IOUs to Muni and Coop customers, the project team developed a proxy-based approach to addressing the matter. Changes in overall IOU generation and transmission costs were estimated and applied to Munis and Coops with wholesale supply contracts, and changes in SPP zonal prices and regional transmission charges were estimated and applied to the remaining Munis and Coops.

5.7.3.2 STAKEHOLDER FEEDBACK

Few participating stakeholders had direct experience with this matter, though several referred the project team to the fact that some Kansas Munis and Coops purchase power from Evergy and expected that their rates may be impacted to the extent those costs have changed.

5.7.4 KEY FINDINGS, ANALYSIS AND CONCLUSIONS

Determining how rate increases, or the associated rising costs of Kansas investor-owned electric public utilities, impact the retail electric rates of Kansas electric cooperatives and municipal utilities requires an assessment of the role of G&T costs in electric rates, the degree to which IOU G&T costs have changed, and the extent to which these costs have been passed on to Muni and Coop customers directly or indirectly, as well as the resulting electric rate impacts.

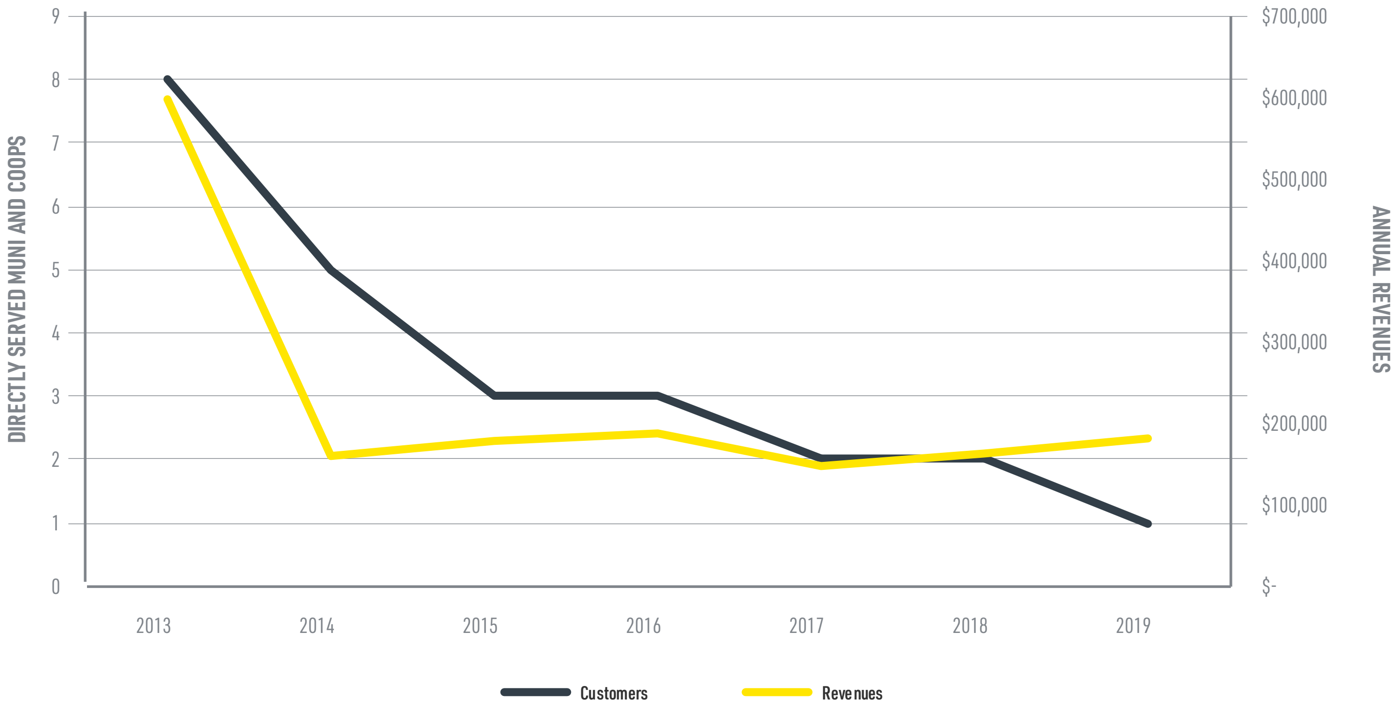
The following section summarize the project team's key findings, analysis, and conclusions for this matter.

5.7.4.1 MUNI AND COOP SEGMENTS

The total estimated number of Coop and Muni customers and their total annual consumption provided by IOUs versus G&T Coops was discussed in Section 5.7.1. Based on information provided by IOUs in response to the RFI, the number of Munis and Coops directly purchasing G&T services from them has fallen from eight in 2013 to two in 2019, excluding Kansas Municipal Energy Agency (KMEA), Kansas Power Pool (KPP)[87], and KEPCo. Annual revenues generated from these wholesale contracts, as well as from their contracts with KMEA, KPP, and KEPCo, have fallen from $600,000 to $200,000 over the 2013 to 2019 period. Based on this analysis, summarized in FIGURE 56. Muni and Coop Organizations with IOU Wholesale Contracts, IOUs are currently estimated to hold a 0.01% share of the Muni and Coop G&T market.

87 KMEA and KPP are member service agencies for Kansas Munis

FIGURE 56. Muni and Coop Organizations with IOU Wholesale Contracts

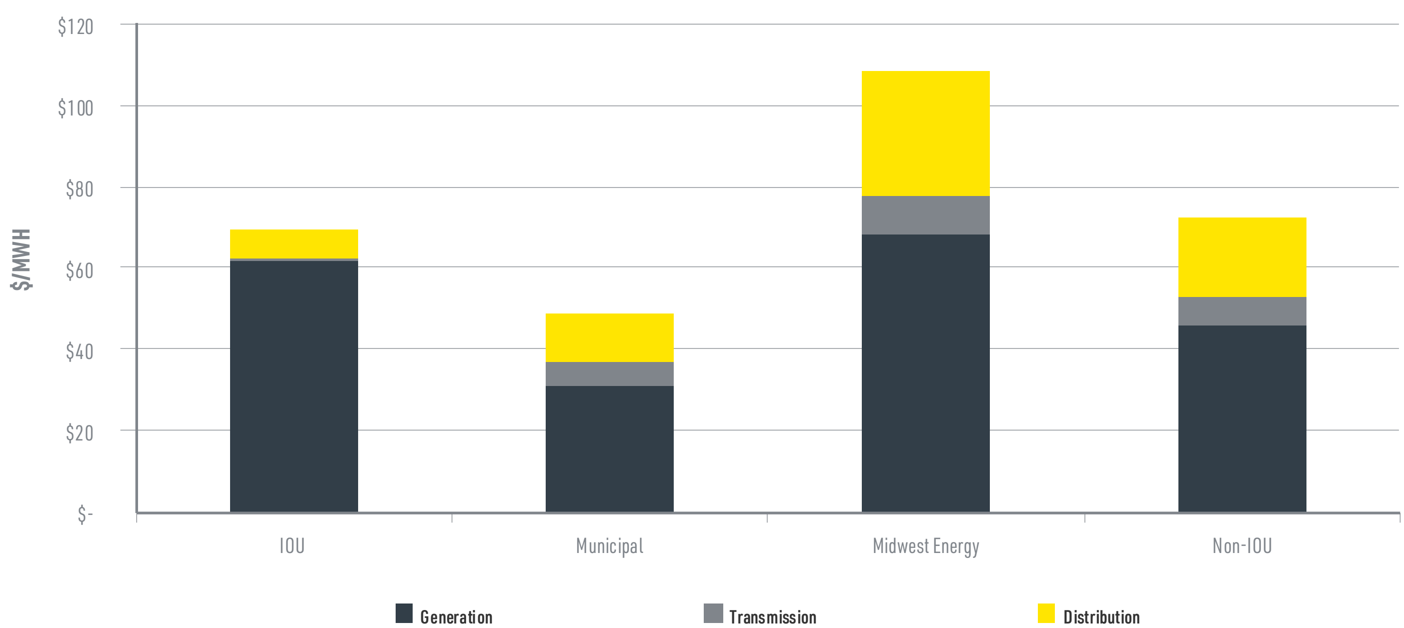


Source: IOUs (2020), Energeia

5.7.4.2 MUNI AND COOP ELECTRICITY COST DRIVERS

To illustrate the role of G&T costs in electric rates, **FIGURE 57. Cost Factor Unit ($/MWh) Costs by Utility Type** summarizes utility-reported cost per MWh by generation, transmission, and distribution services. The analysis shows average IOU G&T costs are high compared to Muni G&T costs but low compared to Coop costs. The non-G&T costs reported by Munis and Coops are used to estimate the overall contribution of G&T cost increases to electric rates.

FIGURE 57. Cost Factor Unit ($/MWh) Costs by Utility Type



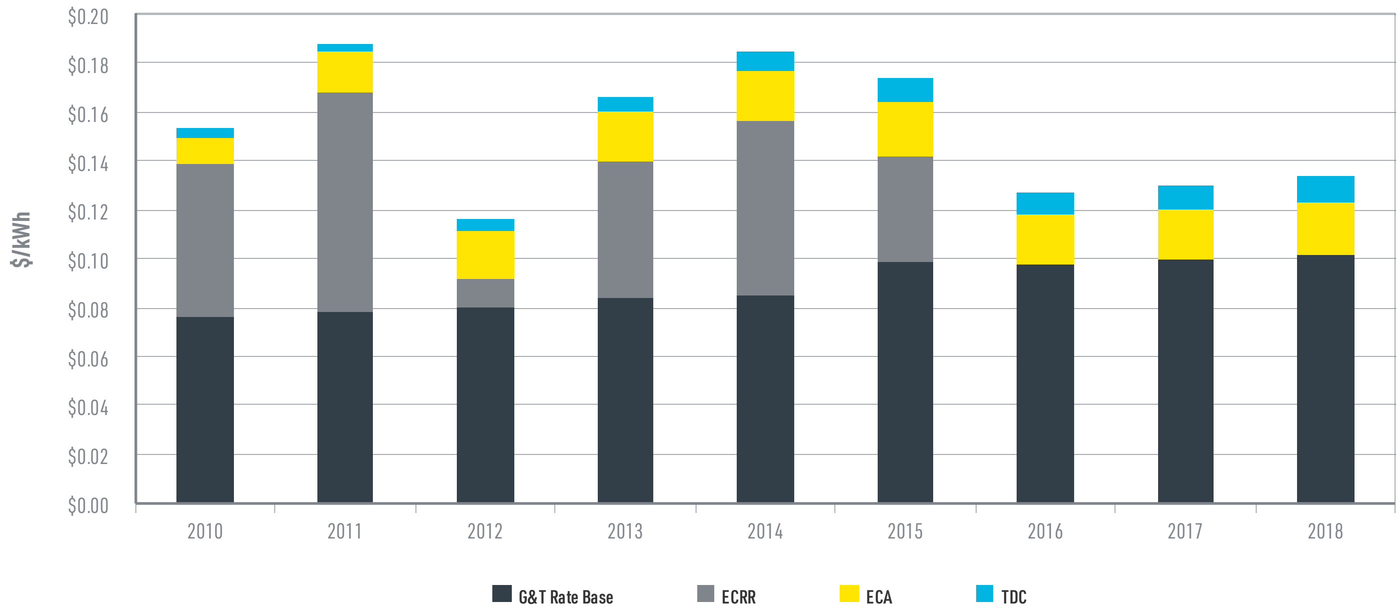
Source: Utility Cost of Service Models, Energeia

5.7.4.3 WHOLESALE CONTRACTED MUNIS AND COOPS

As discussed in **Section 5.7.1**, IOU G&T cost increases can impact Muni and Coop customer rates directly where they are being directly served by the IOU for G&T services, and indirectly, when their SPP generation settlement node includes IOU generation, and as part of IOU transmission cost recovery from regional transmission customers.

FIGURE 58. Key IOU Generation and Transmission Costs by Key Driver reports on the estimated increase in IOU G&T costs over the 2010 to 2018 period by key cost driver on a consumption-weighted average basis. Given the significant magnitude of the environmental cost rider (ECRR), which ended in 2015, it was not included in the analysis that follows.

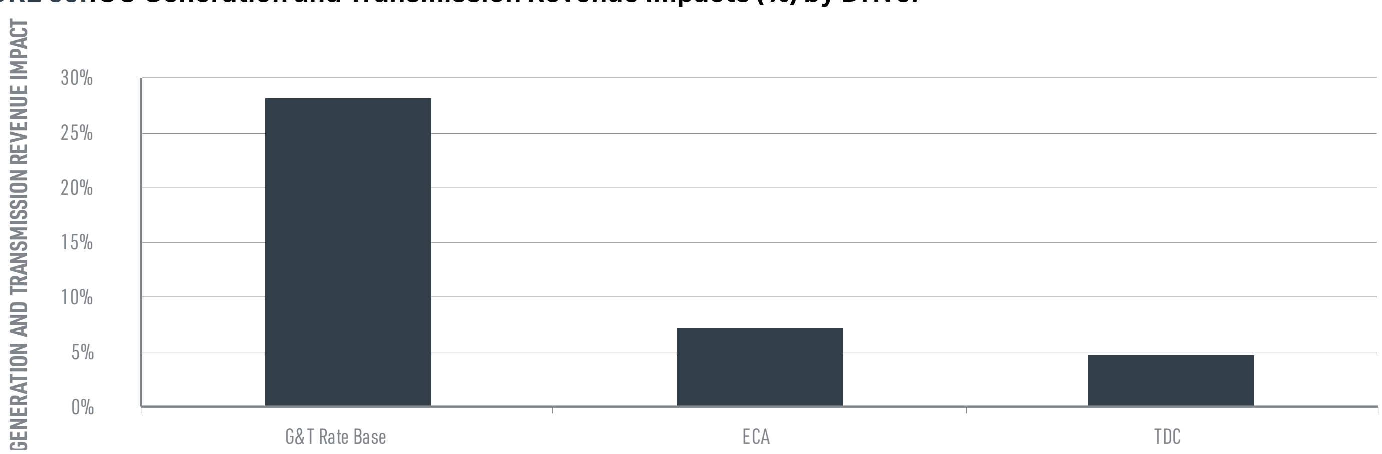
FIGURE 58.Key IOU Generation and Transmission Costs by Key Driver



Source: IOUs (2020), Energeia

FIGURE 59. IOU Generation and Transmission Revenue Impacts (%) by Driver shows the estimated increase in IOU G&T costs by key driver by the following cost drivers in percentage terms: rate base, fuel cost, and SPP transmission investment. The analysis shows that these factors, in total, increased by 48% over the 2010 to 2018 period. The largest contributor to this increase was the change in rate base, largely due to increased investments in wind generation. Although the analysis above identifies changes in key IOU G&T cost drivers, whether or not they were passed on to Munis and Coops under wholesale contracts depends upon the contract terms.

FIGURE 59.IOU Generation and Transmission Revenue Impacts (%) by Driver



Source: IOUs (2020), Energeia

Based on this analysis, the project team has reached the conclusion that the impact of IOU cost increases on Muni and Coops for which IOUs provide G&T services could be as high as 48% if the terms of their wholesale contracts allowed costs to be fully passed onto the purchaser. However, given that IOUs' share in the Muni and G&T market peaked at 0.36% in 2011 and was estimated to be 0.01% in 2018, the overall impact on the Muni and Coop sectors is limited.

5.7.4.4 NON-IOU CONTRACTS, MUNIS AND COOPS

Munis and Coops that do not receive electricity from IOUs under wholesale agreements may still be impacted by rising IOU G&T costs in two ways:

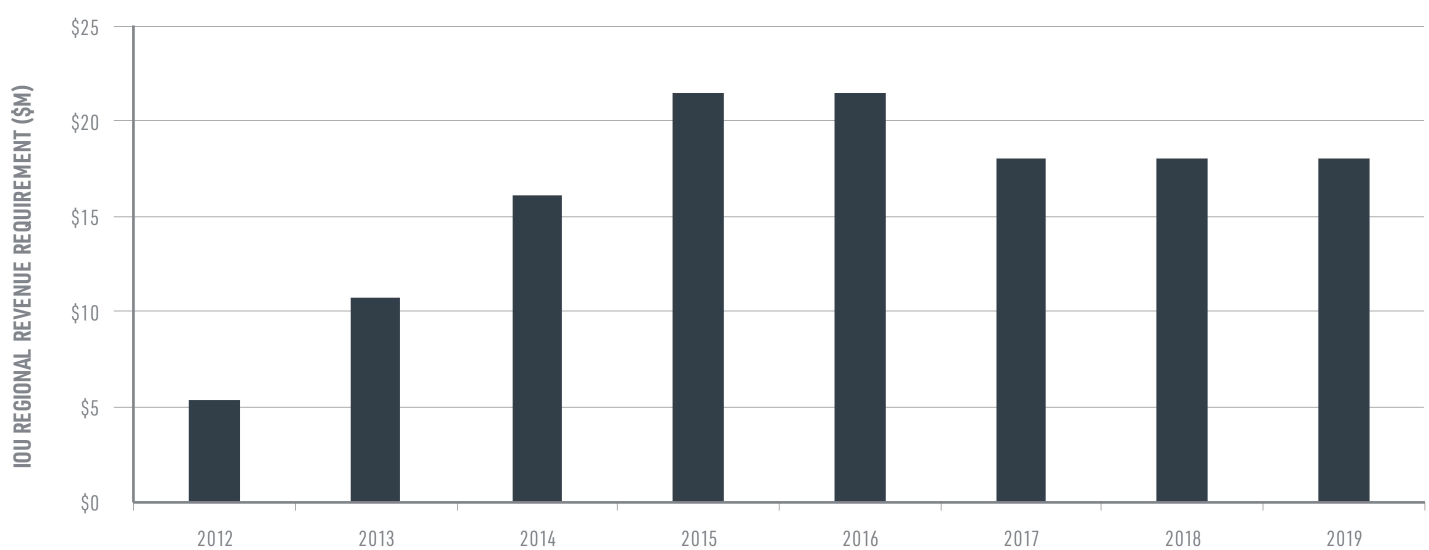
- Increased transmission charges as a result of IOU expenditure that is recovered on a regional basis under FERC rules; and
- The impact of higher-cost IOU generation units on SPP settlement nodes impacting non-IOU contracted Munis and Coops.

REGIONAL TRANSMISSION COSTS

In the case that IOU transmission investments are recovered across the region, meaning all transmission customers in the SPP are impacted (and not just those directly served by the IOU's respective transmission zone customers), Muni and Coops would be impacted in proportion to the cost increase driven by the investment.

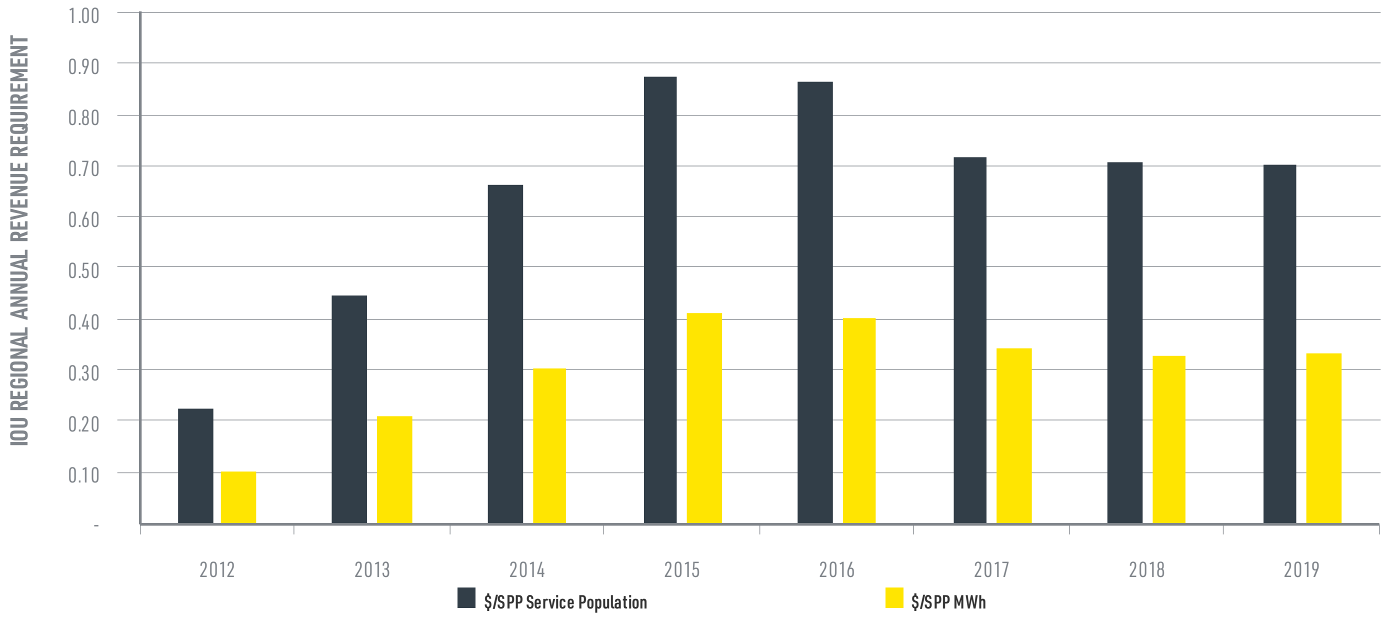
FIGURE 60. IOU Regional Revenue Requirement by Year shows the change in how IOU regional cost recovery from 2012 to 2019 has been allocated to non-IOU transmission service providers for Muni and Coop customers. The analysis shows regional investment charges rising at the same rate as those allocated under the direct-cost impact analysis, albeit from a smaller base.

FIGURE 60. IOU Regional Revenue Requirement by Year



Source: SPP (2020), Energeia (2020)

FIGURE 61. IOU Regional Revenue Requirement by Customer and Consumption



Source: SPP (2020), Energeia (2020)

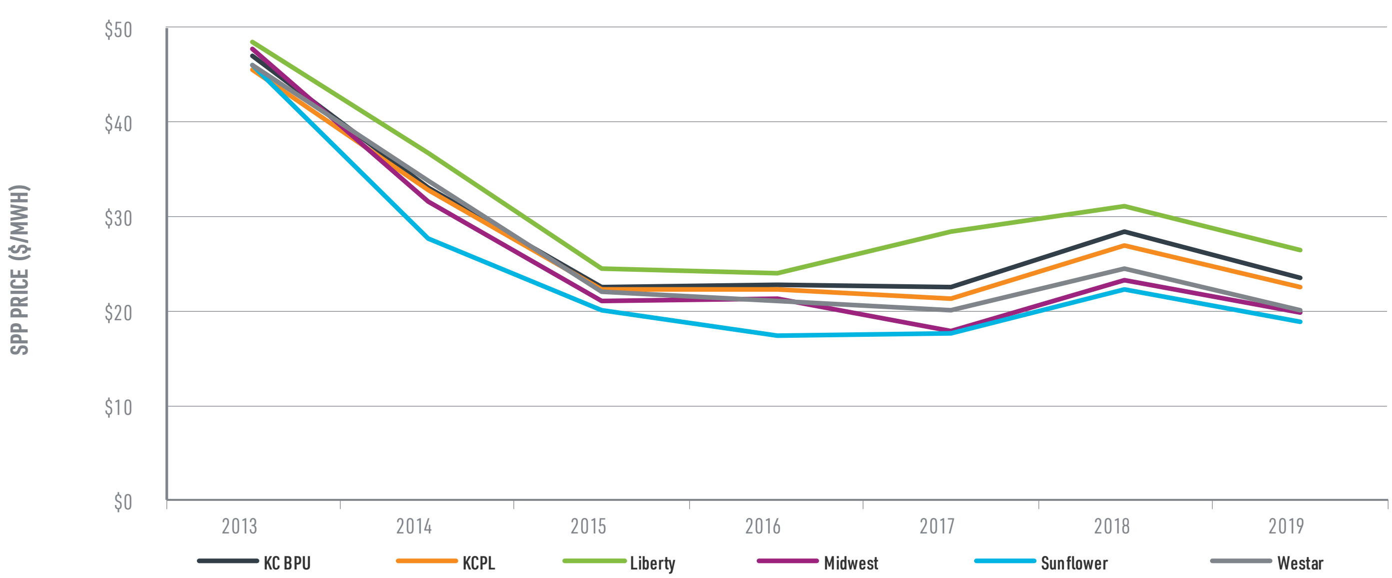
SPP MARKET PRICE IMPACTS

Due to the complex nature of the regional SPP market, it is not possible to directly determine the impact of higher IOU G&T investment and fuel costs on SPP settlement prices, and their resulting impact on other Muni and Coop G&T providers. Nevertheless, two primary but opposing impact mechanisms could be identified:

- Lower SPP prices due to the significant increase in wind generation; and
- Higher SPP prices due to increases in (ECA) fuel costs.

FIGURE 62. Time Weighted SPP Day Ahead Prices by Selected Utility shows decreasing prices for Muni and Coop transmission systems, and not just IOU transmission systems. Based on the analysis explained in **Section 5.13**, approximately 85% of price changes appear to be due to changes in fuel price; the remaining changes could be explained, in part, by an increase in wind investment by IOUs and others.

FIGURE 62. Time Weighted SPP Day Ahead Prices by Selected Utility



Source: SPP, Energeia (2020)

Differences in reporting periods may explain the difference between the role fuel costs played in reducing SPP market costs and increasing the magnitude of the ECA fuel rider.

5.7.4.5 MUNI AND COOP RATE IMPACTS

The project team found that the impact of key IOU G&T cost increases on Muni and Coops for which IOUs do not G&T services is difficult to detect due to the 40-45% reduction in SPP pool prices over the 2013 to 2019 period, despite the increase in G&T cost drivers. The $0.02/kWh SPP price reduction also outweighs the estimated $0.003/kWh increase in regional transmission costs.

5.8 The Impacts of Retail Electric Rates on Kansas Economic Development

Whether retail electric rates in Kansas are a material barrier to economic development in Kansas.

5.8.1 INTRODUCTION

In order to answer the question, "Are retail electric rates in Kansas a material barrier to economic development?" the project team broke the question into a series of research questions:

- What industries are the most sensitive to retail electric rates in Kansas?
- What is the contribution of these potentially electricity dependent industries to Kansas' economy?
- Has economic growth in high electricity dependent industries been slower than in peer States or the U.S. average?

The hypothesis of this research is that if retail electric rates in Kansas are a material barrier to economic development, then the economic growth (e.g., employment growth, establishment growth, gross regional project growth) of electricity-dependent industries will be slower in Kansas than peer states due to the higher retail electric rates in Kansas. The ideal methodology to test this hypothesis requires access to data that was not available at the time of this research, namely economic indicators of individual employers in each year and the electricity rate that is being paid by each specific employer, and their total electricity usage. Lacking this data, the project team instead:

1. Compared the economic health (i.e., total employment, wage, and establishment growth rates) of Kansas generally to nine peer States[88] and U.S. average to understand baseline conditions.
2. Identified which industries may be most sensitive to retail electric rates by calculating the share of input purchased by each industry sector that were electricity related: the higher the total electricity related inputs, the more electric-rate sensitive the sector.
3. Compared the economic health of these electric-rate sensitive sectors in Kansas to those in peer states.
4. Align quantitative findings from previous steps with stakeholder insights to determine if quantitative findings are recognized.

The results of this analysis highlight the complex environment in which electricity-dependent industries make economic development decisions. While the economic health data does suggest that Kansas may be less economically competitive overall than its peers, the data does not signal that electricity rates are the sole explanatory factor. If retail electric rates were the primary factor for Kansas' economic position relative to its peers, flat or negative job growth would be expected in electricity dependent industries. However, the data identifies some electricity dependent industries that are thriving and some that are not. It is likely, as corroborated by anecdotal examples from stakeholder interviews, that Kansas' higher retail electric rates do serve as a barrier to economic development in some instances; however, it is likely one explanatory factor since electricity is one economic input factor. Other factors, such as water, raw materials, or labor, play a significant role in financially driven expansion, relocation, or development decisions. As part of a broader economic development program, it is recommended that additional industry inputs including water,

88 For purposes of this section, peer states are those in the region including Arkansas, Colorado, Iowa, Missouri, Nebraska, North Dakota, Oklahoma, South Dakota and Nebraska.

raw materials, and labor be reviewed for their impacts on economic development to isolate the relative impact of electric rates for specific industries.

Furthermore, attraction incentives in peer states, market saturation, larger macroeconomic trends such as oil and gas prices, and individual state characteristics such as access to broadband play a key role in economic development in the region. The stakeholder engagement process identified that economic development incentives are relatively equal between Kansas and peer states. However, softer location specific factors such as presence of a trained workforce, proximity to primary inputs, or attractiveness of the location to target workforce can distort the impact of seemingly similar economic development programs. Likewise, strong oil and gas markets in peer states often create positive economic impacts in other sectors, driving economic growth across the state. Additional research would need to be conducted to normalize for these factors and compare the equality of economic development incentives and programs to isolate the impact of retail electric rates.

5.8.2 BACKGROUND

Since 2010, industrial retail electric customers in Kansas have been paying higher electric rates than the regional average and since 2011 commercial and residential retail electric customers have also been paying higher rates than the regional average. While electricity rates grew slower than the regional average in Kansas from 2001 to 2007, after the great recession starting in 2010, rates have been increasing faster than the regional average for all the three rate classes. This spike in rates has fostered concern over the impact on economic development goals.

5.8.3 SCOPE AND APPROACH

To answer this question, the project team conducted a quantitative analysis reinforced by stakeholder insights. Data for the analysis was collected from EMSI, a proprietary source of industry employment and output data and from the U.S. Energy Information Administration (EIA). The following process was used for this analysis:

- Compared the economic health (i.e., total employment, wage, and establishment growth rates) of Kansas generally to nine peer States and U.S. average to understand baseline conditions.
  - Compare total employment, wage, and establishment growth rates for Kansas, nine peer States and U.S. average.
  - Collect industry employment, input-output, and establishment data from EMSI for Kansas and peer States.[89]
- Identified which industries may be most sensitive to retail electric rates by calculating the share of input purchased by each industry sector that were electricity related: the higher the total electricity related inputs, the more electric-rate sensitive the sector.
  - Determine the share of all inputs purchased by each industry that are electricity related. The electricity share of inputs was used as a proxy to determine which industries were most electricity dependent.[90]
- Compared the economic health of these electric-rate sensitive sectors in Kansas to those in peer states.
  - Analyze industry sectors, or two-digit North American Industrial Classification System (NAICS) Codes, and specific industries, or four-digit NAICS Codes, to determine whether Kansas is outperforming or underperforming relative to peer States.
  - Collect EIA electricity rate data for Kansas and peer states.
  - Align electricity rate data with industry growth data to identify potential economic development weaknesses associated with electricity rates.
- Align quantitative findings from previous steps with stakeholder insights to determine if quantitative findings are recognized.

The findings from this process were used to inform whether economic development in Kansas appeared to be materially impacted by retail electric rates. Outputs from the process were used to answer the following questions:

- What industries are the most sensitive to retail electric rates in Kansas?

89 Industry employment refers to the number of jobs in each industry. Input-output refers to the dollar value of inputs that are purchased by each industry to produce $1 of output. Establishment data refers to the number of physical locations where industry employment is located.

90 This metric was used to determine which industries are relatively more electricity intensive. If an industry is large enough it can still create significant electricity demand even though this represents a small share of inputs.

- What is the contribution of these potentially electricity dependent industries to Kansas' economy?
- Has economic growth in high electricity dependent industries been slower than in peer States or the U.S. average?

5.8.4 INFORMATION GATHERING

The RFI was issued with the following information requests related to this matter:

8.1: Please send number of non-residential customers for last ten years by year, rate category and location

8.2: Please send non-residential customer consumption (MWh) for last ten years by year, rate category and locations.

8.3: Please send information regarding any economic development rates and/or contracts agreed to over the last ten years, including information, by year for each customer, usage, applicable rate schedule and percent of reduction under the economic development tariff/rider/rate or contract.

8.4: Please send information regarding current or previous economic development policies or programs for the last 10 years.

8.5: Please provide any economic development program tariff/rider/contract feasibility studies prepared or utilized in the last 10 years regardless of whether the program/tariff/rider/rate/contract was implemented.

8.6: Please provide copies of tariffs, riders or other cost recovery mechanisms associated with the economic development rates or contracts described above.

5.8.4.1 SUMMARY OF RFI RESPONSES

The first two information requests for this analysis had among the highest response rate of all questions posed by the RFI, though the others, which centered on economic development policies, contracts, and rates, and were thus critical to the project team's original approach to this matter, received very few responses. In light of these gaps, the methodology was adapted to align with publicly available industry data from EMSI and focused on gauging electricity-related industries' sensitivity to utility rates in Kansas relative to its peer states.

5.8.4.2 STAKEHOLDER FEEDBACK

Feedback from stakeholder meetings provided anecdotal evidence of companies leaving Kansas or choosing not to locate in Kansas due to higher retail electric rates. It underscored the impact that rates seem to be having on clean energy sector development related to additional demand charges on solar customers. This feedback drove exploration into specific data considerations.

5.8.5 KEY FINDINGS AND CONCLUSIONS

5.8.5.1 COMPARATIVE ELECTRICITY RATES AND MACROTRENDS

Before discussing the findings of this analysis, it is first important to understand the trends related to electric rates in Kansas and the region, and their correlation with economic performance. This section compares regional retail electric rates and maps them against gross regional product (GRP) to understand macro-level trends before delving into sector- and industry-specific trends. Please note, this section repeats information previously presented in Section 5.5 that is important to this discussion as well. For a more detailed analysis of electricity rates by utility type (IOU, Muni, and Coop), please refer to the Part 1 of the Study.[91]

RETAIL ELECTRIC RATES

In 2019, Kansas customers were paying higher electricity rates in the industrial, commercial, and residential Sectors. Additionally, electricity rates grew more slowly than the regional average in Kansas from 2001 to 2007, and subsequently more quickly than the regional average from 2010 to 2019 for the three customer classes examined.

91 Prepared for the Kansas Legislative Coordinating Council by London Economics International LLC in January of 2020

TABLE 18. Average Annual Electricity Rates

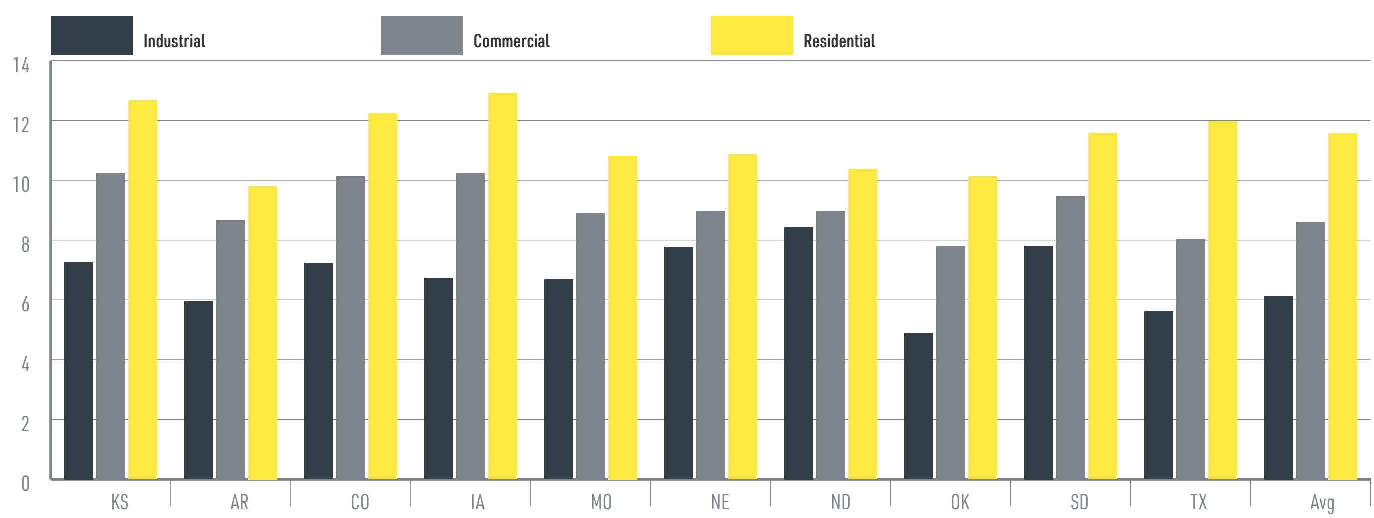
		2019 Rate (cents/kwh)	CAGR 2001-2007	CAGR 2010-2019
Industrial	Kansas	7.26	2.02%	1.95%
	Regional Average*	6.14	5.06%	-0.02%
Commercial	Kansas	10.23	1.62%	2.95%
	Regional Average*	8.60	3.91%	0.16%
Residential	Kansas	12.67	1.12%	3.21%
	Regional Average*	11.57	4.01%	0.92%

* Weighted average of Kansas, Arkansas, Colorado, Iowa, Missouri, Nebraska, North Dakota, Oklahoma, South Dakota, and Texas

Source: EIA, AECOM

In 2019, customers in Kansas experienced electricity rates that were among the highest in the region. Industrial rates in Kansas were surpassed only by South Dakota, North Dakota, and Iowa, while commercial and residential rates were the second highest in the region, with only customers in Iowa paying higher rates.

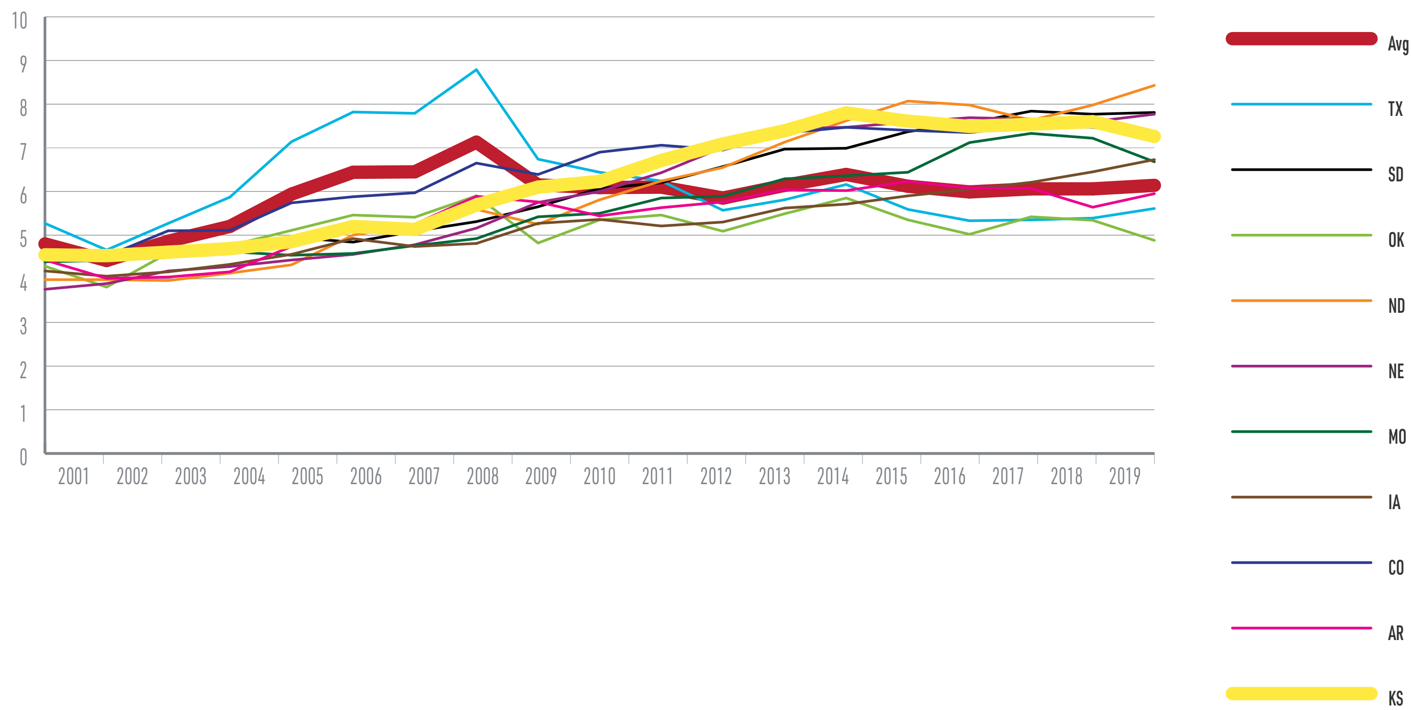
FIGURE 63. Average Annual Electricity Rate (cents/kwh) (2019)



Source: EIA

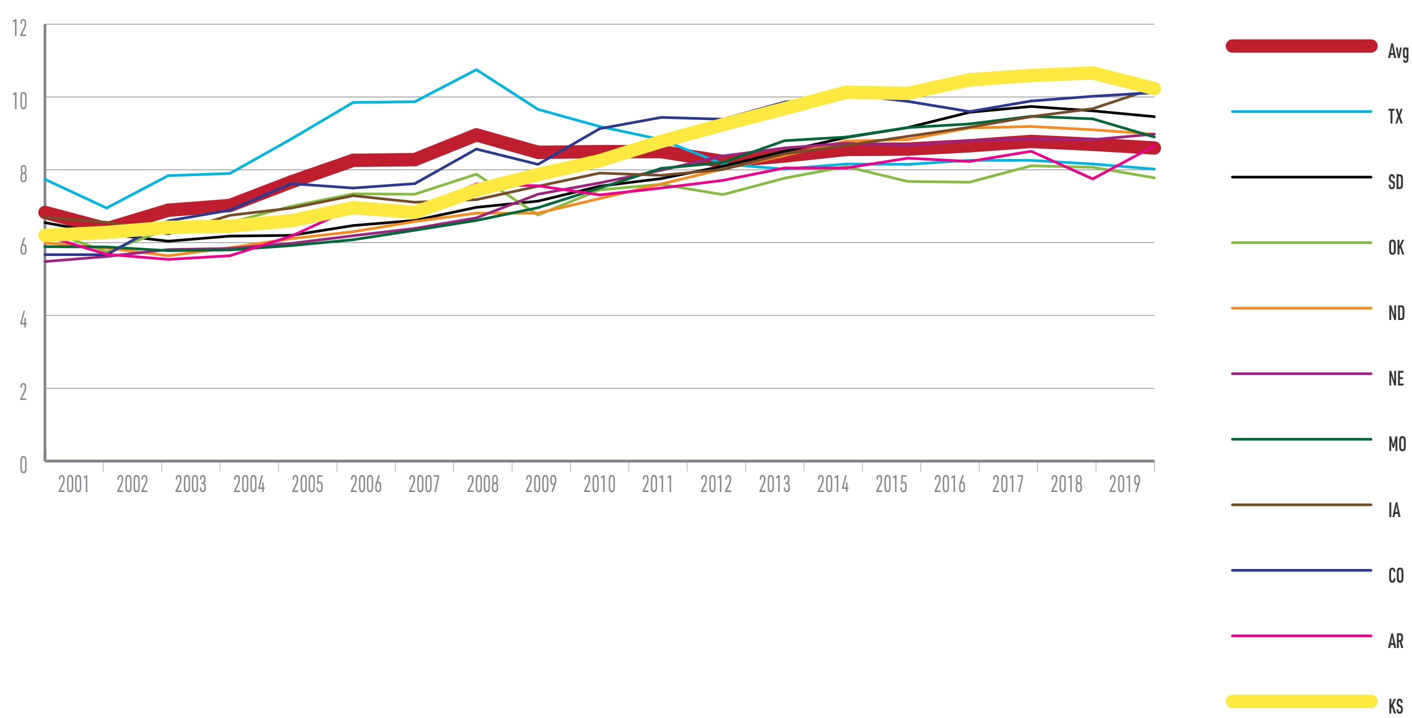
Figures 64-66 show the historical rates across the region for the three classes of electricity customers. The average annual industrial rate in Kansas surpassed the regional average in 2010, and both the commercial and residential rates surpassed the average in 2011. Thus, Kansas electricity rates were lower and grew more slowly than the regional average during the first period of observation (2000-2007) and were then higher and grew more quickly during the second period (2010-2019).

FIGURE 64. Average Industrial Rate (cents/kwh)



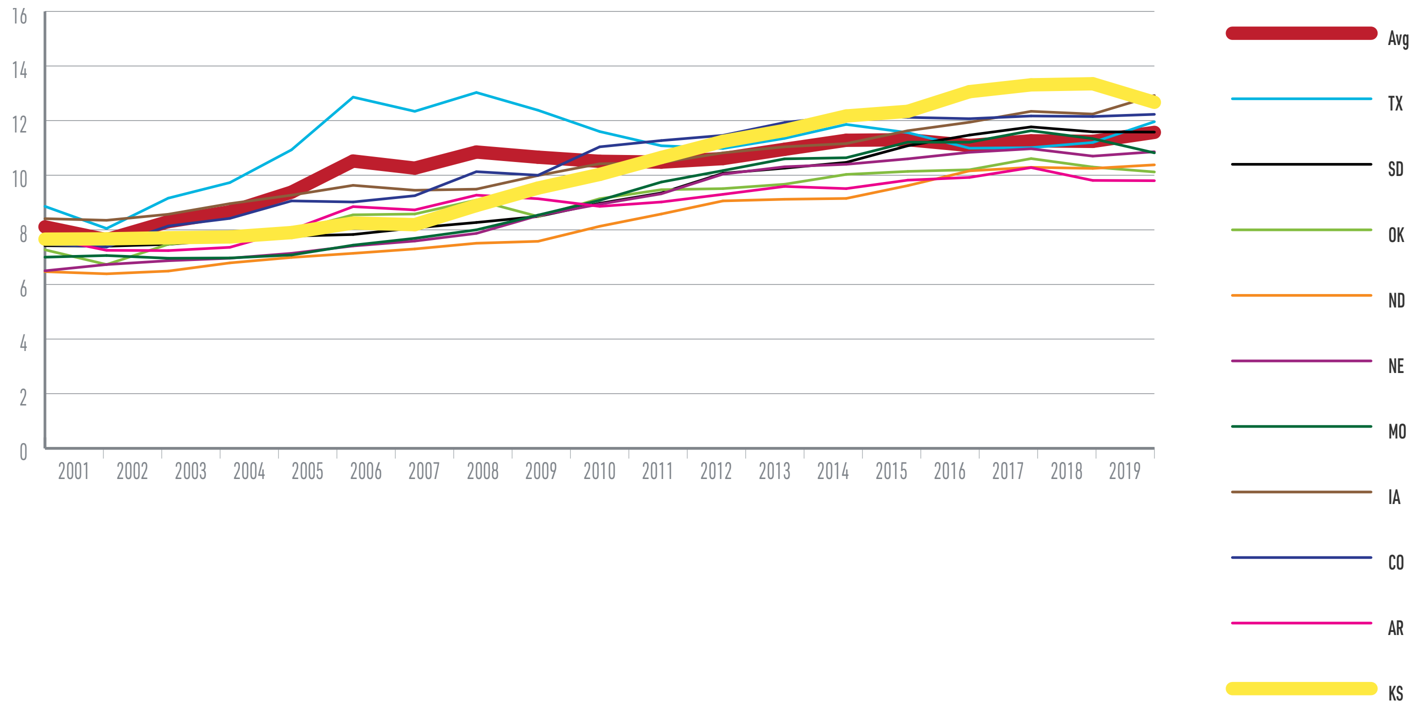
Source: EIA

FIGURE 65. Average Commercial Rate (cents/kwh)



Source: EIA

FIGURE 66. Average Residential Rate (cents/kwh)



Source: EIA

GROSS REGIONAL PRODUCT – REGIONAL COMPARISON

This section considers the growth rates of the aggregate industrial and commercial sectors to first understand macroeconomic trends and their correlation to electricity rates before analyzing individual NAICS sectors and industries in later sections.

From 2010 to 2019, the GRP of industrial and commercial sectors in Kansas has experienced weaker growth than the average of peer states' sectors (regional average).[92] The industrial sector in Kansas grew at a Compound Annual Growth Rate (CAGR) of 3.4% over this time period, and the commercial sector grew at a CAGR of 3.3%, compared to 4.1% and 4.3%, respectively, for the regional average. Over the same period, the electricity rates paid by customers in these sector categories has increased at a faster rate in Kansas than the regional average. The average annual electricity rate grew at a CAGR of approximately 2% for industrial customers and 2.9% for commercial customers from 2010 to 2019, while the regional average experienced negligible growth for industrial customers and a CAGR of 0.2% for commercial customers. Thus, Kansas experienced below average economic growth and above average electricity rate growth from 2010 to 2019. The role that electric rates play in this below average economic performance is analyzed through sector and industry specific analyses.

TABLE 19. Economic and Electricity Growth Rates (CAGR 2010-19)

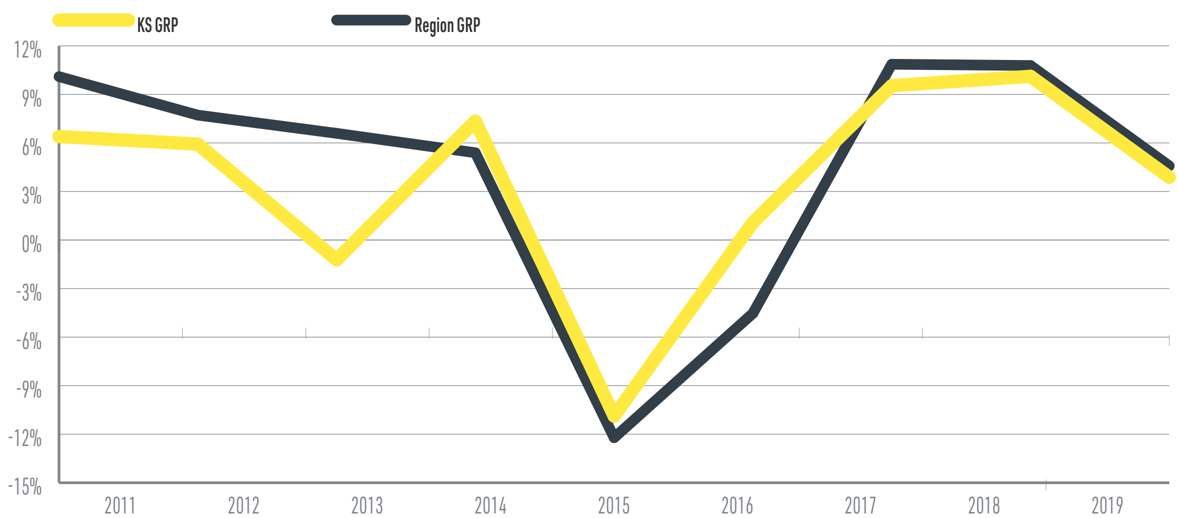
		Kansas	Regional Average
Gross Regional Product	Industrial	3.4%	4.1%
	Commercial	3.3%	4.3%
Average Annual Electricity Rate	Industrial	2.0%	0.0%
	Commercial	2.9%	0.2%

Source: EMSI, EIA, AECOM

92 For the purposes of this section, Kansas was compared to the following nine peer states: Arkansas, Colorado, Iowa, Missouri, Nebraska, North Dakota, Oklahoma, South Dakota, and Texas.

To further explore the relationship between economic growth and electricity rates in Kansas, the change in GRP was analyzed over time for all NAICS sectors classified by the EIA as falling into industrial and commercial customer classes. In general, GRP growth in the industrial sector has trended with that of the region, although with lower growth rates from 2010 to 2014. The industrial sector in both Kansas and the region experienced a sharp downturn in 2015 and 2016.

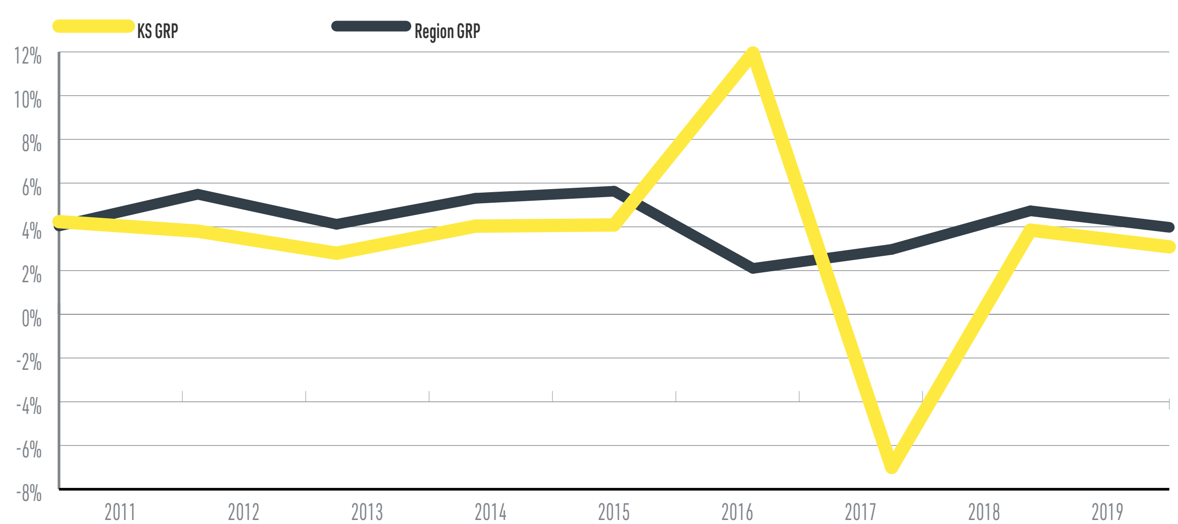
FIGURE 67. Industrial Sector GRP Growth (Year over Year)



Source: EMSI

GRP growth in the commercial sector has also generally trended with the region, although there was a notable spike and subsequent dip in growth from 2015 to 2017. In the case of Kansas, this decline in commercial GRP growth is largely attributable to a negative shock from low and negative growth in Kansas' industrial sector. Lost jobs and revenue in the aerospace manufacturing, agriculture, and oil/gas extraction sectors, apparent in the drop of industrial GRP from 2014 to 2016, diminished consumer spending and hit the commercial sector by 2017. With fewer jobs and less revenue from these anchor industries being captured by Kansas workers and residents, the downturn rippled through other sectors of the economy. Further evidence for this negative impact in the commercial sectors is found in the drop in sales tax revenues experienced by a majority of counties in Kansas in 2017.[93]

FIGURE 68. Commercial Sector GRP Growth (Year over Year)



Source: EMSI, EIA

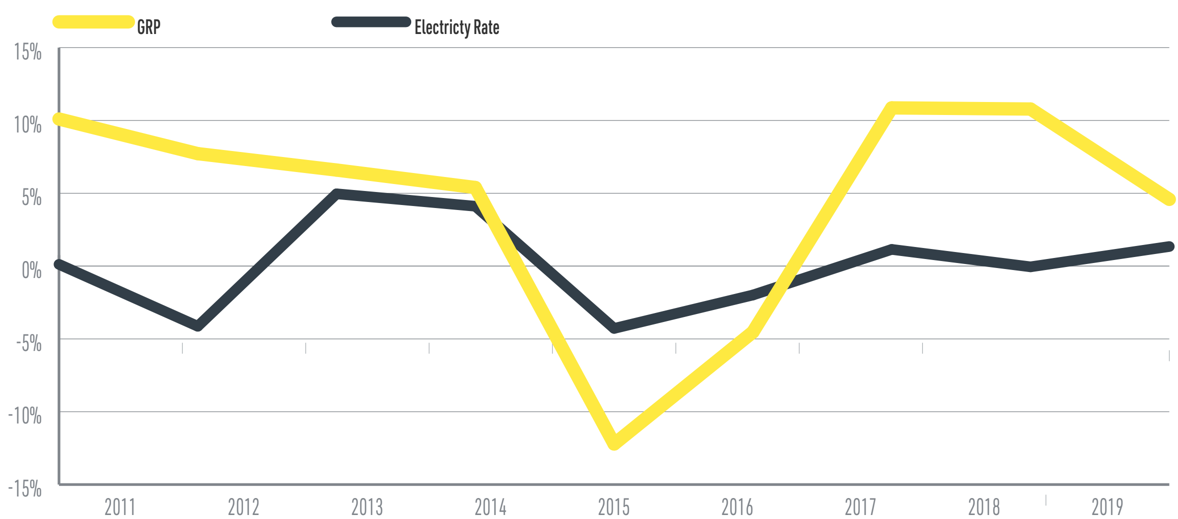
93 Trabert, D. (2017). Tax Cuts and the Kansas Economy. Kansas Policy Institute. Retrieved from: https://kansaspolicy.org/tax-cuts-kansas-economy/

If higher electricity rates are a material impediment to growth in the industrial and commercial sectors, the expected correlation between GRP growth and electricity rate growth would be strong and negative: decreasing electric rates would track with increased GRP and vise-versa. However, as demonstrated in **FIGURE 69. Regional Industrial Growth Rates (Year over Year)**, this trend is not uniform in the industrial sector. Since 2015, the industrial NAICS sectors have grown strongly throughout the region, and this period is marked by low and negative growth rates for the industrial electricity rate. Nonetheless, due to the logistics of industrial production, economic growth in these sectors does not respond to the changes in electricity rates on an annual basis. This indicates that industrial sector growth does not accelerate or decelerate because of electricity prices in the short term. Interviews with stakeholders revealed that longer-term considerations of where to locate facilities are highly responsive to electricity prices for the sectors identified with high electricity consumption.

For the commercial sector, the correlation between GRP growth and the electricity rate is more apparent. The correlation for both the entire study period and year over year growth is clear and negative.[94] While this correlation does not indicate causation, the relationship between the two variables is likely a key consideration for sectors with the logistical capacity to shift their resources. Especially for the sectors identified as having significant electricity inputs to their production, shifts in electricity prices are an important factor in decision making for both short- and long-term planning. A breakdown of potentially electric-rate sensitive industries in the commercial sectors is discussed later in these findings.

The following Figures show the year over year comparison of these growth rates for region across the 2010 to 2019 period.

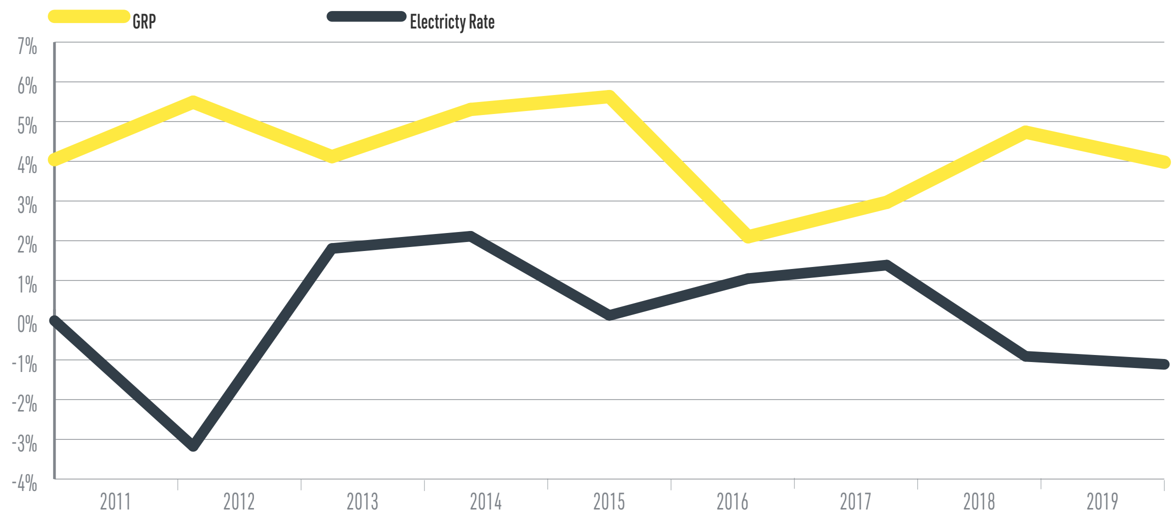
FIGURE 69. Regional Industrial Growth Rates (Year over Year)



Source: EMSI, EIA

94 A unique dataset was built from EIA and EMSI data and used for a multivariate regression analysis to specify the relationship of industrial and commercial rates on GRP growth for each NAICS sector at the state level. The testing revealed a correlation of approximately -$50 million and -$100 million across the region for industrial and commercial classes, respectively, with a 1 cent increase in kWh.

FIGURE 70. Regional Commercial Growth Rates (Year over Year)

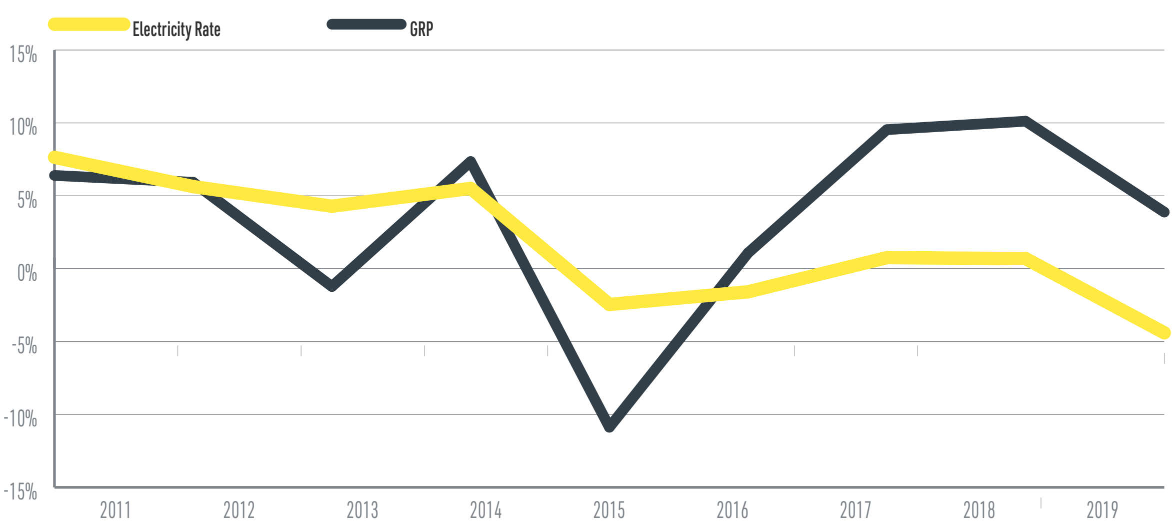


Source: EMSI, EIA

GROSS REGIONAL PRODUCT – KANSAS COMPARISON

The long-term negative correlation between electricity rates and electrical growth across the region applies to Kansas, which saw slower GRP growth and faster industrial and commercial electricity rate growth from 2010 to 2019. Yet, the record of Kansas' economy is more nuanced. As described above, the drop in the commercial sector GRP in 2017 is likely attributable to negative spillovers from a drop in Kansas' key industrial sectors. The correlation between GRP growth and electricity rate growth in Kansas is weaker than that for the region – but it is still a significant factor in commercial and industrial class' economic performance over the long term.[95]

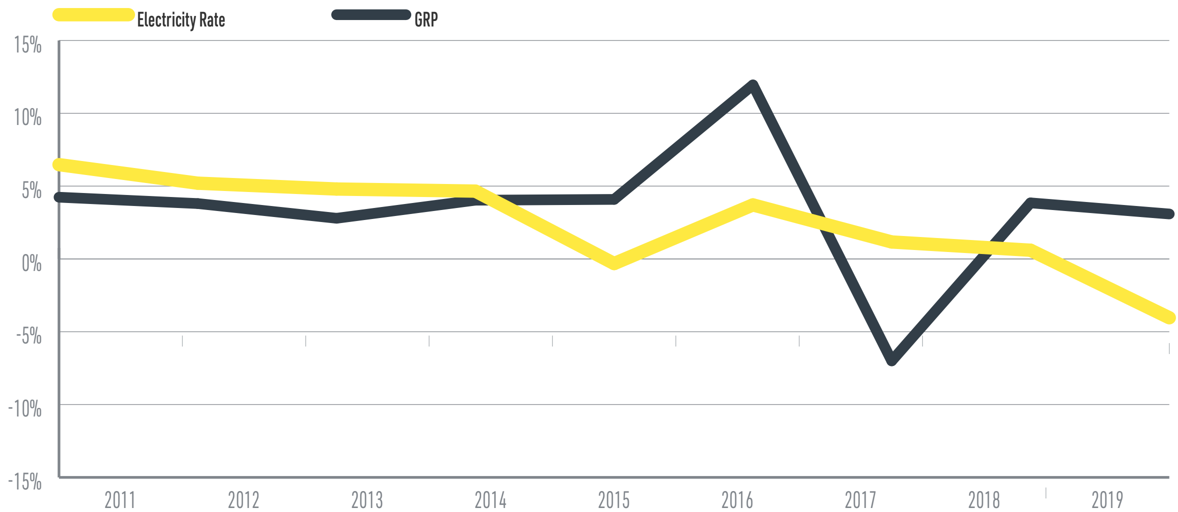
FIGURE 71. Kansas Industrial Growth Rates (Year over Year)



Source: EMSI, EIA

95 A unique data set was built with EIA and EMSI data and used to conduct a multivariate regression analysis to specify the relationship of industrial and commercial rates on GRP growth for each NAICS sector at the state level. The testing revealed a correlation of approximately -$50 million and -$100 million across the region for industrial and commercial classes, respectively, with a 1 cent increase in kWh. The correlation for these sectors in Kansas only was approximately -$10 million and -$25 million, which was still significant at a 95% confidence interval. There is more variance, even with a smaller average class size, in Kansas as compared to the region.

FIGURE 72.Kansas Commercial Growth Rates (Year over Year)



Source: EMSI, EIA

5.8.5.2 KANSAS ECONOMIC DEVELOPMENT PERFORMANCE

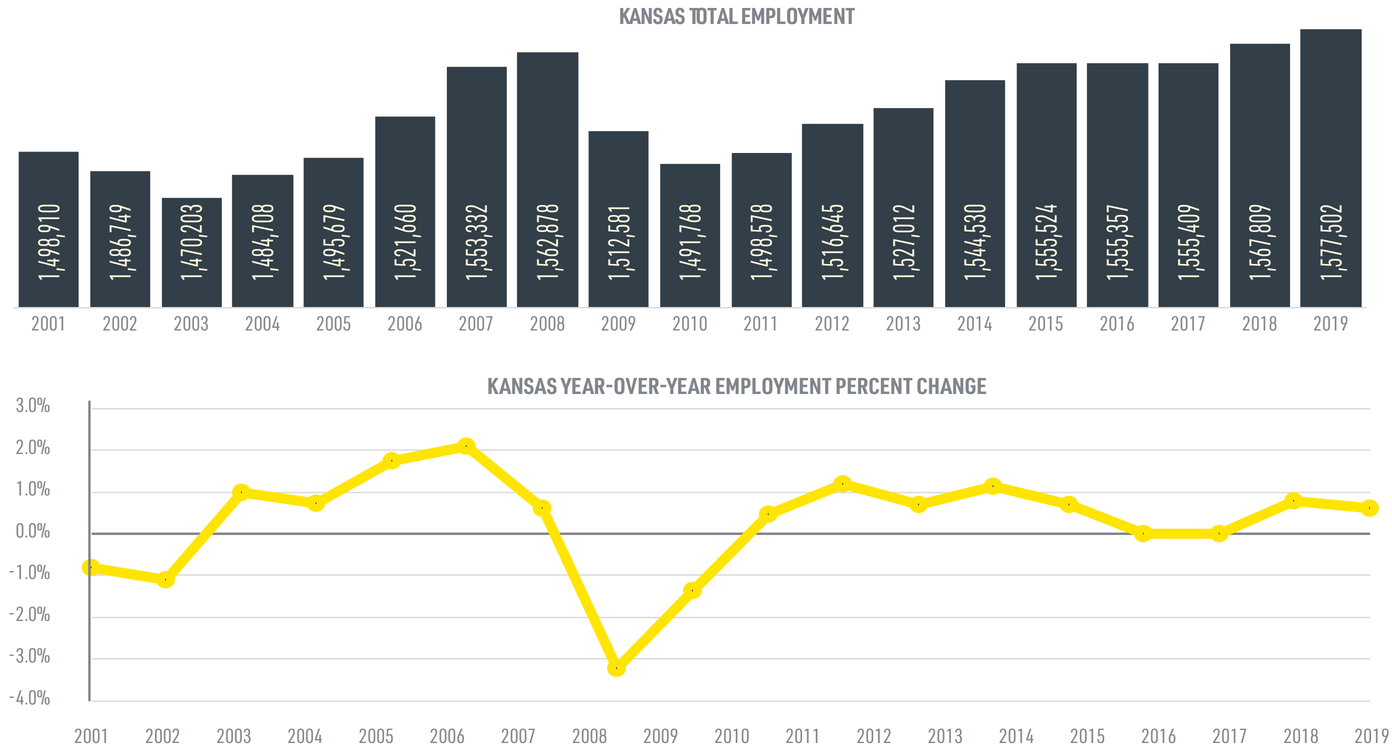
With an understanding of regional trends and a confirmation that electric rates appear to correlate with changes in economic performance at a regional level, an understanding Kansas' general economic performance became the project team's focus. To determine whether retail electric rates are a material barrier to economic development in Kansas, aggregate economic development metrics was analyzed across all Kansas sectors.

This analysis helps determine how Kansas' overall economic performance compares to other states in the region. In recent years, Kansas' economy has generally tended to underperform relative to peer states. Specifically, since 2001, economic growth in Kansas has tended to be consistently less pronounced than other regional states and the U.S. average. The following sections demonstrate this underperformance in relation to job growth, gross regional product and wages, and business establishments.

JOB GROWTH

Between 2001 and 2019, Kansas added 79,000 jobs, equating to an annual job growth rate of 0.3%. Over the same period, the U.S. added jobs at a 0.7% annual rate, a little over two-times the Kansas job creation rate. Of all states in the region, only Missouri added jobs at a comparable rate to Kansas, with all other states adding jobs at faster annual rate. Year-over-year job growth in Kansas peaked between 2006 and 2007, when the number of jobs in the state increased by 2%. Since 2007, Kansas has not seen an increase in jobs by 2% or more in any given year.

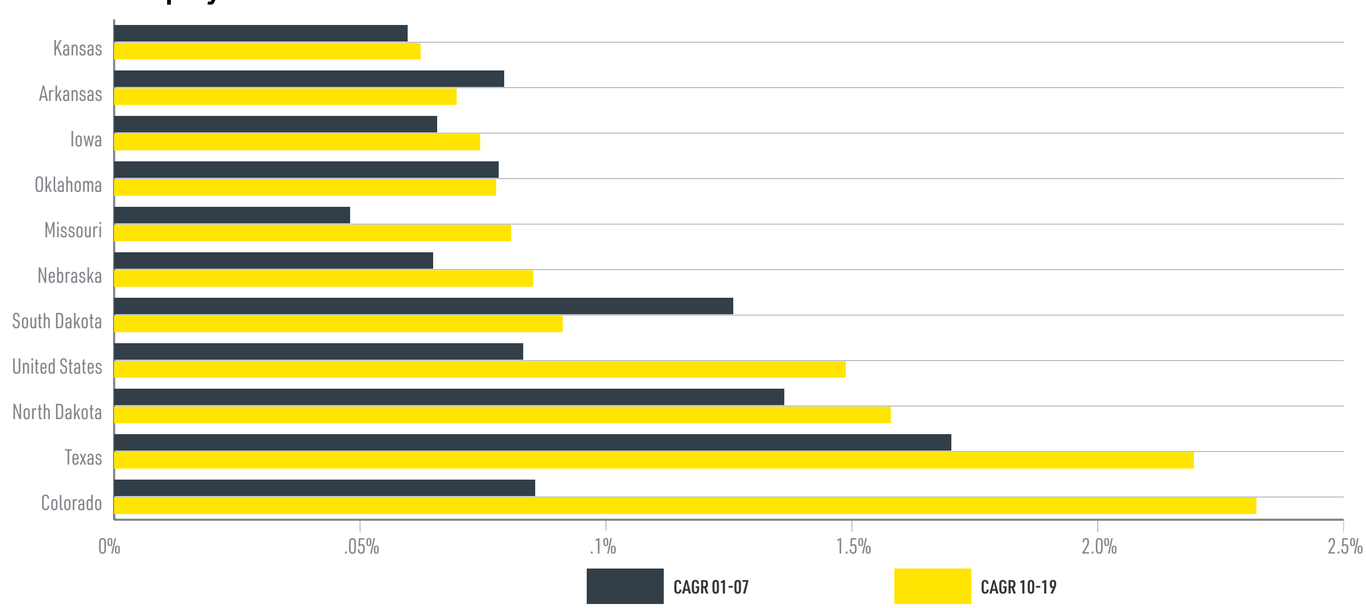
FIGURE 73. Kansas Total Employment & Year-over-Year % Change



Source: EMSI

Relative to its nine regional peers, Kansas economic growth has historically been consistently slower. Kansas added jobs at equivalent annual rates between 2001 and 2007 as it did between 2010 and 2019, 0.6%. Between 2001 and 2007 Kansas ranked ninth in the region for job creation (only outpacing job growth in Missouri), and tenth for job growth between 2010 and 2019. **FIGURE 74. Employment CAGR - All Jobs** depicts annual job changes in Kansas, its peer states, and the U.S. average across both time periods. The annual job changes are expressed as CAGRs, which show the percent change in jobs that occurred between 2 years.

FIGURE 74. Employment CAGR - All Jobs

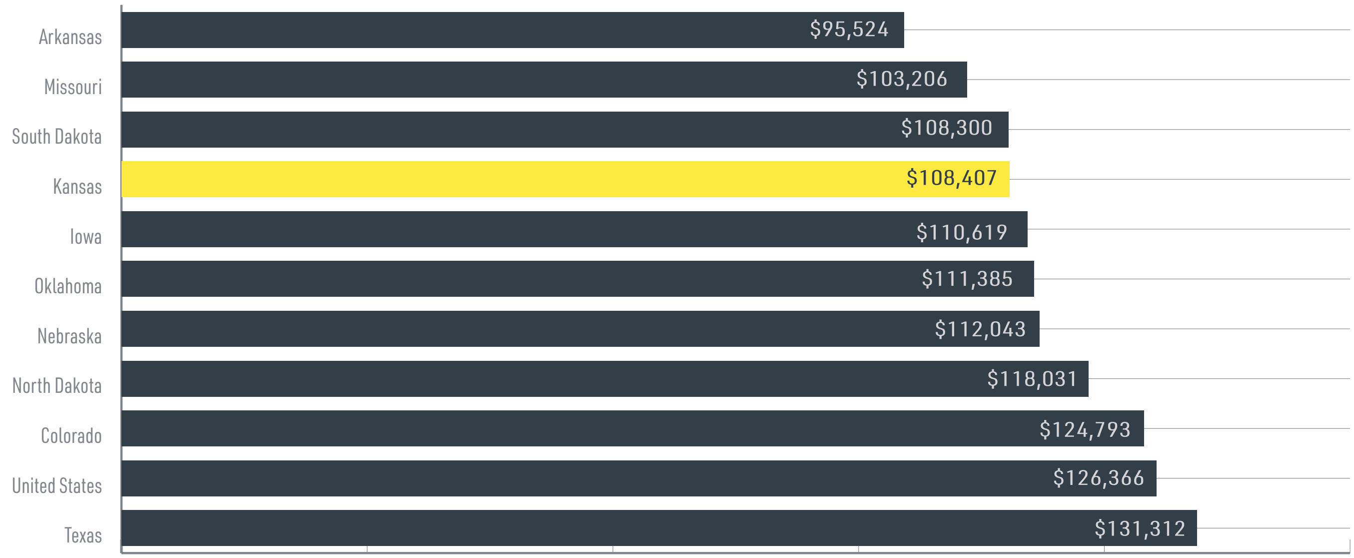


Source: EMSI

GROSS REGIONAL PRODUCT & WAGES

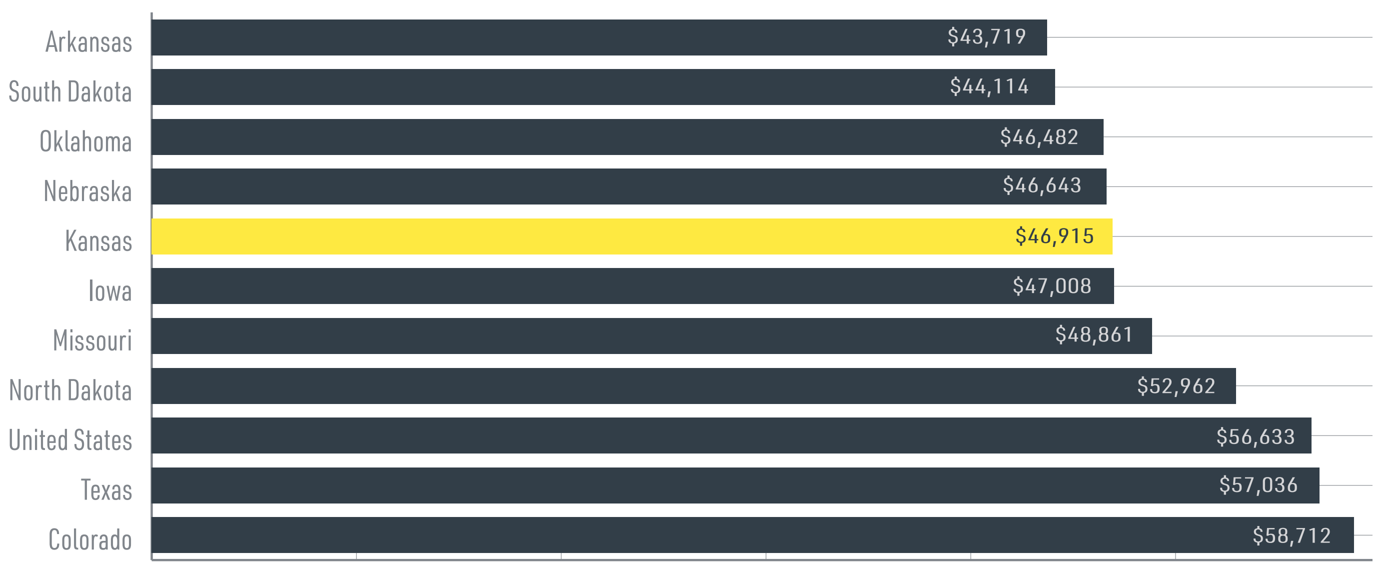
As of 2019, Kansas ranked seventh of ten in GRP, or value-added per worker and sixth for average wages per worker. **FIGURE 75. GRP Per Worker (2019)** depicts GRP per worker in 2019, or the amount of value that is added by each worker, by state and **FIGURE 76. Wages Per Worker (2019)** shows the relative wages per worker in the region.

FIGURE 75. GRP Per Worker (2019)



Source: EMSI

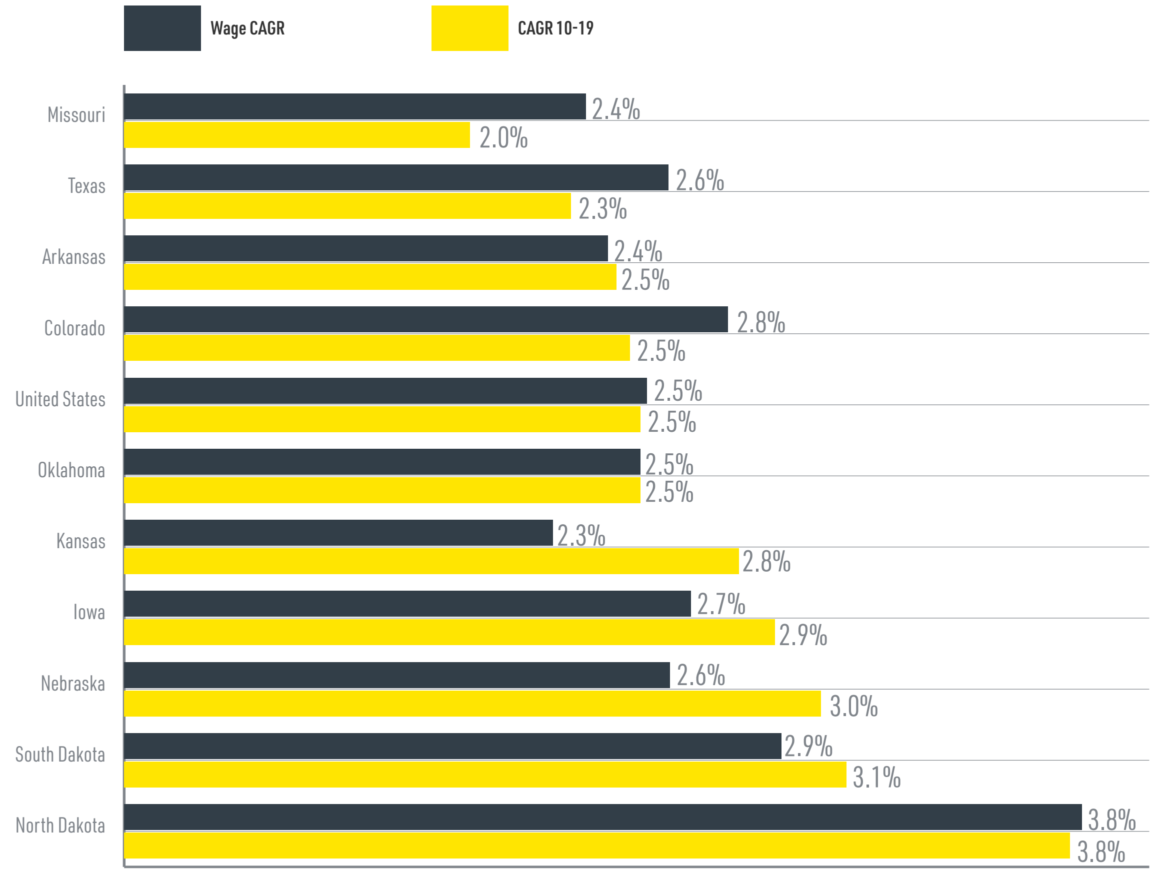
FIGURE 76. Wages Per Worker (2019)



Source: EMSI

Similar to post-Recession job growth trends, Kansas also exhibited slower wage growth rates than all its peer states between 2010 and 2019, with annual wage growth of 2.3%. Despite being ranked last for wage growth, Kansas ranked fifth for GRP per worker growth, suggesting that labor productivity is increasing more from physical capital (e.g., machinery upgrades) than human capital or job quality. Kansas had the greatest disparity between its wage growth rate and GRP per worker growth rate in the region. In other words, Kansas had the greatest difference between wage increases (2.3%) and output increases (2.8%). This suggests that Kansas is shifting reliance from human capital inputs (e.g., workers) to physical inputs, and more so than its peers. **FIGURE 77. GRP & Wages Per Worker CAGR (2010-2019)** depicts annualized changes in wages and GRP per worker between 2010 and 2019.

FIGURE 77. GRP & Wages Per Worker CAGR (2010-2019)



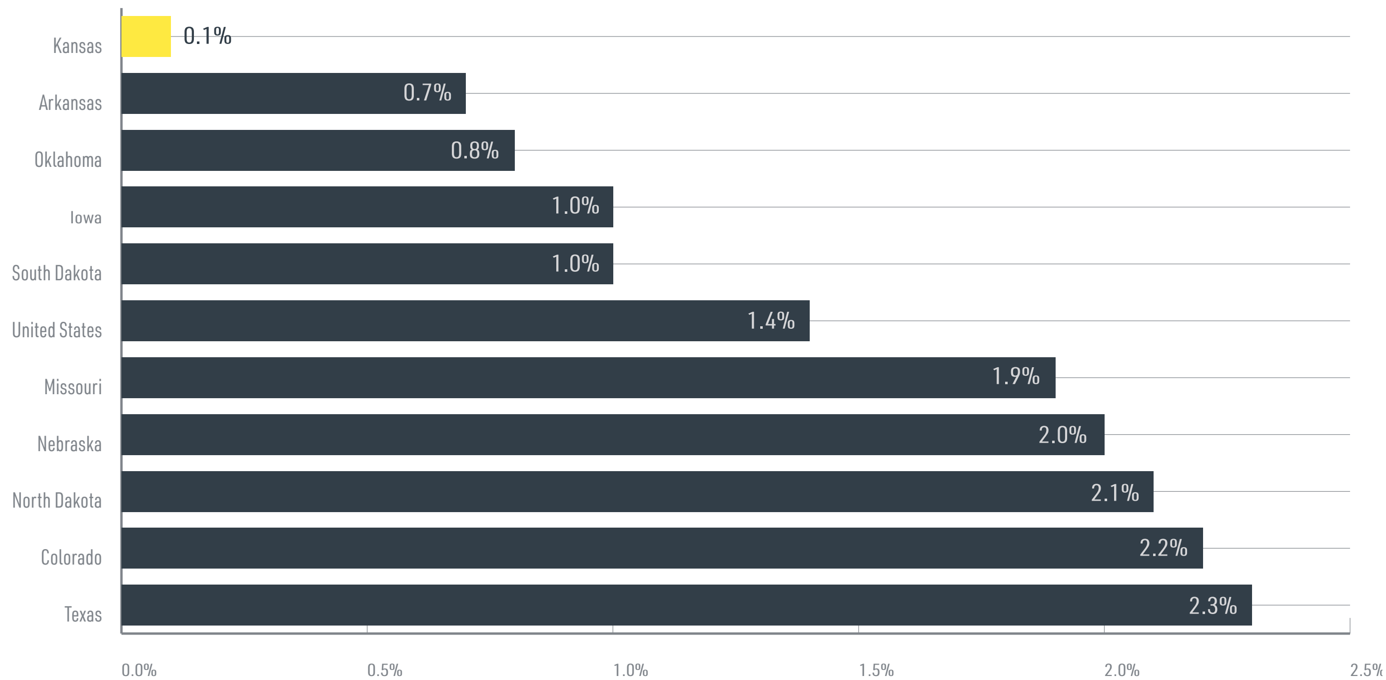
Source: EMSI

BUSINESS ESTABLISHMENTS

The final aggregate economic development metric reviewed was business establishment trends. Each physical location where a job is created is considered a business establishment. Increases in business establishments suggest that business expansion or attraction is taking place, while decreases in establishments indicate business contraction or relocation to other states. Between 2010 and 2019, business establishments in Kansas increased at an annual rate of 0.1%, slower than all peer states and the U.S. average. Consequently, Kansas had the second highest average establishment size in the region with an average establishment size of 17.8 jobs. Increases in jobs per establishment can indicate a weakness in business attraction or development, since job growth is dominated by existing establishments. Between 2010 and 2019, the average number of jobs per establishment increased at an annual rate of 0.5%, faster than all of its peers (of which seven of ten experienced decreases in average establishment size), reinforcing a weakness in business attraction relative to peer states. Stakeholders during the interview process confirmed this finding through their perceptions that business attraction or development in Kansas is less competitive than peer states. The potential impact of retail electric rates on Kansas' soft establishment trends is explored in the next section.

FIGURE 78. Business Establishment CAGR (2010-2019) depicts annualized changes in establishments between 2010 and 2019, or the year-to-year growth, on average, of establishments between 2010 and 2019.

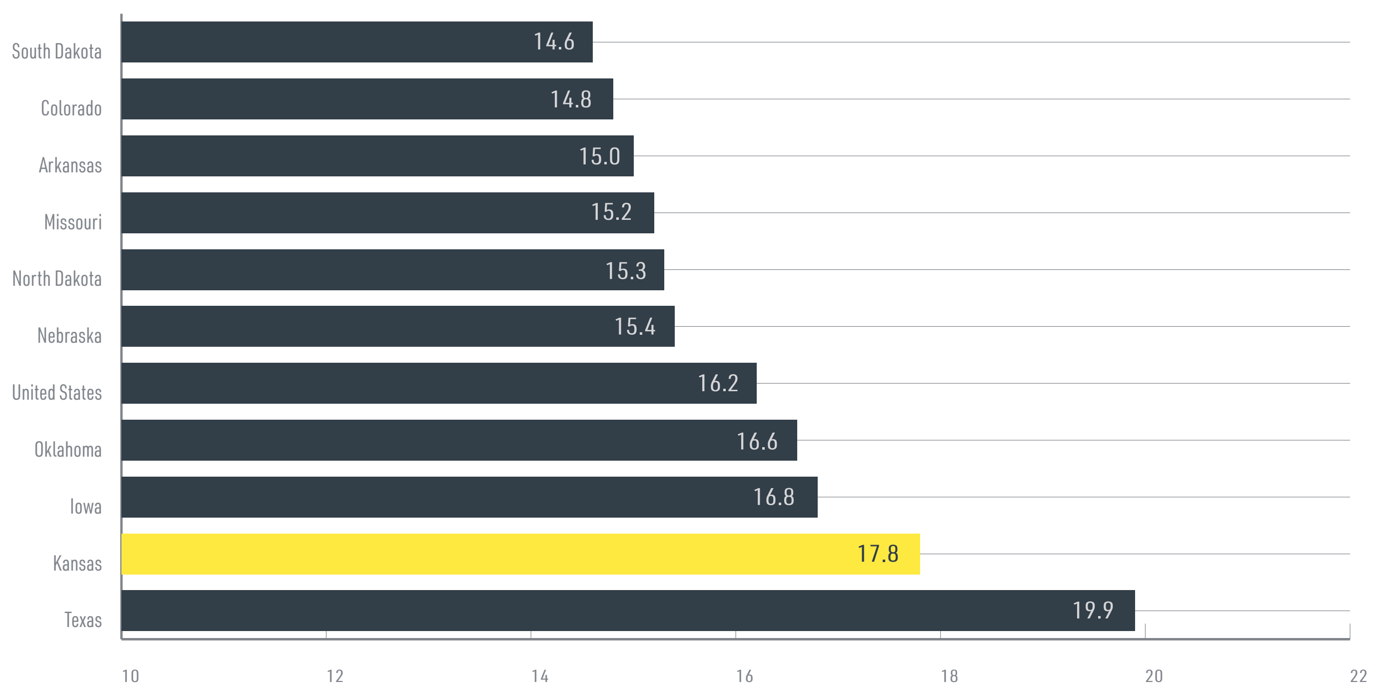
FIGURE 78. Business Establishment CAGR (2010-2019)



Source: EMSI

FIGURE 79. Jobs per Establishments (2019) shows the average number of jobs per establishment in 2019, or the number of people, on average, working at each establishment during the year.

FIGURE 79. Jobs per Establishments (2019)



Source: EMSI

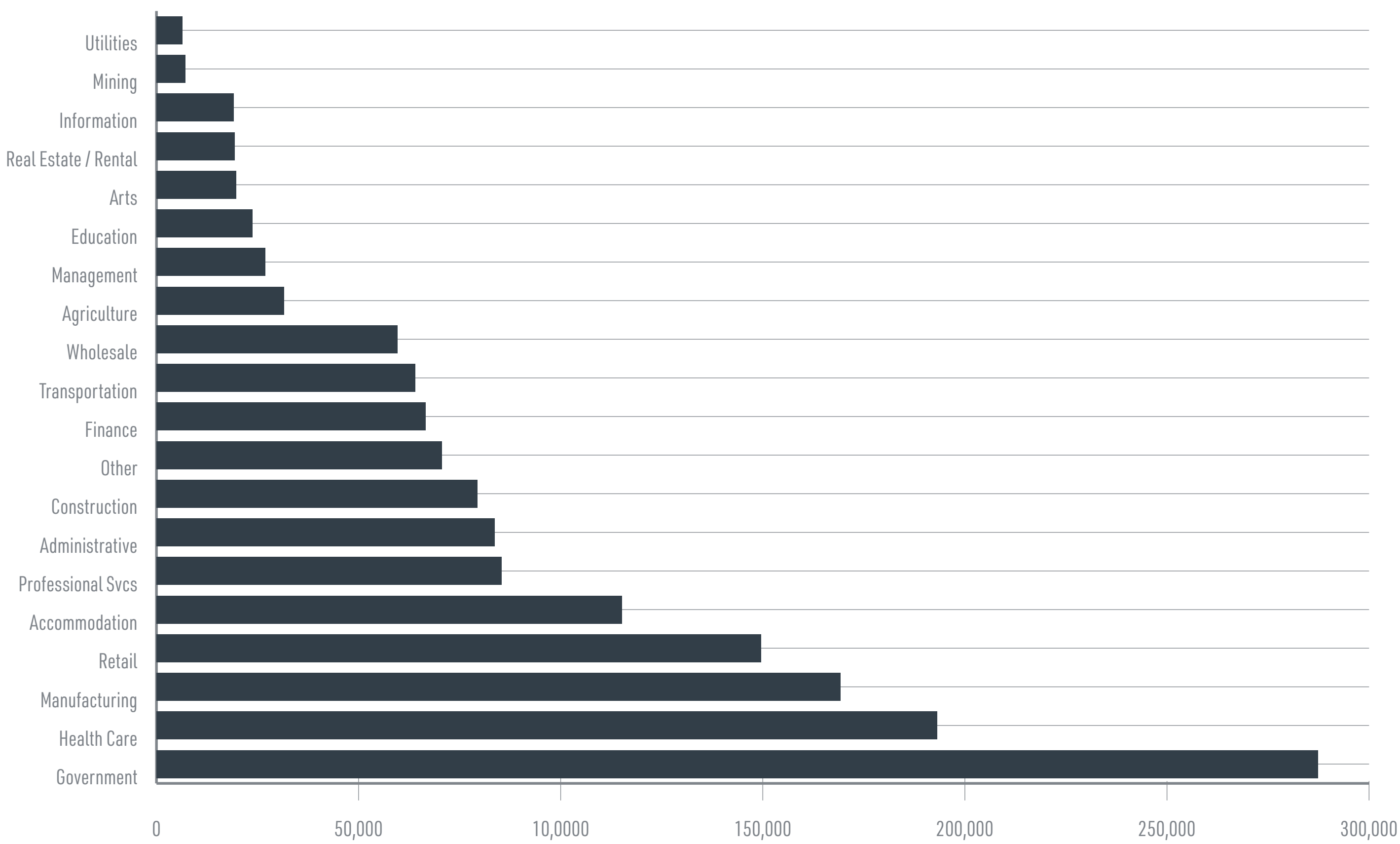
5.8.5.3 SECTOR ECONOMIC DEVELOPMENT PERFORMANCE

Economic trends at a two-digit NAICS Code, or sector level, can help provide insights into which parts of an economy are performing well and which are lagging. High-level sector trends can help identify which family of industries (four-digit NAICS Codes) should be analyzed further. This analysis, combined with an understanding of electric rate-sensitive industries, provides insights into the potential impact of high retail electric rates in Kansas. This section discusses the largest employment sectors and how concentrated these are in Kansas, potential electric-rate sensitive sectors in Kansas.

JOBS AND JOB CONCENTRATIONS

As of 2019, the 3 largest sectors in Kansas' economy were government, health care, and manufacturing. These three sectors accounted for over 41% of all jobs in Kansas. **FIGURE 80. Kansas Sector Job Levels (2019)** depicts total job levels by sector in 2019.

FIGURE 80. Kansas Sector Job Levels (2019)

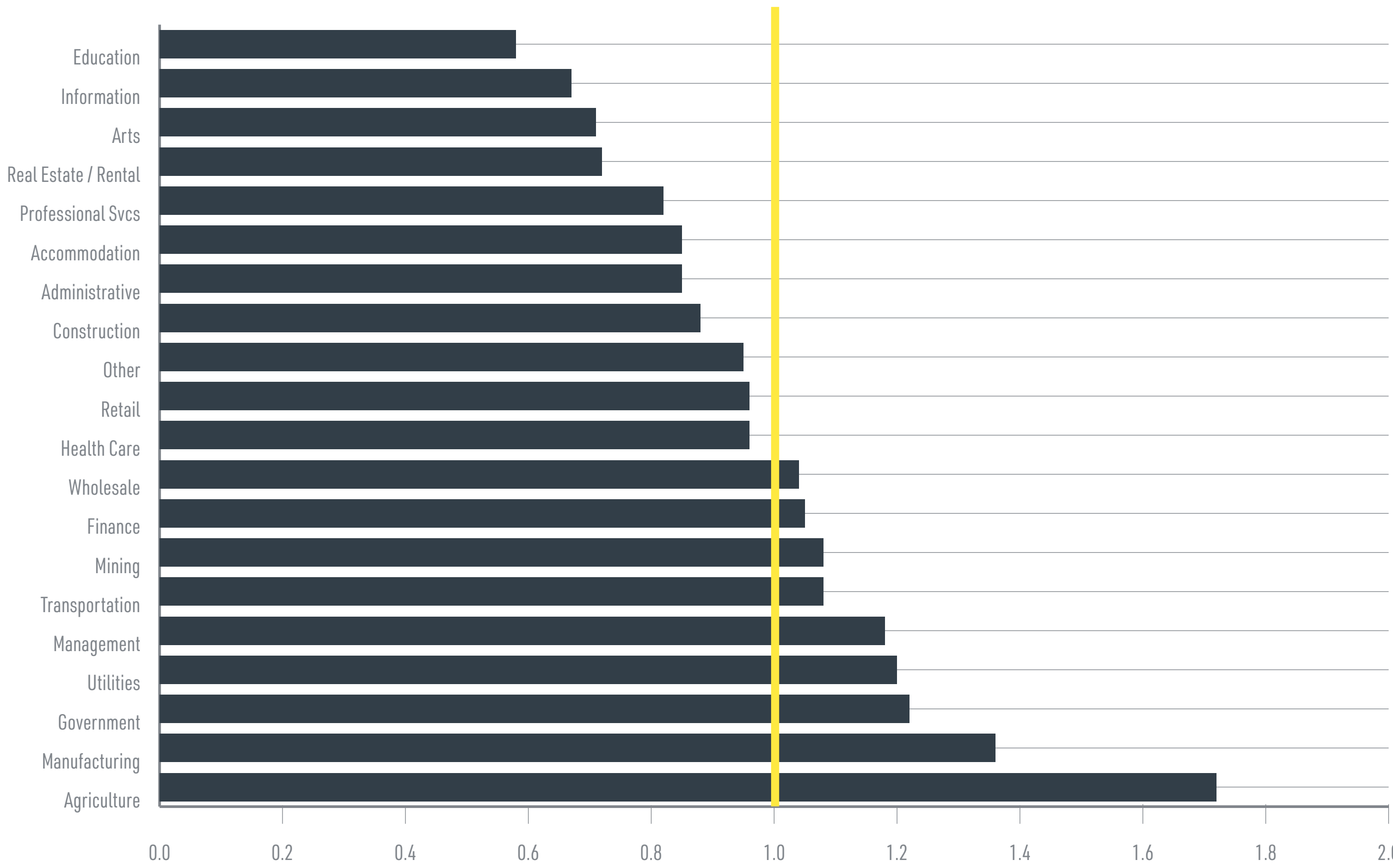


Source: EMSI

Government and manufacturing are also two of Kansas' most concentrated industries. **FIGURE 81. Kansas Sector Job LQ (2019)** shows job location quotients (LQ) in Kansas for 2019, which show whether or not a sector is a larger share of Kansas jobs than the sector is in the U.S. or not. If an LQ is above one it means that the sector represents a larger share of employment in Kansas than in the U.S.

The three most concentrated sectors in Kansas were agriculture, government, and manufacturing. Nine of 20 sectors are more concentrated in Kansas than U.S. average, or have job LQ above one. Compared to its peers, Kansas is more concentrated than **see APPENDIX D State and Regional Jobs and Job LQ** for LQ comparisons with peer states.

FIGURE 81. Kansas Sector Job LQ (2019)



Source: EMSI

ELECTRIC-RATE SENSITIVE SECTORS

Building on an understanding of the concentrated and large sectors in Kansas, it is next important to understand which sectors may be most sensitive to increases in retail electric rates. Lacking establishment-specific input-output data, the input-output data was analyzed at the national level. Using input-output information for each sector, the share of input purchased by each industry sector in the U.S. that was electricity-related was determined. The electricity share of inputs was used as a proxy to determine which sectors were the most electricity-dependent. The higher the total electricity-related inputs, the more electricity-dependent the sector. From this analysis, real estate/rental, accommodation/food, retail, and education were found to be the four most likely electric rate dependent sectors in Kansas. **TABLE 20. Kansas Sector Job Growth & Electricity Share of Inputs** shows Kansas sector job growth from 2001 to 2019 and 2010 to 2019 as well as the electricity-related share of inputs (purchases) by sector.

TABLE 20. Kansas Sector Job Growth & Electricity Share of Inputs

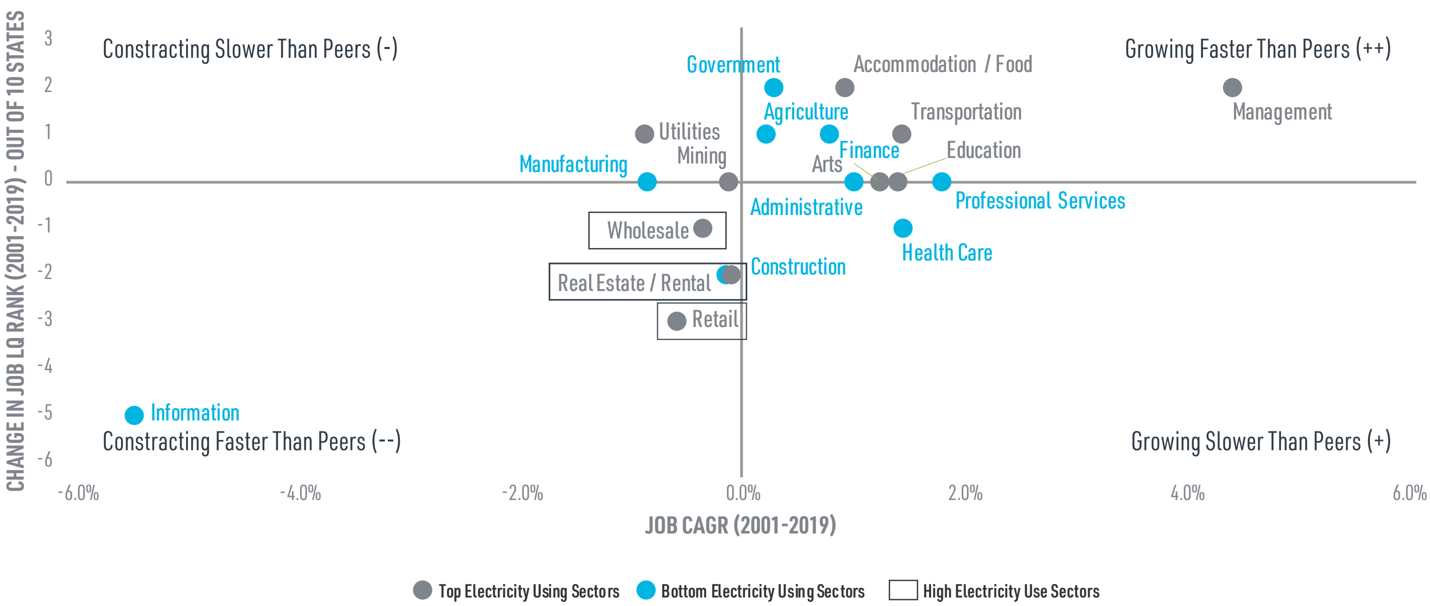
Sector	Jobs 2019	CAGR 01-19	CAGR 10-19	Energy Share of Purchases
Utilities	6,370	-0.9%	-2.2%	N/A
Real Estate / Rental	19,381	-0.1%	0.6%	7.1%
Accommodation / Food	115,142	0.9%	1.4%	4.0%
Retail	149,582	-0.6%	0.1%	3.6%
Education	23,747	1.4%	0.6%	3.6%
Management	26,913	4.4%	6.5%	2.9%
Mining	7,176	-0.1%	-2.3%	2.0%
Transportation	64,019	1.4%	3.5%	1.7%
Wholesale	59,625	-0.3%	-0.3%	1.5%
Arts	19,739	1.2%	2.6%	1.4%
Manufacturing	169,227	-0.8%	0.5%	1.1%
Agriculture	31,498	0.2%	0.1%	0.8%
Health Care	193,126	1.5%	1.1%	0.8%
Government	287,346	0.3%	-0.4%	0.7%
Construction	79,360	-0.1%	1.1%	0.5%
Information	19,139	-5.5%	-4.9%	0.4%
Administrative	83,614	1.0%	0.9%	0.4%
Professional Services	85,370	1.8%	2.4%	0.3%
Finance	66,570	0.8%	1.0%	0.2%

Source: EMSI

Hypothetically, if sectors are being negatively impacted by high retail-electric rates, this should be presented by economic underperformance of electricity dependent sectors. To analyze how sectors have performed in Kansas relative to all peer States between 2001 and 2019 and test if sectors with higher electricity dependency (i.e., higher electricity share of purchases) are more significantly underperforming, sectors were plotted on an X/Y plot and color coded based on their electricity usage. Sectors were ranked based on their electricity share of all input purchases and color coded based on their rank (the top 50% are blue and the bottom 50% are red). The x-axis of the plot depicts annual job changes between 2001 and 2019 while the y-axis depicts Kansas' job LQ rank. The cross-tabulation of these variables helps visualize how each sector has performed in Kansas, with the top right quadrant representing the highest performing sectors and the bottom left quadrant representing the lowest performing sectors. Each quadrant of the plot below is labeled as to how the sector has performed.

Note that the electricity share of input purchases is a relative measure, as it helps illustrate the share of all inputs used by the sector are electricity-related. Some sectors, such as manufacturing, are large users of electricity in absolute terms, but because more inputs are needed, electricity represents a relatively smaller share. The goal of using this relative measure is to identify which sectors may be more sensitive to changes in retail electric rates because electricity composes a larger share of their overall input costs.

FIGURE 82. Kansas Sector Growth Comparison



Source: EMSI

As depicted in **FIGURE 82. Kansas Sector Growth Comparison**, there are three electricity-sensitive sectors that are losing jobs in Kansas at a faster rate than in peer states (i.e., jobs are decreasing and Kansas is becoming less concentrated in the sector relative to peers). The three sectors are wholesale, real estate/rental, and retail. In contrast, some higher-than-average electricity-sensitive sectors performed better or equal to peer states. For some of these sectors, such as education and food service, economic growth is closely tied to population growth and increased community services. Job increases in the transportation and management sectors are positive indicators given their higher-than-average share of electricity input purchases, however transportation job growth lagged behind the U.S. average. Management is the only highly electricity-sensitive sector to perform better in Kansas than in peer States and the rest of the U.S. – despite the rate environment. Most of the growth in management was centered around Kansas City; employment opportunities in this sector are not as common in the remainder of the state.

5.8.5.4 INDUSTRY ECONOMIC DEVELOPMENT

Although a sector analysis is helpful for understanding high-level trends related to economic development and electric rates, to better understand this relationship, it is useful to identify specific industries that are under- or over-performing in Kansas. From this analysis, several industries were identified as under-performing. In 2019, almost one-in-five jobs in Kansas was in an under-performing industry with high electricity use (i.e., higher share of electricity inputs than the average industry). Underperforming industries that are potentially sensitive to electric rates were also identified during the stakeholder engagement process, and drew the project team's focus for further discussion.

HIGHLIGHTED INDUSTRIES

- Oil and gas extraction employed 2,000 people and generated $8.2 billion of GRP in Kansas as of 2019, and the industry has a higher share of electricity inputs than the average industry. Between 2001 and 2019, Kansas lost jobs in oil and gas extraction at an annual rate of 2.2%, worse than the U.S. average. Oil price trends have placed pressure on extraction firms, however the electricity rate environment in Kansas appears to be making job retention more difficult, as neighboring states with more attractive electricity rates (e.g. Oklahoma) outperform Kansas in extraction employment growth.

- Kansas foundries employed over 1,100 people, generated $118 million of GRP as of 2019, and purchased more electricity inputs than the average industry. Still, even as foundries elsewhere in the U.S. added jobs, Kansas foundries lost jobs at an annual rate of 2.1% between 2001 and 2019.
- Grocery wholesale employed 5,000 people and generated $541 million of GRP in Kansas as of 2019, but the industry lost jobs at an annual rate of 2.1% between 2001 and 2019 – even as employment across the U.S. increased at a 1.1% annual rate. Electricity represents a larger share of inputs in this industry as compared to most other wholesale industries.
- Lessors of real estate employed 5,100 people and generated $1.8 billion of GRP in Kansas as of 2019. The industry has above average shares of electricity input purchases and underperformed the U.S. average in job growth. Kansas lost jobs at an annual rate of 1.1% while jobs in the U.S. increased at annual rate of 0.9%.

See **see APPENDIX E Industry Summaries** for detailed tables show the following variables for each industry:

- Kansas Jobs in 2019
- Kansas Job growth rate between 2010 and 2019
- Kansas Job LQ in 2019
- Kansas job LQ rank of 10 State sample (1st is highest LQ, 10th is lowest)
- U.S. job growth rate between 2010 and 2019
- Share of all inputs that are electricity related (% of all inputs)
- The name of the State that had the highest job LQ in 2019 of the 10 State sample
- The 2019 job LQ of the State with the highest LQ
- Kansas GRP in 2010
- Kansas GRP in 2019
- Kansas GRP growth rate between 2010 and 2019
- U.S. GRP growth rate between 2010 and 2019
- Share of all inputs that are electricity related (% of all inputs)

5.8.6 CONCLUSION

Stakeholder input identified anecdotal examples of large industrial companies who chose to not locate in Kansas due to electricity rates. These discrete examples are supported by quantitative evidence that some industrial sectors have experienced less growth than peer states and the U.S. average. Under-performing sectors include wholesale trade and real estate/leasing services, which use more electricity as a share of inputs than the average sector. Top line economic growth in Kansas has been slower than in all nine peer states included in this analysis since 2010. It appears that electricity rates in Kansas likely contribute to such under-performing economic development, including business attraction and retention. However, these findings are not conclusive that retail electric rates are the only barrier to economic development in Kansas, but insinuate they are one correlate with negative economic outcomes in some cases.

5.9 Impact of Contract and Economic Development Rates on Other Customer Classes

The impact of contract rates with commercial and industrial customers and economic development rates on other customer classes, including whether expanded utilization of such approaches can benefit all customers over time.

5.9.1 INTRODUCTION

In order to understand the impacts of contract rates for commercial and industrial customers and economic development rates (EDR) on other customer classes, as well as whether expansion of these rates could benefit all customers over time, responses to the following two questions were attempted by the project team:

- **EDR Impact:** What has been the retail rate impact of EDRs on Kansas ratepayers?
- **EDR Efficacy:** Do economic development contracts address the competitiveness gap between Kansas and peer states?

To determine the impact EDRs have on retail rates, the specific data was requested from utilities related to existing EDRs. Unfortunately, as described below, insufficient data was available to determine the impact of these policies on other customer classes.

Similar data limitation issues were encountered in conducting the analysis of EDRs' success or failure at reducing the competitiveness gap between Kansas and its peer states. This analysis aimed to provide a foundation for policy recommendations related to the expansion of EDRs. At least one utility in each peer state offers a form of EDR. On average, Kansas EDRs have lower load requirements and lower discounts than utilities in peer states, and the discounted rate applies to the net monthly bill. The discounted rates offered by Kansas utilities partially address the competitiveness gap by offering an electric rate to non-residential customers below the regional average for the five-year term of the contract. However, the diversity of EDRs complicates a direct comparison, both in terms of the discount offered and qualifying criteria. Additionally, EDRs often function as part of a broader economic development program. This section describes the EDRs in Kansas and its peer states, then identifies next steps to support determination of development program effectiveness.

5.9.2 BACKGROUND

To offset economic development underperformance linked to Kansas' higher-than-average retail electric rates, utilities may offer EDRs. EDRs are a program option that incents business development through discounted electricity rates over a determined time period. EDRs address two principal policy objectives that provide benefits to the residents and ratepayers in Kansas. The first is to encourage businesses to locate their operations in existing and other new Kansas businesses (indirect impacts), and generate consumer spending the state, which stimulates job creation and capital investment. New business in Kansas directly support new jobs and economic output (direct impacts), purchase inputs of intermediate goods and services from in the communities where workers live (induced impacts). An increase in the number of taxpayers will also introduce new fiscal revenues in Kansas and its jurisdictions.

The second principal policy objective is to lower the electricity rates of all customers through the diffusion of fixed costs among more ratepayers and the increased efficiency of generating capacity. The presence of large, stable customers in the utilities' service area should provide these long-term benefits to both the utilities and their customers.

5.9.3 SCOPE AND APPROACH

To conduct this analysis, a process involving the following steps was planned:

- Compiling available data for EDRs for Kansas and peer state utilities;
- Compiling retail electric rate and usage data for Kansas;
- Determining changes in retail electric rates related to EDRs and their impact to other customer classes;

- Comparing business attraction and expansion in Kansas and its peer states related to EDRs; and
- Comparing impact of EDRs on ratepayers to reach a determination of EDRs' efficacy in improving Kansas economic development outcomes.

However, due to data gaps described below, the project team instead sought to answer the following questions:

- EDR Impact: What has been the retail rate impact of EDRs on Kansas ratepayers?
- EDR Efficacy: Do economic development contracts address the competitiveness gap between Kansas and peer states?

5.9.4 INFORMATION GATHERING RESULTS

The RFI was issued with the following information requests related to this matter:

9.1: Please send information regarding treatment of economic development contracts and rates in terms of cost of service and revenue recovery.

9.2: Please send the last ten years of 8760 profiles of non-residential customers and a metering ID enabling mapping of the data to customer information.

9.3: Please send information regarding non-residential customers including transformer ID, customer ID, premise ID, meter ID, address, XY, Parcel ID, NAICS, rate code, economic development contract, annual consumption, annual charges.

5.9.4.1 SUMMARY OF RFI RESPONSES

Information was provided related to certain EDRs offered by utilities and was supplemented by publicly available sources; however, a key gap in the requested information was the lack of detailed cost of service and customer load profile and billing data, as well as customer asset mapping information. Without these inputs, the project team was unable to estimate the impact of EDRs on other customer classes.

5.9.4.2 STAKEHOLDER FEEDBACK

Stakeholders engaged throughout the project suggested that while EDR contracts may impact residential customer classes, the benefits associated with increasing electricity sales while maintaining generation loads may outweigh the costs of potential cross-subsidies (especially if rates were to be restructured to encourage peak shedding). Additionally, stakeholders pointed to the ripple effects of economic development rates, that not only do they encourage economic regeneration on behalf of the contract holders, but also their suppliers.

5.9.5 KEY FINDINGS AND CONCLUSIONS

5.9.5.1 ECONOMIC DEVELOPMENT RIDERS USE IN KANSAS

EDRs offer a discounted rate to eligible customers to incent business development. In theory, the generation of additional power sales would eventually lower rates for all customers as utilities' fixed costs are spread over a larger base of customers. In Kansas, the availability of EDRs is limited to industrial and commercial customers that are not providing goods and services directly to the general public (no retail activity) and would otherwise not maintain or establish operations in the state. Eligibility is further determined by meeting minimum load requirements and establishing permeant jobs within the service area. Both general EDR rates available to qualifying entities and the terms of special contracts that affect tariffs are subject to KCC approval. Municipal utilities and certain Coops take a holistic approach to economic development that may take discounted rates into consideration for customers in their services areas. This section focuses on the general EDR rates for customers that meet the utilities' criteria, which may vary depending on the terms of the contract but are still subject to approval and oversight by the KCC.

The IOUs in Kansas currently offer EDRs to customers that meet their criteria, which includes a load requirement of 200 kW. Additionally, all but three Coops in Kansas are members of the member-owned generation and transmission cooperatives, KEPCO and Sunflower, which offer EDRs to attract new loads to their service territory. These credits are passed on to the final consumer through the distribution Coops. Discounted rates are usually phased out after a set number of years, after which the business is required to pay the standard sector rate. The following table compares a portion of the EDR discount rates for Kansas utilities and a selected sample of comparable utilities in neighboring states.

TABLE 21. Economic Development Rider Discount: Kansas and Selected Peer State Utilities

	Utility	Load Requirement (kW)*	Year of Contract				
			1	2	3	4	5
Kansas Utility	Evergy Kansas Metro	200	30%	25%	20%	15%	10%
	Evergy Kansas Central	200	25%	20%	15%	10%	5%
	Empire District Electric Company	200	25%	20%	16%	13%	10%
	Sunflower Electric Power Cooperation	1,000	$5.00/kW	$3.00/kW	$1.50/kW	N/A	N/A
	KEPCO Member Service Territory	50	$5.00/kW	$4.00/kW	$3.00/kW	$2.00/kW	$1.00/kW
Peer State Utility	Oklahoma Municipal Power Authority A	100	15%	10%	5%	0%	0%
	Oklahoma Municipal Power Authority B	250	25%	20%	15%	10%	5%
	Oklahoma Municipal Power Authority C	1,000	50%	40%	30%	20%	10%
	Entergy Arkansas Option 1	500	50%	40%	30%	20%	10%
	Entergy Arkansas Option 2	500	30%	30%	30%	30%	30%
	Lincoln Electrical System	Varied	50%	40%	30%	20%	10%
	SWEPCO Texas A**	1,000	30%	20%	10%	0%	0%
	SWEPCO Texas B	1,000	35%	25%	15%	0%	0%
	SWEPCO Texas C	1,000	40%	30%	20%	0%	0%
	Ameren Missouri	300	40%	40%	40%	40%	40%
	Alliant Energy Iowa	Varied	Discount according to cost/benefit analysis approved by Iowa Utilities Board				
	Montana-Dakotas Utilities Company	200	Negotiated demand charge for years 1-3, phased out years 4 (-25%) and 5 (-50%)				

* Minimum load requirement per month (kW)

** SWEPCO applies a billing credit based on Additional Full-Time Employees: A: 4-19 employees, B: 20-30 employees, C: >31 employees

Source: London Economics International, Evergy, EDE, Sunflower, KEPCO, LES, SWEPCO, Alliant , Montana Dakotas Utility Company

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 utilities in the peer states (such that the discounted rate applies to the net monthly bill).

Nonetheless, there are a wide variety of EDRs that complicate a direct comparison, both in terms of the discount offered and qualifying criteria. For example, Lincoln Electrical System and Montana-Dakotas Utilities Company offer discounts only on the demand charge, while Alliant Energy in Iowa requires a cost/benefit analysis for each potential customer and determines the discounted rate on a case-by-case basis. SWEPCO in Texas, on the other hand, offers three different discount rates contingent on the number of permanent full-time jobs created by the business seeking a discounted rate.

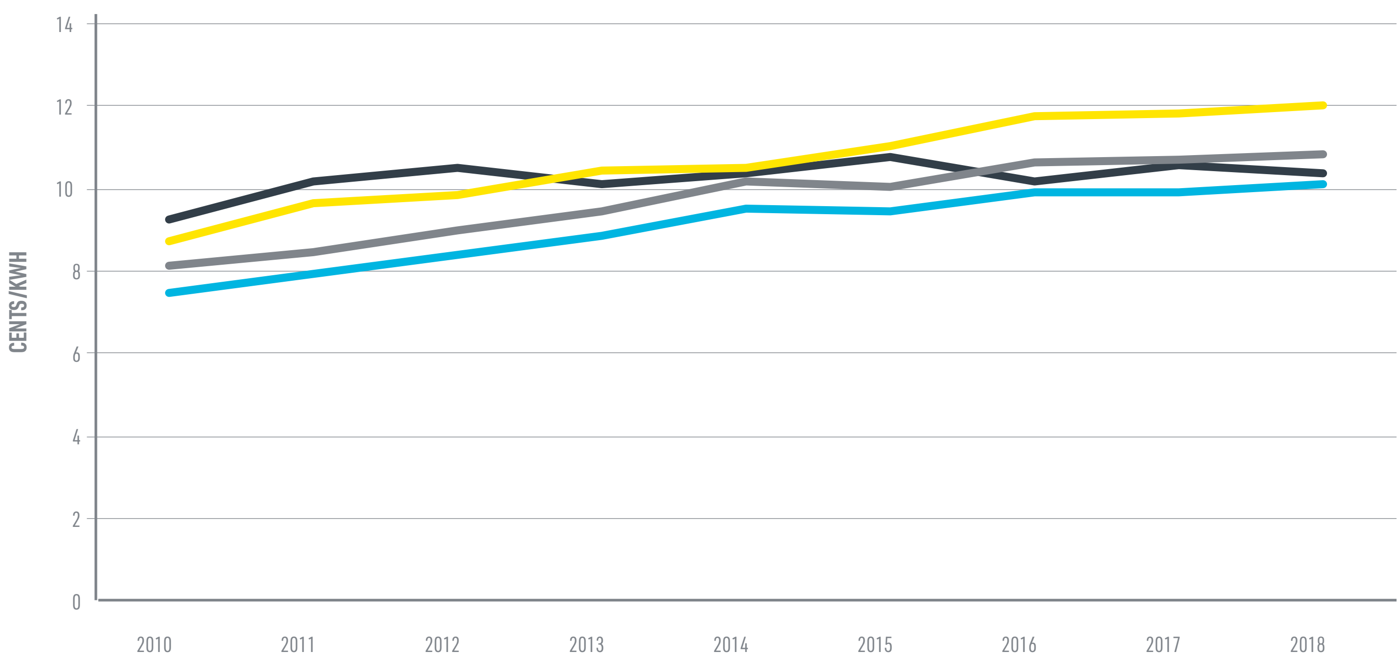
5.9.5.2 IMPACTS AND EFFICACY OF ECONOMIC DEVELOPMENT RIDERS IN KANSAS

Sufficient information was provided to allow a limited estimate of the impact and efficacy of EDRs on the average ratepayer in each customer class for one utility. This utility provided information about 31 contracts with 24 businesses that began the terms of their EDRs between 2008 and 2020, with usage data for 2018 to 2020. Approximately 70% of the contracts began in 2015 or later with 5-year terms and 92% were located in the same service territory. The lack of geographic diversity, and the fact that the majority of the contracts are still active make complete impact and efficacy analysis not possible.

However, the data received indicates the discounts may bridge the competitiveness gap for the first five years of business development or expansion compared to the average annual rate for the region. From 2010 to 2019, the average annual electric rate in Kansas was 12% and 16% higher on average than the Region for Commercial and Industrial sector customers respectively. The discounted rates available through EDRs result in an average discounts ranging from 15% to 20% depending on the specific location, effectively neutralizing Kansas' higher electric rates. However, there are two further considerations. The first is that utilities in the peer states also offer EDRs, and some of their discounts are larger than those offered by IOUs in Kansas. The second is that 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 non-energy 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. **FIGURE 83. Average Annual Rate for Total Customers** compares the average annual rate for all customer classes for the analyzed utility, Evergy Metro and a sample of other Kansas utilities.

FIGURE 83.Average Annual Rate for Total Customers

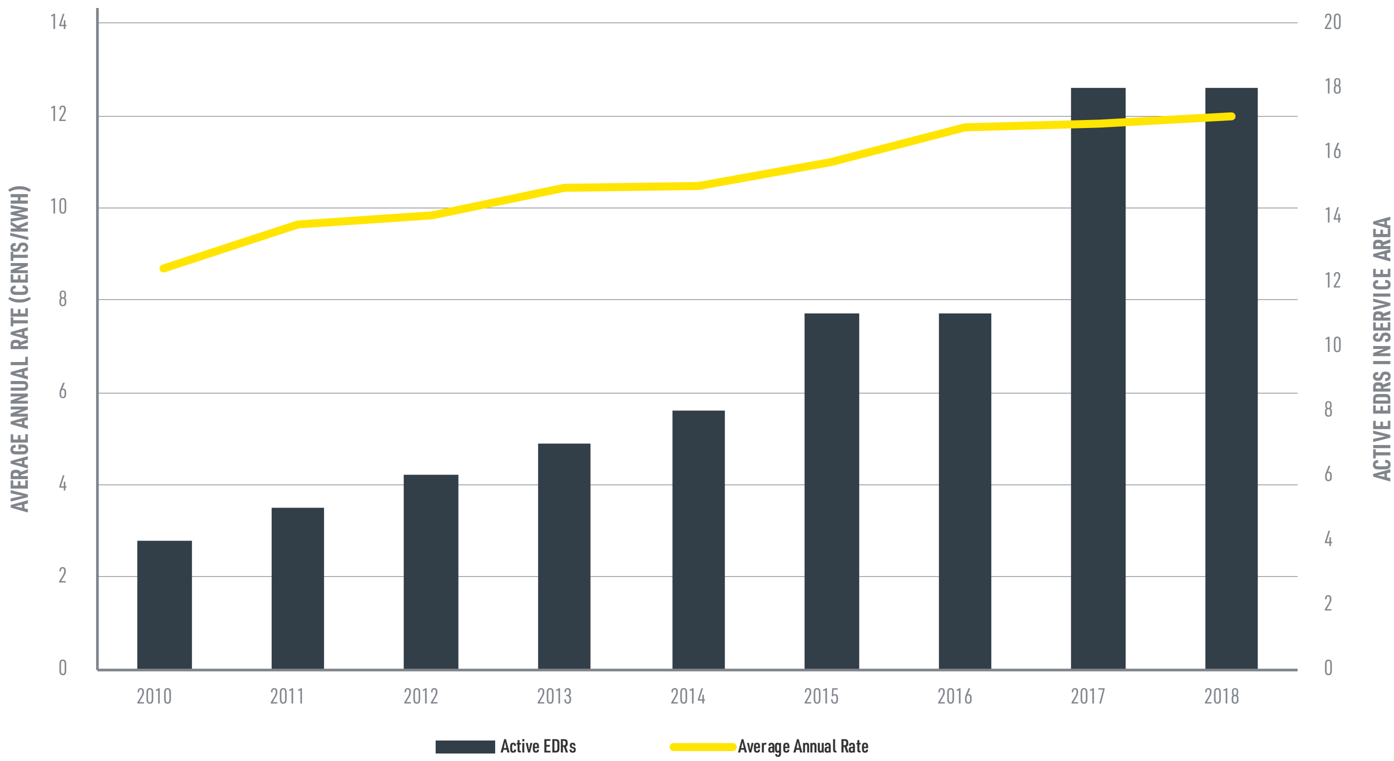


Source: EIA

Since 2015, Evergy Metro, the analyzed utility, 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. Due to the five-year terms defined by most EDR contracts, most EDRs in the sample are still active and data is not yet available to estimate their impact on electric rates for all ratepayers, and will not be until the contracts have expired. 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. **FIGURE 84. Evergy Metro Total**

Customer Rate and EDRs shows the average annual rate for ratepayers across the analyzed utility's customer classes against the total number of active EDRs each year.

FIGURE 84. Evergy Metro Total Customer Rate and EDRs



Source: EIA, RFI

While the Evergy Metro's annual retail electric rates were higher than its peers' from 2015 to 2018, the impact of EDRs cannot be isolated from the available data. In 2018, 18 businesses received discounted rates through EDRs in the analyzed service area. Nonetheless, these contracts represented 2.6% of the utility's non-residential sales, and the extent to which this small percentage of one utility's sales can be used to understand the statewide impacts of EDRs is limited by available data and the relatively short period of time the programs have been in place.

The 24 total businesses that established or expanded operations in the analyzed service areas were required, by contract, to demonstrate that the price of electricity was a material consideration in their operations and that the discounted rate would be necessary to locate or expand facilities in the service area. While criteria vary between utilities, EDRs generate the incentive for businesses to invest in capital and bring jobs to Kansas. Further analysis is necessary to determine the extent to which this increased economic activity can be attributed to EDR programs and what the overall impact on Kansas ratepayers will be once businesses begin to pay the standard rate associated with their customer class.

Due to of the multiple potential benefits of using EDRs to stimulate economic growth and lower the base rate for all customer classes, careful consideration should be given to the optimal discount rates and eligibility criteria so as to maximize such benefits. LEI's report further details the potential benefits and drawbacks of EDRs, as well as the necessity of establishing clear criteria for their administration, including methodology for determining if the EDR is both necessary and sufficient to incent the establishment or expansion of business in a state.[96] The report warns of the potential to crowd out smaller firms that do not meet the established load requirement or provide discounted rates to businesses that would locate in the state with a smaller (or no) discount. Further analysis of the businesses

96 London Economics International, LLC (2020). Study of Retail Rates of Kansas Electric Public Utilities. Kansas Corporation Commission. Retrieved from: https://estar.kcc.ks.gov/estar/ViewFile.aspx/S20200108144309.pdf?Id=1a3a31e5-e38d-4445-aada-1cd0170a7b85

that have entered into EDR contracts with Kansas utilities to date could reveal the efficacy of the incentive and eligibility requirements to generate net benefits for the utilities and their customers. A more thorough analysis of these businesses, their NAICS industry sectors, employment data, and historical electricity usage could highlight where Kansas EDRs have been effective or could improve.

5.9.5.3 PEER ECONOMIC DEVELOPMENT STRATEGIES

Based on reported information, stakeholder feedback and research, Kansas utilities' success in attracting or maintaining customers through their EDR programs appears to vary. Discounts on electricity bills and additional eligibility criteria if the load requirement is not met, including job creation, capital investment, off-peak usage, and the development of new industries and technologies are all criteria that may signal to businesses that the utility has a diverse approach to meeting multiple economic development policy objectives and will offer a competitive location by offering further technical assistance.

Utilities in other states have attracted capital investments and created jobs through comprehensive economic development strategies. A few examples standout:

Hoosier Energy, Indiana: created an economic development website with a comprehensive database of sites and buildings, and multiple financial tools that promote and streamline business development.

Entergy Corporation, Louisiana: offers workforce training grants to communities to target high growth industries, and schools-to-career grants to develop local human capital for the workforce.

Alliant Energy, Iowa: developed a dynamic marketing campaign that promotes economic development initiatives and actively recruits businesses by offering technical support.

LG&E KU Energy LLC, Kentucky: offers zero-interest loans in select communities.

Omaha Public Power District, Nebraska: working towards a goal of 50% retail sales from renewable energy sources and leveraging this goal to attract businesses with their own renewable energy goals.

EDR provisions can be optimized through a comprehensive economic development strategy that combines discounted rates with technical support, marketing, and potential tax breaks or other financial incentives. This multipronged approach has proven successful for other states and could help attract businesses to Kansas – and ultimately benefit the average ratepayer. Recently passed legislation, Kansas Senate Sub for HB 2585, takes a step forward to develop a more comprehensive economic development strategy that provides tax breaks to Coops, creates flexibility for other utility economic development initiatives and associated financing needs, and requires detailed reporting to allow for more thorough impact analysis in the future.

5.9.6 CONCLUSION

Due to data constraints, it is not possible to discretely determine if contract or economic development rates could, over time, lead to lower rates for Kansas utility customers in all classes. Based on the limited data that was collected for this study, it does not appear that economic development rates that were instituted in 2010 materially impacted average rates.

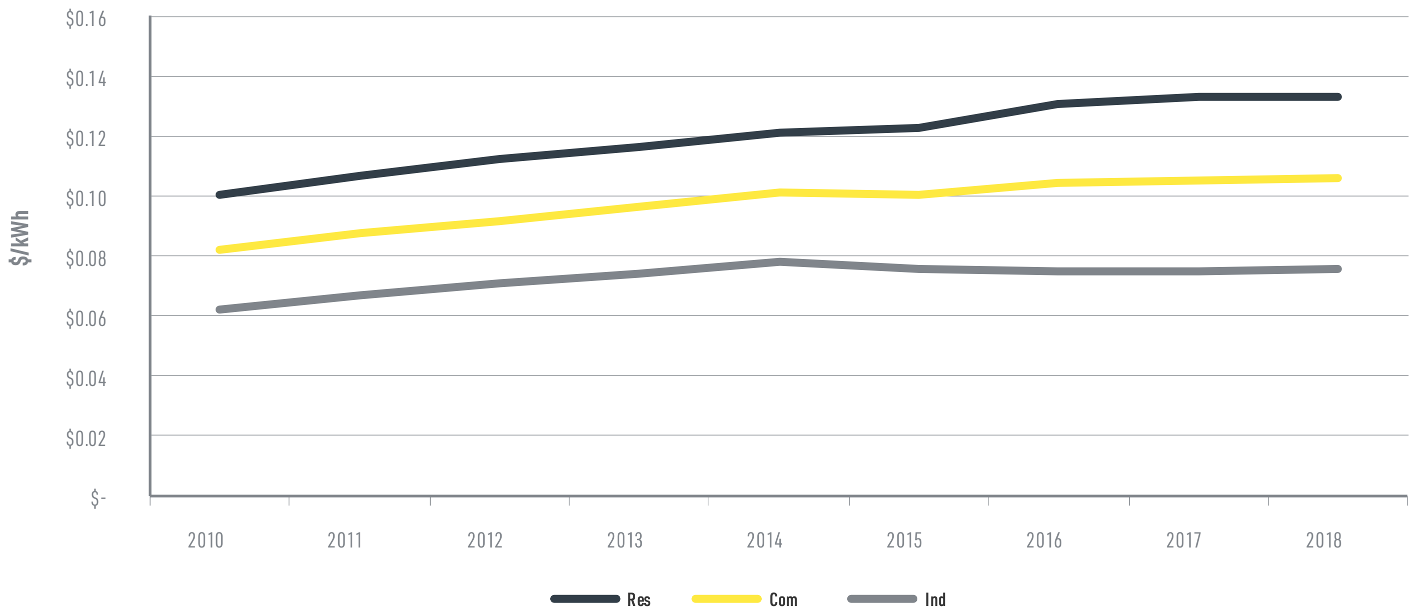
5.10 Cost Recovery on the Basis of Causation

Whether Kansas electric public utilities recover their costs of serving customers from each customer class on the basis of cost causation.

5.10.1 BACKGROUND

As reported in the Part 1 of the Study,[97] retail prices in Kansas have been rising over the last five years, as shown in **FIGURE 85. Retail Price Trends in Kansas**. It is worth noting that industrial rate increases have been largely flat since 2014, while residential and commercial rates have risen, albeit at a lower rate than inflation.

FIGURE 85. Retail Price Trends in Kansas



Source: EIA (2019)

According to the KCC, and Part 1 of the Study, the trend since 2014 is mainly due to changes in production, environmental retrofitting[98] and transmission costs, and flattening demand.[99] The combined impact of these factors explained 60-62% of the cost increases since 2009 for the two largest IOUs.

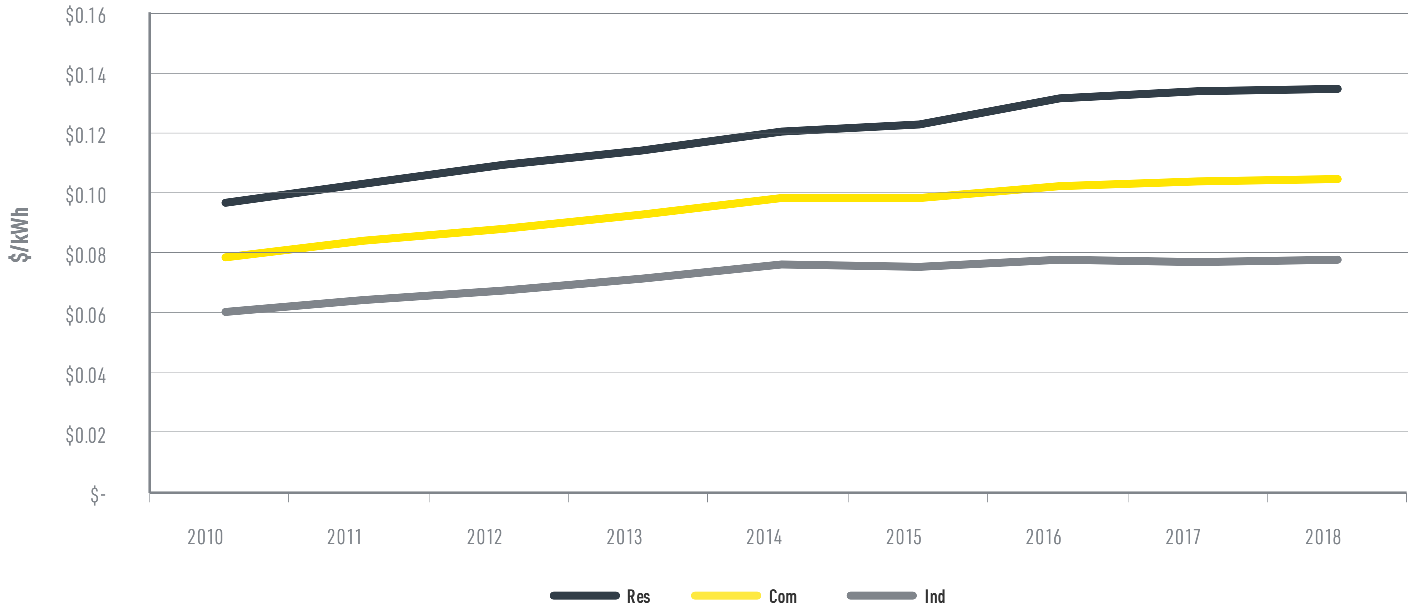
FIGURE 86. Retail Price Trends in Kansas for Investor Owned Utilities - FIGURE 88. Retail Price Trends in Kansas for Cooperative Utilities show the same information broken out by IOU, Muni and Coop customers. At the utility category level (i.e. when looking at each utility), residential rates have been increasing consistently. Industrial rates have been flattening or, in the case of Coops, declining. Finally, commercial rates have been rising for residential for IOU and Muni customers, though at a lesser gradient than residential rates, but have been flattening for Coop customers.

97 London Economics International, LLC (2020). Study of Retail Rates of Kansas Electric Public Utilities. Kansas Corporation Commission. Retrieved from: https://estar.kcc.ks.gov/estar/ViewFile.aspx/S20200108144309.pdf?Id=1a3a31e5-e38d-4445-aada-1cd0170a7b85

98 Retrofitting cost recovery reportedly ended in 2015, according to the Part 1 of the Study.

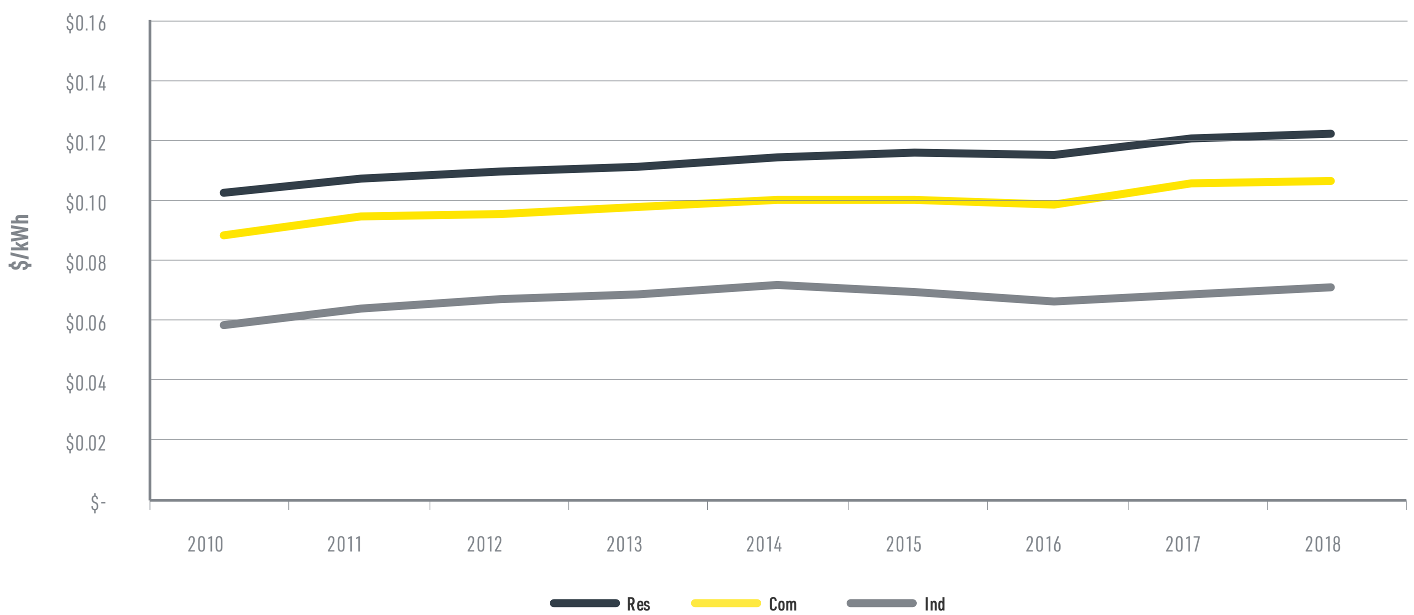
99 London Economics International, LLC (2020). Study of Retail Rates of Kansas Electric Public Utilities, page 47. Kansas Corporation Commission. Retrieved from: https://estar.kcc.ks.gov/estar/ViewFile.aspx/S20200108144309.pdf?Id=1a3a31e5-e38d-4445-aada-1cd0170a7b85

FIGURE 86. Retail Price Trends in Kansas for Investor Owned Utilities



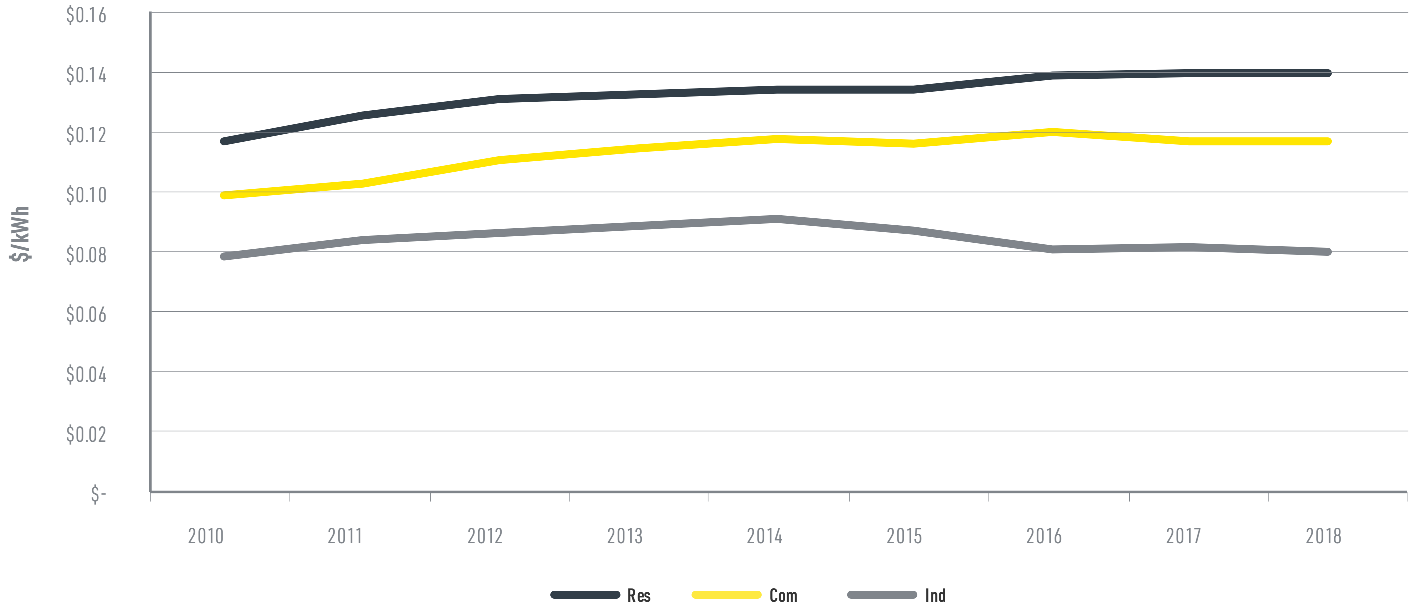
Source: EIA (2019)

FIGURE 87. Retail Price Trends in Kansas for Municipal Utilities



Source: EIA (2019)

FIGURE 88.Retail Price Trends in Kansas for Cooperative Utilities



Source: EIA (2019)

Rising retail prices have naturally caused customers and their advocates to query whether these costs are being allocated on a cost causation basis to ensure one customer class is not subsidizing others. There is particular concern that residential and commercial customers' rising rates, as compared to flattening industrial rates, could be due to costs not being allocated on a cost causation basis.

5.10.1.1 COST CAUSATION

Setting electricity rates on the basis of cost causation is one of the most fundamental principles in rate design, as Part 1 of the Study reported:

> *One of the most fundamental principles of utility rate design is that the customer that causes a cost to be incurred should pay that cost. If cost causation could be perfectly identified, cross-subsidies (either between or within customer classes) could be avoided.*[100]

The study went on to confirm[101] that IOUs and Coops were setting rates on the basis of cost causation:

> *[IOU] cost components are allocated to different customer classes after the KCC staff and other relevant parties conduct a Class COS ("CCOS") study. The CCOS study focuses on determining 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.*[102]

> *In terms of cost causation and avoidance of cross-subsidies, Coops hire a consultant to conduct a cost of service study designed to ensure that customers that cause a cost to be incurred pay for that cost. Therefore, as long as this approach is consistently followed, LEI would conclude that the Coop's ratemaking process conforms to that principle.*[103]

100 London Economics International, LLC (2020). Study of Retail Rates of Kansas Electric Public Utilities, page 51. Kansas Corporation Commission. Retrieved from: https://estar.kcc.ks.gov/estar/ViewFile.aspx/S20200108144309.pdf?Id=1a3a31e5-e38d-4445-aada-1cd0170a7b85

101 The Study did not specifically comment on whether Muni rates were being set on the basis of cost causation.

102 London Economics International, LLC (2020). Study of Retail Rates of Kansas Electric Public Utilities, page 65. Kansas Corporation Commission. Retrieved from: https://estar.kcc.ks.gov/estar/ViewFile.aspx/S20200108144309.pdf?Id=1a3a31e5-e38d-4445-aada-1cd0170a7b85

103 London Economics International, LLC (2020). Study of Retail Rates of Kansas Electric Public Utilities, page 103. Kansas Corporation Commission. Retrieved from: https://estar.kcc.ks.gov/estar/ViewFile.aspx/S20200108144309.pdf?Id=1a3a31e5-e38d-4445-aada-1cd0170a7b85

Under cost causation principles, the above-mentioned production, environmental and transmission costs should be allocated to whomever is using generation and transmission services in proportion to their causation of these costs.

Given rate increases have mainly impacted residential and commercial customers, a key question is whether or not this is due to the application of cost causation principles.

5.10.2 SCOPE AND APPROACH

The project team's approach to answering this question involved the following steps:

- Gathering and analyzing information regarding each utility's cost allocation policies and practices via the RFI process;
- Gathering stakeholder views and materials related to this question and other related issues via stakeholder engagement processes; and
- Developing an independent estimate of cost causation for selected utilities with sufficient information and comparing these estimates to supplied cost allocation outcomes.

5.10.3 INFORMATION GATHERING

Information to answer this question was gathered via the RFI process, meetings with key stakeholders as outlined in **Section 4.2**, and additional background research.

5.10.3.1 SUMMARY OF RFI REQUESTS, RESPONSES, GAPS AND WORKAROUNDS

The RFI was issued with the following information requests related to this question:

4.1: Please send us your cost of service, cost allocation and rate design models from the last five years.

4.2: Please send us your cost of service, cost allocation and rate design studies/reports for the last five years.

4.3: Please send us your 8760 profiles for the last five years by customer rate class.

In other portions of the RFI, additional related information was requested for use as a basis for assessing cost causation:

- System hourly load data;
- Distribution network hourly load data by voltage (i.e. SCADA data);
- Cost of service models, including key inputs, assumptions, and outputs; and
- Customer hourly load, or if unavailable, hourly load by customer class.

Cost of service models and reports were provided by 75% of the utilities, along with accompanying reports.

A key gap in the requested information was the lack of detailed cost of service and customer load profile and billing data needed to split up commercial and industrial costs and loads in order to analyze cost causation and allocation at a more granular level.

Another significant gap was the lack of customer to asset mapping information enabling the build-up of distribution network load profiles by customer segment, voltage and asset level. This made it impossible to independently estimate the contribution of each customer class to distribution cost causation.

Transmission costs were requested by charge, including the CP12 calculations, which would have enabled the project team to identify the contribution to cost by customer class. Instead, a cost contribution workaround was developed, the process of which is detailed in **Section 5.10.4**.

5.10.3.2 STAKEHOLDER FEEDBACK

Stakeholder views varied on the question of whether costs were recovered on the basis of cost causation.

It was suggested that utilities should modify their approach to cost allocation, given that the benefits (to the utility and society in general) provided by some customer classes, like customer generators, are not considered in the cost allocation process.

One stakeholder stated that current cost allocation practices in Kansas are not the "most reasonable or beneficial for the ratepayers." This individual, however, defended the rate case process, because experts on opposing sides tend to compromise on a methodology which lands in the "zone of reasonableness" mandated by court.

Furthermore, a stakeholder explained that the CCOS are based on the concept of cost causation, rendering them valuable to the project team's analysis (though that they should only be regarded as guides).

More specifically, one consumer advocate stated that oil rig rates should be lower than other rates (they currently are the same or higher), because "oil load is the base load for the utilities" and has a less variable load than its counterparts.

5.10.4 KEY FINDINGS AND CONCLUSIONS

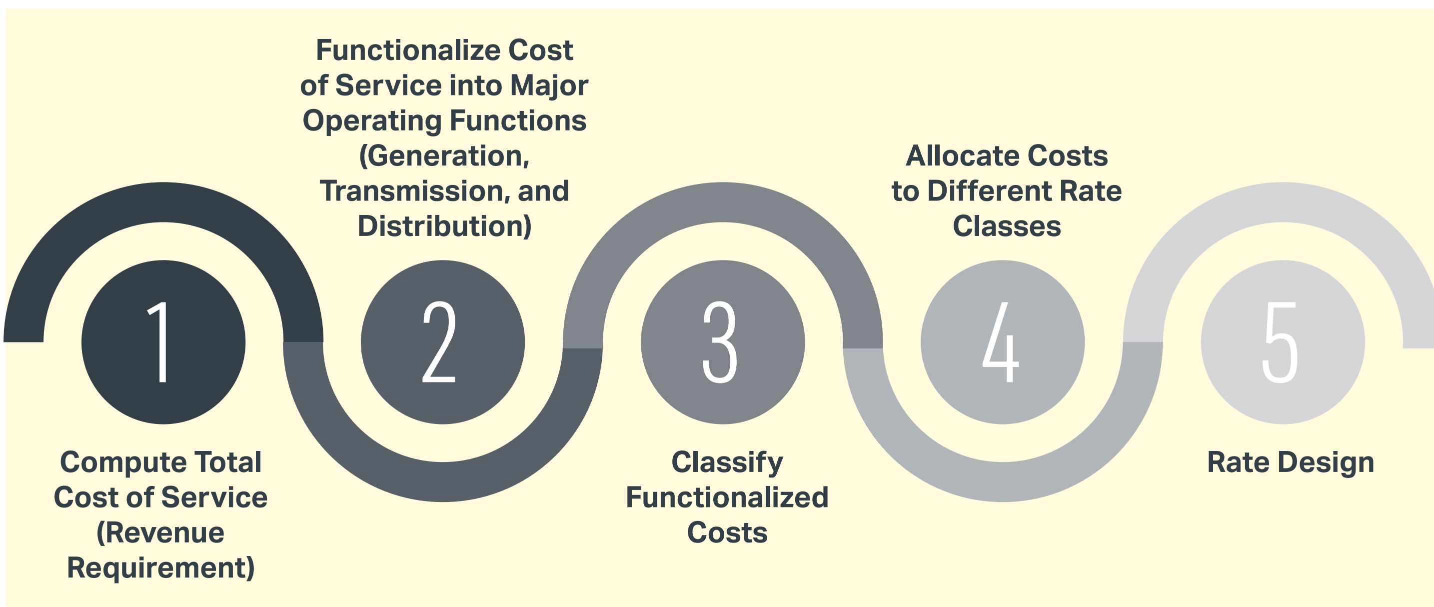
Determining whether Kansas electric public utilities recover their costs of serving customers from each customer class on the basis of cost causation requires understanding the practices and resulting cost allocation of each utility, and then comparing this information to an estimate of each customer class's contribution to costs.

The following sections summarize the project team's analysis, key findings, and conclusions regarding how Kansas utilities recover their costs, whether it is based on cost causation, and whether it can be independently verified.

5.10.4.1 UTILITY COST ALLOCATION PRACTICES

As reported in **Section 5.2**, the KCC's ratemaking process, as shown in **FIGURE 89. Key Steps in the KCC CoS Study Methodology**, includes steps to estimate cost of service and the contribution of each customer class to these costs.

FIGURE 89. Key Steps in the KCC CoS Study Methodology



Source: LEI (2020)[104]

However, it is also important to note that the KCC approves final rate designs on the basis of their being just and reasonable, which requires that they fall into a zone of reasonableness, as discussed in **Section 5.2.4**. Cost recovery can therefore vary in the balancing of investor, ratepayer, and public interests.

104 London Economics International, LLC (2020). Study of Retail Rates of Kansas Electric Public Utilities, page 66. Kansas Corporation Commission. Retrieved from: https://estar.kcc.ks.gov/estar/ViewFile.aspx/S20200108144309.pdf?Id=1a3a31e5-e38d-4445-aada-1cd0170a7b85

Review of the 27 cost of service models provided through the RFI, representing about 75% of the utilities participating in the RFI process, found that they all followed the NARUC methodology, shown in **FIGURE 90. NARUC Steps via DER Rates Manual**, in their allocation of reported costs to each customer class.

FIGURE 90. NARUC Steps via DER Rates Manual

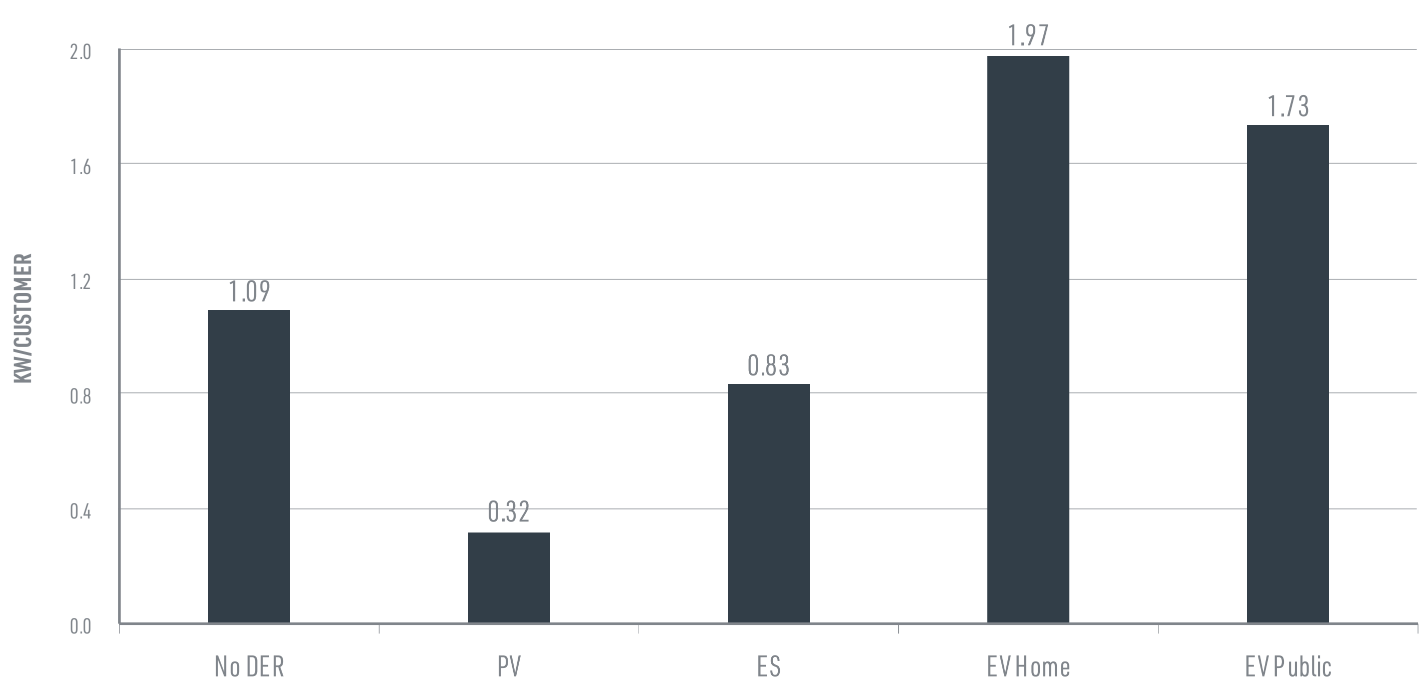
FUNCTIONALIZATION	CLASSIFICATION	ALLOCATION
Production	Demand	Residential
Transmission	Energy	Commercial
Distribution	Customer	Industrial
Customer Service		Other
Administrative and General		

Source: KCC Rate Study (2018)

It should be noted that the frequency at which cost of service studies are updated appears to be inconsistent, with one study being over ten years old. Older studies are less likely to reflect each customer class's contribution to cost causation, as these contributions change over time, especially with increasing DER adoption.

An example of a residential customer's contribution to their transmission zone CP12, based on their adoption of rooftop solar PV, battery storage, and EVs is reported in **FIGURE 91. Estimated CP12 per Residential Customer by Adopted DER - KCP&L.**[105] It shows a significant difference compared to those not adopting each of these types of DER.

FIGURE 91. Estimated CP12 per Residential Customer by Adopted DER - KCP&L



Source: Energeia

105 More information about the modeling method and key assumptions can be found in see APPENDIX C Cost of Service Modelling Methodology.

Based upon this information, the project team has reached the conclusion that Kansas utilities are recovering their generation and transmission costs on the basis of cost causation. However, the basis used may be out of date, and is likely to become more inaccurate over time given changes in customer load shapes and cost factors. Analysis conducted by the project team (shown below) suggested significant variation between some utility cost allocation outcomes and our independent estimate of cost causation factors using 2019 data.

5.10.4.2 COST CAUSATION BY CUSTOMER CLASS

An independent estimate of customer class contribution to each utility's cost to serve was developed for the largest cost categories using the following methodologies:

- **Generation Costs:** generation cost causation was estimated by settling the customer class hourly load profile against the SPP delivery point[106] for the given utility in 2019.
- **Transmission Costs:** transmission cost causation was estimated by estimating the CP12[107] contribution of each customer class using 2019 data.[108]
- **Distribution Costs:** as explained in **Section 5.10.3**, an estimate of each customer class's contribution to non-coincident peak demand could not be reached.

The results of our comparative cost causation and cost allocation analysis is reported in **FIGURE 92. Generation Utility Allocation vs. SPP Settlement Costs (Estimated Causation) by Utility Type** by cost category.

GENERATION COSTS

FIGURE 92. Generation Utility Allocation vs. SPP Settlement Costs (Estimated Causation) by Utility Type reports the project team's cost to serve estimates against the utility cost allocation for generation costs. At the consumption-weighted state level, the analysis shows residential customers paying slightly more, and non-residential customers paying slightly less, than the estimated cost to serve using 2019 SPP pricing and load data, as well as pricing assumptions that were made in the absence of detailed 2019 SPP settlement costs (due to confidentiality concerns).

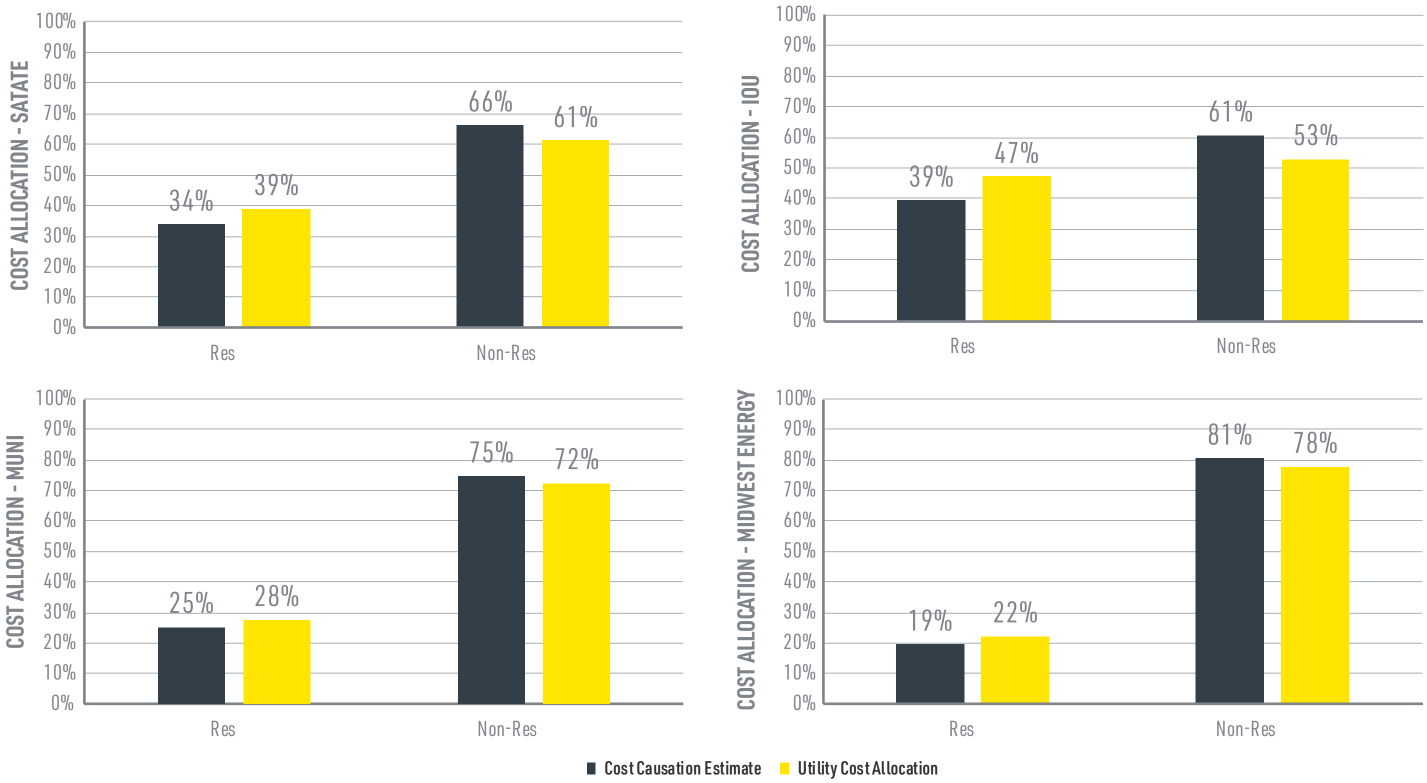
Utility category-level analysis shows similar outcomes in terms of utility cost allocation for residential customers being slightly higher than the project team's estimate, and non-residential customers being slightly lower. Differences in the proportion of costs between residential and non-residential customers reflects differences in the level of residential and non-residential loads across utility categories.

106 Settlement prices were equally weighted, as load weightings were not provided by SPP due to confidentiality requirements

107 CP12 refers to the monthly maximum demand in the transmission zone.

108 The assumed mapping of utility transmission to transmission system zones is reported in **see APPENDIX E Industry Summaries**

FIGURE 92. Generation Utility Allocation vs. SPP Settlement Costs (Estimated Causation) by Utility Type



Source: EIA (2018), Utility Cost of Service Models, Energeia

In other words, the independent cost causation-based analysis carried out for this project suggests that generation cost allocations in utility cost of service models are broadly consistent with 2019 SPP settlement costs. Explanations for this variation include the use of different base years, SPP price weighting, and allocation for reasons other than cost causation.

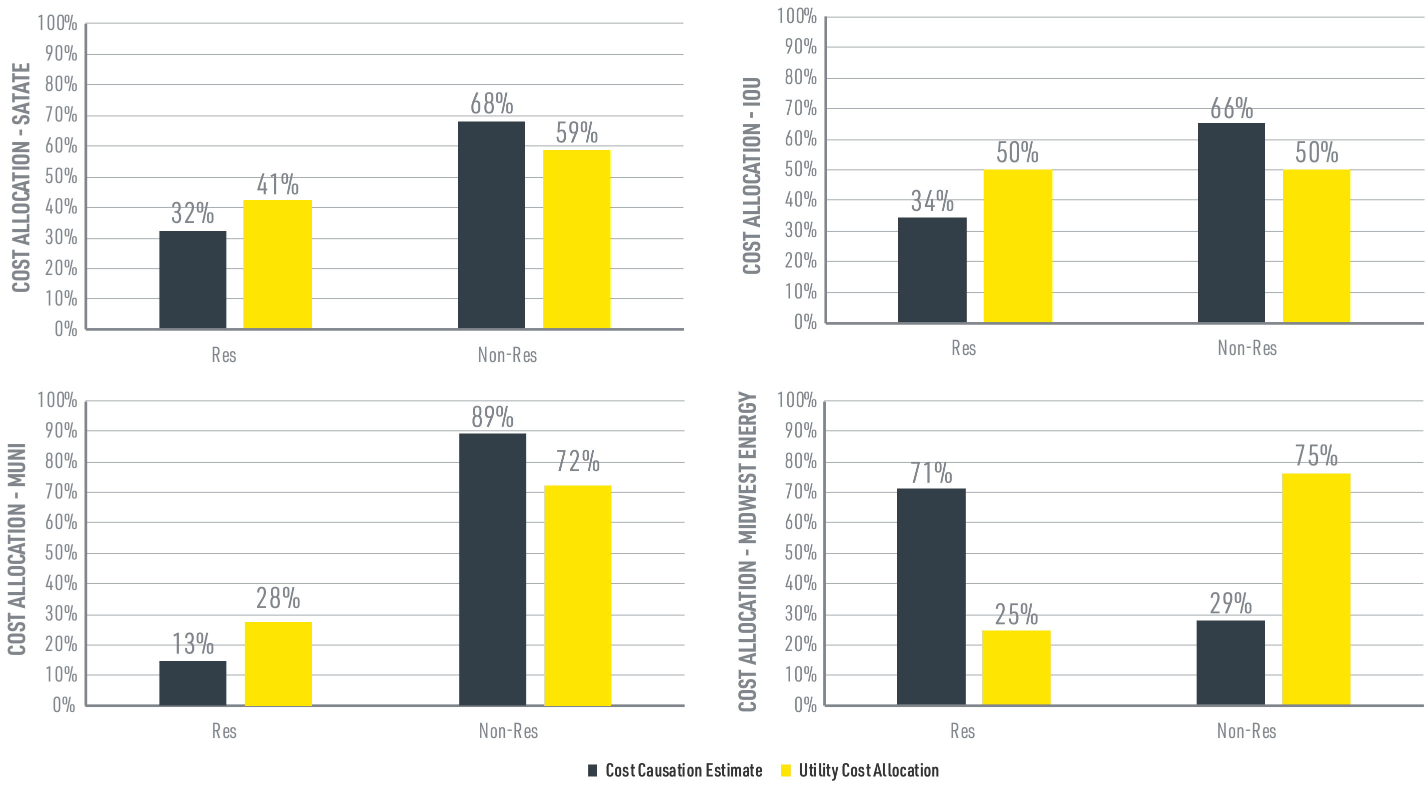
Based on this analysis, the project team has reached the conclusion that there are differences between estimated utility generation cost to serve and the corresponding cost allocation by customer class. However, it is important to note the significant caveats underpinning these conclusions, including differences in inputs (e.g. SPP pricing year, load growth) and/or differences in SPP price weighting due to lack of data.

TRANSMISSION COSTS

FIGURE 93. Utility Allocation vs. Estimated Transmission Charges (Estimated Causation) by Utility Type reports on the project team's cost to serve estimates versus the utility cost allocations for transmission costs. This analysis shows a relatively close correlation between estimated transmission cost of service and utility cost allocation practices at the state level.

However, at the utility-type level, while the alignment of cost of service and utility cost allocation is relatively close for IOUs, there is a significant variation for Munis and Midwest Energy. Muni transmission cost recovery from residential customers is significantly lower, and Midwest Energy cost recovery is significantly higher, than the project team's estimated cost to serve, based on residential load contribution to CP12 in their respective estimated transmission zones.

FIGURE 93. Utility Allocation vs. Estimated Transmission Charges (Estimated Causation) by Utility Type



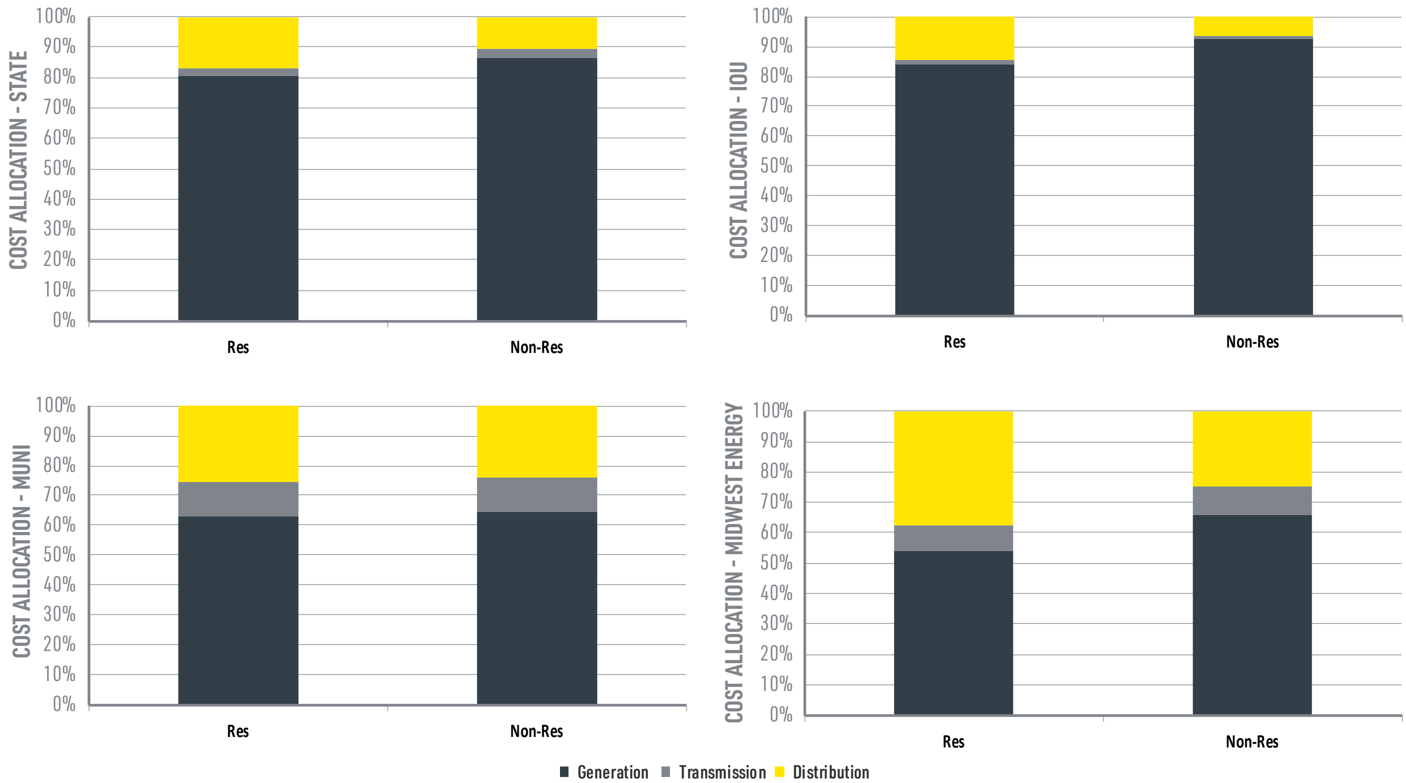
Source: EIA (2018), Utility Cost of Service Models, Energeia

Based on the analysis above, the project team concludes there are differences between utility and project team estimates of transmission cost causation by customer class for residential and non-residential customers, particularly in the case of Midwest Energy, which show a significant variation. Again, these results may be explained by key differences in the inputs and assumptions made such as load year and growth, and in methodology, including the use of a different transmission zone peak period.

DISTRIBUTION COSTS

Distribution costs represent the second largest cost category after generation costs, and a higher share of total costs for residential customers in comparison to non-residential customers, as shown in **FIGURE 94. Distribution of Electricity Costs by Customer Class and Utility Type**. With respect to utility type, distribution costs account for a larger share of Muni and Midwest Energy rates than IOU rates.

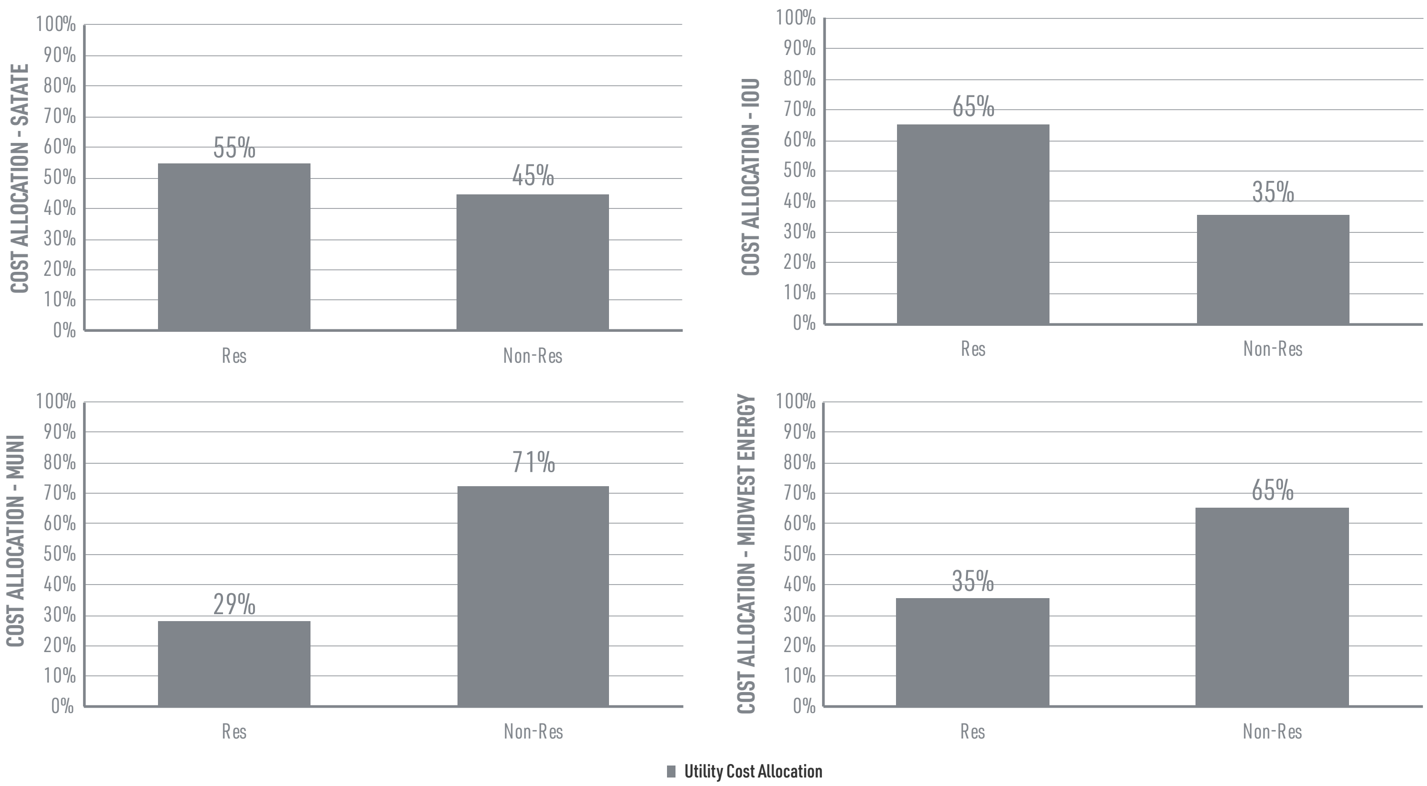
FIGURE 94. Distribution of Electricity Costs by Customer Class and Utility Type



Source: Utility Cost of Service Models, Energeia

FIGURE 95. Utility Cost Allocation of Distribution Charges by Utility Type reports on the allocation of distribution costs between customer classes by utility type. In the absence of data on customer contribution to each sub-network's costs, or the splitting out of each sub-network's cost to serve in the cost allocation models and studies, it was not possible to independently develop a reasonable estimate of each customer's distribution network cost to serve.

FIGURE 95. Utility Cost Allocation of Distribution Charges by Utility Type



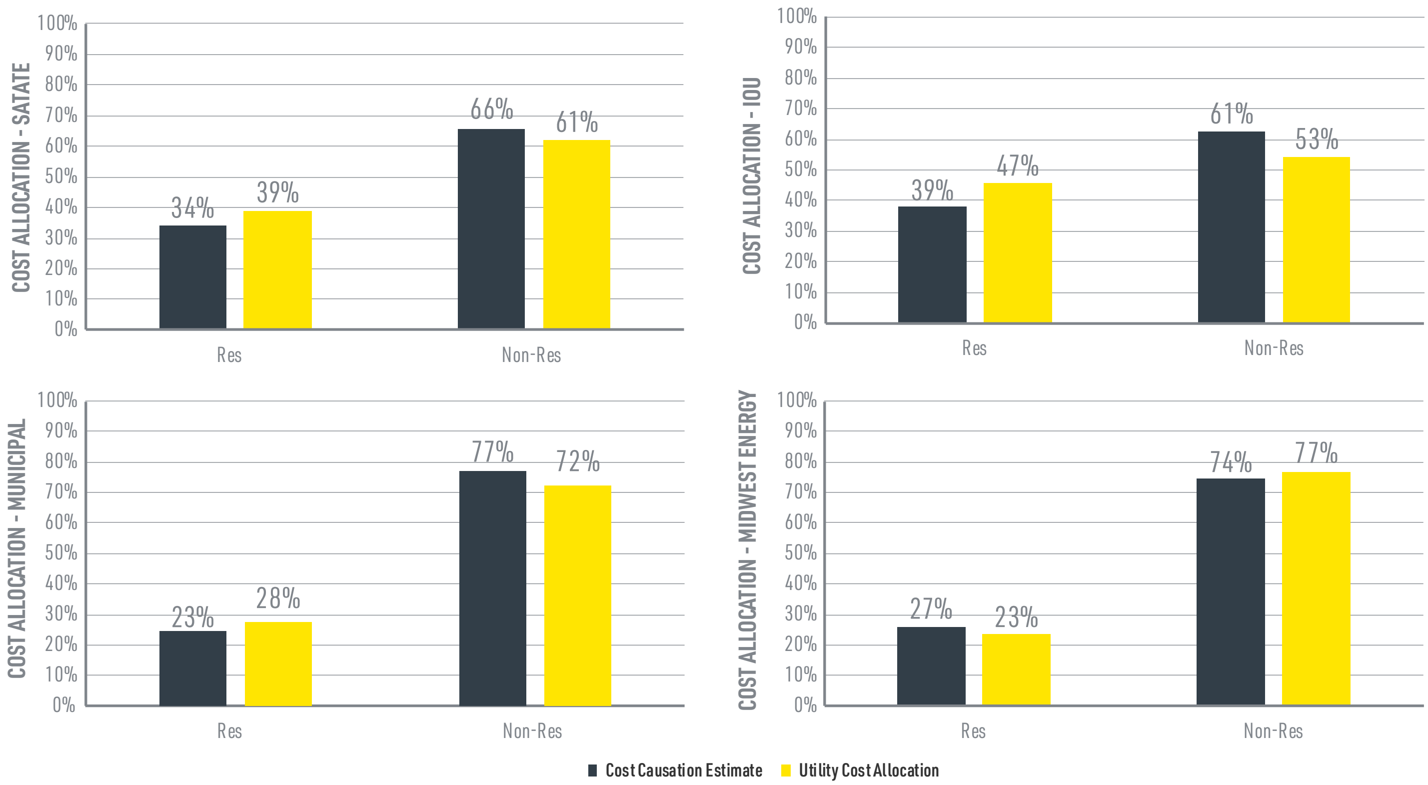
Source:Utility Cost of Service Models

The project team is unable to conclude whether Kansas utility distribution cost allocations are consistent with independently estimated cost causation factors due the lack of data required to reach an estimate at the customer class, network voltage, and asset levels.

TOTAL COSTS

FIGURE 96. Utility Cost Allocation of Total Charges by Utility Type depicts the combined generation and transmission cost to serve estimates versus utility cost allocations. This largely follows the generation cost allocation analysis, as generation costs represent a far greater share of total utility costs than transmission. Overall, this analysis shows utility cost allocation to be +/- 15% of estimated cost causation factors at the state level, and a maximum of +/- 22% of estimated factors in the case of Midwest Energy residential customers.

FIGURE 96. Utility Cost Allocation of Total Charges by Utility Type



Source: EIA (2018), Utility Cost of Service Models, Energeia

FIGURE 96. Utility Cost Allocation of Total Charges by Utility Type does not include distribution costs because the project team has not been able to develop a reasonable proxy for cost causation with the data received. Contribution to non-coincident peaks and cost of service by voltage level are needed to complete this analysis.

Based on this analysis, the project team has reached the conclusion that there is up to a 22% difference between the utility estimated cost causation for generation and transmission by customer class, as compared to the independent analysis carried out for this Study.

To ensure cost allocation does not vary from cost causation factors due to the use of out of date information, is recommended that cost of service study updates be conducted periodically, depending on the expected rate of change in cost causation factors.

5.11 The Impact of Cyber and Physical Security and Grid Stabilization Efforts on Rates

How cyber and physical security and grid stabilization efforts have affected, or are projected to affect, electric public utility rates.

5.11.1 BACKGROUND

As security threats against major infrastructure systems – such as those operated by Kansas utilities – become increasingly sophisticated, the systems required to maintain grid stability and service reliability have similarly grown in their complexity. Utilities must balance their security expenditures to ensure they are sufficiently protected, but not placing undue financial burden on their ratepayers.

The North American Electric Reliability Corporation (NERC) functions as the Electric Reliability Organization (ERO) for the Federal Energy Regulatory Commission (FERC), as designated on July 20, 2006. As the ERO, NERC has a mission to improve the reliability and security of the Bulk-Power System across the United States, Mexico, and Canada. This mission includes the development, monitoring, and enforcement of Reliability Standards in addition to helping the industry through leadership and education. Within NERC, the Critical Infrastructure Protection Committee (CIPC) was developed to coordinate and develop standards related to physical and cyber security.

The Critical Infrastructure Protection (CIP) Standards for cyber and physical security include 91 total standards, including 74 inactive, one pending inactive, 11 subject to enforcement, and five subject to future enforcement (as of June 25, 2020). The currently subject to enforcement CIP Standards include CIP-002 through CIP-011 for cyber security and CIP-014 for physical security.[109] **TABLE 22. CIP Standards** summarizes the CIP Standards that are currently subject to enforcement.

TABLE 22. CIP Standards

CIP Standard Reference	CIP Standard Name
CIP-002-5.1a	Cyber Security - BES Cyber System Categorization
CIP-003-8	Cyber Security - Security Management Controls
CIP-004-6	Cyber Security - Personnel & Training
CIP-005-5	Cyber Security - Electronic Security Perimeter(s)
CIP-006-6	Cyber Security - Physical Security of BES Cyber Systems
CIP-007-6	Cyber Security - System Security Management
CIP-008-5	Cyber Security - Incident Reporting and Response Planning
CIP-009-6	Cyber Security - Recovery Plans for BES Cyber Systems
CIP-010-2	Cyber Security - Configuration Change Management and Vulnerability Assessments
CIP-011-2	Cyber Security - Information Protection
CIP-014-2	Physical Security

Source: NERC

109 NERC (n.d.). CIP Standards. Retrieved from: https://www.nerc.com/pa/Stand/Pages/CIPStandards.aspx

5.11.2 SCOPE AND APPROACH TO THE QUESTION

The project team's approach to determining the cost impact of Kansas utility security spending included:

- Analyzing utility security spending data obtained through a formal RFI;
- Understanding, at a high level, projected trends in utility security spending from discussions held in stakeholder interviews; and
- Conducting research into cost-saving mechanisms Kansas and peer state utilities are employing to manage security expenditures and mitigate the burden on ratepayers.

5.11.3 INFORMATION GATHERING

5.11.3.1 SUMMARY OF RFI REQUESTS, RESPONSES, GAPS AND WORKAROUNDS

At the beginning of the Study, the project team issued an RFI with the following requests pertaining to this matter:

11.1: Please send us five year historical and planned capital and operating costs related to physical security efforts by type.

11.2: Please send us any studies undertaken related to physical security needs and costs prepared (whether or not implemented) or utilized in the last five years.

11.3: Please send us five year historical and planned capital and operating costs related to cyber security efforts by type.

11.4: Please send us any studies undertaken related to cyber security and costs prepared (whether or not implemented) or utilized in the last five years.

11.5: Please send us five year historical and planned capital and operating costs related to any other grid stabilization efforts.

11.6: Please send us any studies undertaken related to grid stabilization needs and costs prepared (whether or not implemented) or utilities in the last five years.

The degree of detail in utility responses were highly variable, with some utilities unable to provide any data; as such, analysis was run on a relatively small number of utilities. Further review of the RFI responses revealed significant alignment in how physical and cyber security dollars are spent, with funds dedicated toward personnel managing internal security programs, staff security awareness training, third party assessments of security infrastructure performance, as well as the following category-specific line items:

- **Physical security:** building access control systems and locks, lighting and fencing along the facility perimeter, video surveillance, and emergency notification systems.
- **Cybersecurity:** firewall installation and maintenance, liability insurance, and annual subscriptions for antivirus/malware software, VPN keys, and multi-factor identification.

Despite these overlaps, there were notable inconsistencies in how utilities reported grid stabilization spending. The most common interpretation of the term grid stabilization, both from utilities and other stakeholders engaged throughout the project, was the work necessary to maintain service reliability with changes in generation, such as underfrequency load shedding – especially as volatile generation resources (e.g. renewables) are increasingly integrated to the grid. Some utilities, though, perceived grid stabilization as including all expenditures that would be logged as part of a Construction Work Plan (CWP), which includes line clearance, pole testing, and other transmission and distribution line operations and maintenance activities.

5.11.3.2 STAKEHOLDER FEEDBACK

All utilities and stakeholders engaged agreed that security spending is expected to increase. Furthermore, utilities noted that, especially with respect to cybersecurity protections, spending has significantly shifted from capital (capex) to operating expenditures (opex). Stakeholders also provided background and information relating to various KCC proceedings regarding security.

5.11.3.3 POLICY RESEARCH

Utilities faced with increasing security costs – both holistically and on an annual basis – may be allowed to recover those costs. Two such cost recovery mechanisms, cost trackers and single-issue riders, are currently implemented by utilities in Kansas and its peer states.[110] [111]

COST TRACKER

KCC Docket No. 15-WSEE-115-RTS established a grid security tracker such that Westar (now part of Evergy) could track and defer non-labor operations and maintenance costs related to protection of infrastructure that were accrued between rate cases and exceeded the costs already accounted for in its base rates. The KCC had previously approved a similar CIP/cybersecurity cost tracker for KCP&L in Docket No. 15-KCPE-116-RTS.

In its 2018 rate case, Westar reported that it had deferred $2,137,485 in grid security costs since the tracker had been established, and requested that it be allowed to recover these costs over a three-year period.[112] The final settlement allowed Westar to recover the costs over a five-year period. Interviews with stakeholders involved in the rate case proceedings revealed that there was little dispute over the value of costs to be deferred, only the amortization period, and that the tracker is generally considered to have served its intended purpose of helping the utility manage unforeseen increases in spending in order to remain sufficiently protected against security threats.

The tracker was scheduled to sunset at the time of the utility's first rate case filing on or after January 1, 2020; the deadline would only be extended should the utility demonstrate a need for the tracker to remain in place. Per the terms of Westar and KCP&L's merger, Evergy is not permitted to file a full rate case prior to January 1, 2023, at which point they will determine if they would like to seek an extension.[113]

In advance of Evergy's rate case in 2023, the KCC may consider how expanding the use of a tracker to other utilities in Kansas would align with State resilience objectives and reduce the burden of increasing security costs on ratepayers.

SINGLE ISSUE RIDER

In 2011, the Texas Legislature amended Texas Administrative Code (TAC) 16 § 25.243 to create a single-issue rider for distribution system investments, the Distribution Cost Recovery Factor (DCRF), which would mimic an existing rider for incremental recovery of transmission system investments and encompass security expenditures. Utilities providing either wholesale or retail distribution may apply to adopt a DCRF. Applications are only permitted outside of traditional ratemaking proceedings; the rate of return determined in the utility's most recent ratemaking proceeding is applied to the DCRF at the time of application.[114]

Utilities may file to change their DCRF rate of recovery as frequently as once per year, though may not submit more than four filings between consecutive ratemaking cases. The prudency and compliance of investments recovered through the DCRF are evaluated at the utility's subsequent rate case. If investments are found to be imprudent or non-compliant the utility must refund the resulting revenues and pay ratepayers a carrying charge assessed on such revenues. The carrying charge is determined using the same rate of return applied to the DCRF.

Single-issue riders remain a contentious issue in the industry, as reflected in the analysis LEI conducted for Part 1 of the Study. LEI found that, over the past ten years, the total cost of single-issue riders to investor-owned utility ratepayers were, on average, increasing more quickly as compared to base rates.[115] Other common critiques of single-issue riders include the time and cost of proceedings (to utilities, regulators, and intervenors), and that restricting the lens of analysis to one issue may eliminate the opportunity to identify synergies or efficiencies with other line items.

110 Shea, D. (2020). Cybersecurity and the Electric Grid: The State Role in Protecting Critical Infrastructure. National Conference of State Legislatures. Retrieved from: https://www.ncsl.org/Portals/1/Documents/energy/Cybersecurity-Electric-Grid_v04.pdf

111 James, M., McGovern, A., Somelofske, J., Valentine-Fossum, C., and Zweifel, K. (2019). Improving the Cybersecurity of the Electric Distribution Grid: Identifying Obstacles and Presenting Best Practices for Enhanced Grid Security, Section 6. Institute for Energy and the Environment, Vermont Law School. Retrieved from: https://www.vermontlaw.edu/sites/default/files/2019-04/VLS_IEE_Electricity_Distribution_Grid_Cybersecurity_Phase_1%20Report%5B1%5D.pdf

112 KCC Docket No. 18-WSEE-328-RTS

113 KCC Docket No. 18-KCPE-095-MER

114 If the rate case was more than three years prior to the application, the rate of return is determined by a formula defined in 16 TAC § 25.243(d)(1).

115 London Economics International, LLC (2020). Study of Retail Rates of Kansas Electric Public Utilities, pages 74-75. Kansas Corporation Commission. Retrieved from: https://estar.kcc.ks.gov/estar/ViewFile.aspx/S20200108144309.pdf?Id=1a3a31e5-e38d-4445-aada-1cd0170a7b85

Still, single-issue riders are slowly becoming a more prominent solution for proactively addressing security expenditures, specifically. Prior to Texas' implementation of the DCRF, the Ohio State Legislature introduced a Distribution Investment Rider in 2007.[116] More recently, in 2019 the Virginia State Legislature enacted a bill that allows utilities to petition the regulatory authority for a rate adjustment for distribution-related investments.[117] The KCC might consider joining these states in pursuit of an innovative cost-mitigation solution.

Either of these mechanisms may be introduced in tandem with other administrative policies recommended by industry experts to further help both utilities and regulators navigate the rapidly changing security landscape, such as instituting data reporting and auditing requirements.[118]

5.11.4 KEY FINDINGS AND CONCLUSIONS

To determine the level of cost impact resulting from security needs, the expenditures reported for each of the major categories – physical security, cybersecurity, and physical security – were divided by the utility's revenue (used as a proxy for the rate base). The following assumptions were made to facilitate the analysis:

- Physical security and grid stabilization capital expenditures were amortized over a 20-year period and cybersecurity expenditures over a five-year period, with a weighted average cost of capital (WACC) of 7%.
- If a total expenditure was given for a multi-year period and not further broken down on a year-to-year basis, the lump sum was either assigned to the first year of the designated period or averaged over across the entire timeframe, whichever approach best aligned with the accompanying narrative describing the project.
- If a utility did not specifically delineate capex and opex in their RFI response (and it could not be easily determined), an average capex/opex ratio from a representative utility was used to separate the expenditure types.

The minimum and maximum level of cost for each spend category in 2018, the year for which there was most complete data (accounting for amortizations, etc.), is presented in **TABLE 23. Security Expenditure Level of Cost (2018)**. Physical and cybersecurity expenditures are relatively consistent amongst the utilities that were included in the model, and do not assume significant proportion of revenue. The variation in the grid stabilization results was driven by utilities' differing interpretation of this terminology. The utilities that took grid stabilization to encompass all activities promoting service reliability, such as those that responded to the RFI with a CWP, returned higher than average levels of cost.

TABLE 23.Security Expenditure Level of Cost (2018)

	Minimum	Maximum	Average
Physical Security	0.01%	2.72%	0.70%
Cybersecurity	0.02%	1.00%	0.22%
Grid Stabilization	0.15%	12.87%	6.38%

Source: EIA, Kansas Utilities

To translate these level of cost estimates into rate impacts for each major customer class, the percent of total revenue allocated to each category was multiplied by the proportion of total revenue generated by each class. The results of this analysis are summarized in **TABLE 24. Security Expenditure Rate Impact by Customer Class (2018)**. Based on the available data, physical security and cybersecurity appear to, at most, account for less 1.5% of residential and commercial rates, and a fraction of a percent of industrial rates. Because of the broader implications of grid stabilization, these costs have higher rate impact on all customer classes.

116 Ohio Senate Bill 221 (2007-2008 Legislative Session)

117 Virginia Senate Bill 966 (2018-2019 Legislative Session)

118 Shea, D. (2020). Cybersecurity and the Electric Grid: The State Role in Protecting Critical Infrastructure, page 5. National Conference of State Legislatures. Retrieved from: https://www.ncsl.org/Portals/1/Documents/energy/Cybersecurity-Electric-Grid_v04.pdf

TABLE 24. Security Expenditure Rate Impact by Customer Class (2018)

		Minimum	Maximum	Average
Physical Security	Residential	0.00%	1.33%	0.34%
	Commercial	0.00%	1.24%	0.14%
	Industrial	0.00%	0.31%	0.04%
Cybersecurity	Residential	0.01%	0.69%	0.14%
	Commercial	0.01%	0.22%	0.05%
	Industrial	0.00%	0.10%	0.03%
Grid Stabilization	Residential	0.08%	8.83%	3.34%
	Commercial	0.04%	4.63%	1.85%
	Industrial	0.03%	4.11%	1.25%

Source: EIA, Kansas Utilities

Although these results indicate that, for the utilities included in the model, physical and cybersecurity expenditures may not currently have a significant impact on rates, with the expected upward trend in spending, the State may wish to proactively consider instituting a state-wide cost recovery mechanism to provide formal guidance as to what efficient security spending may entail and more frequent oversight into the prudency of security investments – as well as allow utilities to recover costs in a timely manner. In doing so, it must first determine the outcomes it wishes to achieve, and then it may begin to evaluate the feasibility of implementing a cost tracker or single-issue rider, specifically, or any other innovative, industry-recommended financing mechanism outside the scope of this Study.

To facilitate this process, as well as additional information exchange between the Legislature, regulatory authority, and utilities, the State may consider adopting security data reporting standards, as has been done in Colorado[119] and Texas.[120] With this new data, the State can better anticipate how each of these mechanisms may capture benefits aligned with the State's stated objectives, as well as reduce the security cost burden passed onto Kansas ratepayers.

119 Colorado Senate Bill 19-236

120 Texas Senate Bill 936 (2019-2020 Legislative Session)

5.12 The Value of an Resource Planning Process Requiring State Regulatory Approval

The value of a utility integrated resource planning process that requires state regulatory approval.

5.12.1 BACKGROUND

Integrated resource plans (IRPs) are currently leveraged in 33 states, with the fundamental goal of promoting utility consideration of new resource alternatives – including both supply- and demand-side resources – to reliably meet generation needs at the least possible cost to both the utility and their ratepayers.

In Part 1 of the Study, LEI recommended instituting a state-regulated IRP process in Kansas, believing it would be beneficial in promoting state policy objectives, reducing regulatory burden through synchronizing utility ratemaking filing cycles, encouraging proactive mitigation of costs that may lead to an increase in rates, and ensuring utility load forecasts are conducted using common assumptions and consistent methodology and are thus more easily interpretable.[121]

5.12.2 SCOPE AND APPROACH

The project team's research builds off LEI's analysis and works to further evaluate the viability of these potential benefits, assess the anticipated costs to utilities in adhering to the guidelines of a state-wide IRP process, and ultimately recommend a course of action for the State Legislature and KCC.

All recommendations are based on the team's review of:

- The guidelines for current resource planning processes followed by Kansas utilities;
- Industry-recognized best practices for IRPs, including peer state IRP guidelines; and
- Additional data gathered through the RFI, interviews with utilities and representatives from their joint-action agencies, and discussions with stakeholders.

5.12.3 BACKGROUND RESEARCH

The project team's preliminary background research sought to better understand the components of an IRP and how these components may be addressed in state-defined guidelines – and more specifically, the work Kansas utilities currently perform with respect to each of these components. Sources consulted included:

- Regulatory Assistance Project (RAP)[122] [123], U.S. Environmental Protection Agency[124], and Lawrence Berkeley National Lab[125] reviews of utility IRP practices across the nation; and
- RAP[126] and Brattle Group[127] recommendations as to how current IRP guidelines may evolve to better fit utilities' future needs.

121 London Economics International, LLC (2020). Study of Retail Rates of Kansas Electric Public Utilities, Section 6.1.2. Kansas Corporation Commission. Retrieved from: https://estar.kcc.ks.gov/estar/ViewFile.aspx/S20200108144309.pdf?Id=1a3a31e5-e38d-4445-aada-1cd0170a7b85

122 Farnsworth, D. (2015). Integrated Resource Planning: Some Issues and Methods [PowerPoint slides]. Regulatory Assistance Project. Retrieved from: https://www.raponline.org/wp-content/uploads/2016/05/farnsworth-irp.pdf

123 Wilson, R., and Biewald, B. (2016). Best Practices in Electric Utility Integrated Resource Planning: Examples of State Regulations and Recent Utility Plans. Regulatory Assistance Project. Retrieved from https://www.raponline.org/wp-content/uploads/2016/05/rapsynapse-wilsonbiewald-bestpracticesinirp-2013-jun-21.pdf

124 United States Environmental Protection Agency (2015). Energy and Environment Guide to Action: State Policies and Best Practices for Advancing Energy Efficiency, Renewable Energy, and Combined Heat and Power, Chapter 7.1. Retrieved from https://www.epa.gov/sites/production/files/2017-06/documents/gta_chapter_7.1_508.pdf

125 Wilkerson, J., Larsen, P., Barbose, G. (2014). Survey of Western U.S. Electric Utility Resource Plans. Energy Policy, 66, 90–103. doi: 10.1016/j.enpol.2013.11.029

126 Seidman, N. (2019). Why Integrated Resource Planning Matters for Air Quality [PowerPoint slides]. Regulatory Assistance Project. Retrieved from: https://www.raponline.org/wp-content/uploads/2019/04/rap_seidman_nacaa_irp_2019_apr_4.pdf

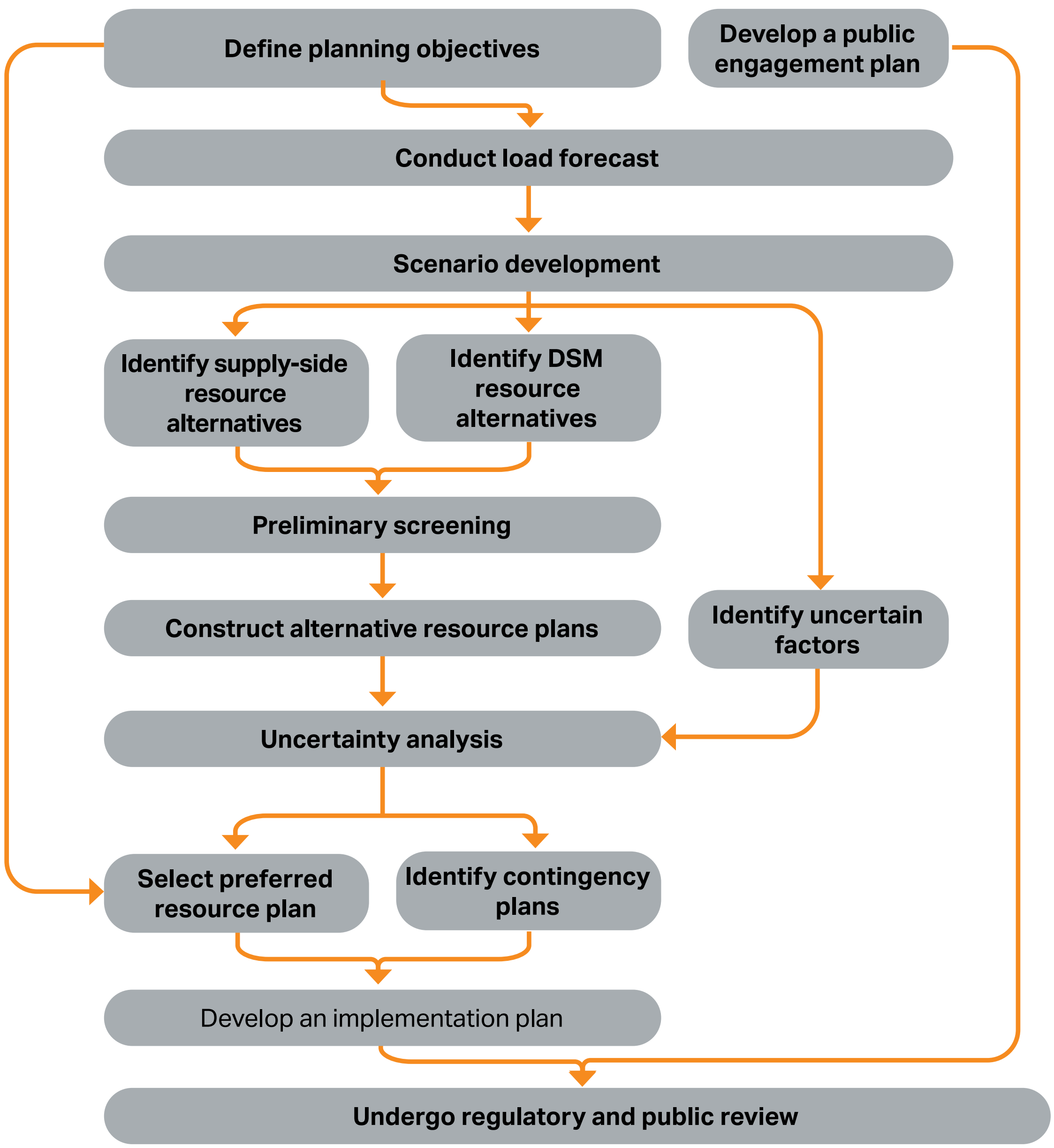
127 Chupka, M., Murphy, D., and Newell, S. (2018). Reviving Integrated Resource Planning for Electric Utilities: New Challenges and Innovative Approaches. The Brattle Group. Retrieved from http://files.brattle.com/files/6665_energy_newsletter_2008_no_1_-_irp.pdf

5.12.3.1 IRP OVERVIEW

Fundamentally, an IRP requires utilities to directly compare the value of supply side resources – adding generation capacity and improving transmission and distribution (T&D) infrastructure to minimize losses – to that of demand-side management (DSM) resources, such as energy efficiency and conservation (EE&C), distributed generation, and demand response (DR) programs. The preliminary goal of an IRP is to identify a portfolio of energy resources that will meet forecasted future energy loads while imposing the least cost on the utility or ratepayer, though utilities may also be required to investigate the environmental, reliability, and other implications of their resource choices. In balancing these factors, the resource portfolio that is ultimately selected might not be the least-cost alternative.

Developing an IRP is a multi-stage process, as summarized in **FIGURE 97. Overview of the IRP Process**, and can take utility staff six months to a year to complete, even with additional help from third-party consultants. The remainder of this section will elaborate upon this Figure, describing each of its components in more detail.

FIGURE 97. Overview of the IRP Process



Planning objectives. To begin, the utility defines its planning objectives. This may be as simple as explicitly defining the term "least cost", which typically takes the form of minimizing the present value of the revenue requirement, but often involves a more extensive list of objectives. As described above, this may include making conscious effort to minimize environmental or other societal costs, or directives to maximize the proportion of the resource mix dedicated to renewable or energy efficiency alternatives – potentially even more so than state-mandated renewable portfolio and energy efficiency alternatives. Planning objectives may also encompass other state policies or regulations that impact a utility's choice of resource mix, such as Energy Efficiency Resource Standards (EERS) or Renewable Portfolio Standards (RPS). Regardless, these objectives will serve as a reference point for the rest of the IRP process: the resource mix that is ultimately selected should fulfill these objectives.

Load forecasting. An IRP load forecast extrapolates years of historical energy use data within the utility's service territory to the end of the document's planning horizon, typically between ten to 20 years. The most detailed forecasts may compute anticipated generation capacity needs on a 15-minute increment or hourly basis and will also project the system's greatest demand during peak periods. There are several industry-accepted methods for conducting such forecasts: time-series models, econometric models, and end-use models. Econometric and end-use models build upon time-series models by incorporating demographic and economic factors and further disaggregating metered customer energy use by the purpose of the use (e.g. lighting, heating, cooling). Gathering such data may require issuing a survey to customers.

Scenario development. Because there is significant uncertainty surrounding load forecasting, utilities will introduce several load growth scenarios. The baseline scenario assumes business-as-usual energy use trends for the entirety of the planning horizon. Utilities will commonly develop low-growth and high-growth trend forecasts as well, though they may also consider even more specialized load cases.

Supply- and demand-side resources. The foundational premise behind an IRP is that a utility must weigh both supply- and demand-side resources in determining how to meet load forecasts. In addition to taking stock of their existing resources – and any maintenance or operational changes that could better support planning objectives – the utility must scope out new resources to meet projected growth in demand. This may come from constructing new generation facilities, executing purchase agreements with other utilities or independent power producers (IPPs), or implementing new DSM programs. In addition to IRP guidelines, some states have strict rules as to how utilities can solicit new resources.

Preliminary screening. Once an exhaustive list of resources is developed, the utility will often conduct a preliminary screening to eliminate the least cost-effective alternatives before continuing with more intensive analyses. The utility may rank alternatives solely based on the cost to the utility or may also consider externalities. The utility may also impose a threshold such that only resources with a benefit-cost ratio (BCR) of greater than one may be considered further.

Alternative resource plans. The utility will construct several portfolios of complementary resources that emerge from the preliminary screening. These portfolios may consider different resource mixes, different timelines for bringing new resources online or retiring existing resources, among other considerations.

Uncertainty analysis. Planning with up to a 20-year foresight requires utility planners to make several assumptions regarding the state of its future operations, the greater industry and economy, and federal and state regulations – all of which introduce uncertainty. In order to minimize the risk of failing to meet energy demand, the utility must test these assumptions through a risk or uncertainty analysis. Utilities most commonly utilize sensitivity analyses, which consider the range of values key variables may hold under different future conditions. Probability analyses go a step further, assigning a probability to each of these values and calculating the expected value of each potential outcome. The most common factors studied in an uncertainty analysis are load projections, fuel and electricity prices, variability of renewable energy supply, DSM program energy savings, and greenhouse gas emissions regulations.

Select a preferred resource plan and identify contingency plans. From the uncertainty analysis, the utility can select the resource plan that best meets its planning objectives and is also robust – meaning it minimizes risk of needing to import emergency power to meet gaps in demand under several future scenarios. Should an unanticipated development in utility operations occur, whether that be a drastic flux in demand or change in the capacity of a highly relied upon resource, the utility should have identified contingency plans to adapt their preferred resource plan and remain effective under these new conditions.

Implementation plan. The culmination of the detailed analysis described above, an implementation plan identifies the clear set of actions the utility needs to take to achieve its preferred resource plan and sketches out a timeline for when each of these actions will take place. The plan may also recognize metrics from which to evaluate the efficacy of the resource plan and off-ramps for when a utility will need to adopt one of its contingency plans. Annual reports submitted to the regulatory authority provide updates on the utility's progress with respect to its implementation plan.

Regulatory process. After the IRP is complete, the utility will submit its report and any supporting technical documentation to its respective regulatory authority for review. The authority may simply acknowledge the IRP and its intent to adhere to all guidelines, offer feedback as to how to improve the IRP – or formally accept or reject the IRP. Additionally, the authority may evaluate the prudency of a proposed investment in a traditional ratemaking hearing.

Engaging the wider public is an essential part of the regulatory review process. Regulatory bodies will typically designate official intervenors, public interest groups not typically represented by utilities or large industrial customers, that as a result, receive funding directly from the utility to participate in the IRP process. At the very least, regulators require a public comment period, but may also expect utilities to host public meeting(s) during the period of IRP review so stakeholders can more directly engage with the utility staff that drafted the IRP. In some cases, the utility may engage the public at the very beginning of the IRP process; for example, by designating a committee representative of its customer base and industry interests to provide feedback and guidance through the whole IRP process.

Depending on the complexity of the IRP, the utility may choose to engage other planning entities within the state or the region in addition to the wider public. For example, if the utility were to develop comprehensive emissions plans in conjunction with the baseline resource plan, they may consult the State environmental regulatory authority, which is responsible for submitting the Air Quality State Implementation Plan to the federal government. Or, if the utility were to conduct more intensive transmission planning than is typically conducted in an IRP, it may consult its Regional Transmission Organization (RTO) or Independent System Operator (ISO), which manages transmission planning and operations within the state.

New IRPs are typically developed every two to five years, at which point this entire process is repeated. Meanwhile, formal updates are submitted to the regulatory authority each year within the planning cycle. If a utility finds it needs to pursue one of its contingency plans in advance of its scheduled resubmission period, it may need to file for additional regulatory review.

5.12.3.2 EXISTING KANSAS RESOURCE PLANNING PROCESSES

This section presents an overview of the resource planning activities all Kansas utilities under the scope of this study currently undertake, per requirements dictated by state, regional and federal utility regulators and power authorities. As summarized in **TABLE 25. Summary of Kansas Utility Resource Planning Processes**, utilities may be required to participate in several planning processes:

- The utilities with the largest footprint and member agencies representing smaller utilities are all required to conduct generation capacity planning, as overseen by the KCC, and the region's RTO, the SPP;
- Evergy, as a stipulation of its merger, will begin submitting IRP documentation to KCC later this year;
- Kansas utilities operating in other states may have to submit an IRP for review by the respective state's electric utility regulatory authority; and
- All utilities participating in the U.S. Department of Energy's Energy Planning and Management Program, as administered by the Western Area Power Administration (WAPA), must submit an IRP for federal review.

The guidelines for each of these activities are described in more detail in the following subsections of this report. While IOUs and Munis submit necessary reporting independently, generation and transmission (G&T) Coops typically submit documentation on behalf of their distribution Coop members. All but two distribution Coops in Kansas are partnered with a G&T; these two Coops purchase power independently.

TABLE 25. Summary of Kansas Utility Resource Planning Processes

Utility Type	Utilities Under SB 69 Jurisdiction	State-wide and Regional Generation Capacity Planning	Integrated Resource Planning		
			Required by Kansas Utility Regulator	Required by Peer-state Utility Regulator	Required by WAPA
IOU	Evergy	✓	✓	✓	
	Liberty	✓		✓	
G&T Coops	KEPCo	✓			✓
	Midwest	✓			✓
	Sunflower	✓			✓
Distribution Coops*	Doniphan				
	Nemaha-Marshall				✓
Muni**	KCBPU	✓			✓
	Garden City				✓
	City of Gardner				✓

* There are two additional distribution Coops that are not members of the G&Ts, Alfalfa Electric Cooperative, Inc. and Tri-County Electric Cooperative, Inc. Both are headquartered in Oklahoma and have minimal footprint in Kansas, so were determined to fall outside the scope of this study.

** The scope of SB 69 and this study only encompass the three largest Munis in Kansas by customer count – KCBPU, Garden City, and City of Gardner. In total, there are 118 Munis in Kansas.

5.12.3.2.1 State-wide & Regional Generation Capacity Planning

Current KCC and SPP legislation necessitate load forecasting to demonstrate proof of generation capacity planning, which, if done in concert with the other analyses discussed in **Section 5.12.3.1,** could serve as the foundation for work done to fulfill a state-regulated integrated resource plan.

Under KCC Docket No. 13-GIME-256-CPL and SPP Form EIA-411, Westar Energy and KCP&L, Liberty, KEPCo, Midwest, Sunflower, Kansas Municipal Energy Agency (KMEA), Kansas Power Pool (KPP), and KC BPU are required to file ten-year forecasts of annual generation capacity needs and system hourly and seasonal peak capacity needs every two years to prove they are able to meet ongoing systems obligations while maintaining a 12% reserve margin. These forecasts are computed based on at least one year of historic data, and must encapsulate:

- Wholesale sales and purchases, listing all parties (e.g. utilities or municipalities) involved in the transactions, especially noting state imports and exports;
- Native retail sales, owned generation capacity, and interruptible loads;
- Overall system capacity responsibility and peak demand; and
- If the utility is voluntarily subscribing to the Renewable Energy Standard Act (RESA), renewable generation practices.

KCC Docket No. 99-GIME-321-GIE further established precedent for the Corporation to officially investigate any utility that fails to meet their system load demand and adhere to the requirements above.

This planning process supplements the traditional ratemaking process, of which the goal is to assess the prudency of any capital investments proposed to meet future capacity demand before the financial burden is passed on to ratepayers. For a more detailed analysis of the current ratemaking procedure in Kansas, refer to LEI's 2020 Study of Retail Rates of Kansas Electric Public Utilities.

5.12.3.2.2 Evergy IRP Framework

Another Kansas resource planning process emerged from the KCC's approval of Westar and KCP&L's merger in 2018. As a stipulation of the merger, the KCC ordered that the utility develop an integrated resource plan framework (Docket No. 19-KCPE-096-CPL), the first documented involvement of a Kansas agency in an IRP process. Following several rounds of revision and public comment from the CURB, the Kansas Industrial Consumer's Group (KIC), KEPCo, and the Kansas chapter of the Sierra Club, the final order was accepted by the KCC on February 6, 2020. The framework dictates that Evergy must submit a formal IRP with a ten-year planning horizon every three years, in addition to an annual report. The first annual report is expected in July 2020, with the first IRP to be submitted a year later. This timeline was designed to follow the Missouri IRP schedule, but with a three-month delay; Evergy submitted its 2020 annual report to the Missouri Public Service Commission (MPSC) in April and will submit its next triennial IRP in April 2021.

Under the framework, the IRP must provide a holistic overview of the utility's current and near-term operations, including:

- A history of annual seasonal load requirements;
- A geographic overview of its service territory, with observations surrounding areas of service decline or growth;
- Current load forecasts, generation portfolios, and transmission and distribution requirements, especially noting planned generation retirements and penetration of existing demand-side management and distributed generation programs; and
- The capital expenditure budget corresponding to the analysis period.

Additionally, the framework outlines several expectations for analyses informing the utility's longer-term planning commitments. The IRP must:

- Use multiple methodologies to develop a robust load forecasts, such as econometric and structural models. Loads must be forecasted on either a daily or monthly basis.
- Establish a clear business-as-usual or baseline case and develop several scenarios to measure how supply- and demand-side resource needs may deviate from the baseline case. Scenarios must be built upon a strong understanding of macroeconomic and industry trends, such as increased prominence of distributed generation, electric vehicles, and energy efficiency & conservation technologies.
- Test all preliminary assumptions made while developing load forecasts and resource scenarios should be tested through a sensitivity analysis. Uncertainties surrounding changes in the federal and state regulatory environment and market penetration of emerging technologies must be modeled in this analysis, which in turn will inform identification of a contingency plan for each scenario.
- Thoroughly document the rationale for selection of a preferred resource plan that did not exhibit the lowest present value of revenue requirements.

Evergy must hold a public meeting within 30-days of filing an IRP, and stakeholders will have 150-days from the date of submission to issue public comments. Despite introduction of an IRP, the KCC maintains the right to evaluate the prudency of any proposed investment through a traditional ratemaking hearing.

5.12.3.2.3 Kansas Utility Participation in Federal or Peer State IRP Processes

With the exception of Doniphan, a distribution Coop, all Kansas utilities under SB 69 jurisdiction already participate in a formal IRP process (either individually or through their generation and transmission partner, such as KEPCo) directed by a federal agency or peer state and are currently up to date on their required filings. **TABLE 26. Summary of Kansas Utility IRP Practices** summarizes the most recent filings for each of these utilities.

TABLE 26. Summary of Kansas Utility IRP Practices [128] [129] [130]

Utility Type	Utilities Under SB 69 Jurisdiction	Most Recent IRP Report Available	IRP Guidelines Followed	Approximate Proportion of Total Kansas Retail Customers
IOU	Evergy	2018	Missouri	64.0%
	Liberty	2019	Arkansas, Missouri, and Oklahoma	
G&T Coops	KEPCo	2016	WAPA	20.0%
	Midwest	2015		
	Sunflower	2018		
Distribution Coops*	Doniphan	NA	NA	0.3%
	Nemaha-Marshall			
Muni**	KCBPU	2019	WAPA	6.0%
	Garden City			
	City of Gardner			

The utilities predominantly follow the guidelines set by either the WAPA or MPSC. Although Empire also serves customers in Arkansas and Oklahoma, because the Missouri IRP guidelines are the most prescriptive, they are able fulfill both the Arkansas and Oklahoma IRP requirements by replicating their Missouri analysis for their respective service territories in these states.

The following subsections of this report first discuss the WAPA and Missouri IRP documentation in detail – as these requirements most significantly drive Kansas utility resource planning – and then offer a brief comparison between the Missouri, Arkansas, and Oklahoma guidelines to illustrate their relative level of specificity and how Empire is able to satisfy all three requirements with the same analysis.

Western Area Power Administration. Under the Energy Planning and Management Program (EPMP), in order to receive hydropower generated at WAPA sites, utilities or cooperatives with annual energy sales greater than 25 gigawatt hours (GWh) are required to submit an IRP for WAPA review every five years.

WAPA IRPs are required to evaluate the viability of adding generating capacity, power purchase agreements, energy conservation and efficiency programs, cogeneration and district heating and cooling applications, and renewable resources to their portfolio while minimizing risk to the utility. The utility may also weigh financial feasibility, expected environmental impact, and consumer preference against their ability to implement projects and continue to meet energy demand, which should be forecasted using time-series, econometric, or end-of-use models. In fact, the utility is expected to thoroughly document their efforts to minimize environmental impact and engage the public in their planning process.

Ultimately, the output of a WAPA IRP is an action plan that clearly delineates all steps the utility must take to accomplish the goals laid out in its analysis (e.g. construction or procurement of resources), the energy and capacity benefits associated with each of these steps, and finally, methodology for measuring and validating these benefits at key milestones within the planning period. WAPA requires the utility submit annual reports to document the steps already

128 Because the scope of this study does not include all Kansas utilities, this table is not exhaustive of all IRP activities currently underway in Kansas. For example, several other Munis submit IRPs to WAPA

129 With the exception of Doniphan, all utility retail customer count and energy sales data are from 2018 and were gathered from Form EIA-861 (Schedules 4A & 4D and EIA-861S). Doniphan was not included in this EIA survey. Their 2019 customer counts and sales were provided by KEC. Additionally, because the scope of this study does not include all Kansas utilities, the values in this column will not sum to 100%.

130 KEPCo and Sunflower do not directly serve retail customers. Their impact on the retail power sector was found by summing their members' customer counts and energy sales, as represented in the EIA survey – because costs generate by G&Ts are typically passed onto their members, and thus their members' retail customers, AECOM feels this is an appropriate proxy for understanding an IRP's potential impact on Kansas ratepayers.

taken towards implementing its action plan and steps still needed to be taken in the future and compare the actualized benefits versus those that were initially anticipated.

Missouri. Missouri's IRP process is enforced for all utilities, regardless of their type, that sell more than one million megawatt hours (MWh) to Missouri retail customers (per EIA data, roughly 73% of Missouri retail customers are served by utilities that are subject to this requirement). As is described below, the guidelines are far more prescriptive than those dictated by WAPA – and are among the most prescriptive guidelines enforced by any of Kansas's peer states. The Liberty and KCP&L reports, for example, are several chapters and hundreds of pages long, covering:

- **Load analysis and forecasting:** the utility must first create load profiles for a peak weekday, a representative weekday, and a representative non-working day per month from the most recent year from which data is available. From these profiles and using end-use and demographic data from customers each major class and subclass, they must then forecast both actual and weather-normalized hourly net system loads and monthly demand for each year of the 20-year planning horizon.
- **Supply-side resource analysis:** the utility must consider the following resources:
  - Constructing new plants using either existing or new generation technologies;
  - Extending the life of, refurbishing, or enhancing emissions controls at existing generation sites;
  - Purchasing power from other utilities, co-generators, or independent power producers; and
  - Upgrading transmission and distribution infrastructure to reduce power losses.

Each of these resources must be screened and ranked by both the expected cost to the utility and cost of environmental mitigation. From these results, the utility must identify the most cost-effective alternatives, which are then included in the integrated resource analysis.

- **Demand-side resource analysis:** the utility must first calculate the BCR of all demand-side programs under consideration and build DSM portfolios from programs with BCRs above one. Then, the portfolios found to have a total cost ratio (TCR) greater than one must be included in the integrated resource analysis.
- **Integrated resource analysis:** the utility will develop alternative resource plans from the list of cost-effective supply- and demand-side resources. In addition to the minimizing financial impact, the alternative resource plans must satisfy at least one of the utility's long-term planning objectives.
- **Risk analysis and strategy selection:** the utility must analyze the level of uncertainty associated with each alternative resource plan through a comprehensive sensitivity analysis, which will then inform the construction of a probabilistic decision-tree diagram. The utility may pick from alternative resource plans that meet their planning objectives while ensuring there is little risk of needing to import emergency power.

As with all Kansas utilities submitting IRPs to WAPA, this analysis culminates in an implementation plan. Once the IRP is filed with the MPSC, there are 120 days for public comment. If the PSC identifies significant deficiencies in the IRP, the utility must either file an alternative, improved report within 45 days or participate in a public hearing. Should the utility need to pivot to one of its identified contingency plans, it must draft a report and submit to the PSC for further review. This process is repeated every three years.

Arkansas and Oklahoma. The Arkansas and Oklahoma IRP policies offer guidance on each of the components that are part of the Missouri IRP process, though in most cases, in less detail. For example, while the Oklahoma Corporation Commission (OCC) does not specify a required load forecasting methodology and the Arkansas Public Service Commission (APSC) gives utilities the choice of using an economic or end-use model, the MPSC outlines specific instructions as to how data should be gathered, let alone modelled. Furthermore, while the APSC and OCC policies both recognize the inherent level of uncertainty in resource planning and require utilities to broadly consider how uncertain factors impact load forecasts and ability to meet demand, the guidelines do not characterize the different scenarios that should be modelled – or how these scenarios should be modelled. The MPSC, though, not only specifies the uncertain factors and sensitivity cases that must be considered in each phase of the analysis, but also requires utilities to conduct a more sophisticated form of probabilistic modelling.

A more complete analysis of the Arkansas and Oklahoma IRP processes – and how they compare to Missouri's – is conducted in the next section.

5.12.4 ANALYTICAL APPROACH AND RESULTS

5.12.4.1 IRP BENCHMARKING

As evidenced in the differences between the WAPA, Missouri, Arkansas, and Oklahoma IRP guidelines, there is significant variation in how oversight authorities at the state or federal level may require utilities to address each of the IRP elements discussed in the IRP Overview subsection of this report. Most generally, regulators can take a baseline, mid-level, or prescriptive approach:

- **Baseline:** requires each utility to go through the process outlined in **FIGURE 97. Overview of the IRP Process** to fulfill the definition of an IRP, but either offers little explicit guidance as to how the utility must facilitate each step or only expects the utility to undertake higher-level forms of analysis.
- **Mid-level:** more explicitly defines requirements for each consideration as compared to the baseline approach but does not yet approach the level of specificity designated by especially prescriptive requirements. Guidance at this level is most common.
- **Most prescriptive:** offers very specific guidelines for the utility's analysis and/or requires a more intensive analysis. Considerations originate from the project team's review of peer state guidelines recognized as industry best practice.

Considerations for each element of an IRP under these approaches are outlined in **TABLE 27. IRP Considerations under a Baseline, Mid-Level, and Prescriptive Approach**.

TABLE 27. IRP Considerations under a Baseline, Mid-Level, and Prescriptive Approach

Element of an IRP	Baseline	Mid-Level	Most Prescriptive
Planning Entity	Only the utility.	Requires the utility to coordinate with other entities within the state (e.g. state environmental agencies).	Requires the utility to coordinate with other entities within the region (e.g. ISO/RTO).
Planning Objective	Does not define policy-level objective for IRP process or only states the definition of an IRP.	Requires consideration of several definitions of "least cost" and/ or weigh several potentially conflicting objectives.	Challenges the utility to adopt industry best-practices that are not required by law.
Coverage and Geographical Scale	Requires a high-level discussion of service area & customer classes.	Requires discussion of changes in demand with respect to customer classes.	Requires discussion of changes with respect to both customer class and localized energy use/ demand.
Time Horizon	10 years	10-20 years	20-40 years
Scenario Development	Only defines a baseline "business-as-usual" scenario from which to compare other scenarios.	Dictates the number of additional scenarios that must be considered.	Defines the scenarios that must be addressed.
Resource Alternatives	Broadly categorizes resource alternatives.	Further specifies the types of resources that must be considered.	Dictates the relative proportion of each resource in the total mix.
Uncertain Factors	Broadly categorizes uncertain factors or offers recommendations, but no requirements.	Further specifies the factors that must be considered (e.g. future environmental regulation vs. cost of potential carbon tax).	Dictates the range of values each factor should hold and/or the relative weight each factor should hold in the analysis.
Technical Methodology	Specifies the type(s) of analysis required but leaves preferred modelling methodology unspecified.	Offers a list of several acceptable alternatives (e.g. time-series, econometric model, end-use model).	Requires a specific or multiple type(s) of model(s).

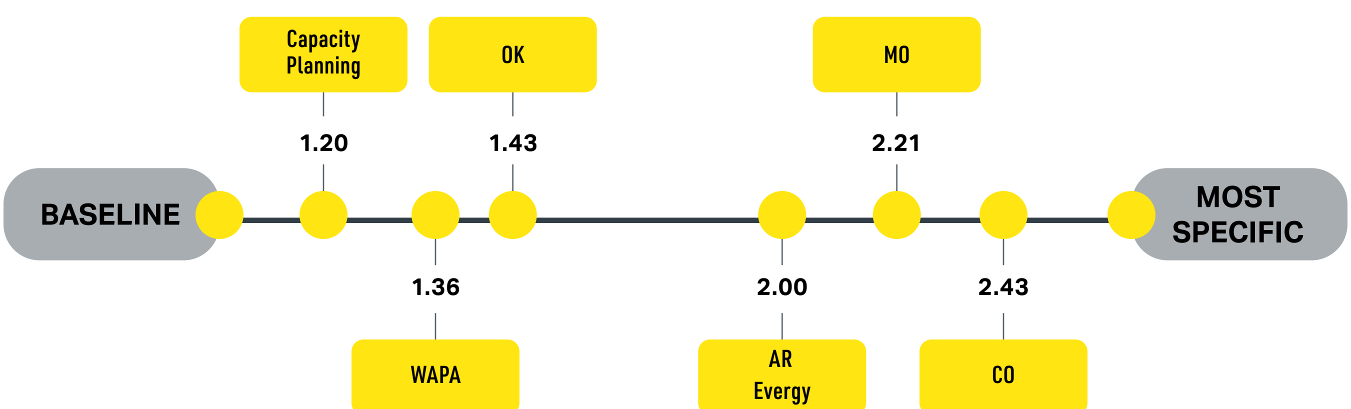
Element of an IRP	Baseline	Mid-Level	Most Prescriptive
Preliminary Screening & Construction of Alternative Resource Plans	Does not defined process for screening or directs utility to assume best judgment.	Requires basic cost-effectiveness screening (e.g. utility cost test).	Requires the utility to balance multiple cost considerations, including externalities (e.g. societal cost test).
Selection of Preferred Resource Plan	Directs utility to select the least-cost alternative that maintains reliable service.	Directs utility to select the portfolio that best optimizes for all mid-level planning objectives.	Directs utility to select the portfolio that best optimizes for all mid-level planning objectives and follows industry best-practice and/or community preference.
Documenting Methodology	Requires clear documentation of all assumptions for model inputs.	Requires thorough documentation of modeling methodology.	Requires models to be shared.
Action Plan	Requires annual progress report, but no explicit guidelines for action plan within the IRP.	Requires discussion of steps and timeline needed to secure preferred resource plan and meet demand.	Specifies how the utility should manage its action plan (e.g. how it should acquire resources) and/or requires submission of contingency plan(s) in addition to a preliminary action plan.
Update Frequency	5 years	3-4 years	2 years
Public Engagement	Does not specify the type of public engagement required or only requires a public comment period.	Requires the utility to host public meeting(s) during period of IRP review.	Invites a working group (representative of all stakeholders) to participate throughout whole IRP process.

This framework was then used to evaluate each of the resource planning activities described in the Existing Kansas Resource Planning Processes subsection – the generation capacity planning requirements, as well integrated resource planning guidelines set forth by the KCC, WAPA, MPSC, APSC, and OCC – as well as the rules set by the Colorado Public Utilities Commission (CPUC), which are recognized as an example of industry best practice.

For each element where the guidelines only fulfilled the baseline requirements, the policy was assigned a score of one, whereas mid-level and even more prescriptive guidelines were assigned scores of two and three, respectively. To assess the overall level of specificity of each policy, as represented in **FIGURE 98. State IRP Performance in Benchmarking Exercise**, the average of all element scores were taken. Because generation capacity planning does require utilities to consider of each component of an IRP process, the value depicted in **FIGURE 98. State IRP Performance in Benchmarking Exercise**is only a partial score.

A more detailed breakdown of how each policy scored with respect to each IRP element can be found in **see APPENDIX G Benchmarked Integrated Resource Plan Policies**.

FIGURE 98.State IRP Performance in Benchmarking Exercise



Source: ASPC, CPUC, KCC, MPSC, OCC, WAPA

5.12.4.2 COSTS AND BENEFITS OF IRP PROCESSES

IRP processes do not directly reduce customer rates, but instead require utilities to adhere to a consistent and transparent planning process that balances least-cost alternatives and other stated policy objectives for an optimal mix of resources to meet energy demand. Theoretically, such a process could result in more competitive energy rates by creating more efficient planning processes, uncovering least-cost alternatives, and enhancing coordination around state-level objectives. As part of this study, the project team engaged with Kansas utilities, major energy users, environmental interests, ratepayer representatives and others, who recognized several potential benefits associated with adopting an IRP program requiring KCC approval, such as:

- Cost savings from uncovering a previously unknown least cost alternative or reapportioning the resource mix to be more inclusive of demand-side resources;
- Encouraging a more streamlined and transparent planning process, which might lead to additional efficiencies and cost savings;
- Creating the opportunity for meaningful engagement during the planning process, which can lead to increased customer satisfaction; and
- Giving the state and industry better insight into decisions made by utilities, the drivers for those decisions, and the impact those decisions may have on the ratemaking process.

These concepts, as well as other benefits identified through project team research, are summarized in **TABLE 28. Potential Benefits of Requiring IRPs with State Approval**, which also notes the benefits considered "priority" by stakeholders. The ability for an IRP to capture the full extent of these benefits and reduce rates depends on many factors, including the final design of the IRP process. The Policy Recommendations section further discusses how these design considerations can be best leveraged to capture priority benefits.

TABLE 28.Potential Benefits of Requiring IRPs with State Approval

Benefit	Description	Stakeholder Identified Priority
Capital Investment Deferment	By requiring the examination of both supply and demand side resources, IRPs can result in least-cost alternatives at a system level that may allow the deferment of larger capital investments such as construction of new generation resources.	X
Distributed Energy Resource Integration	IRP regulations can require the consideration of distributed energy resources, including battery energy storage, in least cost resource scenarios, potentially increasing the integration of these resources to meet load demands.	X
Energy Efficiency Integration	IRP regulations can require the consideration of energy efficiency in least cost resource scenarios, potentially increasing the use of energy efficiency to meet load demands.	X
Progress Toward State Level Policy Objectives	An IRP process can require the consideration of specific state level policy objectives (such as economic development targets) and thus help to achieve stated policy priorities.	X
Transparency	An IRP process requiring state approval increases transparency for the State government/regulatory bodies to understand utility investment decision making. It also increases transparency for major utility customers such as industrial users who have better insight into utility system, resource, and investment planning.	X
Consistency	IRP guidelines may require utilities to use the same data sources and technical methodologies, as well as maintain assumptions with respect to uncertain factors. This allows the regulatory body to more directly compare utility planning processes and identify best practices for prudent spending, while also increasing transparency.	
Customer Satisfaction	By requiring the engagement with utility customers to finalize an IRP, an IRP process required by the state could increase customer satisfaction by requiring utilities to understand and listen to customer priorities.	

Greenhouse Gas Emissions Reduction	IRP regulations can require the consideration of other state goals, such as the reduction of GHG emissions.
Public Engagement	An IRP process often requires some form of public engagement around proposed plans. While the scale of engagement differs based on applicable regulations, the ability for the public to provide input allows ratepayers a voice in resource planning.
Resilience	IRP regulations can require the consideration of other state goals, such as increasing grid resilience in response to weather or security threats.

There are two key costs to consider for an IRP process requiring state approval. The first is the IRP development costs to the utility and the second is the costs to the regulating entity for the review and approval process. Similar to capturing benefits, the magnitude of these costs depends on the design of the IRP process. For example:

- Requiring more frequent IRP submissions increases the frequency for which spending for resource planning activities is necessary;
- Requiring more intensive modeling procedures may impose a need for utilities to invest in more advanced software, offer additional software training for employees, and dedicate more staff hours to resource planning;
- Requiring more significant consideration of DSM resources may impose a need for utilities to hire an (additional) external consultant to lead program feasibility studies and evaluation, management and verification studies, as is industry recommended best practice. Additionally, encouraging ratepayer participation in DSM programs may require increased marketing and communications spending; and
- Requiring a longer planning horizon may increase the complexity of load forecasting and other modeling work, though also provides the utility with prolonged opportunity to mitigate costs associated with expected construction and accommodating changes in regulation;
- Requiring more extensive public engagement processes will also lead to increased staff hours and spending for marketing and communications materials.

The marginal costs and benefits of introducing a state-regulated IRP process in Kansas are highly dependent on the utilities' existing capacity and IRP practices. The IOUs, for example, are already equipped to follow an especially prescriptive IRP process (imposed by Missouri) and can conduct analyses for their Kansas and out-of-state service territories simultaneously – they anticipate their spending would only marginally increase, as the only unique expenditures to Kansas would be those for retaining legal local counsel and conducting public engagement. Munis and Coops, on the other hand, currently only conduct high-level resource planning activities (as evidenced by WAPA's relatively low score in the benchmarking exercise). These utilities speculate that costs for internal staff time, consultant contracts, software subscriptions, and legal support could fall within the range of $100,000 to $300,000[131] depending on the breadth of state requirements. Spending could extend upwards of $1.5 million to $3 million for resource plans requiring complex methodology and extensive community engagement, as well as consideration of several resources, load scenarios, and uncertain factors.[132]

5.12.4.3 POLICY RECOMMENDATIONS

The value of a utility integrated resource planning process that requires state regulatory approval depends on the design of the policy requiring the IRP. As discussed in the **Section 5.12.3.1**, there are different elements of an IRP and as discussed in **Section 5.12.4.1**, different oversight authorities at the state or federal level require utilities to address each of the IRP elements in different ways. In order to capture the maximum value from an IRP process, the KCC must first confirm the desired outcomes from an IRP process that requires state regulatory approval so that the policy can be appropriately designed to achieve identified outcomes. In **Section 5.12.4.2**, the potential benefits of an IRP process are identified, and benefits stakeholders discussed as being most important were highlighted. In this section, the policy design considerations are discussed for each priority stakeholder benefit (referred to as desired objectives).

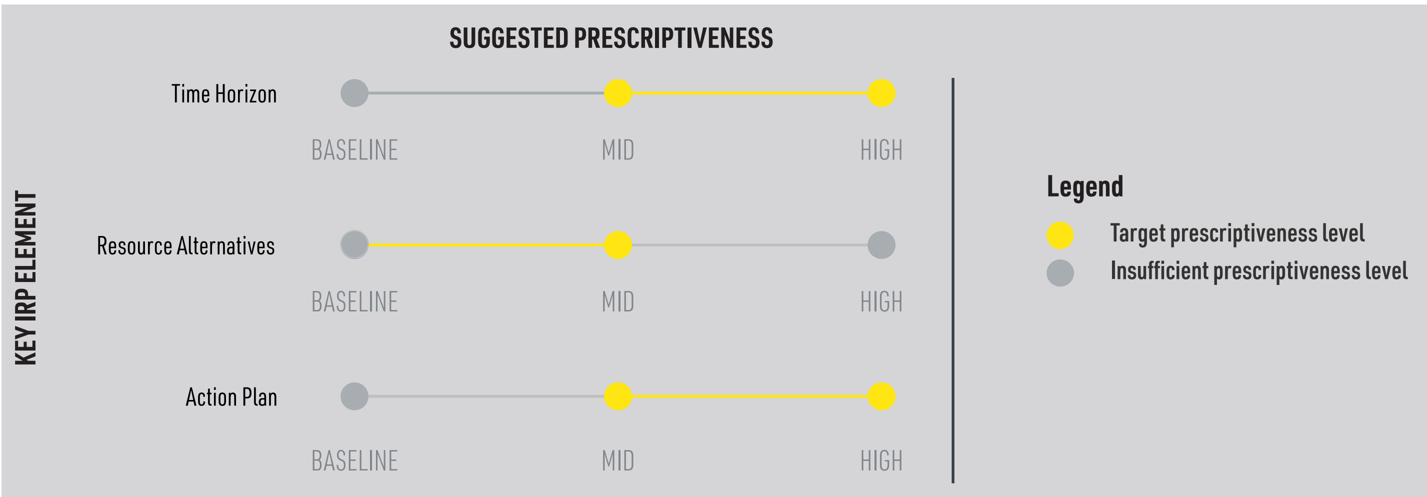
131 RFI responses from Coops and Munis that already submit IRPs and were able to provide estimates of past expenditures were consistent with this figure.

132 RFI responses from both IOUs fell within this range.

Recommendations in this section are strictly related to the design of a KCC-regulated IRP process and do not serve as statements as to whether or not Kansas utilities already carry out such actions.

Capital Investment Deferment. In order for IRPs to support deferment of large capital investments in generation, transmission or distribution the framework should require the consideration of diverse resources including demand side resources (e.g., energy efficiency) and distributed energy resources. It may also be beneficial to require longer forecast horizons to allow appropriate consideration of potential future spending and future infrastructure needs. Finally, as part of defining action plan annual reporting guidelines, stipulating metrics with which utilities can evaluate the continued efficacy of their preferred resource plan and linking these metrics to off-ramps (at which point a utility would be required to adopt one of its proposed contingency plans) may mitigate sunk cost bias associated with continuing to push forward an expensive plan that is not meeting planning objectives.

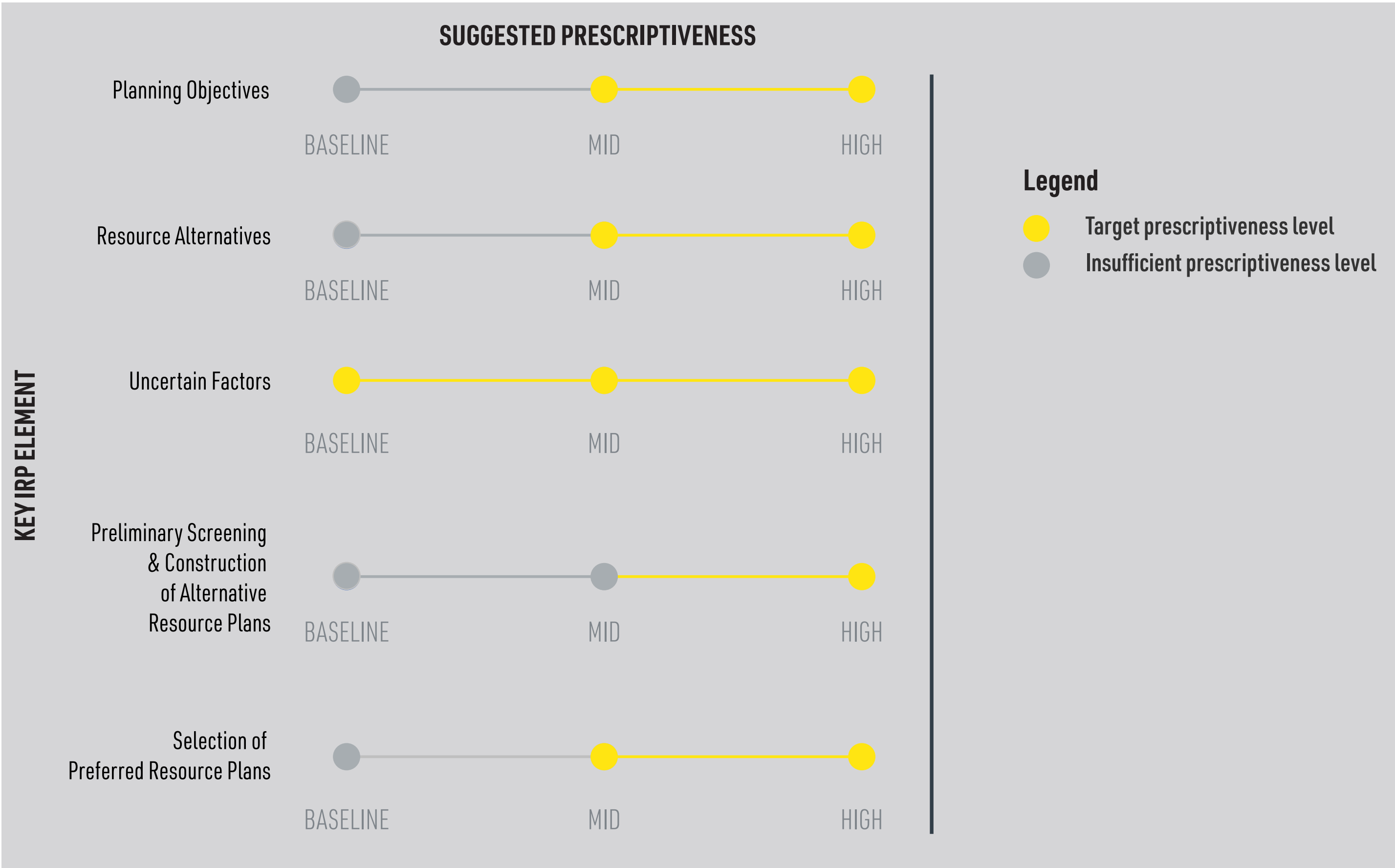
FIGURE 99. Suggested Prescriptiveness to Achieve Capital Deferment Objectives



Distributed Energy Resource Integration. Any type of IRP process can help to increase distributed energy resource (DER) integration by requiring the consideration of low-cost distributed energy resources as a future generation option. However, specific design components may advance greater integration of all or specific distributed energy resources. Specifically, IRP frameworks can dictate planning objectives that require the integration of DERs at a specific rate. Additional weight can also be given to consideration of DERs in resource alternatives analyses and the utilities can be required to balance environmental and societal costs in additional to economic costs when constructing and selecting preferred resource plans.

If the increased integration of DERs is a desired outcome of the IRP process, it may also be prudent to require the consideration of DER specific uncertainty factors in IRP modeling and forecasting.

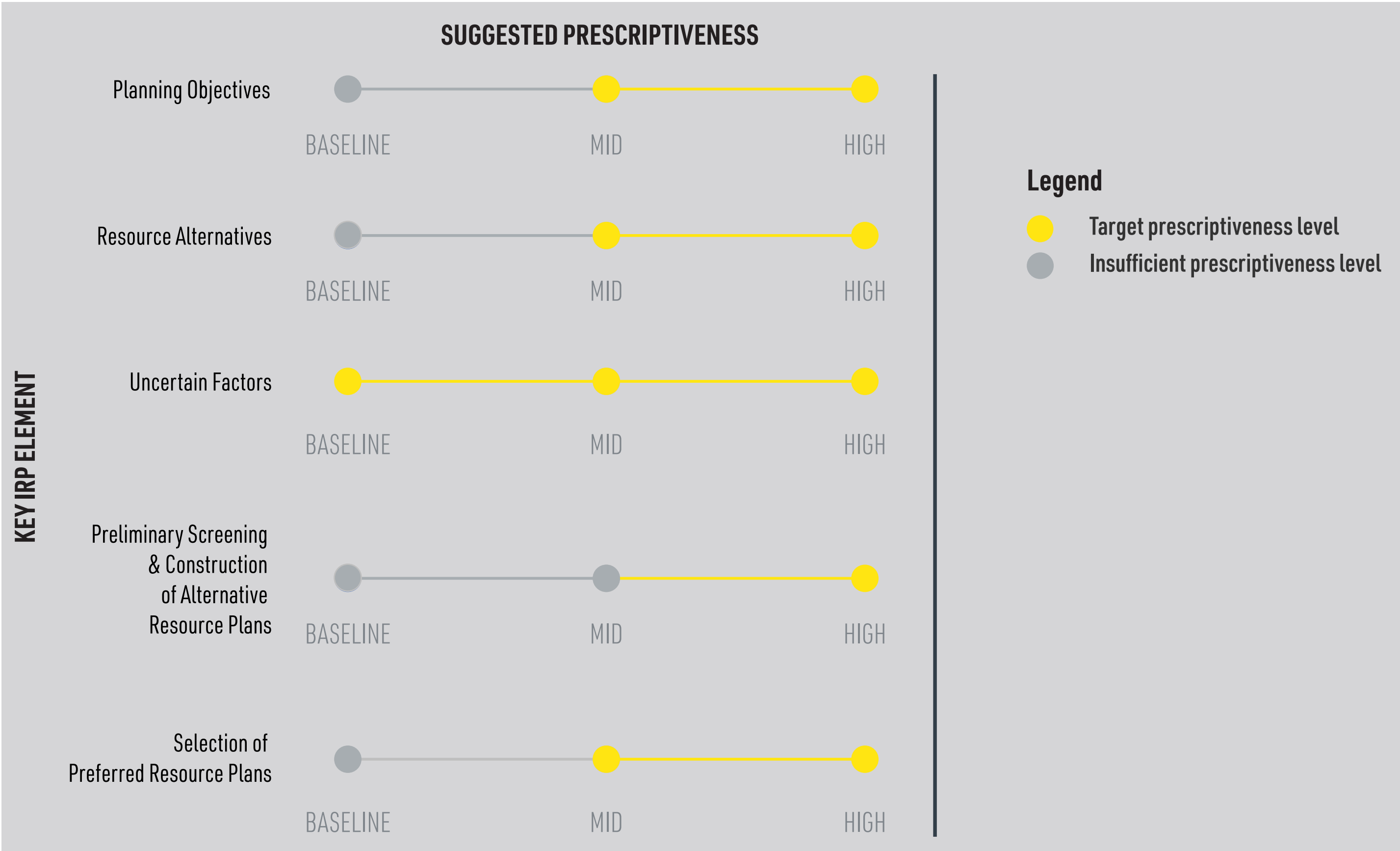
FIGURE 100. Suggested Prescriptiveness for DER Integration Objectives



Energy Efficiency Integration. Similar to DER integration, IRP processes can help increase energy efficiency integration simply by requiring the consideration of all types of low-cost resources. State policy frameworks can take this further by defining state-wide energy efficiency resource standards requiring additional weight be given energy efficiency in resource alternatives analyses and requiring utilities to balance environmental and societal costs in additional to economic costs when constructing and selecting preferred resource plans.

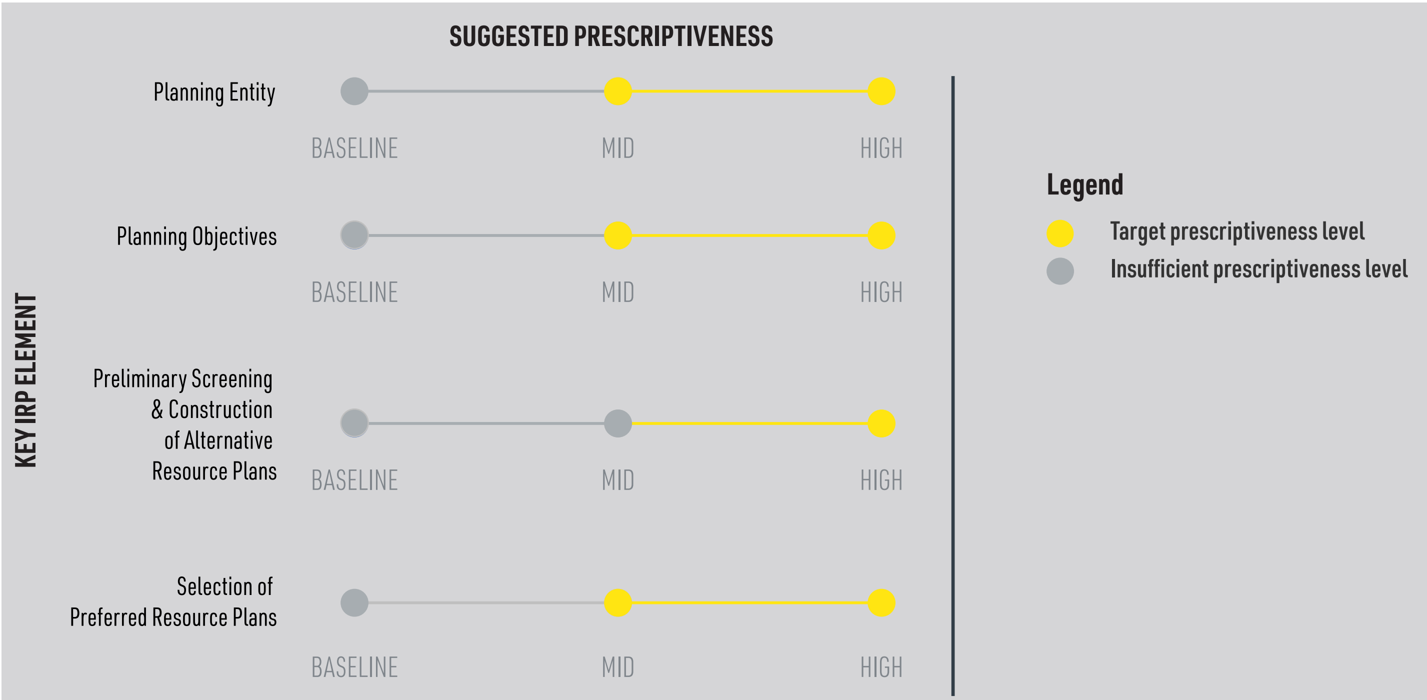
If the increased integration of energy efficiency is a desired outcome of the IRP process, it may also be prudent to require the consideration of energy efficiency program participation uncertainty in IRP modeling and forecasting.

FIGURE 101. Suggested Prescriptiveness to Achieve Energy Efficiency Objectives



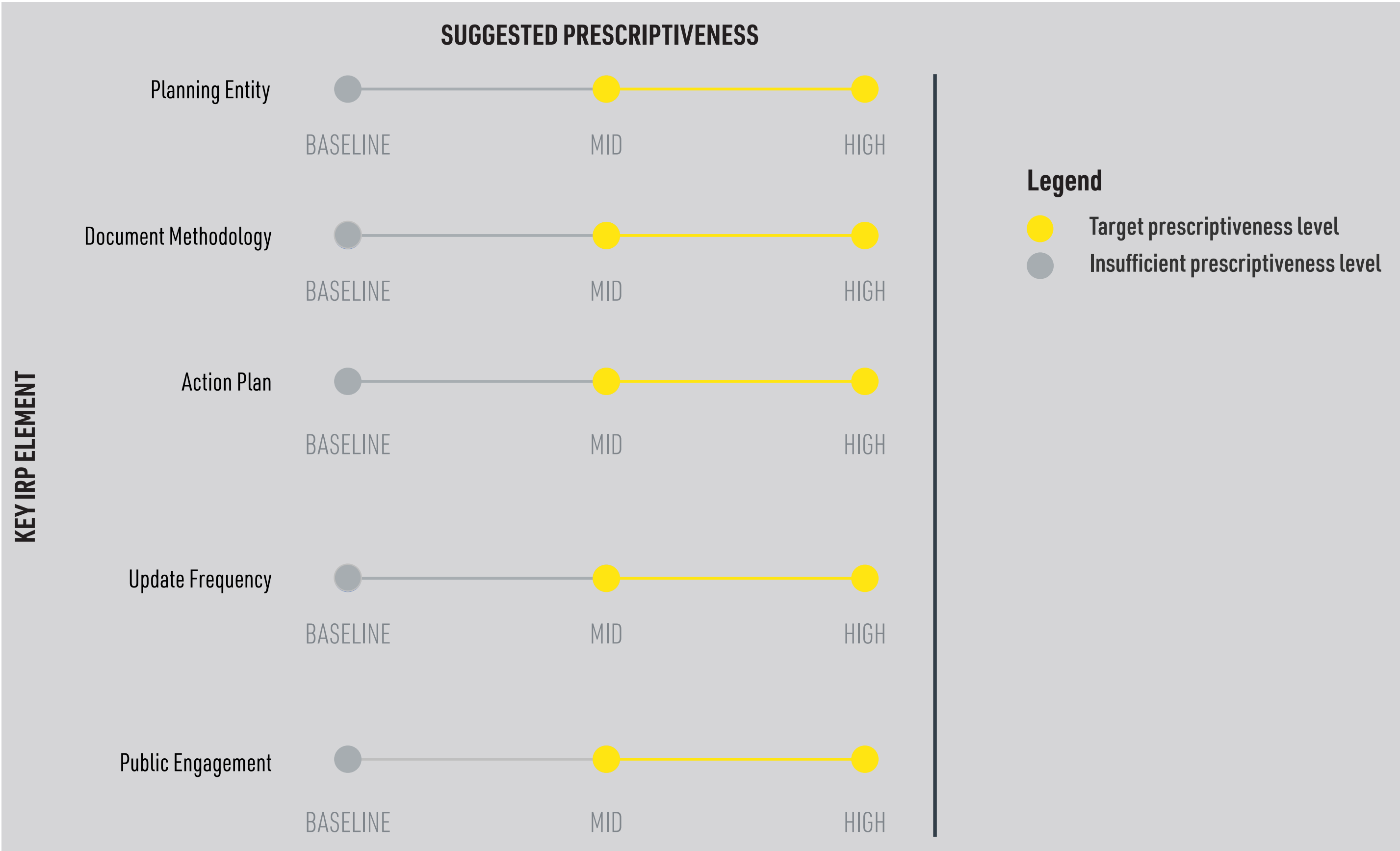
State-Level Policy Objectives. To achieve policy objectives prioritized by the state, the IRP process should require utilities to coordinate with other entities within the state (e.g. agencies leading the environmental and economic development policy agendas). It should also require the consideration of several definitions of "least cost" such that externalities – including potential environmental and economic development impacts – associated with each proposed resource scenarios are evaluated. In order for utilities to successfully consider impacts on economic development, for example, explicit economic development outcomes and targets should be identified and communicated. Utilities should be given as much foresight as possible to adapt to new outcomes and provided with clear guidelines as to how they should consider such outcomes in their IRP process.

FIGURE 102. **Suggested Prescriptiveness to Achieve State-Level Policy Objectives**



Transparency. IRP processes have a range of potential transparency benefits which can be augmented through policy design. By being more prescriptive about who utilities must coordinate with, how methodologies and actions plans must be documented and communicated, when plans must be updated, and how public engagement is structured, IRP processes are more likely to improve transparency for a diverse range of customers.

FIGURE 103. Suggested Prescriptiveness to Achieve Transparency Objectives



Scale of Impact. There are three primary approaches for defining the scale of impact of an IRP requirement: requiring an IRP for all utilities under the regulatory authority's jurisdiction, requiring an IRP for all utilities of a certain type (which may only include a subset of utilities under the authority's jurisdiction, or extend to an additional group of utilities outside of the authority's jurisdiction for price regulation), or for all utilities exceeding a certain threshold of customers or sales. All three are represented within the set of guidelines analyzed for this report. As summarized in **TABLE 29. IRP Guideline Scale of Impact**, while Arkansas and Oklahoma institute a blanket IRP requirement, Colorado more explicitly scopes the jurisdiction of their IRP requirements by utility type, and WAPA and Missouri have implemented a sales threshold.

TABLE 29. IRP Guideline Scale of Impact

Policy	IRP Jurisdiction	Applicable Kansas Utilities	Approximate Proportion of Total Kansas Retail Customers Impacted
WAPA	All utilities with sales greater than 25,000 MWh per year	All utilities except for Tri-County Coop	96%
Colorado	IOUs and G&T Coops	Evergy, Liberty, KEPCo, Midwest, and Sunflower	84%
Missouri	All utilities with retail sales greater than 1,000,000 MWh per year to in-state customers	Evergy, KCBPU	71%
Arkansas **Oklahoma**	All utilities under the ratemaking jurisdiction of the regulatory authority	Evergy, Liberty, Southern Pioneer	65%

Source: ASPC, CPUC, KCC, MPSC, OCC, WAPA, EIA

Under these models, the IOUs are nearly universally expected to submit an IRP, with the only exception being Liberty under the Missouri approach (although their total retail sales exceed 1 million MWh per year, the volume of sales in Kansas is relatively small). The KCC already implemented an IRP requirement for Evergy and must weigh the expected costs and benefits of extending the requirement to also include Liberty – or designing a new IRP process altogether. As the Evergy framework, in some ways, parallels the Missouri IRP process, and because Liberty already submits an IRP to the MPSC, the marginal cost to the utility of following the Evergy framework would be minimal. On the other hand, by nature of their extensive existing resource planning practices, and because their Kansas service territory is relatively small, there would also be nominal gain in benefits. Furthermore, while designing a new process may result in higher regulatory cost, it may also allow the State, utilities, and ratepayers to better capture the benefits associated with IRPs.

As for Coops and Munis, because they fall outside the price-regulation jurisdiction of the KCC, they would be less impacted by the introduction of an IRP requirement under any of the models presented in **TABLE 29. IRP Guideline Scale of Impact** (with the exception of WAPA). G&T Coops are only implicated by Colorado's guidelines, and the only Muni that would be required to submit an IRP under any of these approaches is KC BPU. The KCC could explore a change in regulatory authority if it would like Coops or Munis to be subject to an IRP requirement, for which there is precedent. G&T Coops are not subject to CPUC ratemaking oversight. The KCC may also consider whether an IRP requirement for Coops and Munis would take a different form than that imposed for IOUs.

5.12.5 KEY FINDINGS AND CONCLUSIONS

The project team's preliminary research found that all but one Kansas utility under SB 69 jurisdiction already engage in integrated resource planning. State Coops and Munis follow guidelines posed by WAPA, and the IOUs primarily base their resource plans off MPSC requirements. By July 2021, Evergy is expected to release its first IRP following a framework issued by the KCC in 2019.

Further evaluation of these guidelines (as well as those regulated by the CPUC, APSC, and OCC) with respect to all 14 components traditionally part of the IRP process found the Colorado and Missouri guidelines to be among the most prescriptive, while WAPA guidelines offered the least specificity. The Evergy IRP Framework was mid-tier, and comparable to the Arkansas requirements. Increasing guideline prescriptiveness above the baseline level may cause utilities to incur higher costs, but better positions them – as well as ratepayers, state and regional policy makers, and members of industry – to capture the benefits associated with a state-regulated IRP process.

Continued analysis of the benefits emphasized to be of high priority by stakeholders engaged throughout the study – capital investment deferment, distributed energy resource integration, energy efficiency integration, progress toward state-level policy objectives, and transparency – found that their associated objectives become more achievable as utilities are required to weigh several definitions of "least cost", consider a wide array of resource alternatives, screen preliminary resource plans with a comprehensive list of externalities in mind, and ultimately select the resource plan that takes these externalities, industry-recognized best practice, and consumer preference into account.

The fundamental value of a state-regulated IRP process is dependent on its scale of impact, or the suite of utilities for which the requirement would apply. Under the set of guidelines benchmarked, it was found that although IOUs are nearly universally required to participate in state-regulated IRP processes, there are few cases in which Coops and Munis are also required to submit an IRP for state review. As a result, the expected marginal cost of introducing an IRP state-regulated IRP requirement would be lowest for IOUs, followed by G&T Coops, and then distribution Coops and Munis.

As a result of this research, the State must first determine the outcomes it wishes to achieve in introducing a state-regulated IRP requirement. The State Legislature and KCC may wish to consult other governing organizations at the state or regional levels – such as the Kansas Department of Health and Environment, Kansas Department of Commerce, and SPP – to understand how an IRP requirement may further advance their core policy objectives. Then, the KCC may begin to design a set of guidelines that optimize the level of prescription with respect to each component of an IRP to maximize these outcomes, and finally, characterize the appropriate scale for which these guidelines will be enforced.

5.13 Economic Analysis of Generation Fuel Price Fluctuations on the Cost of Electricity

Economic analysis of the price fluctuations of generation fuels on the cost of electricity.

5.13.1 BACKGROUND

Part 1 of the Study identified changes in electricity production costs as one of the key drivers of rate increases in Kansas[133] over the past ten years, based on the findings of the cost of service study completed by the KCC.[134] The other two predominant factors contributing to rate increases were environmental regulations and rising transmission costs, which when taken into consideration with production costs, explained 60 - 62% of total cost increases over the period.[135]

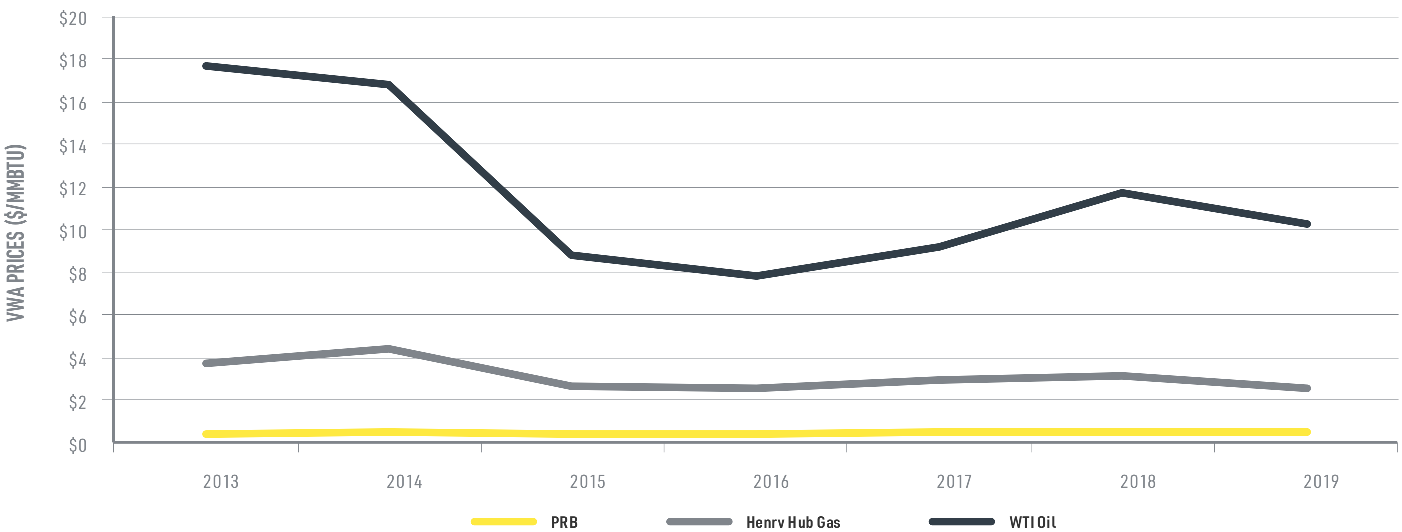
Cost recovery of environmental compliance costs ended in 2015, and impact of transmission costs on utility rates are reported in **Section 5.5** and **5.10** of this report, leaving this section to focus on economic analysis of the price fluctuation of generation fuels and their impact on the cost of electricity.

5.13.1.1 FUEL PRICES

There are three major fuel pricing hubs that serve Kansas utilities. Henry Hub is the largest gas pricing hub[136] in the U.S., located in Texas with pipelines connecting it to Kansas utilities. West Texas Intermediate (WTI) is the benchmark for U.S. oil price, and is also quoted for delivery in Texas but deliverable to Kansas utilities via pipeline. The final commodity benchmark price is from the Powder River Basin (PRB), which is the reported source[137] of coal used in Kansas power stations.

Commodity market fuel pricing dynamics are driven by local supply and demand factors in the short-term; however, coal and natural gas prices tend to follow oil price movements long-term, due to the oil market being the largest and most fungible energy commodity in the world, as well as a fuel substitute via kerosene and jet fuel. **FIGURE 104. Fuel Prices at Major Pricing Nodes Serving Kansas Utilities** show the change in volume weighted average (VWA) fuel prices for commodity benchmarks over the 2013 to 2019 period.

FIGURE 104. Fuel Prices at Major Pricing Nodes Serving Kansas Utilities



Source: EIA

133 State and utility pricing trends by customer class are reported in **Section 5.10.1**.

134 London Economics International, LLC (2020). Study of Retail Rates of Kansas Electric Public Utilities, page 48. Kansas Corporation Commission. Retrieved from: https://estar.kcc.ks.gov/estar/ViewFile.aspx/S20200108144309.pdf?Id=1a3a31e5-e38d-4445-aada-1cd0170a7b85

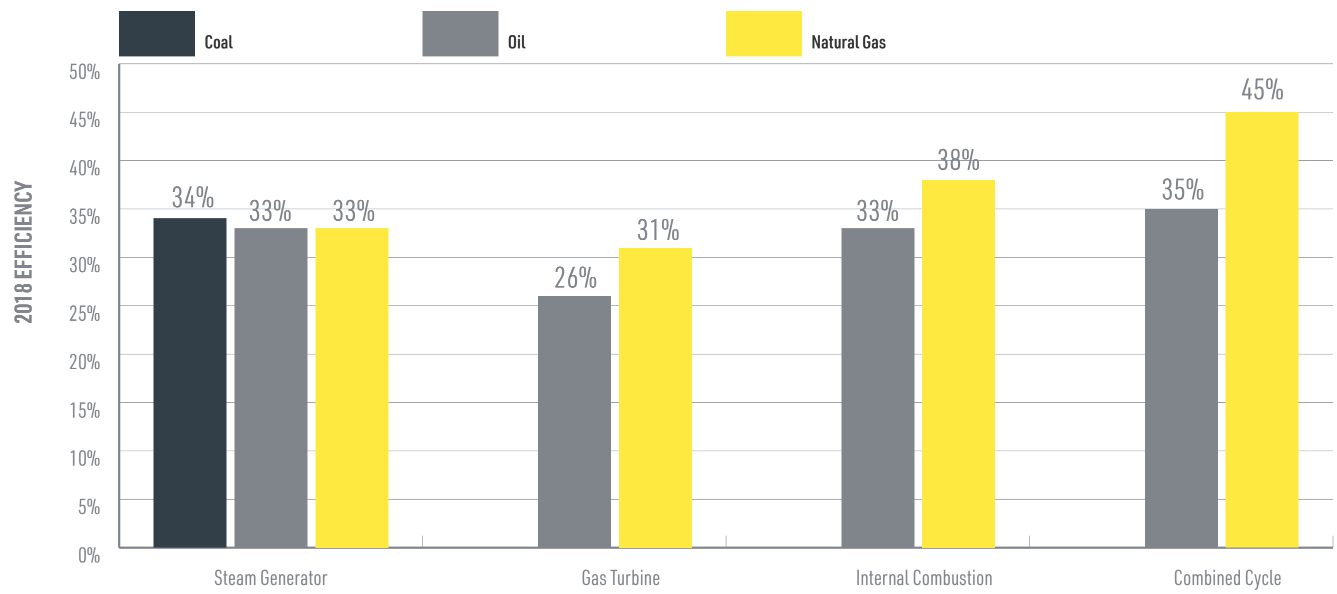
135 London Economics International, LLC (2020). Study of Retail Rates of Kansas Electric Public Utilities, page 48. Kansas Corporation Commission. Retrieved from: https://estar.kcc.ks.gov/estar/ViewFile.aspx/S20200108144309.pdf?Id=1a3a31e5-e38d-4445-aada-1cd0170a7b85

136 A pricing hub is typically associated with a marketplace where commodities can be bought and sold at that designated price.

137 Not all utilities reported the source of or the pricing basis for their coal.

To more directly compare fuel pricing, prices have been normalized by commodity energy content and expressed as price per one million British thermal unit ($/MMBtu) in **FIGURE 104. Fuel Prices at Major Pricing Nodes Serving Kansas Utilities**. These results show oil prices to be many times more expensive than gas, which are in turn many times higher than coal. However, the fuel price impact on generation costs is also affected by the energy conversion efficiency of each type of generation technology, which is shown for a range of power generation technologies in **FIGURE 105. Conversion Efficiency by Tech Type and Fuel Source**.

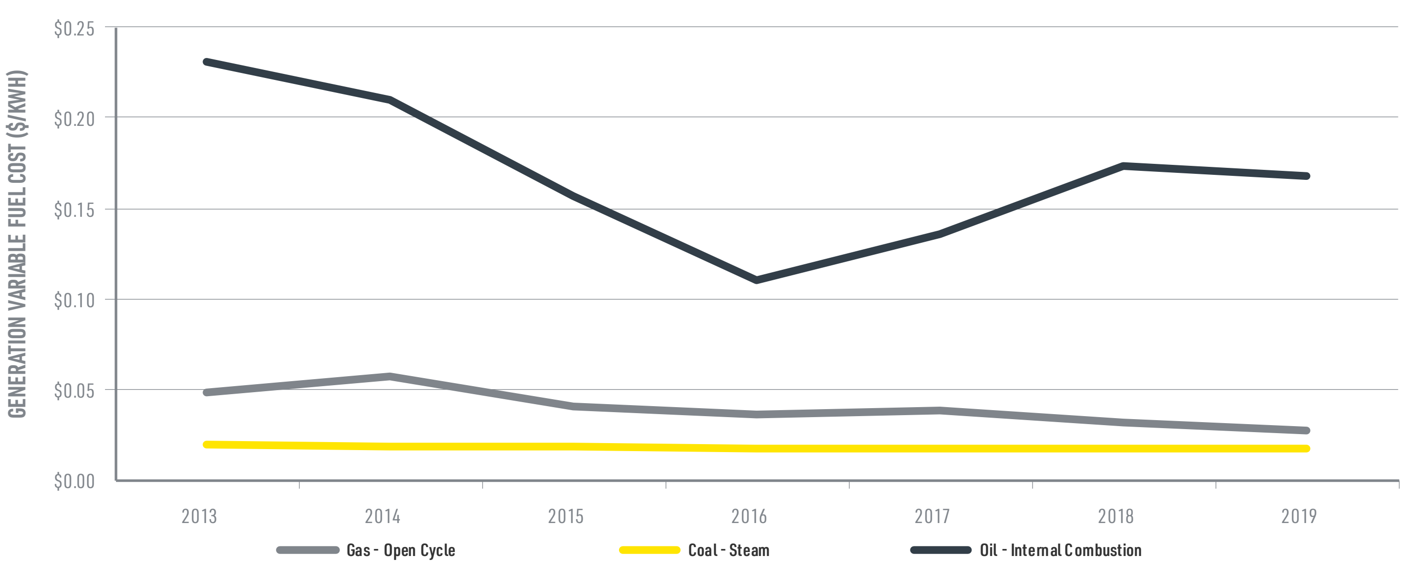
FIGURE 105. Conversion Efficiency by Tech Type and Fuel Source



Source: EIA, Energeia Analysis

Fuel prices impact on the cost of electricity mainly originates from the direct impact fuel prices have on thermal generation operating costs. **FIGURE 106. Electricity Generation Costs by Fuel and Tech Type** reports on the cost per kWh for each type of generation using the fuel prices and energy conversion efficiencies reported in **FIGURE 104. Fuel Prices at Major Pricing Nodes Serving Kansas Utilities - FIGURE 105. Conversion Efficiency by Tech Type and Fuel Source**. Although this simplified approach does not include all variable operating and maintenance costs associated with generation, it does provide a more accurate assessment of the relative competitiveness of each fuel with respect to market dispatch.

FIGURE 106. Electricity Generation Costs by Fuel and Tech Type



Source: EIA, Energeia

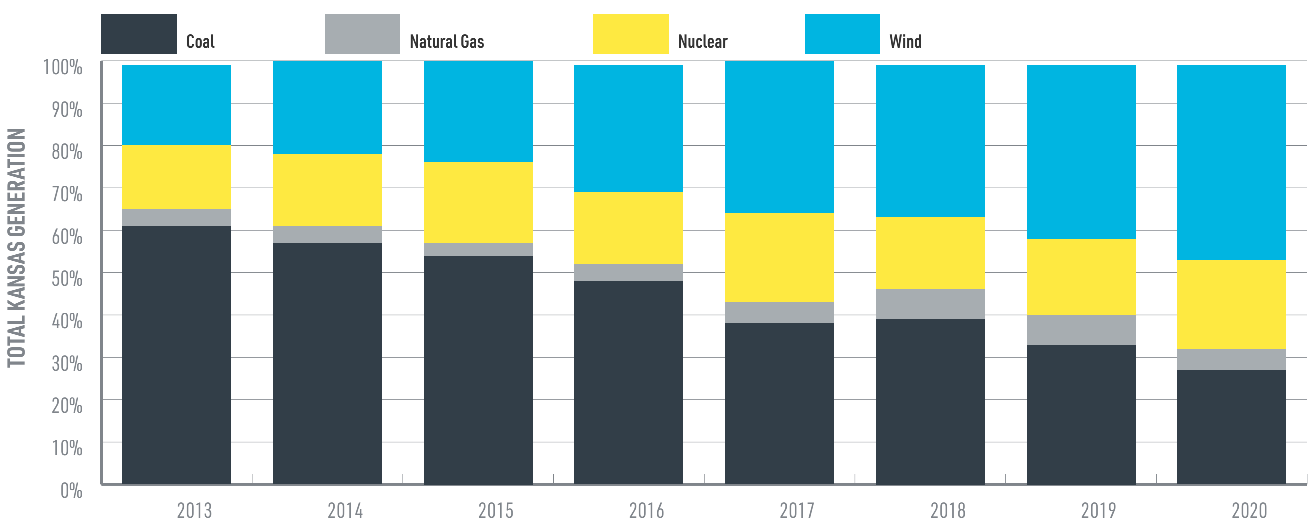
5.13.1.2 KANSAS GENERATION MIX

Kansas is part of the SPP, which dispatches generation based on the principle of least cost, subject to transmission and other operational constraints. Generation prices are set, with some exceptions, based on the most expensive generator needed to serve demand. Each generator's cost is determined by their market bids, subject to transmission and operational constraints.

FIGURE 107. Kansas Generation by Type and Year (2013-2020) shows the significant change in Kansas' generation mix over the last seven years, with coal generation falling from just over 60% of the resource mix in 2013 to 33% by 2019. The decrease in coal generation has been mainly driven by the rise in wind generation, which has grown from 20% in 2013 to 41% by 2019. Gas's market share has remained relatively constant at 5%, and nuclear generation has increased from 15% in 2013 to 18% by 2019.

Wind operating costs are effectively zero in the short term, rendering wind generation able to displace other, higher cost fuels in the SPP merit (least cost) order. Nuclear is typically the next lowest cost source of generation on a short-term operating basis. Other than combined-cycle generation, which does not take place in Kansas, coal is the highest cost generation source for baseload generation.

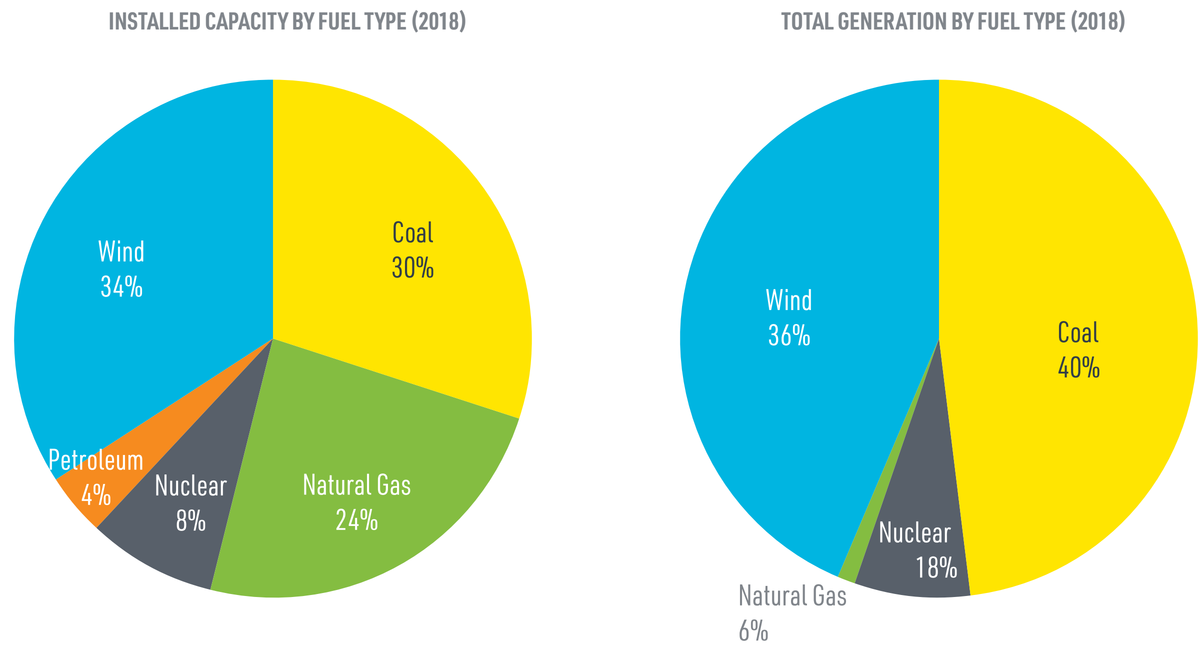
FIGURE 107. Kansas Generation by Type and Year (2013-2020)



Source: EIA (2020)

FIGURE 108. Kansas Generation Capacity and Output by Fuel Type compares the installed capacity of generating stations by fuel type (left) with total generation by fuel source (right). This comparison highlights that mid-merit and peak period generators, including natural gas and oil, generate proportionally less over the year than the baseload generation fuel types discussed above.

FIGURE 108. Kansas Generation Capacity and Output by Fuel Type (2018)

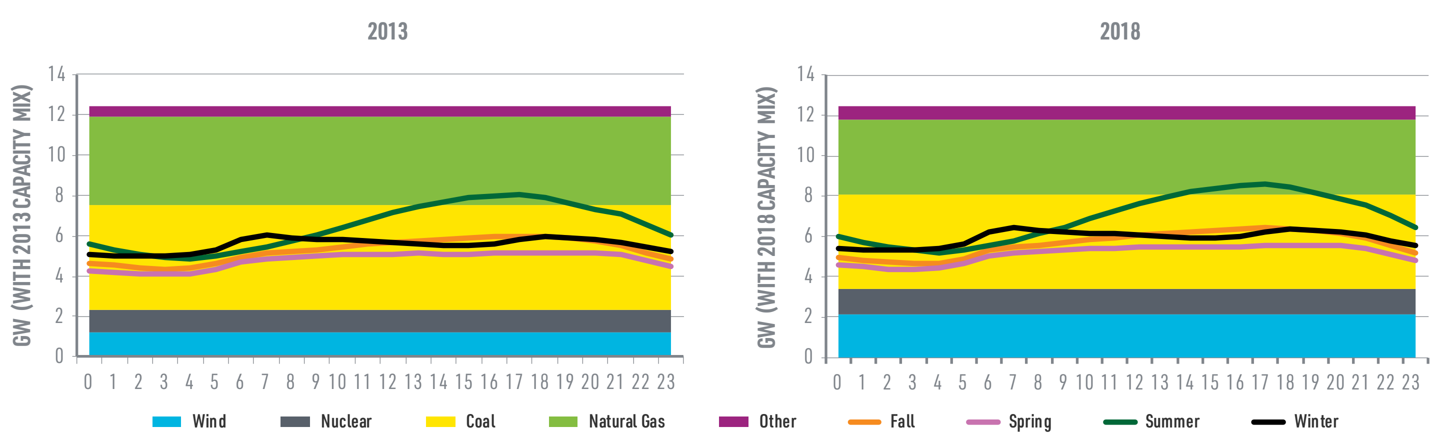


Source: LEI Report, Part 1 of the Study (2020)

As previously mentioned, the key generating station and its associated fuel that drive the price of generation for electricity customers is called the marginal unit.[138] The marginal unit varies over time, as illustrated in **FIGURE 109. Illustration of Marginal Fuel to Meet Kansas Load by Season in 2013 (Left) vs. 2019 (Right)**. Coal is the marginal generating fuel for most of the year, though gas is the marginal fuel during the summer season. It is important to note that the load data summarized by this Figure reflects seasonal averages; loads can be much higher during peak periods.

Interestingly, there is not much difference between 2013 and 2018 data in terms of the expected marginal generating fuel, as the rise in wind generating capacity has been offset by the drop in coal capacity.

FIGURE 109. Illustration of Marginal Fuel to Meet Kansas Load by Season in 2013 (Left) vs. 2019 (Right)



Source: EIA (2013, 2018), Energeia

138 The marginal unit is the last unit dispatched to meet demand at any time, which sets the market price.

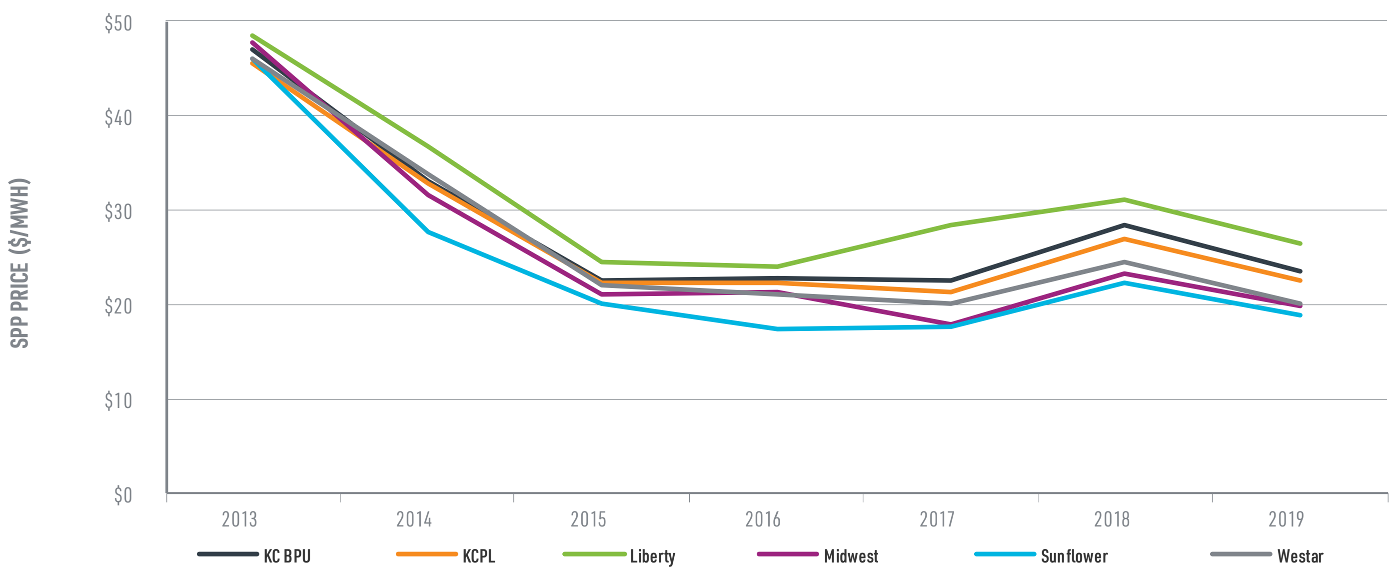
Based on **FIGURE 109. Illustration of Marginal Fuel to Meet Kansas Load by Season in 2013 (Left) vs. 2019 (Right)**, natural gas power stations would be most frequently expected to set prices in the SPP during peak periods.

5.13.1.3 GENERATION PRICES

As the SPP has expanded regionally and the generation mix has changed due to fuel costs, generation prices paid by Kansas utilities and their customers have varied significantly since 2013. **FIGURE 110. Time Weighted SPP Day Ahead Prices by Selected Utility** shows the time weighted average prices[139] by utility.

All utility prices fall significantly from around the $45/MWh level in 2013 to $20-$25/MWh by 2015, but then prices diverge, ranging from $20/MWh to $30/MWh over the 2016 to 2019 period.

FIGURE 110. Time Weighted SPP Day Ahead Prices by Selected Utility



Source: SPP, Energeia

A visual comparison of SPP generation prices for selected KS utilities in **FIGURE 110. Time Weighted SPP Day Ahead Prices by Selected Utility** against fuel price movements reported in **FIGURE 106. Electricity Generation Costs by Fuel and Tech Type** suggests SPP market pricing for Kansas utilities mostly correlates with oil and to a lesser degree natural gas prices.

The robustness of this qualitative assessment against more rigorous analytical methods, and the ultimate bearing of generation cost changes on customers' overall electricity costs, is the focus of this matter.

5.13.2 SCOPE AND APPROACH

The project team's approach to the question posed by this matter involved the following steps:

- Gathering and analyzing information regarding each utility's fuel purchasing policies and practices, and the fuel delivery and pricing points used for settlement;
- Gathering stakeholder views and materials with respect to the question and related matters via stakeholder engagement processes; and
- Modeling the relationship between fuel prices and generation prices, as well as the level of change in retail electricity costs that can be explained by changes in fuel prices.

139 The SPP was unable to provide volume weightings for each price node due to confidentiality requirements.

5.13.3 INFORMATION GATHERING

Information to answer this question was gathered via the RFI process, via meetings with key stakeholders as outlined in **Section 4.2**, and independent research.

5.13.3.1 SUMMARY OF RFI REQUESTS, RESPONSES, GAPS AND WORKAROUNDS

The RFI was issued with the following information requests related to this matter:

13.1: Please send ten year historical and forecast fuel prices (e.g. distillate/kerosene, natural gas, coal, etc.) and total costs by fuel and cost type (e.g. trucking, storage, etc.).

13.2: Please send details regarding fuel price procurement contracts for last five years, esp. state, end, duration, delivery point, pricing and take or pay terms.

13.3: Please send fuel price hedge policies.

In other portions of the RFI, additional information was requested for use as a basis for economically assessing the impact of fuel prices on electricity costs:

- SPP pricing data by utility; and
- SPP load data by utility.

Historical fuel prices were provided by most of the generating utilities, while forecasted prices were provided by a smaller subset of utilities. Few fuel contracts were provided; some could only be viewed in person at the utility's head office. Hedge policies were provided by 31% of the utilities that responded to the RFI.

SPP data was provided by pricing node, along with information regarding how SPP settlement operated. Due to confidentiality restrictions, utility-specific load data could not be provided by the SPP by the time the Study was due. This represented the most significant gap in data, as utility-specific prices could not be directly determined. To work around this gap, a simple averaging of all settlement nodes for a given utility was performed to estimate SPP prices.

In the absence of information regarding fuel contracts and hedging policies, it was not possible to provide additional insight into how fuel prices are passed through to generation prices, above and beyond the statistical analysis of the pricing relationships completed below.

5.13.3.2 STAKEHOLDER FEEDBACK

One consumer advocate stated that high electricity rates in the state are due to coal plants being overpriced and under-utilized from hold-over utility contracts established 20 years ago, when coal was cheaper than gas. Other stakeholders agreed, adding that coal plants and combustion turbine natural gas plants cannot compete with new technologies (wind, solar and long-term low-cost natural gas), which also helps drive up generation costs, and thus electricity rates.

An environmental advocate argued that fuel price fluctuations largely depend on whether the energy source is fossil or renewable. They cited the Rocky Mountain Institute, which determined that energy portfolios incorporating renewable energy sources and demand-side management show lower risk and better prices than gas-fired plants. Based on this analysis, they concluded that renewables are cheaper and more stable than fossil fuels.

5.13.4 KEY FINDINGS AND CONCLUSIONS

An *economic analysis of the price fluctuations of generation fuels on the cost of electricity* requires an assessment of the relationship between fuel price fluctuations and generation costs, and an understanding of the role of generation costs on the overall cost of electricity.

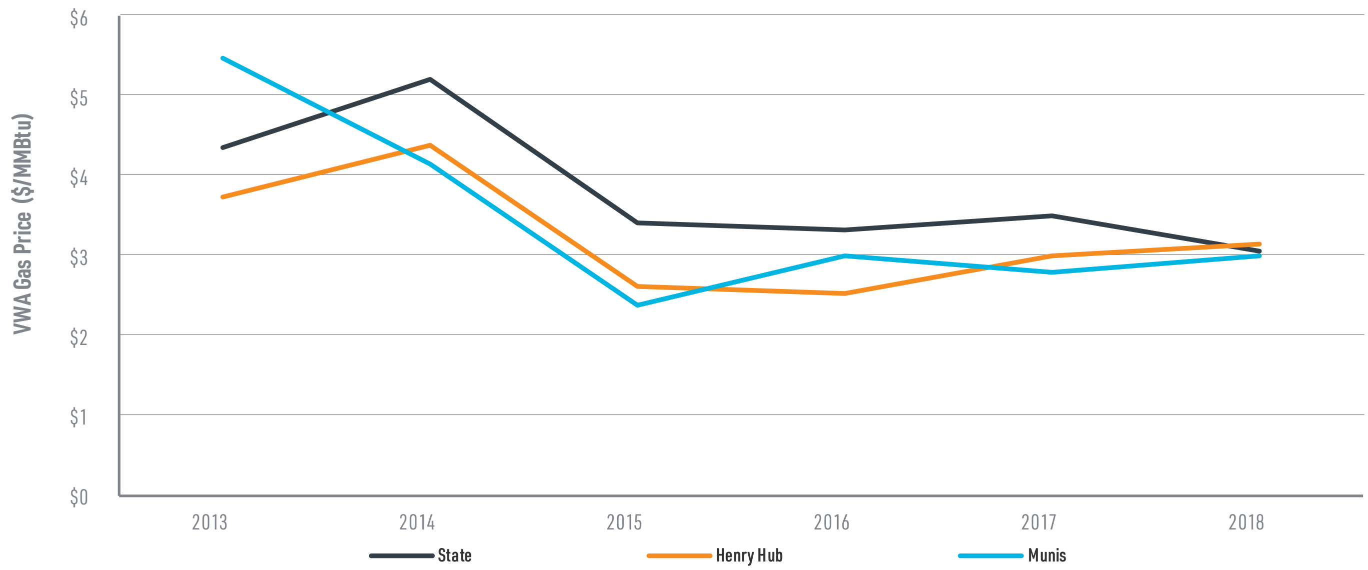
The following sections summarize our key findings, analysis and conclusions related to this matter.

5.13.4.1 GENERATION UTILITY FUEL PRICES

Utility gas prices are reported by utility type and at the state level in **FIGURE 111. Annual Gas Priced by Utility Type and Commodity Benchmarks**, along with the benchmark Henry Hub price. [redacted]

[redacted]

FIGURE 111. REDACTED Annual Gas Priced By Utility Type and Commodity Benchmarks (IOUs and Coop information is omitted)



Source: EIA, Energeia

Where gas-fired power stations are setting the SPP price, higher fuel prices will flow through to higher SPP generation prices and generation costs. Thus, higher IOU fuel prices can impact Munis and Coops who share common SPP settlement points with IOUs, as described in **Section 5.7**.

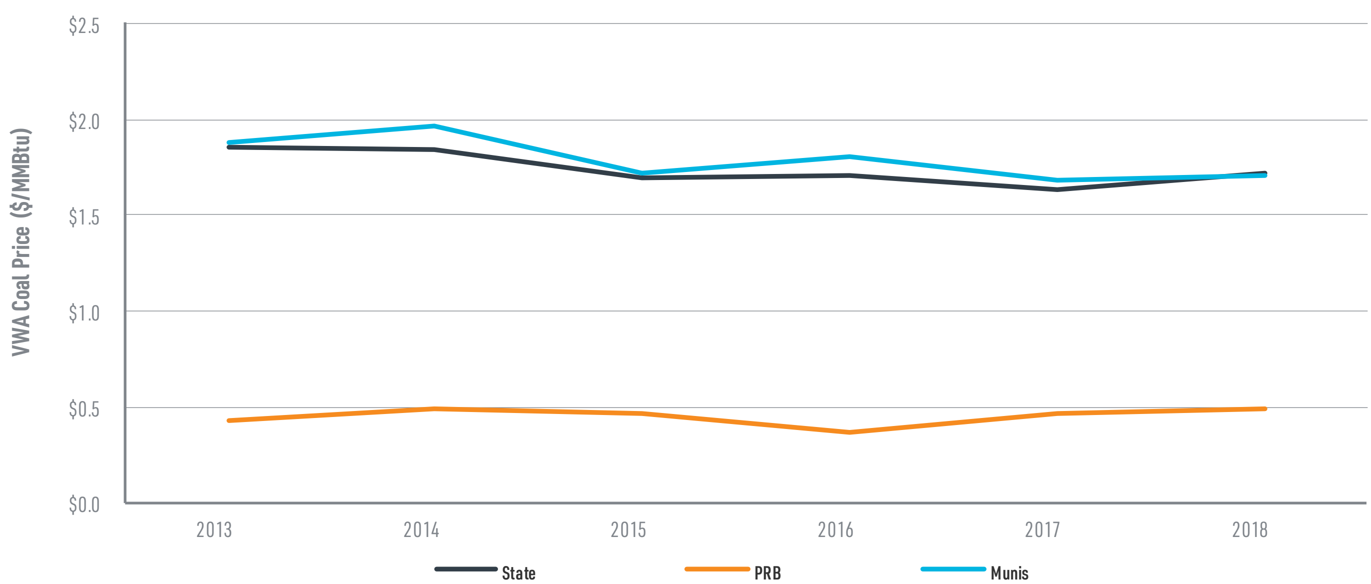
[redacted]

Source: EIA, Energeia

Although oil is very rarely the marginal unit and thus rarely sets the SPP market clearing price, it is usually during times of extreme shortages, when prices spike. This can lead to an over-representation of kerosene and diesel fired unit costs in SPP pricing outcomes over the year.

Utility-reported coal prices are shown by utility type at the state level in **FIGURE 113. Annual Coal Prices by Utility Type and Commodity Benchmarks**, along with the Powder River Basin (PRB) commodity benchmark market price.[140] The coal prices shown exhibit a much different and less volatile pricing trajectory as compared to natural gas and oil. [redacted]

FIGURE 113. REDACTED Annual Coal Prices by Utility Type and Commodity Benchmarks (IOU and Coop information is omitted)



Source: EIA (2019), Energeia

As previously discussed, coal fired power stations do not ordinarily set the SPP price because they are almost never the marginal unit to be dispatched. Therefore, coal fuel prices would not be expected to feed through to SPP generation prices. As wind generation increases, however, coal units could increasingly find themselves setting the market clearing price during periods of relatively low consumption.

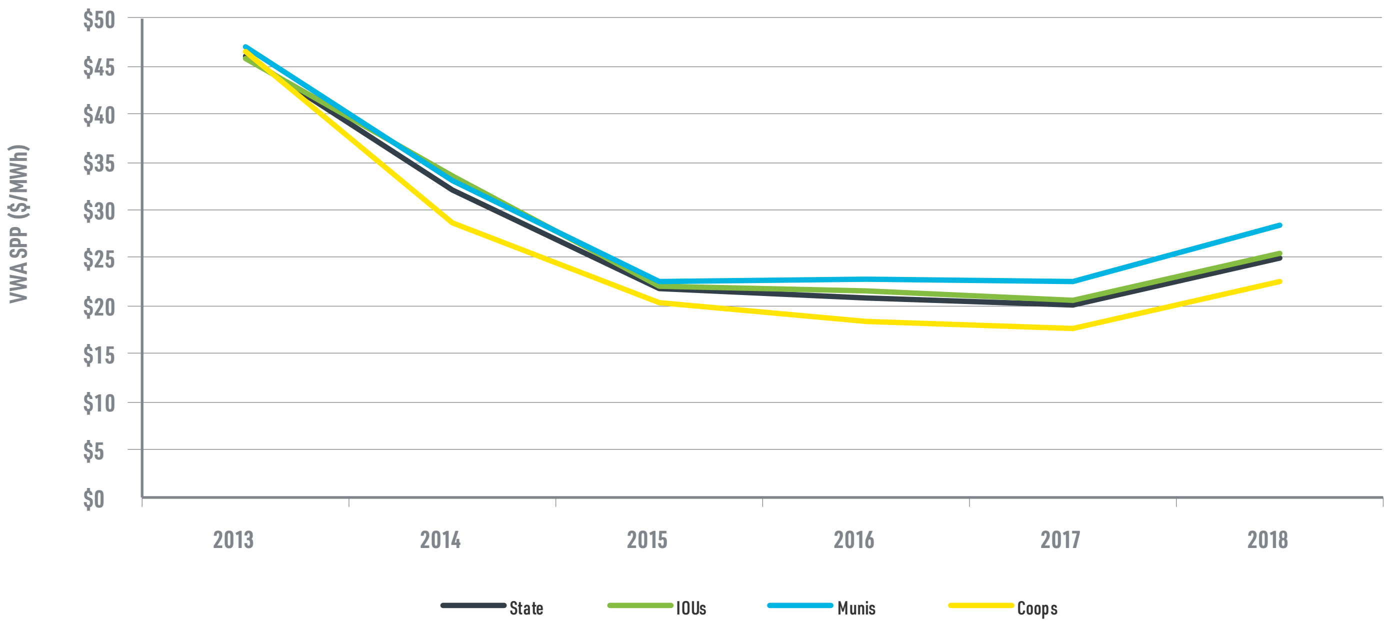
5.13.4.2 GENERATION & TRANSMISSION UTILITY WEIGHTED ELECTRICITY PRICES

The next phase of the analysis involved determining the SPP market prices over time, which are used to settle utilities' consumption in the SPP. Due to a lack of data, pricing node weighted averages were determined. Then, each utility's average settlement price per half hour in 2019 was multiplied by its reported hourly load to arrive at average annual generation cost.

FIGURE 114. Volume Weighted Average SPP Prices by G&T Utility Category provides the estimated volume weighted average SPP price by utility over time. The resulting price series show that utilities experience similar SPP prices and therefore marginal generation costs per MWh. Muni costs have increased more over time relative to other utility types, while Coop costs have fallen by comparison. IOU costs sit about midway in between.

140 A benchmark price is a published price from a trading hub that is typically used to set prices in contracts.

FIGURE 114. Volume Weighted Average SPP Prices by G&T Utility Category



Source: SPP, Energeia

The penultimate step in this analysis was merging the fuel and SPP market prices, first using a visual heuristic and then with a more analytically robust methodology.

5.13.4.3 FUEL PRICE IMPACTS ON GENERATION COSTS

FIGURE 115. Load weighted SPP, Gas, Oil and Coal Prices shows consumption-weighted fuel price series for each fuel type alongside the similarly weighted SPP price, at the state level. The time series was shortened relative to the previous analysis to better isolate retail price trends after 2014. An index is used to better compare pricing levels.

At the state level, **FIGURE 115. Load weighted SPP, Gas, Oil and Coal Prices** shows that natural gas prices appear to be most closely correlated with SPP price movements over the 2014 to 2017 period, after which time, oil prices appear to be most closely correlated. Although less obvious due to their relative stability, coal prices also follow a similar path as SPP prices over time. [redacted]

FIGURE 115. Load weighted SPP, Gas, Oil and Coal Prices

Source: EIA, Energeia

Statistical relationships between fuel prices and SPP prices for each Kansas utility were also analyzed by the project team. This was done by regressing each utility's annual VWA SPP price against each of its fuel prices. The results of the regression, summarized by R-squared (R^2) values, are provided in the **FIGURE 116. Statistical Assessment of Fuel and SPP Generation Prices** for selected utilities.[141]

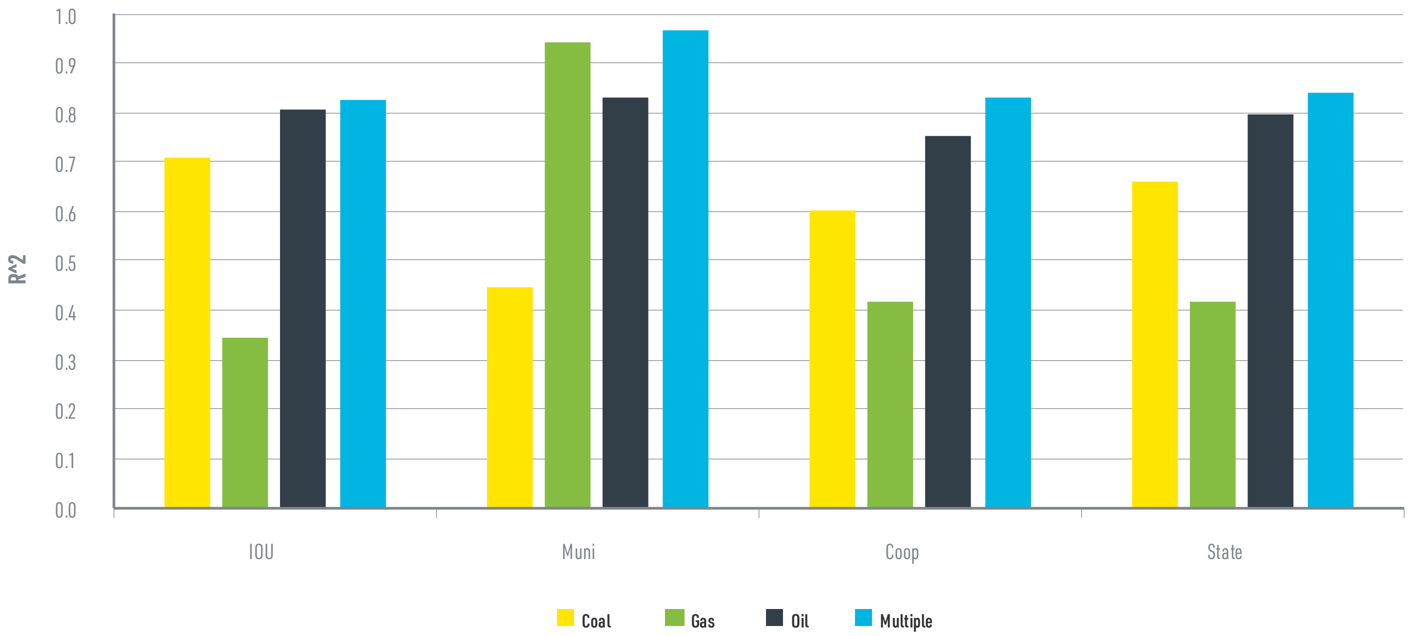
For the most part, this more comprehensive statistical analysis confirms the earlier visual analysis. Based purely on the input SPP prices and fuel prices by utility, the statistical analysis shows:

- IOUs: Oil prices show the highest correlation with SPP prices, however coal prices are also strongly correlated. Gas appears to be correlated only about 30% of the time.
- Munis: Munis included in this analysis have a higher percentage of gas fired generation, so their SPP prices are most strongly correlated with gas prices.
- Coops: Coops included this analysis show a more mixed picture, with neither coal nor gas showing a high correlation with their SPP price.

The final step in the statistical analysis was to regress all input fuel prices on the SPP price to determine the combined impact on generation prices. The results are reported in **FIGURE 116. Statistical Assessment of Fuel and SPP Generation Prices**, which show fuel price movements accounting for between 79% and 96% of the overall movement in generation prices, depending on the utility category. The minimal increase in R^2 resulting from using all fuel inputs in the multi-factor regression suggests that utility, oil, and natural gas prices tend to move together.

141 R^2 is a statistical measure of how much one variable changes with another variable. In this case, it is used to measure the variation in the SPP price given variation in fuel price.

FIGURE 116. Statistical Assessment of Fuel and SPP Generation Prices



Source: Energeia

There are important caveats related to this analysis. First, the analysis was limited to utilities that provided fuel prices and for which the project team could reasonably associate their load with SPP settlement prices. Secondly, the annual volume weighting was based on each utility's reported system load, rather than the actual SPP settlement volumes, which were not provided due to confidentiality restrictions.

Based on this analysis, the project team has reached the conclusion that fuel price variations account for 79-96% of utility generation cost variations over the 2014 to 2016 period.

5.13.4.4 GENERATION COST IMPACTS ON ELECTRICITY COSTS

The final step in the analysis was to put the impact of fuel prices on generation costs into perspective by considering the role of generation in overall electricity costs, which was reported by utility category and customer class in the **FIGURE 96. Utility Cost Allocation of Total Charges by Utility Type** in **Section 5.10**. Based on the analysis, the impact of fuel price fluctuations has been estimated by customer class and utility category in **FIGURE 117. Impact of Fuel Fluctuation on Total Retail Electricity Costs** below.

The analysis shows that between 50% and 70% of variation in electric rates can be explained by fluctuations in fuel price. [redacted] These differences can be partially explained by generation costs' relative share of total electric costs, as well as differences in the R^2 relationship.

[redacted]

[redacted]

[redacted]

Based on this analysis, the project team has reached the conclusion that fuel price variations account for 50-70% of electricity cost variations over the period from 2014 to 2018, depending on the type of utility.

5.13.4.5 THE ROLE OF CONTRACTS AND HEDGING ACTIVITY

The impact of utility contracting and hedging strategies on electricity rates could not be analyzed due to the lack of information provided regarding fuel contracts and hedging policies and practices. The above estimated impacts on overall rates could vary significantly where fuel contracts and hedging strategies change a utility's exposure to the SPP market price.

A REQUEST FOR INFORMATION

Matters to be addressed by the Study as set forth by Senate Bill 69, are shown in blue in the table below. Data and information requests to address those matters are shown under each matter.

TABLE 30. Request for Information

1	**Whether any costs incurred by Kansas electric public utilities to build and operate electric vehicle charging stations, including any necessary upgrades to distribution infrastructure, are recovered from ratepayers not using electric vehicle charging services;**
1.1	How many public EV charging stations do you operate or plan to operate in the future?
1.2	What is your calculated current or forecast capital and operating expenses (including replacement costs) needed to fund EV charging services?
1.3	How much of these costs are passed on to ratepayers not using EV charging services?
1.4	What is your calculated current or forecast capital and operating expenses by type (including replacement costs) relating to upgrades to distribution & transmission infrastructure necessitated to fund EV charging services not provided above?
2	**How rates for electric vehicle charging services should be designed to ensure such rates are just and reasonable and not subsidized by other utility customers;**
2.1	How do you recover the costs of EV charging services (e.g. monthly fixed fee, flat kWh, Time of Use kWh, etc.)?
2.2	How do you or will you ensure that EV charging services are just and reasonable and not subsidized by other utility customers?
2.3	Provide copies of tariffs, riders, or other cost recovery mechanisms associated with EV charging services.
3	**The potential effects of deregulating electric vehicle charging services in Kansas, including whether deregulation would ensure that electric vehicle charging services are not subsidized by public utility ratepayers not using electric vehicle charging services;**
3.1	What costs (e.g. inspection, compliance, market development and market support costs) do you expect to incur if EV charging services are deregulated in Kansas?
3.2	What benefits do you expect your rate payers will forego (e.g. higher asset utilization, lower cost of capital) if EV charging services are deregulated?
3.3	What benefits do you expect your rate payers to receive (e.g. more competitive pricing, greater choice, more innovation) if EV charging services are deregulated?
4	**Whether Kansas consumers could benefit from improved access to advanced energy solutions, including micro grids, electric vehicles, charging stations, customer generation, battery storage and transactive energy;**
4.1	Please send us a table of customer advanced energy solution program enrollment that includes customer ID, premise ID, program ID, start date, solution sizing / configuration, etc. which can be used to generate #s, MWs, and MWhs of each program by year for the last five years.
4.2	Please send us the last 5 years of 8760 profiles of residential customers (including sub-loads where available) including meter ID to map to customer data.
4.3	Please send information regarding residential customers including transformer ID, customer ID, premise ID, meter ID, address, XY, Parcel ID, customer type, rate code, economic development contract, annual consumption, annual charges
4.4	Please send the number of microgrids, EVs, charging stations, customer generation (solar PV, cogeneration, backup gensets), battery storage and/or transactive energy sites on your network by customer class by year for the last five years.

4.5	Please send the MWs of microgrids, EVs, charging stations, customer generation (solar PV, cogeneration, backup gensets), battery storage and/or transactive energy sites on your network by customer class by year for the last five years.
4.6	Please send the annual MWhs of microgrids, EVs, charging stations, customer generation (solar PV, cogeneration, backup gensets), battery storage and/or transactive energy sites on your network by customer class by year for the last five years.
4.7	What programs to you currently or plan to offer related to microgrids, EVs, charging stations, customer generation, battery storage and/or transactive energy by customer class?
4.8	Please provide copies of all feasibility studies (economic, technical, etc.) relating to the types of programs described above which were prepared and/or utilized by your utility during the last five years, regardless of whether the program was implemented.
4.9	Please provide copies of tariffs, riders or other cost recovery mechanisms associated with the programs described above.
5	**The extent to which transmission investments by Kansas electric public utilities have impacted retail rates, including any incremental regional transmission costs incurred by Kansas ratepayers for transmission investments in other states, and whether such costs have been fully offset by financial benefits such as improved access to low-cost renewable energy and wholesale energy markets;**
5.1	Please send your transmission investment and associated operating expenses over the last 10 years in Kansas and in other states by year.
5.2	Please send us the economic feasibility analysis completed and accepted by the SPP related to each of the above investments.
5.3	Please send us any economic feasibility analysis completed within the past 10 years (whether or not accepted by the SPP) with regard to transmission investments.
5.4	Please send transmission costs recovered from your consumers over the last 10 years by rate and year.
6	**The costs and benefits incurred by Kansas ratepayers for transmission investments in Kansas, used to export energy out of Kansas**
6.1	Please send us a GIS map of your transmission system, including voltages, ratings, etc.
6.2	Please send us 8760 data (and meter IDs to relate to asset and network data) on flows over the lines used to export power over the past 10 years
6.3	Please send us total transmission imports and exports (GWhs) by transmission asset and year for the last 10 years
6.4	Please send total revenue received for transmission service for imports and exports over the past 10 years by asset, year and type of service
6.5	Please send us the total capital and operating costs by type (e.g. construction, operations, maintenance, etc.) of each transmission line used to export power from Kansas over last 10 years by year.
6.6	Please send us the allocation of transmission costs to each customer class over the past 10 years by year.
6.7	Please send us the cost-benefit studies used to justify the transmission investments over the past 10 years or note if any such studies were provided in response to previous requests.
7	**How rate increases, or the associated rising costs of Kansas investor-owned electric public utilities, impact the retail electric rates of Kansas electric cooperatives and municipal utilities;**
7.1	Please send generation costs recovered from your consumers over the last 10 years by rate, year and type of charge.
7.2	Please send SPP costs other than generation and transmission recovered from your consumers over the last 10 years by rate, year and type of charge.
7.3	If a Muni or Coop, please send any other costs from IOUs passed on to consumers over the last 10 years by year, rate and type of charge.
8	**Whether retail electric rates in Kansas are a material barrier to economic development in Kansas;**
8.1	Please send number of non-residential customers for last 10 years by year, rate category and location.

8.2	Please send non-residential customer consumption (MWh) for last 10 years by year, rate category and location.
8.3	Please send information regarding any economic development rates and/or contracts agreed to over the last 10 years, including information, by year for each customer, usage, applicable rate schedule and percent of reduction under the economic development tariff/rider/rate or contract.
8.4	Please send information regarding current or previous economic development policies or programs for the last 10 years.
8.5	Please provide any economic development program/tariff/rider/rate/contract feasibility studies prepared or utilized in the last 10 years regardless of whether the program/tariff/rider/rate/contract was implemented.
8.6	Please provide copies of tariffs, riders or other cost recovery mechanisms associated with the economic development rates or contracts described above.
9	**The impact of contract rates with commercial and industrial customers and economic development rates on other customer classes, including whether expanded utilization of such approaches can benefit all customers over time;**
9.1	Please send information regarding treatment of economic development contracts and rates in terms of cost of service and revenue recovery.
9.2	Please send the last 5 years of 8760 profiles of non-residential customers and a metering ID enabling mapping of the data to customer information.
9.3	Please send information regarding non-residential customers including transformer ID, customer ID, premise ID, meter ID, address, XY, Parcel ID, NAICS, rate code, economic development contract, annual consumption, annual charges.
10	**Whether Kansas electric public utilities recover their costs of serving customers from each customer class on the basis of cost causation;**
10.1	Please send us your cost of service, cost allocation and rate design models from the last 5 years.
10.2	Please send us your cost of service, cost allocation and rate design studies / reports for the last 5 years.
10.3	Please send us your 8760 profiles for the last 5 years by customer rate class.
10.4	Please send us, if not identified in the above requests, your cost of service directly related to environmental regulation and the allocation of those costs from the last 10 years.
11	**How cyber and physical security and grid stabilization efforts have affected, or are projected to affect, electric public utility rates;**
11.1	Please send us 5 year historical and planned capital and operating costs related to physical security efforts by type.
11.2	Please send us any studies undertaken related to physical security needs and costs prepared (whether or not implemented) or utilized in the last 5 years.
11.3	Please send us 5 year historical and planned capital and operating costs related to cyber security efforts by type.
11.4	Please send us any studies undertaken related to cyber security and costs prepared (whether or not implemented) or utilized in the last 5 years.
11.5	Please send us 5 year historical and planned capital and operating costs related to any other grid stabilization efforts.
11.6	Please send us any studies undertaken related to grid stabilization needs and costs prepared (whether or not implemented) or utilities in the last 5 years.
12	**The value of a utility integrated resource planning process that requires state regulatory approval; and**
12.1	Please send us your resource planning policies and procedures.
12.2	Please send us your current resource planning costs (e.g. hours, rates, contract expenses) by year for the last 5 years. If actual costs are unknown, provide an estimate of the costs with the methodology (hours, rates, contract expenses, etc) under which the estimate was prepared.
12.3	Please provide a copy of your most recent Kansas Generation Planning Survey and/or Integrated Resource Plan.

12.4	Provide a statement of costs to prepare each of the document(s) described in item 12.3 and similar documents prepared as part of your resource planning and procedures described in 12.1. If actual costs are unknown, provide an estimate of the costs with the methodology (hours, rates, contract expenses, etc) under which the estimate was prepared.
12.5	Please provide an estimate of the cost of moving to an IRP process with state regulatory approval along with the methodology (hours, rates, contract expenses, etc) under which the estimate was prepared.
12.6	Please provide an estimate of the benefits of moving to an IRP process with state regulatory approval.
13	**Economic analysis of the price fluctuations of generation fuels on the cost of electricity.**
13.1	Please send 10 year historical and forecast fuel prices (e.g. distillate/kerosene, natural gas, coal, etc.) and total costs by fuel and cost type (e.g. trucking, storage, etc.).
13.2	Please send details regarding fuel price procurement contracts for last 5 years, esp. state, end, duration, delivery point, pricing and take or pay terms.
13.3	Please send fuel price hedge policies.

B NON-UTILITY STAKEHOLDERS

Representatives from the non-utility organizations below were involved the stakeholder engagement process:

- Advanced Biofuels
- Americans for Prosperity
- Berexco
- Central Kansas Clean Cities Coalition
- Climate and Energy Project
- Consumer Utility Ratepayer Board
- East Kansas Agri-Energy
- Flint Hills Renewable Energy & Efficiency Cooperative
- Good Energy Solutions
- Kansans for Lower Electric Rates
- Kansas Chamber
- Kansas Corporation Commission
- Kansas Department of Commerce
- Kansas Independent Oil and Gas Association
- Kansas Industrial Consumers Group
- Kansas Interfaith Action
- Kansas Sierra Club
- Kansas Soybean Association
- Kansas Advanced Power Alliance (The Wind Coalition)
- Metropolitan Energy Center
- Natural Resources Defense Council, Inc.
- Southwest Power Pool
- US Amy, Regional Environment and Energy Office
- Wichita Public Schools

C COST OF SERVICE MODELLING METHODOLOGY

OVERVIEW

Energeia's cost of service model generates bottom-up estimates of utility cost to serve by calculating the impact of any 8760-load profile on utility cost factors including:

- Generation
- Transmission
- Distribution
- Supply [1]

Impacts can be calculated using actual benchmark loads and costs or forecast future loads and unit costs using scenarios-based assumptions.

The model was configured with Kansas utility customer load and generation profiles and marginal cost information by cost factor provided via the Request for Information or via research were necessary.

The modelling results were used to estimate current marginal utility cost of service, customer bill impacts and cross-subsidies for a range of different load and generation types including:

- Residential, commercial and industrial customer load
- Solar PV generation
- Electric vehicle charging load
- Behind the meter battery storage
- Microgrids

The last step was to aggregate results by utility category and at the state level, based on each category's total annual consumption.

METHODOLOGIES

The Cost of Service Model (COSM) estimates the impact of load and distributed energy resource profiles on customer, utility and community costs per the table of cost factors, impact assessment and cost estimation measures below.

1 Also referred to as customer costs and/or retailing costs.

TABLE 31. Cost of Service Estimation Methodologies by Type

Cost Center	Cost Category	Impact Measure	Cost Measure	Included in Study
Customer	Electricity Bill	Varies by rate structure	Qty * rate	✓
	Gas Bill	Varies by rate structure	Qty * rate	
	Gasoline Bill	Change in fuel consumption	Qty * rate	✓
	Unserved Energy	Change in minutes * load	kWhs * value of lost load	✓
Generation	Resource Adequacy	Change in CP1	CP1 * marginal cost	
	Energy Costs	Change in hourly kWh	kWh * hourly price	✓
	AS* Costs	Change in AS levels	Qty * VWA** price	
	CO2 Costs	Change in CO2 emissions	CO2 * certificate price	
	Renewable Costs	Change in kWh	kWh * certificate price	
Transmission	Thermal Overload	Change in CP1/4/12	CP1/4/12 * marginal cost	✓
	Transmission Charges	Varies by rate structure	Qty * rate	
Distribution	Thermal Overload	VWA change in asset NCP	NCP * marginal cost	✓
	Voltage Constraints	Change in PV kW	kW * marginal cost	
Supply	Metering	Change in customer numbers	Customers * marginal cost	
	Other	Change in customer numbers	Customers * marginal cost	

* AS = Ancillary Services

**VWA = Volume Weighted Average

Source: Energeia

DER OPERATION RULES

When estimating the impact of controllable DER including battery storage, thermal generation and load management (including EVs), the model can be configured to operate (by the customer) so as to minimize the customer's bill or operated (by the utility) to minimize the utility's cost of service.

MICROGRIDS

When estimating the cost to serve of a microgrid, the model is set such that all load must be satisfied by the selected resource options, which include thermal generation plant, solar PV, battery storage and load management.

RESOURCE OPTIMIZATION

The model can be configured to identify optimal DER configurations for a given load profile, utility cost structure and optimization constraints, for the purpose of integrated resource planning. This can be applied at the premise, asset or other level of load aggregation.

FORECASTING

The model can be configured for a given year, with 2019 being the benchmark year for load and cost actuals. Future years are estimated using forecast values and/or scenario growth assumptions.

KEY INPUTS AND ASSUMPTIONS

The following sections describe our key inputs and assumptions.

LOAD PROFILES

Load profiles for each customer class were taken from RFI responses and scaled to a common annual consumption for cross utility-category comparisons.

For example, commercial customer class load profiles were scaled to 100 MWh of annual consumption.

SOLAR GENERATION PROFILES

Solar generation profiles were obtained from NREL's solar generation tool[2] configured for an appropriate location in Kansas for the given utility.

GENERATION MARGINAL COST

Generation energy costs were sourced from SPP settlement data. Due to the lack of settlement load data, settlement prices were simply averaged across the relevant transmission area for the given utility.

TRANSMISSION MARGINAL COSTS

SPP transmission charges per CP12 for the relevant transmission customer were used as a proxy for marginal transmission costs.

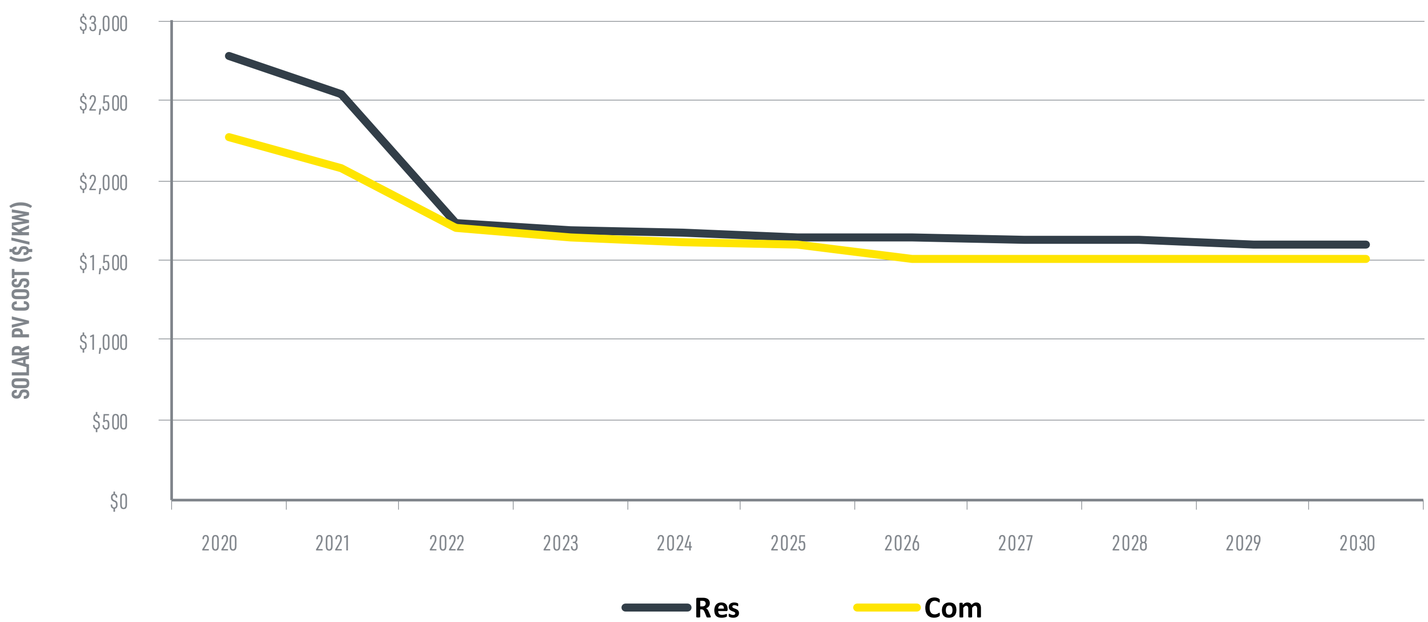
DISTRIBUTION MARGINAL COST

In the absence of detailed load and marginal cost information by voltage level, total distribution costs from each utility's cost of service model was divided by the utility's CP1 as a proxy for distribution marginal cost. Energeia recognizes that this is an embedded rather than marginal cost estimate.

SOLAR PV COST

Solar PV costs were estimated by researching current solar PV prices in Kansas, and then applying Energeia's forecast solar PV growth rates, which are based on an industry consensus forecasting approach. The forecast values are shown below.

FIGURE 118. Forcasted Costs of Rooftop Solar PV



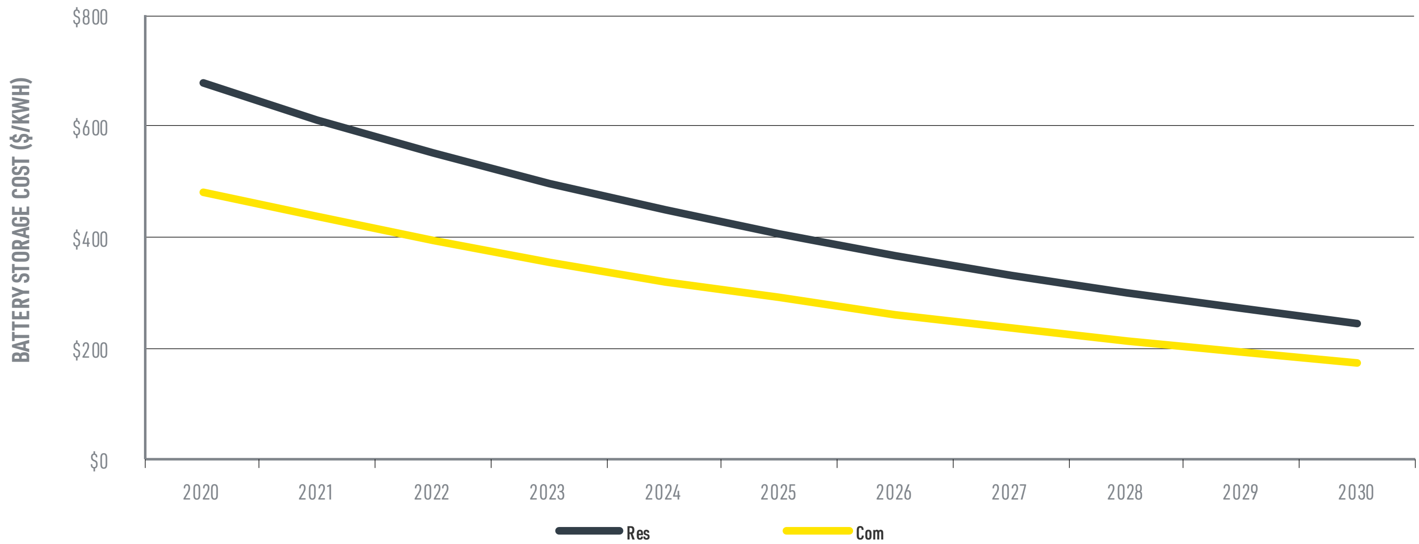
Source: Energeia (2019)

2 https://pvwatts.nrel.gov/

BATTERY STORAGE COSTS

Lithium battery costs were estimated by researching current lithium battery prices in Kansas, and then applying Energeia's forecast lithium battery growth rates, which are also based on an industry consensus forecasting approach. The forecast values are shown below.

FIGURE 119. Forecast Costs of Lithium Battery Storage

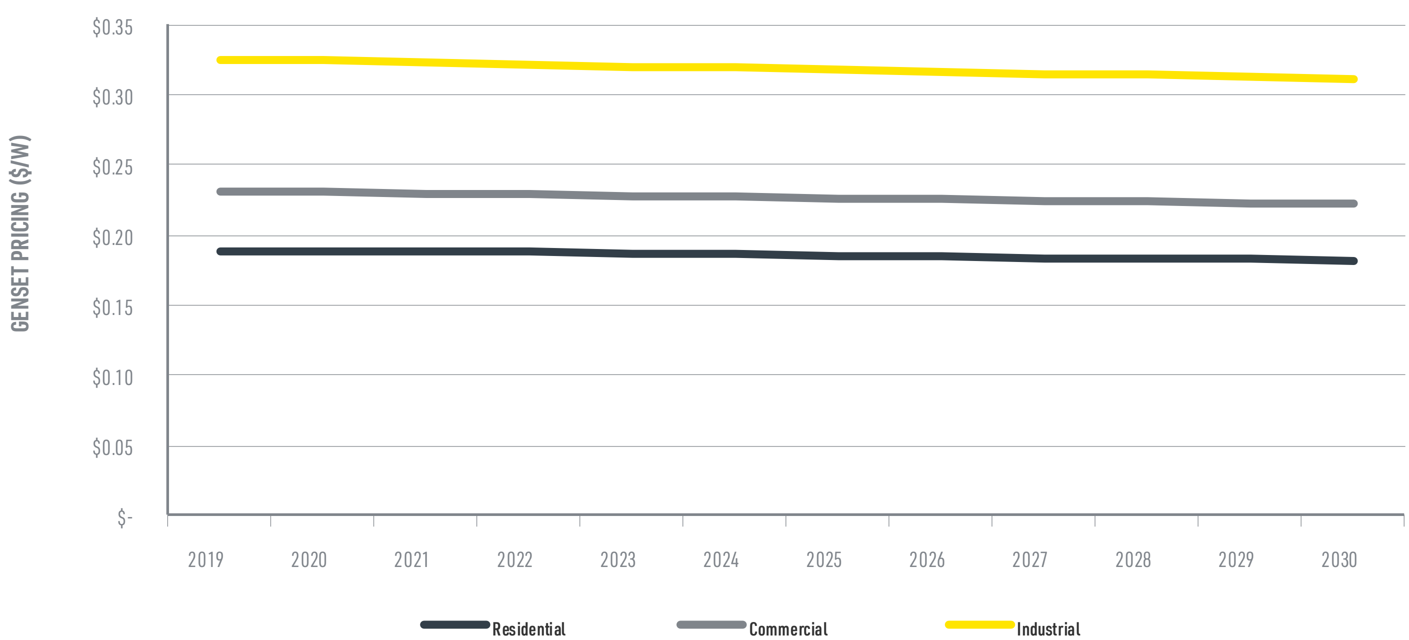


Source: Energeia (2019)

THERMAL GENERATION COSTS

Thermal generation costs were estimated by researching current backup generation prices in Kansas, and assuming a CPI level of cost growth.

FIGURE 120. Thermal Generation Costs

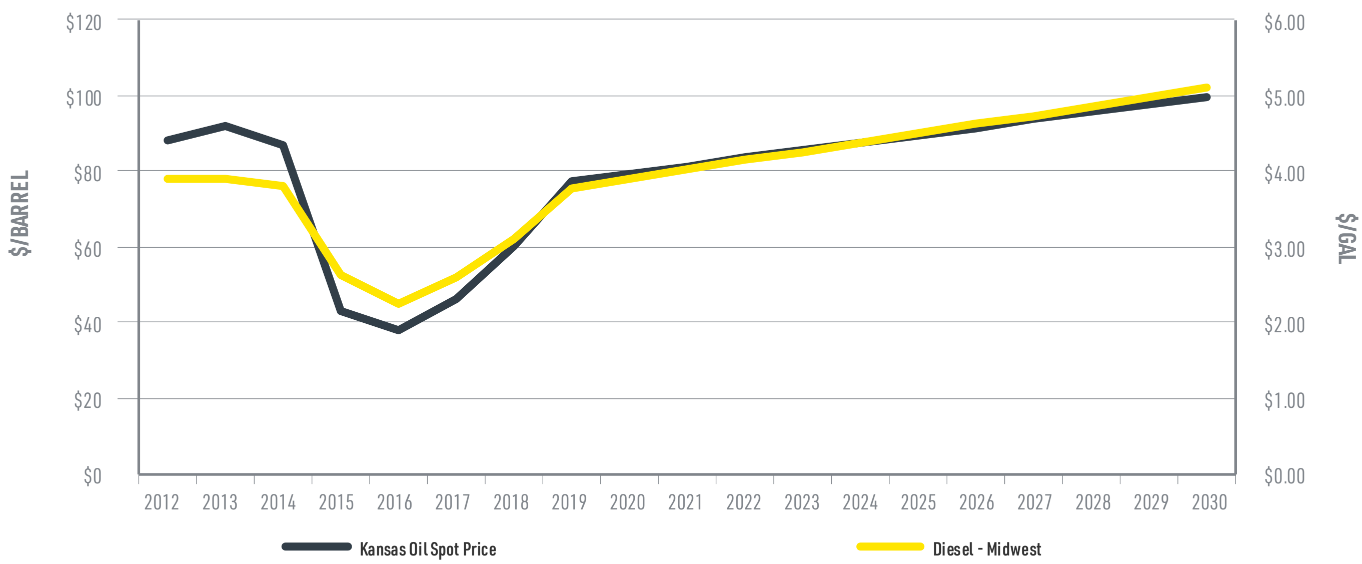


Source: Energeia

DIESEL PRICES

Diesel prices were forecast by regressing diesel prices against EIA oil prices over the last 10 years and then applying the resulting estimates to forecast EIA diesel prices.

FIGURE 121. Forecast of Diesel and Oil Prices



Source: EIA (2018), Energeia

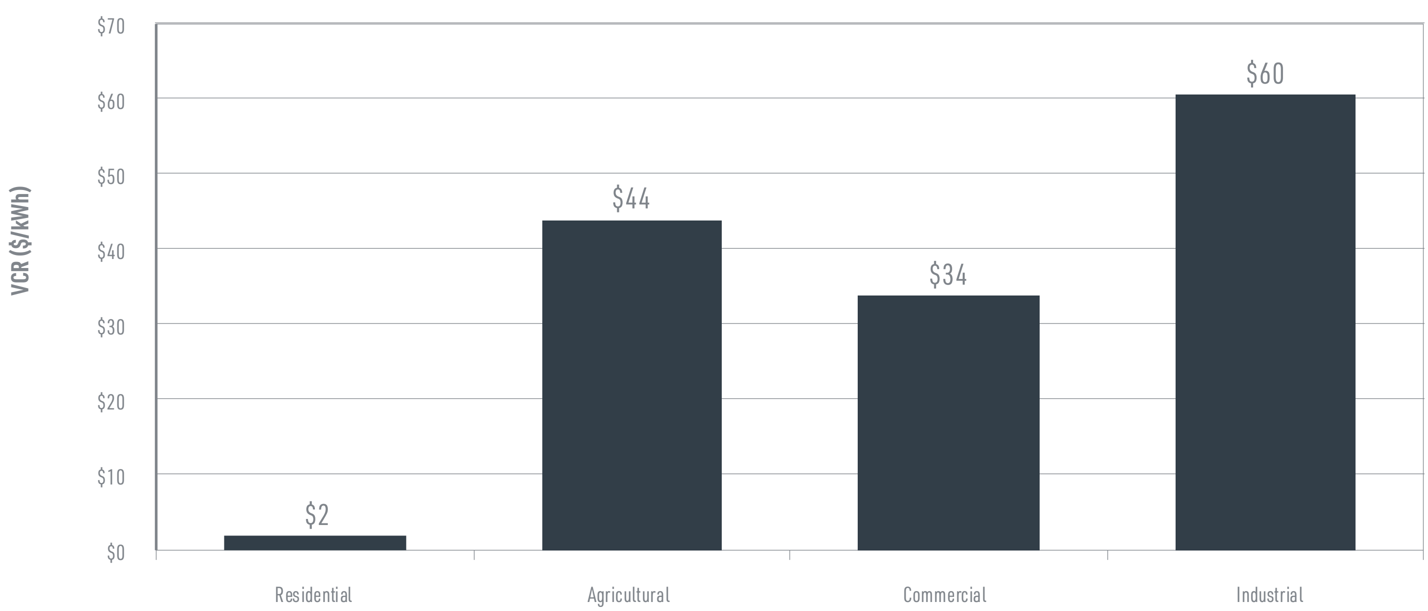
CUSTOMER ELECTRICITY RATES

Customer rates for a given utility were selected based on the rates with the most customers on them.

VALUE OF LOST LOAD

The value of load used values from published studies in the Midwest, which are reported below.

FIGURE 122. Estimated Value of Lost Load by Customer Type (U.S. Midwest)



Source: LEI (2013)

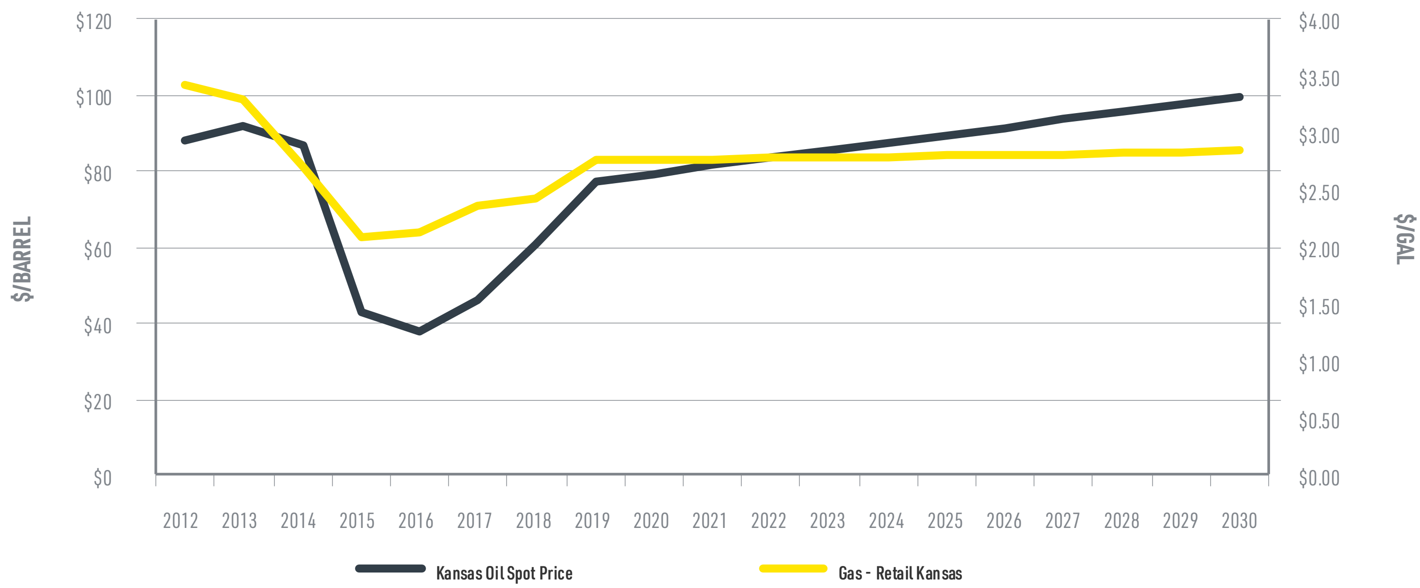
VEHICLE LEASING COSTS

Vehicle leasing costs were obtained via desktop research. Tesla Model 3 lease payments were estimated at $4,452 annually, while Honda Civic lease payments were estimated at $2,880 annually.

VEHICLE GASOLINE COSTS

Gasoline prices were forecast by regressing gasoline prices against EIA oil prices over the last 10 years and then applying the resulting estimates to forecast EIA prices.

FIGURE 123. Forecast of Gasoline and Oil Prices



Source: EIA (2018), GasBuddy (2018), Energeia Analysis

D STATE AND REGIONAL JOBS AND JOB LQ

The table below shows Kansas jobs and job LQ for 2019 as well as the job LQ rank of the state versus that of its regional peers by sector.

TABLE 32. Kansas Sector Employment Totals (2019 Summary)

Sector	Jobs 2019	Job LQ 2019	Job LQ Rank 2019 (of 10 States)
Government	287,346	1.22	2
Health Care	193,126	0.96	6
Manufacturing	169,227	1.36	3
Retail	149,582	0.96	9
Accommodation	115,142	0.85	7
Professional Services	85,370	0.82	4
Administrative	83,614	0.85	6
Construction	79,360	0.88	10
Other	70,558	0.95	7
Finance	66,570	1.05	6
Transportation	64,019	1.08	5
Wholesale	59,625	1.04	6
Agriculture	31,498	1.72	5
Management	26,913	1.18	4
Education	23,747	0.58	7
Arts	19,739	0.71	7
Real Estate / Rental	19,381	0.72	7
Information	19,139	0.67	7
Mining	7,176	1.08	5
Utilities	6,370	1.20	4

Source: EMSI

E INDUSTRY SUMMARIES

TABLE 33. Agriculture Industry Summary

Industry	NAICS	Kansas Metrics				Benchmarks			
		JOBS		JOB LQ		USA		MAX LQ STATE	
		2019	CAGR	2019	LQ Rank	Job CAGR	Electricity % Purchase	2019	LQ
Crop Production	1110	12,649	-0.5%	1.65	5	-0.1%	0.9%	North Dakota	5.08
Animal Production	1120	13,092	-0.3%	3.16	5	-0.1%	0.8%	South Dakota	8.23
Timber Tract Operations	1131	0	N/A	0.00	7	-2.1%	0.0%	Arkansas	5.55
Forest Nurseries	1132	0	N/A	0.00	9	-4.2%	0.0%	South Dakota	4.86
Logging	1133	18	-14.5%	0.03	9	-0.8%	0.1%	Arkansas	5.23
Fishing	1141	2	-14.1%	0.01	10	-1.0%	0.7%	Texas	0.33
Hunting and Trapping	1142	39	-6.0%	0.94	4	0.1%	0.6%	South Dakota	4.45
Support for Crop Production	1151	5,155	2.7%	1.06	6	2.0%	0.7%	North Dakota	1.94
Support for Animal Production	1152	523	3.7%	1.23	4	0.8%	0.7%	Arkansas	2.21
Support for Forestry	1153	19	-0.6%	0.09	9	1.9%	0.7%	Arkansas	4.66

Source: EMSI

TABLE 34. Mining & Extraction Industry Summary

Industry	NAICS	Kansas Metrics				Benchmarks			
		JOBS		JOB LQ		USA		MAX LQ STATE	
		2019	CAGR	2019	LQ Rank	Job CAGR	Electricity % Purchase	2019	LQ
Oil and Gas Extraction	2111	2,034	-2.2%	1.47	5	-1.2%	2.1%	Oklahoma	10.63
Coal Mining	2121	10	-19.8%	0.02	7	-5.0%	2.8%	North Dakota	8.17
Metal Ore Mining	2122	0	N/A	0.00	8	1.8%	5.2%	Colorado	1.88
Nonmetallic Mineral Mining	2123	1,516	3.6%	1.58	7	1.5%	3.9%	North Dakota	2.68
Support Activities for Mining	2131	3,616	-3.9%	1.05	5	2.0%	0.2%	North Dakota	16.05

Source: EMSI

TABLE 35. Food Manufacturing Industry Summary

Industry	NAICS	Kansas Metrics				Benchmarks			
		JOBS		JOB LQ		USA		MAX LQ STATE	
		2019	CAGR	2019	LQ Rank	Job CAGR	Electricity % Purchase	2019	LQ
Animal Food Manufacturing	3111	4,138	3.7%	6.72	1	2.3%	0.4%	Kansas	6.72
Grain and Oilseed Milling	3112	1,782	4.0%	3.03	5	0.5%	1.2%	Iowa	10.09
Sugar Product Manufacturing	3113	1,575	2.9%	2.12	2	1.5%	0.9%	North Dakota	4.84
Fruit and Vegetable Preserving	3114	1,454	-2.0%	0.88	5	0.0%	1.1%	Arkansas	2.84
Dairy Product Manufacturing	3115	659	5.3%	0.45	8	1.6%	0.6%	South Dakota	2.87
Animal Slaughtering	3116	18,189	0.3%	3.60	5	0.9%	0.5%	Nebraska	7.87
Seafood Product Preparation	3117	0	-100.0%	0.00	9	-0.4%	0.4%	Texas	0.51
Bakery Manufacturing	3118	2,496	1.5%	0.78	8	1.4%	1.0%	Arkansas	1.54
Other Food Manufacturing	3119	3,870	1.4%	1.77	2	3.7%	0.7%	Iowa	2.05
Beverage Manufacturing	3121	1,190	12.4%	0.45	7	5.6%	1.0%	Colorado	1.71
Tobacco Manufacturing	3122	13	N/A	0.12	3	-4.0%	0.8%	Oklahoma	0.22

Source: EMSI

TABLE 36. Textile Manufacturing Industry Summary

Industry	NAICS	Kansas Metrics				Benchmarks			
		JOBS		JOB LQ		USA		MAX LQ STATE	
		2019	CAGR	2019	LQ Rank	Job CAGR	Electricity % Purchase	2019	LQ
Fiber, Yarn, and Thread Mills	3131	5	-8.7%	0.02	4	-0.5%	4.0%	North Dakota	0.09
Fabric Mills	3132	51	-11.8%	0.10	5	-0.6%	2.3%	Nebraska	0.37
Textile Finishing Mills	3133	64	-0.4%	0.22	5	-2.2%	1.2%	Texas	0.42
Textile Furnishings Mills	3141	59	-2.3%	0.12	8	-1.3%	1.0%	Oklahoma	0.48
Other Textile Product Mills	3149	1,240	-2.0%	1.85	2	0.6%	0.9%	South Dakota	2.72
Apparel Knitting Mills	3151	0	-100.0%	0.00	6	-7.0%	0.6%	Arkansas	6.12
Cut and Sew Manufacturing	3152	360	-3.1%	0.38	5	-3.6%	0.5%	Texas	0.56
Apparel Accessories	3159	160	-12.3%	1.19	4	-0.9%	0.5%	Iowa	3.35
Leather Tanning and Finishing	3161	14	-2.9%	0.35	6	-0.8%	0.5%	Nebraska	13.36
Footwear Manufacturing	3162	1	-35.2%	0.00	9	-0.4%	0.5%	Arkansas	8.34
Other Leather Manufacturing	3169	28	-13.7%	0.24	7	0.0%	0.5%	Arkansas	2.00

Source: EMSI

TABLE 37. Wood Manufacturing Industry Summary

Industry	NAICS	Kansas Metrics				Benchmarks			
		JOBS		JOB LQ		USA		MAX LQ STATE	
		2019	CAGR	2019	LQ Rank	Job CAGR	Electricity % Purchase	2019	LQ
Sawmills and Wood Preservation	3211	43	4.9%	0.05	9	1.3%	1.5%	Arkansas	6.23
Engineered Wood Manufacturing	3212	304	1.3%	0.39	9	2.9%	1.8%	South Dakota	2.73
Other Wood Manufacturing	3219	1,536	0.8%	0.64	8	1.9%	0.8%	Iowa	3.20
Pulp, Paper, and Paperboard Mills	3221	180	4.4%	0.20	4	-1.7%	3.9%	Arkansas	4.88
Converted Paper Manufacturing	3222	1,633	-2.1%	0.63	6	-0.5%	1.2%	Arkansas	2.57
Printing Support Activities	3231	7,848	-2.1%	1.85	1	-1.5%	1.9%	Kansas	1.85

Source: EMSI

TABLE 38. Chemical Manufacturing Industry Summary

Industry	NAICS	Kansas Metrics				Benchmarks			
		JOBS		JOB LQ		USA		MAX LQ STATE	
		2019	CAGR	2019	LQ Rank	Job CAGR	Electricity % Purchase	2019	LQ
Petrol and Coal Manufacturing	3241	2,347	2.7%	2.15	2	0.1%	1.0%	Texas	2.37
Basic Chemical Manufacturing	3251	2,054	0.6%	1.41	6	0.8%	2.6%	Texas	2.74
Resin Fibers Manufacturing	3252	269	-4.8%	0.29	6	0.7%	2.1%	Texas	1.41
Agricultural Chemical Manufacturing	3253	473	5.4%	1.36	6	0.1%	1.5%	Iowa	5.31
Pharmaceutical Manufacturing	3254	3,478	6.1%	1.19	1	0.9%	0.5%	Kansas	1.19
Paint Manufacturing	3255	249	2.2%	0.40	7	1.7%	0.7%	Missouri	1.61
Soap Manufacturing	3256	742	-2.0%	0.68	4	1.1%	0.6%	Missouri	2.17
Other Chemical Manufacturing	3259	976	-2.2%	1.19	2	0.0%	1.1%	Texas	1.37
Plastics Product Manufacturing	3261	7,591	3.1%	1.33	3	1.9%	2.1%	Iowa	1.40
Rubber Product Manufacturing	3262	2,853	-0.1%	2.15	4	1.4%	1.5%	Arkansas	3.66

Source: EMSI

TABLE 39. Mineral Manufacturing Industry Summary

Industry	NAICS	Kansas Metrics				Benchmarks			
		JOBS		JOB LQ		USA		MAX LQ STATE	
		2019	CAGR	2019	LQ Rank	Job CAGR	Electricity % Purchase	2019	LQ
Clay Product Manufacturing	3271	285	-2.1%	0.71	7	-0.9%	1.9%	Colorado	2.32
Glass Manufacturing	3272	574	2.2%	0.67	6	1.0%	3.7%	Oklahoma	1.65
Cement Manufacturing	3273	2,760	-1.4%	1.46	4	1.6%	1.7%	South Dakota	2.29
Lime Manufacturing	3274	296	3.3%	1.92	6	1.9%	3.7%	Iowa	4.47
Other Nonmetallic Manufacturing	3279	1,139	-0.4%	1.43	1	2.3%	2.1%	Kansas	1.43

Source: EMSI

TABLE 40. Metal Production Industry Summary

Industry	NAICS	Kansas Metrics				Benchmarks			
		JOBS		JOB LQ		USA		MAX LQ STATE	
		2019	CAGR	2019	LQ Rank	Job CAGR	Electricity % Purchase	2019	LQ
Iron and Steel Manufacturing	3311	117	0.6%	0.14	8	0.0%	2.6%	Arkansas	4.66
Steel Product Manufacturing	3312	171	-1.7%	0.30	9	1.3%	1.3%	Arkansas	4.87
Alumina and Aluminum Production	3313	206	4.1%	0.35	6	1.3%	3.7%	Iowa	4.60
Nonferrous Metal Production	3314	357	-2.5%	0.60	5	0.8%	1.6%	Missouri	1.00
Foundries	3315	1,102	-2.1%	0.95	4	0.9%	3.5%	Iowa	1.91

Source: EMSI

TABLE 41. Metal Product Manufacturing Industry Summary

Industry	NAICS	Kansas Metrics				Benchmarks			
		JOBS		JOB LQ		USA		MAX LQ STATE	
		2019	CAGR	2019	LQ Rank	Job CAGR	Electricity % Purchase	2019	LQ
Forging and Stamping	3321	204	-6.4%	0.21	8	1.5%	1.5%	Arkansas	0.59
Cutlery and Handtool Manufacturing	3322	514	2.6%	1.38	3	-0.6%	1.3%	Iowa	1.92
Architectural Metals Manufacturing	3323	5,883	2.1%	1.54	2	2.4%	0.7%	Iowa	1.68
Boiler Manufacturing	3324	1,814	2.3%	2.00	3	1.3%	0.9%	Oklahoma	5.15
Hardware Manufacturing	3325	186	12.8%	0.76	5	0.8%	0.7%	South Dakota	2.69
Spring and Wire Manufacturing	3326	113	-9.5%	0.27	8	0.3%	1.0%	Oklahoma	1.83
Machine Shops Manufacturing	3327	3,742	5.5%	1.04	3	1.8%	1.5%	Iowa	1.35
Coating / Engraving	3328	1,690	3.5%	1.24	1	1.7%	2.6%	Kansas	1.24
Other Metal Manufacturing	3329	2,729	4.4%	1.01	6	1.5%	0.9%	Arkansas	2.40

Source: EMSI

TABLE 42. Machinery Manufacturing Industry Summary

Industry	NAICS	Kansas Metrics				Benchmarks			
		JOBS		JOB LQ		USA		MAX LQ STATE	
		2019	CAGR	2019	LQ Rank	Job CAGR	Electricity % Purchase	2019	LQ
Agriculture Machine Manufacturing	3331	7,865	2.6%	3.68	5	0.9%	0.3%	Iowa	9.41
Industrial Machinery Manufacturing	3332	1,887	2.7%	1.62	1	2.2%	0.6%	Kansas	1.62
Commercial Machinery Manufacturing	3333	995	0.0%	1.12	5	0.0%	0.6%	Iowa	1.91
HVAC Equipment Manufacturing	3334	2,797	2.9%	2.13	5	0.9%	0.6%	Oklahoma	4.02
Metal Machinery Manufacturing	3335	1,159	4.5%	0.67	4	1.6%	1.3%	Missouri	1.55
Engine, Turbine Manufacturing	3336	890	4.8%	0.93	7	1.0%	0.6%	Iowa	3.11
General Machinery Manufacturing	3339	4,304	2.6%	1.61	4	2.3%	0.5%	Iowa	2.62

Source: EMSI

TABLE 43. Electronics Manufacturing Industry Summary

Industry	NAICS	Kansas Metrics				Benchmarks			
		JOBS		JOB LQ		USA		MAX LQ STATE	
		2019	CAGR	2019	LQ Rank	Job CAGR	Electricity % Purchase	2019	LQ
Computer Equipment Manufacturing	3341	69	-9.9%	0.04	9	0.1%	0.3%	North Dakota	1.57
Communication Manufacturing	3342	724	-16.6%	0.89	3	-3.5%	0.1%	Texas	1.53
Audio and Video Manufacturing	3343	153	5.7%	0.76	3	0.2%	0.1%	Nebraska	1.06
Semiconductor Manufacturing	3344	1,212	-3.4%	0.34	8	0.1%	0.9%	South Dakota	1.33
Measuring Tool Manufacturing	3345	1,717	-3.4%	0.43	6	0.3%	0.2%	Iowa	2.51
Manufacturing Optical Media	3346	6	-21.4%	0.05	8	-7.5%	0.6%	Colorado	1.37
Electric Lighting Manufacturing	3351	291	-6.9%	0.66	5	0.1%	0.5%	Iowa	1.33
Household Appliance Manufacturing	3352	178	2.2%	0.30	3	0.7%	0.4%	Iowa	6.00
Electrical Equipment Manufacturing	3353	1,076	1.1%	0.77	6	0.8%	0.4%	Arkansas	2.35
Other Electrical Manufacturing	3359	1,969	1.9%	1.38	2	2.6%	1.1%	Missouri	2.04

Source: EMSI

TABLE 44. Transportation Manufacturing Industry Summary

Industry	NAICS	Kansas Metrics				Benchmarks			
		JOBS		JOB LQ		USA		MAX LQ STATE	
		2019	CAGR	2019	LQ Rank	Job CAGR	Electricity % Purchase	2019	LQ
Motor Vehicle Manufacturing	3361	2,379	-4.9%	1.03	2	5.2%	0.1%	Missouri	2.57
Motor Vehicle Body Manufacturing	3362	1,755	-2.0%	1.11	6	4.5%	0.3%	South Dakota	4.95
Motor Vehicle Parts Manufacturing	3363	2,041	2.1%	0.35	8	4.2%	0.6%	Nebraska	1.12
Aerospace Manufacturing	3364	32,988	0.0%	6.53	1	1.1%	0.3%	Kansas	6.53
Railroad Rolling Stock Manufacturing	3365	233	4.3%	1.01	4	3.0%	0.1%	Arkansas	4.38
Ship and Boat Building	3366	600	0.0%	0.44	3	1.5%	0.5%	Arkansas	1.98
Other Transportation Manufacturing	3369	250	6.4%	0.73	6	0.6%	0.2%	Nebraska	6.32

Source: EMSI

TABLE 45. Other Manufacturing Industry Summary

Industry	NAICS	Kansas Metrics				Benchmarks			
		JOBS		JOB LQ		USA		MAX LQ STATE	
		2019	CAGR	2019	LQ Rank	Job CAGR	Electricity % Purchase	2019	LQ
Household Furniture Manufacturing	3371	2,679	-0.7%	1.07	4	0.9%	0.9%	South Dakota	2.81
Office Furniture Manufacturing	3372	600	-0.6%	0.55	9	1.5%	0.8%	Iowa	3.29
Other Furniture Manufacturing	3379	247	0.9%	0.73	3	-0.5%	0.2%	Colorado	2.62
Medical Equipment Manufacturing	3391	1,553	-1.2%	0.49	7	0.6%	0.8%	South Dakota	2.05
Other Miscellaneous Manufacturing	3399	2,806	0.5%	0.90	2	1.1%	0.7%	South Dakota	3.07

Source: EMSI

TABLE 46. Durable Wholesale Industry Summary

Industry	NAICS	Kansas Metrics				Benchmarks			
		JOBS		JOB LQ		USA		MAX LQ STATE	
		2019	CAGR	2019	LQ Rank	Job CAGR	Electricity % Purchase	2019	LQ
Motor Vehicle Wholesalers	4231	3,467	2.5%	0.99	8	1.4%	1.2%	Missouri	1.56
Furniture Wholesalers	4232	830	7.2%	0.72	3	2.3%	1.7%	Colorado	1.14
Lumber Wholesalers	4233	2,250	1.8%	0.94	5	2.9%	1.7%	Colorado	1.42
Professional Equipment Wholesalers	4234	4,815	0.9%	0.73	5	1.2%	1.0%	Texas	1.52
Metal Wholesalers	4235	1,392	4.0%	1.05	3	2.3%	1.7%	Texas	1.81
Household Appliances Wholesalers	4236	2,751	1.8%	0.80	7	1.6%	1.1%	Colorado	1.44
Hardware Wholesalers	4237	2,498	4.5%	0.92	7	2.7%	1.7%	Texas	1.23
Machinery Wholesalers	4238	10,656	0.5%	1.54	5	1.7%	1.5%	North Dakota	3.00
Miscellaneous Durable Goods Wholesalers	4239	1,892	-3.2%	0.62	9	0.4%	1.7%	Missouri	1.24

Source: EMSI

TABLE 47. Nondurable Wholesale Industry Summary

Industry	NAICS	Kansas Metrics				Benchmarks			
		JOBS		JOB LQ		USA		MAX LQ STATE	
		2019	CAGR	2019	LQ Rank	Job CAGR	Electricity % Purchase	2019	LQ
Paper Wholesalers	4241	1,138	4.4%	0.91	3	0.3%	1.6%	Missouri	1.75
Drugs Wholesalers	4242	2,272	3.9%	0.99	1	2.5%	1.4%	Kansas	0.99
Apparel Wholesalers	4243	1,282	1.3%	0.84	1	1.0%	1.6%	Kansas	0.84
Grocery Wholesalers	4244	4,971	-2.1%	0.64	10	1.1%	2.4%	Texas	1.00
Farm Product Wholesalers	4245	6,133	0.1%	8.93	5	-0.8%	1.6%	South Dakota	15.25
Chemical Wholesalers	4246	1,545	4.9%	1.07	5	2.3%	1.6%	Texas	1.70
Petroleum Wholesalers	4247	1,821	1.9%	1.81	5	0.9%	1.0%	North Dakota	5.67
Alcoholic Beverage Wholesalers	4248	1,644	2.2%	0.84	8	2.4%	1.6%	Texas	1.15
MiscNondurable Wholesalers	4249	3,890	0.9%	1.19	7	-0.1%	1.6%	South Dakota	3.13
Wholesale Electronic Markets	4251	4,379	-9.4%	0.84	5	-4.5%	1.7%	Missouri	1.28

Source: EMSI

TABLE 48. Information Industry Summary

Industry	NAICS	Kansas Metrics				Benchmarks			
		JOBS		JOB LQ		USA		MAX LQ STATE	
		2019	CAGR	2019	LQ Rank	Job CAGR	Electricity % Purchase	2019	LQ
Newspaper, Periodical Publishers	5111	3,530	-4.6%	1.11	4	-5.3%	0.3%	Iowa	1.73
Software Publishers	5112	1,212	-2.8%	0.28	6	6.2%	0.3%	Colorado	1.82
Motion Picture Industries	5121	1,896	-0.6%	0.41	5	1.9%	0.4%	Texas	0.73
Sound Recording Industries	5122	89	20.7%	0.32	6	1.0%	0.1%	Texas	0.65
Radio and TV Broadcasting	5151	1,881	-1.3%	0.89	8	0.0%	0.1%	North Dakota	1.62
Cable Programming	5152	10	-35.7%	0.02	8	-4.8%	0.1%	Colorado	3.10
Telecommunications Carriers	5173	6,894	-9.1%	1.12	5	-1.9%	0.5%	Colorado	1.93
Satellite Telecommunications	5174	22	-8.9%	0.27	6	-3.3%	0.6%	Colorado	4.35
Other Telecommunications	5179	359	2.4%	0.44	8	-3.8%	0.5%	Colorado	2.19
Data Processing / Hosting Services	5182	1,937	3.1%	0.58	6	3.8%	1.0%	Colorado	2.09
Other Information Services	5191	1,310	13.9%	0.39	4	9.9%	0.4%	Nebraska	0.64

Source: EMSI

TABLE 49. Real Estate & Rental Industry Summary

Industry	NAICS	Kansas Metrics				Benchmarks			
		JOBS		JOB LQ		USA		MAX LQ STATE	
		2019	CAGR	2019	LQ Rank	Job CAGR	Electricity % Purchase	2019	LQ
Lessors of Real Estate	5311	5,126	-1.1%	0.62	9	0.9%	7.9%	Texas	1.23
Offices of Real Estate Agents	5312	2,804	0.6%	0.59	7	1.6%	7.9%	Colorado	1.45
Activities Related to Real Estate	5313	7,601	3.5%	0.94	3	2.9%	7.9%	Colorado	1.35
Automotive Rental and Leasing	5321	1,094	2.7%	0.50	9	3.7%	1.0%	Oklahoma	1.25
Consumer Goods Rental	5322	1,351	-5.9%	0.94	6	-3.0%	1.6%	Arkansas	1.53
General Rental Centers	5323	217	-1.2%	0.63	8	-1.5%	1.6%	Texas	1.76
Machinery Rental	5324	958	1.6%	0.58	8	4.6%	0.4%	North Dakota	2.97
Lessors of Intangible Assets	5331	228	2.2%	1.02	5	-0.9%	0.2%	Colorado	1.62

Source: EMSI

OUTPUT TABLES

This section of the technical memo takes high level sectors and displays economic development data on detailed industries. Each industry's output (gross regional product) trends are depicted, along with the electricity share of inputs that are used by the industry. The tables show the following variables for each industry:

- Kansas GRP in 2010
- Kansas GRP in 2019
- Kansas GRP growth rate betwen 2010 and 2019
- U.S. GRP growth rate between 2010 and 2019
- Share of all inputs that are electricity related (% of all inputs)

TABLE 50. Agriculture Industries Industry Summary

Industry	NAICS	Kansas GRP (in millions)			United States	
		2010	2019	CAGR	GRP CAGR	Energy Share of Inputs
Crop Production	1110	$1,171.5	$1,096.4	-0.7%	3.0%	0.9%
Animal Production	1120	$2,075.2	$1,616.0	-2.7%	-0.4%	0.8%
Timber Tract Operations	1131	$0.0	$0.0	0.0%	0.3%	0.0%
Forest Nurseries	1132	$0.0	$2.1	0.0%	3.6%	0.0%
Logging	1133	$3.5	$1.9	-6.8%	3.9%	0.1%
Fishing	1141	$0.5	$1.5	11.6%	0.4%	0.7%
Hunting and Trapping	1142	$6.4	$11.6	6.8%	3.1%	0.6%
Support for Crop Production	1151	$205.3	$298.9	4.3%	5.9%	0.7%
Support for Animal Production	1152	$61.4	$68.2	1.2%	3.2%	0.7%
Support for Forestry	1153	$5.8	$5.7	-0.3%	4.8%	0.7%

Source: EMSI

TABLE 51. Mining & Extraction Industry Summary

Industry	NAICS	Kansas GRP (in millions)			United States	
		2010	2019	CAGR	GRP CAGR	Energy Share of Inputs
Oil and Gas Extraction	2111	$5,428.6	$8,214.7	4.7%	3.2%	2.1%
Coal Mining	2121	$24.6	$29.3	2.0%	-4.6%	2.8%
Metal Ore Mining	2122	$6.6	$14.5	9.1%	0.7%	5.2%
Nonmetallic Mineral Mining	2123	$145.3	$277.0	7.4%	2.2%	3.9%
Support Activities for Mining	2131	$521.4	$385.4	-3.3%	0.8%	0.2%

Source: EMSI

TABLE 52. Food Manufacturing Industry Summary

Industry	NAICS	Kansas GRP (in millions)			United States	
		2010	2019	CAGR	GRP CAGR	Energy Share of Inputs
Animal Food Manufacturing	3111	$512.8	$829.3	5.5%	3.5%	0.4%
Grain and Oilseed Milling	3112	$227.9	$476.2	8.5%	1.8%	1.2%
Sugar Product Manufacturing	3113	$91.3	$139.5	4.8%	2.2%	0.9%
Fruit and Vegetable Preserving / Specialty Food	3114	$98.2	$128.6	3.0%	1.8%	1.1%
Dairy Product Manufacturing	3115	$38.1	$111.0	12.6%	4.0%	0.6%
Animal Slaughtering and Processing	3116	$1,284.7	$1,777.5	3.7%	4.2%	0.5%
Seafood Product Preparation and Packaging	3117	$1.7	$7.1	16.8%	3.1%	0.4%
Bakeries and Tortilla Manufacturing	3118	$152.6	$224.3	4.4%	1.4%	1.0%
Other Food Manufacturing	3119	$453.3	$490.3	0.9%	1.8%	0.7%
Beverage Manufacturing	3121	$47.3	$175.5	15.7%	5.3%	1.0%
Tobacco Manufacturing	3122	$0.0	$16.8	0.0%	-2.0%	0.8%

Source: EMSI

TABLE 53. Textile Manufacturing Industry Summary

Industry	NAICS	Kansas GRP (in millions)			United States	
		2010	2019	CAGR	GRP CAGR	Energy Share of Inputs
Fiber, Yarn, and Thread Mills	3131	$0.3	$0.3	-2.8%	3.7%	4.0%
Fabric Mills	3132	$6.9	$2.7	-9.8%	2.4%	2.3%
Textile Finishing and Fabric Coating Mills	3133	$2.0	$2.5	2.5%	0.7%	1.2%
Textile Furnishings Mills	3141	$3.8	$5.6	4.3%	2.2%	1.0%
Other Textile Product Mills	3149	$64.0	$63.8	0.0%	2.9%	0.9%
Apparel Knitting Mills	3151	$7.5	$0.0	-100.0%	-6.5%	0.6%
Cut and Sew Apparel Manufacturing	3152	$30.5	$39.0	2.8%	-1.4%	0.5%
Apparel Accessories Manufacturing	3159	$31.9	$8.7	-13.4%	0.5%	0.5%
Leather and Hide Tanning and Finishing	3161	$0.2	$1.2	22.1%	2.6%	0.5%
Footwear Manufacturing	3162	$0.1	$0.2	14.5%	3.5%	0.5%
Other Leather Product Manufacturing	3169	$3.7	$1.7	-8.2%	4.0%	0.5%

Source: EMSI

TABLE 54. Wood Manufacturing Industry Summary

Industry	NAICS	Kansas GRP (in millions)			United States	
		2010	2019	CAGR	GRP CAGR	Energy Share of Inputs
Sawmills and Wood Preservation	3211	$1.5	$2.5	6.1%	6.4%	1.5%
Engineered Wood Manufacturing	3212	$16.1	$30.2	7.2%	8.5%	1.8%
Other Wood Product Manufacturing	3219	$73.8	$125.1	6.0%	6.7%	0.8%
Pulp, Paper, and Paperboard Mills	3221	$28.3	$49.3	6.4%	-0.8%	3.9%
Converted Paper Product Manufacturing	3222	$164.3	$177.4	0.9%	1.6%	1.2%
Printing and Related Support Activities	3231	$608.8	$596.8	-0.2%	0.4%	1.9%

Source: EMSI

TABLE 55. Chemical Manufacturing Industry Summary

Industry	NAICS	Kansas GRP (in millions)			United States	
		2010	2019	CAGR	GRP CAGR	Energy Share of Inputs
Petrol and Coal Products Manufacturing	3241	$1,489.2	$3,273.1	9.1%	4.5%	1.0%
Basic Chemical Manufacturing	3251	$526.1	$1,053.5	8.0%	7.3%	2.6%
Resin Synthetic Fibers Manufacturing	3252	$68.4	$59.6	-1.5%	4.7%	2.1%
Agricultural Chemical Manufacturing	3253	$92.4	$291.0	13.6%	2.3%	1.5%
Pharmaceutical Manufacturing	3254	$525.0	$1,044.4	7.9%	1.7%	0.5%
Paint Manufacturing	3255	$41.1	$47.3	1.6%	3.7%	0.7%
Soap Manufacturing	3256	$387.8	$284.0	-3.4%	1.4%	0.6%
Other Chemical Manufacturing	3259	$141.4	$162.4	1.6%	2.3%	1.1%
Plastics Product Manufacturing	3261	$470.3	$703.5	4.6%	3.3%	2.1%
Rubber Product Manufacturing	3262	$236.9	$279.7	1.9%	3.2%	1.5%

Source: EMSI

TABLE 56. Mineral Manufacturing Industry Summary

Industry	NAICS	Kansas GRP (in millions)			United States	
		2010	2019	CAGR	GRP CAGR	Energy Share of Inputs
Clay Product Manufacturing	3271	$14.8	$21.6	4.3%	3.3%	1.9%
Glass Manufacturing	3272	$40.0	$62.3	5.0%	5.0%	3.7%
Cement Manufacturing	3273	$235.8	$284.8	2.1%	6.6%	1.7%
Lime Manufacturing	3274	$20.7	$60.7	12.7%	9.6%	3.7%
Other Nonmetallic Mineral Manufacturing	3279	$139.0	$224.9	5.5%	5.5%	2.1%

Source: EMSI

TABLE 57. Metal Production Industry Summary

Industry	NAICS	Kansas GRP (in millions)			United States	
		2010	2019	CAGR	GRP CAGR	Energy Share of Inputs
Iron and Steel Manufacturing	3311	$10.3	$13.8	3.4%	3.7%	2.6%
Steel Product Manufacturing	3312	$15.6	$12.4	-2.5%	3.8%	1.3%
Alumina and Aluminum Production	3313	$9.7	$19.7	8.2%	4.3%	3.7%
Nonferrous Metal Production	3314	$31.5	$30.5	-0.4%	1.8%	1.6%
Foundries	3315	$114.4	$118.3	0.4%	2.5%	3.5%

Source: EMSI

TABLE 58. Metal Product Manufacturing Industry Summary

Industry	NAICS	Kansas GRP (in millions)			United States	
		2010	2019	CAGR	GRP CAGR	Energy Share of Inputs
Forging and Stamping	3321	$21.0	$18.7	-1.3%	3.6%	1.5%
Cutlery and Handtool Manufacturing	3322	$30.7	$42.7	3.7%	0.3%	1.3%
Architectural Metals Manufacturing	3323	$298.9	$468.4	5.1%	4.9%	0.7%
Boiler Manufacturing	3324	$112.1	$165.1	4.4%	2.7%	0.9%
Hardware Manufacturing	3325	$4.3	$21.7	19.6%	2.6%	0.7%
Spring and Wire Manufacturing	3326	$17.7	$11.3	-4.9%	2.7%	1.0%
Machine Shops Manufacturing	3327	$152.5	$297.1	7.7%	3.7%	1.5%
Coating / Engraving	3328	$94.5	$153.1	5.5%	3.9%	2.6%
Other Fabricated Metal Manufacturing	3329	$149.7	$277.6	7.1%	3.5%	0.9%

Source: EMSI

TABLE 59. Machinery Manufacturing Industry Summary

Industry	NAICS	Kansas GRP (in millions)			United States	
		2010	2019	CAGR	GRP CAGR	Energy Share of Inputs
Ag, Construction, Mining Machine Manufacturing	3331	$761.0	$950.0	2.5%	1.3%	0.3%
Industrial Machinery Manufacturing	3332	$132.4	$203.7	4.9%	3.6%	0.6%
Commercial Industry Machinery Manufacturing	3333	$105.3	$125.5	2.0%	1.7%	0.6%
HVAC Equipment Manufacturing	3334	$187.1	$281.4	4.6%	2.3%	0.6%
Metalworking Machinery Manufacturing	3335	$57.8	$96.9	5.9%	3.7%	1.3%
Engine, Turbine Manufacturing	3336	$63.4	$136.2	8.9%	2.0%	0.6%
General Purpose Machinery Manufacturing	3339	$356.5	$529.2	4.5%	3.6%	0.5%

Source: EMSI

TABLE 60. Electronics Manufacturing Industry Summary

Industry	NAICS	Kansas GRP (in millions)			United States	
		2010	2019	CAGR	GRP CAGR	Energy Share of Inputs
Computer Equipment Manufacturing	3341	$23.1	$12.3	-6.7%	2.1%	0.3%
Communications Equipment Manufacturing	3342	$872.7	$214.6	-14.4%	-2.6%	0.1%
Audio and Video Equipment Manufacturing	3343	$15.1	$18.7	2.4%	-0.8%	0.1%
Semiconductor Manufacturing	3344	$174.6	$105.6	-5.4%	2.1%	0.9%
Navigational, Measuring Instruments Manufacturing	3345	$224.6	$283.6	2.6%	6.2%	0.2%
Manufacturing Magnetic and Optical Media	3346	$3.9	$0.7	-16.8%	-3.9%	0.6%
Electric Lighting Equipment Manufacturing	3351	$62.2	$44.8	-3.6%	3.2%	0.5%
Household Appliance Manufacturing	3352	$10.9	$17.5	5.4%	3.1%	0.4%
Electrical Equipment Manufacturing	3353	$83.7	$115.2	3.6%	2.6%	0.4%
Other Electrical Equipment Manufacturing	3359	$218.9	$302.3	3.7%	4.7%	1.1%

Source: EMSI

TABLE 61. Transportation Manufacturing Industry Summary

Industry	NAICS	Kansas GRP (in millions)			United States	
		2010	2019	CAGR	GRP CAGR	Energy Share of Inputs
Motor Vehicle Manufacturing	3361	$679.8	$477.8	-3.8%	8.7%	0.1%
Motor Vehicle Body and Trailer Manufacturing	3362	$117.6	$119.9	0.2%	6.5%	0.3%
Motor Vehicle Parts Manufacturing	3363	$114.7	$178.8	5.1%	5.6%	0.6%
Aerospace Product and Parts Manufacturing	3364	$5,405.6	$6,894.0	2.7%	4.3%	0.3%
Railroad Rolling Stock Manufacturing	3365	$14.5	$53.2	15.5%	7.1%	0.1%
Ship and Boat Building	3366	$26.9	$43.7	5.5%	3.9%	0.5%
Other Transportation Equipment Manufacturing	3369	$23.9	$49.2	8.4%	0.9%	0.2%

Source: EMSI

TABLE 62. Other Manufacturing Industry Summary

Industry	NAICS	Kansas GRP (in millions)			United States	
		2010	2019	CAGR	GRP CAGR	Energy Share of Inputs
Household and Institutional Furniture Manufacturing	3371	$113.7	$127.5	1.3%	4.4%	0.9%
Office Furniture (including Fixtures) Manufacturing	3372	$33.4	$50.3	4.6%	3.8%	0.8%
Other Furniture Related Product Manufacturing	3379	$19.4	$23.9	2.3%	1.2%	0.2%
Medical Equipment and Supplies Manufacturing	3391	$160.6	$184.8	1.6%	2.1%	0.8%
Other Miscellaneous Manufacturing	3399	$216.5	$252.2	1.7%	2.7%	0.7%

Source: EMSI

TABLE 63. Durable Wholesale Industry Summary

Industry	NAICS	Kansas GRP (in millions)			United States	
		2010	2019	CAGR	GRP CAGR	Energy Share of Inputs
Motor Vehicle and Motor Vehicle Parts Wholesalers	4231	$258.0	$487.8	7.3%	7.7%	1.2%
Furniture Wholesalers	4232	$39.4	$106.0	11.6%	7.1%	1.7%
Lumber Wholesalers	4233	$146.6	$339.3	9.8%	8.1%	1.7%
Professional and Commercial Equipment Wholesalers	4234	$486.4	$849.2	6.4%	4.5%	1.0%
Metal Wholesalers	4235	$123.8	$189.1	4.8%	6.7%	1.7%
Household Appliances Wholesalers	4236	$377.0	$596.4	5.2%	3.6%	1.1%
Hardware Wholesalers	4237	$163.4	$370.6	9.5%	7.6%	1.7%
Machinery Wholesalers	4238	$880.6	$1,342.3	4.8%	5.3%	1.5%
Miscellaneous Durable Goods Wholesalers	4239	$278.5	$266.7	-0.5%	5.0%	1.7%

Source: EMSI

TABLE 64. Nondurable Wholesale Industry Summary

Industry	NAICS	Kansas GRP (in millions)			United States	
		2010	2019	CAGR	GRP CAGR	Energy Share of Inputs
Paper Wholesalers	4241	$100.6	$162.4	5.5%	2.9%	1.6%
Drugs Wholesalers	4242	$413.7	$993.2	10.2%	5.7%	1.4%
Apparel Wholesalers	4243	$227.9	$233.8	0.3%	2.8%	1.6%
Grocery Wholesalers	4244	$477.1	$541.0	1.4%	3.6%	2.4%
Farm Product Wholesalers	4245	$610.0	$810.6	3.2%	1.3%	1.6%
Chemical Wholesalers	4246	$174.3	$358.7	8.3%	5.6%	1.6%
Petroleum Wholesalers	4247	$2,184.0	$2,834.6	2.9%	2.7%	1.0%
Alcoholic Beverage Wholesalers	4248	$143.4	$244.1	6.1%	5.5%	1.6%
Miscellaneous Nondurable Wholesalers	4249	$444.5	$642.1	4.2%	2.9%	1.6%
Wholesale Electronic Markets	4251	$1,061.4	$579.5	-6.5%	-2.4%	1.7%

Source: EMSI

TABLE 65. Information Industry Summary

Industry	NAICS	Kansas GRP (in millions)			United States	
		2010	2019	CAGR	GRP CAGR	Energy Share of Inputs
Newspaper, Periodical, Book Publishers	5111	$481.7	$385.1	-2.5%	-3.8%	0.3%
Software Publishers	5112	$409.7	$349.4	-1.8%	8.3%	0.3%
Motion Picture and Video Industries	5121	$113.1	$106.5	-0.7%	1.6%	0.4%
Sound Recording Industries	5122	$12.0	$18.3	4.8%	1.7%	0.1%
Radio and Television Broadcasting	5151	$249.3	$301.2	2.1%	5.6%	0.1%
Cable and Other Subscription Programming	5152	$128.3	$3.4	-33.3%	2.7%	0.1%
Wired and Wireless Telecommunications Carriers	5173	$4,846.5	$3,063.1	-5.0%	1.6%	0.5%
Satellite Telecommunications	5174	$3.1	$6.2	8.1%	-2.5%	0.6%
Other Telecommunications	5179	$30.9	$61.2	7.9%	0.5%	0.5%
Data Processing, Hosting, and Related Services	5182	$261.3	$461.5	6.5%	8.9%	1.0%
Other Information Services	5191	$71.9	$240.4	14.4%	16.1%	0.4%

Source: EMSI

TABLE 66. Real Estate & Rental Industry Summary

Industry	NAICS	Kansas GRP (in millions)			United States	
		2010	2019	CAGR	GRP CAGR	Energy Share of Inputs
Lessors of Real Estate	5311	$1,134.8	$1,821.1	5.4%	4.8%	7.9%
Offices of Real Estate Agents and Brokers	5312	$239.9	$463.6	7.6%	6.3%	7.9%
Activities Related to Real Estate	5313	$511.1	$885.1	6.3%	5.4%	7.9%
Automotive Equipment Rental and Leasing	5321	$207.7	$322.9	5.0%	6.4%	1.0%
Consumer Goods Rental	5322	$175.5	$111.6	-4.9%	1.1%	1.6%
General Rental Centers	5323	$22.1	$21.6	-0.2%	1.9%	1.6%
Commercial and Industrial Machinery Rental	5324	$304.8	$591.1	7.6%	4.1%	0.4%
Lessors of Nonfinancial Intangible Assets	5331	$311.3	$606.0	7.7%	5.6%	0.2%

Source: EMSI

F UTILITY TO TRANSMISSION ZONE MAPPING

TABLE 67. Utility to Transmission Zone Mapping

Area Code	Legacy Balancing Authority	Utility
EDE	Liberty Utilities (Empire)	Liberty
KACY	Kansas City Board of Public Utilities	Kansas City BPU
KCPL	Kansas City Power & Light	Evergy Metro
SECI	Sunflower	Coops
WR	Westar	Evergy Central and South, Coops, Munis

Source: Legacy Balancing Authority, SPP, Energeia

G BENCHMARKED INTEGRATED RESOURCE PLAN POLICIES

TABLE 68. Benchmarked IRP Policies

	ARKANSAS[1]	COLORADO[2]	EVERGY FRAMEWORK[3]	GENERATION CAPACITY PLANNING[4]	MISSOURI[5]	OKLAHOMA[6]	WAPA[7]
Planning Entity	3	2	1	1	1	1	1
Planning Objectives	3	2	1	1	2	2	2
Coverage & Geographical Scale	2	2	3	1	2	1	1
Time Horizon	1	3	1	1	2	1	1
Scenario Development	1	3	3	N/A	3	1	1
Resource Alternatives	1	2	1	1	2	1	2
Uncertain Factors	1	2	2	N/A	2	1	1
Technical Methodology	2	3	3	1	3	1	2
Preliminary Screening & Construction of Alternative Resource Plans	3	3	2	N/A	3	1	1
Selection of Preferred Resource Plan	2	3	1	N/A	2	2	2
Documenting Methodology	1	3	3	1	3	2	1
Action Plan	3	3	3	1	3	2	2
Update Frequency	2	2	2	3	2	2	1
Public Engagement	3	1	2	1	1	2	1
Average Score	**2.00**	**2.43**	**2.00**	**1.20**	**2.21**	**1.43**	**1.36**

1 APSC Docket No. 06-028-R
2 4 CCR 723-3 Rules 3600-3627
3 KCC Docket No. KCPE-096-CPL
4 KCC Docket No. 13-GIME-256-CPL
5 4 CSR 240-22
6 OAC 165:35-37-1
7 10 CFR Part 905 Subpart B

Study of Consequential Issues Materially Affecting Kansas Electricity Rates, September 2020

Designation of Confidential Information

Pursuant to the Protective and Discover Order entered in KCC Docket No. 20-GIME-068-GEI, certain information relating to the pricing of generation fuels has been designated as confidential by the utilities. As such, the following information is provided to the Kansas Corporation Commission under Confidential Seal and redacted in the public version of the Study of Consequential Issues Materially Affecting Kansas Electricity Rates:

Page(s)	Location Description
25	Executive Summary, Section 13, Generation Utility Fuel Prices
179-180	Report Section 5.13.4.1, Figures 111* and 112 and associated text
181	Report Section 5.13.4.1, Figure 113* and associated text
182	Report Section 5.13.4.3, text
184-185	Report Section 5.13.4.1, Figure 117 and associated text

*Figures 111 and 113 contain both confidential and non-confidential information. Only confidential information has been redacted.

Utilities with confidential information in the Generation Utility Fuel Prices sections described above (Midwest Energy, Evergy Kansas Central and Kansas Metro, Sunflower Electric Power Corporation, and Empire District Electric) have provided the following justifications for confidentiality:

The fuels data that is directly attributable to Midwest Energy should remain confidential. This data is derived from underlying fuels, pipeline and/or energy contracts that themselves have confidentiality provisions, negotiated rates, etc. and includes market-specific information relating to services offered in competition with others.

The generation fuel information as well as corresponding text in the report should remain designated as confidential since it contains marketing analyses or other market-specific information relating to services offered in competition with others. Disclosure of this information would negatively impact future negotiations with suppliers and provides detailed information to our competitors.

It is commercially sensitive information because it includes marketing analyses or other market-specific information relating to services offered in competition with others.

Due to the nature of commodity prices and fuel procurement processes, a confidential designation is required to prevent harm to the Company and prevent the creation of a competitive advantage for others over Empire and other competitors.

CERTIFICATE OF SERVICE

20-GIME-068-GIE

I, the undersigned, certify that a true and correct copy of the above and foregoing Notice of Filing of Rate Study was served electronically this 28th day of September, 2020, to the following:

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