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Aaron Doll
Direct Testimony
File No. ER-2021-0312

Exhibit No.: _____
Issues: Asbury, Wind Farm Marketing, Affiliate Waivers, Fuel Adjustment Clause
Witness: Aaron J. Doll
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Sponsoring Party: The Empire District Electric Company
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Date Testimony Prepared: May 2021

Before the Public Service Commission
of the State of Missouri

Direct Testimony

of

Aaron J. Doll

on behalf of

The Empire District Electric Company

May 2021

DENOTES CONFIDENTIAL
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PUBLIC VERSION

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THE EMPIRE DISTRICT ELECTRIC COMPANY
BEFORE THE MISSOURI PUBLIC SERVICE COMMISSION
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DIRECT TESTIMONY OF AARON J DOLL
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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Aaron J. Doll. My business address is 602 South Joplin Avenue, Joplin, Missouri.

Q. By whom are you employed and in what capacity?

A. I am employed by Liberty Utilities Service Corp. ("LUSC") as Senior Director of Energy Strategy for the Liberty Central Region, which includes The Empire District Electric Company ("Empire" or the "Company").

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of Empire.

Q. Please describe your educational and professional background.

A. I graduated from Missouri State University in 2003 with a Bachelor of Science degree in Psychology and a minor in Philosophy. I received my Master of Business Administration from Missouri State University in 2008.

I have worked for Empire for approximately 14 years. I worked in the Planning and Regulatory Department for six years as a Planning Analyst and was responsible for load forecasting, weather normalization, and sales and revenue variance analysis. In 2012, I transferred to the Supply Management Department as the Market Risk Manager and eventually the Manager of Market Settlements and Systems. In this capacity, I worked to facilitate the migration of the daily power marketing activities from the Southwest Power Pool, Inc. ("SPP") Energy Imbalance Market ("EIS") to the SPP

Integrated Marketplace ("IM") and oversaw the procurement of the Transmission Congestion Rights ("TCRs"). Additionally, I provided oversight of the meter management, market settlements, and market applications.

In 2020, I was promoted to my current position of Senior Director of Energy Strategy. In this role, I oversee the procurement of fuel for electrical generation, the day-to-day interfacing, systems, and settlements with SPP as it relates to the IM, the long term and short-term load forecasting, and the production cost modeling. I also provide regulatory support relating to those responsibilities.

Q. Have you previously testified before the Missouri Public Service Commission ("Commission") or any other regulatory agency?

A. Yes. I have testified on behalf of the Company before this Commission, the Oklahoma Corporation Commission, the Kansas Corporation Commission, and the Arkansas Public Service Commission.

Q. What is the purpose of your Direct Testimony in this proceeding?

A. As the Senior Director of Energy Strategy, I am responsible for the overall strategy associated with generating revenues from the Company's generation fleet, as well as advising on the long-term economics of that fleet. In that regard, my testimony addresses the market benefits of the retirement of the Asbury power plant given the deteriorating performance of Asbury in the Southwest Power Pool's Integrated Marketplace ("SPP IM" or "market"). I also discuss the net benefits gained by Empire's customers through a combination of Asbury's retirement and commissioning of the three new wind farms that are described in detail in Mr. Mooney's and Mr. Rooney's testimonies (the "Wind Farms"). I explain how the Wind Farms are bid into the SPP IM, their impact on the Company's fuel adjustment clause ("FAC"), and affiliate waivers that were granted by the Federal Energy Regulatory Commission allowing Empire to market the Wind Farms. I also address proposed changes to the Company's FAC tariff.

II. ASBURY RETIREMENT – MARKET IMPACTS

Q. Please describe your involvement with Asbury and the SPP IM over the years.

A. I have been involved with Asbury's participation in the SPP IM since it went live on March 1, 2014. My position at that time was focused on the new SPP settlements created as a result of the SPP IM construct and the management of congestion derivatives. I worked closely with market settlements and internal reporting to inform management of the Company's performance in the market which included Asbury. As it relates to the management of congestion hedging products, I evaluated the locational marginal pricing ("LMP") between all of the Company's generating units and load to determine whether a Financial Transmission Right ("FTR") was valuable. The evaluation included the basis differential in LMPs between the Asbury power plant and the Company's load settlement location. As my role expanded in the department, I was involved in management discussions to increase the economics of Asbury as it relates to its performance in the SPP IM which is discussed in more detail in my testimony below.

Q. Please describe Asbury's primary operating characteristics at the beginning of the SPP IM.

A. Asbury was a 200-megawatt (MW) coal plant with a 10,638 average heat rate (Btu/kWh), 16-hour start-up time, 96-hour minimum run-time, and 48 hour minimum down-time.

Q. Explain what is meant by average heat rate, start-up time, minimum run-time, and minimum down-time.

A. Average heat rate is a metric of efficiency that is calculated as the amount of energy used to generate 1 Kilowatt-hour (kWh). Incremental heat rates, or heat rates along an output curve supplied by power plant testing, can be multiplied by fuel costs to provide the fuel-related cost curve of an entity's energy offer into the SPP IM. As heat rate increases, efficiencies decrease.

Start-up Time, as defined by the SPP IM, is the time required to start a resource and reach the Minimum Economic Capacity Operating Limit following receipt of a start-up order from SPP. Asbury began participation in the SPP IM with a 16-hour Start-Up Time.

Minimum Run Time is the length of time a Resource must run from the time the Resource is put online to the time the Resource is shut down. Asbury began participation in the market with a 96-hour Minimum Run Time.

Minimum Down Time is the minimum length of time required following desynchronization that a Resource must remain off-line prior to a subsequent synchronization. Asbury began participation in the SPP IM with a Minimum Down Time of 48 hours.

Q. Describe Asbury's first few years of participation in the SPP IM?

A. From March 2014 until October 2016, Asbury was offered in the SPP IM with a Day-Ahead ("DA") market status of "Self." The "Self" status communicates to SPP that the Market Participant, Empire in this case, is committing the Resource and SPP should include it as committed in either the DA Market and/or Reliability Unit Commitment ("RUC") as specified. As a result of Asbury's "Self" status, Empire could be sure that the unit would be online the following day which prevents unit cycling from an SPP de-commitment instruction and also helps manage fuel inventory. However, as a result of the "Self" status, the unit is considered a "price taker" which means it could not be certain that the LMPs would be greater than the cost of generation during its run.

Q. What is unit cycling and why was Empire seeking to avoid it?

A. Unit cycling is the continual starting up and shutting down of a unit. In the SPP IM, cycling is caused by economic signals that do not support the continuous operation of a generating unit day-to-day and instead signals the unit to start up or shut down. As discussed below, Empire attempted to avoid cycling out of concern for daily energy pricing to serve load, start-up risk, and fuel inventory management.

Q. Please describe each of the aforementioned risks that Empire was attempting to mitigate.

A. **(1) Daily Energy Pricing to Serve Load**: If Asbury was de-committed from the IM, the unit would only receive a start-up instruction in instances where DA prices could support both start-up costs (which are not insignificant for baseload coal units) and the energy offer which is comprised of a no-load offer and incremental energy offer. If the prices didn't justify the Start-Up and energy offer of the unit, Asbury would not be selected, even if its marginal energy costs were in the money. This creates a situation in which units that may not be as economical as Asbury on an energy-only basis are being called on more frequently, simply due to Asbury's start-up cost, thereby raising the cost of energy and negatively impacting Empire's customers. Avoiding cycling of the unit mitigated this risk, as it took the start-up costs out of the equation and allowed dispatch of the unit based solely on incremental energy costs.

(2) Start-up Risk: Cycling introduces a fair amount of risk in that with every start-up instruction there is a possibility that the unit is unable to start-up when receiving a commitment from the market. Coal plants are designed for base load generation and are not made for continuous starts and stops and often exhibit problems when asked to cycle. If a unit receives a Day-Ahead commitment instruction in the SPP IM, it has created a financial position relating to the sale of energy to serve a portion of SPP load. If the generating unit is unable to meet its obligation to provide the energy that has already been sold in the Day-Ahead market, then the Market Participant that is offering the unit is forced to purchase back the energy that it was unable to deliver in the Real-Time Balancing Market ("RTBM"). Often, the generation purchased back in the RTBM is at a higher cost than what it was sold for in the DA, because a less efficient unit would need to be called on to replace the generation that failed to make it online. The spread between what the energy was sold for in the DA and what is was purchased back for in the RT, often called the DART spread, creates a financial position for the market participant which can often result in dollars owed for power that was sold but that was not delivered. Keeping Asbury from cycling served to mitigate the risk associated with the failure to provide energy when committed. In his Direct Testimony, Empire witness Shaen Rooney discusses in more detail the negative impacts on power plants like Asbury when asked to continuously start and stop (cycling).

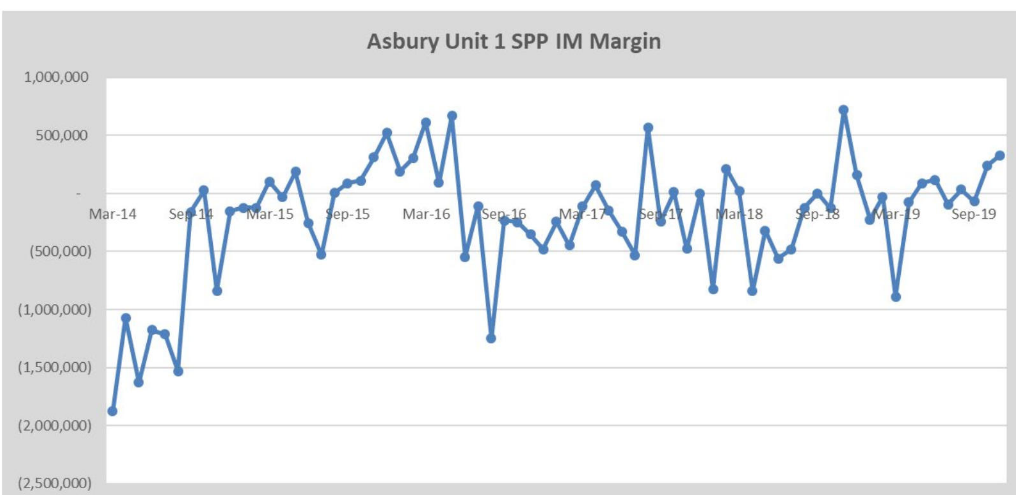
(3) Fuel Delivery Contract Management: Empire, not unlike many coal plant owners, had coal delivery contracts that have specific required amounts of delivery. If Asbury was left offline for extended periods of time, the amount of delivered coal on the ground could present both environmental and safety issues. These issues include bulldozer safety, permitted coal pile size, water discharge, required packing to prevent spontaneous combustion, etc. Keeping Asbury from cycling was an effective mitigant to prevent excess coal inventory problems.

Q. Did Empire cease Self-Committing Asbury in October of 2016?

A. Right around that time, Empire ceased self-committing Asbury for the reasons mentioned below. The only self-commitment of Asbury on a forward-going basis would have been for discrete scenarios similar to other generating units in the Company's fleet such as unit testing.

Q. Why did Empire not continue self-committing the unit if it avoided costly and damaging cycling, mitigated start/stop risk, and helped manage fuel inventory, as described above?

A. Empire believed the initial decisions to self-commit Asbury were justified based on the supporting locational marginal prices ("LMP") which, when netted with fuel costs, resulted in favorable net operating margins. In essence, our customers were still receiving net revenues that were offsetting the cost to purchase generation. However, the margins began to diminish in 2015 and by the summer of 2015, the unit began to exhibit negative net operating margins for 10 consecutive months.



***Negative values indicate favorable margins (unit costs – SPP IM revenues) and positive values represent unfavorable margins**

In the 2015 Annual State of the Market ("ASOM"), the SPP Market Monitoring Unit ("MMU") stated:

> In 2014, coal, combined cycle, and combustion turbine technologies were able to support their ongoing maintenance costs with that year's prices. However…while 2015 prices did support the ongoing maintenance cost of combined cycle and combustion turbine units, they did not support the cost of scrubbed coal units.

The report went on to describe that the "MMU expects the market to signal the retirement of inefficient generation." The MMU provided more details on its long run price signals including the table below.

Technology	AVG Marginal Cost ($/MWh)	Net Revenue from SPP Market ($/MW Yr)	Annual Revenue Requirement ($/MW Yr)	Able to Recover New Entry Cost	Annual Fixed O & M Cost ($/MW Yr)	Able to Recover Avoidable Cost
Scrubbed Coal	23.74	20,626	421,684	NO	31,160	NO
Gas Combined Cycle	19.22	36,122	151,525	NO	15,370	YES
Combustion Turbine	34.55	9,533	284,437	NO	7,040	YES

The 2016 and 2017 MMU ASOM found consistent results with the 2015 ASOM, in that prices did not support the cost of scrubbed coal units.

Q. Did Empire stop self-committing Asbury immediately following the reduction in prices?

A. No. Empire still had must-take coal delivery challenges to navigate. However, in October 2016, Empire was able to renegotiate its coal delivery contract to avoid must-take scenarios, which would allow the Company to manage its coal pile without having to self-commit Asbury to keep inventory levels manageable. From November 2016 forward, Asbury was almost exclusively offered in "market" status in which case SPP would commit the unit based on sufficient pricing.

Q. What was the result of allowing Asbury to be offered in "Market" status?

A. Although the unit was then only committed and dispatched when it was considered "in-the-money," in order to improve its net operating margins, Asbury operated less and less. Below is a table with Asbury's Net Capacity Factor ("NCF"):

Asbury Unit 1	
Year	NCF
2010	76.42%
2011	70.72%
2012	70.32%
2013	78.17%
2014	64.05%
2015	63.50%
2016	62.69%
2017	56.92%
2018	48.01%
2019	46.97%

Q. What is a Net Capacity Factor ("NCF")?

A. A Net Capacity Factor is an industry standard used to assess how much a unit generates over a period of time compared with how much it could generate if it ran at the top of its net capacity during that same time. For example, a 200 MW net capacity unit is capable of generating 1,752,000 MWh annually (200 MW * 8,760 hours [assuming a non-leap year]). If the unit actually generates 1,314,000 MWh over the same 8,760 hours, it would have a NCF of 75% (1,314,000 MWh /1,752,000 MWh).

Q. What do the NCF figures in the table above say about the operation of Asbury?

A. The NCF figures show that the unit was running lower and lower annually when compared to what it was capable of running (assuming 100% availability). The NCF is used to make an apples-to-apples comparison of a unit's amount of generation compared to what it is capable of generating over a fixed period of time. Over time, a unit's capacity may fluctuate based on degradation or investment in that unit, but an NCF takes that information into account to isolate its generation performance compared to its respective capabilities.

Q. As Asbury's NCF began to decline, what did Empire do to try and improve its performance in the SPP IM?

A. As Asbury's NCF continued to decline, plant personnel worked on various aspects of its operating characteristics to make it more amenable to market commitments, therefore improving its NCF.

Q. What aspects of Asbury's operating characteristics were modified?

A. During 2018, plant personnel worked on getting the unit to be more flexible with the hope that improvements in its market-operating agility would increase its NCF. Around February 2018, Empire decreased Asbury's Minimum Run Time from 96 hours to 48 hours. Additionally, plant personnel were able to successfully operate the plant with a new Minimum Down Time of 6 hours compared to its previous Minimum Down Time of 48 hours. Please see the Direct Testimony of Empire witness Shaen Rooney for a discussion of how these changes were made and the effects they had on the unit.

Q. How did these new operating parameters change Asbury's operation?

A. Asbury could now cycle down for a short period of time, often during low price periods, and come back online as needed by SPP. With the operating parameters of Asbury closer to those of a combined cycle generator, Asbury was able to maximize its ability to offer into the IM unencumbered by its lack of market-operating agility and the result was a record number of starts in its last 2 years of operation.

Asbury Unit 1	
Year	Starts
2010	10
2011	9
2012	7
2013	2
2014	8
2015	11
2016	10
2017	11
2018	34
2019	26

Q. Did this greater number of starts impact the NCF trend?

A. No. As you can see above, the NCF continued to fall, even with the greater number of starts.

Q. Ultimately, what happened with Asbury?

A. Empire notified SPP of Asbury's coming retirement in August 2019, and Asbury was officially de-designated as a network resource on March 1, 2020.

Q. What were the considerations underlying Empire's analysis to retire Asbury?

A. Not unlike the aforementioned ASOM's prediction based on long term price signals, market fundamentals eventually signaled the need for the retirement of Asbury. The evaluation of Asbury's ongoing useful life given market conditions, the lower cost of wind, and the avoidance of additional environmental compliance-related investment in Asbury, was first conducted by Charles River Associates ("CRA") in the Generation Fleet Savings Analysis ("GFSA"). The GFSA found that the lowest cost way for Empire to serve its load obligations over the next twenty to thirty years was to undertake a near-term strategy that builds up to 800 MW of strategically located wind in or near Empire's service territory and retires Asbury. In particular, Asbury's selection for retirement was provoked by coal combustion residual rules that required significant investment in a bottom ash conveyance system and coal pond enclosure, along with its actual performance in the SPP IM. Based on these factors, as well as the ability to add wind generation before the production tax credits began to phase out at 100%, the Company determined that it was prudent to retire Asbury.

Q. Was this analysis confirmed in Empire's 2019 Integrated Resource Plan ("IRP") filing?

A. Yes. Based on the 2019 IRP, retiring Asbury results in savings of approximately $93 million on a 20-year expected value basis. From a risk perspective, retiring Asbury also demonstrated significant savings. Under a stochastic analysis conducted by CRA looking at 54 different scenarios (*see* Case No. EO-2019-0049), retiring Asbury resulted in savings over maintaining Asbury until end of life 94% of the time, on a probability-weighted basis. Savings range from $18 million to $144 million. Only under limited combinations of high capital costs, high gas and power prices, and no carbon price did retiring Asbury not reduce costs, as compared to continuing to operate Asbury until fully depreciated.

Q. Does Empire's analyses of cost savings relating to the retirement of Asbury take into account Empire's request in this proceeding for customers to continue to pay the pre-tax return on the retired investment?

A. Yes. My understanding of the customer savings calculated in the GFSA assumed that customers would pay the remaining outstanding balance on Asbury over 30 years, the cost of the capital, and decommissioning costs. The cost of the capital reflects the cost of debt and the allowed return on equity, calculated on a pre-tax basis.

Q. Are there other benefits to retiring Asbury?

A. Yes. The wind generation would provide cost savings to Empire's customers over the next 20-30 years, would serve as a replacement of Asbury's capacity, and would enable

Empire to meet the Renewable Portfolio Standards ("RPS") of Missouri when the Elk River Wind Farm and Meridian Way Wind Farm purchase power agreements expire in 2025 and 2028. Additionally, risks associated with costs for further emissions controls investment or potential carbon tax are reduced by the retirement of Asbury.

Q. Was the decision to retire Asbury reasonable and prudent?

A. Yes.

Q. What was the actual retirement date of Asbury?

A. As noted above, Asbury was de-designated from the market on March 1, 2020. That was the earliest possible retirement date for Asbury per the SPP guidelines that were in place at the time and it was retired as a coal-fired generating facility at that time.

III. <u>WIND FARM MARKETING</u>

Q. Explain how Empire is marketing the Wind Farm into the SPP IM in accordance with applicable SPP IM rules and in a manner that is not detrimental to customers, as required by the Commission's June 19, 2019 Report and Order in Case No. EA-2019-0010 (the "Order").

A. The Wind Farms are registered as dispatchable variable energy resources ("DVER") in the SPP IM and the offering strategy is very similar to the strategy utilized with the Elk River and Meridian Way wind farms. During their first 10 years of operation, both of these purchased power agreements ("PPA") were offered into the SPP IM at a negative offer calculated to reflect the lost production tax credit. After 10 years of each contract, the offer was then reduced to nearly a $0/MWh offer to reflect the ten-year expiration of the production tax credit. Empire will also be offering the wind farms in at a negative offer reflective of a lost production tax credit if the market chooses to curtail.

In my experience, this is consistent with how much of renewable generation is offered into the SPP IM and is permitted by documents governing participation in the SPP IM. Additionally, as indicated below, Empire, as the Service Provider, is restricted from any scheduling activities that are not in accordance with the SPP Market Protocols and the SPP Open Access Transmission Tariff ("OATT"). Essentially, the interests of both Empire, on behalf of its customers, and the tax equity partners, are aligned and policies are in place to ensure adherence to the guidelines set forth in the SPP IM.

Q. Is this bidding strategy consistent with the Order?

A. Yes. Section 6(b) of the Order requires that "[t]he Wind Project(s) shall be operated in accordance with applicable SPP Integrated Marketplace rules and in a manner that is not detrimental to Empire's customers." The bidding strategy that I describe above comports with this requirement.

Q. Is Empire marketing the Wind Farms in the SPP IM now?

A. Yes. Empire began marketing the North Fork Ridge Wind Farm in the SPP IM in October 2020 and the Kings Point Wind Farm in March 2021, and the Neosho Ridge Wind Farm in November 2020. Empire is the acting Market Participant ("MP") for all three projects which allow the Company to claim the capacity for resource adequacy requirements and obligate the marketing activities for the projects.

Q. Are Empire's responsibilities regarding marketing of the Wind Farms memorialized in any agreements?

A. Yes. Empire entered into an Energy Management Service Agreement ("EMSA") with each of the three Wind Farm companies, Neosho Ridge Wind, LLC, North Fork Ridge Wind, LLC, and Kings Point Wind, LLC. In each of the EMSAs, Empire agrees to provide services for the dispatch and scheduling of energy and ancillary services from the Wind Farms into the SPP IM. The agreement specifically provides the granular level of responsibilities that are to be performed by the scheduling entity (Empire), in accordance with SPP Market Protocols and the SPP OATT and what rate will be charged for those responsibilities. Furthermore, the EMSA outlines the requirements for both the Project Company (the wind farm LLCs) and the Service Provider (Empire), in regard to the data collection and communication from the facility via Remote Terminal Units ("RTU") and the Supervisory Control and Data Acquisition ("SCADA").

Q. Is Empire being compensated for the services for which it provides to each of the Project Companies (the Wind Farm LLCs)?

A. Yes. Each EMSA provides a Services Fee for the annual provision of services outlined in the document.

Q. What are the Services Fee amounts and how were those determined?

A. The service fees are market assessments for a third party to perform similar activities. The annual EMSA service fees are: **[redacted]** for North Fork Ridge, **[redacted]**, for Neosho Ridge, and **[redacted]** for Kings Point.

IV. WIND IMPACT ON THE FAC

Q. Will the sales of the generation from the Wind Farms have any impact on the FAC?

A. Yes. We anticipate that sales of energy from the Wind Farms will lower the costs in the FAC by an estimated $56.4 million on a Total Company annual basis or $49.6 million on a Missouri retail basis.

Q. How are you proposing that the market revenue from the Wind Farms be calculated?

A. Market revenue is simply the revenue received by Empire for generation and any other products sold into the SPP IM, net of any market charges that are typically assessed to generators as distribution payments. The market revenue generated from each Wind Farm should be treated exactly as Empire treats the revenue from the rest of its generation assets. Empire also proposes to include the following additional sources of revenue and expense received in the "market revenue" calculation: Paygo, Tax Equity distributions, Renewable Energy Credits ("RECs"), and PTCs.

Q. Why would Paygo be included in Empire's calculation of market revenues?

A. Paygo, which as more completely described in the Direct Testimony of Empire witness Todd Mooney, is a variable amount of revenue received from the tax equity ("TE") partners for generation beyond what was originally calculated as part of the contribution to the project. Since this component is variable and is directly related to generation levels that are subject to the IM, it is appropriate to be included into the FAC as an immediate source of revenue to customers for generation greater than that which was calculated for the original contribution to the project.

Q. Why would Empire include TE Distributions in its calculation of market revenues?

A. TE distributions, as more fully described in Mr. Mooney's Direct Testimony, is a necessary component of the TE structure and allows the TE partner to invest an amount of approximately 45%-60% of the project costs, in exchange for 99% of the PTC, accelerated depreciation, and a cash distribution of market revenues estimated to be between 25%-50% for years 6-10. Without these components, the amount of contribution to the projects would be reduced, therefore increasing the costs to Empire customers.

Q. Why should RECs be included in the calculation of market revenues?

A. Each of the Wind Farms will generate RECs. These RECs will be purchased by Empire as the "buyer" from Neosho Ridge, LLC, North Fork Ridge, LLC, and Kings Points, LLC as the "sellers" for **[redacted]**. The three Wind Farm LLCs are 100% owned by Empire Wind Holdings, LLC of which The Empire District Electric Company is a Class B member representing approximately 50% of the ownership, with the other 50% owned by TE as the Class A member. This process is outlined and memorialized in the Non-Energy Products Agreement for each respective Wind Farm. After Empire takes ownership of the RECs, any sales of excess REC's, beyond what is required to meet different renewable standards and meet the requirements of the proposed REC tariff, will generate revenue which will be refunded to the customer through the FAC.

Q. Should the revenues from PTCs also be included as market revenues as a credit against fuel costs in the FAC?

A. Yes. Each of the Wind Farms are eligible for PTCs which are based on the amount of wind generated and sold into the SPP IM. Empire will retain approximately 1% of the PTCs and, thus, a revenue credit commensurate with the values associated with from these PTCs should also flow through the FAC as an immediate refund of these tax credits offsetting the Company's tax liability that is reflected in customer's rates. Since the PTCs are variable and based on generation, it would be appropriate to include them in fuel and return their value to customers as quickly as possible.

Q. Will any adjustments to the FAC be necessary to accommodate the net wind revenues as described above?

A. Yes. Empire has proposed to adjust the language in the Off-System Sales Revenue ("OSSR") to reflect the net wind revenues received from the components described above. This will ensure the timely pass through of benefits to Empire customers, as presented in File No. EO-2018-0092. These changes are further described in Section VI - FAC Tariff Revisions in this testimony.

Q. If the Commission objects to the inclusion of some or all of the components listed above for pass through via the Empire FAC, how would the Company propose to ensure the timely return of net revenues to customers?

A. Empire wants to ensure that customers receive the benefit of the wind energy as soon as possible. The Company is receptive to other mechanisms that would allow a return of net wind revenues so long as the mechanism is transparent, and the distributions are timely to its customers. Further, the Company must create a mechanism to support any distributions from the Market Price Protection Mechanism ("MPPM") as ordered by the Commission in File No. EA-2019-0010 and as described by Empire witness Tisha Sanderson in her Direct Testimony in this proceeding.

The Company is further receptive to creating a mechanism that supports any future distribution of revenues and any disbursements to customers that may result from the MPPM.

V. <u>AFFILIATE WAIVERS</u>

Q. Please describe the affiliate waivers Empire obtained from the Federal Energy Regulatory Commission ("FERC") in regard to the Wind Farms.

A. Empire obtained waivers from FERC from Title 18 of the Code of Federal Regulations ("CFR") relating to three affiliate related restrictions. In particular, Empire sought and received a waiver from (1) affiliate restrictions between franchised public utilities with captive customers and market-regulated power sales affiliates, 18 CFR §35.39 (2019); and (2) cross subsidization rules, 18 CFR §35.44 (2019). Specifically, the waivers addressed sections 35.39(c)(2), 35.39(d)(1), 35.39(e), and 35.39(f), which would allow Empire employees to schedule and market the Wind Farms which are market-regulated power sales affiliates.

Q. What would otherwise be required by those sections?

A. Section 35.39(c)(2) states that "(t)o the maximum extent practical, the employees of a market-regulated power sales affiliate must operate separately from the employees of any affiliated franchised public utility with captive customers." FERC conditionally supported this request for waiver with reliance on Empire's "representations that scheduling and related activities to maximize efficiencies, coordinate scheduling, perform forecasting, and other sharing of information will be used to the benefit of the captive customer."

Section 35.39(d)(1) states that "(a) franchised public utility with captive customers may not share market information with a market-regulated power sales affiliate if the sharing could be used to the detriment of captive customers, unless simultaneously disclosed to the public." FERC granted this requested waiver on Empire's representation and commitment that any information shared will be not used to the detriment of the captive customer and the captive customer will not be harmed.

Sections 35.39(e)(1) and 35.44(b)(1) state that "(u)nless otherwise permitted by rule or order, sales of any non-power goods or services by a franchised public utility with captive customers, to a market-regulated power sales affiliate must be at the higher of cost or market price" and "(u)nless otherwise permitted by rule or order, and except as permitted by of this section, sales of any non-power goods or services by a franchised public utility that has captive customers or that owns or provides over jurisdictional facilities, including sales made to or through its affiliated exempt wholesale generators or qualifying facilities, to a market-regulated power sales affiliate or non-utility affiliate must be at the higher of cost or market price," respectively.

Finally, sections 35.39(f)(i) and 35.39(f)(ii) state that "(t)he market-regulated power sales affiliate must offer the franchised public utility's power first" and "(t)he arrangement between the market-regulated power sales affiliate and the franchised public utility must be non-exclusive," respectively. FERC granted this waiver based on Empire's commitment that any brokering activities would be at cost and that the waiver will not be used to harm or be used to the detriment of the captive customers.

Q. What was the purpose of the waivers?

A. The purpose of the waivers obtained by Empire was for the existing Empire power marketing staff and their responsibilities, which I currently oversee, to offer the new Wind Farms into SPP IM. Since the Wind Farms are not directly owned by Empire, but rather are directly owned by Empire Wind Holdings, LLC, of which Empire owns Class B membership shares, Empire needed a waiver to perform the same power marketing duties it would normally perform if the assets were owned directly.

Q. Please describe the process used by Empire to obtain the waivers from FERC.

A. Empire staff met with FERC staff on April 25, 2019, to discuss the affiliate waivers that were to be filed and answer any questions they may have about the proposed waivers. Empire filed its application for waiver on November 20, 2019, creating Docket No. ER20-432. Empire filed a Supplement and Amendment to its original application on April 9, 2020 and a second Supplement and Amendment to its application on May 1, 2020, before receiving a Commission Order on May 29, 2020, with a retroactive effective date of May 1, 2020. Additionally, FERC requested that

Empire revise the limitations of exemptions of Empire's market-based rate tariffs as discussed in the order.

VI. FAC TARIFF REVISIONS

Q. Does the company have any FAC tariff sheet changes to accommodate the structure of the new wind farms as discussed in EA-2019-0010?

A. Yes. As discussed earlier in my testimony, the Company is proposing minor changes to the FAC tariff to flow back to its retail customers the net impact of the items discussed earlier my Direct Testimony.

Q. What changes does the company propose to its FAC tariff sheet?

The Company proposes to modify the OSSR definition in the FAC tariff sheet to include net revenues from Neosho Ridge, North Fork Ridge, and Kings Point. The proposed changes to the FAC tariff are included in **Schedule AJD-1**.

Q. What additional FAC tariff changes is the Company proposing for this case?

A. The company is proposing changes to the FAC tariff to allow 100% of the SPP & Midcontinent Independent System Operator ("MISO") transmission costs and revenues associated with transmission service for retail load and inclusion of revenues received from the sale of energy to the Southwest Missouri Power Electric Pool ("SWMPEP").

Q. Please explain the current SWMPEP capacity and energy sale agreement.

A. The SWMPEP Capacity and Energy Sale Agreement ("SWMPEP Agreement") is a 5-year term agreement with the Missouri Joint Municipal Electric Utility Commission ("MJMEUC") on behalf of the SWMPEP to provide both capacity and energy to the cities of Monett and Mount Vernon. The capacity sale is a slice-of-system approach identical to how Monett and Mount Vernon were served as full-service requirement contract customers of Empire District Electric Company prior to June 1, 2020. The cities of Monett ("MCU") and Mount Vernon ("MTVN") are their own Network Service customers as defined in Part III of the SPP OATT. Energy (fuel-related expense and additional energy margin) is purchased by MJMEUC which reduces the amount of fuel expense Empire's retail customers pay through the FAC. Empire sells all energy from its resource fleet into the SPP IM and the energy-related percentages as defined in the SWMPEP Agreement results in an allocation of revenue for the same percentage based on SPP's Combined Interest Resource ("CIR") logic.

Q. What change in the FAC is Empire proposing related to the SWMPEP agreement?

A. Currently, Empire is precluded from sharing revenues received from full and partial sales requirements sales to municipalities. In ER-2019-0374, my Surrebuttal Testimony characterized the SWMPEP Agreement as a partial requirements sales contract that would preclude the Company from sharing the margin received from energy sales with its retail customers. In the Amended Report & Order for Docket ER-2019-0374, the Commission agreed with the Company in that "Empire's current FAC tariff language does not allow revenues from its MJMEUC contract to flow through its FAC." However, since this case will allow the allocations for Missouri retail to be updated to reflect the transition of Monett and Mount Vernon away from being served under Empire's Generation Formula Rate ("GFR"), the Company believes it would be fair to distribute the energy margin back to Empire's retail customers through its FAC.

Q. How does Empire propose to modify its FAC to allow the distribution of energy margin back to retail customers?

A. The company proposes to modify the OSSR definition in its FAC to include revenue associated with energy sales to the SWMPEP. See **<u>Schedule AJD-1</u>** for a redline of the proposed changes described above.

Q. Why doesn't the company remove the language excluding revenue from full and partial sales requirements to municipalities to accommodate this change?

A. Empire is still serving a municipality as a full-service sales requirement customer under its GFR contract. Removing this language would financially harm the Company by allocating revenue obtained from a full-service sales requirement customer to retail customers for production expenses not allocated to their base rates or fuel adjustment clause. Empire's retail customers are allocated a percentage of production expenses based on the total costs which include costs that are billed to full-service sales requirements customers. To credit back the revenue received from a full-service sales requirements contract would be tantamount to distributing revenue to Kansas retail customers for revenue received from Missouri retail customers and vice versa.

Q. What percentage of transmission expense is the company proposing to flow through its FAC?

A. Empire is proposing to flow 100% of its SPP and MISO transmission expense through the FAC.

Q. How does this compare to the current allocation factor of transmission costs through the FAC?

A. Currently, 34% of SPP costs and 50% of MISO costs are considered eligible to flow through the FAC. This was an agreed to percentage based on a calculation of "purchased power" or purchases of energy needed to serve native load beyond what is supplied by current owned generation.

Q. Why does the company believe that 100% of transmission costs ought to be recovered through the FAC?

A. It is the Company's opinion that language from Missouri statute 386.266 allows transmission costs associated with purchased-power costs to be included for recovery in the FAC. In ER-2014-0258, the Commission interpreted the statute as one that "…limits the costs that can be flowed through the FAC for recovery between rate cases. It allows for recovery of transportation costs, which has been determined to include transmission costs, but such transmission costs are limited to those connected to purchased power costs." Not unlike what Ameren represented in that docket, Empire sells all of its generation to SPP and separately purchases energy needed to serve native load. Empire's FAC tariff defines SPP costs and revenues as both purchased power and off-system sales revenue. The Commission went on to surmise what scenarios the drafters of the FAC envisioned when crafting that particular statute. In the Commission's decision, it was stated that "the statute was meant to insulate the utility from unexpected and uncontrollable fluctuations in transportation costs of purchased power. At the time the statute was drafted, and even in our more complex present-day system, the costs of transporting energy in addition to the energy generated by the utility or energy in excess of what the utility needs to serve its load are the costs that are unexpected and out of the utility's control to such an extent that traditional rate making is justified." This language suggests that only the purchased power above what a utility generates are the costs that are unexpected and out of the ability for the utility to control. The reality is that serving native load, irrespective of its source, requires transmission service, and transmission service comes with costs that are unexpected, outside of the utility's ability to control, or both. These costs are directly related to investments in the bulk electric system ("BES") or administration of the BES to ensure reliability.

Q. Can you provide an example(s) of costs that are unexpected and/or outside the ability of the utility to control?

A. Yes. One example would be in February 2016, a settlement was reached with a number of parties regarding a RTOR settlement. The MISO RTOR Settlement refers to the partial resolution of litigation brought by a number of MISO Transmission Service Agreement ("TSA") customers related to long-term Point-to-Point ("PTP") service agreements originally entered into with Entergy prior to their 2013 admittance into MISO. Upon Entergy granting functional control of its transmission facilities in Arkansas, Mississippi, Louisiana, and Texas, to MISO, transmission customers with long-term PTP TSAs were billed the significantly higher MISO RTOR rate. At issue was the application of a MISO system-wide rate for through and out transmission customers from the new MISO-South region which appeared to violate the no-cost-sharing rule in the Attachment FF of the MISO Tariff, in particular the FERC separation of new (South) and old (Legacy) regions for cost allocation and rate design purposes. After approximately two years of litigation, a settlement agreement was reached (subject to refund) between MISO and the TSA customers. The rate relief settlement schedules are as follows:

<u>Schedule 7</u>: Years 1 & 2 (2014 & 2015) the TSA Customers will be refunded for the difference between the MISO RTOR charged and the Entergy-only RTOR which is calculated based on the 2014 & 2015 Attachment O formula rate, respectively. Years 3 (2016) - 9 (2022) the TSA Customers will pay the then-current Entergy RTOR plus a systematically increasing portion of the difference between the then-current MISO

and then-current Entergy RTOR. Year 10 the TSA customers will begin paying the full then-current MISO RTOR.

Schedule 26: The TSA customers will be refunded for Years 1 & 2 (2014 & 2015) for Schedule 26 payments. Years 3-5 (2016-2018) the TSA customers will pay no Schedule 26 charges. Years 6-12 (2019-2025) the TSA customers will pay a systematically increasing amount (increasing by 12.5% annually) of the then-current MISO schedule 26 rate. Year 13 the TSA customers will pay the then-current MISO Schedule 26 rate. However, if transmission investment were to occur in the new MISO-South region, the TSA customers would be charged the applicable Schedule 26 charges. Again, due to the limited sharing of transmission expense in the Company's Missouri FAC, Empire's customers were not able to realize a significant portion of this refund.

Another more recent example would be the Balanced Portfolio Transfers. The Balanced Portfolio Transfers (BPT) refer to the transfers of Schedule 11 zonal revenue requirements from the zone to the region. The reason for these transfers is a collection of regional economic projects, called Balanced Portfolio projects, approved by the SPP for the purpose of reducing congestion on the SPP transmission system resulting in lower generation production costs. The term "balanced" refers to language in Attachment O of the SPP OATT which requires the sum of benefits must at least equal, if not exceed, the costs for each zone. If any zone is deficient, the tariff allows for a portion of the zonal revenue requirement to be transferred to the region for the purpose of achieving a "balance" or a benefit/cost ratio of at least 1.0. Since the Empire zone was not initially "in balance" with the approved portfolio of projects, a systematic set of zonal-to-regional transfers over the course of 10 years was designed to ensure a "balance". The transfers began in October 2012 (realized November 2012 as Schedule

11 settlements are one month in arrears) and for Empire resulted in a systematic increase of approximately $1.26 million each year for the first five years and then held constant for the next five years at approximately $6.3 million. Beginning in October 2015 Empire did not have enough zonal revenue requirements to transfer another $1.26 million from the zone to the region. As a result, a significant portion of the transfer was received as Schedule 9 revenue. However, since the BP projects were all completed in mid-2015, it was determined that Year 6 would true-up the estimated costs of the BP projects to the actual costs and hold those reallocated values steady for years 6-10. Although the projects as a group came in under budget, the allocation of benefits was not quantified to be commensurate between the different zones. When taking into account the estimated-to-actual cost variance on a project by project basis, a reallocation occurred in various zones including Empire's which resulted in an increase for the year's 6-10 amount of approximately $900,000/year or $7.196 million total transfer/year. In October 2022, shortly after the conclusion of this case, the BPT transfers will end, and Empire will see an increase in Schedule 11 Zonal expense of approximately $7.2 million/year. Although this transmission expense increase can be considered expected, or rather understood, it is certainly outside of the utility's ability to control.

Q. How did Empire treat the BPT transfers that were received in the form of revenue after October 2015?

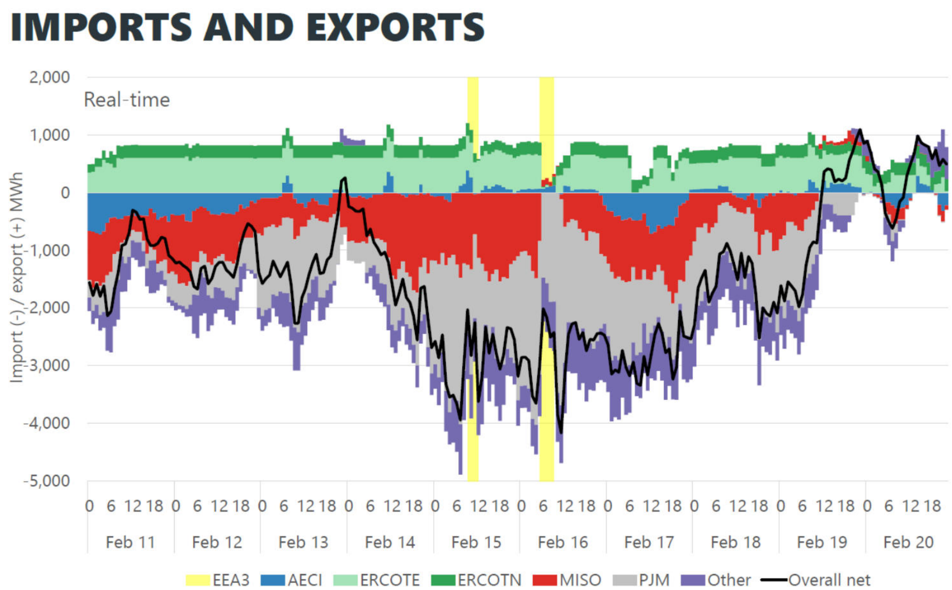
A. Empire determined that the intent of the BPTs is to credit back the zone for transmission investments out of balance and thus should be credited to transmission expense in the form of negative expense (rather than transmission revenue). Although Empire was limited to only returning 34% of Schedule 11 costs per the restrictions of transmission expense in the FAC tariff, the Company determined that reclassifying the revenue, for which no amount would be eligible to be returned to customers, as negative expense would allow for at least some amount of inclusion in the FAC so those dollars could be returned to customers.

Q. Does the company propose to include transmission revenue in the FAC?

A. Yes. The Company would propose to flow 100% of transmission revenue related to retail load back to customers through the FAC.

Q. What is the Company's overall opinion when it comes to the inclusion of transmission revenue and expense?

A. The Company believes that investment in the BES is critical to ensure reliability and to allow for the more efficient delivery of low-cost power to customers. One needs only to look at the recent Winter Storm Uri in February 2021 to understand the value of a robust transmission system. Below is a graphic from the SPP MMU's presentation to the Market Operations Policy Committee ("MOPC") in April 2021 that details the amount of imports and exports that the RTOs achieved due in part to a robust transmission. As a load serving entity ("LSE") sitting near the Southeastern seam, Empire implores the Commission to reconsider its stance on transmission cost inclusion to ensure that there is no disincentive for investing in transmission assets that increase reliability and lower production costs, both of which provide benefits that flow immediately to customers.



Q. If the Commission does not allow transmission expense and revenue to flow through the fuel at 100%, what does the Company recommend?

A. As an alternative, the Company would recommend a tracker for transmission revenues and transmission expenses that are not allowed to flow through fuel. This tracker would allow the Company to link costs and revenues related to transmission assets to the customers who are receiving the benefits of those investments. This would be similar to how transmission costs are recovered in the others states in which Empire operates with retail load.

Q. Does the Company have any additional changes to the FAC for the impact of the new Time-of-Use ("TOU") rate option?

A. Yes. As further discussed in the Direct Testimony of witness Gregory Tillman, the Company is proposing new TOU rates, part of which reflect the fuel impact as it relates to more efficient energy consumption.

Q. Please explain why changes to the FAC tariff are necessary as a result of the new TOU rates?

A. The current FAC tariff calculates a single Net Base Energy Cost ("NBEC") by multiplying the Net System Input ("NSI") by the Base Factor ("BF"). The Company's proposal in the TOU tariff is to establish an On-Peak BF and an Off-Peak BF. To accommodate this structure into the FAC, an adjustment needs to be made to the NBEC to reflect the different BF for TOU customers.

Q. How does the Company propose to modify the FAC tariff to accommodate a different BF for TOU customers?

A. The Company proposes to define Unadjusted NBEC using the current formula (NSI * BF), create a TOU NBEC Adjustment, and finally define the NBEC as the sum of the two.

Q. How is the TOU NBEC Adjustment calculated?

A. Utilizing the sales from the TOU customers, and the TOU FAC rate established in the TOU Tariff, the formula would be (On-Peak TOU Sales Adj for losses * On-Peak FAC BF + Off-Peak TOU Sales Adj for losses * Off-Peak FAC BF) + [(NSI kWh – On-Peak TOU Sales Adj for losses – Off-Peak TOU Sales adj for losses)*BF] – NBEC.

Q. How will sales from TOU customers be adjusted for losses?

A. The sales kWh for both On-Peak and Off-Peak will be multiplied by a monthly loss factor created by dividing NSI by Total System kWh. Both the NSI and Total System kWh are already included in the current FAC tariff.

Q. Why does the Company need to make these changes to the FAC tariff?

A. The NBEC is defined in 20.CSR 4240-20.090 1.U. as the fuel and purchased power costs net of fuel-related revenues billed during the accumulation period in base rates. Since TOU customers have a different base rate, in part due to base fuel revenue, it is appropriate to calculate the NBEC accurately to reflect the different level of the fuel component in base rates. If the Company would continue to calculate NBEC as NSI*BF, a mismatch would be created that would cause the Company to under-recover or over-recover fuel, which would have an impact on all customers.

Q. Does this conclude your Direct Testimony at this time?

A. Yes.

VERIFICATION

I, Aaron J. Doll, under penalty of perjury, on this 28th day of May, 2021, declare that the foregoing is true and correct to the best of my knowledge and belief.

/s/ Aaron J. Doll