Exhibit No.: _____
Issue(s): FAC Transmission Inclusion
Witness: Aaron J. Doll
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Sponsoring Party: The Empire District Electric Company d/b/a Liberty
Case No.: ER-2024-0261
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Before the Public Service Commission
of the State of Missouri

Direct Testimony

of

Aaron J. Doll

on behalf of

The Empire District Electric Company d/b/a Liberty

November 6, 2024

Liberty™

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THE EMPIRE DISTRICT ELECTRIC COMPANY D/B/A LIBERTY
BEFORE THE MISSOURI PUBLIC SERVICE COMMISSION
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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 d/b/a Liberty ("Liberty" or the "Company").

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

A. I am testifying on behalf of Liberty.

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 Liberty for approximately 18 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 became 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 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 procurement of fuel for electrical generation, the day-to-day interfacing, systems, and settlements with SPP as it relates to the IM, long-term and short-term load forecasting, and 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 before this Commission, the Kansas Corporation Commission, the Oklahoma Corporation Commission, the Arkansas Public Service Commission, the Kentucky Public Service Commission, and the New Hampshire Public Utilities Commission.

Q. What is the purpose of your direct testimony in this proceeding?

A. I provide support that the Company's Missouri Fuel Adjustment Clause ("FAC") tariff should be modified to include 100% of transmission expense incurred as a result of the Company's participation in the SPP. The recommendation to include transmission expense is good regulatory policy which is supported throughout my testimony by describing the contextual background of the transmission service which is administered by SPP, and I also outline the importance to our customers of the SPP transmission service. I further describe how SPP transmission planning and cost allocation is determined, including the Commission's role in those planning and cost allocation decisions. Additionally, I discuss the appropriateness of the Company's Market Price

Protection Mechanism calculation. Furthermore, I recommend a revision to the Company's Renewable Energy Purchase Program tariff. Finally, I discuss the need for the Company's request of a New Natural Gas Generation Investment Accounting Authority Order ("AAO").

Q. Are you sponsoring any schedules in this testimony?

A. Yes. I sponsor the below schedules.

Direct Schedule AJD-1	Liberty's Response to OPC's MPPM Motion
Direct Schedule AJD-2	Revised Renewable Energy Purchase Program Schedule REP Tariff
Direct Schedule AJD-3	SPP Winter Storm Uri Report

II. TRANSMISSION EXPENSE IN FAC

Q. What is transmission service?

A. Transmission service provides the delivery of electric energy over high-voltage transmission lines and facilities to local distribution facilities for the purpose of providing energy for end-user consumption.

Q. Why is transmission service important to Liberty and its customers?

A. Transmission service and Network Integration Transmission Service ("NITS") allow for a more efficient pooling of resources that lowers costs and improves reliability.[1] This is accomplished because Liberty can optimize its load serving efficiency by utilizing a market geared toward maximizing economic commitment and dispatch efficiency. Rather than each market participant determining which resources need to generate to cost effectively serve load, Liberty's customers share in the benefits of all SPP members by allowing for a regional solution to serve load to maximize cost-

[1] SPP OATT Section 30.5. "*As a condition of receiving Network Integration Transmission Service, the Network Customer agrees to redispatch its Network Resources as requested by the Transmission Provider pursuant to Section 33.2 and in accordance with the Energy and Operating Reserve Markets procedures in Attachment AE.*"

effectiveness. The transmission infrastructure in the SPP footprint enables this construct and creates immediate benefits for members.

Q. Who provides transmission service for Liberty?

A. The SPP is a Regional Transmission Organization ("RTO") and is responsible for independently coordinating non-discriminatory access to transmission services. Transmission service is taken through the SPP Open Access Transmission Tariff ("OATT"), and Liberty is considered a Transmission Customer.

Q. Describe Liberty's background regarding transmission service within SPP.

A. Liberty was a co-founder of SPP in 1941 to help provide generation for wartime efforts, and the Company has been a member of SPP ever since. Liberty has been participating with SPP as it has evolved from coordinating voluntary agreements between neighboring utilities to its current RTO status in 2004 through its role in facilitating today's IM that began in March 2014.

Q. Has Liberty always had its transmission facilities administered by a SPP Tariff?

A. No. The Company did not place its transmission facilities under the SPP OATT until 1998. In 2002, Liberty became a NITS customer of SPP.[2]

Q. Is the OATT approved by a regulatory authority?

A. Yes. The OATT has been approved by the Federal Energy Regulatory Commission ("FERC").

Q. How often does SPP seek to revise its OATT?

A. SPP routinely seeks FERC approval for OATT revisions to accommodate the changing needs of SPP's members and market participants as determined through revision

[2] SPP OATT: Section 28.1. "*Network Integration Transmission Service is a transmission service that allows Network Customers to efficiently and economically utilize their Network Resources (as well as other non-designation generation resources) to serve their Network Load.*"

request and subsequent working group processes. Liberty actively participates in reviewing revision requests and proposed OATT revisions prior to their submission to FERC for approval. Liberty does so through its voting position on the Regional Tariff Working Group, which is responsible for the development, recommendation, and overall implementation and oversight of the SPP OATT, as well as Liberty's voting position on the Markets Operation and Policy Committee.

Q. Does the Company have any control over the OATT tariff approved by FERC?

A. As discussed above, Liberty is a member of SPP and an active participant in many SPP working groups. Thus, Liberty does participate in the OATT tariff revision process as part of its SPP responsibilities, though it does not control that process. Ultimately, FERC is the regulatory body that approves, modifies, or disapproves all proposed OATT revision.

Q. Does Liberty have to pay for transmission projects included in the OATT?

A. Yes. As a current Transmission Owner and Transmission Customer of SPP, Liberty is obligated to pay for its share of transmission facilities planned and constructed according to the cost allocation methodology approved in the OATT.

Q. How are transmission projects planned and evaluated?

A. Most transmission service projects are planned through an annual process administered by SPP called Integrated Transmission Planning ("ITP"), which assesses near- and long-term economic and reliability needs. The process seeks to achieve a reasonable balance among the cost of transmission investment, reliability, and the cost of congestion on the system; it therefore parallels NERC guidelines on transmission planning.[3] In the ITP process, member companies help identify and evaluate the needs

[3] NERC TPL-001-04.

of the SPP footprint over a defined planning horizon. At the conclusion of each ITP cycle, a list of projects is identified that furthers the goals of achieving reliability, providing economic benefits, and facilitating public policy goals.[4] The projects that are identified are considered base plan projects, otherwise known as Schedule 11 projects, and qualify for cost sharing according to the FERC-approved cost allocation methodology for network facilities.

Q. Are there other processes that result in network facilities that qualify for cost sharing among SPP members?

A. Yes, though the lion's share of active portfolio projects is from the ITP process, as shown in the figures below.[5] While other SPP study processes may produce network upgrades that qualify for cost allocation amongst members, they all share similar conditions as outlined in the SPP OATT to ensure value to the paying members and protect regional load from inequitable subsidization.[6]

[4] SPP OATT. Attachment O. Section III.7) d) ii). "*quantifying the benefits resulting from dispatch savings, loss reductions, avoided projects, applicable environmental impacts, reduction in required operating reserves, interconnection improvements, congestion reduction, and other benefit metrics as appropriate.*"
[5] Staff 1Q 2024 Quarterly Project Tracking Report Appendix 1&2: https://www.spp.org/spp-documents-filings/?id=18641.
[6] SPP OATT. Attachment J. Section III.

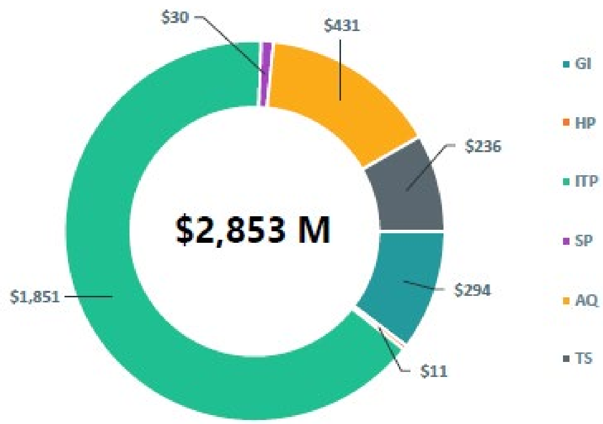

Figure 4: Total Active Portfolio (Millions)

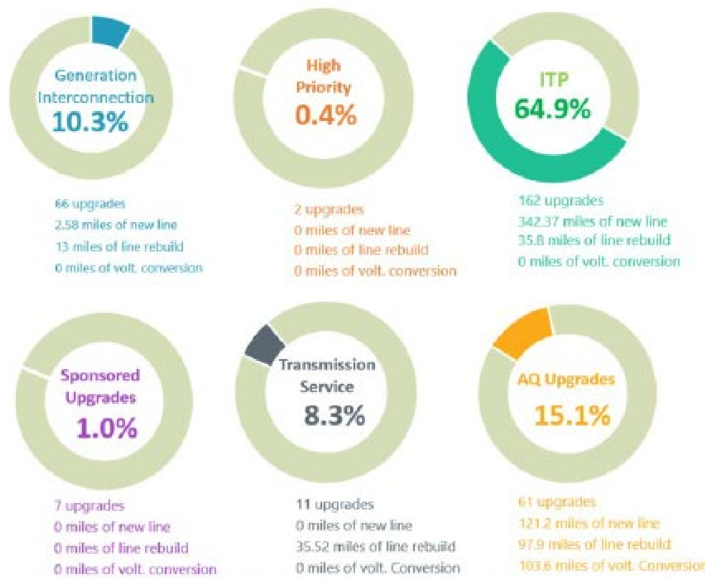

Figure 5: Upgrade by Type Cost Summary4

Q. How does Liberty pay for charges that are associated with the investment in the transmission system through the various SPP study processes?

A. Liberty pays for charges that are associated with the investment in the transmission system through the Annual Transmission Revenue Requirement ("ATRR"). This mechanism is updated on an annual basis. The most significant charges included in the ATRR are generally the Schedule 11 Zonal and Regional charges, which fund a large portion of the transmission investment in the bulk electric system ("BES"). Liberty supports BES investment through the aforementioned Schedule 11 charges which are dynamic.

Q. What benefits do customers realize from investments in the BES?

A. As discussed in the 2021 Value of Transmission Report,[7] published by SPP on March 31, 2022, the benefits of investment in a robust transmission system include:

- **Adjusted Production Cost ("APC") Savings**
    - Reduced production costs due to lower unit commitment, economic dispatch, and economically efficient transactions with neighboring systems,
    - Impact of generation outages and operating reserve unit designations,
    - Reduced transmission energy losses,
    - Reduced congestion due to transmission outages,
    - Mitigation of extreme events and system contingencies,
    - Mitigation of weather and load uncertainty,
    - Reduced cost due to imperfect foresight of real-time system conditions,
    - Reduced cost of cycling power plants,
    - Reduced amounts of costs and operating reserves,
    - Mitigation of reliability must-run ("RMR") conditions;
- **Reliability and Resource Adequacy ("RA") Benefits**
    - Mandated reliability projects,
    - Avoided/deferred reliability projects,
    - Reduced loss of load probability/Reduced planning reserve margin;
- Other benefits such as: increased wheeling revenues, generation capacity savings from reduced on-peak losses, public policy benefits for renewable development, storm hardening, fuel diversity, system flexibility, reduced emissions of air pollutants, improved utilization of transmission corridors, increased employment and economic activity; increased tax revenues.

While different members of SPP will have different exposure to the amount and timing of benefits due to the timing of projects and geographic location, it is reasonable to

[7] https://www.spp.org/documents/67023/2021%20value%20of%20transmission%20report.pdf.

conclude that some level of benefits would have been received by all members of the SPP.

Q. How are costs associated with Schedule 11 investments allocated?

A. Costs for Schedule 11 investments can either be through a Direct Assignment or recovered through either a zonal charge, a regional charge, or a combination of zonal and regional charges by SPP.

Q. Are Direct Assignment costs shared between members of the SPP?

A. No, Direct Assignment costs are assigned directly to the load based on specific requirements as outlined in different sections of Attachment J of the SPP OATT.[8]

Q. How are regional charges allocated?

A. Regional charges are allocated to the SPP footprint according to Load Ratio Share ("LRS") with different bright lines of total SPP load established for new significant geographic areas joining the SPP. This is sometimes referred to as a "postage stamp" cost allocation methodology.

Q. How are zonal charges allocated?

A. Zonal charges are allocated to the SPP zones, largely created from legacy balancing authority ("BA") areas and allocated to Load Responsible Entities ("LREs") within the zone based on LRS. This is often referred to as a "license plate" cost allocation methodology.

[8] SPP OATT. Section 1. D. Direct Assignment Facilities: "*Facilities or portions of facilities that are constructed by any Transmission Owner(s) for the sole use/benefit of a particular Transmission Customer or a particular group of customers or a particular Generation Interconnection Customer requesting service under the Tariff. Direct Assignment Facilities shall be specified in the Service Agreements that govern service to the Transmission Customer(s) and Generation Interconnection Customer(s) and shall be subject to Commission approval.*"

Q. How does cost sharing as a combination of zonal and regional cost allocation work?

A. Based on certain criteria within the SPP OATT, some network upgrades qualify for Highway/Byway funding. Highway/Byway cost allocation methodology allocates costs based on the voltage of the upgrade: (1) facilities operating at 300 kV and above are allocated 100% across the SPP region; (2) facilities operating above 100kV and below 300 kV are allocated one-third regionally and two-thirds zonally; and (3) facilities operating at or below 100 kV are allocated 100% zonally.[9]

Q. Why are the costs associated with Schedule 11 facilities shared amongst LREs?

A. In its filing on April 19, 2010, SPP stated that its then-new (now current) transmission cost allocation methodology "evolved from participant funding and zonal methodology focusing on reliability impacts, to an approach that recognizes the regional benefits of an integrated transmission plan addressing both reliability and economic needs in the SPP region and allocating costs accordingly."[10] Section III of SPP's filing for the Highway/Byway OATT revision stated:

> The Highway/Byway methodology is based on the Commission's core cost causation principles; namely those who benefit from new transmission facilities should pay the costs of the building the facilities. Large scale, EHV facilities tend to provide benefits across a wider region, while smaller facilities benefit more discrete areas within that region. Moreover, influenced by the realities of an integrated network and Commission policy such as Order No. 890, transmission system planning in SPP has evolved from a utility-by-utility approach focusing primarily on maintaining reliability at the local level to a region-wide approach to the development of a robust transmission system that is required to take into account not only reliability issues, but economic opportunities facilitated by reduced congestion, as well as state and federal policy goals such as increased use of renewable energy resources, greater incorporation of demand response and energy

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[9] ER10-1069-000. Submission of Tariff Revision to Modify Transmission Cost Allocation Methodology, page 7.

[10] ER10-1069-000, page 8.

> efficiency technologies, and reduced carbon dioxide emissions. Guided by these principles, the RSC [Regional State Committee] developed the Highway/Byway proposal to govern future transmission cost allocation in the region.[11]

Q. What entity is charged with overseeing the cost allocation of transmission investment in the SPP?

A. The Regional State Committee ("RSC") has the primary responsibility for determining:

- whether and to what extent participant funding will be used for transmission enhancements,
- whether license plate or postage stamp rates will be used for regional access charge,
- financial transmission rights ("FTR") allocation, where a locational price methodology is used, and
- the transition mechanism to be used to assure that existing firm customers receive FTRs equivalent to the customers' existing firm rights.[12]

Q. What individuals or positions compose the RSC?

A. The RSC is composed of one designated commissioner or board member from the state regulatory utility commission or board of each state in which SPP provides RTO services.[13]

Q. When SPP codified its current cost allocation methodology, what was this Commission's view of transmission cost sharing among SPP's members?

A. On May 17, 2010, the Commission filed Comments of the Majority of the Missouri Public Service Commission in FERC Docket No. ER10-1069-000 stating:

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[11] ER10-1069-000. Submission of Tariff Revision to Modify Transmission Cost Allocation Methodology, pages 12-13.
[12] Southwest Power Pool, Inc. Bylaws, First Revised Volume No. 4, Section 7.2 (a)-(d).
[13] Southwest Power Pool, Inc. Bylaws, First Revised Volume No. 4, Section 7.2.

> The MoPSC supports cost effective transmission that improves economic opportunity for Missouri customers, that improves reliability for Missouri customers and that provides Missouri utilities the access to low-cost electricity.
>
> The MoPSC Mission Statements read that the MoPSC has the statutory charge of assuring "safe, adequate, and reliable service" at "just and reasonable" rates. The MoPSC believes that transmission improvements and upgrades in the SPP are a necessary part to providing safe, adequate and reliable service to Missouri customers. Cost Allocation methodologies are critical components of the determination of whether that service is being provided at just and reasonable rates.
>
> The MoPSC will continue to actively and aggressively participate in the SPP planning process in working groups, committees and the RSC in evaluating projects, addressing inequities to Missouri customers and advocating for the Missouri interests.[14]

Q. Are all of the transmission costs Liberty incurs due to its SPP participation prudent?

A. Absolutely. As I explained above, Liberty's SPP participation has produced significant transmission, reliability, and efficiency benefits. SPP's transmission charges are a necessary cost of achieving and continuing to receive those benefits and savings. Moreover, Liberty has not incurred any SPP transmission costs that it could avoid. Therefore, it is accurate to say that 100% of the transmission cost Liberty incurs as an SPP participant is reasonable and prudent.

Q. Does Liberty recover a portion of its prudent transmission expense?

A. Yes. Currently, Liberty is recovering approximately 19.39% of eligible SPP transmission expense and 50% of eligible MISO expense. These percentages relate to any deviation from what is set in the base rates and also subject to the 95%/5% sharing mechanism in Missouri. It should be noted these costs are revised on an annual basis,

[14] FERC Docket No. ER10-1069-000, Comments of the Majority of the Missouri Public Service Commission (May 17, 2010).

which could result in large discrepancies between amounts previously included in base rates and are largely outside of the Company's control.

Q. Are there SPP transmission charges other than Schedule 11 that the Company incurs that do not receive timely recovery?

A. Yes. The Company incurs costs related to administration of the OATT and the SPP IM in the form of Schedule 1-A and administrative oversight by the FERC in the form of Schedule 12.

Q. Are these charges currently recovered through the FAC or some sort of other timely recovery mechanism outside of a general rate case?

A. No. Both Schedule 1-A and Schedule 12 are currently considered FAC-ineligible and excluded from any sort of true-up outside of a general rate case. Within this proceeding, the Company is now proposing to include these charges in its FAC cost recovery.

Q. As an SPP participant, why is it reasonable and appropriate for Liberty to recover 100% of its prudently incurred SPP transmission costs through its Missouri FAC?

A. First, as I discussed in my previous answer, 100% of the transmission expense Liberty incurs as an SPP participant is prudent. It is reasonable that a utility's rates both reflect and provide an opportunity to recover *all* of its prudently incurred costs.

Second, good regulatory policy ensures the alignment of costs and benefits, including the timing of recovery. For example, it is just and reasonable to initiate the recovery of costs linked to benefits derived from improved APC and reliability enhancements, which begin to deliver benefits to customers the moment the facilities are operational and charged through the SPP Schedule 11 process. Complete FAC recovery of such costs is therefore appropriate and reasonable because it aligns the timing of costs with the onset of the related benefits as closely as possible.

Third, the Company incurs these costs under SPP's FERC-approved tariff, and the cost allocation reflected in that tariff is prescribed by SPP's Regional State Committee, of which a member of this Commission is a voting member.

For additional discussion on the full recovery of transmission expense through the FAC, please see the direct testimony of Liberty witness John J. Reed.

III. MARKET PRICE PROTECTION MECHANISM ("MPPM")

Q. Briefly summarize the MPPM and the most recent submission from the Company.

A. The MPPM is a mechanism designed to share the risk associated with Liberty's wind projects between shareholders and customers and was originally approved as part of a stipulation and agreement in Docket No. EA-2019-0010. In the Fourth Partial Stipulation and Agreement in Docket ER-2021-0312, paragraph 21(c), it was agreed that the Company "(b)alances as of the end of each MPPM year shall be submitted to the Commission 60 days following the end of each MPPM year."[15] On July 29, 2024, the Company filed its second annual submission with the Commission in the same docket.

Q. Were there any responses disagreeing with the Company's MPPM calculation as supplied in this docket ER-2021-0312?

A. Yes. The Office of Public Counsel ("OPC") filed a response disagreeing with the purchased power agreement ("PPA") replacement values in the Company's original MPPM calculation submission. OPC argued the PPA replacement values represent the value associated with avoiding replacement of the existing wind power purchase

[15] MoPSC Case No. ER-2021-0312, Fourth Partial Stipulation and Agreement at page 8 (Feb. 5, 2022).

agreements. OPC claimed that the PPA replacement values through 2025 should be zero until the Company's Elk River wind PPA expires at the end of 2025. Additionally, OPC stated that the Company's calculation excluded the value of certain renewable energy credits ("RECs").

Q. What did the Commission order as result of the Company's original MPPM calculation submission?

A. The Commission ordered the signatories to address the PPA replacement values in the MPPM and to address RECs as a separate issue in the next general rate case.

Q. What is your response to the Commission Order Directing the Signatories to Address PPA Replacement Values in Liberty's Rate Case?

A. As discussed in great detail in Liberty's Response to OPC's MPPM Motion, I believe the Company properly tracked and reported all costs and revenue components of the MPPM, including the PPA replacement value. The Company's complete Response is attached to my testimony as **<u>Direct Schedule AJD-1</u>**. Briefly, the Company's Response states:

- Liberty properly tracked and reported all costs and revenue components of the MPPM, including the replacement value;
- Liberty provided background on how the MPPM was negotiated during the EO-2018-0092 and EA-2019-0010 dockets, including different stakeholder positions;
- Liberty referenced the Commission's determination that OPC's proposed conditions for its recommended Customer Protection Plan were "unreasonable";

- Liberty stated that in an effort to get OPC more comfortable with the MPPM during the ER-2021-0312 settlement discussions, the parties discussed and settled on a more specific set of criteria for some of the perceived ambiguity in the original MPPM mechanism; and
- Liberty demonstrated that language proposed by OPC that was contrary to the spirit of the MPPM was not included in the 4th Stipulation and thus not agreed to by the Company nor any of the signatories.

IV. RENEWABLE ENERGY PURCHASE PROGRAM

Q. What is the Company's Renewable Energy Purchase Program?

A. The Company's Renewable Energy Purchase Program (Schedule REP) allows non-residential customers the opportunity to offset the carbon emissions of up to 100% of their electricity consumption through the purchase of RECs. Generally, RECs to be provided through the program would result from the renewable energy production of the Company's wind facilities.

Q. How is the REC price for Schedule REP determined?

A. The price for REC sales reflects the average weighted price for the Company's REC sales for the previous calendar year. This price will approximate the value of the RECs associated with the Company's wind resource for our customers to ensure that the value they receive for the RECs is commensurate with market conditions. Subsequent REC price updates will be published by February 1 each year based on the previous calendar year's REC sales and become effective 60 days thereafter. Currently, to respond to changes in market conditions, if the value of RECs changes by more than five percent during any quarter, the price will be updated to reflect the updated value.

Q. What change does the Company propose to the Renewable Energy Purchase Program?

A. The Company proposes an increase of the quarterly five-percent threshold. The Company currently exceeds this threshold during every quarterly update due to the current methodology of the calculation. In the calculation, the Company includes any RECs transacted in the period, which is causing the swinging movement. For example, 2024 1st quarter went from $2.21 to $2.52 which is an increase of 14% or $0.31 per REC transacted. The future period is always sold at a premium to try to maximize the value. In order to limit the administrative burden of number of tariff submissions that occur the Company proposes a ten percent threshold. There are currently no customers participating in the Renewable Energy Purchase Program, so this proposal will have no current customer impact, and it may make the program more attractive to customers due to less frequent REC price changes.

Q. Has this change been reflected in the proposed tariff sheets included in the rate case filing?

A. Yes, the Company has made the proposed change, and I have included a copy of the revised tariff sheet with my direct testimony in **Direct Schedule AJD-2.**

V. NEW NATURAL GAS GENERATION INVESTMENT ACCOUNTING AUTHORITY ORDER ("AAO")

Q. What is the Company proposing regarding a new natural gas generator AAO?

A. Given the unique circumstances that have evolved over the past few years regarding RA, the Company is asking the Commission to issue an AAO for capital investment relating to new natural gas generation that is needed for increased reliability and to support potential economic opportunities if they arise (i.e. load additions). Specifically, the Company is proposing deferral accounting for all capital expenditures relating to new natural gas generator investment, namely investment in the Riverton Units 13 and 14 for which the Commission granted Liberty a Convenience and Necessity ("CCN") on June 5, 2024, in Case No. EA-2023-0131 to replace the existing gas-fired Riverton Units 10 and 11.[16]

Q. What unique circumstances exist today which necessitate the need for the special deferral accounting treatment for all new natural gas generator investments?

A. Following the events of Winter Storm Uri, SPP conducted an in-depth analysis of the conditions its membership faced during the extreme temperatures that resulted in two incidents of mandatory load shed across the SPP footprint. The report was published on July 19, 2021, a copy of which is attached as **Direct Schedule AJD-3**. The report identified and recommended "22 actions, policy changes and assessments categorized in three tiers."[17] Regarding the **Resource Planning and Availability** recommendations, the report recommended (1) performing ongoing assessments of the minimum reliability attributes needed from SPP's resource mix and (2) developing or improving policies regarding RA assessments, accreditation criteria, minimum reliability criteria, and market-based incentives to ensure sufficient resources will be available during extreme conditions.[18] The result of these policy recommendations has been the rapid implementation of new RA standards and criteria that challenge utilities to perform reliably under all conditions. Although reliable operations are nothing new

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[16] *In the Matter of the Application of The Empire District Electric Company d/b/a Liberty to Obtain a Certificate of Convenience and Necessity to Enhance System Resiliency*, Case No. EA-2023-0131, Order (MoPSC June 5, 2024).
[17] A Comprehensive Review of the Southwest Power Pool's Response To The February 2021 Winter Storm – Analysis and Recommendations, page 9.
[18] *Id.* at 11.

to utilities such as Liberty, the increasingly severe weather conditions and the penalty for non-performance has created a unique and extraordinary situation.

Q. As a result of the above-mentioned report, did SPP implement a new policy to address reliability as it specifically relates to RA?

A. SPP made sweeping changes to its RA construct to ensure reliable operations through use of its newly formed Resource and Energy Adequacy Leadership ("REAL") team. The REAL team is composed of regulators of SPP members, utilities, and energy advocates to guide, prioritize, and recommend changes to increase assurance that sufficient energy will be available to meet expected load. The effort of the REAL team led to new policy changes that primarily focused on: (1) an increased the Planning Reserve Margin ("PRM"), (2) implementing performance based accreditation, (3) modifying Effective Load Carrying Capability for the accreditation of renewables, (4) a new outage and availability policy for generating units, and (5) additional fuel assurance requirements for critical hours.

Q. Please summarize each of these policy changes.

A. <u>Planning Reserve Margin</u>

The Planning Reserve Margin is the amount of accredited generation beyond projected peak load that is needed for reliability to maintain the "1 day in 10 years" standard. Planning Reserve Margin modeling is based on a variety of factors, including weather, planned and unplanned maintenance outages, hourly load profiles, and transmission limitations. The primary purpose of Planning Reserve Margin modeling is to create a foundation for the amount of additional accredited capacity needed to reliably serve load. The Planning Reserve Margin is calculated as follows:

$$\frac{\text{Total Accredited Capacity - Net Peak (including utility-controlled interruptible)}}{\text{Net Peak (including utility-controlled interruptible)}}$$

In essence, LREs such as Liberty must have enough accredited capacity to serve net peak load plus additional capacity for risk-balanced uncertainty, which is based on a quantitative analysis performed by SPP on a biennial basis.

Performance Based Accreditation for Conventional Resources

Performance Based Accreditation ("PBA") attempts to quantify the amount of accredited capacity that a conventional resource (coal, natural gas, etc.) receives based on past performance and availability, rather than simply accrediting the resource based on the maximum generation that unit can provide each season. Currently, a conventional resource's capacity is accredited based on a triennial performance test regardless of whether the resource has demonstrated the ability to reliably start and operate during times of extreme need. Beginning in summer 2026, PBA will be used to more accurately calculate the capacity value to calculate PRM and incentivize resource generators that underperform historically to improve. Since the outcome of PBA will only serve to decrement existing resource generator capacity, it serves as an asymmetric risk that will strain utilities RA positions, especially utilities such as Liberty that operate within a slim margin of excess capacity.

Effective Load Carrying Capability

Effective Load Carrying Capability ("ELCC") attempts to quantify the capacity value for non-traditional generating resources such as wind, solar, and energy storage resources. The ELCC methodology determines the SPP system-wide capacity value for each category using a probabilistic analysis to determine the value that each resource type contributes to a system as the penetration of that resource type increases. The ELCC methodology then creates a two-tier system depending on whether the respective resource has firm transmission service and additional simulations are performed to determine the amount of non-traditional generation resources that can be counted on to maintain the "1 day in 10 years" outage standard.

Q. What impact do these various policies have on LREs such as Liberty?

A. The net impact of these policies is an increased uncertainty regarding how generation will be accredited each season and year, as well as how much accredited generation capacity will be needed to stay in compliance with the SPP RA requirements. This highlights the value of and need for conventional resources like the Riverton 13 and 14 units.

Q. How have these policies created a condition where special accounting treatment to defer natural gas generation investment is necessary?

A. The Company operates within a slim margin when it comes to meeting the RA requirements as outlined by the SPP. Due to the dynamic nature of the calculations as described above, and the uncertainty regarding future PRMs, the Company needs to invest in generation to ensure reliability of the bulk electric system and comply with applicable RA requirements. Given the timing of this rate proceeding and the June 5, 2024, CCN approval for Riverton 13 and 14, it is unlikely that Liberty will be able to engage in a regulatory proceeding for recovery of those investments without experiencing significant regulatory lag that would jeopardize the Company's opportunity to earn a fair return.

Q. Will Liberty's customers receive any value from Riverton 13 and 14 prior to including cost recovery for them in customers' rates?

A. Yes. Upon the units' in-service dates, they will generate electricity that will be sold into the SPP IM. The Company is proposing any revenue from the units' sales made into the SPP IM or to a third party would help offset the units' proposed AAO deferral capital investment cost. Furthermore, to the extent Liberty is short capacity prior to the units being reflected in rates, these units will be considered firm capacity and may be counted on to meet RA requirements. For specifics on how this proposed special accounting deferral mechanism would work, see the direct testimony of Company witness Charlotte T. Emery.

Q. Does this conclude your direct testimony at this time?

A. Yes.

VERIFICATION

I, Aaron J. Doll, under penalty of perjury, on this 6th day of November, 2024, declare that the foregoing is true and correct to the best of my knowledge and belief.

/s/ Aaron J. Doll