Figure 3

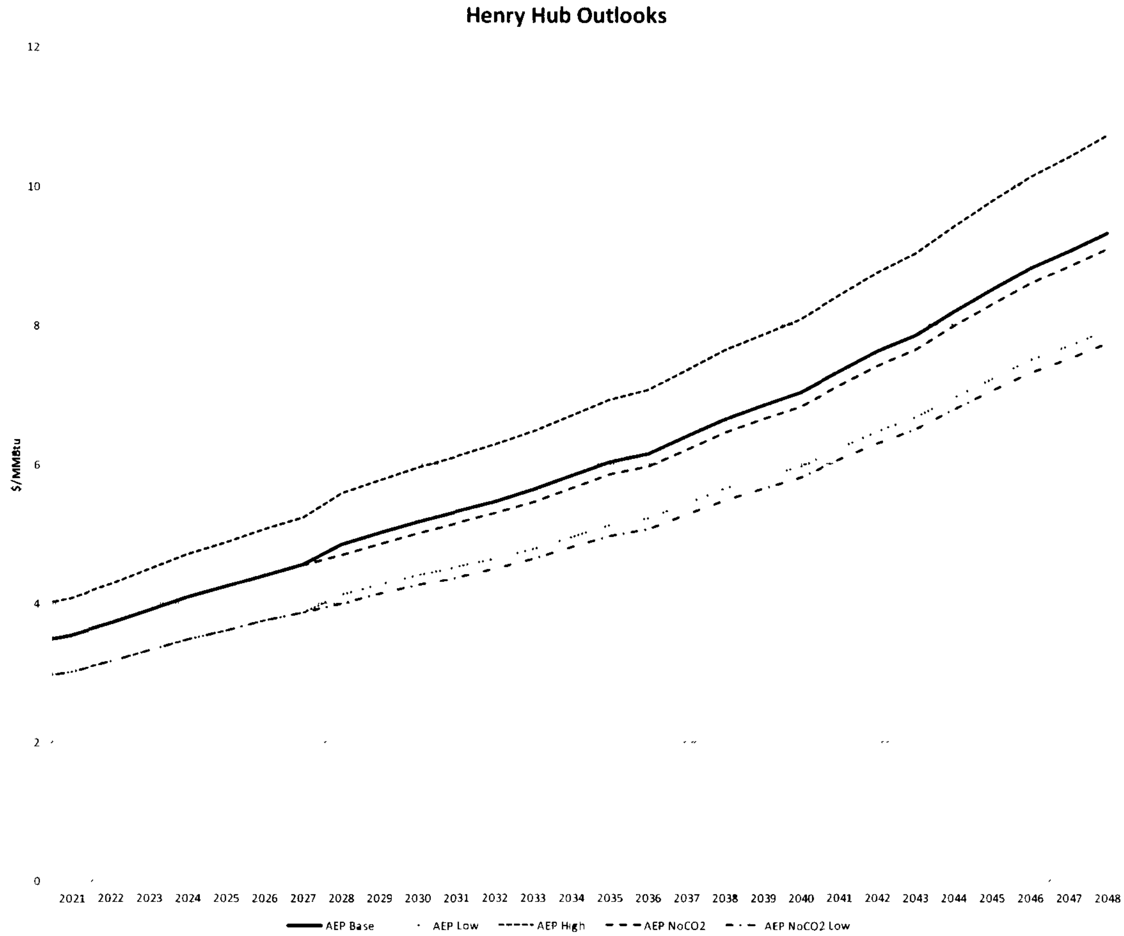
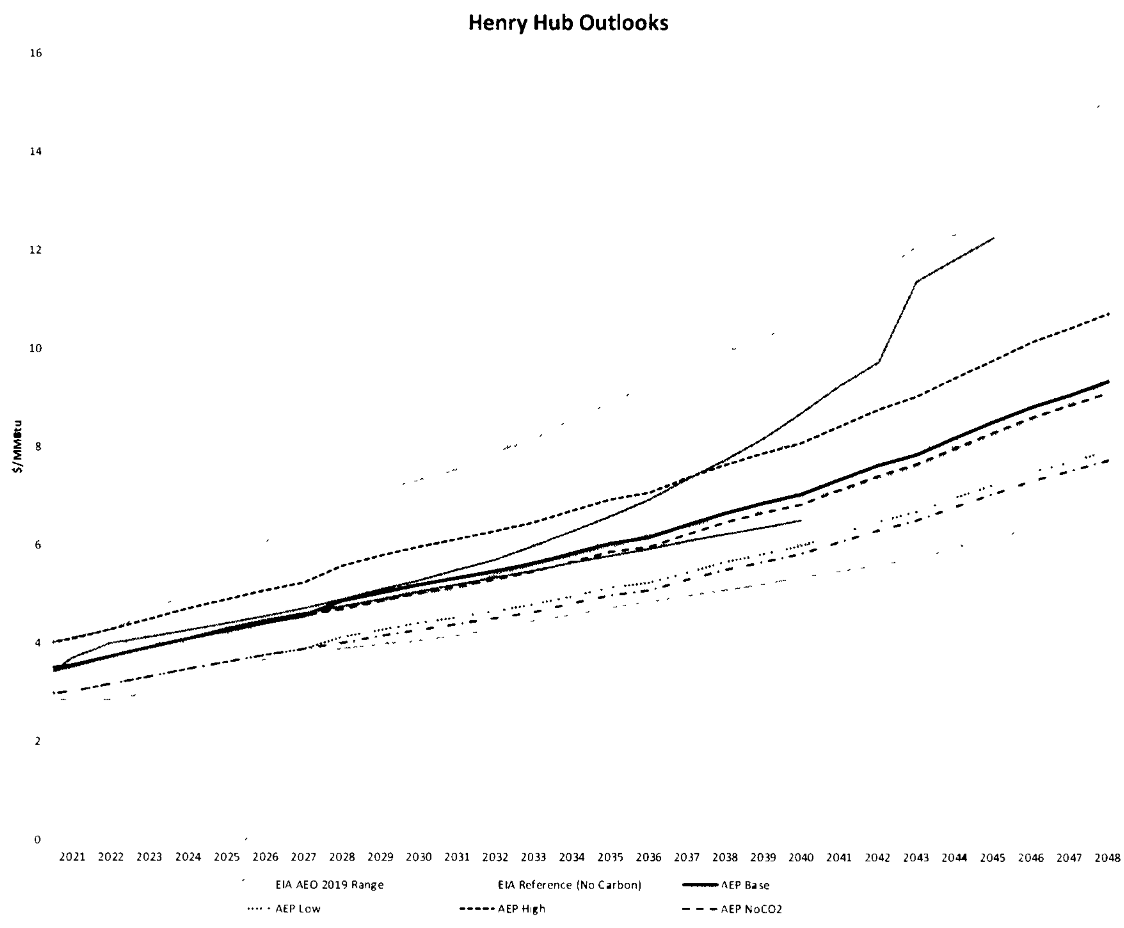


Figure 4 compares the Fundamentals Forecast Henry Hub natural gas price cases with other contemporaneous forecasts including the Energy Information Administration's (EIA's) 2019 Annual Energy Outlook, the International Energy Agency's (IEA's) 2017 Current Policies Forecast and SPP's 2019 Integrated Transmission Planning Forecast. The EIA (a part of the U.S. Department of Energy) collects, analyzes, and disseminates independent and impartial energy information to promote sound policymaking, efficient markets, and public understanding of energy and its interaction with the economy and the environment. In addition to their Reference (No

Carbon) Case, the EIA presents six plausible Side Cases represented by the shaded area. This figure shows, beyond 2037, SPP's 2019 Integrated Transmission Planning Forecast rises well above the High Fundamentals Forecast while the IEA 2017 Current Policies and the EIA 2019 Annual Energy Outlook forecasts, through the entire period, are quite similar to the Company's Fundamentals Forecast's Base Case.

Figure 4



CO$_2$ Mitigation. The 2019 Fundamentals Forecast employed a CO$_2$ dispatch burden on all existing fossil fuel-fired generating units that escalates 3.5% per annum from $15 per ton commencing in 2028. This CO$_2$ dispatch burden is less stringent than, and not intended to achieve, the national mass-based emission targets similar to those previously proposed (and now withdrawn) in the Clean Power Plan.

Q. DO RECENT LOW NATURAL GAS PRICES INDICATE THAT PRICES WILL BE LOW FOR A LONG TIME?

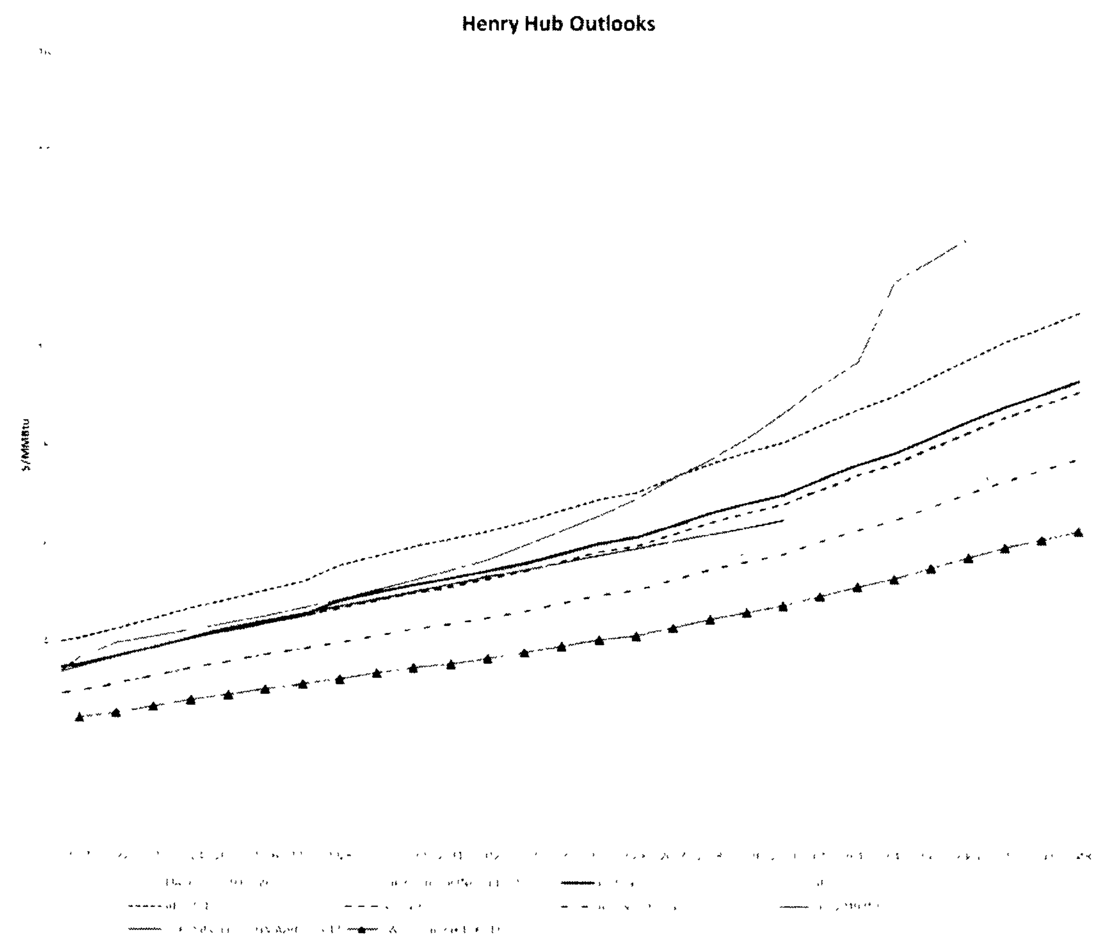
A. No, not necessarily. Natural gas prices can deviate from forecasted values for extended periods due to a variety of reasons, including abnormal weather and force majeure situations such as hurricanes Katrina and Rita. As addressed earlier, actual heating- and cooling-season weather can deviate dramatically from normal. Warmer than normal winters result in less gas demand and less storage refill demand in the following summer with correspondingly discounted natural gas prices. This is exactly what the U.S. experienced in the winters of 2011-2012, 2015-2016 and 2016-2017 (the second, third and fourth warmest winters since 1895, respectively), which resulted in natural gas spot prices that were significantly lower than weather-normal values.

IV. SELECTED WIND FACILITIES BREAK-EVEN NATURAL GAS PRICE EVALUATION

Q. PLEASE DESCRIBE THE BREAK-EVEN NATURAL GAS PRICE EVALUATION FOR THE SELECTED WIND FACILITIES.

A. The break-even natural gas price evaluation yielded the analogous Henry Hub natural gas prices implied by the SPP electric energy prices as provided by Company witness Torpey. Figure 5 illustrates that the Selected Wind Facilities break-even Henry Hub natural gas prices are positioned well below all of the Company's Fundamentals Forecasts and other publicly available forecasts.

ERRATA Figure 5



Q. WHAT METHOD DID YOU USE TO PERFORM THE SELECTED WIND FACILITIES BREAK-EVEN NATURAL GAS PRICE EVALUATION?

A. Please refer to Company witness Torpey's Direct Testimony for the derivation of the Company-specific Break-Even SPP electric power prices. Forecasted power price divided by forecasted natural gas price yields the Implied Heat Rate (also known as the break-even natural gas market heat rate). Only a natural gas generator with an operating heat rate (a measure of unit efficiency expressed in mmBtu/MWh) below the Implied Heat Rate can be profitable by burning natural gas to generate power. Therefore, dividing Company-specific Break-Even power prices ($/MWh) by the Implied Heat Rate (mmBtu/MWh), taken from the comparable Low No Carbon Fundamentals Forecast case, resulted in the appropriate Break-Even natural gas price ($/mmBtu).

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

PUC DOCKET NO.

PUBLIC UTILITY COMMISSION OF TEXAS

APPLICATION OF SOUTHWESTERN ELECTRIC POWER COMPANY FOR CERTIFICATE OF CONVENIENCE AND NECESSITY AUTHORIZATION AND RELATED RELIEF FOR THE ACQUISITION OF WIND GENERATION FACILITIES

DIRECT TESTIMONY OF

THOMAS P. BRICE

FOR

SOUTHWESTERN ELECTRIC POWER COMPANY

JULY 15, 2019

TESTIMONY INDEX

SECTION | PAGE

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is Thomas P. Brice. My business position is Vice President Regulatory and Finance for Southwestern Electric Power Company (SWEPCO or Company). My business address is 428 Travis Street, Shreveport, Louisiana 71101.

Q. WHAT ARE YOUR PRINCIPAL AREAS OF RESPONSIBILITY WITH SWEPCO?

A. I am responsible for SWEPCO's financial results and regulatory matters in Arkansas, Louisiana, and Texas. I have responsibility for the preparation, filing, and litigation of regulatory cases. Additionally, I am responsible for regulatory interactions, monitoring of regulatory filings, participation in rulemakings, rate and tariff administration, and ensuring compliance with regulatory requirements. I am also responsible for the financial matters of the Company, which includes serving as the primary interface with SWEPCO's parent company, American Electric Power Company, Inc. (AEP).

Q. WILL YOU BRIEFLY DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I graduated from the University of Louisiana at Monroe (formerly Northeast Louisiana University) in 1985 with a Bachelor of Business Administration in Accounting and a minor in Finance. I am a certified public accountant and certified internal auditor. I am a member of the American Institute of Certified Public Accountants and the Louisiana State Society of Certified Public Accountants. I have more than 34 years of experience in the electric and natural gas utility industries.

After graduation, I was employed by Arkla, Inc., which at the time was a vertically integrated natural gas company, in the internal audit department. Upon my departure in 1992, I was a senior auditor with primary responsibilities in contract and joint venture auditing.

In 1992, I was employed by SWEPCO as an audit manager and soon thereafter assumed the responsibilities of audit director on an interim basis in early 1993. My primary responsibilities as audit manager/interim audit director included managing the day-to-day operation of the department, ensuring successful completion of the annual audit plan, and reporting annual audit results to SWEPCO's Board of Directors.

From 1994 through 2004, I worked as a senior consultant for SWEPCO in the areas of planning and analysis, business ventures, and regulatory services. During this period of time, I had the opportunity to manage a diverse set of projects for the Company.

In 2004, I assumed the position of Director, Business Operations Support. I was responsible for the Company's financial plans and coordination with other organizations within the AEP system on matters directly affecting SWEPCO's financial and operational results.

In June 2010, I assumed the responsibilities of Director, Regulatory Services. In this capacity, I was responsible for the regulatory matters of SWEPCO in Arkansas, Louisiana, and Texas. In May 2017, I assumed my current responsibilities of Vice President of Regulatory and Finance.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSION?

A. Yes. I have filed testimony before the Arkansas Public Service Commission (APSC), the Louisiana Public Service Commission (LPSC), and the Public Utility Commission of Texas (PUCT).

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony supports the Company's request for Certificate of Convenience and Necessity (CCN) authorization for the acquisition of a 54.5% share of three wind generation facilities with a total capacity of 1485 MW of capacity (collectively referred to as the Selected Wind Facilities). SWEPCO's sister company, Public Service Company of Oklahoma (PSO), will acquire the remaining 45.5% share. Specifically, SWEPCO proposes the acquisition of the following facilities:

- Traverse 999MW
- Maverick 287MW
- Sundance 199MW

All of the Selected Wind Facilities were selected as a result of a competitive Request for Proposals (RFP). The Selected Wind Facilities are forecasted to provide SWEPCO's customers a savings over the 30-year expected facilities life of approximately $567 million (total Company) on a net present value (NPV) basis, or more than $2.03 billion on a nominal basis. The Facilities provide customer benefits under a wide range of possible future conditions analyzed by the Company, including production at the level guaranteed by the Company, and would break even at future power and gas prices below the low range of plausible forecasts.

Q. WHY DOES SWEPCO REQUEST AUTHORITY TO ACQUIRE THE SELECTED WIND FACILITIES?

A. SWEPCO's most recent Integrated Resource Plan (IRP) concludes that customers will benefit from SWEPCO's acquisition of low-cost wind generation resources. That plan shows that increases in renewable energy, including wind and solar, over the planning period will provide significant benefits to customers. Under that plan, energy output attributable to wind resources increases from 9% to 26% of SWEPCO's total energy mix. Acquisition of the Selected Wind Facilities will reduce customers' energy costs, help meet capacity needs, provide renewable energy credits (RECs) that customers may desire to acquire, and further diversify SWEPCO's portfolio of supply-side resources. Further, SWEPCO continues to see customer interest in more renewable energy to meet their sustainability and renewable energy goals. Therefore, SWEPCO is seeking to acquire the Selected Wind Facilities to save customers money *and* further diversify SWEPCO's energy resource mix.

Q. PLEASE IDENTIFY THE WITNESSES WHO WILL BE SPONSORING TESTIMONY IN SUPPORT OF THE PROPOSED ACQUISITION.

A. In addition to me, the following witnesses support SWEPCO's request in this proceeding:

Witness	Testimony Summary
Malcolm Smoak	Need for Selected Wind Facilities, Customer Benefits, and Company Guarantees
Jay Godfrey	RFP Process, Transactions with Developers and Expected Wind Output
Joseph DeRuntz	Description of Selected Wind Facilities
Karl Bletzacker	Fundamentals Forecast
Akarsh Sheilendranath	Congestion Cost Analysis and Value
Kamran Ali	Deliverability Assessment and Congestion Modeling and Mitigation
John Torpey	IRP, RFP and Economic Benefits Evaluation
Johannes Pfeifenberger	The Reasonableness of the Company's RFP, Congestion Analysis and Economic Benefits Analysis
Joel Multer	Production Tax Credits, Intercompany Allocations and Deferred Tax Asset
Noah Hollis	Credit Metrics/Financing
John Aaron	Customer Impacts/Recovery Mechanisms/Accounting Treatment

Q. WHAT TOPICS ARE COVERED BY THE REMAINDER OF YOUR TESTIMONY?

A. The remaining sections of my testimony are as follows:

- Section III - Describes the Selected Wind Facilities;
- Section IV - Discusses the expected benefits for SWEPCO's customers associated with acquisition of the Selected Wind Facilities;
- Section V - Discusses the guarantees offered by the Company;
- Section VI – Provides an overview of the RFP and the IRP that led to the RFP;
- Section VII – Describes how the acquisition is scalable if regulatory approvals are not obtained from one or more jurisdictions;
- Section VIII - Describes the regulatory approvals the Company seeks, including a request for a CCN under the Public Utilities Regulatory

Act (PURA) § 37.056 and a public interest finding under PURA § 14.101, to the extent that later provision applies;

- Section IX – Describes the requested Commission findings; and
- Section X - Conclusion.

III. DESCRIPTION OF THE SELECTED WIND FACILITIES

Q. PLEASE DESCRIBE THE WIND FACILITIES TO BE ACQUIRED.

A. The Selected Wind Facilities will be located to take advantage of one of the better wind resources in North America within the western portion of the Southwest Power Pool (SPP) in North Central Oklahoma. The Selected Wind Facilities consist of three separate projects totaling 1,485 MW of installed nameplate capacity: Traverse, Maverick, and Sundance.

Selected Wind Facilities Overview

	Traverse	Maverick	Sundance
Size (Nameplate)	999 MW	287 MW	199 MW
Planned COD	2021	2021	2020

As discussed by SWEPCO witness DeRuntz, the Selected Wind Facilities will be engineered to have a design life of 30 years and will consist of a selection of General Electric (GE) 2.3 MW, 2.5 MW, and 2.82 MW wind turbine generators.

Q. WHAT IS THE AGREED-UPON PURCHASE PRICE FOR THE SELECTED WIND FACILITIES?

A. As described in detail in the testimony of Company witness Godfrey, the total purchase price for the project companies that own the three Selected Wind Facilities providing 1,485 MW is $1.86 billion, or approximately $1,253/kW, which includes all costs associated with interconnecting the facilities to the SPP transmission system and any assigned network upgrade costs.

Q. WHAT IS THE EXPECTED TOTAL COST OF THE FACILITIES?

A. Total project costs including PSA price adjustments and owner's costs are expected to be $1.996 billion as discussed by witness DeRuntz.

Q. PLEASE DESCRIBE THE TRANSACTIONS THAT WILL ACCOMPLISH THE PROPOSED ACQUISITION.

A. The acquisition transactions are structured as a build-transfer arrangement pursuant to which, following completion of each Facility, the Companies will purchase all of the equity interests in the project company from the seller for the agreed-upon purchase price. The developers of the Selected Wind Facilities will design, develop, construct, and commission the facilities on a turn-key basis. No progress payments will be made by SWEPCO during that process. Company witness Godfrey further addresses the transactions with the sellers.

Q. WILL SWEPCO AFFILIATE PUBLIC SERVICE COMPANY OF OKLAHOMA ALSO PARTICIPATE IN THE ACQUISITION OF THE SELECTED WIND FACILITIES?

A. Yes. Contemporaneous with SWEPCO's RFP, PSO also issued an RFP that sought the same wind energy resources in the same geographical area as SWEPCO through the acquisition of one or more wind projects. SWEPCO and PSO are AEP affiliate electric operating companies and anticipate that they will jointly own the Selected Wind Facilities, subject to receipt of necessary regulatory approvals. A bidder that submitted a proposal in response to SWEPCO's RFP was also required to submit an identical proposal in response to the PSO RFP. The bids submitted in the two RFPs were evaluated and selected in a single RFP proposal evaluation. The RFP evaluation process and results are further discussed by Company witness Godfrey.

IV. CUSTOMER BENEFITS

Q. WHAT BENEFITS DOES SWEPCO EXPECT THE SELECTED WIND FACILITIES TO PROVIDE TO CUSTOMERS?

A. The Facilities will provide a significant volume of low-cost energy, diversify the Company's generation mix, provide capacity benefits, lower fuel costs, and provide a renewable energy credit option for customers that desire it. The addition of the Selected Wind Facilities to SWEPCO's generation portfolio will have a positive economic impact on customers' energy costs. Advances in wind turbine manufacturing, in conjunction with the federal production tax credit (PTC), have positioned wind resources to be an economical source of energy for SWEPCO's customers. The benefits of the Selected Wind Facilities are shown in the following table and discussed by Company witness Torpey.

Errata Table 1 – SWEPCO Base Fundamentals Analysis ($ millions)

Year	31 Year NPV	Total 31 Year Nominal
Production Cost Savings Excluding Congestion/Losses	$1,660	$5,095
Congestion and Losses	($322)	($893)
Capacity Value	$70	$311
Production Tax Credits (grossed up, net of DTA)	$507	$750
Wind Facility Revenue Requirement	($1,348)	($3,233)
Net Customer Benefits	**$567**	**$2,030**

Q. PLEASE EXPLAIN THE BASIS FOR THESE BENEFITS CALCULATIONS.

A. To determine the customer benefits of the Selected Wind Facilities, the Company developed a case with (Project Case) and without (Baseline Case) the Selected Wind Facilities. The Company then compared the difference or "delta" between these two cases for the period modeled, 2021 to 2051. The benefits also include the Selected Wind Facilities' capacity value, which was determined using the PLEXOS model. The adjusted production cost savings were added to avoided capacity value and the value of PTCS (grossed up, net of Deferred Tax Asset (DTA) carrying charges) to arrive at the total customer benefit. Project costs including the wind project revenue requirements and congestion and line loss costs are then subtracted from the total benefit to arrive at an annual net benefit to customers. The present value of all costs and benefits is then calculated.

Q. WERE A VARIETY OF FUTURE NATURAL GAS PRICES AND THE POSSIBILITY OF NO FUTURE CARBON BURDEN CONSIDERED IN THE CALCULATION OF EXPECTED CUSTOMER BENEFITS?

A. Yes. After the final selection was made, the customer benefits associated with the Selected Wind Facilities were calculated under a variety of sensitivities, including a number of natural gas price projections both with and without a projected carbon emissions burden. Each was run on the overall portfolio to estimate net revenue requirements and net benefits to customers. The expected customer benefits under a range of natural gas and carbon burden assumptions analyzed by the Company are shown in the following table:

Errata Table 2 – Customer Benefits Summary

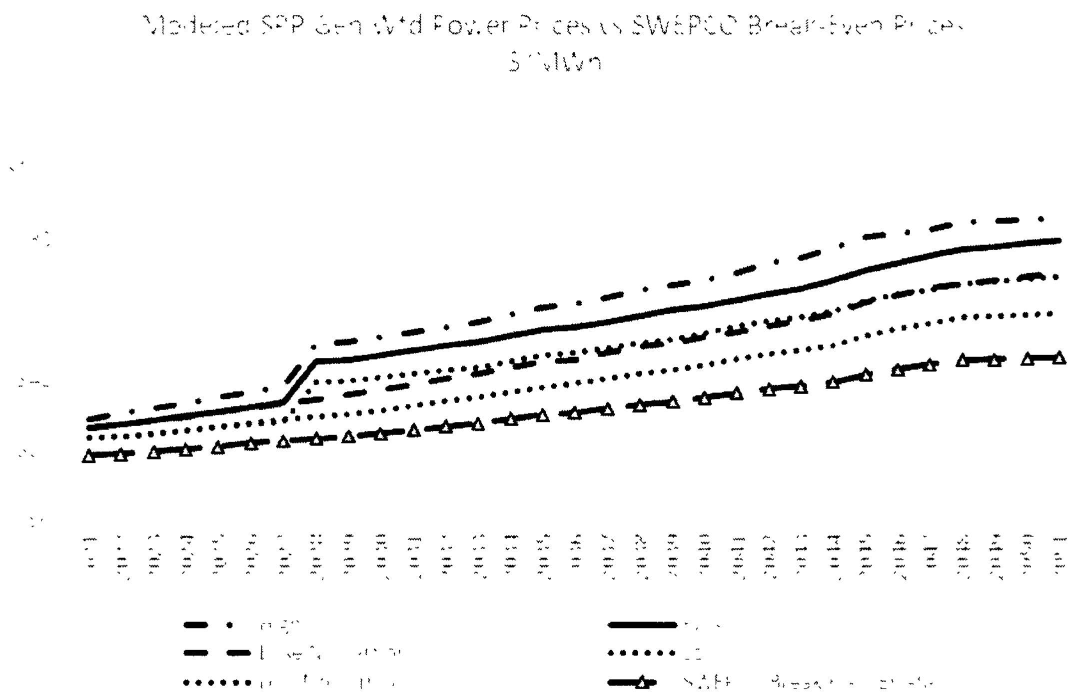
Amounts in Millions	31 Year NPV	PTC Period - First 11 years Nominal Total	Full 31 Year Nominal Total
High Gas With CO2	$718	$520	$2,501
Base Gas With CO2	$567	$418	$2,030
Base Gas Without CO2	$396	$318	$1,453
Low Gas With CO2	$396	$296	$1,532
Low Gas Without CO2	$236	$211	$971

(Amounts in Millions, P50 capacity factor)

The Company's fundamentals natural gas price and carbon emissions burden forecasts are further discussed by Company witness Bletzacker. The stress tests around expected customer benefits are further discussed by Company witness Torpey.

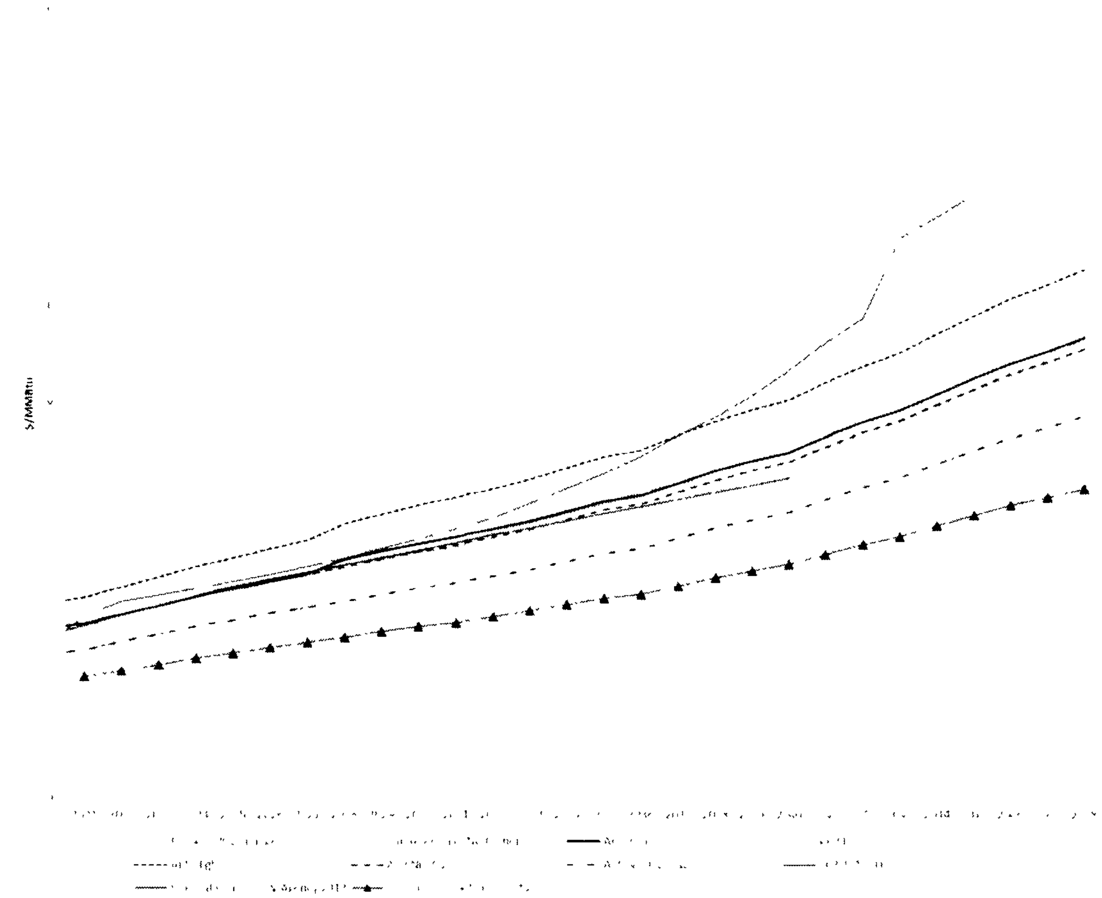
Q. DID THE COMPANY ANALYZE THE POWER AND NATURAL GAS PRICES AT WHICH THE SELECTED WIND FACILITIES WOULD "BREAK EVEN"?

A. Yes. The "break-even," which is the equivalent power price analysis conducted by Company witness Torpey, shows that the Selected Wind Facilities would provide $0 net customer benefits at the Facilities' expected output even if the low gas no carbon fundamentals energy price was reduced by 21%, as shown in the following Errata Figure from Mr. Torpey's testimony:



Company witness Bletzacker derived the "break-even" (equivalent) gas price from the equivalent power price provided by Mr. Torpey. The break-even gas price is below all gas prices in the Company's fundamentals forecast (including the low, no-carbon gas price) and is below the gas price range of plausible third-party forecasts, as shown in the following Errata figure from Mr. Bletzacker's testimony:

Henry Hub Outlooks



Q. HOW WILL THE SELECTED WIND FACILITIES TAKE ADVANTAGE OF THE PTC?

A. Company witness Multer discusses the requirements for PTC qualification and explains that the amount of PTCs that the Company will earn for any given year is equal to a PTC rate that is adjusted annually for inflation multiplied by the kilowatt hours of electricity produced by the Selected Wind Facilities over the first 10 years of operation. Over that period, the facilities are projected to earn PTCs net of DTA carrying costs valued at approximately $750 million for the benefit of SWEPCO customers.

Q. WILL THE SELECTED WIND FACILITIES PROTECT CUSTOMERS FROM THE RISK OF FUTURE FUEL PRICE INCREASES?

A. Yes. The Wind Facilities would not be impacted if fuel prices increased in the future, since they are powered by wind. While natural gas prices are currently low, they have historically been quite volatile and have seen periods when they were substantially higher than at present. During their expected 30-year lives and perhaps longer, the Selected Wind Facilities will protect customers from the risk of increased natural gas and power prices as further discussed by SWEPCO witnesses Torpey and Pfeifenberger.

Q. IN ADDITION TO THE ECONOMIC ENERGY THEY WOULD PRODUCE THROUGHOUT THEIR LIFE, WHAT OTHER BENEFITS WOULD BE DERIVED FROM THESE ASSETS?

A. The Selected Wind Facilities will produce one REC for each MWh of energy they generate. The RECs would be the property of the Company. If the Commission were to grant SWEPCO authority to acquire the Selected Wind Facilities, SWEPCO intends to propose the creation of a new tariff schedule through which customers could purchase the RECs created by these assets. This would have the dual benefit of giving SWEPCO's customers a choice by which to meet their own renewable energy goals and producing revenue that would further reduce costs for all customers.

Q. WHY DID SWEPCO SEEK ACQUISITION OF WIND RESOURCES?

A. Through its RFP, SWEPCO sought competitively-priced wind energy resources on a fixed-price, turnkey basis through the acquisition of one or more wind projects totaling up to 1,200 MW. While SWEPCO currently has 469 MWs of wind resources under Power Purchase Agreements (PPAs), SWEPCO owns no wind resources. Acquisition of wind generation facilities will further diversify SWEPCO's generation resources and offers several benefits to SWEPCO and its customers, including:

- The ability for the Company to offer guarantees discussed hereinafter;
- Company control and ability to react to changes in the market that are not available under a PPA;
- Ability to manage congestion risk and preserve customer benefits if congestion becomes a problem;
- Allowing SWEPCO, on behalf of customers, to determine the feasibility of running the facilities beyond their estimated depreciable life or of repowering facilities to maximize value to customers;
- Providing the Company the opportunity to take advantage of 1) existing or new generation technologies including the installation of battery storage systems or 2) turbine performance improving technologies that include potential improved or advanced parts, system conversions, modifications or upgrades that result in improved performance of the existing wind turbine generators; and
- Management of credit risk and metrics associated with PPAs.

Q. WILL YOU PLEASE DISCUSS FURTHER HOW FACILITIES OWNERSHIP WILL FACILITATE THE MANAGEMENT OF CONGESTION RISK AND THE PRESERVATION OF CUSTOMER BENEFITS?

A. In the event substantial congestion develops in the future, facilities ownership will facilitate the construction of an extended generation-tie line to relieve that congestion if and when it becomes economically beneficial to do so.

Q. PLEASE DISCUSS FURTHER HOW FACILITIES OWNERSHIP AND OPERATION MAY PROVIDE THE OPPORTUNITY TO MAXIMIZE VALUE TO CUSTOMERS.

A. Ownership allows the Company, on behalf of customers, to have control of determining the feasibility of running the facilities beyond their expected useful life, or to repower the facilities. These alternatives provide the Company the ability to maximize the overall value to customers given the fuel-free nature of wind generation facilities.

Q. PLEASE DISCUSS FURTHER HOW FACILITIES OWNERSHIP WILL PROVIDE THE COMPANY THE ABILITY TO REACT TO POTENTIAL CHANGES IN THE MARKET.

A. Market conditions and market rules pertaining to frequency regulation, ancillary services, congestion charges, and other factors continually evolve over time. With direct operational control over the Selected Wind Facilities, the Company would be better positioned to respond to changes in market rules than it would be with an asset owned by a third party. There would be no need to seek amendments to contractual arrangements, to which a counterparty may or may not be amendable, in order to conform to changing market conditions or rules, for example.

Q. PLEASE SUMMARIZE THE BENEFITS OF THE SELECTED WIND FACILITIES.

A. The acquisition of the Selected Wind Facilities is designed to support SWEPCO's long-term commitment to affordable rates, fuel diversity, and environmental responsibility. Specifically, the Facilities will:

- Create significant economic benefits with the delivery of clean, low-cost energy previously not available to SWEPCO customers, resulting in estimated customer savings (SWEPCO total company) of approximately \$567 billion NPV;
- Provide customer value through delivery of PTCs associated with energy production at the Selected Wind Facilities;
- Provide capacity benefits by deferring future capacity additions;

- Continue SWEPCO's strategy of diversifying its generation portfolio, including both owned assets and Power Purchase Agreements, and mitigate fuel price volatility; and
- Advance customers' sustainability and renewable energy goals.

V. COMPANY GUARANTEES

Q. IS THE COMPANY OFFERING GUARANTEES THAT ASSURE CUSTOMER BENEFITS OF THE SELECTED WIND FACILITIES?

A. Yes. The Company is providing guarantees related to the Facilities' energy production levels, qualification for the PTC, and total cost. Witness Torpey's testimony shows that the customer benefits of the Facilities, if they operated at these guaranteed levels at the base gas fundamentals price forecast with and without an assumed carbon cost, would be $1,386 million (NPV $330 million) and $883 million (NPV $181 million), respectively, over the life of the Facilities.

Q. PLEASE DESCRIBE THE GUARANTEES SWEPCO IS PROVIDING TO CUSTOMERS ASSOCIATED WITH THE ACQUISITION OF THE SELECTED WIND FACILITIES.

A. SWEPCO is offering a suite of guarantees that, taken in total, are designed to ensure value to customers. These guarantees include:

1. **Capital Cost Cap Guarantee**

   SWEPCO proposes a cost cap equal to 100% of the aggregated filed capital costs of approximately $1.996 billion (SWEPCO share approximately $1.09 billion), as outlined in EXHIBIT JGD-3 of Company witness DeRuntz's testimony. The Capital Cost Cap Guarantee has no exceptions, including for *Force Majeure* (FM).

2. **Production Tax Credit Eligibility Guarantee**

   If PTCs are not received at the 100% level for Sundance and the 80% level for the other two Facilities because a Selected Wind Facility is determined to be ineligible, customers will be made whole for the value of the lost PTCs based upon actual production. The Production Tax Credit Eligibility Guarantee is subject to changes caused by a Change in Law that affects the federal Production Tax Credit.

3. Minimum Production Guarantee[1]

Beginning in 2022, the Company is willing to provide a guaranteed minimum production level, in aggregate from the Selected Wind Facilities, of an average of 87% (P95 Capacity Factor Case) of the expected output of the facilities over each five-year period for 10 years average across all facilities. This scenario represents a 38.1% capacity factor and 4,959 GWh per year, in the aggregate for the Selected Wind Facilities. If the minimum production level is not achieved, customers will be made whole on an energy and PTC (if applicable) basis. There is an exception for FM and curtailment in SPP.

Q. PLEASE DISCUSS HOW THE GUARANTEES THAT SWEPCO OFFERS ENHANCE THE VALUE TO CUSTOMERS OF SWEPCO'S ACQUISITION OF THE SELECTED WIND FACILITIES.

A. The Capital Cost Cap Guarantee helps to ensure customer benefits even if the Selected Wind Facilities cost more than projected and insulates the customer from the risk of any *Force Majeure* event. The PTC eligibility guarantee helps to ensure customer benefits even if the Selected Wind Facilities fail to qualify for PTCs at the 80% level for Traverse and Maverick or at the 100% level for Sundance for any reason other than a change in law specific to the federal PTCs, as discussed further by Company witness Multer. In addition, the minimum production guarantee helps to ensure customer benefits even if the Selected Wind Facilities, over each five-year

[1] The Minimum Production Guarantee will be subject to *force majeure* events, which by definition are events the Company cannot control. A lack of wind velocity will not be considered a *force majeure* event. This guarantee is subject to curtailments in SPP. Payments made under this guarantee will be net of any make-whole payment made under the PTC eligibility guarantee.

period for the first ten years, perform at the P95 Net Capacity Factor, which is lower than the expected net capacity factor.

Q. IN REGARDS TO THE OUTPUT OF A WIND FACILITY, PLEASE EXPLAIN THE DIFFERENCE BETWEEN A P50, THE EXPECTED OUTPUT, AND P95 LEVEL.

A. The "P" refers to the probability that the wind will blow with the stated wind profile, at a specific velocity, at a percentage of the time. The P-number value defines how many megawatt hours will be produced from the wind facility. A P50 scenario is indicative of the expected output (number of megawatt hours) that will be produced over the life of the project. In other words, the facility will produce more megawatt hours than the expected output 50% of the time and fewer megawatt hours than the expected output 50% of the time. It is the middle probability and is the most likely and expected outcome. A P95 level means that ninety-five percent of the time the facility will produce more megawatt hours than the indicated number of megawatt hours.

VI. RFP AND SUPPORTING IRP

Q. WAS THE SELECTION OF THE SELECTED WIND FACILITIES THE RESULT OF AN RFP?

A. Yes. SWEPCO and PSO both issued RFPs for wind generation resources on January 7, 2019. A bidder that submitted a proposal in response to the SWEPCO RFP was required to also submit an identical proposal in response to the PSO RFP. SWEPCO requested proposals for the acquisition of up to 1,200 megawatts of wind energy resources to be in commercial operation by December 15, 2021. SWEPCO sought facilities on a turnkey, fixed-cost basis in which it individually, or together with PSO, would acquire all of the equity interests in the facility. Key considerations in the RFP evaluation process included cost, performance, and long-term deliverability. SWEPCO sought projects located in, and interconnected to, the SPP regional grid in Arkansas, Louisiana, Texas, or Oklahoma – the four states in which SWEPCO and PSO operate. The projects bid into the RFP were required to interconnect to the SPP and have a completed System Impact Study by the proposal due date of March 1, 2019. SWEPCO's RFP is further discussed by Company witness Godfrey.

Q. PLEASE BRIEFLY DESCRIBE HOW THE RFP PROCESS WAS DEVELOPED AND EXECUTED PURSUANT TO REQUIREMENTS IN SWEPCO'S JURISDICTIONS?

A. Once the Company developed its draft RFP, in accordance with LPSC orders, the Company provided that draft to the LPSC Staff and its consultant for review. The final RFP was then produced with input provided by LPSC Staff. Further, in December of 2018, the Company hosted a technical conference and webinar to review the proposed RFP process. LPSC Staff and potential bidders participated by telephone and SWEPCO responded to questions from the attendees. SWEPCO and PSO both issued their RFPs after this input on January 7, 2019. SWEPCO continued to coordinate closely with LPSC Staff and its consultant to confidentially review the proposed bid packages, while the Company completed its evaluation of bids. The development and execution of the RFP is further discussed by Company witness Godfrey.

Q. PLEASE PROVIDE AN OVERVIEW OF THE RESULTS OF THE RFP.

A. The Company was pleased with the robust response from the market. The Company received 35 bids totaling 5,896 MW and representing 19 unique wind projects. Fifteen projects were located in Oklahoma and four projects were located in Texas. Using the eligibility and threshold criteria of the RFP, 11 projects, with 19 separate bids including project variations, were evaluated in the RFP. Three projects were selected for a total 1,485 MWs.

Q. WAS THE POTENTIAL FOR TRANSMISSION GRID CONGESTION CONSIDERED IN THE EVALUATION OF RFP BIDS?

A. Yes. Future congestion costs are uncertain and could have a significant impact on the delivered cost of energy from wind facilities. The Company analyzed the expected cost of future transmission congestion for the proposals along with the cost of mitigating such potential future congestion, such that customers obtain the lowest risk, highest value projects to ensure the expected benefits from the Selected Wind Facilities. This consideration included a focus on managing congestion risk and included the possibility of constructing an extended generation-tie line, if necessary, to mitigate and cap congestion risk. Resources with higher deliverability and less congestion to the AEP West Load Zone will tend to have higher value to customers.

The Company sought facilities that will be physically located in, and interconnected to, the SPP in Arkansas, Louisiana, Texas, or Oklahoma that are not currently experiencing, or anticipated by the Company to experience, significant congestion or deliverability constraints that are likely to result in adverse facility economics. The RFP analysis is further discussed by Company witnesses Godfrey, Torpey, Ali, Sheilendranath, and Pfeifenberger.

Q. IS SWEPCO SEEKING APPROVAL OF AN EXTENDED GENERATION-TIE LINE IN THIS PROCEEDING?

A. No. The Company does not anticipate the need for a generation tie line based on current expectations concerning implementation of SPP's ten-year plan. Any future construction of a generation-tie line to mitigate congestion or curtailment risk would need to be supported by the economics at that time with consideration of the current state of the SPP transmission system. However, this option is available for the Company to use as a mitigation option against future congestion risk, if necessary.

Q. PLEASE DISCUSS SWEPCO'S MOST RECENTLY COMPLETED AND FILED IRP AND HOW IT SUPPORTS THE RFP.

A. To meet its customers' future energy requirements, SWEPCO will continue the operation of, and ongoing investment in, its existing fleet of generation resources. In addition, SWEPCO must consider the impact of the promulgation of environmental rules, as well as the emergence of new technologies and renewable energy resources. In accordance with Arkansas and Louisiana regulatory requirements, SWEPCO prepares an Integrated Resource Plan (IRP) to guide its resource planning activities. The IRP analyzes various scenarios that would provide adequate supply and demand resources to meet SWEPCO's peak load obligations and reduce or minimize costs to customers, including energy costs, for the next 20 years. Under the plan, SWEPCO's energy output attributable to solid fuel generation decreases from 83% to 44% over the planning period, while energy from natural gas resources increases from 7% to 19%. The plan introduces solar resources, which contributes 10% of total energy. Additionally, energy from wind resources increases from 9% to 26%, while Demand Side Management (DSM) resources increase from 0.3% to 1.3% of SWEPCO's total energy mix. Acquiring wind resources to help achieve this energy mix goal was a primary purpose of the RFP that led to the selection of the Selected Wind Facilities SWEPCO now seeks to acquire.

VII. THE ACQUISITION IS SCALABLE

Q. IS SWEPCO'S PROPOSED ACQUISITION OF THE SELECTED WIND FACILITIES SCALABLE TO ALIGN WITH REGULATORY APPROVALS BY STATE?

A. Yes. Along with this request before the Public Utility Commission of Texas, SWEPCO simultaneously filed requests for approval of the requested acquisitions with the APSC and the LPSC. PSO has also filed a request for approval of cost recovery for the acquisition with the Oklahoma Corporation Commission (OCC). SWEPCO and PSO anticipate jointly acquiring the Selected Wind Facilities if each obtains their respective state regulatory approvals.

However, realizing that it is possible that not all four of the regulatory commissions will grant the requested relief, SWEPCO and PSO have designed the proposed acquisition of the Selected Wind Facilities to be scalable to allow for the jurisdictions that approve the Companies' applications to move forward with the acquisition in order to maximize the benefits of the Company's proposal for its customers in those jurisdictions. SWEPCO believes it can do so consistent with the minimum number of megawatts necessary to preserve the economies of scale of the Selected Wind Facilities, and the Companies' minimum contractual obligations of 810 MWs under the PSA. However, the timing associated with any decision concerning scalability is important to customers in producing the expected benefits. Therefore, the Company is requesting additional approvals from the Commission concerning scalability that need to be addressed by the Commission in the order issued for this proceeding. In addition to requesting that the Commission amend its CCN to acquire 810 MW of the Selected Wind Facilities based on receipt of all regulatory approvals by SWEPCO and PSO, SWEPCO requests the following additional Commission approvals if either it or PSO does not receive certain state regulatory approvals:

1. If one of SWEPCO's other state jurisdictions does not approve acquisition of the Selected Wind Facilities, SWEPCO requests:

    a) if PSO also does not receive approval, this Commission amend SWEPCO's CCN to acquire 810 MW of the Selected Wind Facilities and to allocate the costs and benefits of that acquisition to Texas and the other approving SWEPCO jurisdiction proportionately (provided both approving SWEPCO jurisdictions grant approval to acquire their additional, proportionate shares), or

    b) if PSO does receive approval, this Commission amend SWEPCO's CCN to: i) acquire only the originally-proposed jurisdictional shares of Texas and the other approving SWEPCO jurisdiction (including the wholesale share), instead of 810 MW, of the Selected Wind Facilities; or ii) acquire 810 MW of the Selected Wind Facilities and allocate the costs and benefits of that acquisition proportionately to Texas and the other approving SWEPCO jurisdiction. These options are dependent on <u>both</u> approving jurisdictions having accepted the same option.

2) In the event this Commission is the only SWEPCO jurisdiction to approve the acquisition, the Company requests that the Commission amend its CCN to acquire only the Texas share (adjusted to recognize a percentage must be allocated to wholesale customers) of the Selected Wind Facilities. This

acquisition will only move forward if PSO's application before the OCC is also approved as necessary to preserve economies of scale for the acquisition and comply with the Companies' minimum contractual obligations under the PSAs.

Q. HOW WILL THE STATE JURISDICTIONS THAT DO NOT APPROVE THE PROPOSED ACQUISITION BE IMPACTED IF SWEPCO MOVES FORWARD WITH THE ACQUISITION BASED ON APPROVALS IN OTHER STATES?

A. Any jurisdiction that does not approve the acquisition will neither bear the costs nor receive the benefits of any of the Selected Wind Facilities acquired by the Company or PSO.

VIII. REGULATORY APPROVALS SOUGHT

Q. WHAT CCN AUTHORIZATION IS SWEPCO REQUESTING IN THIS CASE?

A. Under PURA § 37.056 and 16 TAC § 25.101(b)(2), SWEPCO is requesting CCN authorization to acquire its share of the Selected Wind Facilities, as described in my testimony above.

Q. WHAT CCN REGULATORY STANDARDS AND CRITERIA ARE ADDRESSED BY THE COMPANY'S APPLICATION?

A. An application for a generation CCN must comply with the requirements in PURA § 37.056. That section states the Commission may approve an application if it finds the certificate to be necessary for the service, accommodation, convenience, or safety of the public. It requires the Commission consider the following criteria: adequacy of existing service; need for additional service; effect of granting the CCN on the recipient and any electric utility serving the proximate area; and other factors such as community values, recreational and park areas, historical and aesthetic values, environmental integrity, the probable improvement of service or lowering of cost to consumers, and the effect of granting the CCN on the state's ability to meet the renewable generating capacity goal.

Because the Selected Wind Facilities are located in Oklahoma, the site-specific factors identified above are not relevant to the Commission's decision regarding the Company's request. In a previous CCN proceeding, the Commission found that a generation facility located outside of Texas would have no effect on site-specific factors such as community values, recreational and park areas, historical and aesthetic values, environmental integrity, and the impact on other utilities serving Texas.[2]

Q. ARE THE SELECTED WIND FACILITIES NECESSARY FOR THE SERVICE, ACCOMMODATION, CONVENIENCE, OR SAFETY OF THE PUBLIC IN TEXAS?

A. Yes. Granting a CCN for the Selected Wind Facilities would serve the public convenience and necessity by enhancing the Company's ability to provide low-cost energy to its customers. The Selected Wind Facilities would produce energy at lower than avoided cost as demonstrated by Company witness Torpey. The addition of the Selected Wind Facilities to SWEPCO's generation supply, considering the expected reduction in energy costs and the PTC, would save SWEPCO customers an estimated $2.03 billion, or $567 million on an NPV basis. This low-cost energy and the associated customer benefits justify the addition of these resources to SWEPCO's

[2] *Application of Southwestern Electric Power Company for Certificate of Convenience and Necessity Authorization for a Coal-Fired Power Plant in Arkansas*, Docket No. 33891, Order at Findings of Fact Nos. 43, 46, 48, 50, and 51 (Aug. 12, 2008).

generation supply portfolio. In addition, the Selected Wind Facilities would provide capacity benefits by deferring future capacity additions. Furthermore, as a renewable resource, wind generation incurs no fuel costs, produces no emissions, and enables the Company to respond to customer desire for additional options to satisfy their long-term renewable energy goals.

Q. WOULD GRANTING THE CCN AFFECT THE ABILITY OF THE STATE TO MEET THE RENEWABLE ENERGY GOAL SET OUT IN PURA?

A. No. It is my understanding that the State has exceeded the renewable energy goal set out in PURA § 39.904(a).

Q. WOULD THE GRANTING OF THIS CCN BY THE COMMISSION HAVE A NEGATIVE EFFECT ON SWEPCO?

A. No. From an operational perspective, the Selected Wind Facilities would enhance the Company's ability to provide low-cost energy to its customers, as described above and explained in more detail by Company witness Torpey. Furthermore, the Company has a plan in place to ensure reliable ongoing operation and maintenance of the Facilities at a reasonable cost, as described by Company witness DeRuntz. Although acquisition of the Selected Wind Facilities would be a significant investment for SWEPCO, the proposed rate treatment discussed later in my testimony will mitigate any negative impact on the Company's financial standing from those investments. In addition, as detailed by Company witness Hollis, SWEPCO's parent company, AEP, will provide necessary equity to SWEPCO to maintain its capital structure and support its current Moody's Baa2 credit rating. Thus, the effect of granting the CCN would be positive for the Company and for its customers.

Q. IS A PUBLIC INTEREST FINDING REQUIRED UNDER PURA § 14.101 FOR SWEPCO'S PROPOSED ACQUISITION OF THE SELECTED WIND FACILITIES?

A. The Company's position is that such a finding is not required. Section 14.101 requires Commission review of any transaction in which a utility intends to sell, acquire, or lease a plant as an operating unit or system in this state for a total consideration of more than $10 million. The Selected Wind Facilities will be located in Oklahoma, so it does not appear to be "an operating unit or system in this state." However, in an abundance of caution, SWEPCO requests a public interest finding under PURA § 14.101 if such a finding is required.

Q. IS THE PROPOSED ACQUISITION CONSISTENT WITH PURA SECTION 14.101?

A. Yes. Under § 14.101, the Commission considers:

(1) the reasonable value of the property, facilities, or securities to be acquired, disposed of, merged, transferred, or consolidated;

(2) whether the transaction will:

  (a) adversely affect the health or safety of customers or employees;

  (b) result in the transfer of jobs of citizens of the state to workers domiciled outside this state; or

  (c) result in the decline of service;

(3) whether the public utility will receive consideration equal to the reasonable value of the assets when it sells, leases, or transfers the assets; and

(4) whether the transaction is in the public interest.

Q. WHY IS SWEPCO'S ACQUISITION OF AN INTEREST IN THE SELECTED WIND FACILITIES IN THE PUBLIC INTEREST?

A. As discussed above, the proposed acquisition will produce significant and immediate cost savings for SWEPCO customers by locking in a long-term, low-cost power supply. As a result, it is in the public interest.

Q. WILL THE PROPOSED ACQUISITION ADVERSELY AFFECT THE HEALTH OR SAFETY OF CUSTOMERS OR EMPLOYEES, RESULT IN THE TRANSFER OF JOBS FROM TEXAS, OR RESULT IN A DECLINE IN SERVICE?

A. No. The acquisition will have no effect on the health or safety of customers or employees and will not result in the transfer of jobs from Texas. With regard to its effect on service, the addition of these resources is expected to result in lower overall costs for customers.

Q. IS SWEPCO PAYING A REASONABLE VALUE FOR THE SELECTED WIND FACILITIES?

A. Yes. After conducting an RFP to select the most competitive proposals, the Companies have diligently negotiated with the developers of the Selected Wind Facilities to arrive at terms for the respective purchase agreements that provide reasonable pricing, performance assurance, and risk mitigation to protect SWEPCO customers. The pricing achieved through such negotiations represents the vast majority of the costs considered in the economic evaluation of the Selected Wind Facilities.

Q. WHAT IS SWEPCO'S PROPOSAL FOR COST RECOVERY ASSOCIATED WITH THE PROPOSED ACQUISITION?

A. The Legislature has recently passed and the Governor has signed legislation that amends the PURA. Chapter 36. to allow recovery of generation investment by a non-ERCOT utility such as SWEPCO outside the confines of a comprehensive base rate case. That legislation allows for the recovery of generation investment effective on the date the power generation facility begins providing service to customers. subject to reconciliation in the utility's next comprehensive base rate case. SWEPCO intends to use this legislation to begin recovery of its investment in the Wind Facilities at the time those facilities begin providing service to customers. SWEPCO witness Aaron further discusses SWEPCO's cost recovery plan.

IX. REQUESTED COMMISSION FINDINGS

Q. PLEASE DISCUSS THE SPECIFIC RELIEF SWEPCO IS SEEKING IN ORDER TO ACHIEVE THE CUSTOMER SAVINGS ASSOCIATED WITH THE SELECTED WIND FACILITIES.

A. SWEPCO requests that the Commission:

- Amend SWEPCO's CCN and authorize acquisition of the Selected Wind Facilities under PURA § 37.056;
- If the Commission determines PURA § 14.101 is applicable. find that SWEPCO's purchase of the Selected Wind Facilities is in the public interest under that provision; and
- Approve SWEPCO's request to include any unrealized PTCs in a deferred tax asset included in rate base in the event the PTCs cannot be fully utilized in a given year(s) as discussed by Company witness Aaron.

X. CONCLUSION

Q. PLEASE SUMMARIZE WHY THE COMMISSION SHOULD APPROVE SWEPCO'S ACQUISITION OF AN INTEREST IN THE SELECTED WIND FACILITIES.

A. The Selected Wind Facilities will produce a significant volume of low-cost energy, diversify the Company's generation mix, provide capacity benefits, reduce fuel costs, and provide enhanced renewable energy credit options for customers that desire it. For these reasons and those explained above, the Company's application satisfies the requirements of PURA §§ 14.101 and 37.056.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes. Thank you.

PUC DOCKET NO.

PUBLIC UTILITY COMMISSION OF TEXAS

APPLICATION OF

SOUTHWESTERN ELECTRIC POWER COMPANY

FOR CERTIFICATE OF CONVENIENCE AND NECESSITY

AUTHORIZATION AND RELATED RELIEF FOR

THE ACQUISITION OF WIND GENERATION FACILITIES

DIRECT TESTIMONY OF

JOHANNES P. PFEIFENBERGER
FOR

SOUTHWESTERN ELECTRIC POWER COMPANY

JULY 15, 2019

TESTIMONY INDEX

SECTION PAGE

EXHIBITS

EXHIBIT	DESCRIPTION
EXHIBIT JPP-1	QUALIFICATIONS OF JOHANNES P. PFEIFENBERGER

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is Johannes P. Pfeifenberger. I am a Principal at The Brattle Group and I am based in the company's Boston office. My business address is One Beacon Street, Suite 2600, Boston MA 02108.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Southwestern Electric Power Company (SWEPCO or the Company). SWEPCO and its sister company Public Service Company of Oklahoma (PSO) are operating companies of American Electric Power Company, Inc. (AEP) located in the Southwest Power Pool (SPP).

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I received a M.A. in Economics and Finance from Brandeis University and a M.S. and B.S. in Electrical Engineering with a specialization in Power Engineering and Energy Economics from the University of Technology, Vienna, Austria.

Q. PLEASE DESCRIBE YOUR BACKGROUND AND PROFESSIONAL EXPERIENCE AS THEY RELATE TO THIS DIRECT TESTIMONY.

A. I am an economist with a background in power engineering and over 25 years of work experience in the areas of regulated industries, energy policy, and finance. I am the author and co-author of numerous articles, reports, and presentations on subject areas related to regional power markets, the economic benefits of transmission investment, and renewable generation. For example, I have worked with SPP and its Regional State Committee (RSC) on a number of topics such as supporting SPP with the market simulations and quantification of transmission-related benefits for the Regional Cost Allocation Reviews (RCAR) and working with the RSC to develop a framework for the planning and cost allocation of transmission projects that span regional market seams.

I have previously filed testimony addressing regional power markets, transmission, and renewable generation before a number of regulatory commissions, including in Oklahoma, Arkansas, Texas, Louisiana, Mississippi, Wisconsin, Illinois, Arizona, Maine, Alberta, and at the Federal Energy Regulatory Commission (FERC). For example, I have filed before FERC testimony on behalf of RITELine Transmission Development, LLC in Docket No. ER11-4049 regarding the congestion reduction and related economic and renewable integration benefits associated with the RITELine transmission project spanning from western Illinois to the Indiana-Ohio border within the ComEd and AEP zones of PJM Interconnection, L.L.C; and on behalf of the Atlantic Wind Connection Companies in Docket No. EL11-13 regarding the renewable integration, reliability, operational, congestion relief, and other benefits of the Atlantic Wind Connection Project, a proposed offshore high-voltage transmission backbone along the Mid-Atlantic coast to interconnect up to 6,000 MW of offshore wind generation with the PJM wholesale market. EXHIBIT JPP-1 to my testimony contains a more complete description of my qualifications and expert witness experience.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. Together with PSO, SWEPCO has contracted to purchase three wind generation facilities (Selected Wind Facilities) that are the subject of this application.

Subject to regulatory approvals and satisfaction of other conditions, SWEPCO will purchase a 54.5% share of the facilities and PSO will purchase the remaining 45.5% share. In the context of this selection, my testimony has four purposes.

First, I discuss the PROMOD® tool, and the SPP-developed Reference Case as utilized in the Company's bid evaluation and benefits analysis for the wind facilities proposed in response to its Request for Proposals (RFP).

Second, I explain SPP market congestion and losses, and why they are important to the value of a wind generation facility. I then provide an overview of congestion costs that have been experienced by wind plants in the SPP system and discuss the inherent uncertainty in estimating future congestion costs across time and locations.

Third, I testify to the reasonableness of the Company's RFP bid-evaluation process employed in choosing the Selected Wind Facilities. In reviewing the bid-evaluation process, I assess the reasonableness of the Company's assumptions, analyses, and approach employed to choose the Selected Wind Facilities, considering the costs of the bids, the locations of the wind farms, exposure to future system congestion and deliverability limitations, and the feasibility of deploying potential congestion risk mitigation options in the event that high levels of congestion materialize in the future.

Fourth, I review the assumptions, analyses, and approach employed by the Company to determine the customer benefits of the Selected Wind Facilities and then evaluate the reasonableness of the estimated benefits. My review specifically focuses on the reasonableness of the overall benefits evaluation methodology and the congestion and loss estimates for the Selected Wind Facilities as applied in the Company's customer benefit analysis.

III. OVERVIEW OF PROMOD AND THE SPP-DEVELOPED REFERENCE CASE

Q. WHAT DATA AND TOOL HAS THE COMPANY USED TO ESTIMATE SPP CONGESTION AND LOSS-RELATED COSTS FOR THE RFP BID EVALUATION AND FOR THE CUSTOMER BENEFITS ANALYSIS ASSOCIATED WITH THE SELECTED WIND FACILITIES?

A. The Company has relied on the PROMOD Reference Case that SPP developed through its currently, ongoing stakeholder-based 2019 Integrated Transmission Plan (ITP) process. With minor modifications to account for the proposed and selected wind facilities and upgrades to the SPP-identified transmission needs, the Company has relied on these SPP PROMOD cases for both the RFP bid evaluation analysis and for the customer benefits analysis, particularly for estimating congestion and loss-related costs in SPP.

I will discuss both the RFP bid evaluation and customer benefit analyses in this direct testimony, including a discussion of the key input assumptions for each. Witness Sheilendranath explains the specifics of how the estimates of potential future congestion and losses were developed through PROMOD simulations for both the RFP bid-evaluation and the customer benefits analysis of the Selected Wind Facilities. He also discusses how PROMOD congestion and the Company's fundamentals forecasts were combined for the customer benefits analysis to develop the necessary estimates for wholesale energy market prices for the Company's load zone and generation locations.

Q. PLEASE EXPLAIN WHAT THE PROMOD MODEL IS, HOW IT GENERALLY WORKS, AND HOW IT CALCULATES CONGESTION AND LOSS COSTS.

A. PROMOD is a widely-used and universally-accepted market and production cost simulation tool, primarily employed for forward-looking locational market simulations. PROMOD simulations are premised on a competitive wholesale electricity market. SPP uses PROMOD to simulate, for the assumed market conditions, the chronological hourly dispatch of generation needed to meet load in the entire SPP footprint and neighboring markets, subject to transmission constraints. Among the main simulation outputs are the locational market prices (LMP) for SPP load zones and individual generation resources. PROMOD outputs also include the hourly marginal congestion cost and marginal loss charge components of the LMP for each pricing node. These marginal congestion cost and marginal loss charge components are essential for computing congestion and loss-related costs associated with the delivery of power from generation facilities, including the wind generators being evaluated by the Company, to the AEP West load zone.

The PROMOD simulations, like those of similar other nodal market simulations, make certain simplified assumptions about market conditions that tend to yield conservatively low market price fluctuations and congestion levels. For example, PROMOD simulations generally use long-term projections of fuel prices (which do not have as much daily and monthly volatility as actual fuel prices), weather-normalized loads (which do not include occasional heat waves or unusual cold weather), and a fully intact transmission system (*i.e.*, no temporary transmission outages). Thus, the simulations do not capture the actual daily or monthly fluctuations in these variables, nor the added stresses associated with the encountered more challenging system conditions. The simulations are based on perfect foresight of daily real-time conditions—which approximates day-ahead power markets but understates real-time market uncertainties, including variances in wind generation output and therefore the likely generation curtailment driven by the uncertainty of real-time market conditions and temporary transmission outages. Despite these simplifying assumptions and the associated impact, the simulation results are the best available projection of locational market conditions that are used for long-term transmission planning and congestion analyses.

Q. DOES SPP, THE MARKET WHERE PSO AND SWEPCO ARE LOCATED, USE PROMOD TO PROJECT CONGESTION AND LOSSES IN ITS REGIONAL FOOTPRINT?

A. Yes. PROMOD is SPP's main simulation tool for analyzing congestion and losses, including for analyzing how proposed new generation or transmission facilities affect locational market prices and costs within its market region. SPP uses PROMOD for both its ITP efforts as well as its periodic Regional Cost Allocation Reviews.

Q. PLEASE DESCRIBE THE PROMOD DATASET, AS DEVELOPED BY SPP AND ITS STAKEHOLDERS, WHICH THE COMPANY USED FOR THE BID EVALUATION AND CUSTOMER BENEFITS ANALYSES.

A. The PROMOD models developed for SPP's currently-ongoing 2019 ITP10 stakeholder process reflect the most current information regarding expected future system conditions. Because the data-intensive region-wide and locational simulations make it computationally challenging and time consuming to analyze more than a few years, SPP develops PROMOD cases for only select future years—including 2024 and 2029 for the currently-ongoing 2019 ITP effort.

The Company relied on the PROMOD "Reference Case (Future 1)" that SPP staff and stakeholders developed for the 2019 ITP.[1] As SPP notes, the objective of the 2019 ITP Assessment is to develop a regional transmission plan that provides reliable and economic delivery of energy and facilitates achievement of public policy objectives, while maximizing benefits to the end-use customer. The PROMOD models developed for this ITP effort include all SPP-planned and -approved transmission projects as well as planned and/or needed future generating resources, including wind resources at levels and locations that SPP and its stakeholders have deemed feasible for development by 2024 and 2029.

Q. ARE THE SPP REFERENCE CASE ASSUMPTIONS A REASONABLE STARTING POINT FOR THE COMPANY'S EVALUATION OF CONGESTION AND LOSSES OF WIND FACILITIES?

A. Yes, relying on the SPP Reference Case is reasonable for a number of reasons. First, the assumptions were developed by SPP staff and stakeholders independently of the Company's effort in this case. The SPP Reference Case represents a "current trends" case, which includes SPP and its stakeholders' general expectations about the future state of the market and does not include the more aspirational assumptions of SPP's "Emerging Technologies" Case. Second, the main

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[1] See SPP Engineering, *2019 Integrated Transmission Planning Assessment Scope*, Published on 10/16/2018, posted at: https://www.spp.org/documents/60005/2019%20itp%20scope.pdf

SPP also developed an "Emerging Technologies Future (Future 2)," which explores assumptions that include higher amounts of electric vehicles, distributed generation, demand response, energy efficiency, and higher wind and solar penetration based on an assumption of reduced technology costs.

assumptions that will affect the overall levels of wholesale power prices and congestion costs for the purpose of the Company's bid evaluation are reasonable within the range of both independent industry reference points and the Company's own market fundamentals forecasts.

Q. PLEASE SUMMARIZE THE SPP REFERENCE CASE ASSUMPTIONS.

A. The SPP Reference Case reflects a continuation of current industry trends and environmental regulations. This case assumes that coal and gas-fired generators over the age of 60 will be retired. Gas and coal prices are based on long-term industry forecasts. Specifically, the natural gas prices used in the SPP PROMOD simulations are based on ABB-developed forecasts, averaging $4.62/MMBtu in 2024 and $5.44/MMBtu in 2029 for Oklahoma. The 2024 and 2029 transmission topology reflects all transmission facilities that are included in the SPP Transmission Expansion Plan (STEP) including those that have already been approved for construction.[2] And, finally, the SPP Reference Case solar and wind additions exceed current renewable portfolio standards (RPS) due to economics, public appeal, and the anticipation of potential policy changes, as reflected in historical renewable installations. Specifically, SPP includes in its PROMOD simulations a total of 24,200 MW of installed wind generation for 2024 and 24,600 MW by 2029. Solar generation has been assumed to grow from approximately 250 MW today to 3,000 MW in 2024 and 5,000 MW in 2029. I further discuss these SPP assumptions in my review of the Company's RFP bid evaluation and customer benefit analysis below.

[2] SPP's methodology for developing the transmission topology for its PROMOD cases is specified in its October 17, 2018 ITP Manual, Sections 2.1.4 (for reliability studies) and Section 2.2.1.6 (for economic studies). Available at: https://www.spp.org/Documents/22887/ITP%20Manual%20version%202.3.docx

IV. CONGESTION IN SPP

Q. WHAT ARE THE MAIN DRIVERS OF CONGESTION AND LOSS-RELATED COSTS IN THE SPP REGION?

A. Congestion and loss-related costs in SPP are driven by two major factors. First, congestion in SPP is driven to a large extent by the amount of interconnected wind generation relative to the transmission system's transfer capability, which determines the frequency and quantity of congestion on the SPP system. Second, the cost of transmission congestion and system losses will depend on the level of wholesale power prices and the underlying generation costs, which determine the $/MWh cost of supplying lost energy and managing congestion through generation redispatch. All else equal, the cost of congestion and losses would be greater as more wind generation facilities compete for limited transmission capability. Similarly, those costs increase when it is more costly to redispatch generating plants to manage power flows, including from constrained wind generation, to not exceed the capability of the transmission system. Conversely, congestion will decline as SPP facilitates the upgrade of transmission constraints and addresses other transmission needs.

Q. PLEASE EXPLAIN THE INHERENT UNCERTAINTY IN FORECASTING THE MAGNITUDE OF CONGESTION COSTS.

A. The level of congestion in the SPP footprint is difficult to forecast as it varies greatly both (1) over time and (2) across locations.

Often, the SPP transmission planning solutions have not been able to mitigate congestion costs in a timely fashion because the necessary transmission facilities can take 5–10 years to plan within the SPP transmission planning process and be built.

Further, there are significant uncertainties around future generation resource mix in SPP. For example, there is a possibility that more wind generation could be built in the SPP footprint than projected due to the potential for future carbon charges or other environmental regulations of fossil resources, customers' shifting preferences for clean energy resources, continued declines in renewable generation costs, future increases in natural gas prices, and the retirement of older and inefficient generators. These uncertainties can affect future congestion in uncertain ways. In the absence of timely transmission upgrades, greater than expected additions of wind generation pose the risk that future increases in congestion costs could be significantly higher than currently projected. But it is also possible that SPP transmission upgrades will reduce congestion costs below projected levels.

Table 1 below illustrates this uncertainty for congestion between existing wind generation facilities in Oklahoma and the AEP West load zone by summarizing actual historical real-time market outcomes for 2014 through (year to date) 2019. Table 1 shows the simple historical averages of annual congestion charges between individual existing Oklahoma wind plants and the AEP West load zone. The historical annual congestion charges have ranged from a low of less than $1/MWh in 2014 and 2015 to approximately $8/MWh in 2017, before dropping to around $5/MWh in 2018 and $5.87/MWh (year to date) 2019—reflecting the congestion-reducing effect of SPP transmission additions that came online in recent years. Because the hourly wind generation data is not publicly available for SPP wind facilities, the numbers presents the simple averages of the congestion costs over all hours of the respective years. Although the simple averages will understate the actual annual congestion costs faced by the owners of these wind facilities, because hours with higher wind generation will tend to be correlated with higher congestion charges, these averages nevertheless document congestion trends over time and allow for a comparison of historical and simulated future congestion costs.

Table 1: Historical Wind-to-AEP West Congestion For Oklahoma Wind Facilities
($/MWh, simple all-hours annual average)

	Capacity (MW)	2014	2015	2016	2017	2018	2019
Arbuckle Mountain Wind Project	100	-	-$0.30	-$0.92	-$0.06	$3.21	$1.74
Balko Wind Project	300	-	$5.12	$9.68	$13.86	$6.01	$6.55
Big Smile Wind Farm	132	$3.75	-$0.38	$2.24	$6.46	$5.45	$5 46
Blue Canyon	423	-$0.89	-$0 75	-$0.17	$4.44	$5.04	$4.35
Bluestem Wind Project	198	-	-	$15.63	$14.51	$5.97	$6.59
Canadian Hills Wind Project	299	-$0.87	-$0.40	$2.29	$5.12	$4.96	$6.80
Centennial Wind Farm	120	$9.48	$10.38	$17.69	$22.95	$6.28	$6.59
Chisolm View Wind Project I	235	$0.55	-$0.26	$1.80	$10.57	$6.65	$8.52
Crossroads Wind Project	227	$1.46	-$0.89	$0.24	$0.65	-$0.56	-$0.31
Drift Sand Wind Farm	108	-	-	-$1.12	$1.65	$2 78	$1.71
Elk City Wind	200	$3.75	-$0.38	$2 24	$6.46	$5.45	$5.46
Flat Ridge II	470	$1.69	$0.90	$2.70	$10.23	$6.30	$8.19
Goodwell Wind Project	200	-	$4.36	$8.72	$13.58	$6.07	$6.16
Grant Plains	147	-	-	$1.32	$9.87	$6.52	$8.45
Grant Wind Farm	152	-	$0.98	$1.76	$9.90	$6.53	$8.44
Great Western Wind Project	225	-	-	$17.59	$15.51	$5.97	$6.76
High Majestic Wind	159	$9.32	$4.81	$13.73	$14.56	$8.21	$6.06
Kay County Wind Project	299	-	$1.00	$2.09	$5.19	$5.09	$7.86
Kingfisher Wind Farm	298	-	-$0.58	$2 29	$5.12	$4.96	$6.80
Mammoth Plains Wind Energy	199	$2.10	$6.07	$12 25	$16.01	$5.99	$6.98
Minco Wind	199	-$0.89	-$0.36	$1.88	$4.67	$4.83	$6.01
Oklahoma (Sooner) Wind Energy Center	102	-$11.08	-$18.52	-$19 95	-$12.76	$3.41	$5.41
Origin Wind Energy Project	150	-$0.70	-$0.21	-$0.86	-$0.12	$2 53	$1 13
Osage Wind Farm	150	-$1.57	-$0.42	-$0.08	$0.92	-$0.19	$1.42
OU Spirit/CPV Keenan II	253	$8.29	$8.30	$14.60	$19.61	$6.06	$6.64
Persimmon Wind Farm	199	-	-	-	-	$6.28	$6.76
Red Dirt Wind Farm	300	-	-	-	$16.43	$5.63	$7.09
Red Hills Farm	123	-$0.81	-$3.68	-$2.43	$0.11	$3.58	$4.47
Rock Falls Wind Farm	155	-	-	-	-	$6.37	$9.85
Rocky Ridge Wind Project	149	$0.19	-$0.89	$0 21	$3.14	$3.01	$3.24
Rush Springs Wind Farm	250	-$0.97	-$0.58	-$0.85	$0 94	$2 42	$1.24
Seiling Wind I	199	$2.10	$6.06	$12.25	$16.03	$5.99	$6.98
Sleeping Bear	95	-$8.32	-$15.39	-$15.49	-$11.21	$3.73	$5.53
Taloga Wind Plant	130	-$1.09	-$3.95	$6.24	$10.91	$5.26	$5.12
Thunder Ranch Wind Farm	298	-	-	-	$2.68	$5.18	$7.21
Weatherford Wind Energy Center	147	-$0.39	-$1.54	-$4.44	-$1.09	$3.85	$4.08
MW-Weighted Avg		***$0.97***	***$0.64***	***$3.95***	***$7.80***	***$5.02***	***$5.87***

Source: Calculated from Real-Time congestion compiled by ABB Velocity Suite. Averages for 2019 are through May 9, 2019.

Table 1 also shows that the differences across wind locations are just as significant as the overall year-to-year variances. The variances across locations are particularly pronounced in years with high overall congestion levels. For example, when average overall congestion levels were the highest at \$7.80/MWh in 2017, the average annual congestion charges at the individual wind facilities ranged from *negative* \$12.76/MWh (a credit) to *positive* \$22.95/MWh (a cost). In contrast, after important SPP transmission upgrades came online and overall annual congestion dropped to \$5.02/MWh in 2018, congestion charges for individual wind facilities ranged from a low of negative \$0.56/MWh to a high of only \$8.21/MWh.

Q. DO THE IMPACTS OF CONGESTION AND LOSSES ON WIND FACILITIES WITHIN THE SPP FOOTPRINT SIMILARLY AFFECT THE WHOLESALE POWER PRICES FOR THE COMPANY'S LOAD ZONE AND CONVENTIONAL GENERATION FACILITIES?

A. Yes, to some extent. Because the Company's load zone and conventional generation facilities are primarily located in the eastern portion of the SPP footprint, congestion and losses within SPP also affects the wholesale power prices paid by the Company to serve its load. Because of the prevailing west-to-east power flows in the SPP region, which cause congestion and losses along the way, the wholesale prices close to the Company's load tend to be higher than the average prices in SPP. The magnitude of these impacts is discussed further in my review of the Company's customer benefit analysis below.

V. REASONABLENESS OF THE COMPANY'S BID SELECTION

Q. PLEASE SUMMARIZE THE BID EVALUATION PROCESS THAT THE COMPANY USED TO CHOOSE THE SELECTED WIND FACILITIES.

A. As explained in detail by Company witness Godfrey, PSO and SWEPCO selected three wind facilities with 1,485 MW of total nameplate capacity from the proposals received. They arrived at this selection by: (a) applying the bid eligibility and threshold criteria (as specified in Section 9.1 of the RFP); and then (b) performing a detailed analysis of the proposed wind projects and their associated congestion costs and risks (Section 9.2.1 of the RFP with 90% weight); plus (c) an additional consideration of non-price factors (Section 9.2.2 of the RFP with 10% weight).

My review focuses on the economic portions of the evaluation process. In that regard, in performing the bid evaluation process, the Company:

1. Clustered the proposed wind facilities based on the similarity of the expected impact from their power flow (distribution factor or DFAX) on the transmission system;

2. Evaluated the deliverability of the wind facilities to the AEP West load zone by calculating the First Contingency Incremental Transfer Capability (FCITC) between each cluster of proposed wind facilities and the AEP West load zone;

3. Performed PROMOD market simulations to estimate congestion and loss costs associated with each of the wind project bids to estimate the likely delivery costs of the project's energy to Company loads;

4. Estimated the costs of mitigating congestion to account for the risk of incurring unexpectedly high congestion costs in the future, using the estimated cost of a generation-tie line as a proxy for its future congestion risk mitigation options; and

5. Calculated a Levelized Adjusted Cost of Energy (LACOE) as the sum of each bid's Levelized Cost of Energy (LCOE) plus (a) the bid's estimated congestion and loss cost (with 50% weight) and (b) the cost of mitigating congestion (with 50% weight).[3]

[3] In accordance with Section 9.2.1.2 the Company calculated as a preliminary metric of customer benefits the Levelized Net Revenue Requirement by taking the difference between (a) the levelized

Q. DID THE COMPANY'S EVALUATION PROCESS RESULT IN REASONABLE SELECTION OF WIND FACILITIES FOR THE COMPANY TO PROCURE?

A. Yes. The Company selected the most cost-effective wind projects that met the qualification thresholds, while considering the risks of future system constraints, congestion costs, and the cost of available options to mitigate the risks of incurring unexpectedly high congestion costs in the future.

Q. DID THE COMPANY USE THRESHOLD CRITERIA SPECIFIED IN SECTION 9.1 OF THE RFP TO EXCLUDE CERTAIN PROPOSED WIND FACILITIES FROM FURTHER EVALUATION USING THE ECONOMIC CRITERIA SPECIFIED IN SECTION 9.2?

A. Yes, as explained in the testimony of Company witness Godfrey, the Company received 19 proposals for individual wind projects with a total of 35 different configurations, totaling approximately 5,896 MW. Of these projects and configurations, eight proposals and 16 configurations did not meet the RFP-specified threshold criteria. Four of these eight proposals that did not meet the Section 9.1 threshold criteria (consisting of five configurations) were located in clusters that did not meet the FCITC deliverability criteria under Section 9.1.12 of the RFP. Company witness Ali discusses the deliverability assessment under Section 9.1.

Q. WAS IT REASONABLE THAT THE COMPANY "CLUSTERED" THE PROPOSED WIND FACILITIES IN ITS DELIVERABILITY ASSESSMENT?

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expected SPP Load Revenues for the Proposal's energy in the SPP market and (b) the LACOE for each Proposal. However, because the SPP load revenues of wind *delivered* to the AEP West load zone are essentially identical for all wind delivered to the AEP load zone, variations in this metric are a function of the LACOE. As a consequence, the LACOE was used directly for the "economic analysis" portion of project selection under Section 9.3 of the RFP.

A. Yes. Starting out by clustering wind farms based on their power flow impacts on the transmission system is an objective, reasonable approach to grouping wind projects such that their combined deliverability to load can be evaluated. The clusters are also necessary for the development of congestion mitigation options to address potential future congestion costs that might be significantly greater than those estimated. For all clusters that passed the cluster-based deliverability test under Section 9.1.12 of the RFP, the Company then analyzed both (1) congestion and loss costs associated with delivering each bid-in wind farm from each cluster to AEP West load zone; and (2) the cost of transmission solutions that might be available to mitigate these congestion costs should they rise to unexpectedly high levels. The estimated congestion costs are based on the Company's PROMOD market simulations using SPP's 2019 ITP PROMOD Reference Case model, with only slight modification as discussed below.

Q. PLEASE EXPLAIN WHY IT WAS REASONABLE TO INCLUDE THE FCITC DELIVERABILITY CRITERIA AS A THRESHOLD CRITERIA.

A. Assessing limitations in deliverability for clusters is a useful threshold criteria as it provides a good indication of the transmission capacity "head room" that exists on the SPP system for developing additional wind at these locations, considering that most of these projects will compete with other wind projects for available transmission capability. As explained by Company witness Ali, the deliverability assessment from the wind farms in each cluster to the Company's load zone is based on studying the FCITC, using standard industry methodology and the power flow models developed by SPP for its Definitive Interconnection System Impact Study (DISIS) that evaluates generation interconnection requests received during the DISIS Cluster Window. Specifically, the Company used the models developed for SPP's evaluation of Energy Resource Interconnection Service (ERIS) Requests, which ensures that transmission network upgrades identified by SPP to connect ERIS are considered in SPP's planning process.

The FCITC thus measures the robustness of the transmission system between wind locations and the AEP West load zone and quantifies the amount of transmission capability headroom that is available to accommodate the additional generation. Less available headroom means greater risks of encountering unexpectedly high congestion costs or wind generation curtailments, which could occur due to unexpected market fundamentals, transmission outages, or the interconnection of additional wind facilities in that location. The FCITC metric thus supplements the congestion cost estimates obtained through the PROMOD simulations by: (1) indicating how quickly congestion may increase beyond the congestion levels simulated in PROMOD due to the lack of transmission capability to accommodate additional wind facilities that may interconnect in the future; and (2) providing an indication of wind curtailment risks—a factor that can substantially increase the net cost of wind facilities but that is not captured adequately in PROMOD simulations due to the fact that these simulations do not consider temporary transmission outages or real-time market uncertainties, the main sources of wind curtailments. The FCITC headroom additionally indicates the likelihood of being able to obtain congestion hedges from SPP in the future for those locations (as more transfer capability will increase that likelihood).

There is some overlap between the FCITC as a threshold measure for analyzing congestion risk and the estimates of congestion costs and congestion risk mitigation costs that the Company has applied to evaluate qualifying bidders under Section 9.2.1 of the RFP. However, as shown below, even without applying FCITC as a Section 9.1 threshold criteria, the Section 9.2.1 economic cost and risk analysis would have ranked poorly those proposed projects eliminated via the FCITC metric compared to other remaining projects because congestion risk mitigation would be very expensive at these locations.

Q. HOW DID THE COMPANY EVALUATE POTENTIAL CONGESTION COSTS AND LOSSES FOR THE RFP BIDS THAT PASSED THE THRESHOLD CRITERIA?

A. As stated previously, the Company used SPP's PROMOD Reference Case for 2024 and 2029 as the starting point for the economic analysis of qualifying RFP bids. Through these nodal market simulations, the Company estimated the potential congestion costs and losses for each of the project bids.

Q. DID THE COMPANY UPDATE THE SPP REFERENCE CASE ASSUMPTIONS FOR THE PURPOSE OF THE RFP BID EVALUATION?

A. Yes, but only as required to add the RFP bid projects that were evaluated by the Company. As the first update, the Company added the wind facilities associated with individual RFP bids if those wind generation facilities were not already included in the SPP PROMOD Case. This involved the addition of approximately 4,400 MW of wind generation facilities submitted in the RFP that were not sufficiently advanced to be included by SPP when it developed its PROMOD case. Second, the Company relieved transmission constraints associated with the transmission upgrades that SPP identified in the DISIS and require through its generation interconnection process for the individual wind generation facilities bid into the Company's RFP.

Q. ARE THE ASSUMPTIONS IN THE SPP PROMOD CASE THAT THE COMPANY USED TO EVALUATE THE RFP BIDS REASONABLE?

A. Yes, they are. Focusing first on natural gas prices in the SPP Reference Case, I find that they are reasonable for the purpose of the Company's bid evaluation. The natural gas prices, along with other commodity price assumptions, are reviewed and approved by SPP stakeholders for inclusion in the ITP. While these ABB-developed natural gas price forecasts are higher than some other industry forecasts, they are well within the range of industry and current Company forecasts as shown further in Company witness Bletzacker's testimony. In addition, the absolute level of gas prices and associated wholesale power prices has a minimal impact on bid selection, which is driven more by the *relative* congestion costs across the wind generation proposals received in the response to the Company's RFP.[4]

Q. IS IT REASONABLE TO ADD THE WIND GENERATION FROM THE RFP BIDS?

A. Yes. With respect to the wind generation assumptions, SPP's Reference Case includes total wind generation capacity of 24,200 MW by 2024 and 24,600 MW by 2029 as noted earlier. With the addition of 4,400 MW of RFP bids that were not included in SPP's Reference Case, the PROMOD case used for bid evaluation includes

[4] While bid evaluation is driven more by *relative* congestion costs, the *absolute* level of gas prices and associated wholesale power prices and congestion costs is more important for analyzing customer benefits associated with the Selected Wind Facilities. The Company consequently has evaluated customer benefits for a range of different natural gas price, wholesale power price, and congestion levels as discussed further in the Customer Impact Analysis Section of my testimony.

a total of 29,000 MW of wind generation in the SPP footprint—an increase of 7,600 MW from the approximately 21,400 MW of wind generation installed today.[5] Coincidentally, this exactly matches the 7,600 MW of proposed SPP wind facilities that are "on schedule" in SPP's generation interconnection queue with a fully executed interconnection agreement and an SPP forecast of 28,000 MW to 33,000 MW of installed wind capacity by 2025.[6] While not all of the forecast wind facilities may actually be developed, ABB reports in its Velocity Suite database that a total of 3,900 MW of these new wind facilities are already under construction or permitted.

Although the level of wind generation that will be installed over the next decade is uncertain—which leads to congestion risk and the need to evaluate mitigation options—the levels of wind generation additions included in the Company's SPP PROMOD simulations are reasonable.

Q. ARE THE TRANSMISSION ADJUSTMENTS TO THE SPP REFERENCE CASE REASONABLE FOR THE PURPOSE OF THE COMPANY'S BID-SELECTION PROCESS?

A. Yes. The Company has assumed that the SPP-required transmission upgrades to facilitate individual wind resources interconnection would be built. By relieving the constraints on transmission facilities for which SPP has identified upgrades as part of the wind plants' generation interconnection process, the simulations

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[5] See page 3 of https://www.spp.org/documents/59992/spp_mmu_qsom_winter_2019.pdf. Note that some of these wind resources may be considered in-service, but not yet in commercial operation. In this situation, the capacity will be counted but the resource may not be providing any generation to the market.

[6] See slide 123 of https://www.spp.org/documents/31587/intro%20to%20spp.pdf.

can ensure that the congestion-reducing impacts of the mandated transmission upgrades are reflected in the congestion results.[7]

Q. FOR THE PURPOSE OF ITS BID EVALUATION PROCESS, HAS THE COMPANY REFLECTED IN ITS MARKET SIMULATIONS ANY ADDITIONAL TRANSMISSION UPGRADES THAT SPP MAY APPROVE FOR CONSTRUCTION AT SOME POINT IN THE FUTURE?

A. No. For the purpose of the RFP bid evaluation, and with only one exception,[8] the Company has not reflected in its PROMOD simulations other transmission upgrades that SPP may approve for construction aside from those already approved by SPP or identified by SPP as necessary to interconnect the wind facility bids in the RFP. While not modeling possible future SPP transmission upgrades may result in higher congestion costs than ultimately may be realized, doing so in this PROMOD "Bid Evaluation Case" is reasonable for the purpose of: (1) evaluating the various wind generation bids *relative to each other*; and (2) identifying the most attractive bids when including considerations for their potential congestion cost and risk exposure. As I explain further below, after the Selected Wind Facilities were chosen, the Company further refined the SPP PROMOD case to reflect its selection of

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[7] Note that, to be able to simulate congestion realistically, the Company also had to analyze which new transmission constraints will likely be caused by adding new wind generation facilities to the simulations—and adding those new constraints to the list of monitored constraints in the PROMOD case that have been specified by SPP. This adjustment ensures that the Company's simulations can actually enforce the transmission capability limits associated with the constraints caused by the new wind generation additions. This "constraint identification" step is necessary because PROMOD cannot monitor power flows and enforce limitations for every single transmission facility in the footprint. Rather, to make the simulations computationally feasible, PROMOD monitors power flows and enforces limits only for a pre-specified set of transmission constraints.

[8] The company assumed that the Cleveland 138 kV bus-tie, located west of Tulsa, will be addressed by an SPP solution in the near term since it was identified by SPP as both an economic and operational need in the 2019 ITP Study and the transmission upgrade costs were expected to be low.

wind facilities and likely future SPP transmission upgrades for the purpose of the customer benefit analysis.

Q. WHAT ARE THE PROMOD CONGESTION AND LOSS ESTIMATES USED FOR THE BID EVALUATION OF THE WIND FACILITIES PROPOSED IN THE RFP?

A. The 2024 and 2029 Bid Evaluation Case estimates of congestion and loss-related charges between the wind facilities proposed by the bidders who met the eligibility and threshold requirements of Section 9.1 of the Company's RFP and the AEP West load zone are discussed in Company witness Sheilendranath's testimony and summarized in Table 2 below. This summary includes annual averages that are weighted by the hourly MWh output of each RFP Wind Facility.[9] To discuss the reasonableness of the Company's RFP bid-evaluation process, I have also included congestion and loss estimates for wind generation proposals that did not meet the FCITC threshold requirements in Section 9.1.12 of the Company's RFP.

To allow for a comparison to the simple average of historical congestion costs discussed earlier, Table 2 summarizes both the simple average of congestion and loss-related costs across all hours of the year as well as the wind-generation-weighted average. As shown in the table, the wind-generation-weighted average of annual congestion charges, which more closely represents the congestion cost that the Company and its customers would pay under the simulated market conditions, tends to

[9] These average congestion and loss-related costs include the full congestion charge (not considering any TCR congestion hedges) and half the marginal losses charge (reflecting that SPP refunds approximately half of its marginal loss revenues because average line losses are half of marginal line losses).

be higher than the simple average by a factor of approximately two. This is because congestion is typically higher when wind generation output is higher.

Table 2: Simulated Wind-to-AEPW Congestion and Loss Costs for RFP Bids
(Bid Evaluation Case, $/MWh)

		2024							
Company		Simple Avg		Gen-Wtd Avg		Simple Avg		Gen-Wtd Avg	
Bid	Bid	Congestion	Losses	Congestion	Losses	Congestion	Losses	Congestion	Losses
Ranking	Number	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]
Average		*7.08*	*0.78*	*12.95*	*1.19*	*7.97*	*1.06*	*14.07*	*1.54*
P1*	21	6.75	0.65	12.02	1.02	8.04	0.90	13.75	1.32
P2*	15	5.78	0.79	11.33	1.36	5.80	1.05	11.50	1.70
P3*	17	6.14	0.93	13.16	1.54	6.77	1.20	13.86	1.90
P4	12	10.43	1.15	15.71	1.55	12.00	1.53	17.82	2.00
P5	1	5.91	0.46	10.45	0.87	7.37	0.72	12.48	1.18
P6	6	8.22	0.70	15.64	1.14	8.71	0.94	16.10	1.44
P7	4	7.94	1.16	14.29	1.63	9.35	1.58	16.25	2.14
P8	30	7.29	0.91	13.19	1.33	8.64	1.25	15.07	1.74
P9	2	8.19	1.29	14.53	1.79	9.63	1.73	16.46	2.34
P10	31	9.55	0.72	19.28	0.94	8.49	0.94	16.16	1.16
P11	32	10.69	0.92	19.75	1.36	10.54	1.16	20.19	1.59
P12**	3	3.43	0.27	6.01	0.62	4.24	0.43	6.91	0.82
P13**	29	8.07	1.31	14.99	1.83	9.39	1.76	16.86	2.38
P14**	33	3.50	0.26	6.11	0.60	4.42	0.41	7.22	0 81
P15**	34	4.36	0.20	7.71	0.34	6.20	0.36	10.46	0.52

Source and Notes:

*Unit is one of the three selected units.

**Units reported for informational purposes as they were disqualified from the Companies' evaluation based on deliverability.

2024 and 2029 PROMOD simulation outputs for Bid Evaluation Case.

[B] & [D] & [F] & [H]: Average loss costs represent half of the wind-generation-weighted marginal loss charges for the wind resources.

Q. ARE THESE CONGESTION FORECASTS REASONABLE FOR THE PURPOSE OF BID EVALUATION?

A. Yes, they are reasonable for the simulated market conditions, which includes significant amounts of added wind generation without SPP transmission investments beyond the interconnection-related upgrades. While the absolute levels of the simulated congestion costs in this bid evaluation case may be higher than likely outcomes in a future where SPP further expands its transmission system, these congestion results are reasonable for the purpose of assessing congestion costs and risks of the different bids *relative* to each other.

Q. THE COMPANY HAS EVALUATED THE COST OF MITIGATING UNEXPECTEDLY HIGH CONGESTION. IS IT REASONABLE TO CONSIDER THE COSTS OF CONGESTION MITIGATION IN THE EVALUATION OF THE RFP BIDS?

A. Yes, it is. As illustrated in Table 1 and discussed earlier in my testimony, congestion costs are uncertain and can vary significantly both over time and across locations. They can be lower than currently projected if less wind generation is developed in certain locations or if SPP transmission upgrades exceed current expectations. But they can be much higher than currently projected—particularly in certain locations—if more wind generation is added to the system, if SPP is not able to upgrade transmission to relieve high congestion costs (or do so in a timely fashion), or if increases in fuel and generation costs increase the cost of congestion relief. Because not all of the congestion costs can be hedged through SPP-allocated Transmission Congestion Rights (TCRs), unexpected increases in congestion costs could increase the total cost of the delivered wind generation. If the Company is able to reduce this risk of unexpectedly high future congestion costs—such as through the construction of a generation tie or other transmission upgrades—analyzing the option to do so is valuable from a total customer cost and risk perspective.

In short, the unpredictability of future congestion costs is a risk that warrants consideration of options to manage if they were to manifest in the future. Therefore, it is advisable and reasonable that the availability and cost of congestion mitigation is used as one of the criteria in project selection as the Company has done.

Q. WAS IT REASONABLE TO USE A 50% WEIGHTING FOR EACH OF CONGESTION COST AND CONGESTION MITIGATION COST IN THE COMPANY'S CALCULATION OF LACOE?

A. Yes. As discussed below, the bid selection results are also robust across a range of alternative weights.

Q. WHAT WAS THE COMPANY'S FINAL SELECTION OF PROJECTS AND IS THAT SELECTION REASONABLE?

A. PSO and SWEPCO selected three wind facilities, amounting to approximately 1,500 MW in total, by applying the evaluation methodology outlined in Sections 9.1 and 9.2 of the RFP sections. I have reviewed the selections based on the methodology outlined, focusing on the costs of each individual bid, the congestion costs estimates developed for each bid, the deliverability of wind generation within each cluster of bids, as well as the consideration of congestion mitigation option costs. Based on my review, I find the selection process was comprehensive and consistent with the methodology outlined in its RFP. I also find that the selections are reasonable and robust across a range of alternative economic selection criteria that could have been applied. The Selected Wind Facilities represent the most economic bids that simultaneously offer the lowest congestion costs and lowest congestion risks.

Q. PLEASE EXPLAIN IN MORE DETAIL HOW YOU ARRIVED AT THE CONCLUSION THAT THE SELECTIONS ARE REASONABLE AND ROBUST ACROSS A RANGE OF ALTERNATIVE ECONOMIC SELECTION CRITERIA.

A. To arrive at the conclusion that the Selected Wind Facilities represent an economically reasonable choice that is optimal in terms of overall costs and risk, I have evaluated the bids across a range of alternative selection criteria. Table 3 below demonstrates the robustness of the cost- and risk-minimizing properties of the Selected Wind Facilities. I have assessed the relative economics of the Selected Wind Facilities (shown by their project names and in **bold**) that the Company chose based on its selection criterion (shown as "Criterion 4" in the table) against four other possible selection criteria. As I will explain, the Selected Wind Facilities perform well across all of the five different sets of criteria tested:

<u>Criterion 1</u>: Project Cost only (*i.e.*, only the Levelized Cost of Energy or LCOE)

<u>Criterion 2</u>: Project Cost + Congestion (including losses)

<u>Criterion 3</u>: Project Cost + Gen-Tie Cost (proxy for cost of congestion risk mitigation)

<u>Criterion 4</u>: Project Cost + 50% Congestion + 50% Gen Tie (as used by Company)

<u>Criterion 5</u>: Project Cost + 75% Congestion + 25% Gen Tie

Table 3 highlights in shading the lowest-cost portfolio of approximately 1,500 MW of wind facilities for each of the five criteria. Table 3 shows that the three Selected Wind Facilities (shown in **bold***):

1. Are the lowest-cost option for the Company's criterion (Criterion 4) and the alternative Criterion 5. Specifically, the Selected Wind Facilities are lowest-cost portfolio for the Company's "Criterion 4" (with 50% weight to the cost of a gen-tie as a proxy for the available congestion risk mitigation options) and for "Criterion 5" (which applies only a 25% weight to the gen-tie risk mitigation option).
2. Offers total costs that are very close to and generally within the range of lowest-cost portfolios when using each of the other selection criteria 1, 2 and 3. For example, the average cost of the three Selected Wind Facilities is only slightly above the lowest cost portfolio if only the project cost itself were considered (Criterion 1) or if only project cost and estimated congestion were considered (Criterion 2) without considering the cost of mitigating congestion risk.

3. Offers total costs that are substantially below the least-cost portfolios derived from Criteria 1 and 2, if congestion increased unexpectedly and needed to be mitigated in the future.

Table 3: Assessment of Wind Facilities Selection with Alternative Selection Criteria
("Criterion 4" = Company Bid Selection Criterion)

Criterion 1: Project Cost Only		Criterion 2: Project Cost + Congestion		Criterion 3: Project Cost + Gen Tie		Criterion 4: Project Cost + 50% Congestion + 50% Gen-Tie		Criterion 5: Project Cost + 75% Congestion + 25% Gen-Tie	
Bid Number	% of Lowest Cost	Bid Number	% of Lowest Cost	Bid Number	% of Lowest Cost	Bid Number	% of Lowest Cost	Bid Number	% of Lowest Cost
2	100%	3*	100%	Traverse (21)	100%	Traverse (21)	100%	Traverse (21)	100%
Sundance (17)	121%	2	114%	Maverick (15)	106%	Maverick (15)	102%	Maverick (15)	100%
12	126%	1	117%	6	107%	Sundance (17)	106%	Sundance (17)	101%
4	129%	Sundance (17)	119%	Sundance (17)	116%	12	113%	1	105%
Maverick (15)	132%	Maverick (15)	121%	12	121%	1	115%	12	109%
Traverse (21)	133%	Traverse (21)	124%	1	139%	6	121%	4	117%
1	133%	4	130%	30	147%	4	129%	2	118%
32	135%	33*	130%	4	156%	30	133%	30	126%
3*	135%	12	131%	31	180%	2	145%	6	128%
29*	160%	34*	141%	2	204%	31	157%	32	138%
30	163%	32	146%	32	207%	32	160%	31	146%
31	184%	30	149%						
33*	185%	29*	155%						
34*	189%	6	166%						
6	189%	31	168%						
Capacity Weighted Average of Lowest Costs 1,500 MW	**100%**	**Capacity Weighted Average of Lowest Costs 1,500 MW**	**100%**	**Capacity Weighted Average of Lowest Costs 1,500 MW**	**100%**	**Capacity Weighted Average of Lowest Costs 1,500 MW**	**100%**	**Capacity Weighted Average of Lowest Costs 1,500 MW**	**100%**
Capacity Weighted Average of Selected Wind Facilities	**107%**	**Capacity Weighted Average of Selected Wind Facilities**	**104%**	**Capacity Weighted Average of Selected Wind Facilities**	**101%**	**Capacity Weighted Average of Selected Wind Facilities**	**100%**	**Capacity Weighted Average of Selected Wind Facilities**	**100%**
				Weighted Average of Lowest Cost 1,500 MW in Criterion 1	**140%**	**Weighted Average of Lowest Cost 1,500 MW in Criterion 1**	**118%**	**Weighted Average of Lowest Cost 1,500 MW in Criterion 1**	**108%**
				Weighted Average of Lowest Cost 1,500 MW in Criterion 2	**155%**	**Weighted Average of Lowest Cost 1,500 MW in Criterion 2**	**124%**	**Weighted Average of Lowest Cost 1,500 MW in Criterion 2**	**110%**

Source and Notes:

*Unit was disqualified from Company's evaluation based on deliverability.

Named units represent the Company's Selected Wind Facilities.

Lowest Cost 1,500 MW in each ranking are highlighted blue.

Capacity, LCOE, LCOC, and Gen-Tie costs come from AEP's RFP IE Briefing, dated April 16, 2019.

Capacity weighted average of lowest-cost 1,500 MW portfolios for Criterion 1 and Criterion 2 shown under the Criteria 3, 4, and 5 columns calculated using the project cost and the respective Criteria 3, 4, and 5 congestion and gen-tie assumptions For gen-tie costs, costs developed by Independent Evaluator of Oklahoma Corporation Commission is used for units disqualified from Company's evaluation based on deliverability.

For example, if congestion were ignored entirely, the results in the "Criterion 1" (project cost only) panel of the table show that the average levelized project cost of the Selected Wind Facilities is only 7% above the cost of a 1,500 MW portfolio with the lowest project costs (not considering congestion). This is reflected in the bottom half of the table, comparing the costs of the lowest cost projects that would accumulate to 1,500MW (under each criterion) against the costs of the three selected facilities. The calculations on the bottom half of the table show that the Selected Wind Facilities would cost 4% more than the lowest cost 1,500 MW portfolio, if Criterion 2 were used (without considering congestion risk mitigation).

Moving to the right in the Table 3, the bottom half of the table shows the relative costs of the Criterion 1 portfolio (shown as the shaded resources in the first column) and Criterion 2 portfolio (shown as the shaded resources in the second column) are respectively 40% and 55% more costly than the Selected Wind Facilities if Criterion 3 (high congestion costs that need to be mitigated) is used for evaluating the projects. Based on these calculations, Table 3 shows that the portfolio with the lowest project costs (based on Criterion 1) is significantly more costly than the Selected Wind Facilities if congestion mitigation became necessary and a gen-tie would need to be built (Criterion 3). The calculations show that the facilities with the lowest project costs (under Criterion 1) would have a delivered cost that is *40% above* those of the Selected Wind Facilities' delivered cost. The same is true if the lowest-cost portfolio based on Criterion 2 (congestion and loss-related costs added to the project costs, without considering congestion risk mitigation) faced a future in which congestion mitigation becomes necessary (Criterion 3). As shown, if congestion mitigation became necessary (Criterion 3), the cost of the portfolio selected solely based on Criteria 2 would be *55% above* the cost of the Selected Wind Facilities.

The comparisons in Table 3 show that for a very modest amount (4 to 7%) above the lowest project costs with or without estimated congestion costs (Criteria 1 or 2), the Selected Wind Facilities offer a very valuable protection against the risk of higher-than-expected congestion costs (Criterion 3). Unlike the other possible portfolios of wind projects, the Selected Wind Facilities thus offer a more robust portfolio that is much less exposed to unexpected future increases in congestion costs. This is not surprising considering that the three Selected Wind Facilities are located relatively close to the Company's Tulsa load center, which reduces congestion risk and facilitates lower-cost mitigation options—whether through a gen-tie or other transmission upgrades—in case such mitigation was needed in the future.

Finally, Table 3 shows that the portfolio of Selected Wind Facilities is optimal across a range of likelihoods that implementing the available congestion risk mitigation option would actually be necessary. Criterion 3 implies a 100% likelihood that a gen-tie would need to be built to mitigate congestion, Criterion 4 assumes a 50% chance that the congestion risk mitigation may become necessary (the Company's selection criteria), while Criterion 5 assumes only a 25% chance that risk mitigation may need to be implemented. As shown, the Selected Wind Facilities represent the least-cost choice for both Criterion 4 and 5.

Q. THE TWO COMPANIES INITIALLY CONSIDERED PROCURING UP TO A COMBINED 2,200 MW OF WIND GENERATION, BUT HAVE SELECTED

APPROXIMATELY 1,500 MW FROM THE RFP. WAS THAT DECISION REASONABLE?

A. Yes. As shown in the Company's economic selection criterion (Criterion 4 in Table 3, with a 50% weighting of estimated congestion and gen-tie costs), the delivered costs of the three Selected Wind Facilities are within 6% of each other. The selection would need to include the fourth, fifth, and sixth projects listed under Criterion 4 in Table 3 to reach 2,200 MW. However, the costs of these next three projects are significantly higher, ranging from 13% to 21% above the lowest-cost project. Given the high cost difference between the first three and the next set of three projects, it is reasonable to limit the procurement at 1,500 MW at this point in time.

VI. REASONABLENESS OF THE COMPANY'S BENEFITS ANALYSIS OF THE SELECTED WIND FACILITIES

Q. ONCE THE SELECTED WIND FACILITIES WERE CHOSEN, DID THE COMPANY FURTHER REFINE THE SPP PROMOD SIMULATIONS FOR THE PURPOSE OF ITS CUSTOMER BENEFITS ANALYSIS?

A. Yes. Once the Selected Wind Facilities had been identified, the Company further refined the SPP PROMOD Case to create a "Base Case" for its customer benefits analysis. To do so, three modifications were made to the "Bid Evaluation Case" discussed above. First, the Company considered likely SPP transmission upgrades by assuming that upgrades would be made, at a minimum, to address the transmission needs that SPP has already identified in the currently-ongoing ITP process.[10] Second, the updated PROMOD Base Case assumes the three Selected Wind Facilities will be built and that transmission network upgrades that SPP identified and requires through its generation interconnection process for the Selected Wind Facilities would be built as well. From a generation assumption perspective, the revised Base Case retains all the wind facilities that SPP has added to its PROMOD Reference Case but does not include other wind generation bids beyond the three Selected Wind Facilities. This resulted in total installed wind generation that exceeds the SPP Reference Case by 1,000 MW to account for the Selected Wind Facilities not in the SPP Reference Case.[11]

Q. IS IT REASONABLE THAT THE COMPANY MADE THESE PROMOD CASE REFINEMENTS TO CONSIDER FUTURE SPP TRANSMISSION UPGRADES?

A. Yes. While modeling future SPP transmission upgrades for each bid was not necessary for assessing <u>*relative*</u> congestion-related costs and risks for the purpose of the RFP bid-evaluation process—and could have distorted the selection based on SPP upgrades not yet approved—assessing the impact of likely SPP transmission upgrades is important for the customer benefit analysis. This is because the customer benefit analysis requires an estimate of the likely overall <u>*level*</u> of congestion costs associated with delivering the Selected Wind Facilities to the AEP West load zone to ensure that the benefits that customers receive from these wind facilities are estimated accurately.

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[10] As part of the ongoing 2019 ITP assessment, SPP posted a list of "2019 ITP Needs" which included economic needs in addition to reliability needs prior to the opening of the 2019 ITP Detailed Project Proposal response wind window or the "DPP Window". The Company used this list of SPP-ITP-identified transmission needs for the reference case and implemented the associated transmission upgrades by relieving the SPP-identified constraints in the simulations.

[11] The Company, again, also identified transmission constraints created by the Selected Wind Facilities to make sure these are monitored and enforced constraints in the PROMOD simulations.

Q. HAS THE COMPANY ANALYZED A CASE IN WHICH HIGHER CONGESTION WOULD MATERIALIZE IF THE SPP-ITP-IDENTIFIED TRANSMISSION NEEDS WERE NOT ADDRESSED?

A. Yes, given the uncertainty about the extent and timing of future SPP transmission upgrades, the Company has additionally run simulations with an SPP PROMOD case *without* upgrading (all but one) the SPP-ITP-identified transmission needs.[12] As would be expected, this "No-SPP-Upgrades Case" yields higher congestion charges than the "Base Case," given the lack of additional transmission upgrades. The No-SPP-Upgrade Case still yields lower congestion charges than what has been reflected in the Bid Evaluation Case, since the Bid Evaluation case includes an additional 3,400 MW of proposed wind projects that were not selected by the Company. As discussed in Company witness Torpey's testimony, the Company has used this No-SPP-Upgrades Case to evaluate customer benefits under a higher-congestion scenario in which it is assumed that congestion risk mitigation through a gen tie would become necessary.

Q. HOW DO THE PROJECTED 2024 AND 2029 CONGESTION ESTIMATES FROM THE SPP PROMOD MODEL COMPARE TO THE HISTORICAL CONGESTION LEVELS EXPERIENCED BY EXISTING WIND GENERATION IN SPP?

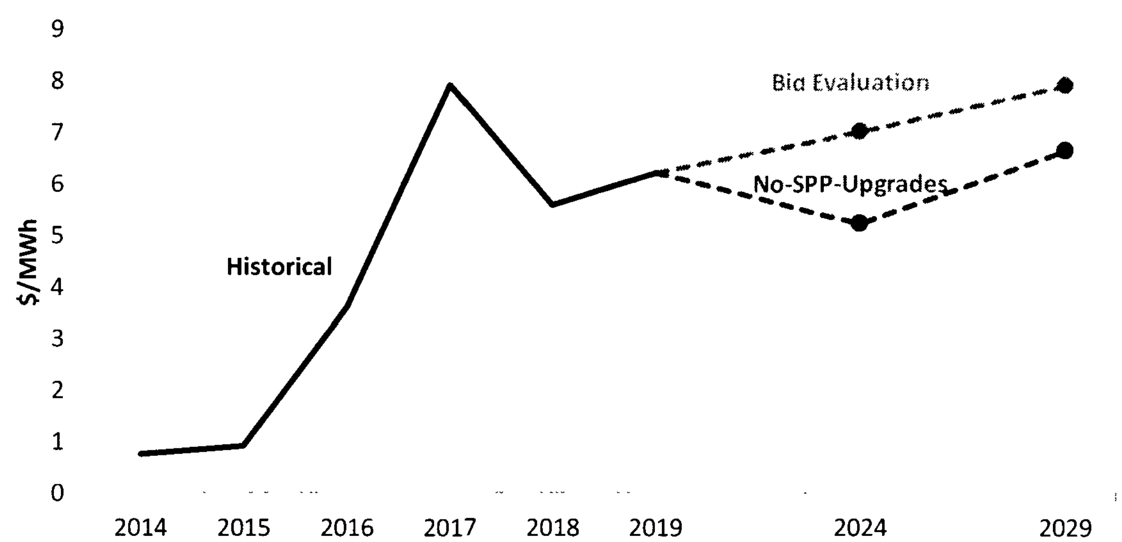
A. Figure 1 below summarizes the simple annual average of hourly congestion charges between the AEP's existing Oklahoma wind facilities and SPP's AEP-West

[12] As noted earlier, the company assumed in all cases that the Cleveland 138 kV bus-tie, located west of Tulsa, will be addressed by an SPP solution in the near term since it was identified by SPP as both an economic and operational need in the 2019 ITP Study and the transmission upgrade costs were expected to be low.

load zone for both historical years (as previously reported in Table 1) and projected future years (as simulated in PROMOD). More specifically, these simple averages[13] of wind-to-AEP West load zone congestion costs are shown both for: (1) the actual historical real-time market outcomes for 2014 through (year to date) 2019; and (2) the 2024 and 2029 simulations results for AEP's existing Oklahoma wind facilities from the Base, No-SPP-Upgrades, and Bid Evaluation PROMOD cases. As shown, the historical average annual congestion charges between AEP's existing Oklahoma wind plants and the AEP West load zone (solid black line) have ranged from a low of less than $1/MWh in 2014 and 2016 to $8/MWh in 2017, before dropping to around $6/MWh in 2018 and (year to date) 2019—reflecting the congestion-reducing effect of SPP transmission additions that came online in recent years. As shown, the simulated future congestion levels are in the upper half of the historically-experienced range.

[13] Again, because hourly historical wind generation data is not publicly available for these wind facilities, the figure presents the simple averages over all hours of the year. Although this will understate the actual congestion costs faced by the owners of these wind facilities (because hours with higher wind generation will tend to have higher congestion charges), the simple averages nevertheless document congestion trends over time and allow for a comparison of historical and simulated congestion levels.

Figure 1: Historical and Simulated Wind-to-AEPW Congestion for Existing AEP Wind Facilities in Oklahoma
(Simple all-hours annual average, weighted by MW plant size)



Looking forward, the figure shows the SPP PROMOD simulation results for the three congestion scenarios simulated by the Company.

1. The "*Bid Evaluation Case*" results from the 2024 and 2029 SPP PROMOD cases used for RFP bid evaluation (the highest dashed line) show the highest simulated congestion charges because the case includes all wind facility bids received by the Company and reflects only transmission upgrades that SPP has identified in the modeled wind facilities' interconnection studies. As shown, these simulation results are at the high end of the historical range for existing Oklahoma wind facilities.

2. The "*Base Case*" simulation results for the 2024 and 2029 SPP PROMOD cases used for the customer benefit analysis (the lowest dashed line) show the lower congestion charges, reflecting (a) the addition of only the Selected Wind Facilities (beyond the wind facilities already in the SPP case), (b) transmission upgrades that SPP has identified in the Selected Wind Facilities' interconnection studies; as well as (c) the assumption that SPP would upgrade the transmission constraints it has identified through the currently-ongoing SPP ITP stakeholder process. As shown, the 2024 and 2029 results for this simulation show congestion charges that are approximately the average of historical congestion, reflecting the congestion-reducing impact of the assumed upgrades of the SPP-ITP-identified transmission constraints.

3. Finally, the "*No SPP Upgrades Case*" used by the Company for conducting the Customer Benefit Analysis (the middle dashed line) shows congestion results below those of the bid evaluation case but above the base case. As discussed further below, this higher-congestion case was used for Company witness Torpey's congestion risk mitigation scenario of the customer benefit analysis. This case shows congestion charges that are lower than the bid evaluation case, because only the three Selected Wind Facilities (*i.e.*, not all received bids) have been added beyond the wind additions reflected in the SPP cases. The congestion charges are above the Base Case results because this case assumes that, beyond the already-approved upgrades, none of the current SPP-ITP-identified transmission needs would be addressed—which, compared to the Base Case, would make it more likely that the congestion risk mitigation option evaluated by Company witness Torpey would need to be implemented.

Q. IS IT REASONABLE THAT 2024 CONGESTION LEVELS FOR THE BASE CASE WOULD BE BELOW THOSE RECENTLY EXPERIENCED?

A. Yes, it is. All SPP-approved transmission upgrades that are currently under development will be placed into service by the 2024 simulation year. This involves over $1.6 billion of transmission upgrades in 2019 through 2024.[14] Because the Base Case simulation further assumes that the additional transmission needs SPP has identified in its current ITP assessment would be addressed through additional upgrades as well, it is reasonable that congestion would be reduced below the recent historical levels.

Q. WHY IS CONGESTION INCREASING BETWEEN 2024 AND 2029 IN ALL THE SIMULATION CASES?

A. The estimated congestion level increases between 2024 and 2029. However, only a small portion of that increase will relate to additional wind generation development because SPP assumes that only 400 MW new wind facilities become

[14] See page 8 of Second Quarterly Project Tracking Report, April 2019 https://www.spp.org/documents/59868/q2%202019%20spp%20quarterly%20project%20tracking%20report.pdf

operational between 2024 and 2029 based on SPP Reference Case. Thus, much of the higher congestion charges are driven by higher generation redispatch costs. To illustrate this point, the simple average of monthly gas prices in the SPP Reference Case is $4.62/MMBtu in 2024 and is $5.44 in 2029, a 17.8% increase. Since congestion increases by 21.9% between the two years of the No-SPP-Upgrades Case, it suggests that the dominant driver of the shown congestion charge increase is accounted for by higher gas prices, which increase the redispatch cost. The other effects are likely accounted for by a combination of the added wind generation, significant new solar generation, and the retirements of some of the aging fossil generating plants in SPP projected for 2029.

Q. IF CONGESTION COSTS WERE TO INCREASE ABOVE PROJECTED LEVELS, WOULD IT BE MORE LIKELY THAT SPP WOULD UPGRADE THE CONSTRAINED TRANSMISSION FACILITIES?

A. Yes. In general, as congestion costs associated with specific transmission facilities increase, it will at some point become either cost effective to upgrade the constraining transmission facilities or necessary to upgrade some of the constrained facilities from a system reliability perspective. Whether and when SPP would identify and approve such further upgrades is uncertain, however, which creates the congestion and deliverability risks that the Company has considered in its RFP bid evaluation process. If congestion increases but SPP transmission upgrades are not implemented to address the higher congestion, the likelihood increases that the Company will need to mitigate that congestion through dedicated transmission upgrades, such as a gen-tie between the Selected Wind Facilities and the Company's Tulsa load center, as evaluated by Company witness Torpey.

Q. ARE CUSTOMERS FULLY EXPOSED TO THE PROJECTED WIND-TO-LOAD CONGESTION CHARGES?

A. No, they are not fully exposed to the congestion charges. Load serving entities are able to obtain from SPP allocations of some Transmission Congestion Rights (TCRs) that allow them to avoid (hedge at no cost) a portion of these congestion charges in the day-ahead market. Unfortunately, due to limited transmission capability and the high levels of wind generation developed in the region, it has been difficult to obtain sufficient TCR allocations for wind facilities from SPP. In addition, some of the congestion is experienced only in the real-time market, which cannot be hedged through TCRs. As noted by Company witness Ali, the Company forecasts that approximately 25% of its wind generation-related congestion costs could be hedged. The benefit of these congestion hedges is not reflected in the congestion costs reported in the summary charts and tables of my testimony, nor are they considered in the congestion cost and risk analysis during the RFP bid evaluation process. They are, however, reflected in the Company's customer benefits analysis (at the 25% hedge ratio).

Q. WHAT ARE THE SPP PROMOD ESTIMATES OF FUTURE CONGESTION AND LOSS-RELATED COSTS FOR THE SELECTED WIND FACILITIES BEFORE AND AFTER CONSIDERING THE LIKELY UPGRADES OF THE SPP-ITP-IDENTIFIED TRANSMISSION CONSTRAINTS?

A. Table 4 below shows congestion and loss-related costs for the Selected Wind Facilities based on the PROMOD results for the Base Case and No-SPP-Upgrades Case simulations.

Table 4: Simulated Wind-to-AEPW Congestion and Losses for the Three Selected Wind Facilities

($/MWh)	2024							
Selected Wind Facility	**Simple Avg**		**Gen-Weighted Avg**		**Simple Avg**		**Gen-Weighted Avg**	
	Congestion	**Losses**	**Congestion**	**Losses**	**Congestion**	**Losses**	**Congestion**	**Losses**
	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]
Base Case								
Average	*3.87*	*0.76*	*7.43*	*1.33*	*4.83*	*1.01*	*9.15*	*1.67*
Traverse	4.17	0.61	7.81	1.02	5.40	0.85	10.02	1.31
Maverick	3.31	0.73	6.30	1.35	4.05	0.97	7.61	1.68
Sundance	4.14	0.94	8.18	1.63	5.03	1.21	9.81	2.01
No-SPP-Upgrades Case								
Average	*4.85*	*0.74*	*9.25*	*1.28*	*6.15*	*0.98*	*11.27*	*1.60*
Traverse	7.05	0.59	12.80	0.98	8.94	0.82	15.69	1.26
Maverick	3.02	0.71	6.01	1.30	3.74	0.95	7.20	1.62
Sundance	4.47	0.91	8.94	1.56	5.78	1.16	10.94	1.92

Source and Notes:

2024 and 2029 PROMOD simulation outputs.

[B] & [D] & [F] & [H]: Average loss costs represent half of the wind-generation-weighted marginal loss charges for the wind resources.

Q. PLEASE SUMMARIZE THE OVERALL METHODOLOGY AND METRICS THE COMPANY USED FOR ITS CUSTOMER BENEFITS ANALYSIS.

A. As explained in the testimony of Company witness Torpey, the Company analyzed customer benefits associated with the three Selected Wind Facilities for thirteen cases covering a range of wholesale power market fundamentals (provided by Company witness Bletzacker), wind availability cases (provided by Company witness Godfrey), congestion risk mitigation cases, and a break-even case (estimated by

Company witness Torpey). These include customer benefits for 50th percentile (P50) annual wind generation for the following five wholesale-power-market fundamentals using the Base Case PROMOD congestion estimates:

1. a "base-gas/with-carbon" case (as the Company's base fundamentals case)
2. a "base-gas/no-carbon" case
3. a "low-gas/with-carbon" case
4. a "low-gas/no-carbon" case
5. a "high-gas/with-carbon" case

In addition to these five P50 cases reflecting Company witness Bletzacker's market fundamentals forecasts, the Company also developed four additional cases based on the five-year 95th percentile (P95)[15] wind production levels. As further explained by Company witness Torpey, these four P95 cases (also using the Base Case PROMOD congestion estimates) include:

6. a P95 case for "base-gas/with-carbon" market fundamentals
7. a P95 case for "base-gas/no-carbon" market fundamentals
8. a P95 case for "low-gas/with-carbon" market fundamentals
9. a P95 case for "high-gas/with-carbon" market fundamentals

As explained further by Company witness Torpey, an additional three cases were developed to evaluate customer benefits in a higher congestion scenario (using the "No-SPP-Upgrades" PROMOD congestion case) under which a generation tie line could be built cost effectively to mitigate the higher congestion costs. These three "Gen-Tie" cases include:

10. a P50 gen-tie case for "base-gas/with-carbon" market fundamentals

[15] Note that applying the 5-year P95 wind capacity values to the 30-year customer benefit analysis yields a conservatively low P95 estimate of 30-year customer benefits because the probability of achieving wind generation better than the 5-year P95 level is greater than 95% over a 30-year period (i.e., six consecutive five-year P95 low-wind periods).

11. a P50 gen-tie case for "base-gas/no-carbon" market fundamentals

12. a P95 gen-tie case for "base-gas/no-carbon" market fundamentals

And finally, to estimate how low natural gas prices and associated wholesale power market prices could be while still producing customer benefits sufficient to cover the Selected Wind Facilities' costs, Company witness Torpey also developed:

13. a "break even" case

Company witness Bletzacker also developed for this break-even case (reflecting P50 wind conditions) a break-even natural gas price estimate.

Q. HOW HAS COMPANY WITNESS TORPEY DETERMINED CUSTOMER BENEFITS?

A. As Company witness Torpey explains, he has used the Company's PLEXOS model to determine how the Company's energy- and capacity-related costs—including its generation dispatch, off system sales and wholesale market purchases—will be affected by the ownership and operation of the Selected Wind Facilities. PLEXOS simulates these costs separately for PSO and SWEPCO. To determine these PSO and SWEPCO net customer costs, PLEXOS uses as an input the wholesale power market prices for the AEP West load zone, PSO and SWEPCO conventional generation, as well as the congestion and loss costs associated with deliveries from the Selected Wind Facilities.

As Company witness Torpey explains, the customer benefits of purchasing the Selected Wind Facilities are then determined by comparing the (1) total customer costs *with* the purchase of the Selected Wind Facilities; to the (2) total customer costs *without* the purchase of the Selected Wind facilities.

Q. HOW DID THE COMPANY DETERMINE THE WHOLESALE-POWER MARKET PRICES AND CONGESTION-COST INPUTS FOR PLEXOS?

A. The Company used the wholesale power market prices from it "markets fundamentals forecasts," which are based on Company witness Bletzacker's wholesale power market simulations for the entire Eastern Interconnection, covering the eastern two-thirds of the United States. As Company witness Bletzacker explains in his testimony, these simulations with the Aurora Energy Market Simulation Model (AURORA) provide a wholesale market price forecast for the "SPP Central" region, but do not further differentiate wholesale power prices by location or simulate congestion costs within SPP. Since the congestion and loss-related costs of delivering power from the Selected Wind Facilities had to be considered, it was necessary to develop for each AURORA simulation of the market fundamentals forecast: (1) a consistent set of estimated congestion and loss costs of delivering wind generation from the Selected Wind Facilities; and (2) an estimate of how market prices for the AEP West load zone and PSO and SWEPCO conventional generation differ locationally from the larger "SPP Central" zone price simulated in AURORA.

Q. HOW HAS THE COMPANY DEVELOPED THE NECESSARY CONGESTION AND LOSS COSTS FOR ITS AURORA-BASED FUNDAMENTALS PROJECTIONS FOR SPP CENTRAL?

A. The Company has utilized its PROMOD locational market simulations to estimate congestion and loss costs as well as the locational differences in SPP wholesale market prices. I have previously explained how congestion and loss costs were projected using the SPP PROMOD Reference Case as modified by the Company for wind generation additions and transmission upgrades. As explained in the testimony of Company witness Sheilendranath, these PROMOD congestion and loss-related costs had to be scaled to the various AURORA-based market fundamentals forecasts in proportion to the difference between (1) the SPP Central prices in the PROMOD simulations and (2) the SPP Central prices from the AURORA-based market fundamentals cases listed earlier.

Q. WHY WAS IT NECESSARY AND REASONABLE TO COMBINE MULTIPLE MODELS—PROMOD, AURORA, AND PLEXOS—TO ESTIMATE CUSTOMER BENEFITS ASSOCIATED WITH THE THREE SELECTED WIND FACILITIES?

A. PROMOD, AURORA, and PLEXOS are simulation tools that can be employed to perform the type of forward-looking market simulations necessary to assess the benefits of the Selected Wind Facilities. However, in this case, all three simulation tools were necessary for a number of reasons.

The Company has been relying on AURORA to project long-term trends of multi-regional market prices and PLEXOS for analyzing the market performance of their individual Company resources and for evaluating expected market revenues and dispatch outcomes for resource planning and customer impact purposes. Relying on AURORA for projecting long-term trends of regional market prices is advantageous because AURORA employs a consistent set of market fundamentals assumptions, such as natural gas and coal prices, for the full range of long-term wholesale power market and fuel price scenarios that AEP companies use for all their long-term planning purposes across all of their service areas. The Company uses these AURORA-based fundamentals forecasts for a variety of resource planning purposes as explained by witness Bletzacker.

Relying on PLEXOS to estimate customer impacts for individual operating companies has several advantages. The model is set up to simulate many years of future market performance quickly and to link and provide input to customer rate impact assessments. Most importantly, unlike PROMOD, the PLEXOS model is set up to simulate PSO and SWEPCO individually, and therefore is able to assess changes in production costs, market purchase costs, off-system sales revenues, and other customer cost items at the operating-company level.

Unlike PROMOD, the AURORA and PLEXOS models are not set up to simulate transmission constraints or losses within the SPP footprint, which means they are unable to assess the extent to which wholesale power prices, congestion costs, and loss-related costs affect the delivered costs of generating resources, including the Selected Wind Facilities.

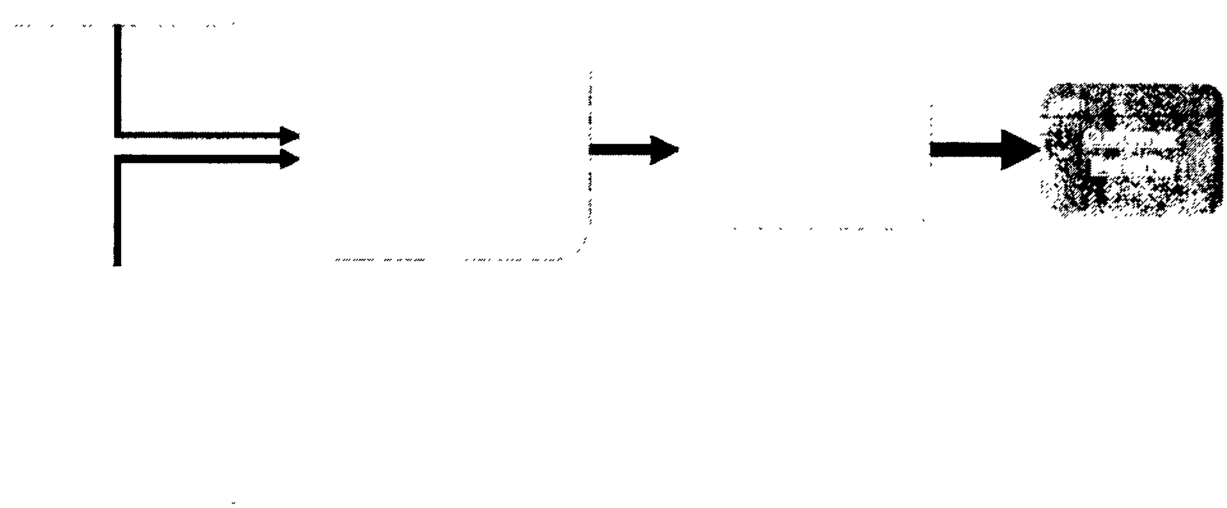
SPP's PROMOD models, as described earlier, simulate the entire SPP system (and surrounding market areas), including the full SPP transmission network and associated transmission constraints and losses. As stated previously in my testimony, transmission constraints have a significant effect on optimal SPP-wide market dispatch outcomes and the associated locational prices. Given that the large levels of wind generation are expected to grow further in the SPP region, it is important to capture the congestion and loss impacts of the transmission network on locational prices when evaluating the delivered costs of wind facilities. SPP's PROMOD model is, however, limited by the fact that it has been set up to analyze load-related impacts only for individual SPP transmission zones—such as the AEP West load zone, which aggregates both AEP companies (PSO and SWEPCO) as well as other public power entities—and without the level of detail that is required to separately assess customer impacts for each of the two AEP operating companies. In addition, SPP's PROMOD models are not conducive to quickly analyzing various sensitivities such as under varying long-term gas and coal price forecasts, and/or sensitizing with future carbon tax assumptions. The Company's AURORA model produces long-term regional price trends under varying sensitivities. Assessing the customer benefits under various market fundamentals sensitivities is essential for a comprehensive evaluation of the costs and benefits of the Selected Wind Facilities. Therefore, to assess the full benefits of the Selected Wind Facilities over the entire 30-year design lives and for each of the two companies, AURORA and PLEXOS were employed in conjunction with SPP's PROMOD models to capture the impact on the individual operating companies and to estimate the delivered cost and customer impact of the facilities.

Q. HOW HAS THE COMPANY DEVELOPED THE NECESSARY PLEXOS LOAD AND GENERATION MARKET PRICE INPUTS FROM ITS AURORA-BASED FUNDAMENTALS PROJECTION FOR SPP?

A. The Company's AURORA market fundamentals forecasts are for the AURORA-defined "SPP Central" zone. The PROMOD simulations were then used to estimate the extent to which the wholesale market prices for the AEP West load zone, PSO conventional generation, and SWEPCO conventional generation differed from market price projections for the SPP Central zone.

As explained in Company witness Sheilendranath's testimony, this was accomplished by scaling the PROMOD-based wholesale market price differences between SPP Central and the AEP load and generation locations based on the extent to which the level of market prices for SPP Central differ between the AURORA and PROMOD simulations. This scaling of PROMOD-based congestion and loss differences between SPP Central and AEP West load and the PSO and SWEPCO generation zones recognizes the SPP locational market price differences relative to SPP Central, but scales those differences up or down to be consistent with the extent to which AURORA market price forecasts for SPP Central are higher or lower than those for SPP Central in the SPP PROMOD simulations. How AURORA and PROMOD simulation results were combined by Company witness Sheilendranath to develop the necessary PLEXOS inputs is illustrated in Figure 2 below.

Figure 2: Simulation Models Used in Customer Benefit Analysis



Q. IS IT REASONABLE TO SCALE THE PROMOD CONGESTION AND LOCATIONAL MARKET PRICE DIFFERENTIAL BETWEEN AEP LOCATIONS AND SPP CENTRAL BASED ON THE LEVEL OF AURORA MARKET FUNDAMENTALS?

A. Yes, it is. Given a certain transmission network and installed generation base in SPP, the congestion and loss-related costs will primarily be a function of the overall level of market prices. If natural gas prices are higher, for example, not only will overall wholesale power prices be higher, but the cost of supplying losses and redispatching generation to manage congestion within the SPP footprint will be correspondingly higher as well. Since the difference in wholesale market prices between different locations in SPP is a direct function of congestion and loss-related charges, it is reasonable to scale the differences in locational market prices with the overall level of market prices.

Q. WHAT ARE THE PROMOD MARKET PRICE DIFFERENCES BETWEEN SPP CENTRAL AND THE AEP WEST LOAD ZONE?

A. As shown in Table 5 below, the simple average of wholesale power prices (locational marginal prices or LMPs) for the AEP West load zone are \$4–\$7/MWh above simulated SPP-Central[16] prices across the three sets of PROMOD simulations used by the Company. As shown, the simulations with higher average wind-related congestion levels (*e.g.*, the No-SPP-Upgrades Case) also result in higher congestion-related wholesale market price differences between AEP load and generation and the

[16] As further discussed in the customer benefits analysis, which relies on the Company's AURORA-based fundamentals forecast, the SPP-Central zone in PROMOD closely matches the SPP-Central zone in AURORA.

SPP-Central region. Similar market price differences exist between SPP Central and the market prices faced by the Company's conventional generating units.

Table 5: PROMOD LMP Difference between SPP Central and AEP-West Load Zone

	Base Case		No-SPP-Upgrades Case		Bid Evaluation Case	
Simple Average LMP ($/MWh)	**2024**	**2029**	**2024**	**2029**	**2024**	**2029**
SPP Central	$28.94	$34.32	$28.06	$33.37	$25.80	$31.09
AEP West Load	$32.46	$38.75	$32.24	$38.90	$31.73	$38.15
AEP Load to SPP Central Differential	$3.52	$4.43	$4.17	$5.53	$5.93	$7.06

Q. WHAT ARE THE COMPANY'S CUSTOMER BENEFIT METRICS AND BENEFITS RESULTS?

A. The results of the Company's Customer Benefit Analysis are summarized in Company witness Torpey's testimony. As he shows, and as I summarize in my discussion of ERRATA Figure 3 below, the benefits to SWEPCO customers of developing the Selected Wind Facilities are quite significant, with 31-year present values of SWEPCO customer benefits that exceed project costs by an amount ranging from approximately $180 million to $395 million under low gas or P95 low wind conditions, to approximately $540 million to $720 million under high gas price, or high-congestion conditions. As Company witness Torpey explains, benefits include lower power purchase costs (net of changes in off system sales), the avoided costs of deferring conventional generation capacity needs, and the Company's ability to take advantage of the federal production tax credit. Costs include the revenue requirement of the Selected Wind Facilities, and the congestion and loss costs associated with delivering the output from the facilities to the AEP load zone. Company witness

Torpey's gen-tie (congestion risk mitigation) cases include the additional benefits of avoided (higher) congestion costs but with the added cost of the gen tie.

Q. ARE THESE CUSTOMER BENEFIT METRICS AND BENEFITS RESULTS REASONABLE?

A. Yes, they are.

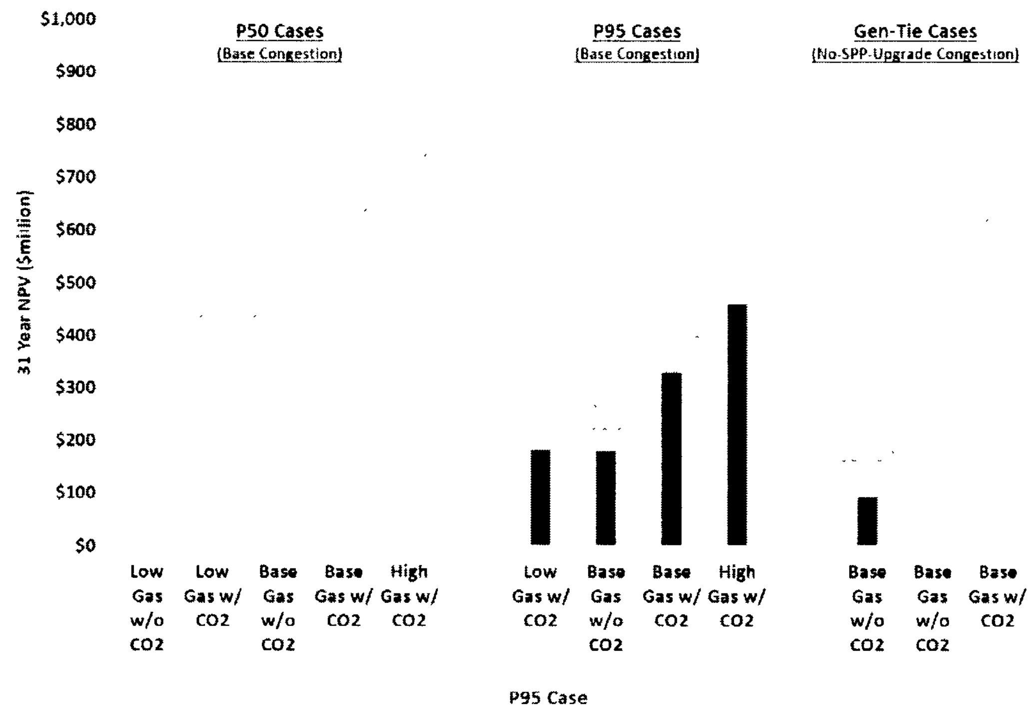
Q. DO YOU AGREE WITH THE BREAK-EVEN ANALYSIS PRESENTED BY THE COMPANY? PLEASE EXPLAIN.

A. Yes, I do. The Company's break-even analysis undertaken by Company witness Torpey starts with the Company's *lowest* whole power price fundamentals forecast (based on the "low-gas/no-carbon" case) to calculate the net present value of customer benefits. The wholesale power prices for the AEP load zone are then decreased in every year until the net present value of customer benefits is zero, as discussed in Company witness Torpey's testimony. Company witness Bletzacker then calculates the break-even natural gas price based on Company witness Torpey's break-even wholesale power price and the SPP "market heat rate" for the low-gas/no-carbon case. This is a reasonable approach for estimating how low SPP wholesale power prices and natural gas prices would need to fall before the present value of benefits are exactly equal to the present value of costs, such that the net benefit is zero—which means the Selected Wind Facilities just break even with benefits covering costs.

Q. WHAT DO THE BREAK-EVEN ANALYSIS AND THE VARIOUS MARKET FUNDAMENTALS CASES INDICATE AS THEY APPLY TO CUSTOMER BENEFITS, COSTS, AND RISKS?

A. Company witness Torpey's break-even and customer benefit analyses show that the Selected Wind Facilities offer significant customer benefits and that these benefits are robust across a wide range of market fundamentals. The analyses also show that in futures in which higher congestion charges would otherwise diminish customer benefits, the ability to mitigate these congestion-related effects through transmission investments (such as a gen tie) safeguards these customer benefits. The results of the customer benefits analyses are summarized for SWEPCO in ERRATA Figure 3 below, with each bar indicating the net present value of customer benefits for one of the 12 cases simulated. The lightly-shaded bars (sorted from lowest to highest customer benefits) represent P50 wind generation cases, while the dark bars represent the P95 low-wind generation cases. The dollar numbers above the bars indicate (for informational purposes) the 2021 and 2029 wholesale power price for the AEP load zone in each of these cases.

ERRATA Figure 3: Summary of SWEPCO Customer Benefit Results



The range of results for the various P50 cases in ERRATA Figure 3 show that the Selected Wind Facilities have an attractive profile of benefits that essentially create a "hedge" against future gas price increases and possible carbon regulations. This hedge pays for itself by virtue of the Selected Wind Facilities' benefits that exceed costs even under the lowest projected market fundamentals. In a scenario of low overall customer costs, when wholesale power prices are low (e.g., $30.79/MWh in 2029 for the low gas w/o CO_2 case), the net customer benefits of the Selected Wind Facilities are lower but still sizable (e.g., $236 million NPV), showing that the facilities more than pay for themselves through avoided fuel and capacity costs. However, in scenarios when overall customer costs are much higher due to higher wholesale power prices (e.g., $51.39/MWh in 2029 for the high gas with CO_2 case), the net benefits of the Selected Wind Facilities are higher (e.g., $718 million NPV), thus providing a valuable offset to the higher costs that would otherwise be faced by the Company's customers.

Q. PLEASE EXPLAIN THE IMPACT OF THE CONGESTION MITIGATION OPTION IN TERMS OF CUSTOMER BENEFITS, COSTS, AND RISKS.

A. The three bars on the right in ERRATA Figure 3 show that in a future of higher congestion costs, the construction of a gen tie can be used to safeguard customer benefits. These gen-tie benefits are based on the "No-SPP-Upgrades" congestion results, which are somewhat higher than the Base Case congestion results as previously shown in Figure 1. Nevertheless, despite the higher congestion costs, customer benefits remain. This means the avoided higher congestion cost would fully pay for the cost of constructing the gen tie under these market conditions. The higher the congestion costs, the more beneficial the gen-tie mitigation option will be.

VII. CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. My conclusions are as follows. First, the Company has reasonably relied on the SPP-developed PROMOD Reference Case. With the discussed modifications, it is reasonable to utilize this case for the congestion and loss analyses in both the Company's bid evaluation and customer benefits analysis of the wind facilities proposed and selected in response to the Company's RFP.

Second, there is significant but uncertain congestion in the SPP footprint, specifically affecting the cost of delivering generation from wind plants to load. This makes it important to evaluate the potential future exposure to such congestion cost and how these costs can be mitigated should they unexpectedly exceed the currently estimated levels.

Third, the Company's RFP bid-evaluation process employed in choosing the Selected Wind Facilities was reasonable. In reviewing the bid-evaluation process, I confirmed the reasonableness of the Company's assumptions, analyses, and criteria employed to choose the Selected Wind Facilities, considering the costs of the bids, the locations of the wind farms, exposure to future system congestion and deliverability limitations, and the feasibility of deploying potential congestion risk mitigation options in the event that high levels of congestion materialize in the future. I also found that the choice of Selected Wind Facilities is robust across a broad range of alternative selection criteria.

Fourth, the assumptions, analyses, and approach employed to determine the customer benefits of the Selected Wind Facilities are reasonable. The Company's Customer Benefits Analysis shows that the Selected Wind Facilities offer substantial net benefits under a broad range of market and wind conditions, including at low future energy prices and wind facility production levels. The break-even wholesale power prices are below recent historical price levels, while benefits increase significantly with higher future energy prices. These characteristics make developing the Selected Wind Facilities a hedge for SWEPCO customers that provides significant benefits under currently projected market conditions and that additionally mitigates the risks and costs associated with future power price increases, higher natural gas prices, possible future carbon regulations, and (through the gen-tie option) increased congestion in the SPP footprint.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

PUC DOCKET NO.

PUBLIC UTILITY COMMISSION OF TEXAS

APPLICATION OF

SOUTHWESTERN ELECTRIC POWER COMPANY

FOR CERTIFICATE OF CONVENIENCE AND NECESSITY

AUTHORIZATION AND RELATED RELIEF FOR

THE ACQUISITION OF WIND GENERATION FACILITIES

DIRECT TESTIMONY OF

A. MALCOLM SMOAK

FOR

SOUTHWESTERN ELECTRIC POWER COMPANY

JULY 2019

TESTIMONY INDEX

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is Albert Malcolm Smoak. I am employed by Southwestern Electric Power Company (SWEPCO or Company) as President and Chief Operating Officer (COO). SWEPCO is an operating company of American Electric Power Company, Inc., (AEP). My business address is 428 Travis Street, Shreveport, Louisiana 71101.

Q. WHAT ARE YOUR PRINCIPAL AREAS OF RESPONSIBILITY WITH SWEPCO?

A. As President and COO of SWEPCO, I am responsible for the safe delivery of reliable electric energy and quality services to our customers. This includes oversight of the following SWEPCO functions in Arkansas, Louisiana, and Texas:

- Distribution;
- Customer service;
- Regulatory and statutory compliance;
- Community and economic development; and
- Maintenance of SWEPCO's financial performance and health.

In addition, I provide strategic coordination of transmission and generation operations as these activities affect SWEPCO's financial health and day-to-day operations. In fulfilling these roles, I coordinate with American Electric Power Service Corporation (AEPSC) departments and leaders responsible for supporting SWEPCO's provision of utility services. I also represent SWEPCO as it interacts with other operating units within the AEP system.

Q. WILL YOU BRIEFLY DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I hold a Bachelor of Science degree in electrical engineering from Louisiana Tech University and I am a registered professional engineer in the State of Louisiana. I am a member of the Institute of Electrical and Electronics Engineers (IEEE) and former President of the IEEE Shreveport chapter. I am a member of the National Society of Professional Engineers (NSPE) and I represent the NSPE on the National Electrical Safety Code, Subcommittee Eight.

My career at SWEPCO began in 1984 as a distribution engineer and I have held positions of escalating responsibility serving as a meterman supervisor, the Louisiana division operations superintendent, distribution operations supervisor, distribution engineering supervisor, and the Shreveport district manager of the distribution system. I assumed the position of Vice President of Distribution Region Operations in 2004 where I had responsibility for Distribution throughout the SWEPCO service territory in Arkansas, Louisiana and Texas. In May 2018, I was promoted to my current position.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSION?

A. Yes. I have filed testimony before the Arkansas Public Service Commission (APSC), the Louisiana Public Service Commission (LPSC or Commission), and the Public Utility Commission of Texas (PUCT). I have previously submitted testimony before this Commission in Docket Nos 46449, 45712, 40443, and 37364.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony: 1) discusses the need to acquire certain new wind facilities (collectively referred to as the Selected Wind Facilities, which are also referred to by the Company as the North Central Energy Facilities) for the benefit of customers; 2) sets out the time sensitive nature of the opportunity to capture the remaining benefits of the federal Production Tax Credits (PTCs) for SWEPCO's customers; 3) describes the opportunity to provide lower energy costs and savings to all SWEPCO customers of $2.03 billion on a nominal basis and $567 million Net Present Value in the Base Fundamentals Forecast; 4) discusses the Company's guarantees for the benefit of customers; and 5) addresses the continued customer demand for renewable energy.

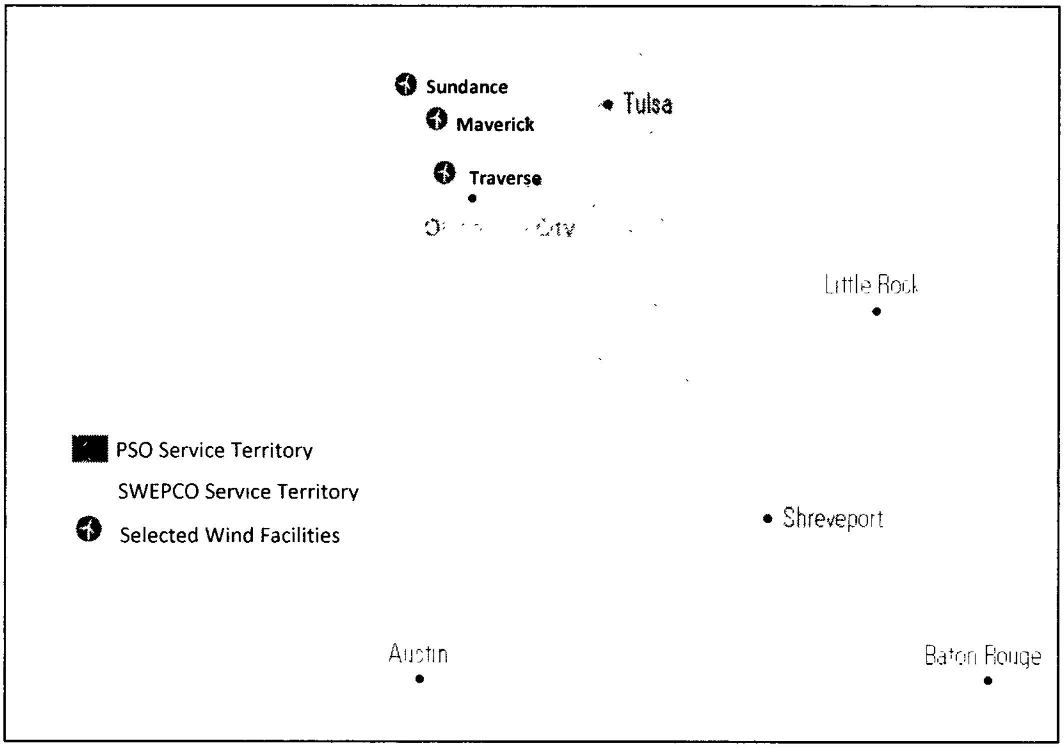
Q. PLEASE DESCRIBE THE SELECTED WIND FACILITIES TO BE ACQUIRED.

A. The Selected Wind Facilities were chosen through a market-competitive RFP process to evaluate and select the best bids for the benefit of customers, as further described by Company witnesses Brice and Godfrey. SWEPCO seeks approval to acquire 54.5% of the following Selected Wind Facilities:

Wind Facility Name	Total MW	SWEPCO Share
Traverse	999	544.5
Maverick	287	156
Sundance	199	108.5
Total	**1485**	**810**

SWEPCO's sister company, Public Service Company of Oklahoma (PSO), will acquire the remaining 45.5% share.

The Selected Wind Facilities are located in Oklahoma to access some of the best wind resources in the region, and are shown on the following map:



The developers of the Selected Wind Facilities will design, develop, construct, and commission the Facilities on a turn-key basis. No progress payments will be made by SWEPCO during that process and no cost recovery will begin until the Selected Wind Facilities are purchased and go into service. Company witness Aaron further describes the requested rate treatment, Company witness Godfrey further discusses the transactions with the sellers, and Company witness DeRuntz provides a more detailed description of the Selected Wind Facilities.

Q. PLEASE PROVIDE A BRIEF SUMMARY OF THE BACKGROUND OF THE NEED FOR THE SELECTED WIND FACILITIES.

A. In accordance with Arkansas and Louisiana regulatory requirements. SWEPCO prepares an Integrated Resource Plan (IRP) to guide its resource planning activities. That plan shows the need for significant increases in renewable energy, including wind and solar, while maintaining fuel diversity, over the next 20 years. PSO's IRP also shows a need for wind resources. Therefore, both SWEPCO and PSO issued Requests for Proposals (RFPs), which were then jointly evaluated resulting in the selection of the Selected Wind Facilities. The RFPs and the RFP evaluation process are discussed further by Company witness Godfrey. Concurrent with this application, SWEPCO is filing its requests for approval of the acquisitions with its jurisdictions in Louisiana and Texas, and with the Federal Electric Regulatory Commission (FERC). PSO has also filed a request with the Oklahoma Corporation Commission related to its acquisition of a share of the Selected Wind Facilities.

Acquisition of the Selected Wind Facilities is time sensitive to meet the requirements to receive at least 80% of the value of the federal Production Tax Credits (PTCs) for the Traverse and Maverick wind facilities and 100% PTC value for the Sundance wind facility. SWEPCO continues to see strong customer interest in more renewable energy to meet their sustainability and renewable energy goals.

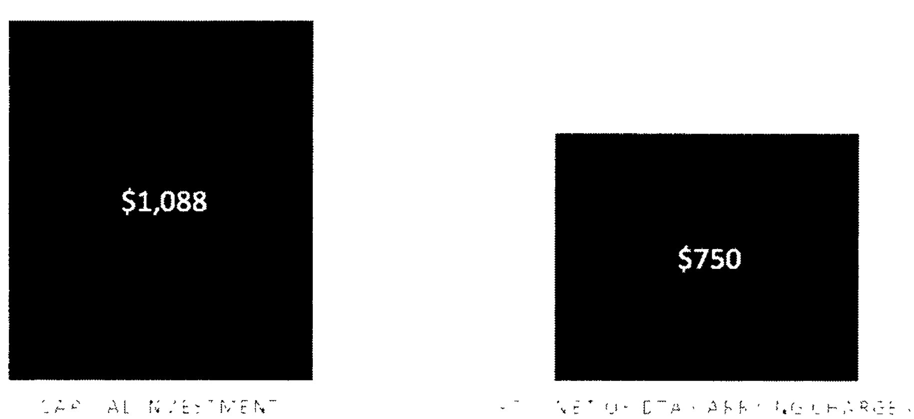
Q. WILL THE SELECTED WIND FACILITIES BENEFIT CUSTOMERS WHILE SERVING CUSTOMERS' NEEDS?

A. Yes. Acquisition of the Selected Wind Facilities is expected to provide substantial benefits in excess of its costs for customers. As I discuss in more detail below, the acquisition will provide low-cost energy to customers and results in fuel savings because there are no fuel costs. It will also contribute to a more diversified generation mix of natural gas, wind, solar, and solid fuels, while meeting the demand for renewables.

Q. IS THE OPPORTUNITY TO CAPTURE SIGNIFICANT SAVINGS FOR SWEPCO'S CUSTOMERS TIME SENSITIVE?

A. Yes, definitely. The savings for SWEPCO's customers available pursuant to this Application are indeed significant, especially when compared to the capital costs of the Selected Wind Facilities. SWEPCO's capital outlay for the Selected Wind Facilities is $1.09 billion. Yet, SWEPCO's customers will receive the benefit of $750 million of PTCs net of deferred tax asset (DTA) carrying costs. But, the federal PTCs are being phased out over the next four years. As discussed in more detail by Company witness Multer there is limited time to assure the capture of these savings for SWEPCO's customers. This is shown in the figure below:

SWEPCO CAPITAL INVESTMENT VS. PTC, NET OF DTA CARRYING CHARGES
(NOMINAL $ IN MILLIONS)



III. SUMMARY OF CUSTOMER BENEFITS

Q. WHAT ARE THE EXPECTED CUSTOMER BENEFITS OF THE SELECTED WIND FACILITIES?

A. The Selected Wind Facilities are expected to provide benefits in excess of costs that create savings of approximately $2.03 billion on a total Company basis in nominal dollars and $567 million Net Present Value over the life of the project in the Company's Base Fundamental Forecast. The Company's analysis shows robust savings and substantial customer benefits under a wide range of scenarios. The Selected Wind Facilities take advantage of federal PTCs for the benefit of customers to secure at least 80% of the value of the PTCs, and in the case of Sundance 100% of the value of the PTCs. Company witness Torpey discusses the specific SWEPCO customer benefits in his testimony.

Acquisition of the Selected Wind Facilities will result in lower costs to customers. With the rate treatment described by Company witness Aaron, the Selected Wind Facilities will reduce future fuel and energy cost escalation and provide more stable and predictable rates for our customers for 30 years. The Selected Wind Facilities will provide a significant volume of low-cost energy for customers while diversifying the generation mix and will reduce fuel costs going forward.

Q. HOW WERE THESE PROJECTED BENEFITS DETERMINED?

A. As further discussed in the testimonies of Company witnesses Bletzacker, Torpey, Sheilendranath, and Pfeifenberger, SWEPCO and PSO went through a robust