SOAH DOCKET NO. 473-19-6862
PUC DOCKET NO. 49737

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APPLICATION OF SOUTHWESTERN ELECTRIC POWER COMPANY FOR CERTIFICATE OF CONVENIENCE AND NECESSITY AUTHORIZATION AND RELATED RELIEF FOR THE ACQUISITION OF WIND GENERATION FACILITIES	§ § § § § § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

SOUTHWESTERN ELECTRIC POWER COMPANY'S ERRATA TO TESTIMONY AND EXHIBITS

AUGUST 23, 2019

TABLE OF CONTENTS

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August 23, 2019

Ms. Ana Treviño
Public Utility Commission of Texas
Central Records
1701 N. Congress Ave.
Austin, Texas 78701

RE: PUC Docket No. 49737; SOAH Docket No. 473-19-6862; *Application of Southwestern Electric Power Company for Certificate of Convenience and Necessity Authorization and Related Relief for the Acquisition of Wind Generation Facilities*; **Errata Filing**

Dear Ms. Treviño:

Southwestern Electric Power Company (SWEPCO or the Company) has identified errata to its testimony and exhibits filed in this case. Redlined and clean versions of the corrected testimony are enclosed, along with errata exhibits. Updated workpapers will be filed separately.

The errata arise from an overstatement of the reservation fee and transportation components of the cost of gas used in SWEPCO's modeling of the benefits of the Selected Wind Facilities in this case. This overstatement did not affect the cost of the Wind Facilities themselves but did affect the calculation of the Company's net production costs with and without the Wind Facilities. For the Company's Base Gas with Carbon (P50 Capacity Factor) case, the net present value (NPV) of project benefits is changed from $588 million to $567 million, a reduction of $21 million or 3.5%. For the Company's Base Gas No Carbon (P50 Capacity Factor) case, the NPV of project benefits is changed from $415 million to $396 million, a reduction of $19 million or 4.7%.

SWEPCO's evidence introduced at hearing will incorporate the enclosed corrected information.

Very truly yours,

Kerry McGrath

Enclosures
cc: Parties of Record

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

JOHN O. AARON

FOR

SOUTHWESTERN ELECTRIC POWER COMPANY

JULY 15, 2019

TESTIMONY INDEX

EXHIBITS

EXHIBIT	DESCRIPTION
ERRATA EXHIBIT JOA-1	Summary of Customer Benefits
ERRATA EXHIBIT JOA-2	Impact on Major Rate Classes

I. INTRODUCTION

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

A. My name is John O. Aaron. I am Director, Regulated Pricing and Analysis in the Regulatory Services Department of American Electric Power Service Corporation (AEPSC). AEPSC is a subsidiary of American Electric Power Company, Inc. (AEP) that provides corporate support services to the operating subsidiaries of AEP, including Southwestern Electric Power Company (SWEPCO or Company). My business address is 212 East Sixth Street, Tulsa, Oklahoma 74119-1295.

Q. PLEASE BRIEFLY DESCRIBE YOUR CURRENT JOB RESPONSIBILITIES.

A. As Director, Regulated Pricing and Analysis, I supervise the preparation of cost-of-service studies, rate design, special contracts and pricing, and tariff provisions for the three AEP West operating companies[1] that operate in the Southwest Power Pool (SPP) and the Electric Reliability Council of Texas (ERCOT). I am also responsible for the preparation of, and support for, filings before the regulatory commissions exercising jurisdiction over the electric operating companies of the western portion of AEP, including SWEPCO.

Q. WOULD YOU PLEASE REVIEW YOUR EDUCATIONAL AND BUSINESS BACKGROUND?

A. I received a Bachelor of Science in Accounting from Louisiana State University in Shreveport in May 1980. I am a Certified Public Accountant (CPA) in the State of Oklahoma and a member of the American Institute of CPAs and the Oklahoma Society

[1] The AEP West operating companies include Southwestern Electric Power Company, Public Service Company of Oklahoma, and AEP Texas Inc.

of CPAs. Upon graduation from college, I was employed as an Internal Auditor for a multi-state wholesale appliance and electrical supplier in Shreveport, Louisiana. In May 1984, I accepted employment with SWEPCO as an accountant in the Property Accounting Department. From 1985 through 1995, I held various positions in the Accounting, Internal Auditing, and Rate Departments, including Supervisor of Regulatory Accounting Support and Supervisor of Wholesale Marketing Support. From 1995 through 2010, I held various accounting positions in the Regulatory Accounting Services Department at Central and South West Services, Inc. (CSWS), the service company for the former Central and South West Corporation (CSW) System. With the merger of AEP and CSW, as of January 1, 2001, AEPSC became the successor to CSWS. In August 2010, I transferred to AEPSC's Regulatory Services Department as manager and was promoted in April 2019 to my current position as Director, Regulated Pricing and Analysis.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY BEFORE THIS COMMISSION OR OTHER COMMISSIONS?

A. Yes. Before the Public Utility Commission of Texas (PUC or Commission), I have filed testimony in the following: SWEPCO Docket Nos. 32624, 32672, 32898, 35137, 36949, 37364, 40443, 42089, 42448, 44496, 46449, 47461, and 49042; AEP Texas North Company Docket Nos. 18607, 18970, 21385, and 23477; AEP Texas Central Company Docket No. 22352; and AEP Texas Docket No. 49494. I have also filed testimony before the Arkansas Public Service Commission, the Louisiana Public Service Commission, and the Oklahoma Corporation Commission.

II. PURPOSE OF TESTIMONY

Q. PLEASE DESCRIBE THE PURPOSE OF YOUR TESTIMONY.

A. I quantify the estimated impact on SWEPCO's costs and rates of SWEPCO's and Public Service Company of Oklahoma's (PSO's) proposal to purchase three wind generating facilities in Oklahoma (Selected Wind Facilities). SWEPCO has contracted to purchase 54.5% of the Facilities and PSO will purchase the remaining 45.5%. My rate impact compares SWEPCO's proposed base rate and fuel revenues in Texas to the base rate and fuel revenues with the Selected Wind Facilities' estimated revenue requirement and fuel cost savings. Acquisition of the Selected Wind Facilities is expected to result in savings that will more than offset SWEPCO's fixed cost revenue requirement, resulting in a net decrease in customer costs over the life of the project.

Q. WHAT EXHIBITS ARE YOU SPONSORING?

A. I sponsor the following Errata exhibits attached to my testimony.

ERRATA EXHIBIT JOA-1: Summary of Customer Benefits.

ERRATA EXHIBIT JOA-2: Impact on Major Rate Classes.

III. IMPACT ON TEXAS CUSTOMERS

Q. HOW ARE THE CUSTOMER IMPACTS DETERMINED?

A. The impact of the Selected Wind Facilities on SWEPCO's costs and rates reflects the annual revenue requirement associated with the Facilities, the estimated cost savings due to the addition of the Facilities to SWEPCO's existing generation, and the offset resulting from federal Production Tax Credits (PTCs). These cost elements, when combined with SWEPCO's current revenues, provide sufficient information for estimating the cost and rate impact to the Texas jurisdiction. This is similar to the standard cost-of-service formula that is applied during a rate case proceeding. ERRATA EXHIBIT JOA-1, a summary of the expected net customer benefits, provides SWEPCO's Texas retail allocation of the revenue requirement, the cost savings for the Facilities, and the credit for the PTCs earned. As shown on this Errata exhibit, it is expected that the Facilities' savings and PTCs will more than offset its fixed cost revenue requirement, resulting in a net decrease in customer costs over the life of the project.

Q. HOW WAS THE REVENUE REQUIREMENT DETERMINED?

A. The Selected Wind Facilities' revenue requirement recovers the return and taxes on the Facilities' assets, a return on a Deferred Tax Asset (DTA), depreciation expense, and the associated operations and maintenance (O&M) expenses. The inputs for this calculation come from the economic model, discussed by Company witness Torpey, used in the evaluation of the Facilities. The facilities' operation and maintenance expenses and the depreciation expense based on a thirty-year life for the wind turbines are discussed in the testimony of Company witness DeRuntz. The return reflects a 52% debt ratio and a 48% equity ratio with a 4.395% cost of debt and a 10% return on equity as discussed in the testimony of Company witness Hollis. When the Facilities are reflected in SWEPCO's Texas rates, the then Commission-approved return on equity, other cost of capital rates, and cost of capital ratios will be used in the revenue requirement calculation.

Q. HOW DO THE ADDITION OF THE SELECTED WIND FACILITIES PRODUCE SAVINGS FOR SWEPCO'S TEXAS CUSTOMERS?

A. First, the addition of the Selected Wind Facilities to SWEPCO's generation mix is expected to lower SWEPCO's energy costs. In the first year (Sundance Facility only), there will be an estimated $3.3 million (Texas retail) reduction in net energy costs (fuel costs reduced by off-system sales) associated with the kWh production from the Sundance Facility. In the second year (all Facilities), there will be an estimated ~~$25.8~~$25.7 million (Texas retail) reduction in net energy costs (fuel costs reduced by off-system sales) associated with the kWh production from all facilities. As discussed by company witness Torpey and summarized in his Errata Exhibit JFT-3, two scenarios were reviewed to identify the energy benefit of the Facilities that is reflected in the rate impact analysis. The first scenario, the "Baseline Case," assumed the Selected Wind Facilities for SWEPCO were not added and the second scenario, the "Project Case," assumed the Selected Wind Facilities are approved and implemented. The total generation costs from the Baseline Case are reflected in the pro-forma revenues in my rate impact analysis and the difference between the Baseline Case and the Project Case generation costs are reflected in the proposed rate impact analysis. Consistent with SWEPCO's current fuel cost recovery, 90% of the off-system sales margins are returned to SWEPCO's customers and reflected in the energy cost savings in the rate impact analysis.

Second, the Selected Wind Facilities are expected to defer future capacity requirements for SWEPCO and result in additional savings to SWEPCO's Texas customers beginning in 2030. Because the capacity savings for SWEPCO do not begin until 2030, my calculation of the impact on major classes for the first four years the Facilities are in service does not show this capacity savings value.

Third, the Selected Wind Facilities will be eligible for federal PTCs during the first ten years of commercial operation. The PTCs will flow through to SWEPCO's customers as an additional benefit valued with a tax gross up. Since the PTCs create a direct reduction to income tax expense, the pre-tax revenue level of the PTCs is determined by applying the applicable tax gross up factor.

Q. WHAT HAPPENS IN THE EVENT THE PRODUCTION TAX CREDITS ARE NOT FULLY UTILIZED IN A GIVEN YEAR?

A. Even though customers will receive the benefit of PTCs earned in any given year, in the event the Company cannot fully utilize PTCs in a given year(s), a DTA will be established on SWEPCO's balance sheet. SWEPCO requests Commission approval to include this DTA in its rate base and revenue requirement in a future proceeding. Because SWEPCO's customers are receiving the benefits of the PTCs as earned by SWEPCO, it is reasonable to also include the DTA associated with the PTCs not used by SWEPCO in its base rate revenue requirement. Company witness Multer discusses PTCs and the DTA in his testimony.

Q. HOW ARE THE SELECTED WIND FACILITIES' REVENUE REQUIREMENT AND THE SAVINGS DESCRIBED ABOVE ALLOCATED TO TEXAS CUSTOMERS?

The revenue requirement of the Facilities along with the cost savings and PTCs in this analysis is allocated to the Texas jurisdiction and retail classes using an estimated energy allocator. An energy allocation matches the costs of the Facilities with the benefits generated by the Facilities and the PTCs earned. Actual Texas jurisdictional and class energy allocation factors will be used when the Facilities are recovered in SWEPCO's rates.

Q. WILL SWEPCO CUSTOMERS SEE A NET DECREASE IN THEIR MONTHLY BILLS IN THE FIRST YEAR OF OPERATION OF THE SELECTED WIND FACILITIES WHILE STILL ALLOWING SWEPCO TO RECOVER THE NEEDED REVENUE REQUIREMENT?

A. Yes. The revenue requirement from the addition of these facilities will be more than offset by the energy savings and credits associated with the federal PTC from the operation of the Selected Wind Facilities. There are net customer savings in 2021, which reflects Sundance only, of approximately ~~$428,000~~ $402,000 but rising to approximately ~~$4.1~~$3.9 million in savings for Texas customers in 2022, which is for all three facilities, as shown in ERRATA EXHIBIT JOA-1.

Q. WHAT ARE THE TEXAS CUSTOMER NET BENEFITS OVER THE FIRST FOUR YEARS OF OPERATION?

A. For the first four years of operations, SWEPCO Texas customers would receive a Net Benefit of approximately ~~$17.1~~$16.6 million in savings, as further shown in ERRATA EXHIBIT JOA-1.

Q. WHAT ARE THE TEXAS CUSTOMER NET BENEFITS OVER THE FIRST TEN YEARS OF OPERATION?

A. For the first ten years of operations, SWEPCO Texas customers would receive a Net Benefit of approximately ~~$121.2~~ $119.5 million in savings, as further shown on ERRATA EXHIBIT JOA-1.

Q. ARE THERE EXPECTED SAVINGS FOR TEXAS RESIDENTIAL CUSTOMERS FOR THE FIRST FOUR YEARS OF OPERATION?

A. Yes. The calculations showing savings for the average residential customer (1000 kWh) are set forth in ERRATA EXHIBIT JOA-2. This Errata exhibit also shows results of the allocations for the Texas retail jurisdiction and major rate classes through 2024.

IV. COST RECOVERY

Q. HOW WILL THE SELECTED WIND FACILITIES' REVENUE REQUIREMENTS BE RECOVERED FROM SWEPCO'S TEXAS RETAIL CUSTOMERS?

A. In a future filing, SWEPCO intends to request implementation of a Generation Investment Recovery Rider pursuant to newly-enacted Section 36.213 of PURA[2] to recover the revenue requirements of the Selected Wind Facilities. Under § 36.213, an electric utility operating outside of ERCOT may request a rider to recover investment in a power generation facility and the Commission may approve the rider before the utility places the facility into service. Such a rider shall take effect on the date the power generation facility begins providing service to customers, and amounts recovered through the rider are subject to reconciliation in the utility's next base rate proceeding. The Company intends to request that the Rider recover the share of its investment in the Selected Wind Facilities that is allocable to Texas, which is 309 MW.

[2] PURA § 36.213 was recently enacted by the Texas Legislature and signed into law by the Governor. Acts 2019, 86th Leg., R.S., Ch. ___ (H.B. 1397), Sec. 4, eff. June 14, 2019.

Q. HOW WILL THE PTC BENEFITS OF THE SELECTED WIND FACILITIES BE CREDITED TO CUSTOMERS?

A. PTCs are recorded in FERC Account No. 409.1 and, therefore, would normally be credited to customers through base rates. Until the Company's investment in the Selected Wind Facilities is placed into base rates, the Company intends to credit the PTC benefits of the Selected Wind Facilities to customers through the future rider filing discussed above, as an offset to the Facilities' revenue requirements.

Q. HOW WILL THE FUEL AND ENERGY COST SAVINGS OF THE SELECTED WIND FACILITIES BE FLOWED THROUGH TO CUSTOMERS?

A. Fuel and energy-related costs are reconcilable costs that are included in the Company's fuel factor, so those cost savings attributable to the Selected Wind Facilities will be flowed through to customers through future fuel factor adjustment and fuel reconciliation proceedings.

VI. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The Selected Wind Facilities are expected to result in savings and PTCs that will more than offset the fixed cost revenue requirement, resulting in a net decrease in customer costs and bills. SWEPCO intends to request in a future filing a Generation Investment Recovery Rider to recover the revenue requirements of the Selected Wind Facilities.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

SOUTHWESTERN ELECTRIC POWER COMPANY
Summary of Net Customer Benefits ($)
Texas Retail Jurisdiction

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Facilities' Revenue Requirement (inc DTA CC)	8,436,051	54 403,233	54,580 422	55,691 540	55,643,346	55 695 533	55 660,302
Project Capacity (Benefit) / Cost	-	-	-	-	-	-	-
Project Energy Savings	(3,308,027)	(25,669,980)	(26 657 915)	(27,975 507)	(28,545,721)	(29,131,149)	(29,616,660)
Production Tax Credits	(5 529 968)	(32,655,155)	(33 911,122)	(34,004 029)	(35 167 090)	(35,167 090)	(36 423 057)
Net Customer (Benefit) / Cost	(401,944)	(3,921,902)	(5,988,615)	(6,287,997)	(8,069,464)	(8,602,705)	(10,379,416)

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Facilities' Revenue Requirement (inc DTA CC)	55 517 876	55,329,269	54 920,139	54 231 178	51 815 469	47 610,706	43,646,879
Project Capacity (Benefit) / Cost	-	-	-	-	-	-	-
Project Energy Savings	(43,267,350)	(42,454,290)	(44,025,601)	(45,361,593)	(47,119,032)	(48,553,082)	(50,472,593)
Production Tax Credits	(36,522,846)	(37 679,025)	(37 679 025)	(32 341,569)	-	-	-
Net Customer (Benefit) / Cost	(24,272,320)	(24,804,045)	(26,784,488)	(23,471,983)	4,696,438	(942,376)	(6,825,714)

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Facilities' Revenue Requirement (inc DTA CC)	41 532 419	40,725 605	39 935 881	39,155,424	38,463 254	37,769 416	37 066,681
Project Capacity (Benefit) / Cost	-	-	(347 735)	(20,689 538)	(21,071,370)	406,308	(21 298,923)
Project Energy Savings	(52,773,816)	(53,508,687)	(55,325,317)	(52,973,373)	(54,567,655)	(60,250,906)	(58,869,969)
Production Tax Credits	-	-	-	-	-	-	-
Net Customer (Benefit) / Cost	(11,241,397)	(12,783,081)	(15,737,170)	(34,507,487)	(37,175,771)	(22,075,182)	(43,102,211)

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Facilities' Revenue Requirement (inc DTA CC)	36,501 244	35,706,102	35 003,304	34,279,458	33 647 372	33,024 527	32,529 691
Project Capacity (Benefit) / Cost	(20 844 431)	974 686	374,300	150,472	235 503	(19 038 926)	(17,614,205)
Project Energy Savings	(61,355,441)	(65,517,165)	(68,505,679)	(71,827,813)	(73,751,495)	(74,177,342)	(76,719,107)
Production Tax Credits	-	-	-	-	-	-	-
Net Customer (Benefit) / Cost	(45,698,628)	(28,836,376)	(33,128,075)	(37,397,883)	(39,868,621)	(60,191,741)	(61,803,621)

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Facilities' Revenue Requirement (inc DTA CC)	32,173,213	32,230 994	30,278 406		1 313,204 935
Project Capacity (Benefit) / Cost	1,134 691	842 091	(1,669 751)	$	(118,456,828)
Project Energy Savings	(79,102,498)	(80,008,969)	(70,020,676)		(1,601,414,408)
Production Tax Credits	-	-	-		(357 079 976)
Net Customer (Benefit) / Cost	(45,794,595)	(46,935,883)	(41,412,021)		(763,746,277)

SOUTHWESTERN ELECTRIC POWER COMPANY
Impact on Major Rate Classes
Texas Jurisdiction

Revenue Impact

		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Proforma Revenue	Residential	242,007,350	240,606,718	245,261,787	248,952,398	249,220,421
	Commercial	199,598,128	196,376,509	200,071,195	202,637,786	201,702,183
	Industrial	187,961,301	192,833,510	199,912,798	204,042,752	203,971,608
		629,566,778	629,816,738	645,245,779	655,632,937	654,894,212
Project Net (Benefit) / Cost	Residential	-	(119,060)	(1,161,711)	(1,773,894)	(1,862,574)
	Commercial	-	(119,758)	(1,168,519)	(1,784,289)	(1,873,489)
	Industrial	-	(163,126)	(1,591,673)	(2,430,432)	(2,551,933)
		-	(401,944)	(3,921,902)	(5,988,615)	(6,287,997)
Total Revenue with Project	Residential	242 007,350	240,487,658	244,100,076	247,178,504	247,357,847
	Commercial	199,598,128	196,256,751	198,902,677	200,853,496	199,828,694
	Industrial	187,961,301	192,670,384	198,321,125	201,612,321	201,419,675
		629,566,778	629,414,793	641,323,877	649,644,321	648,606,216

Rate Impact per kWh

Year		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Proforma Rate	Residential	0 111007	0.110008	0.111799	0.113268	0 113115
	Commercial	0 090247	0.089262	0 091028	0 092475	0.092325
	Industrial	0 065257	0 064349	0 065976	0 067310	0.067172
		0 086573	0 085297	0 086940	0.088354	0.088207
Project Net (Benefit) / Cost	Residential	-	(0.000054)	(0 000530)	(0.000807)	(0.000845)
	Commercial	-	(0.000054)	(0 000532)	(0.000814)	(0.000858)
	Industrial	-	(0 000054)	(0.000525)	(0.000802)	(0 000840)
		-	(0.000054)	(0.000528)	(0.000807)	(0.000847)
Total Rate with Project	Residential	0 111007	0.109954	0.111270	0 112461	0 112270
	Commercial	0 090247	0 089208	0 090496	0 091661	0 091467
	Industrial	0 065257	0 064295	0 065451	0 066509	0.066331
		0 086573	0 085242	0 086411	0.087547	0 087360

Residential Monthly Bill @ 1000 kWh Impact

Year	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Proforma Bill	$ 111 01	$ 110 01	$ 111 80	$ 113 27	$ 113 11
Project Impact	$ -	$ (0 05)	$ (0 53)	$ (0.81)	$ (0.85)
Bill with Project	$ 111 01	$ 109 95	$ 111 27	$ 112 46	$ 112.27

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

KARL R. BLETZACKER

FOR

SOUTHWESTERN ELECTRIC POWER COMPANY

JULY 15, 2019

TESTIMONY INDEX

I. INTRODUCTION

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

A. My name is Karl R. Bletzacker. My position is Director, Fundamentals Analysis, American Electric Power Service Corporation (AEPSC). AEPSC supplies engineering, financial, accounting, planning and advisory services to the electric operating companies of American Electric Power Company, Inc. (AEP), including Southwestern Electric Power Company (SWEPCO or the Company). My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE?

A. I received a BSMEng degree from The Ohio State University in 1980 and have nearly forty years of energy industry experience, which includes petroleum engineering and the management of the purchasing, interstate transmission, and distribution of natural gas and power to both regulated and unregulated consumers. Before joining AEP, I implemented risk management strategies using New York Mercantile Exchange (NYMEX) and over-the-counter natural gas futures, swaps, and options since the NYMEX natural gas contract was first offered in June of 1990. I also purchased short- and long-term natural gas supply from major and independent producers and marketing companies and I monetized arbitrage opportunities using NYMEX futures contracts, local and contract storage, pipeline imbalances and local distribution company banks. As Vice-President and Chief Operating Officer of National Gas & Oil Company (a publicly-traded Ohio natural gas utility) and Licking Rural Electric Cooperative (an Ohio electric cooperative), I was responsible for the natural gas pricing and risk management policies that ensured reliable delivery and managed customers' exposure to volatile commodity prices. As the North American Manager of Energy Procurement for Honda of America Mfg., Inc., I implemented hedging strategies utilizing NYMEX natural gas futures contracts and operated a natural gas supply pool for the benefit of Honda and its suppliers in North America. Additionally, I served as Vice-Chairman of the Industrial Energy Users-Ohio, which is an organization of large Ohio energy consumers that spend collectively over $3 billion per year on electricity and natural gas for their plants and facilities and whose members employ over 250,000. I joined AEPSC in 2005 to focus on the creation of long-term North American energy market forecasts primarily to support the integrated resource and strategic planning of its operating companies.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN PROCEEDINGS BEFORE REGULATORY BODIES?

A. Yes. I have presented testimony on behalf of AEP operating companies and others in Texas, Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Virginia, and West Virginia.

II. PURPOSE OF TESTIMONY

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

A. I sponsor the Long-Term North American Energy Market Forecast ("Fundamentals Forecast") utilized by Company witnesses Torpey and Sheilendranath as a basis for certain elements of the analyses they performed, which are described in their testimony. I describe how the Fundamentals Forecast is derived and, in particular, the basis for the natural gas, electric generation energy and capacity, and CO_2 burden forecasts included in the Fundamentals Forecast. Further, I illustrate other natural gas price forecasts as a source of comparison to the Company's Fundamentals Forecast. Finally, based on a break-even Southwest Power Pool (SPP) power price provided by Company witness Torpey for the wind facilities the Company proposes to acquire in this case ("Selected Wind Facilities"), I calculate a break-even cost for natural gas.

III. FUNDAMENTALS FORECAST

Q. WHAT IS AEP'S FUNDAMENTALS FORECAST?

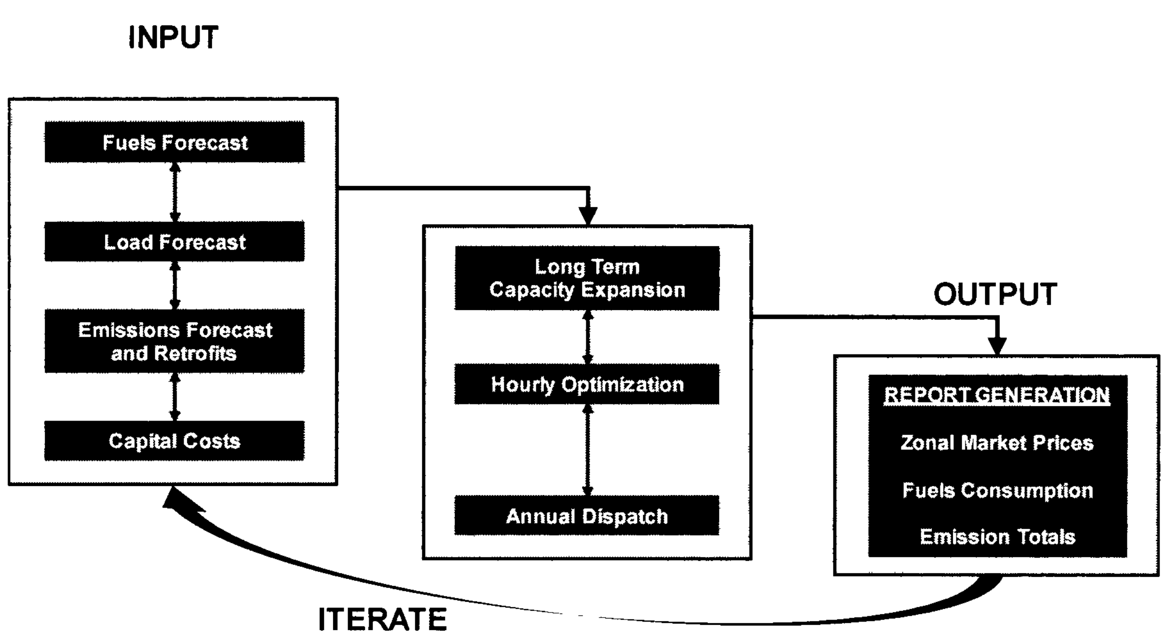
A. The Fundamentals Forecast is a long-term, weather-normalized commodity market forecast. It is not created to meet a specific regulatory need in a particular jurisdiction; rather, it is made available to AEPSC and all AEP operating companies after completion. It is used for purposes such as resource planning, capital improvement analyses, fixed asset impairment accounting, strategic planning and others. These projections cover the electricity market within the Eastern Interconnect (which includes SPP), the Electric Reliability Council of Texas (ERCOT) and the Western Electricity Coordinating Council (WECC). The Fundamentals Forecast includes: 1) hourly, monthly and annual regional power prices (in both nominal and real dollars); 2) prices for various qualities of Central Appalachian (CAPP), Northern Appalachian (NAPP), Illinois Basin (ILB), Powder River Basin (PRB), and Colorado coals; 3) monthly and annual locational natural gas prices, including the benchmark Henry Hub; 4) nuclear fuel prices; 5) SO_2, NOx, and CO_2 burden values; 6) locational implied heat rates; 7) electric generation capacity values; 8) renewable energy subsidies; and 9) inflation factors, among others.

To complement the Base Case Fundamentals Forecast, four associated cases were also created; the Lower Band, Upper Band, Base No Carbon and Lower Band No Carbon cases. The associated cases were designed and generated to define a plausible range of outcomes surrounding the Base Case Fundamentals Forecast. The Lower and Upper Band forecasts consider lower and higher North American demand for electric generation and fuels and, consequently, lower and higher fuels prices, respectively. Nominally, fossil fuel prices vary one standard deviation above and below Base Case values. The Base No Carbon and Lower Band No Carbon cases assume there will be no regulations limiting CO_2 emissions throughout the entire forecast period.

Q. WHAT TOOLS DID YOU USE TO DEVELOP THE FUNDAMENTALS FORECAST?

A. The primary tool used for the development of the North American long-term energy market pricing forecasts is the Aurora energy market simulation model. It iteratively generates zonal, but not company-specific, long-term capacity expansion plans, annual energy dispatch, fuel burns and emission totals from inputs including fuel, load, emissions and capital costs, among others. Ultimately, Aurora creates a weather-normalized, long-term forecast of the market in which a utility would be operating. AEPSC also has ample energy market research information available for its reference, which includes third-party consultants, industry groups, governmental agencies, trade press, investment community, AEP-internal expertise, various stakeholders, and others. Although no exact forecast inputs from these sources of energy market research information are utilized, an in-depth assessment of this research information can yield, among other things, an indication of the supply, demand, and price relationship (price elasticity) over a period of time. This price elasticity, when applied to the Aurora-derived natural gas fuel consumption, yields a corresponding change in natural gas prices – which is recycled through the Aurora model iteratively until the change in natural gas fuel consumption for the electric generation sector is *de minimis*. Figure 1 illustrates that any changes in input assumptions must be iteratively processed through Aurora to determine a new merit order of dispatch. It is this new merit order of dispatch that takes into account the effect of operating conditions across North America and, in turn, ultimately determines zonal energy market prices.

Figure 1



Q. WHY IS IT IMPORTANT TO RECOGNIZE THAT THE FUNDAMENTALS FORECAST IS WEATHER-NORMALIZED?

A. The Fundamentals Forecast is a long-term, weather-normalized energy market forecast because there is the credible modeling expectation that each forecast-year experiences 30-year average heating and cooling degree days. In fact, actual weather can deviate dramatically. The combination of both heating degree day departure from normal and above- or below-normal natural gas storage inventory levels are primary factors affecting any deviation from weather-normalized values. Warmer-than-normal winters result in reduced natural gas demand and materially depressed natural gas prices. Understandably, the Polar Vortex winter of 2013-2014 had the opposite effects. When comparing actual results to a weather-normalized forecast, it is imperative to account for these impacts.

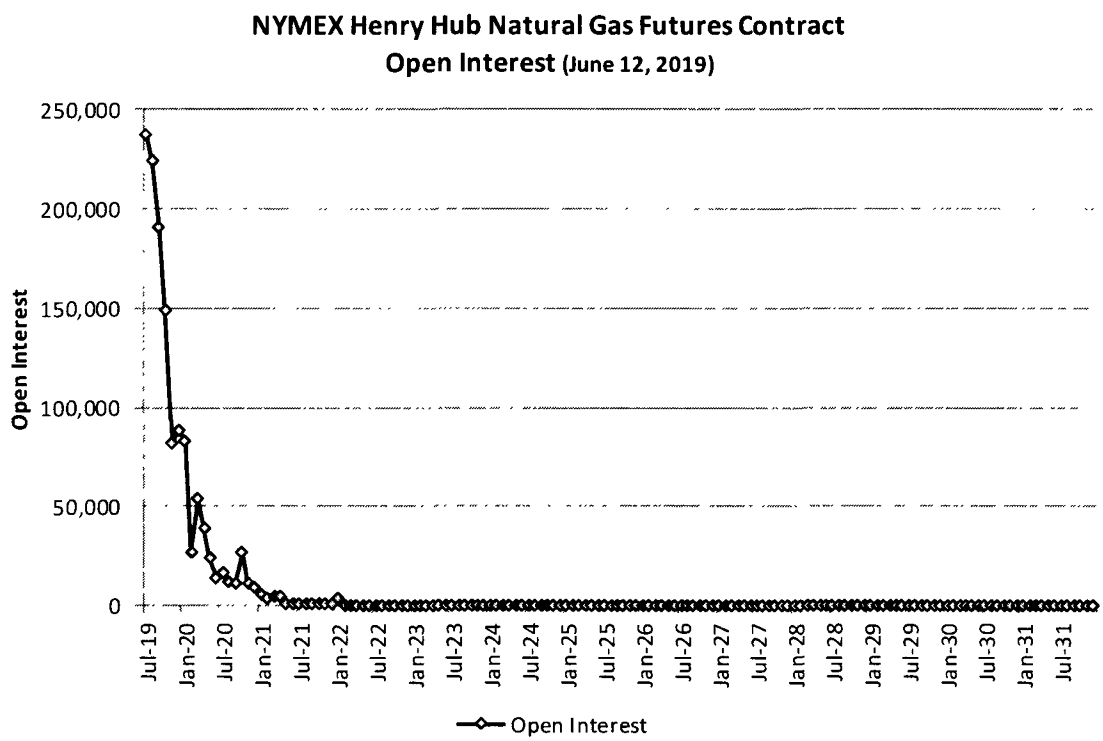
Q. WOULD YOU EXPAND ON OTHER DETAILS ABOUT THE AURORA ENERGY MARKET SIMULATION MODEL?

A. Yes. The Aurora energy market simulation model is widely used by utilities for integrated resource and transmission planning, power cost analysis and detailed generator evaluation. The database includes approximately 25,000 electric generating facilities in the contiguous United States, Canada, and Baja Mexico. These generating facilities include wind, solar, biomass, nuclear, coal, natural gas, and oil. A licensed online data provider, ABB Velocity Suite, provides up-to-date information on markets, entities and transactions along with the operating characteristics of each generating facility, which are subsequently exported to the Aurora energy market simulation model.

Q. WOULD IT BE REASONABLE TO RELY UPON NYMEX FUTURES CONTRACT PRICING IN LIEU OF A FUNDAMENTALS FORECAST FOR LONG-TERM CORPORATE PLANNING PURPOSES?

A. No. NYMEX energy-complex futures contract prices are not a reliable forecast of future, weather-normalized, long-term energy market prices. The total number of futures contracts held by market participants (*i.e.*, Open Interest) is extremely low, or zero, for NYMEX natural gas futures beyond the near term (less than two years) as illustrated in Figure 2. Furthermore, price propositions shown for this period of little or no open interest may not reflect actual NYMEX transactions, and should any attempt be made to purchase natural gas futures contracts in this period, the increased demand would likely run up prices. In addition to the illiquidity of the NYMEX natural gas futures contract beyond the near term, NYMEX natural gas futures contracts <u>are not available at all</u> beyond the next twelve years. The Company's model-driven natural gas price forecasts extend more than thirty years.

Figure 2



Q. WHY ARE NATURAL GAS PRICES IMPORTANT IN A FUNDAMENTALS ANALYSIS?

A. Natural gas prices are important because fuel prices are a key component in determining the supply stack, or merit order, for the dispatch of generating units. Generating units with the lowest variable operating cost are the first to dispatch and plants with incrementally higher variable operating cost are called upon sequentially as electricity demand increases. Although the latest vintage of natural gas electric generators is more efficient, volatile gas prices can quickly advantage or disadvantage them relative to other generation options. While natural gas prices are most often presented at the benchmark Henry Hub located in Erath, Louisiana, the Fundamentals

Forecast recognizes and projects natural gas prices at locations all across the contiguous United States.

Q. WHY IS IT IMPORTANT TO RECOGNIZE THE LOCATIONAL VALUE OF NATURAL GAS?

A. The locational value of natural gas (expressed either as a specific gas price or a price differential to the Henry Hub) can and does vary widely across North America. Generally, natural gas prices are lower near production areas and reduced further in areas with constrained exit pipeline capacity. For example, natural gas values at the west Texas Waha Hub (heavily influenced by prolific, and export-constrained, Permian Basin shale production) are not directly comparable to natural gas values within the areas of SPP in which AEP generation (owned by Public Services Company of Oklahoma and SWEPCO) operates.

Q. WHAT IS THE IMPACT OF A POTENTIAL CO_2 BURDEN ON THE FUNDAMENTALS FORECAST?

A. A CO_2 emission burden would adversely affect the cost of electricity generated by fossil fuels - along with emission rates and implementation timing. CO_2 regulations would also affect fuel markets, *e.g.*, an increase in natural gas consumption will result in increased natural gas prices. The direct effect of a \$10 per metric ton allowance price for a coal plant is an approximate \$10 per MWh increase in plant operating costs. And likewise, the impact of a \$10 per metric ton allowance price for a natural gas-fired combined cycle plant is an approximate \$4 per MWh increase in plant operating costs. Relative to fossil fuels, wind-generated power becomes more valuable because it has no CO_2 emission burden.

Q. WHAT ARE THE SALIENT FEATURES OF YOUR MOST RECENT FUNDAMENTALS FORECAST?

A. Natural Gas. Figure 3 illustrates the most recent natural gas price forecast for the Base, High Band, Low Band, Base No Carbon and Low Band No Carbon cases at the benchmark Henry Hub. The Fundamentals Forecast recognizes the balance between long-term increase in demand (including the expanding role of natural gas for electric generation and the prospect of liquefied natural gas exports) and the likelihood of cost-effective advances in shale-directed drilling and completion techniques. Abundant, relatively low-cost natural gas reserves and productive capacity will continue to grow domestically and globally as shale gas extraction technology becomes more widespread. Over the long term, natural gas pipeline capacity is expected to keep pace with the evolving locations of supply and consumption as the extensive domestic natural gas transportation infrastructure is sufficiently robust to overcome constraints through existing capacity expansions, flow reversals, and new construction.

Figure 3

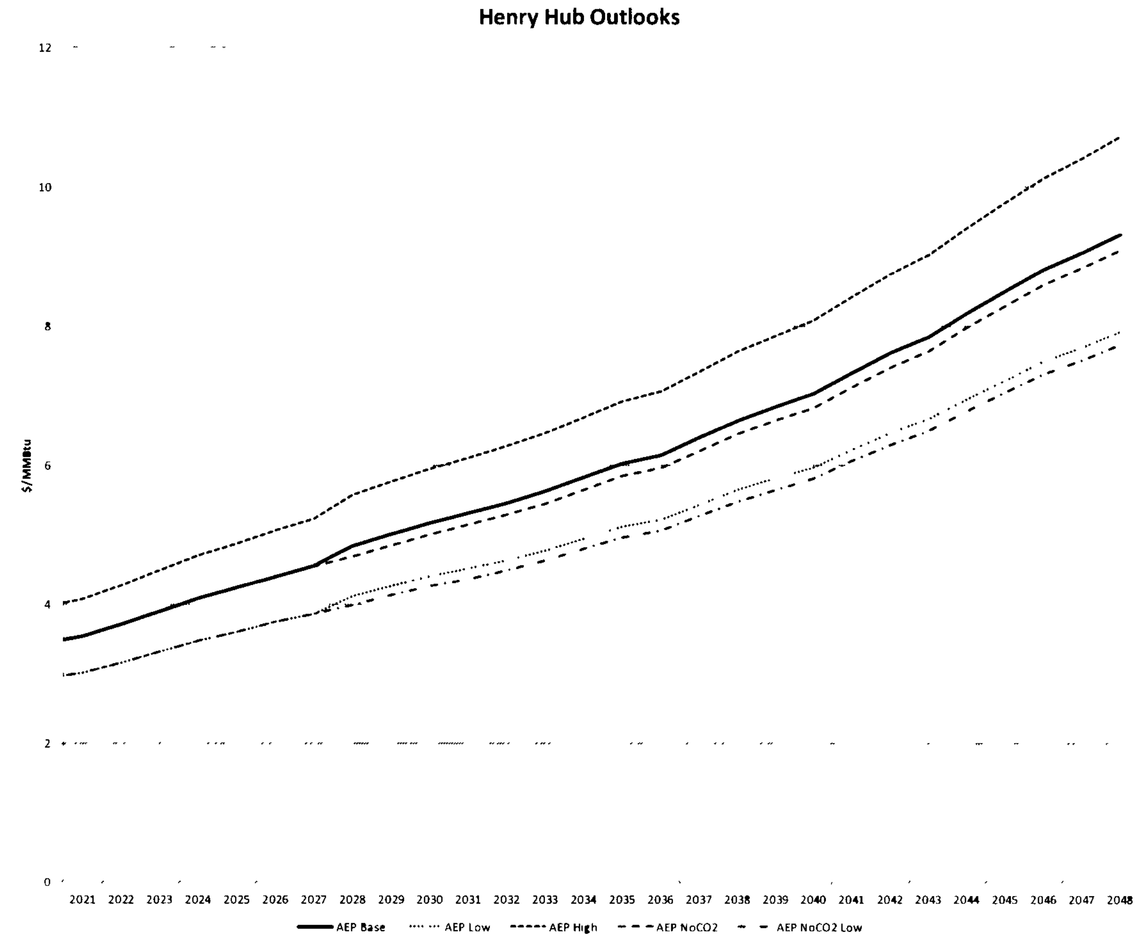
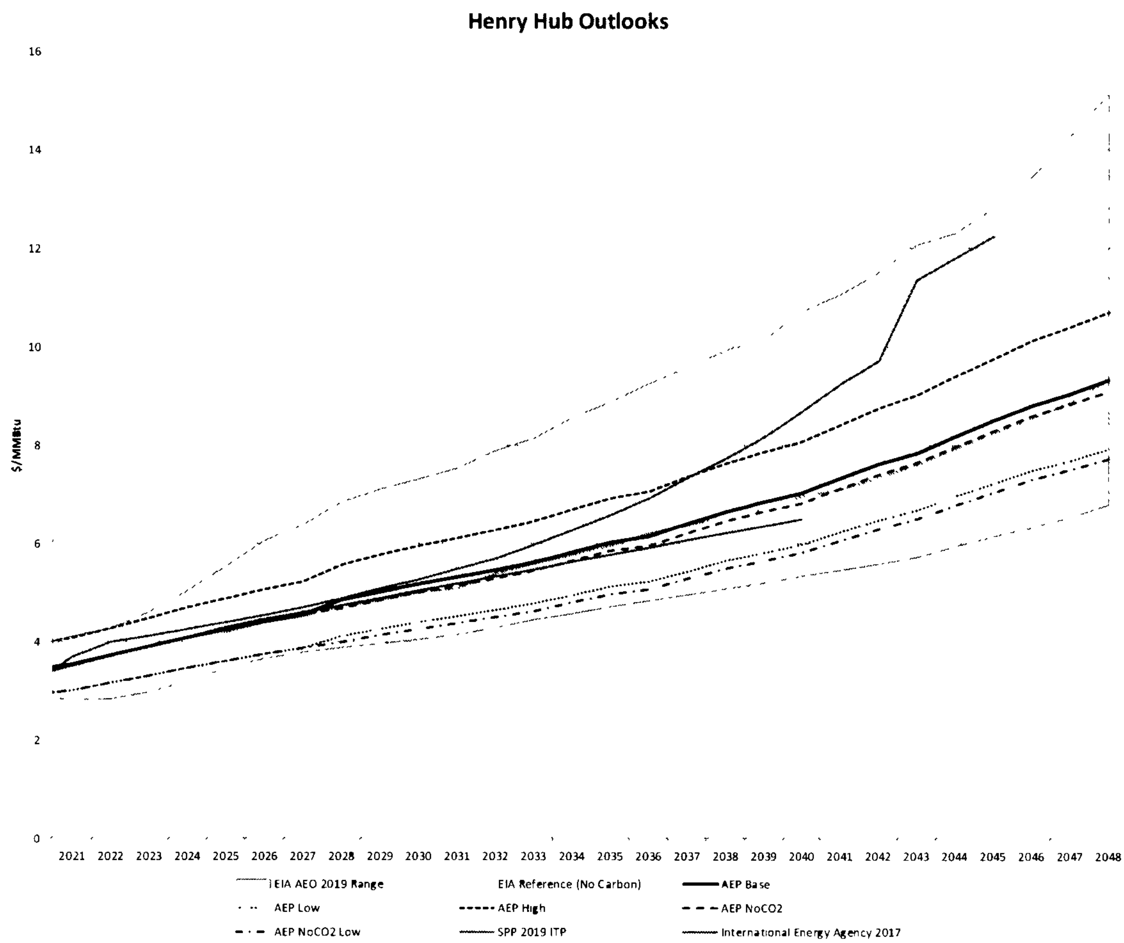


Figure 4 compares the Fundamentals Forecast Henry Hub natural gas price cases with other contemporaneous forecasts including the Energy Information Administration's (EIA's) 2019 Annual Energy Outlook, the International Energy Agency's (IEA's) 2017 Current Policies Forecast and SPP's 2019 Integrated Transmission 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?

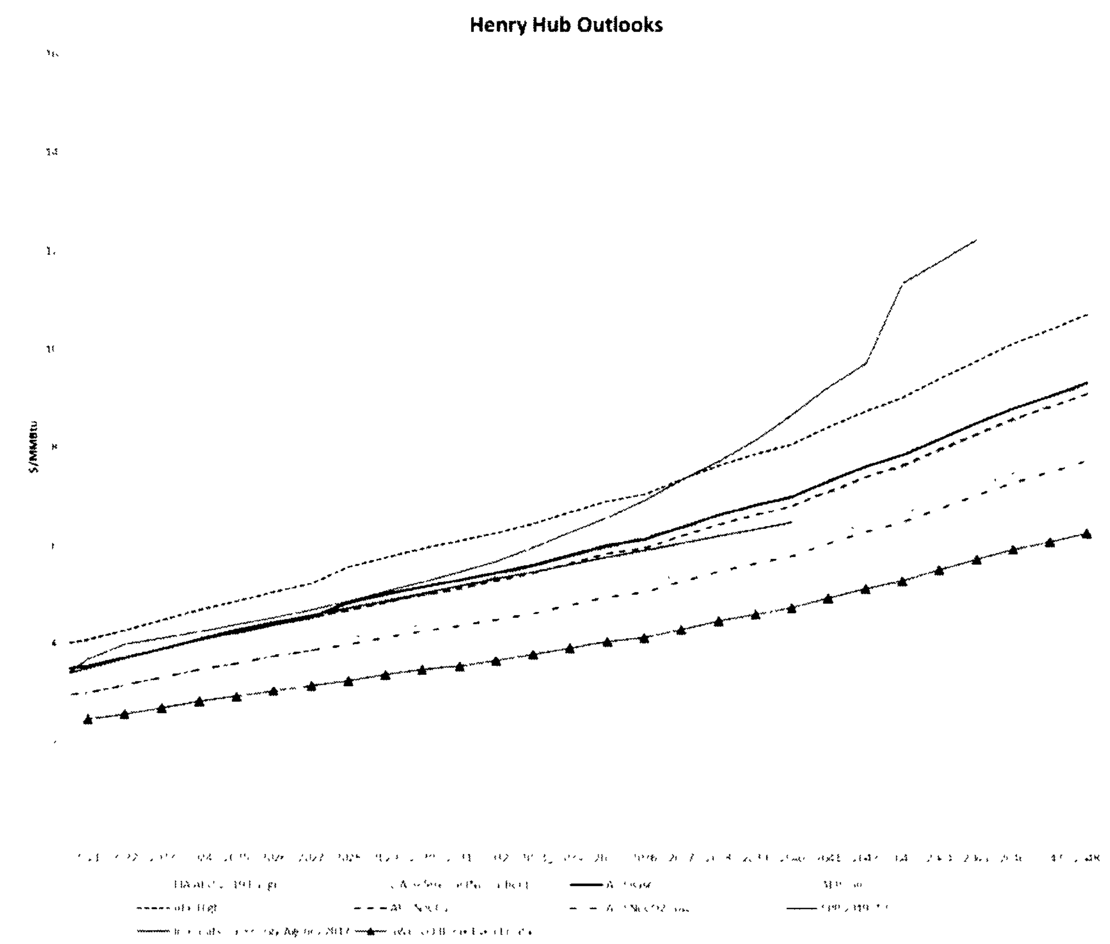
A. No, not necessarily. Natural gas prices can deviate from forecasted values for extended periods due to a variety of reasons, including abnormal weather and force majeure situations such as hurricanes Katrina and Rita. As addressed earlier, actual heating- and cooling-season weather can deviate dramatically 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.

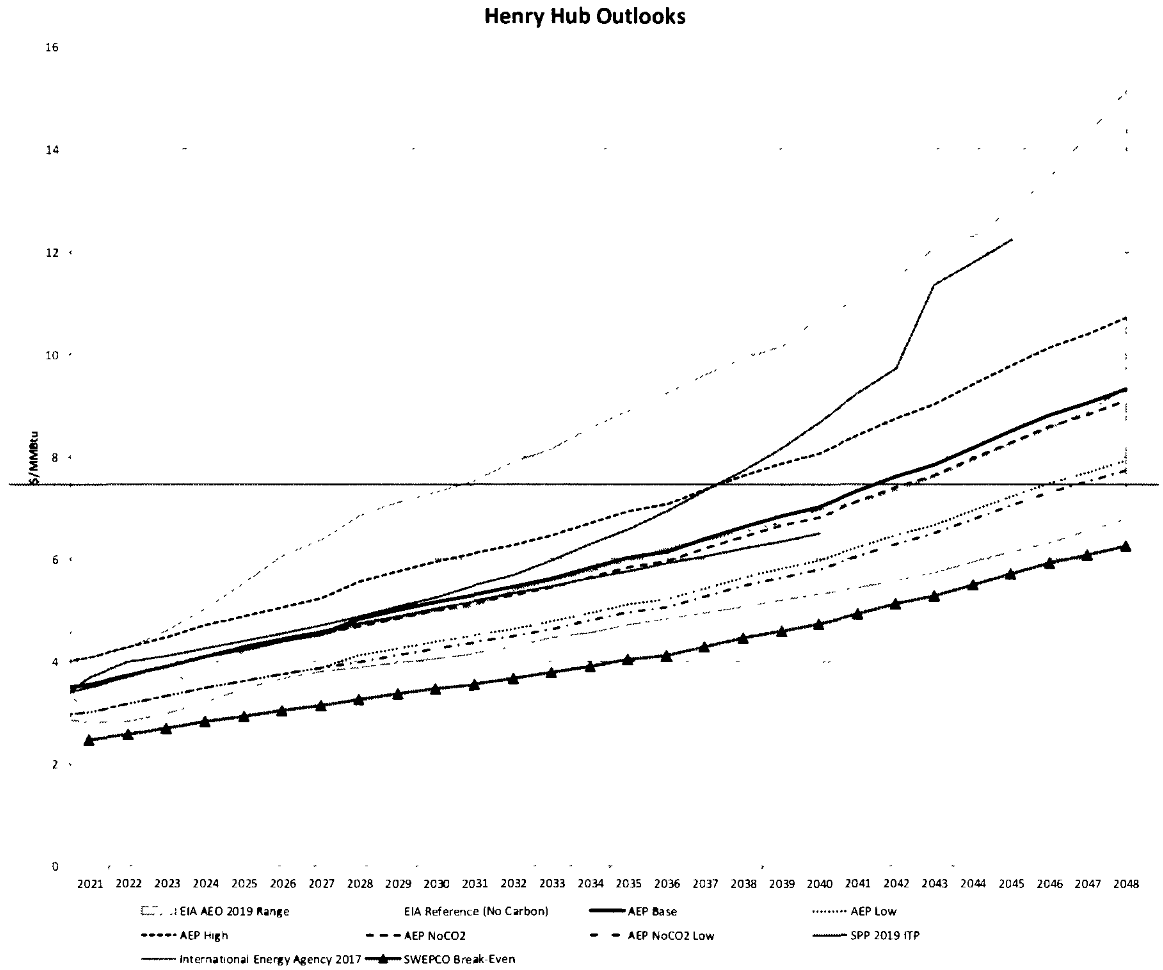
IV. SELECTED WIND FACILITIES BREAK-EVEN NATURAL GAS PRICE EVALUATION

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

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 ~~$588~~$567 million (total Company) on a net present value (NPV) basis, or more than ~~$2.1~~ $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**
~~Year~~	~~31 Year NPV~~	~~Total 31 Year Nominal~~

~~Production Cost Savings Excluding Congestion/Losses~~	~~$1,680~~	~~$5,185~~
~~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~~	**~~$588~~**	**~~$2,120~~**

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)

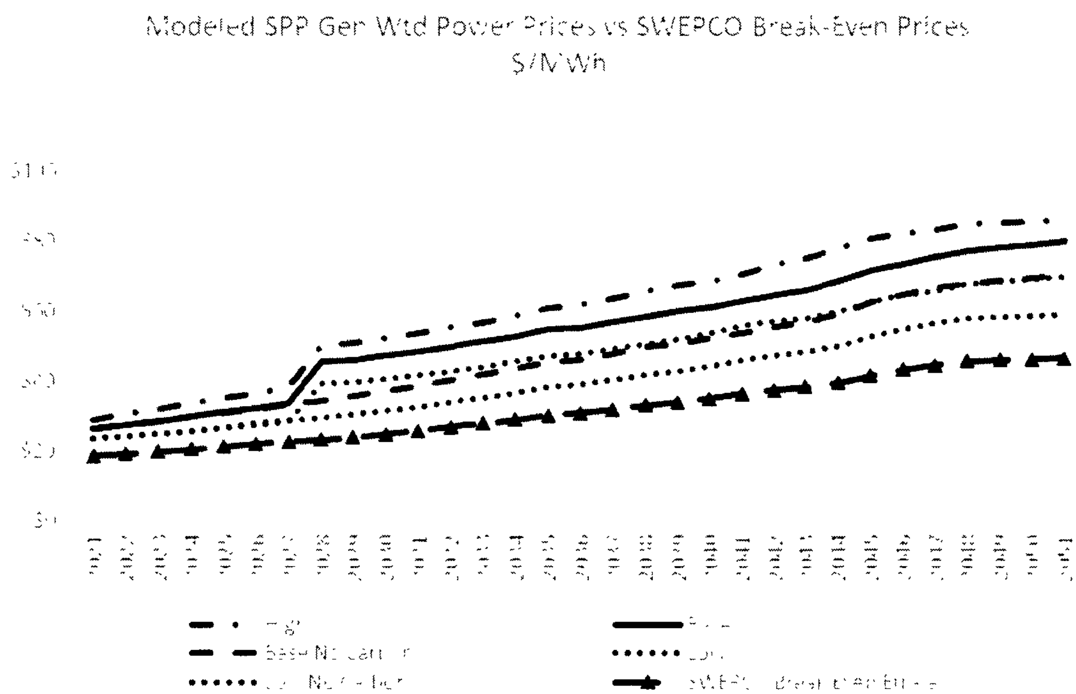
	~~31 Year NPV~~	~~PTC Period – First 11 years Nominal Total~~	~~Full 31 year Nominal Total~~
~~High Gas with CO_2~~	~~$741~~	~~$526~~	~~$2,595~~
~~Base Gas With CO_2~~	~~$588~~	~~$424~~	~~$2,120~~
~~Base Gas Without CO_2~~	~~$415~~	~~$323~~	~~$1,540~~
~~Low Gas With CO_2~~	~~$414~~	~~$298~~	~~$1,612~~
~~Low Gas Without CO_2~~	~~$253~~	~~$214~~	~~$1,055~~

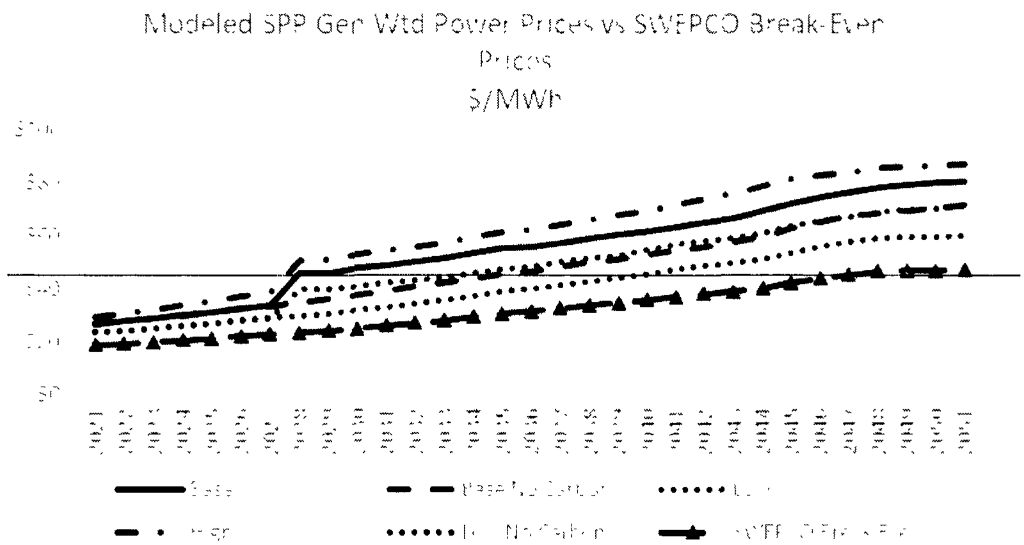
~~(Amounts in Millions, P50 capacity factor)~~

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.

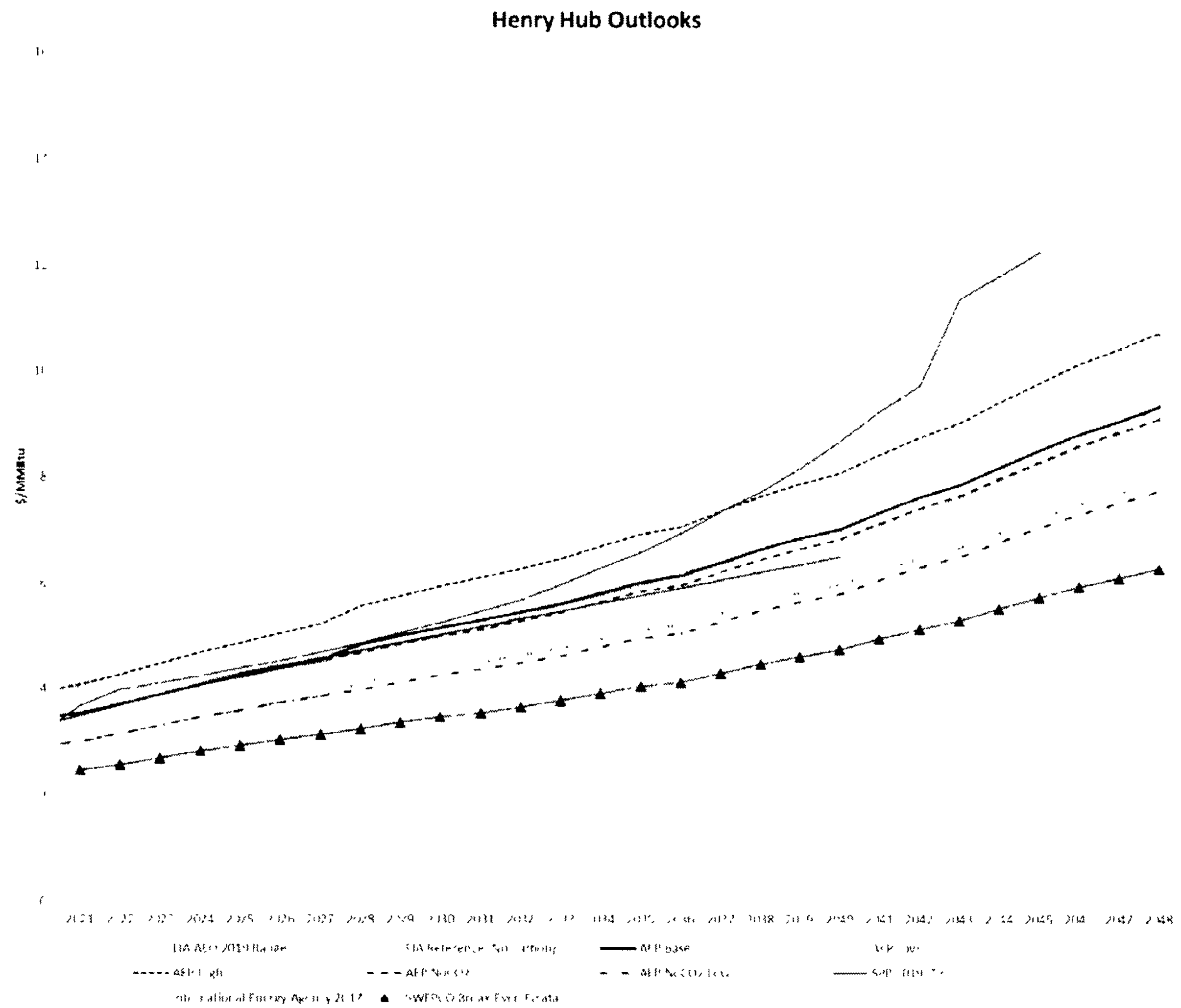
Q. DID THE COMPANY ANALYZE THE POWER AND NATURAL GAS PRICES AT WHICH THE SELECTED WIND FACILITIES WOULD "BREAK EVEN"?

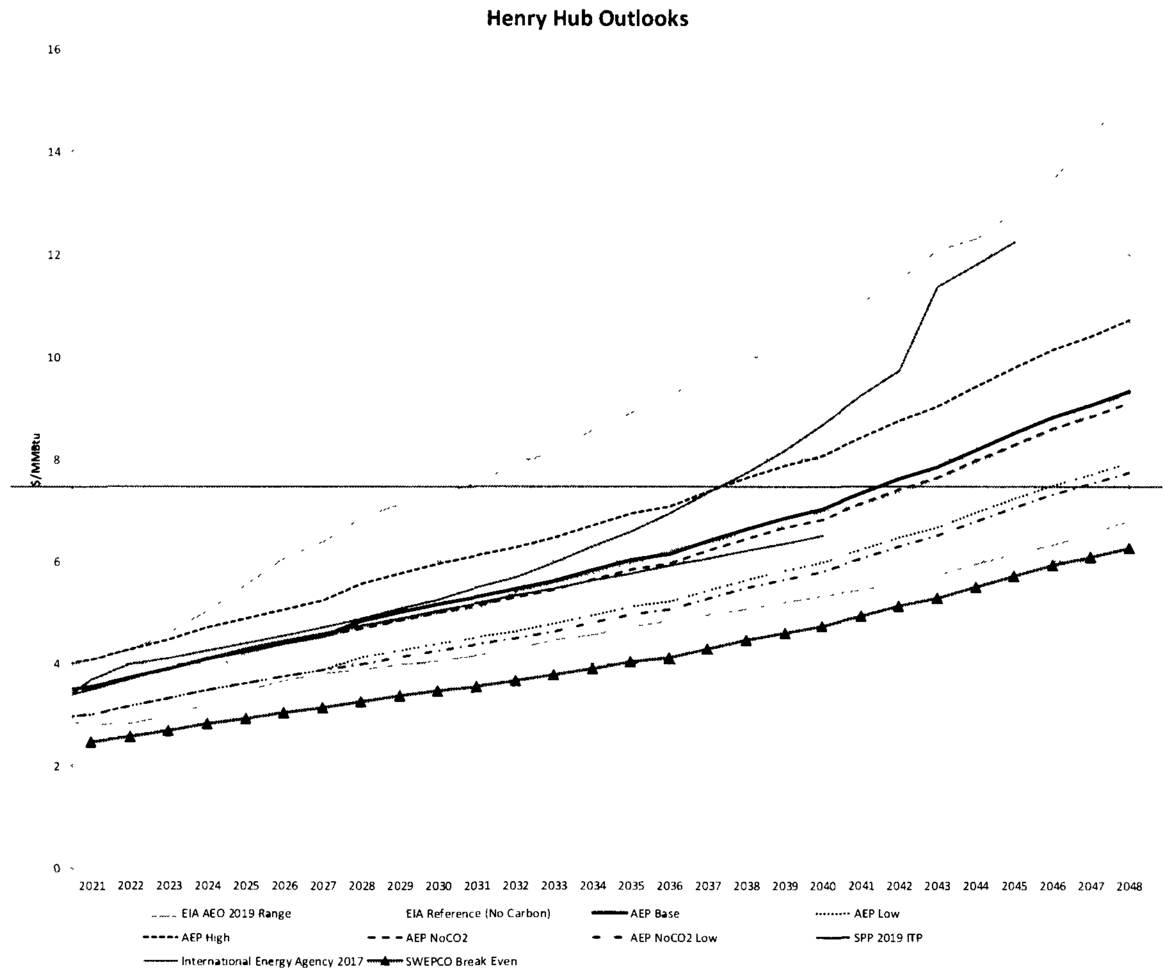
A. Yes. The "break-even," which is the equivalent power price analysis conducted by Company witness Torpey, shows that the Selected Wind Facilities would provide $0 net customer benefits at the Facilities' expected output even if the low gas no carbon fundamentals energy price was reduced by 21%, as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



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 ~~$588~~$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 ~~$1,470~~$1,386 million (NPV ~~$350~~ $330 million) and ~~$964~~$883 million (NPV ~~$199~~$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

[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.

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 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.

<u>VIII. REGULATORY APPROVALS SOUGHT</u>

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?

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[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).

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 ~~$2.12~~$2.03 billion, or ~~$588~~$567 million on an NPV basis. This low-cost energy and the associated customer benefits justify the addition of these resources to SWEPCO's 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]

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[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

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[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~~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:

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

Criterion 2: Project Cost + Congestion (including losses)

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

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

Criterion 5: Project Cost + 75% Congestion + 25% Gen Tie

Table 3~~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~~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~~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~~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~~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~~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~~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~~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 *relative* 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 *level* 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.

[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.