BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

APPLICATION OF SOUTHWESTERN ELECTRIC POWER COMPANY FOR CERTIFICATION AND APPROVAL OF THE ACQUISITION OF CERTAIN RENEWABLE RESOURCES AND NATURAL GAS CAPACITY CONTRACTS IN ACCORDANCE WITH THE MBM ORDER, THE 1983 AND 1994 GENERAL ORDERS	:	DOCKET NO. U-

DIRECT TESTIMONY OF

JAMES F. MARTIN

FOR

SOUTHWESTERN ELECTRIC POWER COMPANY

MAY 2022

TESTIMONY INDEX

EXHIBITS

EXHIBIT	DESCRIPTION
HIGHLY SENSITIVE PROTECTED MATERIALS EXHIBIT JFM-1	CONFIRMATION ANALYSIS RESOURCE OPTIONS

GLOSSARY OF ACRONYMS

AEP	American Electric Power Company, Inc.
AEPSC	American Electric Power Service Corporation
ARO	Asset Retirement Obligation
CC	Combined Cycle
CT	Combustion Turbine
CPA	Capacity Purchase Agreement
CRA	Charles River Associates
DTA	Deferred Tax Asset
EFORd	Equivalent Forced Outage Rate Demand
ELG	Effluent Limitation Guidelines
HS	Highly Sensitive
ICAP	Installed Capacity
ITC	Investment Tax Credit
IRP	Integrated Resource Plan
LOLE	Loss of Load Expectation
LRE	Load Responsible Entity
MW	Megawatt
NCR	No Carbon Regulation
NPV	Net Present Value
O&M	Operation and Maintenance
PRM	Planning Reserve Margin
PTC	Production Tax Credit
REC	Renewable Energy Certificate
SAWG	Supply Adequacy Working Group
SPP	Southwest Power Pool
SWEPCO	Southwestern Electric Power Company

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION IN THE COMPANY, AND BUSINESS ADDRESS.

A. My name is James F. Martin, and I am employed as Director - Resource Planning Strategy for American Electric Power Service Corporation (AEPSC). AEPSC supplies engineering, financing, accounting, planning, and advisory services to the eleven 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. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I graduated from The Ohio State University in 1990, receiving a Bachelor of Science in Business Administration (Accounting Major), and again in 2001 receiving a Master's in Business Administration. Between 1990 and 2000, I held various accounting-related positions in private companies and public accounting firms. In 2000, I joined AEPSC as a Senior Accountant in the Corporate Development department. In 2001, I was promoted to Manager of Financial Analysis. In 2003, I became Manager of Strategic Analysis in Corporate Planning and Budgeting. In 2007, I was promoted to Director-Corporate Budgeting and Capital Investments. In August 2010, I became Manager-Regulated Pricing and Analysis in AEP's Regulatory Services department, with responsibility for preparing retail and FERC jurisdictional and class cost of service studies. In 2016, I was promoted to Regulatory Case Manager, with responsibilities including FERC generation and transmission cost of service studies, along with support for special projects including wind resource additions. In February 2021, I was promoted to my current position in AEP's Resource Planning group.

Q. WHAT ARE YOUR CURRENT RESPONSIBILITIES?

A. My responsibilities primarily include preparing and reviewing various resource planning analyses, including integrated resource plans (IRPs) for regulated operating companies in the AEP system. These studies include using outputs from resource optimization modeling software including Aurora and PLEXOS®[1] and spreadsheet models to evaluate resource plan costs and benefits at both operating company and individual jurisdictional levels. Criteria in these evaluations include maintaining compliance with state energy mandates, state and federal emissions regulations, and generating capacity obligations for AEP companies located in both the PJM and the Southwest Power Pool (SPP) Regional Transmission Organizations, among other factors. Other responsibilities include levelized cost of energy analyses, evaluation and rankings of bids submitted into competitive solicitations for capacity and energy resources, and evaluations of costs and benefits of individual generating resources in Certificate of Public Convenience and Need and similar filings. In addition, I prepare

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[1] The Aurora model is widely used by utilities for integrated resource and transmission planning, power cost analysis, and detailed generator evaluation. Aurora's database includes a representation of electric generating facilities throughout North America, projections for electric demand, and representation of zonal transmission limits, among other inputs. The inputs can be customized to evaluate specific market regions and utility portfolios in detail across a wide range of uncertainty variables.

PLEXOS® is an energy market simulation model used under license from Energy Exemplar. The model analyzes zonal and nodal energy models ranging from long-term investment planning to medium-term operational planning and down to short-term, hourly, and intra-hourly market simulations. The Company uses the model to formulate long-term resource expansion plans and other types of analyses based on least-cost planning principles, generation dispatch studies, and risk assessments.

custom financial modeling for special projects such as the economic analysis used in the recent North Central wind resource proposal by the Company and Public Service Company of Oklahoma.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. Yes. I have testified in Virginia and West Virginia on behalf of AEP affiliates.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony discusses the Company's need for capacity and various economic analyses and resource planning activities performed during 2021 and 2022. These activities culminated in the execution of purchase and sale agreements for two wind facilities and a solar facility (collectively, the Selected Facilities), and three capacity purchase agreements (CPAs). The specific subjects I will describe will include:

1. The Q1 2021 Analysis, prepared in January 2021, established that the Company has a capacity deficit beginning in 2023 and extending out through 2028. That analysis was a resource planning modeling exercise that identified the types of resources and amounts of capacity that would fill the need at the least long-term cost. This analysis led to the issuance of the three RFPs for new resources in June 2021. The preferred types of resources selected in that analysis were subsequently confirmed in the IRP filed with the Arkansas Public Service Commission in December 2021.
2. The Company's current view of its capacity need and how it plans to meet that need. This will include a discussion of how the resources identified through the three RFPs contribute to meeting SPP capacity requirements. I will also discuss potential changes in its capacity market rules that are being considered by SPP, which could increase the need for new capacity for all Load Responsible Entities (LREs) in SPP, including SWEPCO.
3. The Economic Analysis performed for the proposals received pursuant to the 2021 Wind and Solar RFPs.

4. The Confirmation Analysis that the Company directed Charles River Associates (CRA) to perform near the conclusion of the negotiations with the developers of the wind and solar resources. This analysis was used to confirm that the wind and solar assets subject to this application are expected to be less costly than other options to meet the Company's capacity need.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes, I am supporting the following exhibit:

- HIGHLY SENSITIVE PROTECTED MATERIAL (HSPM) EXHIBIT JFM-1
  Confirmation Analysis Resource Assumptions

Q. PLEASE SUMMARIZE YOUR TESTIMONY AND CONCLUSIONS.

A. The Confirmation Analysis supports adding the Selected Facilities rather than other alternatives to satisfy the capacity need. This is the case despite the fact that they cost more than what had been predicted for wind and solar resource costs in the 2021 IRP, under both carbon tax and no-carbon tax fundamental scenarios. Even if all of the Selected Facilities are added, the Company will still need more capacity. Three separate robust modeling efforts, including an IRP, prepared both internally and externally by CRA during 2021 and 2022 support these resource additions and more, prior to expirations of PTCs for wind and a reduction in the ITC for solar. Finally, resource adequacy planning activity is underway at SPP that could increase utility capacity requirements across the region, at the same time SPP is projecting that fossil plant retirements will rapidly reduce the region's supply of reserve capacity.

III. Q1 2021 ANALYSIS

Q. WHAT WAS THE Q1 2021 ANALYSIS?

A. The Q1 2021 Analysis was an internal resource planning exercise performed in the first quarter of 2021 to evaluate the Company's capacity needs at that time. The analysis was prepared using the PLEXOS® resource planning model to prepare a long-term forecast of the Company's capacity position and optimal resource plan using the information available at the time.

Q. WHAT NEAR-TERM CAPACITY NEEDS WERE IDENTIFIED IN THE Q1 2021 ANALYSIS?

A. Please see Table 1 for the Company's near-term capacity needs as identified in the Q1 2021 Analysis. In this testimony, near-term refers to the 2023-2028 period. The Company has additional longer-term capacity needs beyond 2028, which the wind and solar resources proposed in this application will help fill, but the needs through 2028 are the focus of my testimony. Columns 1 and 2 show the estimates of SPP load plus 12% reserve responsibility and the SPP accredited capacity value of the Company's existing resources at the time of the analysis. Accredited capacity is the amount of capacity SPP is expected to credit towards a LRE's capacity obligation, after any downward adjustments SPP makes to nameplate capacity. The "going-in" capacity position, prior to the addition of new resources, is presented in Column 3 and shows a 260 MW capacity need starting in 2023 primarily attributed to recent retirements of aging gas-fired units and the planned retirements of Dolet Hills, Lieberman 3, and Pirkey between 2021 and 2023.

Looking beyond 2023, the combination of the retirements of Lieberman Unit 4 in 2024 and Arsenal Hill Unit 5 in 2025, in addition to the cessation of coal-fired generation at Welsh Units 1 and 3 in 2028 resulted in the total going-in need increasing to 1,628 MW in 2028.

Table 1: Q1 2021 Analysis Capacity Position

Column	1	2	3	4	5	6	7	8	9
2021 Q1 2021 Analysis Capacity Requirement and Going-In Capacity Position (MW)				**Cumulative Utility Scale Additions by Year (SPP Accredited MW)**					
Year	Load Responsibility + 12% Reserve	Existing Resources Firm Capacity Without New Additions	"Going-In' Surplus / (Shortfall)	New Solar	New Wind	Gas Combined Cycle	Short-Term Capacity Purchases	Net Surplus / (Shortfall) Capacity (MW)	Reserve Margin With New Additions
2023 *	4,852	4,592	(260)	180	0	0	50	(30)	11.6%
2024 *	4,857	4,579	(278)	180	210	0	50	162	16.0%
2025 *	4,872	4,471	(401)	165	450	0	50	264	18.4%
2026	4,875	4,363	(512)	135	450	0	50	123	15.1%
2027	4,937	4,363	(574)	135	450	0	50	61	13.7%
2028	4,938	3,310	(1,628)	135	450	1,063	0	20	12.7%

* Wind and solar added December 31 of prior year to take advantage of tax incentives

Q. WHAT TYPES OF RESOURCES WERE SELECTED AS THE LEAST-COST SOLUTION TO MEET THE COMPANY'S MOST IMMEDIATE (2023-2025) CAPACITY NEEDS?

A. The model optimally selected a combination of solar, wind, and short-term capacity contracts to meet these needs. The SPP-accredited capacity value of these new resources is shown in Columns 4 through 7 of Table 1. The nameplate MW associated with the 2023-2025 resource additions were: (1) 300 MW of solar in 2023; (2) 3,000 MW of wind to be added between 2024 and 2025; and (3) 50 MW of annual short-term capacity contracts.

Q. WHAT DECISIONS WERE MADE BASED ON THE RESULTS OF THE Q1 2021 ANALYSIS?

A. The Q1 2021 Analysis resulted in the issuance of three RFPs (wind, solar, and short-term accredited capacity) in June 2021 that Company witness Amy E. Jeffries discusses in detail in her direct testimony.

IV. 2021 ARKANSAS INTEGRATED RESOURCE PLAN (2021 IRP)

Q. HAS THE COMPANY ISSUED AN IRP SINCE THE Q1 2021 ANALYSIS WAS COMPLETED?

A. Yes. The Company filed an Integrated Resource Plan (2021 IRP) with the Arkansas Public Service Commission on December 15, 2021.[2] The Company partnered with CRA to prepare the 2021 IRP. Company witness Patrick N. Augustine of CRA supports the 2021 IRP in his testimony. The 2021 IRP confirmed that the Company has the large capacity need identified in the Q1 2021 Analysis. In addition, in the 2021 IRP Preferred Plan (Preferred Plan), the modeling resulted in the selection of a similar set of optimal new resource types as those selected in the Q1 2021 analysis. The 2021 IRP and its modeling served as a confirmation that the quantities and types of resources that were being solicited in the 2021 RFPs were appropriate.

[2] *See* APSC Docket 07-011-U, Doc. 44-2, http://www.apscservices.info/pdff/07/07-011-U_44_2.pdf.

Q. WHAT WERE THE PROJECTED CAPACITY NEEDS AND THE OPTIMAL SET OF RESOURCE ADDITIONS IN THE 2021 IRP?

A. The 2021 IRP capacity position and the Preferred Plan 2023-2028 resource selections are presented in Table 2. The Preferred Plan is considered to be the optimal mix of future resource additions. Table 2 demonstrates that at the time the 2021 IRP was published the going-in capacity deficit in 2023 was expected to be 271 MW. The deficit was projected to increase and reach 1,611 MW in 2028 when Welsh Units 1 and 3 will cease generating electricity with coal and need to be replaced or repowered. This result is similar to the deficit identified in the Q1 2021 Analysis in Table 1.

TABLE 2 – 2021 IRP CAPACITY POSITION AND RESOURCE ADDITIONS

Column	1	2	3	4	5	6	7	8
2021 Arkansas IRP Capacity Requirement and Going-In Capacity Position (MW)				**Cumulative Utility Scale Additions by Year (SPP Accredited MW)**				
Year	Load Responsibility + 12% Reserve	Existing Resources Capacity	"Going-In" Surplus / (Shortfall)	New Solar	New Wind	Welsh 1 Gas Conversion	Short-Term Capacity Purchases	Net Surplus / (Shortfall)
2023	4,833	4,562	(271)				271	0
2024	4,841	4,562	(279)				279	0
2025 *	4,840	4,454	(386)	256	140			10
2026 *	4,838	4,346	(492)	312	360			181
2027	4,894	4,346	(548)	540	360			352
2028	4,904	3,293	(1,611)	750	360	525		25

(*) 2025 and 2026 wind and solar added 12/31/24 and 12/31/25 to take advantage of tax incentives. The first year used for capacity requirements is 2025 and 2026, respectively.

The Preferred Plan nameplate capacity additions associated with the resources in Table 2 are shown in Table 3.

TABLE 3 – 2021 IRP PREFERRED PLAN NAMEPLATE ADDITIONS

	2021 IRP PREFERRED PLAN NEAR-TERM ADDITIONS - NAMEPLATE (1)				
	New Solar	New Wind	Total New Resources	Welsh 1 Gas Conversion	Short-Term Capacity Purchases
2023			0		271
2024 (2)	450	950	1,400		279
2025 (2)	100	1,500	1,600		
2026			0		
2027	400		400		
2028	450		450	525	
Total	**1,400**	**2,450**	**3,850**		

(1) 2021 IRP Figure 77
(2) Wind and solar added 12/31/24 and 12/31/25 to take advantage of tax incentives. The first year used for capacity requirements is 2025 and 2026, respectively.

V. POST-2021 IRP RESOURCE PLANNING DEVELOPMENTS

Q. HAVE THERE BEEN ANY DEVELOPMENTS SINCE THE 2021 IRP WAS ISSUED?

A. Several significant developments have taken place since the issuance of the 2021 IRP. First, on December 2, 2021, the Company decided to extend the planned retirement date at the 109 MW Lieberman Unit 3 and the 108 MW Lieberman Unit 4 through the end of 2026 to provide capacity and mitigate additional need for short-term capacity purchases.[3] These units had previously been planned for retirement in December 2022 and December 2024, respectively. The Company then entered into an agreement to purchase power from the 72.5 MW Rocking R solar facility subject to regulatory approval in Louisiana and Arkansas. Next, the total wind and solar capacity provided by the Selected Facilities add up to slightly less than one-third of the 3,300 MW that the Company determined was needed by the end of 2025. The Selected Facilities are forecasted to provide 999 MW of nameplate capacity and 237 MW of SPP accredited capacity by the end of 2025, as shown in Table 4.

TABLE 4 – SELECTED FACILITIES

Facility	Type	Size (MW)	Accredited Capacity (MW)	Location	Projected In-Service Date
Wagon Wheel	Wind	598.4	88	OK	December 2025
Diversion	Wind	200.6	29	TX	December 2024
Mooringsport	Solar	200.0	120	LA	December 2025
Total		**999**	**237**		

Finally, the Company elected to contract for short-term accredited capacity resources in 2025 and 2026. This type of resource had been projected to only be needed in 2023 and 2024 in the IRP, to serve as a bridge until the preferred new renewables could have started coming online.

[3] The Lieberman extension announcement was made after the 2021 IRP modeling was completed, and thus was not reflected in that IRP's resource plan.

Q. WHAT IS THE COMPANY'S CURRENT VIEW OF ITS CAPACITY POSITION, REFLECTING UPDATED ASSUMPTIONS?

A. Table 5 presents an updated view of the Company's capacity position and near-term resource plan as of the date of this filing.

TABLE 5 – CURRENT CAPACITY POSITION FORECAST

Column	1	2	3	4	5	6	7 = sum (3 - 6)	8 = 7/1
May 2022 Capacity Requirement and Going-In Capacity Position (MW)				Cumulative Utility Scale Additions by Year (SPP Accredited MW)				
Year	Load Responsibility + 12% Reserve	Existing Resources Capacity	"Going-In' Excess / (Shortfall)	Selected Facilities	Rocking R **	Short-Term Capacity Purchases	Net Surplus / (Shortfall) Capacity (MW)	Reserve Margin With New Additions
2023	4,842	4,769	(73)			250	177	16.1%
2024	4,917	4,759	(159)			350	191	16.4%
2025	4,927	4,759	(169)	29	41	350	251	17.7%
2026 *	4,935	4,651	(284)	237	41	200	194	16.4%
2027	4,943	4,434	(510)	237	41		(232)	6.7%
2028	4,955	3,381	(1,574)	237	41		(1,296)	(17.3%)

* 2026 wind and solar added prior to 12/31/25 to take advantage of tax incentives.

** Rocking R 72.5 MW nameplate solar facility. Filed for approval in Louisiana and Arkansas on January 28, 2022.

Column 1 reflects peak load plus SPP's current 12% reserve requirement. The existing resource capacity in Column 2 has been updated from Table 2 to account for the extension of Lieberman Units 3 and 4 through 2026. Column 3 shows that the Company will be in a short capacity position starting in 2023, increasing to a 1,574 MW shortfall in 2028. Columns 4-6 show the SPP accredited capacity value of all of the planned resource additions. Column 7 demonstrates that even with adding the Selected Facilities and capacity purchase agreements, the Company will be in a short capacity position again by 232 MW in 2027 and 1,296 MW in 2028. Column 8 presents the reserve margin in percentage terms. The small surpluses above the 12% minimum between 2023 and 2026 show that even if the Company's state regulators approve all of these additions, the Company has little room to spare in meeting its projected SPP capacity obligation in those years.

Q. HAVE THERE BEEN RECENT DEVELOPMENTS AT SPP THAT MIGHT IMPACT THE COMPANY'S SPP CAPACITY OBLIGATION?

A. Yes. SPP's Supply Adequacy Working Group (SAWG), which includes a representative from AEP, has been evaluating various ways to improve system reliability. These efforts are being pursued, in part, as a result of reliability concerns arising from the February 2021 winter storm Uri event that severely affected the supply and cost of electricity across the entire SPP region and in Texas. If adopted, such changes will potentially cause utilities across SPP, including SWEPCO, to need to add more capacity to meet increasing reliability requirements.

SPP evaluates its planning reserve margin (PRM) requirements in part through a Loss of Load Expectation (LOLE) study it publishes every two years. The goal of an LOLE study is to determine the amount of capacity needed to meet a desired reliability target. At the April 2022 SAWG meeting, SPP presented its most recent LOLE study results for 2023 and 2026. Those results suggested that the 2023 summer PRM requirement would need to be 17.90%, and the 2026 summer requirement would need to be 16.83% to achieve the desired level of regional reliability.

Additionally, SPP is currently in the process of revamping its Capacity Accreditation approach. The final requirements are still to be determined, but it is likely that the accreditation revisions will reduce the amount of megawatts the SWEPCO fleet has recognized in the accreditation process. The new accreditation paradigm currently being contemplated would be based upon a EFORd (Equivalent Forced Outage Rate

Demand) calculation. Currently, SPP recognizes a conventional resource's Installed Capacity (ICAP) which is commonly referred to as nameplate capacity. For example, currently a 100 MW resource receives recognition for the full 100 MW. Under the proposed revised rules a resource with a 10% $EFOR_d$ would now only be recognized for 90 MW (ICAP * (1-$EFOR_d$)). A phased transition period from the current approach to the revised methodology will ease the impact of this change somewhat, but ultimately the amount of resources required to maintain a compliant SPP plan will increase.

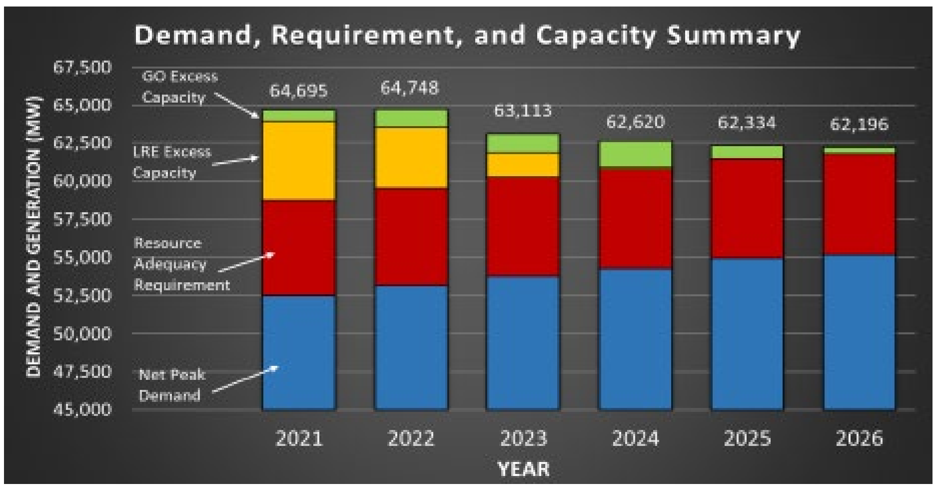
SPP is also considering adoption of a winter reserve margin requirement. Currently, utilities are subject to only a summer requirement. Wind and solar resources get less capacity credit in the winter, and thermal units typically have higher forced outage rates in the winter. SPP's modeling indicates that the winter PRM requirement could be between 26.2% and 39.3%. SWEPCO's winter peak is typically close to its summer peak, so a new winter reserve requirement would likely require additional capacity.

Q. WHAT ELSE HAS SPP PUBLISHED RECENTLY REGARDING RESOURCE ADEQUACY?

A. SPP also published its most recent annual resource adequacy report on June 15, 2021.[4] Figures 2 and 3 below from that report illustrate the SPP view on regional capacity adequacy for the 2021-2026 summer season outlook.

[4] https://spp.org/documents/64801/2021 spp june resource adequacy report.pdf.

SPP Figure 2: SPP BA Area Planning Reserve Margin Summary



SPP Figure 3: Demand, Requirement, and Capacity Summary

SPP's Figure 2 predicts the regional PRM to decline substantially from 23.2% in 2021 to 12.7% by 2026, leaving the region near the minimum 12% requirement. SPP's Figure 3 shows the total generating capacity SPP predicts will be operational declining by 2,499 MW to 62,196 MW by 2026 due to expected fossil generator retirements exceeding new resource additions. The blue bars in the graph represent the peak load, and the red bars represent the amount of capacity represented by the 12% reserve requirement. The total LRE Resource Adequacy Requirement, which is the value at top of the red bars, grows to 61,775 MW by 2026. That leaves only 421 MW (0.7%) of surplus capacity across the region in 2026 as shown by the green bar.

Q. GIVEN ALL OF THIS, WHAT CAPACITY RESERVE MARGIN IS THE COMPANY SEEKING TO MAINTAIN?

A. Based on the direction of the discussions around capacity requirements at SPP, and the prediction of rapidly tightening capacity supply across the region, it is prudent to maintain a minimum of 15% planning reserve margin for the foreseeable future. As a result, after seeing the limited number of renewable resources that remained viable following the due diligence and negotiations phase of the wind and solar RFPs, the Company decided to obtain enough capacity under the CPAs to achieve at least 15% reserve capacity. This additional 3% above the current 12% SPP requirement represents about 130 MW of additional capacity. This level of CPAs also provides a small cushion above the minimum requirement to allow for unforeseen circumstances.

VI. WIND AND SOLAR RFP BID ECONOMIC ANALYSIS

Q. DID THE COMPANY SCORE AND RANK THE BIDS RECEIVED IN THE WIND AND SOLAR RFPS BASED ON THE DETAILED ANALYSIS DESCRIBED IN EACH OF THE RFPS (§9.2)?

A. Yes. Consistent with the Detailed Analysis described in Section 9.2 of the RFPs supported by Company witness Jeffries, a scoring and ranking of bids was completed. With input from various AEP groups, the Economic Analysis phase of the Detailed Analysis was performed under my supervision. These inputs included any transmission upgrades needed to allow these projects to receive firm transmission service, as well as congestion and loss costs, which are supported by Company witness Kamran Ali. The Economic Analysis was completed on bids that 1) met the Eligibility and Threshold requirements, and 2) had not withdrawn its proposals from the RFP. The results of the analysis were shared with SWEPCO and AEPSC personnel including Company witness Jeffries, who discusses the selection process. As she discusses in her testimony, project costs increased above the initial bid values during the due diligence and negotiations phase of the RFP process. In the next section of my testimony I will discuss the cost of energy that reflects of all the final cost assumptions.

VII. SELECTED FACILITIES COST OF ENERGY

Q. WHAT ARE THE SELECTED FACILITIES EXPECTED TO COST CUSTOMERS ON A PER MWH BASIS?

A. After finalizing the costs, the portfolio of the three Selected Facilities is expected to cost approximately $51/MWh levelized over their 30 or 35 year lifetimes and weighted based on energy production. This value is referred to as the levelized cost of energy or LCOE. This amount is based on the summation of all of the lifetime projected retail revenue requirements that I was given by Company witness John O. Aaron. Mr. Aaron computed annual revenue requirements for each of the three SWEPCO states and the wholesale jurisdiction using the cost and energy production inputs provided to him by various Company witnesses. The annual revenue requirements over the lives of the assets were present valued and then divided by the present value of the expected energy production to arrive at the LCOE.

Q. WHAT COSTS AND CREDITS ARE INCLUDED IN THE LCOE CALCULATION?

A. The calculation includes all of the costs of the facilities included in Company witness Aaron's retail rate impacts: return on rate base, income tax expense, depreciation, O&M, and asset retirement obligation (ARO) costs. Production tax credits, net of the carrying charges on the expected PTC deferred tax asset (DTA), are netted against the wind costs. Investment tax credits, reflecting the expected delay in providing those credits to customers in rates, are netted against the solar costs.

Q. ARE ANY OF THE EXPECTED ENERGY REVENUES, REC REVENUES, OR THE VALUE OF THE CAPACITY PROVIDED BY THE SELECTED FACILITIES NETTED AGAINST THE LCOE?

A. No, but these benefits will offset the costs to customers. Company witness Aaron has calculated the rate impacts of these investments netting the energy revenues against the costs.

VIII. CONFIRMATION ANALYSIS

Q. WHAT WAS THE NEXT STEP IN SWEPCO'S REVIEW OF THE RENEWABLE RESOURCES OFFERED INTO THE RFPS?

A. The costs of the wind and solar resources bid into the RFPs were higher than the costs that led to the selection of those resource types as the optimal near-term resources in the IRP. As a result, the Company engaged CRA to assist in performing additional analysis (the Confirmation Analysis) to confirm whether the Selected Facilities were still the least-cost options to meet the near-term capacity requirements. Company witness Augustine of CRA also discusses the Confirmation Analysis in his testimony.

Q. PLEASE DESCRIBE THE CONFIRMATION ANALYSIS.

A. As discussed by Company witnesses Jeffries and Joseph G. DeRuntz, due diligence was performed on proposals received during the RFP process. Following the identification of the short-listed proposals the cost and performance data on the bids was updated to reflect increased costs versus the initial bid price for reasons described by Company witness Jeffries.

CRA then used the Aurora model data set used in the 2021 IRP with updated resource cost information to perform the Confirmation Analysis. Each of the Selected Facilities was input individually into the model as an optional resource at their specific projected capacity, in-service dates, costs, and capacity factors. The model was also given generic resource options to select as possible resource additions. Aurora's resource optimization functionality was used to compute the Net Present Value (NPV) of the revenues and costs (i.e., net cost) of both the Selected Facilities and the other generic resource options. The model selected whichever resource options produced the lowest total company NPV of net cost.

Q. WHAT INFORMATION WAS PROVIDED TO CRA FOR THEIR USE IN PREPARING THIS ANALYSIS?

A. I provided CRA all of the inputs related to the proposals that remained under consideration in March 2022, including capacity MW, capital cost, in-service dates, operations and maintenance (O&M) costs, congestion, property tax expense, expected tax inefficiency cost, and an annual projection of hourly energy production. Company witness DeRuntz provided the O&M and generation capital cost expense information. Company witness Ali provided the estimates of congestion and transmission capital costs. Company witness David A. Hodgson provided the inputs on the expected timing of the usage of tax credits to be earned by renewable resource options.

I also provided CRA the assumptions regarding resource costs and when each type of generic resource option would be available to be placed in service. CRA reviewed those assumptions and determined that they were reasonable. The cost, block size, and first year available for the generic resource options are presented in HSPM EXHIBIT JFM-1.

Q. HOW WERE THE COSTS OF THE GENERIC RENEWABLE RESOURCE OPTIONS DETERMINED?

A. The Company utilized the seven projects that remained viable in March 2022 as the basis for estimating generic resource costs. These bids provided market intelligence regarding the cost of projects in the SPP queue and under study that could be brought online during 2025 and 2026. The highest cost wind and solar bids of the seven projects were used as the cost of those two generic resource types to the model on the first in-service date they were available (12/31/25) and for one year after that (12/31/26). This assumption was based in part on the assumption that the current uncertainties in the market regarding solar panel availability, tariffs, along with inflation will persist long enough to impact the costs of projects that could be available at that time. Company witness Jeffries discusses the factors that led to market uncertainties and increased costs. It is also based in part on the assumption that the most affordable of the limited number of available projects that could be in service by then may be taken by other utilities or corporate buyers.

For projects that could be brought in service on 12/31/27, the generic resource cost was reduced to the average of the viable bids based on the notion that the supply chain, tariff, and inflation issues might have time to abate somewhat by then. Renewable resources that could begin commercial operation on 12/31/28 and beyond were determined by starting with the 12/31/27 resource costs and then applying the same future cost decline rates and inflation assumptions used in the 2021 IRP.

Q. WHAT COST WAS ASSUMED FOR THE GAS-FIRED COMBINED CYCLE (CC) AND COMBUSTION TURBINE (CT) OPTIONS THAT WERE AVAILABLE TO THE AURORA MODEL TO REPLACE THE SELECTED FACILITIES?

A. The Company did not have bid data from RFPs to use as the basis for the cost of the gas options available to the model. AEP subscribes to a resource cost information service provided by a third party. In February 2022, that party provided AEP with estimates of what CTs and CCs that would start construction in 2022 would cost. In addition, I consulted with AEP's engineering department, which has a group that monitors resource construction costs across all resource types. Items including steel and labor and interconnection costs that have increased for wind and solar have also increased for natural gas resource options. As a result of this research, the natural gas options were assumed to increase by 23.5% versus the IRP assumption across all years.

Q. WHEN WERE GENERIC RESOURCE OPTIONS ASSUMED TO BE AVAILABLE?

A. The Company used the best available information based on expertise of various individuals, including Company witnesses Jeffries, Ali, and Augustine to determine when each resource type would first be available.

The natural gas-fired options (CT and CC) were assumed to be first available January 1, 2029. This was based on an estimate of the time it would take to develop a project, get it far enough along in the SPP interconnection queue, have it be selected in an RFP process, obtain regulatory approvals, and then build it. Currently, there are no new gas resources in the SPP Interconnection queue that could submit a qualifying bid into an RFP.

Conversion of Welsh 1 to use gas as its fuel source was included in the model as a resource option available by December 31, 2027. In order to meet the Coal Combustion Residuals Rule's December 31, 2028 ash pond closure deadline, the Company will need to cease burning coal at both Welsh units by March 31, 2028. The Company has not yet decided the future of either unit at the Welsh plant.

Generic wind resources were assumed to be available as of December 31, 2025, and be eligible for 60% PTC that one year. Wind available after 2025 was assumed to not be PTC-eligible. The amount of wind available in any one year was kept at the same 1,600 MW level assumed in the 2021 IRP.

Generic solar assets and storage options were also assumed to be available starting December 31, 2025 and December 31, 2024, respectively. The amount of those resource types available in any one year was kept at the same level assumed in the 2021 IRP – 450 MW per year of solar, and 500 MW of storage.

Q. HOW WERE SHORT-TERM CAPACITY RESOURCES TREATED IN THE CONFIRMATION ANALYSIS?

A. The 2023-2026 contracted short term capacity resources were added into the model at the capacity values included in the contracts. No additional generic short term capacity was made available to the model prior to 2027. An additional 200 MW of short term capacity was made available to the model in 2027 at the same price as the 2026 short term capacity contract. Starting in 2028 it was assumed the Company would have had time to obtain preferred long-term resources, and thus further reliance on short-term capacity would no longer be needed.

In addition, it is uncertain if short term capacity will be available at any price. Based on SPP's projection of the rapidly diminishing level of reserve capacity across the region, and the looming federal effluent limitation guidelines (ELG) compliance-driven retirements of coal-fired resources in 2028, it is not prudent to assume availability of short term capacity after 2027.

Q. HOW WERE FIRM TRANSMISSION DELIVERABILITY AND CONGESTION AND LOSSES ACCOUNTED FOR IN THE CONFIRMATION ANALYSIS?

A. For each of the Selected Facilities, location-specific transmission upgrades and congestion and loss estimates provided by Company witness Ali for each specific asset were included in the cost of Confirmation Analysis. For the generic wind resources, the levelized congestion and losses were assumed to be equal to Diversion's values. For generic solar resources, the levelized congestion and losses were assumed to be equal to Mooringsport's values.

Q. HOW WERE TAX INEFFICIENCY COSTS ACCOUNTED FOR IN THE CONFIRMATION ANALYSIS?

A. As discussed in the testimony of Company witness Hodgson, the Company is not expected to be able to immediately use all of the tax credits earned by the Selected Facilities. For the wind resources (Wagon Wheel, Diversion, and generic wind), a two-year delay in utilizing PTCs was assumed. This resulted in a tax inefficiency cost in the form of a levelized carrying charge on a production tax credit (PTC) deferred tax asset of $1.61/MWh being added to the cost of every MWh generated by all wind resources. For the solar resources (Mooringsport and generic solar), the assumption was that the Company would experience a 13-year delay in the start of the pass-through of investment tax credit (ITC) amortization to customers under the IRS normalization rules. This amounted to a levelized approximately $4.00/MWh increase in the cost of all solar resources.

Q. WERE RENEWABLE ENERGY CERTIFICATES (RECs) ACCOUNTED FOR IN THE CONFIRMATION ANALYSIS?

A. No. The value of RECs, which would make these renewable options more valuable on a stand-alone basis and versus non-renewable options, was conservatively left out of the confirmation analysis. Wind and solar assets generate RECs, which can then be sold in cash REC markets or made available to be retired on behalf of customers who sign up for the Company's REC tariff programs. Had the value been included in the analysis, the same value would have been assumed for both the Selected Facilities and generic wind and solar available to be selected by the model.

Q. WHAT WAS THE RESULT OF THE CONFIRMATION ANALYSIS?

A. Company witness Augustine provides a table of the results on his testimony. The Selected Facilities were selected by the Aurora model's optimizer under both the carbon-tax and no carbon tax commodity price scenarios as a component of a least-cost resource plan designed to meet the Company's capacity needs. This indicates that Selected Facilities will be less expensive as compared to other options.

The model also selected additional generic wind, under the assumption that it can be procured in the near future at a cost consistent with the assets bid into the 2021 RFPs, obtain regulatory approval, make it through the SPP interconnection process, and then be built and placed in service by the end of 2025 to qualify for 60% PTCs. The model added the maximum available 1,600 MW of generic PTC-eligible wind that year in the Reference case (including a carbon tax) case and 1,550 MW of the 1,600 MW available in the NCR case (no carbon tax) case. This result is similar to the other modeling exercises presented in my testimony, which is that both the PLEXOS and Aurora models optimally select as much PTC-eligible wind as the model is allowed to add. This was true in the environments modeled in both the Q1 2021 Analysis and in late-2021 in the Arkansas IRP, in which resources of all types were assumed to be less costly than they have turned out to be. It is also true in today's environment, in which high inflation, supply-chain challenges, import tariffs, and interconnection costs have increased resource costs.

The contracted short term capacity resources were enough to meet the minimum 12% reserve requirement the model was solving for, plus a small cushion above the minimum in all years from 2023 to 2026. Therefore, the binding constraint in the model that caused it to add the Selected Facilities and the other generic wind and solar and short-term capacity resources was that the model could look out to 2028 and see an additional 1,100 MW need it would be required to fill when Welsh 1 and 3 were assumed to be retired. Importantly, because of the value of the PTCs, the model elected to add both the Selected Facilities and additional generic wind at the end of 2025, because the model optimizes over the long-term. Adding wind in 2025 resulted in a lower NPV of cost than waiting until after 2025 to add wind that does not come with PTCs, or adding solar after 2025, which would come with only 10% ITC.

From 2026-2028, the model optimally selected a diverse mix of additional generic solar, wind, storage, short-term capacity, conversion of Welsh Unit 1 to utilize natural gas as its fuel, and a greenfield combined cycle to complete adding the rest of the capacity that will be needed to replace Welsh.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

EXHIBIT JFM-1 - HIGHLY SENSITIVE PROTECTED MATERIAL