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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	§ § § § § § §	**BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS**

MOTION OF SOUTHWESTERN ELECTRIC POWER COMPANY FOR ADMISSION OF ADDITIONAL EVIDENCE PURSUANT TO TEXAS RULE OF EVIDENCE 106

TO THE HONORABLE ADMINISTRATIVE LAW JUDGES (ALJS) PRESIDING:

Applicant, Southwestern Electric Power Company (SWEPCO or the Company) moves for the admission of additional evidence in this proceeding under the doctrine of "optional completeness" and pursuant to Tex. R. Evid. 106. In support, SWEPCO shows as follows:

At the Hearing on the Merits, the ALJs ruled that parties could offer evidence, by Friday, February 28, 2020 for inclusion in the record under the doctrine of optional completeness. Accordingly, this motion is timely filed.

SWEPCO's optional completeness request goes to TIEC Exhibit Nos. 65, 76, and 77. TIEC Exhibit No. 65 is an excerpt of the filed direct testimony of Johannes Pfeifenberger from Docket No. 47461. Because the offered exhibit provides only an excerpt, SWEPCO believes inclusion of the entire direct testimony is warranted as it places the responses of Mr. Pfeifenberger during cross-examination regarding this exhibit in context. Therefore, SWEPCO offers the Direct Testimony of Johannes Pfeifenberger for Southwestern Electric Power Company filed in Docket No. 47461 as SWEPCO Exhibit No. 39.

TIEC Exhibit Nos. 76 and 77 consist of information taken from the EIA website, which was used during the examination of SWEPCO witness Karl Bletzacker. TIEC's Exhibit Nos. 76

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and 77 are both incomplete as the print out from the webpage cuts off a couple lines of input information as well as the footnotes associated with the inputs used to graph information contained on the webpage. Those footnotes in particular provide additional clarifying information regarding the exhibits about which TIEC questioned Mr. Bletzacker. Therefore, SWEPCO believes inclusion of the entire web page for each exhibit is warranted. Accordingly, SWEPCO offers SWEPCO Exhibit Nos. 40 and 41, respectively.

SWEPCO respectfully requests the ALJs grant its motion for admission of SWEPCO Exhibit Nos. 39 through 41 pursuant to Tex. R. Evid. 106. SWEPCO requests such other and further relief to which it may show itself justly entitled.

Respectfully submitted,

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ATTORNEYS FOR SOUTHWESTERN ELECTRIC POWER COMPANY

CERTIFICATE OF SERVICE

I certify that a true and correct copy of this motion was served on all parties of record this 28th day of February, 2020.

Stephanie Green
Stephanie Green

SOAH Docket No. 473-19-6862
PUC Docket No. 49737

SWEPCO Exhibit 39

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 WIND CATCHER ENERGY CONNECTION PROJECT

DIRECT TESTIMONY OF

JOHANNES P. PFEIFENBERGER

FOR

SOUTHWESTERN ELECTRIC POWER COMPANY

JULY 31, 2017

SOAH DOCKET NO. 473-17-5481
PUC DOCKET NO. 47461

SWEPCO Ex. 8

TESTIMONY INDEX

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME, TITLE, EMPLOYER, 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 Public Service Company of Oklahoma (PSO) and Southwestern Electric Power Company (SWEPCO). Both PSO and SWEPCO are operating companies of American Electric Power (AEP), jointly the three are the "Companies."

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony explains the analytical framework and description of the benefits metrics that the Companies used for modeling and analyzing the proposed Wind Catcher Energy Connection Project (Project), which includes the Wind Catcher facility and the Wind Catcher Generation Tie Line. The testimony describes in detail the cases modeled, why each case was selected, and the key assumptions used in the PROMOD simulations. I describe the PROMOD tool, how PROMOD simulation results were transferred for use in the Companies' PLEXOS simulation, and why both modeling tools were used in supporting the Companies' analysis, including the differences between the two models and how the two models work together. My testimony then describes the methodology used for the Companies' benefit calculations based on the PROMOD and PLEXOS simulation results. Finally, I present pricing estimates of power purchase agreements for generic new wind resources in Southwest Power Pool (SPP) regional transmission organization footprint.

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

A. I am an economist with a background in power engineering and over twenty-five years of work experience in the areas of regulated industries, energy policy, and finance. I received a M.A. in Economics and Finance from Brandeis University and a M.S. in Electrical Engineering with a specialization in Power Engineering and Energy Economics from the University of Technology, Vienna, Austria. I am the author and co-author of numerous articles, reports, and presentations on subject areas related to the economic benefits of transmission investment, planning, market design, and cost allocation. For example, I prepared (with colleagues) the report entitled *The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments* that documents the wide range of benefits that can be provided by transmission investments and how these benefits are assessed by the various transmission planning organizations.

I have filed testimony before the Federal Energy Regulatory Commission ("FERC" or "Commission") on a range of subject areas, including the economic benefits of transmission and renewable generation investments by both vertically-integrated and independent transmission companies. For example, I previously submitted testimony regarding the value of the Path 15 Upgrade in Docket Nos. ER14-33 and ER14-1332, and provided testimony on behalf of ITC Holdings Corp. in Docket Nos. EC12-145-000 and

EL12-107-000 regarding the potential benefits of strategic transmission projects. I have also provided testimony (with my colleague Samuel Newell) 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 American Electric Power (AEP) zones of PJM Interconnection, L.L.C. I similarly provided testimony (with my colleague Samuel Newell) 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. In addition, I filed (co-authored with colleagues) comments in response to three Commission notices on regional transmission planning and cost allocation, in Docket Nos. AD16-18, AD09-8, and RM10-23. Further, on behalf of various clients, I have submitted testimonies on transmission tariff design, the costs and benefits of alternative transmission access charge methodologies, and regional transmission organization ("RTO") scope and configuration issues.

I also filed testimony on transmission benefits before a number of state commissions, including in Arkansas, Texas, Louisiana, Mississippi, Wisconsin, and Arizona. For example, I submitted testimony in Wisconsin on behalf of American Transmission Company LLC and ATC Management Inc. in Docket No. 137-CE-149 discussing the economic benefits of the Paddock-Rockdale Transmission Project.

Exhibit JPP-1 to my testimony contains a more complete description of my qualifications and expert witness experience.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I worked with the Companies to develop a methodology, consistent with SPP and industry practices, to support PSO and SWEPCO in analyzing the costs and benefits of developing the Project. This methodology, which PSO and SWEPCO utilize for analyzing the proposed Project, allows for assessment of estimated customer cost savings resulting from the Project, and supports comparison of Project costs and benefits relative to the alternative of procuring generic wind in the SPP footprint through power purchase agreements (PPAs). To support this Project alternative, I also estimated the cost of generic wind generation in SPP, which the Companies utilized for comparing the costs and benefits of the proposed Project with a conventional wind procurement alternative. My estimates for the cost of alternative wind procurements in SPP are reasonable and within the range of cost estimates obtainable from public sources tracking such wind generation development costs. The quantification of the costs and benefits of the proposed Project and the generic wind alternative from a PSO and SWEPCO customer perspective is presented by Company witness Kelly Pearce. My testimony addresses only the methodology of this quantification, making the following points:

Analytical Framework: To support the Companies' benefits and cost evaluation of the Project, I first worked with the Companies to develop an analytical framework based on three market simulation "Cases"—the Base Case, the Project Case, and the Generic Wind Case. The Base Case reflects the baseline approach to meeting the Companies' future energy needs without the development or purchase of future wind resources between 2021 and 2045. The Project Case reflects the development of

1,900 MW of high-quality Oklahoma panhandle wind generation delivered directly to Tulsa via the proposed 765 kV Gen-Tie. Finally, the Generic Wind Case was developed as an alternative to the Project Case, and reflects the procurement of 1,900 MW of wind generation delivered from multiple projects at various sites across the SPP footprint over SPP's existing and planned regional transmission system. The Companies' staff simulated each of these three cases using PROMOD and PLEXOS simulation tools to estimate the production related costs and benefits of each case. The difference of simulated benefits and costs between the Project Case and the Base Case quantifies the net benefits of physically delivering to Tulsa 1,900 MW of high quality wind from the panhandle region of Oklahoma, while the difference between the Project Case and the Generic Wind case identifies the savings that can be realized through the Project relative to purchasing 1,900 MW of generic wind generation with delivery to the SPP system at the wind plants' various SPP locations.

Key Benefit Metrics and Evaluation Methodology: To analyze the benefits of the Project, I supported the Companies in employing the following benefit metrics: (1) Adjusted Production Cost (APC) Savings, (2) Additional Congestion & Loss Savings, including Reduced Quantity of Transmission Loss Savings (3) Wind Curtailment Cost Savings, and (4) Avoided/Deferred Capacity Cost Savings.

1. **APC Savings:** Adjusted production costs were first evaluated through the Companies' PLEXOS simulations of their future production cost, net of off-system market purchase costs and off system sales revenues, for all three cases analyzed. To evaluate APC savings, the difference in APCs between two relevant cases were calculated.

2. **Additional Congestion & Loss Savings**: The Project, with its dedicated Gen-Tie to Tulsa, can avoid the potentially significant future congestion charges between wind sites and the Companies' load that would be incurred in the Generic Wind Case. The extent to which wind-generation-related congestion costs incurred in the Generic Wind Case can be avoided in the Project Case, will be a benefit in addition to the APC savings estimated in the PLEXOS simulations. Additionally, the Project avoids marginal-loss-related costs relative to the Generic Wind Case.

and reduces the quantity of transmission system losses because of differences in the electrical proximity between the wind sites and the operating company loads. These benefits need to be added to the APC savings because the Companies' PLEXOS-based APC calculations simply credit hourly wind generation against the Companies' load, which is valued at the zonal load price and consequently does not capture the additional congestion- and loss-related costs incurred by injecting generic wind at more distant, and more transmission constrained locations.

3. **Wind Curtailment Cost Savings**: New wind generation connected to SPP's existing transmission system in the future very likely will be subject to economic curtailment during high-wind and low-load hours. Curtailed wind outputs require the replacement of the curtailed energy through energy purchases at market prices, imposing a curtailment-related cost on off-taking utilities. This curtailment cost would be especially pronounced in the Generic Wind Case, lacking direct delivery to the Companies' load. Differences in expected curtailment costs between the Generic Wind and the Project Case had to be evaluated as an additional benefit to the Project because the cost of curtailments is not reflected in the PLEXOS-based APC calculations.

4. **Avoided/Deferred Capacity Cost Savings:** Both the Project and the Generic Wind Cases will reduce the Companies' future resource adequacy requirement by a capacity value of up to 15% of the installed generating capacity of the wind resources. This capacity-value benefit, which is not captured in production cost simulations and the associated APC calculations, was quantified as avoiding or deferring the construction of gas-fired generating capacity that would otherwise be needed to meet the future resource adequacy needs of the companies. This additional benefit will exist for both the Project Case and the Generic Wind Case relative to the Base Case.

Details on Market Simulations: The Companies performed simulations of future market performance of all three cases using both PROMOD and PLEXOS to assess the benefits of the Project. Both simulation tools are widely used and accepted in the industry. The PROMOD datasets used for this analysis were originally developed by SPP and its stakeholders in 2015–16 for SPP's "2017 ITP10" transmission planning studies, and reflect expected SPP-wide future system conditions in years 2020 and 2025. The PROMOD simulations were necessary to assess the extent to which locational wholesale power prices, congestion costs, and marginal-loss-related costs are affected by the proposed 1,900 MW wind development. However, because SPP's PROMOD model, which simulates locational prices for the entire SPP footprint and neighboring systems, does not contain sufficient detail to analyze customer costs for the individual Companies over the 2021–2045 evaluation period, the companies employed PLEXOS simulations that are already set up for this purpose. Relying on PLEXOS enabled simulations to assess changes in production costs, market purchase costs, off-system sales revenues, and other customer cost items at the operating-company level also facilitated the simulation of customer impacts for the entire 2021–2045 evaluation period. However, unlike PROMOD, the Companies' PLEXOS model is not set up for simulating transmission constraints and marginal losses and their effect on locational pricing in the SPP footprint, which required reliance on PROMOD as explained further in Section III of this testimony.

Estimation of PPA Prices for Generic Wind: To assess the benefits of the Project relative to the Generic Wind alternative, it was necessary to estimate the likely pricing of PPAs that would be incurred by the companies in the Generic Wind Case. To perform this analysis, I estimated the levelized costs of new wind resources in SPP by relying on publicly-available information of overnight capital costs and related data for the construction of wind generation in the SPP region. Specifically, I relied on the U.S. Energy Information Administration's 2017 Annual Energy Outlook (AEO) report, which reports both cost and operating characteristics of new generating technologies by region. My calculations resulted in a levelized cost of wind energy of $18.62/MWh in 2021, escalating at 2.25% annually for 25 years. This estimate is consistent with the range of PPA pricing of wind generation in SPP as reported in a number of public sources.

II. CASE DEVELOPMENT BACKGROUND

Q. PLEASE DESCRIBE THE ANALYTICAL FRAMEWORK EMPLOYED FOR BENEFITS EVALUATION OF THE PROJECT.

A. To support the Companies' benefits and cost evaluation of the Project, I worked with AEP to develop an analytical framework comprised of three main "Cases" of alternative resource procurement paths. The first case, which represents the baseline case, assumes no new development or purchase of wind resources between 2021 and 2045. This "Base Case" reflects an approach to meeting future energy needs of the Companies without additional wind generation. My second case—the "Project Case" reflects the development of the Project. As explained by Companies' witness Kelly Pearce in his prepared direct testimony, the Project consists of high quality wind resources in the Oklahoma panhandle that would deliver 1,900 MW and approximately 8.7 TWh of energy annually to Tulsa over a dedicated 765 kV Gen-Tie. The Project is proposed to begin operation by December 2020. In addition to the "Project Case" and the "Base Case," the Company evaluated a third alternative—the generic wind procurement alternative, entitled "Generic Wind Case." The Generic Wind Case reflects the procurement of 1,900 MW of wind generation from multiple projects across the entire SPP footprint over SPP's existing and planned regional transmission system.

Figure 1 below summarizes these cases.

Figure 1: Case Description

Case	Wind MW at Point of Delivery to SPP System	Annual Energy at Point of Delivery to SPP System	Point of Delivery to SPP System	Mode of Delivery from Wind Sites to AEP Load
Base Case	-	-	-	-
Project Case	1900 MW	8.7 TWh	Tulsa 345 kV system	Dedicated 765 kV Gen-Tie to Tulsa, and SPP's transmission system from Tulsa to rest of SPP's AEP load zone
Generic Wind Case	1900 MW	8.0 TWh	At 24 different wind sites across SPP system	SPP's Bulk Transmission system—from wind sites to SPP's AEP load zone

The difference of costs between the Project Case and the Base Case quantifies the benefits of physically delivering to Tulsa 1,900 MW of high-quality wind generation from the panhandle region of Oklahoma. The difference between the Project Case and the Generic Wind case identifies the savings the Companies can realize through the Project relative to purchasing 1,900 MW of wind generation delivered to the SPP system at the wind plants' various locations.

Each of these three cases was first simulated by the Companies, using the 2020 and 2025 PROMOD models that SPP and its stakeholders had developed for the 2017 ITP10 transmission planning process,[1] to estimate future SPP locational prices (including congestion and marginal losses) at the Companies' load zone, conventional generation resources, and wind generation resources. The Companies then used these locational price

[1] 2017 ITP10 Modeling Assumption p. 30 of Final Report accessed here: https://www.spp.org/documents/51179/2017_itp10_report_board%20approved_april2017_final.pdf

data as inputs for their PLEXOS market simulations to estimate costs and benefits. For each of the three simulation cases. I relied on the locational price results obtained from the PROMOD simulations for 2020 and 2025 to first interpolate locational pricing results for the 2021–2024 portion of the evaluation period. I then extrapolated the PROMOD-based locational pricing results for 2025 to the 2025–2045 portion of the evaluation period based on the Companies' long-term fundamental forecast between 2025 and 2045. With these locational pricing data as inputs. PLEXOS was then employed to evaluate production cost savings and the impact of estimated SPP congestion and loss charges over the 25-year evaluation period. commencing in 2021. Note that the estimated congestion and loss charges reflected in the PLEXOS cost-of-service calculations are based on inputs from PROMOD simulation results.

It is important to note that the 2020 PROMOD simulations with 1,900 MW of wind (both in the Project Case and the Generic Wind Case) was utilized only to interpolate 2021–2024 pricing estimates. recognizing that the proposed wind generation is planned to become operational only in December 2020.

III. SIMULATION TOOLS & KEY ASSUMPTIONS

Q. PLEASE DESCRIBE THE PROMOD SIMULATION TOOL.

A. PROMOD is a widely-used and universally-accepted market simulation tool. primarily employed for forward-looking locational market simulations. PROMOD simulations are premised on a competitive wholesale electricity market and the tool is used by SPP to simulate chronological hourly dispatch of the entire SPP footprint and neighboring markets subject to transmission constraints for the assumed market conditions. The

PROMOD simulations, like other similar models, need to make certain simplified assumptions about market conditions that tend to lead to somewhat conservative results with respect to market price fluctuations and congestion levels. For example, PROMOD simulations assume that all resources bid their variable costs, that only the "normal" generation outage patterns will occur, and that no transmission outages would occur in the simulated years. The main outputs of the PROMOD market simulation is the locational marginal price (LMP) for energy at various pricing nodes on the SPP system. PROMOD outputs also include the hourly marginal congestion cost and marginal loss charge components of the LMP for each pricing node.

Q. PLEASE DESCRIBE THE PROMOD DATASET DEVELOPED BY SPP AND HOW IT IS USED.

A. SPP employs PROMOD simulation for its transmission planning and economic studies (ITP10 studies) as well as for transmission benefits review assessments performed as part of its Regional Cost Allocation Review (RCAR) studies. These PROMOD models developed for SPP's 2017 ITP10 reflect expected future system conditions in 2020 and 2025, reflecting all SPP-planned and -approved transmission projects as well as planned and/or needed future capacity resources, including wind resources at levels and locations that SPP and its stakeholders have deemed most feasible for development by 2020 and 2025. Note, however, while the SPP PROMOD simulates prices and production costs for all of SPP's transmission zones, including the AEP zone, the model does not contain sufficient detail to analyze the costs for the individual Companies (PSO and SWEPCO), nor does it contain enough detail to analyze how certain costs and revenues would be shared between PSO, SWEPCO, and their customers.

Q. WHAT WERE THE KEY ASSUMPTIONS USED IN THE PROMOD SIMULATIONS AS THEY RELATE TO THIS PROJECT?

A. The Companies' PROMOD simulations began with the SPP's 2017 ITP10 base PROMOD models, but with a few modifications to its key assumptions. The key assumptions, including modifications made, are summarized below. I have described additional details relating to these assumptions in my prepared Exhibit—"PROMOD Assumptions and Benefits Extrapolation Details" (Exhibit JPP-2).

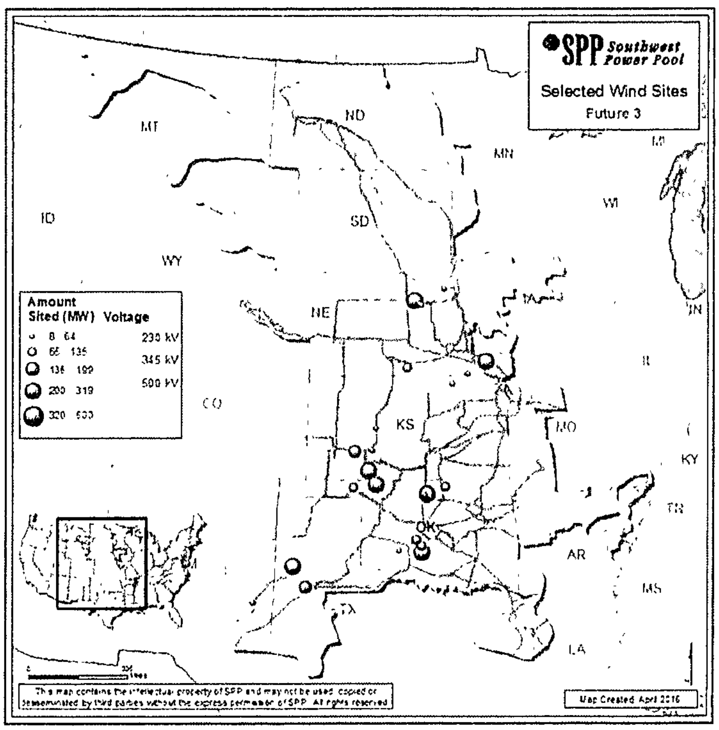
- *"SPP Future" Analyzed:* The Companies employed 2017 ITP10 models that reflected SPP's Future 3—a future that assumed no pricing on carbon emission by thermal generation resources.
- *Future Wind Resources:* SPP's Future 3 base models included approximately 500 MW and 600 MW of new future wind resources in SPP's AEP zone in 2020 and 2025 respectively. The Companies modified this assumption to retain only 200 MW in each year, to reflect inclusion of only planned wind procurement by PSO and SWEPCO. Throughout the SPP footprint, the SPP base models add 2,750 MW of new wind generation between 2016 and 2020 and an additional 420 MW of new wind by 2025, for a total of 17,~~500~~ 025 MW of existing and new wind installed by 2025.
- *Future Capacity Needs:* To meet projected reserve margin requirement, SPP's base models assumed development of new combined cycle and combustion turbine generating resources in several of its zones, including in the AEP zone. The Companies' PROMOD simulation of the Project Case and the Generic Wind Case modified these assumed future capacities slightly to reflect the capacity value of the 1,900 MW of new wind.
- *Gas Prices:* SPP's Future 3 base PROMOD models assumed an annual average natural gas price of $6.03/MMBtu in 2020 and $7.26/MMBtu[2] in 2025. The Companies' PROMOD simulations modified this assumption by updating the gas price inputs to reflect those of the Companies' long-term Fundamental Forecast for the commodity. Company witness Karl Bletzacker provides additional details on these long-term fundamental forecasts of natural gas prices.

[2] Provided by the companies based on review of SPP's 2017 ITP10 PROMOD Models for 2020 and 2025

- *The Companies' New Wind Resources:* As described above, the companies modeled 1,900 MW of new wind generation delivered to the companies in the Project Case and the Generic Wind Case, and no new wind generation in the Base Case. The Project Case, additionally included a new 765 kV Gen-Tie connecting the Companies' contemplated Oklahoma panhandle wind generation to PSO's existing Tulsa North 345 kV substation.

  In the Generic Wind Case, to model 1,900 MW of wind generation delivered to the companies at existing SPP points of interconnection, the Companies' PROMOD simulations used the full range of wind locations that SPP and its stakeholders had assumed to be feasible and likely interconnection locations for such future wind. There were 24 such locations in Oklahoma, Kansas, Missouri, and Nebraska as shown in Figure 2 below. The SPP-assumed new wind generating resources at these locations were scaled up for the Generic Wind Case to add 1,900 MW of additional purchases.

Figure 2: New Wind Procurement Locations in the Generic Wind Case



Source: SPP's 2017 ITP10 Report

Q. PLEASE EXPLAIN IN MORE DETAIL THE PURPOSE OF EMPLOYING BOTH PROMOD AND PLEXOS.

A. Both PROMOD and PLEXOS are simulation tools that can be employed to perform the type of forward-looking market simulations necessary to assess the benefits of the Project. However, in this case both simulation tools had to be utilized for a number of reasons.

First, the Companies have historically relied on PLEXOS for analyzing the market performance of their resources and for evaluating their expected market revenues and dispatch outcomes for resource planning purposes. Relying on PLEXOS has several advantages. The model is already set up to simulate several years of future market performance quickly and to link and provide input to the customer rate impact assessments, for the Companies. Most importantly, unlike PROMOD, the Companies' PLEXOS model is set up to simulate PSO and SWEPCO individually, and therefore is able to assess changes in production costs, market purchase costs, off-system sales revenues, and other customer cost items at the operating-company level. Unlike PROMOD, however, the Companies' PLEXOS model is not set up to simulate the entire SPP footprint and does not simulate transmission constraints or marginal losses, which means it is unable to assess the extent to which wholesale power prices, congestion costs, and marginal-loss-related costs are affected by the proposed 1,900 MW wind generation development.

In contrast, SPP's PROMOD models simulate the entire SPP system (and surrounding market areas), including the full SPP transmission network and associated transmission constraints and marginal losses. Transmission constraints have a significant effect on optimal SPP-wide market dispatch outcomes and the associated locational marginal prices. Given the large additions of wind generation, it is important to capture these effects of the transmission network on locational prices when evaluating the costs and benefits of the Project and its potential alternatives. Unfortunately, the region-wide and locational simulations undertaking in the SPP PROMOD cases makes it computationally challenging and time consuming to analyze more than a few years—the main reason why SPP has produced PROMOD cases for only two future years: 2020 and 2025. SPP's PROMOD model is further limited by the fact that it has been set up to analyze cost impacts only for individual SPP transmission zones—such as the AEP zone, which aggregates both AEP companies (PSO and SWEPCO) as well as other public power entities—and without the level of detail that is required to separately assess impacts on customer rates of the two companies.

Therefore, to assess the present value of future benefits of the Project and its two alternatives, over the entire 25-year horizon from 2021 through 2045 and for each of the two companies, PLEXOS was employed in conjunction with SPP's PROMOD models to capture the impact on the individual operating companies as well as the impact of the additional wind generation on the transmission system and the associated locational marginal prices.

Q. DESCRIBE HOW PROMOD SIMULATION RESULTS WERE USED AS INPUTS FOR THE COMPANIES' PLEXOS SIMULATIONS.

A. To properly evaluate the full benefits of each case analyzed, the Companies had to employ PROMOD in conjunction with PLEXOS for performing forward-looking market simulations. To facilitate these simulations, I performed several data processing tasks that involved preparing PLEXOS inputs from relevant outputs of the PROMOD simulations for 2020 and 2025. I summarize below the data processing tasks I performed on PROMOD outputs for each of the three cases analyzed. Details are provided in "PROMOD Assumptions and Benefits Extrapolation Details" (Exhibit JPP-2).

1. ***Monthly Average Peak, Weekend, and Night Prices:*** As illustrated in Figure 3 below, I processed PROMOD's hourly prices from the 2020 and 2025 simulations to evaluate monthly, generation-weighted average prices for PSO's and SWEPCO's thermal units, and load-weighted average prices for the PROMOD defined AEP SPP zone. I calculated these averages for three different time-definitions—Weekday Peak, Weekend Peak, and Night[3]. These generation and load prices are the standard price inputs used by the Companies for its PLEXOS simulations.

2. ***Monthly Prices for 2021 through 2045:*** Since PROMOD markets simulations were performed only for 2020 and 2025, I interpolated monthly prices for the intervening years by "straight-lining" between the PROMOD-based prices, and extrapolated 2025 monthly PROMOD-based prices using the Companies' fundamental forecast for the Around-the-Clock ("ATC") prices to 2045.

3. ***Congestion, Marginal Losses and Wind-Curtailment Charges for 2021-2045:*** I evaluated the monthly congestion and marginal loss charges associated with PSO's and SWEPCO's existing and new wind generation resources by calculating PROMOD-simulated congestion and loss differences[4] between wind locations

[3] Time Definitions are as follows: Weekday Peak = 6 am to 10 pm, Monday through Friday; Weekend Peak = 6am to 10 pm on Saturday and Sunday, and on NERC Holidays; Night = 10 pm to 6 am on seven days of the week, including NERC holidays

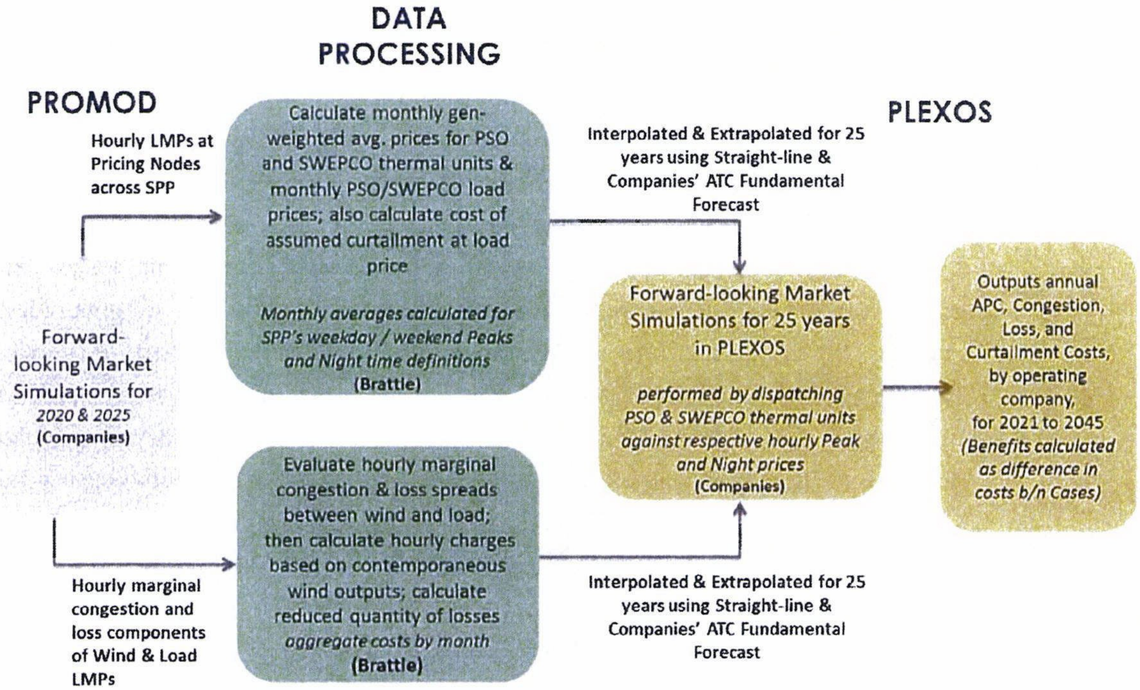
[4] The net loss charges for each operating company was estimated as one-half the marginal loss component differences between wind and load locations to reflect the refund of surplus marginal loss congestion revenues, consistent with the theoretical 1/2 relation between average and marginal losses.

and SPP's AEP zonal load, and applying those per-MWh congestion and loss charges to the hourly output from each wind site. I then calculated congestion and loss charges on a monthly basis for each operating company. Additionally, I assumed that on average about 5% of the annual expected wind energy that could be produced by new wind generation resources in the Generic Wind Case would be curtailed due to limitations on the SPP transmission system.[5] I evaluated a monthly cost associated with such curtailments by using specific PROMOD-based load prices. Note that while the estimated congestion, marginal losses, and curtailment charges I calculated utilized PROMOD simulation outputs, these charges are integrated into the Companies' PLEXOS-based cost of service calculations by the Companies, and thus are reflected in the overall PLEXOS quantification of costs and benefits of the Project. It was necessary to evaluate congestion, losses, and curtailment charges using PROMOD outputs because the Companies' PLEXOS simulations do not include a representation of the SPP's transmission network, and thus are unable to evaluate these important transmission-related charges.

The Companies employed their in-house pricing tool to disaggregate the monthly average into the hourly PSO and SWEPCO thermal generation prices and SPP's AEP zone load prices that are used as PLEXOS simulation inputs. The Companies then simulated in PLEXOS the dispatch of PSO and SWEPCO thermal units against these hourly generation prices for each operating company. PLEXOS calculates each operating company's production cost, adjusted for the cost of any off-system market purchases and for the market revenues from sale of any surplus generation. In addition to this calculation of net production costs for PSO and SWEPCO, PLEXOS accounts for the monthly congestion, loss, and curtailment-related costs associated with delivering 1,900 MW of wind generation resources based on the PROMOD-derived inputs. The use of PROMOD and PLEXOS simulations is summarized in Figure 3 below.

[5] The 5% curtailment future assumption is based on my review of the historical curtailment experience in MISO, and ERCOT as discussed in more detail below.

Figure 3: Process employed for integrating PROMOD and PLEXOS Simulations



Q. PLEASE SUMMARIZE THE METHODOLOGY USED TO INTERPOLATE AND EXTRAPOLATE YEAR 2020 AND 2025 PROMOD PRICES EMPLOYED IN PLEXOS SIMULATIONS FOR THE 25-YEAR STUDY HORIZON.

A. As I noted above, I began with PROMOD simulation results for prices for 2020 and 2025. To interpolate and extrapolate these price results to the other years of the 2021–2045 evaluation period, I employed the following methodology:

1. I began by calculating hourly generation revenue from thermal units for PSO and SWEPCO as simulated by PROMOD. I then aggregated, for each month and each operating company, the total thermal-unit generation revenue and total thermal-unit generation output for three time definitions—Weekday Peak, Weekend Peak, and Nights. The aggregated thermal-unit generation revenues divided by the aggregated thermal unit generation output for each month and each set of peak/night hours yielded the monthly generation-weighted average prices for PSO and SWEPCO.

Similarly, for load prices, I calculated hourly costs to load for the AEP SPP zone in PROMOD, and then aggregated hourly costs to load, and the load MWh for the AEP SPP zone, for each month, by the three defined time frames. I then divided the aggregated costs to load by their corresponding aggregated load MWhs to calculate a load-weighted average monthly load zone price for the three time frames.

These computations resulted in twelve monthly average generation prices for each peak/night time frame, for each operating company, for each PROMOD-simulated year. It also resulted in twelve monthly average load zone prices for each time frame and each simulation year. The load zone prices used are the same for the two operating companies.

2. Next, for interpolating the time-differentiated monthly average prices (load and generation prices), I calculated a constant annual growth rate for each month of the year, based on PROMOD outputs for 2020 and 2025. I then grew the 2020 time-defined monthly average prices for PSO and SWEPCO generation, and load by this constant annual growth rate to produce monthly prices for 2021 through 2024.

3. For years 2026–2045, I employed the annual growth rates for each month implied in the Companies' long-term fundamentals forecast for monthly Around-The-Clock (ATC) prices, and applied the rate of these price changes to the 2025 monthly time-differentiated prices calculated from the PROMOD simulations. Since the Companies' analyses include certain gas price sensitivities, I used the Companies' sensitivity-specific fundamental forecasts of ATC prices to extrapolate monthly time-differentiated PROMOD based prices.

4. For congestion, losses, and curtailment costs I employed the same methodology (as outlined in items 2 and 3 above) to interpolate and extrapolate the monthly costs for the 2021–2045 evaluation period.

IV. BENEFIT METRICS AND METHODOLOGY

Q. DESCRIBE THE BENEFIT METRICS USED IN THIS ANALYSIS.

A. The key benefit metrics employed for analyzing the benefits of the Project are described below. The quantifications of these benefit metrics are presented by company witness Kelly Pearce in his prepared direct testimony.

1. **<u>Adjusted Production Cost (APC) Savings</u>:** The Companies' PLEXOS simulations evaluate the operating Companies' future production costs, net of off-system market purchases and sales of energy, for all three cases analyzed. To evaluate APC savings, it is necessary to calculate the difference in APCs between two relevant cases. This requires that total APC is first calculated for each of the three cases. The Companies estimated these APC savings for (1) the Project Case relative to Base Case; and (2) the Project Case relative to the Generic Wind Case. These savings are calculated annually based on the PLEXOS simulations for 2021 through 2045. Company witness Kelly Pearce provides a summary of APC savings resulting from the development of the Project relative to both the Base Case and the Generic Wind Case.

2. **<u>Additional Cost Savings from Reduced Congestion and Transmission Losses</u>:** The Project can avoid the potentially significant congestion charges between wind sites and the AEP load zone that would be incurred in the Generic Wind Case. As a result, avoiding these wind-generation-related congestion charges incurred in the Generic Wind Case will be a benefit that is realized in addition to the APC savings estimated in the PLEXOS simulations. This is because the PLEXOS simulations do not consider any congestion charges that are incurred serving the Companies' load with the Companies' generation.

   In addition to congestion relief, the Project is expected to reduce SPP marginal-loss-related costs relative to the Generic Wind Case because the Project's generation is injected near Tulsa in close proximity to the Companies' load.[6] Such loss-related SPP costs can differ between the cases because of differences in the electrical proximity between the wind sites and the operating company loads.

   Beyond reducing the marginal loss-related *charges* associated with delivering wind resources to load, the project can also reduce the MWh *quantity* of transmission losses in the Companies' load zone. Standard production cost simulations, such as PROMOD, used to simulate forward-looking market prices (including the charges for transmission losses) hold the MWh quantity of transmission losses constant. This means they do not reflect that delivering large amount of wind energy closer to load in Tulsa may reduce the MWh quantity of transmission losses. As recognized by SPP's Metric Task Force and the Economic Studies Working Group, the additional production cost savings due to such MWh loss reductions can be estimated by post-processing the Marginal Loss Component (MLC) of the LMPs evaluated and reported in PROMOD simulation results.[7] To estimate this benefit, I employ the methodology developed and used by SPP in the company's PROMOD simulation results. I discuss the details of this benefit metric in Exhibit JPP-2.

3. **<u>Reduced Curtailment of Wind Generation</u>:** Wind generation connected to SPP's existing transmission system likely will be subject to curtailment during real-time operations with high-wind and low-load hours. Curtailed wind outputs require the replacement of the curtailed energy through purchases at market prices, imposing

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[6] Losses on the Gen-Tie have been accounted for in the companies' analyses by reducing the Project's MWh delivered at Tulsa.

[7] See Section 7 pg. 17 of SPP Benefit Metrics Manual, November 8, 2016 for a detailed description of SPP Board approved calculation methodology for evaluating changes in MWh quantity of losses based on the Marginal Loss Component of LMPs

curtailment-related costs on the contracting utilities. These curtailment costs would be especially pronounced in the Generic Wind Case, wherein the procured generic wind resources are assumed to be delivered over the SPP transmission system rather than delivered directly to the Tulsa area via the dedicated Gen-Tie. The difference in expected curtailment costs between the Generic Wind and the Project Case is an additional benefit that accrues to the Project.

4. **<u>Capacity Cost Savings</u>:** 1,900 MW of delivered wind generation resources, whether developed as Project or procured from generic wind sites, can reduce the Companies' resource adequacy requirement by a capacity value of approximately 15% of the installed generating capacity. This capacity-value benefit is quantified as the avoided or deferred construction cost of gas-fired generating capacity that would otherwise be needed to meet the future resource adequacy needs of the Companies. Relative to the Base Case, this capacity value benefit will exist for both the Project and the Generic Wind procurement case.

Q. DESCRIBE HOW EACH BENEFIT METRIC WAS CALCULATED IN THIS ANALYSIS.

A. The methodologies used for calculating these benefits are summarized below. Company witness Kelly Pearce discusses in more detail, the calculations undertaken for the APC Savings and Capacity Savings benefit metrics.

1. **Adjusted Production Cost (APC) Savings:** The Companies' PLEXOS simulations evaluate the operating Companies' future production costs, net of off-system market purchases and sales of energy, for all three cases analyzed annually for 2021–2045. Savings are calculated as the difference between APC costs incurred in cases under comparison.

2. **Additional Cost Savings from Reducing Congestion and Transmission Losses:** These savings are evaluated by using PROMOD-based hourly congestion and marginal loss spreads between wind sites and SPP's AEP zone load in 2020 and 2025, and the contemporaneous wind generation outputs. For evaluating transmission losses, I used marginal loss pricing spreads between generation and load in SPP's AEP zone, as well as the loss components associated with purchases imported into the AEP zone.

   The congestion- and loss-related costs are then aggregated on a monthly basis and interpolated/extrapolated between 2021 and 2045 using the same methodology as described for prices previously. These monthly congestion and loss charges are then integrated into the Companies' PLEXOS-based cost-of-service calculations. Similar to the APC savings, congestion and loss related savings are calculated as the difference between the costs incurred in each case under comparison.

3. **Reduced Curtailment of Wind Generation:** Evaluated by applying the contemporaneous monthly average load price (from PROMOD) on an assumed curtailment of 5% of total annual production of Generic Wind, occurring in the night hours of five select months—March, April, October, November, and December. The difference in curtailment costs between the Generic Wind Case and the Project Case is an additional benefit that accrues to the Project. The monthly charges for curtailment are integrated into the PLEXOS-based cost-of-service calculations.

4. **Capacity Cost Savings:** Evaluated by the Companies as the avoided and/or delayed cost of planned Natural Gas Combined Cycle generation resources that can be avoided or deferred as a result of developing or procuring 1,900 MW of new wind generation resources. Calculations include estimating annual savings in the carrying charge as a result of avoiding or deferring planned capacity resources for the operating companies in the Project Case and the Generic Wind Cases, relative to the Base Case.

Q. PLEASE SUMMARIZE THE RESULTS OF PRICES AND BENEFITS EVALUATED BASED ON PROMOD SIMULATIONS

A. Applying the methodology outlined above, and using the PROMOD outputs for 2020 and 2025, I evaluated hourly marginal congestion and loss related costs, transmission loss quantity related costs, and the costs of wind curtailments (applicable only to Generic Wind) for each of the three main cases and the relevant sensitivities analyzed. As explained previously, all benefits are evaluated as the difference in costs incurred in the Project and Base Cases (or the Project and Generic Wind Cases).

Figure 4 below provides a summary of the annual average values of the 2020 and 2025 PROMOD simulation results for the Base Case and the Project Case. The Figure includes a summary of annual average values for time-differentiated locational wholesale marginal prices (Generation LMPs) for PSO and SWEPCO thermal generation resources and for SPP's AEP load zone (which reflects the Load LMP used for both Companies), which are used as inputs for the PLEXOS-based calculations of adjusted production costs presented in company witness Pearce's testimony. Additional details, including summary of the PROMOD simulations' annual average prices and costs and benefits for the Generic Wind Case are provided in Figure 8 of Exhibit JPP-2.

Figure 4: Summary of PROMOD-based Prices and Costs, for Base Case and Project Case in 2020 and 2025

	2020		2025	
	Base Case	Project Case	Base Case	Project Case
Annual Average Weekday-Peak Load LMP ($/MWh)	$48.24	$47.59	$56.78	$55.96
Annual Average Weekend-Peak Load LMP ($/MWh)	$45.72	$45.38	$52.99	$52.35
Annual Average Night Load LMP ($/MWh)	$34.80	$33.55	$40.44	$39.27
Annual Average Weekday-Peak PSO Gen LMP ($/MWh)	$45.44	$44.49	$52.72	$51.13
Annual Average Weekend-Peak PSO Gen LMP ($/MWh)	$43.19	$42.23	$49.36	$48.00
Annual Average Night PSO Gen LMP ($/MWh)	$32.36	$30.10	$37.36	$35.05
Annual Average Weekday-Peak SWEPCO Gen LMP ($/MWh)	$45.88	$45.53	$52.53	$52.12
Annual Average Weekend-Peak SWEPCO Gen LMP ($/MWh)	$44.33	$44.30	$50.14	$49.89
Annual Average Night SWEPCO Gen LMP ($/MWh)	$34.64	$34.12	$40.77	$40.28
Annual Congestion Cost for Wind ($million)	$33	$55	$20	$44
Annual Loss Cost for Wind ($million)	$14	$25	$17	$30
Annual Transmission Loss Quantity Related Costs ($million)	-	$0.2	-	($1.5)

Notes.

1. Figure shows prices and costs incurred for Base Case and Project Case.

2. Reduced Transmission Loss Quantity benefit metric evaluated using SPP methodology, which directly evaluates the difference between two cases under comparison. Negative value in figure above (for Project Case in 2025) reflects the cost reduction associated with the reduced quantity of transmission losses for the Project Case relative to Base Case.

Q. WHY DID YOU SEPARATELY ESTIMATE FUTURE WIND CURTAILMENT LEVELS AS OPPOSED TO RELYING ON THE PROMOD SIMULATIONS OF SUCH CURTAILMENTS?

A. As explained earlier, PROMOD simulations are based on somewhat simplified assumptions that do not fully capture real-world market outcomes. From a wind curtailment perspective, the most impactful simplifying assumption is that PROMOD is based on deterministic inputs for all operating conditions, meaning that it is implicitly assumed that market operators would have perfect foresight of actual system conditions when they make generation unit commitment decisions on a day-ahead basis. This, however, ignores the considerable uncertainty that exists with respect to load and wind generation and makes the PROMOD simulations more akin to a day-ahead market. Just as there are very few wind curtailments scheduled on a day-ahead basis, PROMOD simulations yield very few wind curtailments. Under actual operating conditions, such curtailments do however exist in the real-time market. Because PROMOD does not simulate the uncertainties associated with real-time market conditions, a realistic level of real-time wind curtailments has to be added to the PROMOD simulation results.

On a related note, another simplified assumption is the fact that PROMOD simulations are based on a fully-intact transmission system with transmission constraints defined such that the system would remain reliable for some period of time even if there was an outage on a major transmission line. In other words, the constraints simulated are based on "N-1 contingency conditions" defined by SPP for planning assessments. The simulations, however, do not consider any actual transmission outages which would create more severe transmission constraints based on N-2 contingency conditions.[8] Not simulating actual transmission outages understates estimated congestion charges, which means that the simulated congestion costs associated with generic wind developments will be a conservative estimate.

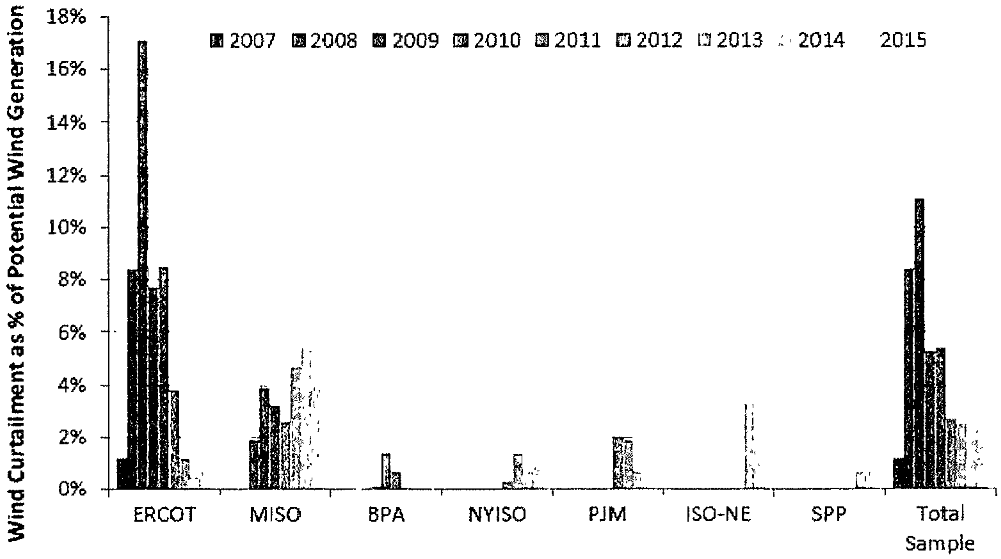
[8] N-1 contingency condition refers to a grid planning and design criteria which allows for the outage of one transmission element of the bulk transmission system. At a minimum, networked transmission systems are designed to withstand the outage of any one transmission element. In other words, the transmission network is designed so that it will not get overloaded even if there is an outage on a major transmission line. Once such an N-1 condition occurs, the rest of the system needs to be operated at lower throughput such that it can remain reliable and dynamically stable if a second transmission line were subject to outage (*i.e.*, creating an N-2 condition).

Q. PLEASE DESCRIBE YOUR ASSUMPTIONS FOR ESTIMATING ANTICIPATED FUTURE WIND GENERATION CURTAILMENT LEVELS.

A. To determine a reasonable estimate of anticipated future wind generation curtailment, I first reviewed historical annual wind generation curtailment data in SPP and other RTOs. SPP's historical curtailment data indicates that economic curtailments of wind generation in SPP thus far have been low: around 1% to 2% annually. However, historical curtailment levels in neighboring regions that have experienced more significant growth in wind generation—Electric Reliability Council of Texas ("ERCOT") and western MISO—have averaged around 5% annually between 2009 and 2015.

ERCOT, for example, has experienced very high curtailment reaching up to 17% in 2009. Wind curtailment levels in MISO have been relatively less varied (see Figure 4) but have also averaged around 5% during the same period. Because SPP is currently in the midst of a similar build-out of wind resources, with significant levels of new wind generation expected between now and 2021, I assumed that SPP average curtailment levels in the Generic Wind case will rise to the average levels similar to those experienced in ERCOT and MISO historically.

Figure 5: Historical Estimate of Wind Curtailment by Region



Source: 2015 Wind Technologies Market Report (Figure 31 on p. 41)

V. ESTIMATING PRICES OF GENERIC WIND PROCUREMENT

Q. PLEASE DESCRIBE HOW YOU ESTIMATED THE PRICES OF GENERIC FUTURE WIND PROCUREMENTS IN SPP.

A. To estimate the likely PPA pricing of wind generation that would be incurred in the Generic Wind Case, I estimated the levelized costs of new wind resources developed in SPP. To undertake this analysis I relied on the U.S. Energy Information Administration's 2017 AEO report, which covers both cost and performance characteristics of new generating technologies by region. The 2017 AEO reported the total overnight costs of on-shore wind resources in the SPP South region, available for operation as of 2019, as $1,536/kW. I use this overnight cost as a reasonable proxy for the 2021 wind additions assumed in the Generic Wind Case. Additionally, I used AEO-reported fixed O&M of $52/kw-year estimate (nominal$) for on-shore wind, and assumed an annual price escalation rate of 2.25%. I also assumed an average capacity factor of 48% for the generic wind as a reasonable estimate based on my review of NREL's wind capacity factor data for locations across SPP. As NREL data indicates, wind generation capacity factors can vary significantly across SPP, averaging around 45% at the 24 sites[9] used by SPP to model generic wind resources in PROMOD. Because SPP's ITP10 PROMOD model used the 2012 data set from NREL and newer technologies have continued to increase average capacity factors, I assumed a higher 48% capacity factor as a more reasonable estimate.

The financial assumptions to estimate the levelized cost of energy (increasing at 2.25% a year in nominal terms) are summarized in Figure 5 below.

Figure 6: Financial Assumptions for Estimating the Levelized Cost of Generic Wind

Economic Life of Asset	25 Years
Equity Capitalization	50%
Cost of Equity	12.50%
Cost of Debt	6%
Marginal Tax Rate	38.90%
Tax Depreciation Schedule	5yr MACRS
Production Tax Credit in 2021	$26/MWh

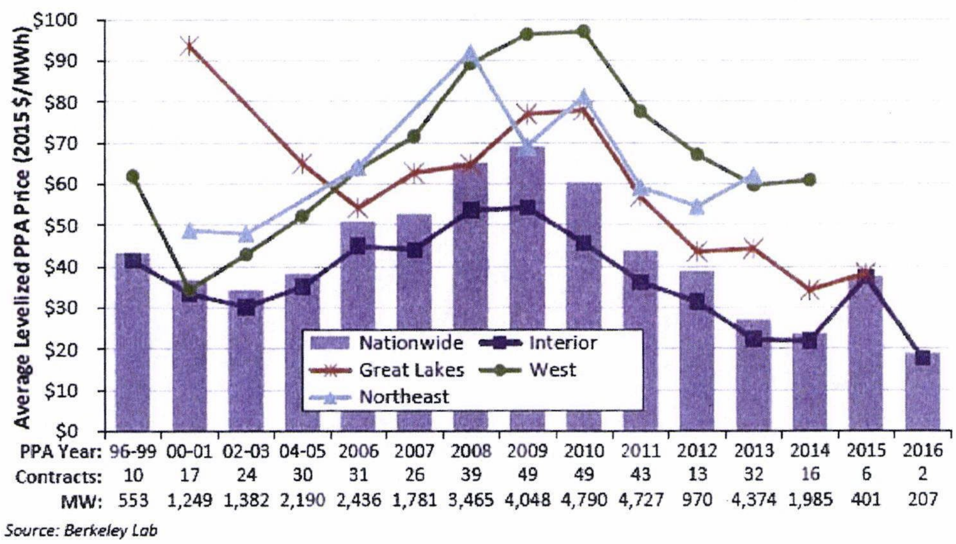
Q. WHAT PRICING ESTIMATE DID YOUR CALCULATIONS YIELD, AND IS IT REASONABLE?

A. My calculations resulted in a levelized cost of wind energy of $18.62/MWh in 2021, escalating at 2.25% annually for 25 years. I believe that this is a reasonable estimate for pricing of new wind generation resources in SPP. For reference, the most recent estimates from Lazard's Levelized Cost of Energy Analysis, shows the levelized costs for wind (when able to take advantage of production tax credits) range from $14/MWh to

[9] Provided by the companies based on SPP's 2017 ITP10 PROMOD Models for 2020 and 2025

$48/MWh[10] across the country. Within that range, the U.S. Department of Energy's 2015 Wind Technologies Market Report reported that the average wind PPA prices (averaged by PPA execution date) for the "Interior" region of the nation had steadily trended down, with a 2016 average executed price of around $19/MWh as shown in Figure 6 below.

Figure 7: Historical Average of Wind PPA Prices



Source: 2015 Wind Technologies Market Report (Figure 48 on p. 63)

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

[10] Lazard's Levelized Cost of Energy Analysis—version 10.0 accessed here: https://www.lazard.com/media/438038/levelized-cost-of-energy-v100.pdf

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Annual Energy Outlook 2020

Table: Table 56. Electricity Generation Capacity by Electricity Market Module Region and Source

Case: Reference case

PUBLICATIONS & TABLES

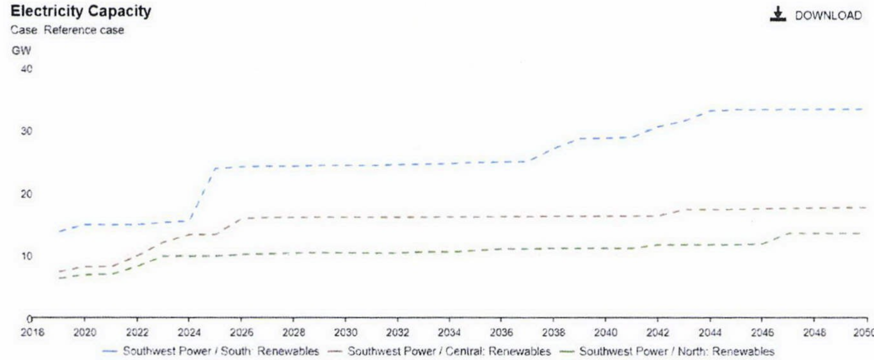

CHART INDEXING OPTIONS: None Index to Start as Percent Index to Start as Value

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Time-series Map Annual Every 5th Year 2019 2050

PIN	2019	2020	2021	2022	2023	2024	2025
Distributed Generation (GW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Southwest Power Pool / Central (GW)	24.9	25.4	24.7	26.2	28.8	29.6	28.5
Coal (GW)	7.7	7.5	7.5	7.3	7.3	6.8	4.9
Oil and Natural Gas Steam[1] (GW)	1.2	1.1	0.4	0.4	0.4	0.3	0.3
Combined Cycle (GW)	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Combustion Turbine / Diesel (GW)	5.8	5.8	5.8	5.8	6.2	6.3	7.1
Nuclear Power (GW)	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Pumped Storage (GW)	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Fuel Cells (GW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[2] (GW)	7.2	8.0	8.0	9.7	11.9	13.1	13.1
Distributed Generation (GW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Southwest Power Pool / North (GW)	16.1	16.7	16.7	18.0	19.5	19.1	18.5
Coal (GW)	5.4	5.4	5.4	5.4	5.4	5.0	4.7
Oil and Natural Gas Steam[1] (GW)	0.4	0.4	0.4	0.4	0.3	0.0	0.0
Combined Cycle (GW)	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Combustion Turbine / Diesel (GW)	2.8	2.8	2.8	2.8	2.8	3.0	3.4
Nuclear Power (GW)	0.8	0.8	0.8	0.8	0.8	0.8	0.0
Pumped Storage (GW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells (GW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[2] (GW)	6.1	6.7	6.8	8.1	9.7	9.7	9.7
Distributed Generation (GW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Western Electricity Coordinating Council							
Southwest (GW)	39.4	39.0	40.1	43.5	49.1	49.2	49.9
Coal (GW)	6.7	5.9	5.9	5.9	5.9	3.2	2.4

[1] Includes oil-, gas-, and dual-fired capacity.

[2] Includes conventional hydroelectric, geothermal, wood, wood waste, municipal waste, landfill gas, other biomass, solar, and wind power.

- = Not applicable.

Note: Totals may not equal sum of components due to independent rounding. Includes electricity-only and combined heat and power plants that have a regulatory status. Values represent net summer capacity, which is the steady hourly output that generating equipment is expected to supply to system load as demonstrated by tests during summer peak load.

Sources:

Report," (preliminary). U.S. Energy Information Administration (EIA), Short-Term Energy Outlook, October 2019 and EIA, AEO2020 National Energy Modeling System. Projections: EIA, AEO2020 National Energy Modeling System.

SOAH Docket No. 473-19-6862
PUC Docket No. 49737

SWEPCO Exhibit 40

Annual Energy Outlook 2020

Table: Table 56. Electricity Generation Capacity by Electricity Market Module Region and Source

Case: Reference case

Electricity Capacity

Case: Reference case

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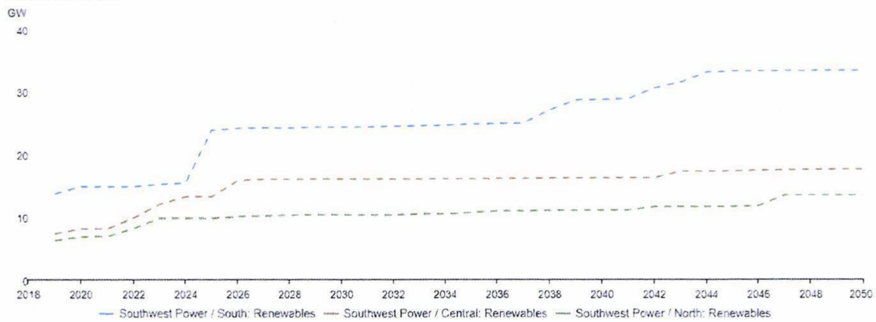

CHART INDEXING OPTIONS: **None** Index to Start as Percent Index to Start as Value

Time-series Map Annual Every 5th Year 2019 2060

PIN	2026	2027	2028	2029	2030	2031	2032
Distributed Generation (GW)	0.0	0.0	0.0	0.0	0.1	0.1	0.1
Southwest Power Pool / Central (GW)	29.9	31.1	31.4	31.5	31.7	31.8	31.9
Coal (GW)	4.9	4.9	4.9	4.9	4.9	4.9	4.9
Oil and Natural Gas Steam[1] (GW)	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Combined Cycle (GW)	1.6	2.0	2.0	2.0	2.0	2.0	2.0
Combustion Turbine / Diesel (GW)	7.3	7.8	8.1	8.2	8.4	8.5	8.6
Nuclear Power (GW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage (GW)	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Fuel Cells (GW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[2] (GW)	15.7	15.9	15.9	15.9	15.9	15.9	15.9
Distributed Generation (GW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Southwest Power Pool / North (GW)	18.7	18.9	19.0	19.2	19.3	19.4	19.4
Coal (GW)	4.7	4.7	4.7	4.7	4.7	4.7	4.7
Oil and Natural Gas Steam[1] (GW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle (GW)	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Combustion Turbine / Diesel (GW)	3.4	3.4	3.4	3.6	3.7	3.7	3.8
Nuclear Power (GW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage (GW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells (GW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[2] (GW)	9.9	10.1	10.2	10.2	10.2	10.2	10.2
Distributed Generation (GW)	0.0	0.0	0.0	0.1	0.1	0.1	0.1
Western Electricity Coordinating Council							
Southwest (GW)	50.4	50.9	51.7	52.4	53.2	54.4	55.5
Coal (GW)	2.0	2.0	2.0	2.0	2.0	2.0	2.0

[1] Includes oil-, gas-, and dual-fired capacity.

[2] Includes conventional hydroelectric, geothermal, wood, wood waste, municipal waste, landfill gas, other biomass, solar, and wind power.

- - = Not applicable.

Note: Totals may not equal sum of components due to independent rounding. Includes electricity-only and combined heat and power plants that have a regulatory status. Values represent net summer capacity, which is the steady hourly output that generating equipment is expected to supply to system load as demonstrated by tests during summer peak load.

Sources:

Report," (preliminary). U.S. Energy Information Administration (EIA), Short-Term Energy Outlook, October 2019 and EIA, AEO2020 National Energy Modeling System. Projections: EIA, AEO2020 National Energy Modeling System.

Annual Energy Outlook 2020
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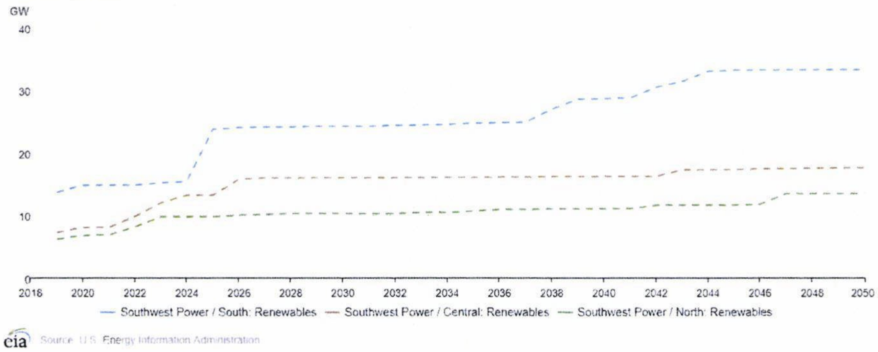

CHART INDEXING OPTIONS: None Index to Start as Percent Index to Start as Value

Time-series Map Annual Every 5th Year 2019 2050

PIN	2033	2034	2035	2036	2037	2038	2039
Distributed Generation (GW)	0.1	0.1	0.2	[illegible]	0.2	0.2	0.3
Southwest Power Pool / Central (GW)	32.1	32.2	32.3	32.5	32.7	32.9	33.1
Coal (GW)	4.9	4.9	4.9	4.9	4.9	4.9	4.9
Oil and Natural Gas Steam[1] (GW)	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Combined Cycle (GW)	2.0	2.0	2.0	2.0	2.0	2.0	2.3
Combustion Turbine / Diesel (GW)	8.7	8.8	8.9	9.0	9.2	9.3	9.3
Nuclear Power (GW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage (GW)	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Fuel Cells (GW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[2] (GW)	15.9	16.0	16.0	16.0	16.0	16.1	16.1
Distributed Generation (GW)	0.0	0.1	0.1	0.1	0.1	0.1	0.1
Southwest Power Pool / North (GW)	19.6	19.8	20.1	20.4	20.6	20.9	21.1
Coal (GW)	4.7	4.7	4.7	4.7	4.7	4.7	4.7
Oil and Natural Gas Steam[1] (GW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle (GW)	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Combustion Turbine / Diesel (GW)	3.8	4.0	4.0	4.1	4.2	4.4	4.6
Nuclear Power (GW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage (GW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells (GW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[2] (GW)	10.4	10.4	10.6	10.9	10.9	10.9	10.9
Distributed Generation (GW)	0.1	0.1	0.1	0.1	0.2	0.2	0.2
Western Electricity Coordinating Council							
Southwest (GW)	56.2	56.9	58.0	59.3	60.5	61.8	62.9
Coal (GW)	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Oil and Natural Gas Steam[1] (GW)	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Combined Cycle (GW)	17.4	17.5	18.2	18.6	19.4	20.5	21.4

[1] Includes oil-, gas-, and dual-fired capacity.
[2] Includes conventional hydroelectric, geothermal, wood, wood waste, municipal waste, landfill gas, other biomass, solar, and wind power.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Includes electricity-only and combined heat and power plants that have a regulatory status. Values represent net summer capacity, which is the steady hourly output that generating equipment is expected to supply to system load as demonstrated by tests during summer peak load.
Sources:
Report," (preliminary). U.S. Energy Information Administration (EIA), Short-Term Energy Outlook, October 2019 and EIA, AEO2020 National Energy Modeling System. Projections: EIA, AEO2020 National Energy Modeling System.

Annual Energy Outlook 2020

Table: Table 56. Electricity Generation Capacity by Electricity Market Module Region and Source

Case: Reference case

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Electricity Capacity

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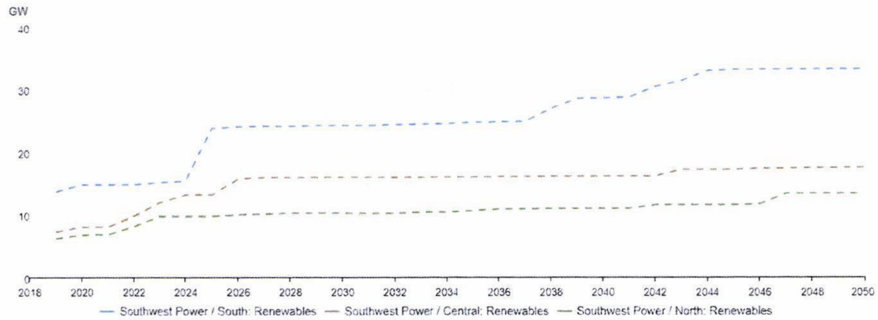

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Time-series Map Annual Every 5th Year 2019 2050

PIN	2040	2041	2042	2043	2044	2045	2046
Distributed Generation (GW)	0.3	0.3	0.4	0.4	0.4	0.4	0.5
Southwest Power Pool / Central (GW)	33.3	33.6	33.7	34.9	35.1	35.3	35.7
Coal (GW)	4.9	4.9	4.9	4.9	4.9	4.9	4.9
Oil and Natural Gas Steam[1] (GW)	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Combined Cycle (GW)	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Combustion Turbine / Diesel (GW)	9.5	9.7	9.9	10.0	10.2	10.4	10.6
Nuclear Power (GW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage (GW)	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Fuel Cells (GW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[2] (GW)	16.1	16.1	16.1	17.2	17.2	17.2	17.3
Distributed Generation (GW)	0.1	0.1	0.1	0.1	0.1	0.2	0.2
Southwest Power Pool / North (GW)	21.2	21.4	22.0	22.1	22.3	22.4	22.7
Coal (GW)	4.7	4.7	4.7	4.7	4.7	4.7	4.7
Oil and Natural Gas Steam[1] (GW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle (GW)	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Combustion Turbine / Diesel (GW)	4.7	4.8	4.8	4.9	5.1	5.2	5.3
Nuclear Power (GW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage (GW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells (GW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[2] (GW)	11.0	11.0	11.5	11.5	11.5	11.5	11.7
Distributed Generation (GW)	0.2	0.3	0.3	0.3	0.3	0.3	0.4
Western Electricity Coordinating Council							
Southwest (GW)	65.4	66.8	71.0	72.7	74.1	76.0	77.1
Coal (GW)	2.0	2.0	2.0	2.0	2.0	2.0	2.0

[1] Includes oil-, gas-, and dual-fired capacity

[2] Includes conventional hydroelectric, geothermal, wood, wood waste, municipal waste, landfill gas, other biomass, solar, and wind power.

- - = Not applicable

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Sources:

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Annual Energy Outlook 2020

Table: Table 56. Electricity Generation Capacity by Electricity Market Module Region and Source

Case: Reference case

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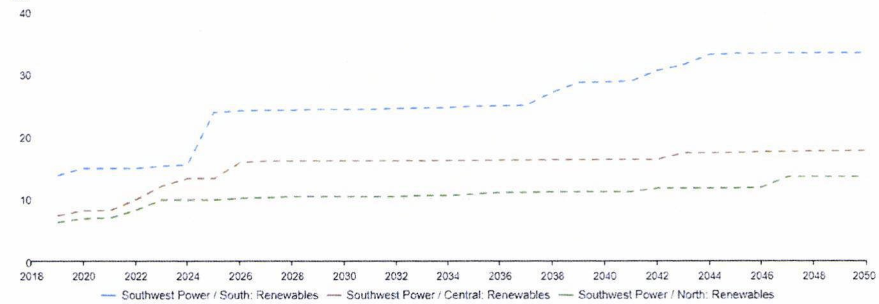
Electricity Capacity

Case: Reference case



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Time-series Map Annual Every 5th Year 2019 2050

PIN	5	2047	2048	2049	2050	Growth (2019-2050)
Distributed Generation (GW)	5	0.5	0.6	0.6	0.6	- -
Southwest Power Pool / Central (GW)	7	35.9	36.3	36.5	36.8	1.3%
Coal (GW)	9	4.9	4.9	4.9	4.9	-1.5%
Oil and Natural Gas Steam[1] (GW)	3	0.3	0.3	0.3	0.3	-4.3%
Combined Cycle (GW)	3	2.3	2.3	2.3	2.3	1.1%
Combustion Turbine / Diesel (GW)	6	10.8	11.0	11.2	11.5	2.2%
Nuclear Power (GW)	0	0.0	0.0	0.0	0.0	- -
Pumped Storage (GW)	2	0.2	0.2	0.2	0.2	0.0%
Fuel Cells (GW)	0	0.0	0.0	0.0	0.0	- -
Renewable Sources[2] (GW)	3	17.3	17.4	17.5	17.5	2.9%
Distributed Generation (GW)	2	0.2	0.2	0.2	0.2	- -
Southwest Power Pool / North (GW)	7	24.2	24.6	24.6	24.8	1.4%
Coal (GW)	7	4.4	4.4	4.4	4.4	-0.6%
Oil and Natural Gas Steam[1] (GW)	0	0.0	0.0	0.0	0.0	-7.5%
Combined Cycle (GW)	7	0.7	0.7	0.7	0.7	0.0%
Combustion Turbine / Diesel (GW)	3	5.3	5.7	5.7	5.8	2.4%
Nuclear Power (GW)	0	0.0	0.0	0.0	0.0	- -
Pumped Storage (GW)	0	0.0	0.0	0.0	0.0	
Fuel Cells (GW)	0	0.0	0.0	0.0	0.0	- -
Renewable Sources[2] (GW)	7	13.4	13.4	13.4	13.4	2.6%
Distributed Generation (GW)	4	0.4	0.4	0.4	0.5	
Western Electricity Coordinating Council						
Southwest (GW)	1	78.4	81.1	84.2	86.3	2.6%
Coal (GW)	0	2.0	2.0	2.0	2.0	-3.8%

[1] Includes oil-, gas-, and dual-fired capacity.
[2] Includes conventional hydroelectric, geothermal, wood, wood waste, municipal waste, landfill gas, other biomass, solar, and wind power.
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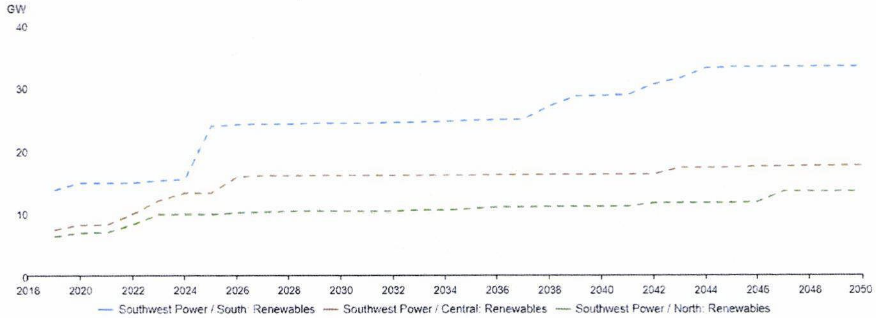

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Time-series Map Annual Every 5th Year 2019 2050

PIN	2019	2020	2021	2022	2023	2024	2025
Combined Cycle (GW)	10.5	10.5	10.5	10.5	10.5	10.5	10.5
Combustion Turbine / Diesel (GW)	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Nuclear Power (GW)	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Pumped Storage (GW)	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Fuel Cells (GW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[2] (GW)	5.6	5.6	5.9	6.0	6.2	7.2	7.2
Distributed Generation (GW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Southwest Power Pool / South (GW)	45.6	46.6	46.3	44.9	43.7	43.6	49.3
Coal (GW)	9.9	9.9	9.9	8.8	7.7	7.7	5.0
Oil and Natural Gas Steam[1] (GW)	8.2	8.0	7.7	7.4	7.0	6.7	6.6
Combined Cycle (GW)	9.2	9.2	9.2	9.2	9.2	9.2	9.2
Combustion Turbine / Diesel (GW)	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Nuclear Power (GW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage (GW)	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Fuel Cells (GW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[2] (GW)	13.6	14.7	14.7	14.7	15.1	15.3	23.7
Distributed Generation (GW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Southwest Power Pool / Central (GW)	24.9	25.4	24.7	26.2	28.8	29.6	28.5
Coal (GW)	7.7	7.5	7.5	7.3	7.3	6.8	4.9
Oil and Natural Gas Steam[1] (GW)	1.2	1.1	0.4	0.4	0.4	0.3	0.3
Combined Cycle (GW)	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Combustion Turbine / Diesel (GW)	5.8	5.8	5.8	5.8	6.2	6.3	7.1
Nuclear Power (GW)	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Pumped Storage (GW)	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Fuel Cells (GW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[2] (GW)	7.2	8.0	8.0	9.7	11.0	12.1	12.1

[1] Includes oil-, gas-, and dual-fired capacity.
[2] Includes conventional hydroelectric, geothermal, wood, wood waste, municipal waste, landfill gas, other biomass, solar, and wind power.
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PUC Docket No. 49737

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Table: Table 56. Electricity Generation Capacity by Electricity Market Module Region and Source

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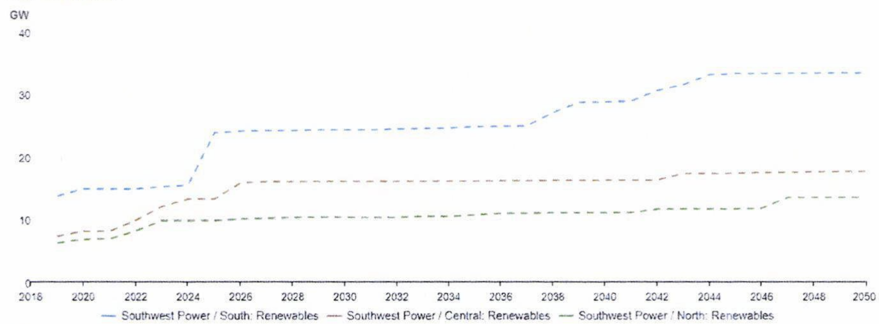

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Time-series Map Annual Every 5th Year 2019 2050

PIN	2026	2027	2028	2029	2030	2031	2032
Combined Cycle (GW)	10.5	10.5	10.5	10.5	10.5	10.5	10.5
Combustion Turbine / Diesel (GW)	7.7	7.7	7.7	7.7	8.1	8.5	8.8
Nuclear Power (GW)	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Pumped Storage (GW)	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Fuel Cells (GW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[2] (GW)	7.8	7.9	8.9	10.3	10.3	10.3	10.3
Distributed Generation (GW)	0.0	0.0	0.0	0.0	0.0	0.1	0.1
Southwest Power Pool / South (GW)	50.4	50.7	51.1	51.4	51.9	52.3	52.9
Coal (GW)	5.0	4.5	4.5	4.2	4.2	4.2	4.2
Oil and Natural Gas Steam[1] (GW)	6.4	6.4	6.2	6.1	6.1	5.8	5.6
Combined Cycle (GW)	10.4	10.7	10.7	11.0	11.0	11.1	11.4
Combustion Turbine / Diesel (GW)	4.4	4.8	5.4	5.7	6.1	6.6	7.1
Nuclear Power (GW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage (GW)	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Fuel Cells (GW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[2] (GW)	24.0	24.1	24.1	24.2	24.2	24.2	24.3
Distributed Generation (GW)	0.0	0.0	0.0	0.0	0.1	0.1	0.1
Southwest Power Pool / Central (GW)	29.9	31.1	31.4	31.5	31.7	31.8	31.9
Coal (GW)	4.9	4.9	4.9	4.9	4.9	4.9	4.9
Oil and Natural Gas Steam[1] (GW)	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Combined Cycle (GW)	1.6	2.0	2.0	2.0	2.0	2.0	2.0
Combustion Turbine / Diesel (GW)	7.3	7.8	8.1	8.2	8.4	8.5	8.6
Nuclear Power (GW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage (GW)	0.2	0.2	0.2	0.2	0.2	0.2	0.2

[1] Includes oil-, gas-, and dual-fired capacity

[2] Includes conventional hydroelectric, geothermal, wood, wood waste, municipal waste, landfill gas, other biomass, solar, and wind power

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Sources

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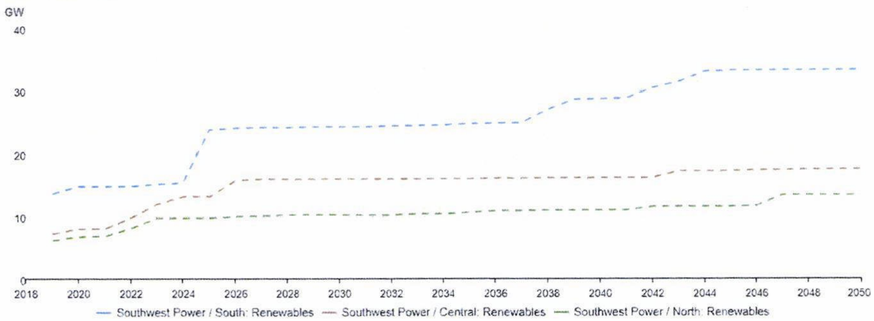

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Time-series Map Annual Every 5th Year 2019 2050

PIN	2033	2034	2035	2036	2037	2038	2039
Combined Cycle (GW)	10.7	10.9	10.9	10.9	11.5	11.9	12.5
Combustion Turbine / Diesel (GW)	9.1	9.3	9.9	10.1	10.1	10.1	10.1
Nuclear Power (GW)	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Pumped Storage (GW)	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Fuel Cells (GW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[2] (GW)	10.4	10.5	10.5	12.1	12.1	12.1	12.1
Distributed Generation (GW)	0.1	0.1	0.1	0.1	0.2	0.3	0.3
Southwest Power Pool / South (GW)	53.2	53.6	54.2	54.9	55.5	57.7	60.1
Coal (GW)	4.2	4.2	4.2	4.2	3.8	2.8	2.4
Oil and Natural Gas Steam[1] (GW)	5.6	5.6	5.3	5.3	5.3	5.3	5.3
Combined Cycle (GW)	11.4	11.6	11.9	12.4	12.6	13.1	13.1
Combustion Turbine / Diesel (GW)	7.3	7.3	7.7	7.8	8.4	9.0	10.2
Nuclear Power (GW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage (GW)	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Fuel Cells (GW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[2] (GW)	24.4	24.5	24.7	24.8	24.8	26.9	28.5
Distributed Generation (GW)	0.1	0.1	0.2	0.2	0.2	0.2	0.3
Southwest Power Pool / Central (GW)	32.1	32.2	32.3	32.5	32.7	32.9	33.1
Coal (GW)	4.9	4.9	4.9	4.9	4.9	4.9	4.9
Oil and Natural Gas Steam[1] (GW)	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Combined Cycle (GW)	2.0	2.0	2.0	2.0	2.0	2.0	2.3
Combustion Turbine / Diesel (GW)	8.7	8.8	8.9	9.0	9.2	9.3	9.3
Nuclear Power (GW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage (GW)	0.2	0.2	0.2	0.2	0.2	0.2	0.2

[1] Includes oil- gas- and dual-fired capacity
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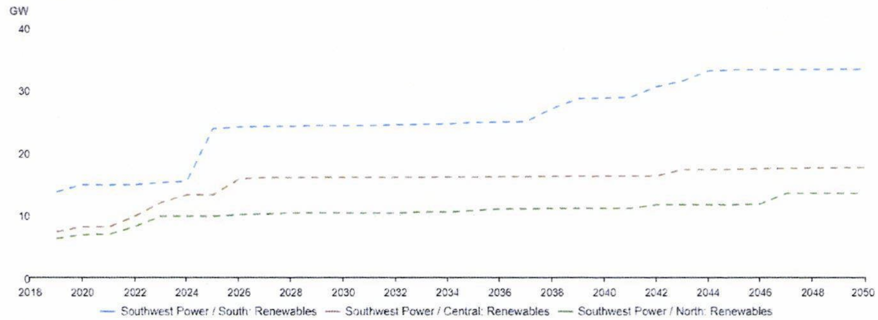

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Time-series | Map | Annual | Every 5th Year | 2019 – 2050

	2040	2041	2042	2043	2044	2045	2046
Combined Cycle (GW)	12.8	12.8	12.8	14.3	14.4	14.6	14.6
Combustion Turbine / Diesel (GW)	10.3	10.3	10.3	10.3	10.6	10.8	11.2
Nuclear Power (GW)	8.3	8.3	8.3	7.1	7.1	7.1	7.1
Pumped Storage (GW)	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Fuel Cells (GW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[2] (GW)	12.1	17.5	17.5	17.5	17.5	17.5	17.5
Distributed Generation (GW)	0.4	0.4	0.5	0.6	0.7	0.7	0.8
Southwest Power Pool / South (GW)	60.6	61.3	63.6	65.1	67.3	68.2	68.6
Coal (GW)	2.4	2.1	2.1	2.1	2.1	2.1	2.1
Oil and Natural Gas Steam[1] (GW)	5.3	5.3	5.3	5.3	5.3	5.3	5.3
Combined Cycle (GW)	13.3	13.5	13.8	13.8	13.8	13.9	13.9
Combustion Turbine / Diesel (GW)	10.4	11.0	11.3	12.0	12.5	12.6	13.0
Nuclear Power (GW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage (GW)	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Fuel Cells (GW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[2] (GW)	28.6	28.7	30.4	31.3	32.9	33.1	33.1
Distributed Generation (GW)	0.3	0.3	0.4	0.4	0.4	0.4	0.5
Southwest Power Pool / Central (GW)	33.3	33.6	33.7	34.9	35.1	35.3	35.7
Coal (GW)	4.9	4.9	4.9	4.9	4.9	4.9	4.9
Oil and Natural Gas Steam[1] (GW)	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Combined Cycle (GW)	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Combustion Turbine / Diesel (GW)	9.5	9.7	9.9	10.0	10.2	10.4	10.6
Nuclear Power (GW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage (GW)	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Fuel Cells (GW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[2] (GW)	16.1	16.1	16.1	17.2	17.2	17.2	17.2

[1] Includes oil-, gas- and dual-fired capacity.

[2] Includes conventional hydroelectric, geothermal, wood, wood waste, municipal waste, landfill gas, other biomass, solar, and wind power.

- - = Not applicable.

Note: Totals may not equal sum of components due to independent rounding. Includes electricity-only and combined heat and power plants that have a regulatory status. Values represent net summer capacity, which is the steady hourly output that generating equipment is expected to supply to system load as demonstrated by tests during summer peak load.

Sources:

Report," (preliminary). U.S. Energy Information Administration (EIA), Short-Term Energy Outlook, October 2019 and EIA, AEO2020 National Energy Modeling System. Projections: EIA, AEO2020 National Energy Modeling System.

Annual Energy Outlook 2020

Table: Table 56. Electricity Generation Capacity by Electricity Market Module Region and Source

Case: Reference case

Electricity Capacity

Case: Reference case

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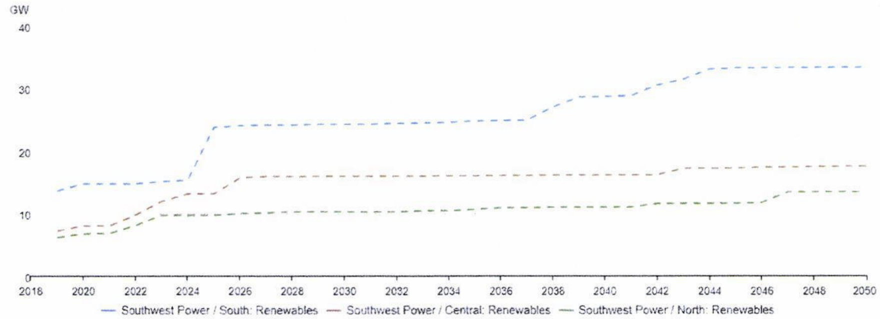

eia Source: U.S. Energy Information Administration

CHART INDEXING OPTIONS: **None** Index to Start as Percent Index to Start as Value

Time-series Map | Annual Every 5th Year | 2019 — 2050

PIN	5	2047	2048	2049	2050	Growth (2019-2050)
Combined Cycle (GW)	6	14.8	14.8	15.5	15.9	1.3%
Combustion Turbine / Diesel (GW)	2	11.4	11.8	11.8	11.8	1.4%
Nuclear Power (GW)	1	7.1	7.1	7.1	7.1	-0.5%
Pumped Storage (GW)	7	1.7	1.7	1.7	1.7	0.0%
Fuel Cells (GW)	0	0.0	0.0	0.0	0.0	- -
Renewable Sources[2] (GW)	5	17.6	17.6	17.6	17.6	3.8%
Distributed Generation (GW)	8	0.9	1.0	1.0	1.1	- -
Southwest Power Pool / South (GW)	6	69.2	69.9	70.6	71.3	1.4%
Coal (GW)	1	2.1	2.1	2.1	2.1	-4.9%
Oil and Natural Gas Steam[1] (GW)	3	5.3	5.3	5.3	5.3	-1.4%
Combined Cycle (GW)	9	14.1	14.1	14.1	14.2	1.4%
Combustion Turbine / Diesel (GW)	0	13.3	13.9	14.3	14.9	3.9%
Nuclear Power (GW)	0	0.0	0.0	0.0	0.0	- -
Pumped Storage (GW)	3	0.3	0.3	0.3	0.3	0.0%
Fuel Cells (GW)	0	0.0	0.0	0.0	0.0	- -
Renewable Sources[2] (GW)	1	33.2	33.2	33.2	33.2	2.9%
Distributed Generation (GW)	5	0.5	0.6	0.6	0.6	- -
Southwest Power Pool / Central (GW)	7	35.9	36.3	36.5	36.8	1.3%
Coal (GW)	9	4.9	4.9	4.9	4.9	-1.5%
Oil and Natural Gas Steam[1] (GW)	3	0.3	0.3	0.3	0.3	-4.3%
Combined Cycle (GW)	3	2.3	2.3	2.3	2.3	1.1%
Combustion Turbine / Diesel (GW)	6	10.8	11.0	11.2	11.5	2.2%
Nuclear Power (GW)	0	0.0	0.0	0.0	0.0	- -
Pumped Storage (GW)	2	0.2	0.2	0.2	0.2	0.0%

[1] Includes oil-, gas-, and dual-fired capacity.
[2] Includes conventional hydroelectric, geothermal, wood, wood waste, municipal waste, landfill gas, other biomass, solar, and wind power.
- - = Not applicable.

Note: Totals may not equal sum of components due to independent rounding. Includes electricity-only and combined heat and power plants that have a regulatory status. Values represent net summer capacity, which is the steady hourly output that generating equipment is expected to supply to system load as demonstrated by tests during summer peak load.

Sources:

Report," (preliminary). U.S. Energy Information Administration (EIA), Short-Term Energy Outlook, October 2019 and EIA, AEO2020 National Energy Modeling System. Projections: EIA, AEO2020 National Energy Modeling System.