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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

DIRECT TESTIMONY

AND EXHIBITS

OF

JOHN W. CHILES

ON BEHALF OF THE

EAST TEXAS ELECTRIC COOPERATIVE, INC.

AND

NORTHEAST TEXAS ELECTRIC COOPERATIVE, INC.

JANUARY 14, 2020

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DIRECT TESTIMONY AND EXHIBITS OF JOHN W. CHILES

I. EXPERIENCE AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John W. Chiles. My business address is 1850 Parkway Place SE, Suite 800, Marietta, Georgia 30067.

Q. PLEASE OUTLINE YOUR FORMAL EDUCATION.

A. I received a Bachelor of Science in Engineering from the University of South Florida in Tampa, Florida in December 1993.

Q. WHAT IS YOUR PRESENT POSITION?

A. I am a Principal in the Transmission Services Group of GDS Associates, Inc. ("GDS") in Marietta, Georgia.

Q. PLEASE STATE YOUR PROFESSIONAL EXPERIENCE.

A. My professional experience is described in Exhibit JWC-1.

Q. WOULD YOU PLEASE DESCRIBE GDS?

A. GDS is an engineering and consulting firm with offices in Marietta, Georgia; Austin, Texas; Auburn, Alabama; Manchester, New Hampshire; Madison, Wisconsin; and Orlando, Florida. GDS has over 160 employees with backgrounds in engineering, accounting, management, economics, finance, and statistics. GDS provides rate and regulatory consulting services in the electric, natural gas, water, storm, and telephone utility industries. GDS also provides a variety of other services in the electric utility industry including power supply planning, generation support services, energy procurement and contracting, energy efficiency program development, financial analysis, load forecasting, and statistical services. Our clients are primarily privately-owned utilities, publicly-owned utilities, municipalities, customers of investor-owned utilities, groups or associations of customers, and government agencies.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. Yes. Included in Exhibit JWC-1 list of regulatory proceedings in which I have presented expert witness testimony.

II. INTRODUCTION

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf East Texas Electric Cooperative, Inc. ("East Texas" or "ETEC") a generation and transmission ("G&T") cooperative and Northeast Texas Electric Cooperative, Inc. ("NTEC"), also a G&T cooperative. Both cooperatives are currently wholesale customers of Southwestern Electric Power Company ("the Company" or "SWEPCO"). Hereinafter, both cooperatives will be referred to as the "Cooperatives."

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my testimony is to address statements made by Witnesses Godfrey, Torpey, Ali, Sheilendranath and Pfeifenberger regarding the deliverability, required transmission facilities, need for the Gen-Tie project, and transmission congestion evaluation.

Q. ARE THE OPINIONS AND INFORMATION CONTAINED IN YOUR TESTIMONY TRUE AND CORRECT TO THE BEST OF YOUR KNOWLEDGE AND BELIEF?

A. Yes.

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR REVIEW AND ANALYSIS.

A. Based on my review and analysis, I have reached the following conclusions and recommendations to the Commission:

(1) SWEPCO has not performed an adequate analysis of transmission system impacts due to the exclusion of voltage and stability issues.

(2) The gen-tie solution is a single-circuit solution with no redundancy that still exposes the Selected Wind Facilities to high congestion costs under N-1 conditions.

(3) The calculation of congestion costs using three different models in PROMOD, AURORA and PLEXOS ignores the operational realities of fuel price changes and carbon changes on the long-term dispatch and congestion costs.

In conclusion, the Company has not performed an adequate analysis of the transmission system impacts resulting from the RFP process. The failure to perform a comprehensive analysis that reflects voltage and stability issues, that proposes a $444 million gen-tie facility that will not resolve congestion under loss of a single facility, and biases the congestion costs by understating the impacts of fuel and carbon price changes on security constrained economic dispatch all point to likely results that understate the cost of the necessary transmission upgrades and understate the cost of congestion.

I recommend that the Company should be required to withdraw the Application and rerun the entire analysis with the changes recommended above, in addition to assessing the impact of the recent Dolet Hills retirement announcement.

III. DESCRIPTION OF PROPOSED TRANSACTION

Q. PLEASE SUMMARIZE THE PROPOSED TRANSACTION.

A. SWEPCO is requesting Commission approval to acquire an ownership interest in three wind generation facilities located in Oklahoma. The three wind generation facilities are: (1) the Traverse Wind Facilities with a capacity of 999 mega-watts ("MW"), (2) the Maverick Wind Facilities with a capacity of 287 MW, and (3) the Sundance Wind Facilities with a capacity of 199 MW (together the three wind facilities are referred to as "the Selected Wind Facilities"). The Selected Wind Facilities will be jointly owned by SWPECO and its affiliate, Public Service Company of Oklahoma ("PSO"). If approved, SWEPCO will own 54.5% of each wind facility for a total capacity of 810 MW. The total cost of the Selected Wind Facilities, including the owner's costs, are estimated to be $1.996 billion. SWEPCO's share of this estimated cost is $1.088 billion.

IV. EVALUATION OF NEEDED TRANSMISSION FACILITIES TO EFFECTUATE THE PROPOSED TRANSACTION

Q. HOW DID SWEPCO EVALUATE THE TRANSMISSION FACILITIES NEEDED TO DELIVER POWER FROM EACH RFP RESPONDENT PROJECT TO THE SWEPCO LOAD?

A. Witness Ali describes the evaluation methodology as including two parts: a distribution factor ("DFAX") analysis to identify generation clusters and a First Contingency

Incremental Transfer Capability ("FCITC") analysis to assess deliverability from each generation cluster to the AEP West area.

Q. PLEASE DESCRIBE THE PURPOSE OF THE DFAX ANALYSIS PERFORMED BY THE COMPANY.

A. The purpose of the DFAX analysis is to group generators into clusters based upon their common impacts on the transmission system.

Q. WHAT IS A DISTRIBUTION FACTOR OR DFAX?

A. The distribution factor is usually expressed as a decimal or in a percentage. DFAX is the percentage of line flow across a specific element of the transmission system resulting from a power transfer from a point of injection to a point of withdrawal.

Q. WHAT CONDITIONS CAN IMPACT THE DFAX OF A PARTICULAR TRANSACTION?

A. The DFAX value is only impacted by the topology and impedance of the transmission system. The DFAX does not change with generation or load. The DFAX calculation assumes that all system elements are in service at the time of the transaction.

Q. DOES THE DFAX ANALYSIS CONSIDER ONLY REAL POWER FLOW OR IS REACTIVE POWER CONSIDERED IN THE ANALYSIS?

A. The DFAX analysis typically only considers real power flow. The impact of VAR flow is not a consideration.

Q. DOES THE FACT THAT THE COMPANY DID NOT EVALUATE REACTIVE POWER AND VOLTAGE CRITERIA A PROBLEM AT THIS STAGE OF THE RFP SCREENING ANALYSIS?

A. No. Using a DFAX methodology is not an issue in this portion of the transmission analysis, but in order to assess the full impact of a generation addition, real power flow, reactive power, voltage criteria and transient stability should be considered. SWEPCO has not included any AC power flow analysis or transient stability analysis as part of this application. As discussed further below, this additional analysis is required to make a reliable estimate of deliverability and transmission requirements associated with new generation.

Q. WHY IS THE FACT THAT NO AC POWER FLOW ANALYSIS OR TRANSIENT STABILITY ANALYSIS HAS BEEN INCLUDED MATTER IN THIS CASE?

A. In the evaluation of a potential interconnection, it is common practice to consider the impact a generating facility has on the thermal loading, the changes in voltage, short circuit current and system stability. A linearized direct current ("DC") solution such as the Company performed with the FCITC analysis is insufficient to ensure that a generating unit can deliver its output to the system without violating the Company's transmission planning standards. The Company has failed to demonstrate that the Selected Wind Facilities do not negatively impact system voltage or system stability. If mitigation plans are needed to address voltage, reactive or stability issues, that is an additional cost that should be assigned to the Selected Wind Facilities that is being withheld from this Commission.

Q. DID THE COMPANY PERFORM AN ANALYSIS OF THE DELIVERABILITY OF PROPOSED PROJECTS BEYOND THE DFAX ANALYSIS?

A. Yes. Witness Ali noted that the Company performed a first contingency incremental transfer capability ("FCITC") analysis following the DFAX analysis.

Q. WHAT IS YOUR UNDERSTANDING OF THE FCITC ANALYSIS PERFORMED BY THE COMPANY?

A. The Company used the power flow models that Southwest Power Pool ("SPP") uses for their Definitive Interconnection System Impact Study ("DISIS") to evaluate Energy Resource Interconnection Service ("ERIS"). The Company ensured that all system upgrades noted by SPP for ERIS interconnection were included in the model.

Q. WHAT IS THE DIFFERENCE BETWEEN ERIS AND NRIS AND HOW DOES THAT IMPACT THE FCITC ANALYSIS?

A. ERIS refers to Energy Resource Interconnection Service and NRIS refers to Network Resource Interconnection Service. NRIS is the amount of capacity from a resource that can be delivered to the entire system on a firm basis without violating thermal, voltage or stability criteria. ERIS refers to the amount of capacity that can be delivered from a generating resource to the entire system on a non-firm basis. A unit that has NRIS in excess of ERIS should be modeled at its NRIS capacity level. Units that do not have NRIS are incapable of firm delivery of their full output. Modeling units at a reduced capacity level and then assuming they are 100% deliverable in the FCITC analysis can create false flows in the model which reduces the amount of power an incremental facility, such as the Selected Wind Facilities, can deliver. In order to guarantee 100% of the plant output can be delivered on a firm basis, additional transmission facilities are required to meet the NRIS standard.

Q. HOW WAS THE GENERATION IN EACH DELIVERY CLUSTER MODELED FOR THE FCITC ANALYSIS?

A. In the FCITC analysis, the base assumption for wind generation in each cluster was modeled at 20% of nameplate capacity consistent with ERIS modeling techniques. The change made by the Company was to increase all wind generation in the cluster to 100% of nameplate capacity. The power transfer from each generation cluster was simulated by decrementing generation in the AEP West area by a proportionate amount.

Q. DO YOU HAVE ANY CONCERNS REGARDING THIS MODELING ASSUMPTION?

A. Yes, I do. First, modeling all wind generators in a cluster assumes that under base conditions, 100% of the wind output of the existing generators can already be delivered without additional facility upgrades other that the upgrades needed for ERIS delivery. That is not a valid assumption given the negative LMPs and congestion in the wind-rich regions of Oklahoma. Second, the assumption to decrement all generation in AEP West on a pro-rata basis means that the wind generation will impact all generation in the AEP West delivery area equally, without regard to the economic dispatch that would likely occur in real-time operation.

Q. PLEASE EXPLAIN YOUR CONCERN REGARDING THE INCREASED WIND OUTPUT IN THE CLUSTER.

A. The upgrades added by the Company for ERIS are based on the SPP assumption that the wind generation will be operating at only 20% of nameplate capacity. Scaling all generation in the cluster results in additional flows on the transmission system that the ERIS upgrades were not designed to accommodate. This assumption will reduce the FCITC from the cluster and could result in RFP proposals being eliminated that could have had a higher FCITC than the Selected Wind Facilities.

Q. WHY WILL THE FCITC FROM EACH CLUSTER BE REDUCED UNDER THE COMPANY'S DISPATCH ASSUMPTION?

A. The FCITC calculation is the difference between the first contingency total transfer capability ("FCTTC") and base flows on the transmission system. Increasing the base flows by raising the dispatch level of existing generation in the cluster means that the FCITC will be reduced even though the FCTTC is unchanged.

Q. WHY IS THIS IMPORTANT FOR THE SCREENING ANALYSIS?

A. Each generation cluster will impact base flows on the transmission circuits in different ways based on the DFAX effects. The relative ranking of the FCITC could have changed and resulted in a different set of RFP proposed units being selected than the Selected Wind Facilities that were the result of the Company's FCITC analysis.

Q. PLEASE EXPLAIN THE ISSUES WITH THE PRO-RATA DECREMENTING OF GENERATION IN THE FCITC ANALYSIS.

A. The Company chose to decrement all generation in the AEP West area without regard to the economic impact of that decision. The more accurate representation for the FCITC analysis would have been to decrement only the generation that would be displaced by the proposed Projects. By decrementing all generation, the Company has improperly modeled the effects of the delivery of the proposed generation. Since generators have an impact on the base flows on the transmission system, whether they are being incremented or decremented, the Company has biased the results of their analysis. This bias undermines the soundness of the Company's RFP process and thus its overall results.

Q. WHAT OTHER OPTIONS DID THE COMPANY HAVE FOR THE GENERATION DECREMENTING APPROACH?

A. The Company could have either modeled the transfer from the generation clusters to a system swing bus, thereby not adjusting the AEP West generation at all. Alternatively, the Company could have performed an economic dispatch to see what units would be displaced by the RFP respondent proposals, and only adjust the output of the affected generators.

Q. WHAT DO YOU RECOMMEND BE DONE REGARDING THE ISSUES YOU HAVE RAISED?

A. I recommend that the Commission direct the Company to rerun the screening analysis using the methodological changes I have proposed to determine if the Company's initial screening analysis eliminated any proposals from advancing in the RFP analysis process due to the assumptions regarding the base modeling of existing wind capacity at 100% of nameplate and the pro-rata decrementing of generation in the AEP West area.

Q. ARE YOU AWARE OF ANY TRANSMISSION ANALYSIS PERFORMED BY THE COMPANY TO ASSESS DELVERABILITY BEYOND THE DFAX ANALYSIS AND THE FCITC ANALYSIS?

A. I am aware of only one other transmission assessment and that is the Company's Gen-Tie analysis, which is discussed later in my testimony.

Q. ARE THERE ISSUES THAT THE COMPANY IGNORED BY NOT PROCEEDING TO ANALYZE THE PROPOSALS BEYOND THE DFAX ANALYSIS AND THE FCITC ANALYSIS?

A. Yes. The DFAX analysis and the FCITC analysis are usually performed using a linearized DC modeling technique for speed and efficiency. However, this technique does not consider the impact of reactive flows, voltage violations or potential transient stability limitations that could occur.

Q. IS IT IMPORTANT FOR THE REACTIVE POWER IMPACTS, VOLTAGE IMPACT AND STABILITY IMPACTS TO BE CONSIDERED?

A. Yes, it is. Within the SPP system, there are areas where stability limits can impact the ability of power transfers before a thermal limit is reached. Ignoring this reality could skew the results and mean that a generator with a high FCITC value using thermal limits that has a stability issue could be selected to advance in the process where a generator with a lower FCITC value and no stability limit is excluded.

Q. HAS THE COMPANY HAD ANY EXPERIENCE WHERE TRANSMISSION FACILITIES WERE REQUIRED TO ACCOMMODATE A GENERATOR ONTO THE GRID DUE TO STABILITY ISSUES?

A. Yes. In the 2007 PUC proceeding to approve the John W. Turk plant, three transmission lines, costing an estimated $157 million, were required to be built to address stability limitations. These stability limitations would not have appeared in a DFAX analysis or a FCITC analysis using a linearized DC modeling technique. Without performing more detailed analysis on the deliverability of the Selected Wind Facilities as I have recommended, there may additional system upgrades resulting from the Selected Wind Facilities whose costs are not included in the Company's current analysis.

Q. DOES THE COMPANY ACKNOWLEDGE THAT VOLTAGE ISSUES CAN OCCUR ON THEIR SYSTEM?

A. Yes. The Company has demonstrated that acknowledgement through the use of voltage criteria in the evaluation of transmission system performance. These criteria are present in the Company's FERC-715 filings.

Q. IS IT LIKELY THAT THE TRANSMISSION COST OF THE SELECTED WIND FACILITIES COULD BE UNDERESTIMATED DUE TO IGNORING VOLTAGE, REACTIVE AND TRANSIENT STABILITY ISSUES?

A. Yes, it is likely that additional transmission facilities would be needed and associated costs would be incurred to permit the Selected Wind Facilities to be deliverable to the AEP West area.

V. EVALUATION OF THE NEED FOR A FUTURE GENERATION TIE TO ACCOMMODATE THE PROPOSED TRANSACTION

Q. DID THE COMPANY PERFORM AN ANALYSIS TO DETERMINE THE NEED FOR A GEN-TIE TO ADDRESS POTENTIAL CONGESTION IN THE SPP REGION?

A. Yes, Witness Ali and Witness Pfeifenberger both address the gen-tie analysis in their testimony.

Q. IS THE COMPANY RECOMMENDING A GEN-TIE AS PART OF THIS APPLICATION?

A. No, the Company is not requesting the gen-tie as part of the application. However, the fact that the Company is exploring the use of a gen-tie to mitigate congestion indicates that the Company is not confident that SPP will address potential congestion that could negatively impact the economics of the Selected Wind Projects. Furthermore, I am concerned that the Company will later propose a gen-tie, with the costs of the wind generation treated as "sunk costs" and not factored as incremental costs. The Company should rerun all of its analysis under the assumption that a gen-tie is needed so that the Commission has more comprehensive results of the Selected Wind Facilities and the related cost and benefits.

Q. PLEASE BRIEFLY DESCRIBE THE GEN-TIE ANALYSIS PERFORMED BY THE COMPANY.

A. The Company evaluated several scenarios from the various generation clusters which would result in the Company building a generation tie from the Selected Wind Facilities to the 345-kV system near Tulsa, Oklahoma in the PSO service territory. The Company believes that the 345-kV system around Tulsa is a robust system that can accommodate the direct injection of power from the Selected Wind Facilities into the Tulsa area. The Company evaluated the cost of the gen-tie scenarios for each cluster and assumed that the addition of the gen-tie would alleviate any congestion associated with the Selected Wind Facilities.

Q. WHAT CONCERNS DO YOU HAVE REGARDING THE COST CALCULATIONS FOR THE GEN-TIE SCENARIOS?

A. I do not address the cost estimates for the gen-tie, but I do have significant concerns with a single gen-tie being assumed to alleviate 100% of the congestion from the Selected Wind Facilities to the AEP West area.

Q. PLEASE EXPLAIN YOUR CONCERNS WITH THE SINGLE GEN-TIE PROPOSAL.

A. First, consistent with the issues I raised with the FCITC analysis, there does not seem to be any analysis regarding additional impacts of the Selected Wind Facilities from a transient stability perspective that could result in additional transmission facilities being needed to accommodate the proposed injection of power. Second, the assumption that a single gen-tie would eliminate 100% of the congestion is inconsistent with transmission planning contingency analysis, where the loss of a single element (N-1) in a normal planning evaluation would result in the loss of the gen-tie and increase flows on the remaining SPP system which would also lead to increased congestion that was supposed to be addressed by the gen-tie. The addition of a 345-kV gen tie to the Company's transmission system, if tacitly approved by this Commission, would now give SWEPCO the ability to convert the gen-tie into a looped facility by building an additional segment. The new looped facility would be eligible for cost recovery from all parties in SPP under the highway/byway methodology.

Q. HOW WOULD A TRANSIENT STABILITY ANALYSIS IMPACT THE GEN-TIE EVALUATION?

A. Had the Company performed a transient stability analysis, it is possible that additional transmission facilities would have been needed to address the identified stability issues. Construction of transmission facilities to alleviate stability concerns may also resolve the need for the gen-tie, thereby making this analysis unnecessary. Additionally, the cost of the facilities needed for transient stability concerns would be added into the evaluation of the proposals. This cost would not be a theoretical, down the road, potential exposure, but would be factored into the analysis of the Selected Wind Facilities early on. It should also be noted that in the Company's congestion cost evaluation, the AURORA expansion model was limited to a 40% penetration, citing potential stability concerns. The Company is clearly aware of the stability issues that can arise from increased wind penetration in SPP and yet did not address that possibility with respect to the Selected Wind Facilities.

Q. WHAT IS THE CONCERN YOU HAVE REGARDING THE USE OF A SINGLE GEN-TIE?

A. The Company is responsible for planning the transmission system in accordance with the NERC Transmission Planning Standards and recognizes that evaluation of the bulk electric system includes the evaluation of the performance of the system under various contingency scenarios. One of the most common contingencies to be evaluated is the loss of a single element, also known as N-1 analysis. The Company is proposing 184 miles of 345-kV transmission lines along with three substations to create a single circuit gen-tie that directly connects the Selected Wind Facilities to the Tulsa load center to address potential unresolved congestion at a total cost of $443,754,526 in 2021 dollars. Under N-1 analysis, loss of the gen-tie means that the Selected Wind Facilities will not be directly connected to the Tulsa load center but will rely on the remainder of the SPP transmission system to export power from the point of interconnection. The loss of the gen-tie, as a matter of normal contingency planning, will increase flows on the surrounding system, which will result in increased congestion. Assuming that 100% of the congestion will be resolved through addition of a gen-tie is not a reasonable assumption.

Q. HOW SHOULD THE COMPANY EVALUATE THE GEN-TIE DESIGN AND IMPACT?

A. First, the Company should price the gen-tie assuming a double circuit configuration. At a minimum, the Company could assume a design of double circuit, monopole construction. A more robust solution would be to have the gen-tie be designed to have two circuits in a common right-of-way. This would eliminate the N-1 issue but still leaves a contingency exposure due to loss of facilities in a common right of way. Either way, the Company needs to have a gen-tie design that not only creates a direct tie to the Tulsa load center, but one that can stand the rigors of NERC TPL standards to significantly reduce the potentiality for unhedged congestion.

Q. HOW WOULD YOUR PROPOSED GEN-TIE CONFIGURATION IMPACT THE COSTS USED BY THE COMPANY IN THEIR EVALUATION?

A. In general, I would expect that the cost of the gen-tie would increase between 50% (monopole construction in common ROW) and 100% (parallel circuits in common ROW). Adding approximately $220 million to $440 million to the cost of the Selected Wind Facilities to account for a more reliable gen-tie would have a significant negative impact on the economics of the Selected Wind Facilities.

Q. WITH THE COMPANY'S CURRENT GEN-TIE MODEL, IS IT REASONABLE TO EXPECT THAT 100% OF THE CONGESTION WILL BE RESOLVED?

A. No, for the reasons given above as a result of the N-1 issue.

Q. WITH YOUR PROPOSED GEN-TIE MODEL, IS IT REASONABLE TO EXPECT THAT 100% OF THE CONGESTION WILL BE RESOLVED?

A. It is much more likely to be a reasonable assumption given the resolution of the N-1 issues. However, the resolution of 100% of the congestion will be offset by the significant cost increase of the gen-tie.

Q. BASED ON YOUR EVALUATION, WHAT CONCLUSIONS DO YOU REACH REGARDING THE GEN-TIE?

A. I have concluded that the Company has overestimated the impact of the single gen-tie to resolve potential congestion and that the Company has significantly underestimated the cost of the gen-tie due to ignoring the N-1 problem. As a result, the Company has not accurately accounted for the total cost of the Selected Wind Facilities in its analysis or its ability to provide the stated benefits to its Texas retail customers.

VI. EVALUATION OF THE CONGESTION ANALYSIS PERFORMED TO EVALUATE POTENTIAL PROJECTS

Q. WHY HAS THE COMPANY CHOSEN TO NOT USE A SINGLE MODEL FOR THE CALCULATION OF CONGESTION COSTS?

A. According to the testimony of Witnesses Sheilendranath and Pfeifenberger, the PROMOD model is effective for the calculation of locational marginal prices, however it assumes an idealized market with perfect understanding of the grid conditions. Due to the computational time associated with assessing a high number of locational marginal prices using an extensive list of potential contingencies, the PROMOD model is not effective for long-term power price projections. The AURORA and PLEXOS models are supposedly more effective in long-term price projection development based on future expansion plan development, but do not contain the detailed transmission modeling necessary to calculate the projections of locational marginal prices for several pricing nodes. The witnesses claim that an amalgamation of all three models in necessary to achieve an accurate long-term forecast of prices and congestion to assess the Selected Wind Facilities.

Q. DO YOU HAVE ANY CONCERNS WITH THIS MULTIPLE MODEL APPROACH TO CALCULATING THE CONGESTION IMPACTS OF THE SELECTED WIND FACILITIES?

A. Yes, I do. The PROMOD analysis has been run for two years (2024 and 2029), with the locational results being interpolated for 2021-2023 and 2025-2028 with levelized congestion costs being used for 2030-2051. The deficiencies of each model get compounded in this technique which results in a low level of confidence in the final congestion analysis.

Q. PLEASE DESCRIBE THE MODELING DEFICIENCIES YOU NOTE IN THE PROMOD PORTION OF THE ANALYSIS.

A. The primary deficiency I note is that the power flow model in the PROMOD cases is not the same as the power flow model used in the FCITC analysis. I have already addressed the concern that the FCITC evaluation is based on a linearized DC solution, which is the same technique used in PROMOD. If the Company would have appropriately assessed the need for additional transmission facilities to compensate for voltage, reactive or stability issues, these new upgrades would have been included in PROMOD and would have changed the system dispatch, along with the corresponding congestion values. The second concern is that the Company has developed a "Base Case" that eliminates new, proposed transmission facilities that are in the current SPP Integrated Transmission Plan. This Base Case includes unrealistic, but material, assumptions, including that SPP's proposed solutions to address identified transmission needs will not be impacted by future generation additions, generation retirements (including the recently announced Dolet Hills retirement), and load forecast changes.

Q. HOW ARE THE PROMOD RESULTS ADJUSTED IN THE AURORA ANALYSIS?

A. The AURORA modeling resulted in a series of ten cases which reflect variations in gas prices and carbon impacts. The PROMOD outputs were scaled by the forecasted AEP West, SWEPCO and PSO load zone prices in Aurora to calculate the adjusted congestion prices used in the PLEXOS-based cost/benefit analysis discussed by Witness Torpey.

Q. DOES SCALING THE PROMOD LOCATION-SPECIFIC PRICES WITH A MODEL THAT DOES NOT INCLUDE TRANSMISSION TOPOLGY SEEM REASONABLE?

A. I am concerned that the Company has created a general supply curve response in AURORA that is not consistent with the more accurate security constrained dispatch pricing that PROMOD provides. When natural gas prices and carbon assumptions are changed, the merit order dispatch of units also changes. AURORA captures these general trends but ignores the impact of the changed dispatch on the resulting transmission flows and corresponding congestion costs. Without modeling the changes in assumptions from the

AURORA cases in PROMOD, the Company has not carried a consistent set of assumptions through the RFP process.

Q. WHAT CHANGES WOULD YOU RECOMMEND TO THE PROMOD-AURORA PROCESS?

A. I recommend that the Company develop ten PROMOD cases to capture the changes in "Base Case" and "No-SPP-Upgrades Case" and then use AURORA results to scale the individual cases. This ensures a consistent starting point for each case and does not bias the results based on the potential congestion costs under a security constrained dispatch.

Q. WITNESS SHEILENDRANATH HAS ASSUMED THAT IT IS REASONABLE THAT 25% OF CONGESTION WILL BE HEDGED WITH TRANSMISSION CONGESTION RIGHTS ("TCR"). DO YOU AGREE WITH THAT ASSUMPTION?

A. I do not agree with that assumption, because (1) the witness has not provided any supporting analysis to back up that statement, and (2) using a premise that any portion of the congestion can be hedged does not account for the possibility that no congestion could be hedged with a TCR. If the Company used a 0% congestion hedge assumption and the Selected Wind Facilities still have economic benefits, then any residual benefit of TCR impacts only enhances the economic evaluation.

Q. DOES ANY OF THE ANALYSIS PERFORMED BY THE COMPANY ASSUME THAT FIRM TRANSMISSION SERVICE CAN BE ACQUIRED AT NO INCREMENTAL UPGRADE COST?

A. At the time of this filing, the Company had not demonstrated that it had procured firm transmission service from the Selected Wind Facilities for delivery to Company load areas.

It is my understanding that the Company has only recently requested firm transmission service from SPP.

Q. IS IT LIKELY THAT THE COMPANY WOULD BE ABLE TO ACQUIRE FIRM TRANSMISSION SERVICE BETWEEN THE SELECTED WIND FACILITIES AND THE COMPANY LOAD WITHOUT REQUIRING INCREMENTAL TRANSMISSION INVESTMENT?

A. It is not possible to fully predict the response to that question until SPP finishes its evaluation of the requested service. Based on the Company's own analysis of the potential need for a gen-tie in 2026, it is likely that there is high loading of transmission facilities between the Selected Wind Facilities and the Company load, which could require incremental transmission construction in addition to the proposed gen-tie.

Q. IF SPP REQUIRED THE DEVELOPMENT OF INCREMENTAL TRANSMISSION FACILITIES TO GRANT FIRM TRANSMISSION SERVICE, WOULD THAT GUARANTEE THAT THE ADDITION OF THOSE FACILITIES WOULD ALLEVIATE 100% OF THE CONGESTION EXPOSURE?

Q. There is no guarantee that incremental transmission would fully hedge the congestion between the Selected Wind Facilities and the Company load. Based on the Cooperatives' experience with their participation in the Grant Wind Farm in Oklahoma and the load being embedded within the AEPW system, having firm transmission service did not alleviate the congestion exposure (see Table 1 of Pfeifenberger testimony).

VIII. SUMMARY AND CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE TRANSMISSION UPGRADE REQUIREMENTS, THE GEN-TIE SOLUTION AND THE CALCULATION OF CONGESTION COSTS.

(1) SWEPCO has not performed an adequate analysis of transmission system impacts due to the exclusion of voltage and stability issues.

(2) The gen-tie solution is a single-circuit solution with no redundancy that still exposes the Selected Wind Facilities to high congestion costs under N-1 conditions.

(3) The calculation of congestion costs using three different models in PROMOD, AURORA and PLEXOS ignores the operational realities of fuel price changes and carbon changes on the long-term dispatch and congestion costs.

Q. BASED ON YOUR CONCLUSIONS, WHAT RECOMMENDATIONS DO YOU HAVE REGARDING THE COMPANY'S APPLICATION FOR THE SELECTED WIND FACILITIES?

A. The Company has not performed an adequate analysis of the transmission system impacts resulting from the RFP process. The failure to perform a comprehensive analysis that reflects voltage and stability issues, that proposes a $444 million gen-tie facility that will not resolve congestion under loss of a single facility, and biases the congestion costs by understating the impacts of fuel and carbon price changes on security constrained economic dispatch all point to likely results that understate the cost of the necessary transmission upgrades and understate the cost of congestion.

I recommend that the Company should be required to withdraw the Application and rerun the entire analysis with the changes recommended above, in addition to assessing the impact of the recent Dolet Hills retirement announcement.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

GDS Associates, Inc
ENGINEERS & CONSULTANTS

JOHN W. CHILES, JR.

Principal-Transmission Services

EDUCATION

Bachelor of Science in Engineering, University of South Florida, 1993

PROFESSIONAL MEMBERSHIP

IEEE, Power Engineering Society

EXPERIENCE

Mr. Chiles has over 30 years of electric utility and consulting experience. He provides regulatory and strategic support for generation and transmission cooperatives, municipal electric systems, independent generation developers, industrial consumers and state commissions regarding regional transmission organization energy markets, open access transmission issues, transmission planning and need certification, generation siting and interconnection, NERC compliance support and training, and stakeholder representation in RTO stakeholder forums. Mr. Chiles has filed testimony at the Federal Energy Regulatory Commission (FERC) and at several State regulatory commissions.

SPECIFIC PROFESSIONAL EXPERIENCE

GDS Associates, Inc., September 2005 to Present
Principal, Transmission Services

As a Principal at GDS Associates, Mr. Chiles consults with utilities, government agencies, and industrial clients in the following areas:

- Serves as Stakeholder Representative for clients within Entergy, the Midcontinent Independent System Operator (MISO) and the Southwest Power Pool (SPP) on matters related to transmission expansion planning and market design
- Assisted multiple clients during the Entergy integration into MISO, including conversion of transmission rights, valuation of generation assets, and Day 2 market preparation

Provided generation interconnection support services for renewable and fossil-fuel based facilities, including siting analysis, technical study support, client representation with Transmission Providers, and negotiation of Interconnection Agreements

- Filed expert witness testimony at FERC and State jurisdictions regarding transmission facility need determination, transmission loss calculations, integrated resource planning and Regional Transmission Organization (RTO) integration activities
- Conducted NERC mock audits on Transmission Planning (TPL), Facility Rating (FAC), and Modeling (MOD) Standards for numerous municipal and cooperative organizations
- Supported generation procurement Request for Proposals (RFPs) through providing technical and strategic support on transmission issues

PREVIOUS EXPERIENCE

- Monitored and provided corrective action on NERC compliance
- Served as Southwest Reserve Sharing Group and WECC Operating Committee representative
- Developed generation optimization process to achieve optimal dispatch of 2,200 MW plant to meet NERC criteria
- Optimized daily transmission positions for 4,400 MW asset portfolio ($3MM/month)
- Determined transmission deliverability (ATC, Generator Operating Limit) to support balance of month and originated transactions
- Provided regulatory support on issues at FERC and state levels
- Assisted in development of and modifications to ERCOT protocols
- Determined how changes in regional markets impacted profitability of asset portfolio
- Represented company at FERC, SeTrans and State jurisdictions
- Developed and Presented of 5- and 10-Year transmission expansion plans
- Representative on GridFlorida Flowgate Working Group
- Transmission-Dependent Utility representative on SERC ATC Working Group
- OASIS site testing
- Consulting support to PA Cooperative group for PA Retail Access Program
- Expansion plan development for Duke Energy, Carolina Power & Light, Dominion Virginia Power
- RFP bid evaluation
- Evaluation of Structured Transactions for external sales

AREAS OF EXPERTISE

REGIONAL TRANSMISSION ORGANIZATION STAKEHOLDER SUPPORT

- Client representation at SPP, MISO, and ERCOT
- Regulatory Support/Expert Witness Testimony

STRATEGIC PLANNING

- Energy Market Design
- Contract Negotiation

OPEN ACCESS TRANSMISSION SERVICE ANALYSIS

- ATC Calculations
- Transmission Scheduling
- Transmission Planning
- Interconnection Analysis
- Control Area Operations

REGIONAL TRANSMISSION ORGANIZATION OPERATIONS AND POLICY SUPPORT

- Market Integration Support for new entrants in California Independent System Operator (CAISO), SPP and MISO
- Market Analysis of Nodal Price Data
- Technical Support on RTO Settlements Issues

ENERGY MARKET DESIGN

- Nodal Market Development (ERCOT)

- Resource Adequacy Market Development (PJM)
- Energy Imbalance Market Development (SPP, WECC)

OPEN ACCESS TRANSMISSION ISSUES
- Loss Study Review and Support
- Deliverability Analysis for Generation Assets
- Negotiation of Agreements for Transmission Service

TRANSMISSION SYSTEM MODELING AND PLANNING
- Power Flow Analysis
- Short Circuit Analysis
- Need Certification Technical Studies
- Review of Impact of Transmission Expansion Plans on Load and Generation

PRODUCTION COST MODELING AND SIMULATION
- PROMOD Studies for Generation Margin Determination and Load Cost Analysis
- Assessment of Economic Transmission Projects
- Financial Transmission Rights Evaluation

GENERATION INTERCONNECTION PROCESS EVALUATION AND SUPPORT
- Power Flow-Based Site Selection Analysis
- Technical Support for Review of Transmission Provider Studies
- Negotiation of Interconnection Service Agreements

NERC COMPLIANCE ACTIVITIES
- TPL Assessments
- Development of Policies, Guidelines and Procedures
- Mock Audits and Gap Analysis
- Subject Matter Expert Training for TPL, FAC, and MOD Standards

REGULATORY, STRATEGIC AND STAKEHOLDER SUPPORT
- Stakeholder Representation at MISO, SPP, and ERCOT
- Technical and Regulatory Support for Clients at FERC and State Jurisdictions

EXPERT WITNESS TESTIMONY

FEDERAL ENERGY REGULATORY COMMISSION (FERC)

PJM Interconnection, LLC, American Transmission Systems, Inc., Docket No. ER12-2399-003

Southwestern Electric Cooperative, Inc., et al., Docket Nos. EL15-72, *et al.*, Panel Member for Technical Conference

ARKANSAS PUBLIC SERVICE COMMISSION (APSC)

In the Matter of a Show Cause Order Directed to Entergy Arkansas, Inc. Regarding Its Continued Membership in the Current Entergy System Agreement, or Any Successor Agreement Thereto, and Regarding the Future Operation and Control of Its Transmission Assets, Docket No. 10-011-U

GEORGIA PUBLIC SERVICE COMMISSION (GPSC)

In the Matter of: Georgia Power Company's 2010 Integrated Resource Plan, Docket No. 31081

In the Matter of: Georgia Power Company's 2013 Integrated Resource Plan, Docket No. 36498

In the Matter of: Georgia Power Company's 2016 Integrated Resource Plan, Docket No. 40161

In the Matter of: Georgia Power Company's 2019 Integrated Resource Plan, Docket No. 42310

MISSISSIPPI PUBLIC SERVICE COMMISSION (MPSC)

In Re: Joint Application of Entergy Mississippi, Inc., and The Midwest Independent Transmission System Operator, Inc., for Transfer of Functional Control of Entergy Mississippi's Transmission Facilities To MISO, Docket No. 2011-UA-376

PUBLIC UTILITY COMMISSION OF TEXAS (PUCT)

Entergy Gulf States, Inc.'s Transition to Competition Plan, PUC Docket No. 33687

Application of Sharyland Utilities, L.P. to Approve Study and Plan Pursuant to the Commission's Order in Docket No. 37990 Concerning the Movement of Sharyland's Stanton and Colorado City Divisions from the Southwest Power Pool to ERCOT, PUC Docket No. 39070

Application of Entergy Texas, Inc., ITC Holdings Corp., MidSouth Transco LLC, Transmission Company Texas, LLC, and ITC MidSouth LLC for Approval of Change of Ownership and Control of Transmission Business, Transfer of Certification Rights, Certain Cost Recovery Approvals, and Related Relief, PUC Docket No. 41223

Updated Application of Entergy Texas, Inc., ITC Holdings Corp., Mid-South Transco LLC, Transmission Company Texas, LLC, and ITC Midsouth LLC for Approval of Change of Ownership and Control of Transmission Business, Transfer Of Certification Rights, and Related Relief, PUC Docket No. 41850

COMMONWEALTH OF VIRGINIA STATE CORPORATION COMMISSION DIVISION OF ENERGY (VSCC)

Virginia Electric and Power Company for Approval and Certification of Electric Facilities for the Surry-Skiffes Creek 500 kV Transmission Line, Skiffes Creek-Whealton 230 kV Transmission Line, and Skiffes Creek 500 kV-230 kV-115 kV Switching Station, Case No. PUE-2012-00029

Virginia Electric and Power Company for Approval and Certification of Electric Transmission Facilities for the Remington CT-Warrenton 230 kV Double Circuit Transmission Line, Vint Hill-Wheeler and Wheeler-Loudoun 230 kV Transmission Lines, 230 kV Vint Hill Switching Station, and 230 kV Wheeler Switching Station, Case No. PUE-2014-00025

AFFIDAVIT

THE STATE OF GEORGIA §

COUNTY OF COBB §

BEFORE ME, the undersigned notary public, this day personally appeared John W. Chiles, to me known, who being duly sworn according to law, deposes and says:

"My name is John W. Chiles. I am of legal age and a resident of the State of Georgia. I certify that the foregoing testimony and exhibits, offered by me on behalf of East Texas Electric Cooperative, Inc. and Northeast Texas Electric Cooperative, Inc. are true and correct based upon my personal knowledge and professional experience."

John Chiles

John W. Chiles

SUBSCRIBED AND SWORN TO BEFORE ME, notary public, on this the 14th day of January 2020.

Faye H. Culpepper

Notary Public in and for the State of Georgia

FAYE H CULPEPPER
MY COMMISSION EXPIRES
MAR 3 2022
COBB CO., GEORGIA
NOTARY PUBLIC