EXHIBIT NO. ______

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of	)	
Ohio Power Company to Initiate	)	Case No. 19-1475-EL-RDR
its gridSMART® Phase 3 Project.	)	

SUPPLEMENTAL TESTIMONY OF
STACEY D. GABBARD
ON BEHALF OF
OHIO POWER COMPANY

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<u>PERSONAL DATA</u>

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Stacey D. Gabbard, and my business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am employed by American Electric Power Service Corporation (AEPSC) as Director – Customer Services Tech Integration.

Q. WOULD YOU PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I graduated from The University of Tulsa with a Bachelor of Science Degree in Psychology, and received a Master's Degree in Business Administration with an emphasis in Finance, also from The University of Tulsa. In 2004 I attended the AEP Strategic leadership Program at The Ohio State University. I began my career in Oklahoma with Public Service Company of Oklahoma in 1990 as a meter reader, and later a meter connect and disconnect representative. I moved from field operations into Operations Analysis for Central and Southwest Corporation (CSW) as a Business Analyst in 1996, supporting business process design and automation of work management and large-power billing processes in support of Texas deregulation. I was also responsible for standardization of front and back-office processes in support of our implementation of inter-queued call centers. In 2003, after the merger between CSW and AEP, I was appointed Supervisor of Other Accounts Receivables. In this position I was responsible for the oversight, reporting, billing and collections of non-electric receivables for all of AEP's seven operating companies. From 2004 to 2012, I served as Manager of Special Billing & Meter Translation, where I was responsible for AEP's large power and complex billings, MV90 meter translation system support and operations, Load Research Operations, and national account EDI translation. From 2012 until 2017, I was Manager of Customer Choice Processes and Systems, where I was responsible for business and operational support of AEP operating companies that serve customers in states with deregulation. From 2017 until 2020 I was Director of Customer Services Support, where I was responsible for daily business operations of meter-to-cash systems supporting AEP's seven distribution operating companies, including CIS system business support, load research, large power and complex billing, deregulation support, and meter revenue systems support. In January of 2021, I become Director of Customer Services Technology Integration, my current role.

Q. WHAT ARE YOUR RESPONSIBILITIES AS DIRECTOR – CUSTOMER SERVICES TECH INTEGRATION?

A. I am responsible for integration of new technology initiatives into the Customer business unit to increase customer satisfaction and drive sustainable efficiencies. In this role, I also serve as the business lead for AEP's Customer Information System (CIS) replacement.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN ANY REGULATORY PROCEEDINGS?

A. Yes. I have testified before the Public Utilities Commission of Ohio (Commission) in Case Nos. 13-2385-EL-SSO, et al. in Case No. 16-1852-EL-SSO on behalf of the Company.

<u>PURPOSE OF SUPPLEMENTAL TESTIMONY</u>

Q. WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL TESTIMONY?

A. In Case No. 17-1234-EL-ATA, Commission directed AEP Ohio to provide testimony that addresses how the Company intends to leverage Advanced Meter Infrastructure (AMI) customer data and further automate processes related to settlement of capacity, transmission charges and energy in PJM. In my testimony, I will discuss and summarize various system improvements in the Choice space related to access of customer AMI interval data to Competitive Retail Energy Suppliers (CRES), as well as the use of that data to settle CRES Peak Load Capacity (PLC), Network System Peak Load (NSPL), and Total Hourly Energy Obligation (THEO) at PJM. To that end, I will review the status of AEP's CIS retirement plans, as well as other solutions under consideration to bring this Choice settlement functionality to the market.

<u>CURRENT CIS SYSTEM OVERVIEW</u>

Q. PLEASE EXPLAIN THE CURRENT ANALYSIS BEING CONDUCTED BY THE COMPANY.

A. AEP uses a highly customized "Customer-One" legacy CIS System that supports billing, revenue reporting, account and receivables management, on-line transactions, customer and premise data management, and Customer Choice. AEP utilizes one instance of the system across all seven distribution operating companies. Though the technology is over 30 years old, numerous auxiliary systems with integrations to the system have been implemented over the years to make prudent investments in functionality. Some of these auxiliary systems include large power billing, AMI meter data management, Choice market settlements and messaging, bill output and customer programs, to name a few. With that said, the company recognizes the need to move forward with planning a CIS replacement due to the continued proliferation of distributed generation, advancing AMI functionality needs, evolving customer expectations, more complex market settlement requirements, and growing risks related to a thirty-year-old technology platform.

Q. PLEASE EXPLAIN THE TIMELINE OF THE NEW CIS SYSTEM.

A. To manage risk associated with a project of this magnitude, AEP has broken the initiative into three phases. The first phase is automation of manually intensive spreadsheet billing not supported by AEP’s legacy CIS system, using new CIS technology. This includes net metering customers that bank negative usage due to net-negative generation, as well as automation of large industrial spreadsheet billing. In addition to this delivered automation, the team will finalize plans around meter data management (MDM) system needs related to a new CIS, as well as overall architecture planning for the program. The first phase is expected to run 18 to 24 months. Phase two will focus on planning for automation of Choice functionality replaced with the new CIS, such as Electronic Data Interchange (EDI) transaction processing and market settlements. Phase three will begin in approximately 2025 and will roll-out the new CIS to operating companies. The company will deploy one operating company at a time to manage risk to operations and assure a seamless transition for customers and third parties. One of the outputs of phase one will be a more detailed deployment schedule for each operating company.

Q. PLEASE EXPLAIN THE PROCESSES NECESSARY TO IMPLEMENT THE ABILITY TO SETTLE ALL AMI METERS FROM A TOTAL HOURLY ENERGY OBLIGATION (THEO) FOR BOTH INITIAL SETTLEMENT AND FINAL SETTLEMENT AT PJM.

A. To settle AMI customers on hourly load, each customer's hourly usage is aggregated by supplier or standard service offer (SSO) on a daily basis. System losses are applied and unaccounted for energy (UFE) is calculated by comparing the total aggregated loads of all suppliers and SSO to a "top-down" metered system load at the generator level. The hourly variance between these aggregated values and the system load is UFE. A portion of the UFE is shared by hour, proportionally with all suppliers and SSO tranche providers based upon each of their shares of the total load at each hour. These aggregated hourly values, including the customer's usage, losses and UFE, is the initial settlement submitted to PJM daily. After 60 days, the process is repeated for the same load period. Non-reported meters that were estimated, meter errors now corrected, and estimates for some system load delivery points not available daily are replaced with actual data, and a comparison is performed between what each supplier's load obligations were for each hour of the period for initial settlement, and what the final value is. An hourly adjustment is then submitted to PJM for each supplier, as well as SSO tranche providers. To automate this process, data from AMI meters must be processed through our MDM system using industry standard validation, estimation for missing data, and editing (VEE) every day for all meters and all intervals of data. Once ready, the data must be moved through integrations to our Clearing House that handles settlement and EDI processing. There, the Clearing House must match each hourly load value to an assigned supplier for the bill period, aggregate the data, apply losses, calculate UFE, and apply UFE to each supplier's aggregated hourly load.

Q. PLEASE EXPLAIN THE ADDITIONAL COSTS, ESTIMATED TIMELINE AND BACKEND SYSTEMS NECESSARY TO IMPLEMENT HOURLY ENERGY SETTLEMENTS FOR ALL AMI METERS.

A. Given the increase in data processing on a daily basis, additional servers are needed to process actual interval usage gathered from the previous day. Changes are necessary to the MDM system to perform VEE on a daily basis prior to processing of data. Changes are also necessary to the Clearing House for settlement and EDI functionality to use actual data for each customer, as opposed to pulling a like-day usage from a historical usage table for initial settlement. In addition, changes are also necessary to submit actual interval data via EDI to CRES so they can use the data for billing or customer programs. EDI is a preferred technology format for CRES as it is standard across the market and used by all participants. EDI is usually fully automated in terms of market participants and their ability to ingest data into their systems, as opposed to manually processing data that may be the case with web portal presentation of customer data. For final settlement, changes are also necessary to use actual AMI interval data to settle load, rather than using a customer class profile load shape derived from sample customer data. Given changes necessary for hardware and multiple systems impacted be these changes, testing required to assure no impact to other operations, the estimate for these changes is roughly $13.7 million dollars. Work would begin sometime in 2022, focusing first on requirements gathering around Ohio market standards. The project would run 24 months after 6 months of resource ramp-up and requirements gathering. We would also expect a 3 to 4 month post deployment production testing period with market participants so they can also make sure their systems are working as expected.

Q. PLEASE EXPLAIN THE PROCESSES NECESSARY TO IMPLEMENT THE ABILITY TO SETTLE PLC AND NSPL FOR ALL AMI METERS.

A. Today, for the Company's 1.3 million residential customers, a profiled load shape derived from representative sample customer data is used to take customer total annual Kwh and derive the average of their five highest peaks (PLC) and single highest peak (NSPL), using PJM's reported system peak times. AEP creates these values, or "tags," yearly after PJM's peak days and times are made available. To use actual AMI interval data, system changes are necessary to pull in all yearly interval data for residential customers. With 96 intervals per day for each customer, that is 45.5 billion intervals the system will process to calculate PLC and NSPL values. Similar to calculating THEO, system hardware and integration changes are necessary to pull this data into settlement systems, as well as changes are necessary to the settlement system to calculate the PLC and NSPL values.

Q. ARE THERE OTHER OPTIONS AVAILABLE THAT THE COMMISSION SHOULD CONSIDER?

A. Yes. Functionality AEP Ohio implemented after our gridSMART Phase II case (Case No. 13-1939-EL-RDR) settles CRES Time of Use (TOU) billed customers on hourly AMI interval data, as well as calculates their PLC and NSPL annual values using actual interval data, rather than a profile. This allows CRES the ability to pass savings in energy or capacity on to the customer. An additional option that can be implemented is to calculate the PLC and NSPL values for all residential customers using actual AMI interval data. This will allow a more precise settlement of capacity in the PJM market, and allow CRES the ability to better estimate the customers potential savings on a TOU rate. PLC values would be made available in AEP Ohio's enrollment list, as well as on the Business Partner Portal and EDI.

<u>RECOMMENDATION</u>

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION?

A. Due to the complexity of significant changes to legacy systems demonstrated above, and the age of AEP's legacy systems in this space, including our CIS system, I recommend a phased approach that balances value to customers through enhanced functionality for CRES, and a prudent approach to investment in systems. First, implement functionality that calculates AEP Ohio's AMI residential NSPL and PLC values using actual interval data. This provides CRES financial incentives through settlement that can be passed to customers on TOU programs and more accurately reflect where customers not on such programs can move their peaks. This functionality can be done partly outside of legacy systems to simplify the changes to our legacy systems as a bridge to future functionality. Costs associated with this change are approximately $800K. Second, I recommend implementing EDI changes noted in Scott Osterholt's testimony that provides EDI functionality for CRES TOU customers and cost approximately $700K. Both of these projects, totaling $1.5M, can be implemented together as one project for efficiency of effort and be implemented within 20 months of project start. Third, I recommend enhancements settling residential customers THEO be implemented as part of AEP's CIS replacement, using modern technology platforms. The primary reason for this approach is it avoids duplication of costs for customers with a limited period of time those enhancements may be used by CRES prior to retirement of legacy systems. It is also important for the Commission to recognize the risk related to significant enhancements to legacy systems being staged for retirement. Due to the timeline and cost estimates, the Commission should recognize implementing a new process that may not be compatible with future systems poses future risks. In addition, enhancing legacy systems creates two deployment windows for the market to adapt to, rather than one. Also, there are risks related to supportability based upon a limited market for talent trained to work on these systems, and complexity of code, potentially impacting multiple markets AEP supports. Modern systems are more configurable, as opposed to hard-coded, and require fewer integrations with shared databases.

Alternatively, if the Commission does choose to implement changes to legacy systems, the Commission should also ensure timely recovery of the costs associated with the process changes prior to the new CIS system if functionality is no longer used and useful or supported by the new CIS system platform. The Commission may also consider requiring CRES share in costs.

Q. DOES THIS CONCLUDE YOUR SUPPLEMENTAL TESTIMONY?

A. Yes.

CERTIFICATE OF SERVICE

In accordance with Rule 4901-1-05, Ohio Administrative Code, the PUCO's e-filing system will electronically serve notice of the filing of this document upon the following parties. In addition, I hereby certify that a service copy of the foregoing *Supplemental Testimony of Stacey D. Gabbard* was sent by, or on behalf of, the undersigned counsel to the following parties of record this 15th day of October, 2021, via electronic transmission.

/s/ Steven T. Nourse
Steven T. Nourse

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Summary: Testimony Supplemental Testimony of Stacey D. Gabbard electronically filed by Mr. Steven T. Nourse on behalf of Ohio Power Company