BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

IN RE: APPLICATION OF 1803 ELECTRIC COOPERATIVE, INC. FOR APPROVAL OF POWER PURCHASE AGREEMENTS AND FOR COST RECOVERY	))))	**DOCKET NO. U-_____**

DIRECT TESTIMONY

OF

KEVIN P. SUHANIC

ON BEHALF OF

1803 ELECTRIC COOPERATIVE, INC.

PUBLIC VERSION

MARCH 17, 2021

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I. INTRODUCTION AND BACKGROUND

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

A. My name is Kevin P. Suhanic and my business address is 4140 West 99th, Carmel, IN 46032. My current position is Executive Director of Portfolio Strategy, Alliance for Cooperative Energy Services Power Marketing LLC ("ACES").

Q. HOW LONG HAVE YOU HELD THE POSITION OF EXECUTIVE DIRECTOR OF PORTFOLIO STRATEGY AT ACES?

A. I have held my current position since April of 2019.

Q. WHAT ARE YOUR RESPONSIBILITIES AND DUTIES AS THE EXECUTIVE DIRECTOR OF PORTFOLIO STRATEGY AT ACES?

A. My areas of responsibilities and job duties include portfolio level strategy development and risk management, primarily for electric cooperatives, including power supply, delivery, fuel hedging, renewable strategy and a variety of strategic imperatives (e.g. ESG, long term financial planning, etc.). Also, I perform these services to utilities some of which are within the Midcontinent Independent System Operator ("MISO").

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I received Bachelor of Business Administration and Master Business Administration degrees from the University of Notre Dame in 2004 and 2005, respectively.

Q. WHAT PROFESSIONAL CERTIFICATIONS DO YOU HOLD?

A. I am a Certified Public Accountant (inactive), in the State of Ohio. I hold the Series 3 certification administered by the Financial Industry Regulatory Authority for the Natural Futures Association.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY PUBLIC UTILITY REGULATORY COMMISSIONS?

A. Yes, I provided filed testimony in Federal Energy Regulatory Commission ("FERC") Docket No. EL18–122–001 Minden, Louisiana v. Southwestern Electric Power Company.

Q. PLEASE DESCRIBE YOUR BUSINESS EXPERIENCE.

A. I have been in the energy industry for over 13 years. Prior to my current position at ACES, I held the position of Director of Portfolio Strategy, Director of Transmission Services, Manager of Transmission Services, Senior Financial Transmission Rights ("FTR") Modeler, and FTR Modeler.

Prior to joining ACES in April 2007, I spent approximately two (2) years as an auditor with an accounting firm that is now part of PricewaterhouseCoopers.

II. PURPOSE & SUMMARY OF DIRECT TESTIMONY

Q. ON WHOSE BEHALF ARE YOU TESTFYING?

A. I am testifying before the Louisiana Public Service Commission ("Commission" or "LPSC") on behalf of 1803 Electric Cooperative, Inc. ("1803"), a member-owned electric cooperative consisting of five (5) member electric cooperatives ("Member Cooperatives"):

1. Beauregard Electric Cooperative, Inc.
2. Claiborne Electric Cooperative, Inc.
3. Northeast Louisiana Power Cooperative, Inc.
4. South Louisiana Electric Cooperative Association
5. Washington-St. Tammany Electric Cooperative, Inc.

The Member Cooperatives have formed 1803 to combine their power needs and to seek power supply opportunities to fulfill the power needs for the Member Cooperatives upon the expiration of current full-requirements wholesale power supply contracts in 2025.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. In its Application, 1803 requests that the Commission issue a decision, supported by the evidence, that 1803's 2019 Request for Proposals for Long-Term Capacity and Energy Resources and resultant power supply plan in accordance with established Commission processes is compliant with applicable Commission Orders and established Request for Proposals ("RFP") processes, and is prudent and is in the public interest.

ACES assisted 1803 in administering 1803's RFP and power supply portfolio selection. I led the ACES' Portfolio Strategy and Analysis Team. My Direct Testimony outlines the processes followed under the RFP, the evaluation of the offers received, and the conclusions reached by 1803 as to the most prudent power supply plan to protect and benefit the members of 1803 with the provision of a reliable reasonable cost power supply.

III. OVERVIEW OF ACES STRATEGIC ANALYSIS PROCESS

Q. PLEASE SUMMARIZE YOUR ROLE AS LEADER OF THE 1803 PORTFOLIO STRATEGY AND ANALYSIS TEAM.

A. As the leader of the 1803 Portfolio Strategy and Analysis Team, I:

- Authored portions of the Demonstration of Need (Section 2) and the Portfolio Strategy and Analysis Team (Section 4.13) portions of 1803's RFP document and also provided edits and information for other sections.
- Oversaw creation of hourly load forecast projections using the load forecast provided to 1803 by Power Stat, LLC and historical meter data provided by the members of 1803.
- Created the capacity accreditation methodology for renewable and battery storage resources as noted in the RFP.
- Led the multi-phased analyses as outlined in the RFP.
- Worked closely and communicated frequently with LPSC Staff regarding the RFP process and 1803 as they determined the most prudent portfolio for their members' future.

Q. WHAT DID LEADING THE MULTI-PHASED ANALYSES ENTAIL?

A. The multi-phased analyses, developed in consultation with the Commission's outside consultant, J. Kennedy and Associates, resulted in 1803's RFP having a two-step bidding process. This process consisted of two (2) phases, Phase 1 and Phase 2, and within these phases we had sub-sections of Step A and Step B. This effectively created a four-step process: Phase 1 consisting of Step 1A and Step 1B and Phase 2 consisting of Step 2A and Step 2B. Bidders were able to update their initial offers between Step 1B and Step 2A, as outlined in the RFP.

Q. WHAT TYPE OF ANALYSIS DID YOU PERFORM IN PHASE 1?

A. Step 1A was a levelized economic cost analysis and Step 1B was a scaled Net Present Value ("NPV") calculation in both of these analyses, results were only compared among similar technology/product types.

Q: WHAT TYPE OF ANALYSIS DID YOU PERFORM IN PHASE 2?

A: Step 2A, led by Mr. Patrick J. Maguire, produced eight (8) potential portfolios for further analysis in Step 2B. Step 2B was a 20-year analysis of each portfolio, with a stochastic energy modeling process and capacity, 1803 overhead costs, as discussed in the Direct Testimony of Brian W. Hobbs, and all other costs captured to determine an 1803 revenue requirement for power supply, as discussed in the Direct Testimony of Brian W. Hobbs, with risk assessed in high and low cases. Furthermore, in parallel, a carbon tax scenario was run with the same parameters and metrics to provide further information to 1803.

Q: WHAT WERE KEY ASPECTS OF THE ANALYSIS ACROSS BOTH PHASES?

A. The multi-phased approach had several key inputs and metrics that were built into ACES' models and assessments across the various steps. My role in determining these included:

- The compilation of forward curves and projections for power, gas, carbon, capacity, ancillary services;
- Forecasted Auction Revenue Rights ("ARRs") as well as basis forecasts utilizing power flow/Locational Marginal Pricing ("LMP") software models;
- Developing values for scenarios that included changes to power, gas, capacity, ancillary service and carbon pricing;
- Developing the portfolio metrics for the analysis scorecard using 1803's preferences as outlined in the RFP and in meetings with the 1803 Board of Directors ("Board");
- A forecast of other MISO settlement costs; and
- Incorporating 1803 overhead costs, as discussed in the Direct Testimony of Brian W. Hobbs to each portfolio where applicable to create level comparisons across the final eight (8) portfolios. This includes costs incurred before 2025 being included in 2025 through 2028 rates to assure fair comparisons.

Q: WHAT TYPES OF PROPOSALS WERE THE FINAL EIGHT (8) PORTFOLIOS?

A: Three (3) portfolios were full-requirements proposals, one (1) portfolio was a partial-requirements offer combined with other PPA resources and the remaining four (4) portfolios were a combination of PPA resources from the RFP.

Q. DID YOUR ROLE ENTAIL ANY OTHER RESPONSIBILITIES?

A. Additionally, as the leader of the Portfolio Strategy and Analysis Team, I represented and/or participated in:

- Meetings with LPSC Commissioners and Staff to explain the 1803 RFP and approach;
- The RFP technical conference in January of 2020;
- Helping draft the RFP document;
- Coordinating with fuels representatives for fuels related modeling questions;
- Meeting with LPSC Staff and their consultant to review bids received;
- Presenting results of Step 1A and Step 1B to LPSC Staff and Commission consultants;
- Providing economic analysis for bid advancement and rejection to ACES' Process Control Team to notify Bidders for Phase 1B; and
- Presenting Step 2B results to LPSC Staff and their consultants.

IV. PORTFOLIO STRATEGY AND ANALYSIS TEAM ACTIVITIES

Q. CAN YOU SUMMARIZE HOW ACES USED FORWARD CURVES FOR ENERGY, ANCILLLARY SERVICES AND CAPACITY IN ITS EVAULATIONS & ANALYSIS?

A. Yes. I determined the forward curves to use in the analysis. While the process evaluated projects and then portfolios against each other, price forecasts are a needed part of the process to run models and anchor values. ACES relied largely on market sources for forward curves for power, natural gas, and capacity, and specifically, IHS Markit price forecasts are widely used in the industry. Ancillary service costs were based upon historical MISO market experience.

These curves represent the "market" cost of these products in the model. The forward curves aligned well with the offers received in the RFP across a variety of products, indicating reasonableness of the assumptions. I developed scenarios around these forward curves, which included upward and downward shocks to the power and gas prices. Ancillary prices were doubled and halved to simulate price shocks in those products.

Q. HOW DID ACES EVALUTE MISO CAPACITY MARKET PRICES TO USE IN THE ANALYSIS?

A. ACES used forward curves based upon market experience and IHS Markit price forecasts. Capacity prices were shocked upward and downward based upon the highest and lowest values in the forward curves. MISO capacity prices largely converge near the end of the study period near values approximating MISO's published cost of new entry less inframarginal energy margins.

Q. CAN YOU SUMMARIZE THESE FORWARD CURVES FOR PHASE 1?

A. Yes. Figure A, Figure B and Figure C detail the actual values used in Phase 1.

Figure A: PHASE 1 ENERGY CURVES – NO CARBON TAX

PHASE 1 ENERGY CURVES - [redacted]				
	LOUISIANA HUB			Natural Gas
	Peak	Wrap		Henry Hub
Year	($/MWh)	($/MWh)		($/MMBtu)
2025	[redacted]			
2026				
2027				
2028				
2029				
2030				
2031				
2032				
2033				
2034				
2035				
2036				
2037				
2038				
2039				
2040				
2041				
2042				
2043				
2044				

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Figure B: PHASE 1 ENERGY CURVES WITH CARBON (2030 Carbon Tax)

PHASE 1 ENERGY CURVES WITH CARBON [redacted]				
	LOUISIANA HUB			Natural Gas
	Peak	Wrap	CO2	Henry Hub
Year	($/MWh)	($/MWh)	($/Metric Ton CO2)	($/MMBtu)
2025	[redacted]			
2026				
2027				
2028				
2029				
2030				
2031				
2032				
2033				
2034				
2035				
2036				
2037				
2038				
2039				
2040				
2041				
2042				
2043				
2044				

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Figure C: PHASE 1 MISO ZONE 9 CAPACITY CURVES

PHASE 1 CAPACITY CURVES			
$/kw-mo.			
Year	Base	High	Low
2025	[redacted]		
2026			
2027			
2028			
2029			
2030			
2031			
2032			
2033			
2034			
2035			
2036			
2037			
2038			
2039			
2040			
2041			
2042			
2043			
2044			

Q. CAN YOU SUMMARIZE THESE FORWARD CURVES FOR PHASE 2?

A. Yes. Figure D, Figure E and Figure F detail the actual values used in Phase 2.

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Figure D: PHASE 2 ENERGY CURVES - NO CARBON

PHASE 2 ENERGY CURVES				
	LOUISIANA HUB			Natural Gas
	Peak	Wrap		Henry Hub
Year	($/MWh)	($/MWh)		($/MMBtu)
2025	[redacted]			
2026				
2027				
2028				
2029				
2030				
2031				
2032				
2033				
2034				
2035				
2036				
2037				
2038				
2039				
2040				
2041				
2042				
2043				
2044				

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Figure E: PHASE 2 ENERGY CURVES WITH CARBON (2030 Carbon Tax)

PHASE 2 ENERGY CURVES WITH CARBON [redacted]				
	LOUISIANA HUB			GAS
	Peak	Wrap	CO2	Henry Hub
Year	($/MWh)	($/MWh)	($/Metric Ton CO2)	($/MMBtu)
2025	[redacted]			
2026				
2027				
2028				
2029				
2030				
2031				
2032				
2033				
2034				
2035				
2036				
2037				
2038				
2039				
2040				
2041				
2042				
2043				
2044				

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Figure F: PHASE 2 MISO ZONE 9 CAPACITY CURVES

PHASE 2 CAPACITY CURVES			
$/kw-mo.			
Year	Base	High	Low
[redacted]			

Q. CAN YOU SUMMARIZE HOW ACES EVALUTED CARBON PRICING RISKS?

A. Yes, carbon pricing was modeled in the carbon tax scenario with the effects of a carbon cost curve also impacting forward power curves, to test offers and portfolios response to such a cost being imposed on 1803. In Phase 1 this was included as a distinct scenario among four (4) scenarios (base, high case, low case, and the carbon tax case.)

Q. PLEASE DESCRIBE MISO'S FINANCIAL TRANSMISSION RIGHTS AND AUCTION REVENUE RIGHTS CONSTRUCT.

A. The primary function of MISO's FTRs Market is the allocation of ARRs and the auction of FTRs. MISO ARRs/ FTRs are allocated to Load Serving Entities ("LSE") based on

transmission capacity and as a means to provide a financial hedging mechanism to the LSE and other Market Participants against congestion charges in MISO's Day-Ahead Market.

Q. PLEASE DESCRIBE HOW MISO FTR/ARRS WERE ASSESSED AND EVALUATED.

A. ACES developed MISO ARR values based on publicly available ARR results for the LAGN.LAGN_1.AZ ARR Zone.

The relevant ARR volumes and clearing prices were compared to ACES forward looking congestion models, which indicated historical price levels were reasonable proxies for use in valuation. The 1803 loads are only a portion of the ARR Zone. Based upon the totals in the zone, 1803 was conservatively estimated to be 50% of the ARR Zone.

There are also positive and negative ARRs assigned to the zone, which can change annually. To be conservative, ACES assumed 80% of positively valued ARRs would still be assigned, and all currently held negative ARRs would still be assigned to 1803. The annual expected value of ARRs to 1803 was approximately [redacted]

MISO provides a secondary ARR revenue stream as their "Stage 2" process that would be expected to net 1803 around $[redacted] as well, so this is a conservative estimate and a minor impact on the overall evaluation of portfolios.

Q. CAN YOU SUMMARIZE HOW ACES ASSESSED RENEWABLE CONTENT AND RESOURCE ACCREDITATION RISK?

A. Yes, the Portfolio Strategy and Analysis Team assigned a value to the capacity rating of renewables (resource accreditation) as indicated in the RFP document in Step 2A and Step 2BIn Step 1A and Step 1B renewable resources were accredited capacity based upon the response in the appendix or upon supplemental data provided.

The Portfolio Strategy and Analysis Team assessed portfolios for the total renewable content and an accreditation under current MISO rules, and a capacity accreditation was developed based upon the project characteristics. Next, based upon portfolio usage of renewables the appropriate discounting was done based upon a likely Effective Load Carrying Capacity ("ELCC") framework as outlined in the RFP. For portfolios with 343 MW of solar resources, this discounting resulted in approximately a 33% reduction in solar capacity accreditation compared to current MISO rules. To the extent renewable projects had degradation factors, these were also incorporated into the annual capacity accreditation and forecasted energy production.

Q. HOW WERE BATTERY ENERGY STORAGE RESOURCES ASSESSED AND EVALUATED?

A. Battery energy storage resources were determined to be accredited based upon 4-hour continuous capability and a 5% derate for potential availability issues. Energy storage rules are still being updated across the country, but currently the four (4) hour convention appears to be the largest consensus and is the current MISO standard. Similar to solar, batteries had degradation factored in as indicated by the offer (some did not degrade as they had augmentation built into the offer.)

V. ACES' PHASE 1 ANALYSIS

Q. PLEASE DESCRIBE THE STEPS IN ACES' PHASE 1 ANALYSIS.

A: Phase 1 of the analysis included Step 1A, a Levelized Cost of Energy ("LCOE") review, and Step 1B, a discounted NPV analysis.

Q. PLEASE DESCRIBE THE ANALYSIS ACES CONDUCTED IN EVALUATING OFFERS IN RFP STEP 1A.

A. For evaluations of Step 1A responses, anonymous bids were submitted to the Portfolio Strategy and Analysis Team, they were grouped with offers of the same types (i.e. solar with solar, full requirements with full requirements, etc.). These offers were analyzed to create a LCOE over the term of the analysis, which is a process to normalize the offer costs into a $/MWh figure.

Depiction of offers in LCOE terms permits evaluation of offers of differing durations on comparable terms. Capacity only offers utilized a Levelized Cost of Capacity performed in a similar way. This served so that offers were comparable to each other within a group, and different offer types being analyzed slightly differently has no impact as there was no cross-group analysis in Step 1A.

Within a group, offers that were not competitive at this step were eliminated, however when possible, more projects were moved forward to Step 1B then would be finally needed, in line with the RFP goals for this step. The Step 1A results were discussed with the 1803 Board and reviewed with LPSC staff and their consultants. The remaining projects were moved to Step 1B where a NPV analysis was performed.

Q. PLEASE DISCUSS HOW YOUR TEAM ANALYZED RFP PROPOSALS IN STEP 1B.

A. The first part of Step 1B was an LMP forecast for basis between proposal settlement points and load points. This was further refined in Step 2B, but for Step 1B this was designed to account for major basis differentials that might make projects not comparable within a group. As most projects were in the MISO South area, these differences were largely confined to moderate differences between Louisiana and surrounding states.

Using the forward curves, fuel basis, bidder response data, and forecast LMP basis, a production cost model was administered simulating each offer using ABB's Planning and Risk ("PaR") software.

Fixed costs and other costs (including expected overheads for non-full requirement offers), were added to these calculations and coupled with a discount rate to determine a NPV for each project other than full requirements offers.

An NPV analysis was created for each project, and these values were compared within project types to eliminate further projects that were less economically viable compared to other projects of the same type.

Valuations were generally performed on a deterministic modeling basis, but with scenarios of higher and lower market values and a carbon tax. Project NPVs were scaled by size (based upon MWh) to create a relative score, this was used such that, for example, a 100 MW proposal did not look better than two equivalent 50 MW proposals. Some offer types had limited RFP responses (for example, Call Options) so in some cases all proposals of a type advanced to Phase 2.

Q. WHAT WAS DONE DIFFERENTLY IN STEP 1B FOR FULL REQUIREMENT OFFERS?

A. The exact same PaR modeling was done for partial and full requirements offers, but in order to better aid the 1803 Board, these proposals were presented in a $/MWh cost ranking. As Step 1 did not include any consideration across product types, this did not affect any results.

All of these NPV and $/MWh calculations were described to the 1803 Board and other non-cost issues were presented as well, largely around MISO generator

interconnection status, as this was of particular interest. Upon review of these metrics, the 1803 Board determined projects within each type that should advance in the RFP.

The Process Control Team for Step 1A and Step 1B informed the Bidders and provided Phase 2 bidding information.

Q: DID YOU REVIEW THE PHASE 1 RESULTS WITH THE COMMISSION AND THEIR CONSULTANT?

A: Yes. The evaluations and Phase 1 RFP decisions were presented and discussed with Commission staff and their consultants. Many of the responses rejected in Phase 1 were partial rejections where bidders offered the same project under different terms (mutually exclusive), and the Step 1 modeling preferred one set of terms over the other, for example, a flat price compared to an escalating price for the same offer. Only selecting one set of terms for a project with multiple offer structures ensured Step 2A modeling would only have the most favorable version of the offer and not select mutually exclusive projects at the same time.

VI. ACES' PHASE 2 ANALYSIS

Q. PLEASE DESCRIBE THE STEPS IN THE PHASE 2 ANALYSIS.

A: Phase 2 was broken into two steps. Step 2A was a capacity expansion model based upon the RFP offers advanced and forward curves modeled. As discussed above, Step 2A was led by Mr. Patrick J. Maguire, who used capacity expansion software called EnCompass modeling to determine five (5) potential portfolios for further analysis in Step 2B along with the three (3) remaining full requirements offers for a total of eight (8) potential 1803 power supply portfolios to be analyzed further. Step 2B was a 20-year analysis of each of

the eight (8) portfolios across a spectrum of metrics, most notably the Present Value Revenue Requirement ("PVRR").

Q. PLEASE DESCRIBE THE ANALYSIS ACES CONDUCTED IN EVALUATING OFFERS IN RFP STEP 2B.

A. The Step 2B analysis drew upon the portfolio possibilities determined in Step 2A and was different than Phase 1 in that now combined portfolios of resource offers and full requirements offers would be analyzed from a total 1803 cost standpoint.

The Step 2B analysis again started with Promod simulations to determine potential basis differences in the market including specific proposal delivery points (Load, Hub or at a generator node).

From there, forward curves, fuel information, proposal data, and forecast LMP basis were used to run a production cost model using (PaR) software, but these runs used the forecasted load and either a full requirements offer or a group of offers comprising a portfolio, from Step 2A.

Q. PLEASE DESCRIBE THE PRODUCTION COST MODELING.

A. ACES' utilized a production cost model with stochastic variables where load levels, market fuel prices, and market energy prices were allowed to vary based upon historical load data and historical market volatilities. This captures the risk dimension of load, fuel and market energy price uncertainty.

A parallel run was done in the same manner but with a carbon tax curve and its associated impacts on energy and fuel prices. The load cost was calculated as the market energy costs, and each full requirement offer or group of other offers had energy margins calculated (MISO market revenues less contract energy cost).

This modeling captured variable costs and resource margins for each of eight (8) potential portfolios (some of which were full requirements offers). These results were then summarized from 100 scenarios per hour to create an expected cost, and a 5th and 95th percentile cost for each portfolio to assess risk in the energy market.

Q. HOW WERE FIXED COSTS TREATED?

A. Fixed costs (and benefits) were added to each portfolio as applicable, with load being charged the full cost of capacity, ancillaries, MISO costs, and 1803 overheads. Then portfolio fixed charges (largely capacity or demand charges) were added, and any portfolio providing offsets to the load cost was credited for that reduction. For example, a full requirements offer that included covering all these aspects was credited back for market capacity, ancillaries, MISO costs, and 1803 overhead costs. Other offers might only get credit for capacity, depending on the terms of each offer.

The energy and capacity curves were determined in the same manner as described in the Step 1 discussion above. Capacity high and low cases that were developed stayed roughly unchanged from Step 1. ARR values were unchanged from Step 1 estimates. Energy costs did not have high and low cases, but rather were included as a stochastic variable in the PaR model, thus creating 100 iterations to assess risk rather than a static scenario.

Q. HOW WERE MISO COSTS TREATED?

A. To evaluate and model MISO costs, ACES reviewed historical experience in MISO, and determined charge types, volumes, and costs the 1803 load would likely pay for MISO administration and overhead. These were forecasts and were halved and doubled for low and high scenarios. Energy market costs were included in the Production Cost Modeling,

including congestion costs. ARRs were accounted for as described above. Transmission costs were not part of any of this analysis as they are expected not to change based on portfolio selection. Any portfolio that included a portion of these MISO costs in the proposal were credited for the cost reduction or elimination, as appropriate.

Q. HOW WERE OVERHEAD COSTS TREATED?

A. 1803's overhead costs were received from consultants at Pain, Garland and Hobbs, who were hired by 1803 to provide cost and budget information. These were all added and/or credited based upon the nature of the portfolio as indicated in the RFP. See Direct Testimony of Brian W. Hobbs for further information on 1803's overhead costs.

Q. PLEASE DESCRIBE WHAT YOU MEAN BY PORTFOLIO?

A. A portfolio may consist of one contract that serves 1803's load or a collection of contracts that jointly serve 1803's load. The eight (8) portfolios considered based upon Step 2A results were three (3) full requirements offers, one (1) partial requirement offer with additional solar PPAs, and four (4) portfolios of varied PPA resources. The following table provides the reference or "short name" for each evaluated portfolio:

Portfolio #	Short Name
1	[redacted]
2	[redacted]
3	[redacted]
4	[redacted]
5	[redacted]
6	[redacted]
7	[redacted]
8	[redacted]

Each portfolio was measured against several metrics considered by 1803. Figure G below delineates and illustrates the components included in each portfolio.

Figure G: Summary of Portfolios

Summary of Portfolios									
Element of Portfolio	Term	#1	#2	#3	#4	#5	#6	#7	#8
[redacted]	20 Years	X							
	20 Years		X						
	20 Years			X					
	20 Years				X				
	20 Years				X	X	X	X	X
	5 Years					X	X		X
	20 Years						X	X	
	20 Years								X
	20 Years					X		X	
	5 Years				X	X	X	X	

Q. WHAT METRICS WERE USED IN EVALUATING THESE PORTFOLIOS?

A. Metrics were developed by the 1803 Board consistent with their desires indicated in the RFP document. These metrics included the PVRR in millions of dollars. The PVRR metric which is a commonly used approach to express the revenue required to serve the load (excluding transmission costs which are independent of the portfolios).

The PVRR is the most holistic measure of the relative economic benefits of each portfolio. The 2026, 2035, and 2044 rates for power supply costs (all costs other than transmission) in $/MWh for the expected (average) case, and the high and low cases were other financial metrics assessed by the 1803 Board.

These years (i.e., 2026, 2035, 2044) were also used for other important metrics, including fixed cost concentration, energy hedge percentage, capacity hedge percentage, natural gas price exposure, energy market exposure, renewable energy serving load, and carbon emissions.

These metrics were evaluated for each of the eight (8) potential portfolios, for both the base scenario and the carbon tax scenario, with an even emphasis on each scenario. These metrics were presented to the 1803 Board to assist their decision making on the portfolios.

Q. PLEASE SUMMARIZE HOW THE PORTFOLIOS PERFORMED IN THE VARIOUS METRICS.

A: The results are best summarized one portfolio at a time, however Figure H and Figure I provide a summary of the modeling results.

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Figure H: Base Case Step 2B Analysis Metrics by Portfolio

Metric	Year	[redacted]
20-Year PVRR	2025 - 2044	
Average Rate ($/MWh)	2026	
	2035	
	2044	
Low Rate ($/MWh)	2026	
	2035	
	2044	
High Rate ($/MWh)	2026	
	2035	
	2044	
Fixed Cost Concentration	2026	
	2035	
	2044	
Energy Hedge Percentage	2026	
	2035	
	2044	
Capacity Hedge Percentage	2026	
	2035	
	2044	
Natural Gas Price Exposure	2026	
	2035	
	2044	
Spot Energy Market Exposure	2026	
	2035	
	2044	
Renewable Energy Serving Load Percentage	2026	
	2035	
	2044	
Carbon Emissions (tons)	2026	
	2035	
	2044	

1

Figure I: Carbon Tax Scenario Step 2B Analysis Metrics by Portfolio

Metric	Year	[redacted]
20-Year PVRR	2025 - 2044	
Average Rate ($/MWh)	2026	
	2035	
	2044	
Low Rate ($/MWh)	2026	
	2035	
	2044	
High Rate ($/MWh)	2026	
	2035	
	2044	
Fixed Cost Concentration	2026	
	2035	
	2044	
Energy Hedge Percentage	2026	
	2035	
	2044	
Capacity Hedge Percentage	2026	
	2035	
	2044	
Natural Gas Price Exposure	2026	
	2035	
	2044	
Spot Energy Market Exposure	2026	
	2035	
	2044	
Renewable Energy Serving Load Percentage	2026	
	2035	
	2044	
Carbon Emissions (tons)	2026	
	2035	
	2044	

1

Q. PLEASE INDIVIDUALLY DESCRIBE THE EIGHT (8) PORTFOLIOS AND THE RESULTS OF MODELING EACH PORTFOLIO, STARTING WITH PORTFOLIO 1.

A. Portfolio 1 was a full requirements offer based upon a heat rate, leaving 1803 100% exposed to natural gas price movements. This portfolio did not perform favorably in the financial metrics, and did not actually provide much hedged energy (the fuel price is floating for 20 years), while leaving the largest gas price exposure. It did provide a perfect capacity hedge, but also performed poorly on the renewable and carbon emission metrics.

Q. WHAT WAS ACES' EVALUATION OF AND 1803'S CONCLUSION WITH REGARD TO THE DESIRABILITY OF PORTFOLIO 1?

A. The 1803 Board decided this option lacked fuel diversity, performed worst under high gas price scenarios, had no plan to address decarbonization in the future and was not a competitive heat rate against newer natural gas-fired technologies. 1803 did not select Portfolio 1 as pursuant to 1803's ten (10) goals this portfolio did not best meet their needs.

Q. PLEASE DESCRIBE PORTFOLIO 2.

A. Portfolio 2 was a block of solar generation coupled with a heat rate similar to Portfolio 1. Analysis of Portfolio 2 indicated that the energy hedge percentage, renewable energy metrics, and carbon output were superior to Portfolio 1, but still performed poorly in terms of PVRR and rate metrics.

Q. WHAT WAS 1803'S CONCLUSION WITH REGARD TO THE ACCEPTABILTIY OF PORTFOLIO 2?

A. The solar pricing offered was higher than other offers in the RFP and included [redacted] escalation. In ACES' discussions with 1803, the Board indicated a concern that solar projects were not fully identified and that without a greater understanding of relevant

commercial features, the project conveyed increased risk. As the costs were greater and risks were higher in comparison to other portfolios, Portfolio 2 was not selected by 1803.

Q. PLEASE DESCRIBE PORTOLIO 3.

A. Portfolio 3 was a cost-of-service type rate with some pass-through costs and charges to 1803. This portfolio performed the worst in the PVRR and rates metrics in both the base and carbon tax scenarios. The fuel and resource diversity was an attractive feature of this portfolio. The 1803 Board was also concerned with a lack of information provided to forecast a rate through 2044.

Q. WHAT WAS ACES' EVALUATION OF AND 1803'S CONCLUSION WITH REGARD TO THE ACCEPTABILTIY OF PORTFOLIO 3?

A. In ACES' discussions with 1803, the Board indicated a concern that even after requesting further certainty and/or forecasts, forecasted rates were only provided up to 2022. This was the most expensive full requirements offer. As low rates and less risk were key goals for 1803, Portfolio 3 was not selected by 1803.

Q. PLEASE DESCRIBE PORTOLIO 4.

A. Portfolio 4 was similar to Portfolio 1, but only covering 75% of the load. Step 2A indicated the best additional resource was solar, so 343 MWs of solar projects was added, and because 1803 expressed concerns with solar during the winter peak, a 5-year 185 MW heat rate call option was also added.

Q. WHAT WAS ACES' EVALUATION OF AND 1803'S CONCLUSION WITH REGARD TO THE ACCEPTABILTIY OF PORTFOLIO 4?

A. Portfolio 4 provided the same strong capacity hedge metrics as the full requirement portfolios, but the PVRR and rates were still significantly higher than other portfolios. The cost metrics were not attractive to 1803 and as such Portfolio 4 was not selected by 1803.

Q. PLEASE EXPLAIN PORTFOLIO 5.

A. Portfolio 5 was also referred to as the reference case, as Step 2A indicated this portfolio appeared the most favorable of the partial requirements portfolios analyzed in the RFP. This portfolio consists of 57.8% of a new natural gas combined cycle power plant capable of burning 50% hydrogen, 343 MWs of solar generation, a 5-year 27% partial requirements contract and a 5-year 185 MW heat rate call option from an existing natural gas power plant.

Q. WHAT WAS ACES' EVALUATION OF AND 1803'S CONCLUSION WITH REGARD TO THE ACCEPTABILTIY OF PORTFOLIO 5?

A. Portfolio 5 provided the lowest PVRR and rates in both the base case and in the carbon tax scenario. The portfolio was balanced across the other metrics, with strong metrics in energy hedge percentage and renewable energy percentage, while being average in other areas.

Portfolio 5 also had strengths of having a diversity of counterparties, technology types, and allowing for some future resource flexibility in a decade. In ACES' discussions with 1803, the Board liked the possible option of using hydrogen as a fuel in the combined cycle, and that the combined cycle had firm interconnection studies and plans, reducing project risk.

Portfolio 5 met all the metrics 1803 had outlined and represented the greatest savings to customers while exhibiting lower risk and having the best decarbonization

potential. For its future power supply needs, and following the criteria set forth by 1803's Board (as explained in the Direct Testimony of Jason M. Painter), 1803 has selected Portfolio 5 as the best fit for their needs, as outlined in the RFP.

Q. PLEASE EXPLAIN PORTFOLIO 6.

A. Portfolio 6 is similar to Portfolio 5, with the only difference being the inclusion of a natural gas combustion turbine replacing the natural gas combined cycle plant. The solar, partial requirements and heat rate call option contract remain unchanged as to Portfolio 6 compared to Portfolio 5. Portfolio 6 performed reasonably in the financial metrics in the base case but had higher PVRR and rates compared to Portfolio 5. These shortfalls were even wider in the carbon tax scenario.

Q. WHAT WAS ACES' EVALUATION OF AND 1803'S CONCLUSION WITH REGARD TO THE DESIRABILITY OF PORTFOLIO 6?

A. Portfolio 6 had higher rates than Portfolio 5. Furthermore, Portfolio 6 was more exposed to carbon tax risk, had a larger spot market exposure, and also had limited information available on MISO generator interconnection timing and prospects. The Portfolio 6 combustion turbine did not perform as well in the carbon tax scenario because the less efficient heat rate lead to higher production costs due to greater carbon emissions per megawatt hour, as compared to the combined cycle plant. 1803 determined that execution risk was higher in Portfolio 6 and that this portfolio offered no additional benefits as compared to the lower cost Portfolio 5. 1803 determined Portfolio 5 had lower risk, and as such did not select Portfolio 6.

Q. PLEASE EXPLAIN PORTFOLIO 7.

A. Portfolio 7 was combining the combined cycle from Portfolio 5 and the combustion turbine from Portfolio 6 with 343 MWs of Solar and the heat rate call option.

Q. WHAT WAS ACES' EVALUATION OF AND 1803'S CONCLUSION WITH REGARD TO THE DESIRABILITY OF PORTFOLIO 7?

A. The financial metrics of Portfolio 7 were not favorable, compared to either Portfolio 5 or Portfolio 6, and included major fixed costs in supporting two (2) new power plants. This Portfolio generally provided more capacity than 1803 needed and a sizeable gas price exposure. 1803 concluded this added risk and costs to their customers and did not select Portfolio 7.

Q. PLEASE EXPLAIN PORTFOLIO 8.

A. Portfolio 8 excluded the new combustion turbine and combined cycle natural gas resources, incorporating 343 MWs of Solar, the 5-year partial requirements contract, and 360 MW of battery storage. 1803 reviewed the metrics which were average across financial measures and mixed in other areas. 1803 asked ACES if anyone was currently using battery storage resources at this scale for a load their size and ACES could not locate such an example in MISO South.

Q. WHAT WAS ACES EVALUATION OF AND 1803'S CONCLUSION WITH REGARD TO THE DESIRABILITY OF PORTFOLIO 8?

A. Ultimately, 1803 did not find it prudent to lead MISO South in battery storage installation, but was hopeful that batteries might be a part of future portfolio additions, and liked that their selected Portfolio 5 would allow them to consider battery storage further into the future as the storage technology matured.

Q. DID ACES' DISCUSS THE EVALUATION OF RFP RESULTS WITH COMMISSION STAFF AND RELEVANT CONSULTANTS?

A. RFP evaluation data was discussed with 1803, as well as the LPSC and their consultant over a series of more than 20 meetings, due to the volume of information throughout the various steps. 1803 and Commission Staff thoroughly questioned the results of each portfolio and reviewed in detail the metrics for each. 1803's conclusion to select Portfolio 5, meets the goals outlined in the 1803 RFP.

VII. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does

BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

APPLICATION OF 1803 ELECTRIC	)	
COOPERATIVE, INC. FOR APPROVAL	)	
OF POWER PURCHASE AGREEMENTS	)	**DOCKET NO. _____**
AND FOR COST RECOVERY	)	

AFFIDAVIT OF WITNESS

I, Kevin P. Suhanic, being duly sworn, depose

that the Direct Testimony in the

above referenced matter on behalf of

1803 Electric Cooperative, Inc.

are true and correct to the best of my knowledge, information and belief.

Kevin P. Suhanic

Subscribed and sworn before
me this 15th day of
March, 2021.

Notary Public

Name of Notary and Notary/Bar Roll No.:

Official Seal
Beth A. Burrows
Marion County
Commission Expire 8/24/2024
Commission # 687277