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MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ET-2018-0063

DIRECT TESTIMONY

OF

STEVEN M. WILLS

ON

BEHALF OF

UNION ELECTRIC COMPANY

d/b/a Ameren Missouri

St. Louis, Missouri
November, 2017

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DIRECT TESTIMONY

OF

STEVEN M. WILLS

FILE NO. ET-2018-0063

I. INTRODUCTION

Q. Please state your name and business address.

A. Steven M. Wills, Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri" or "Company"), One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri 63103.

Q. What is your position with Ameren Missouri?

A. I am the Director of Rates & Analysis.

Q. Please describe your educational background and employment experience.

A. I received a Bachelor of Music degree from the University of Missouri-Columbia in 1996. I subsequently earned a Master of Music degree from Rice University in 1998, then a Master of Business Administration ("M.B.A.") degree with an emphasis in Economics from St. Louis University in 2002. While pursuing my M.B.A., I interned at Ameren Energy, Inc. in the Pricing and Analysis Group. Following completion of my M.B.A. in May 2002, I was hired by Laclede Gas Company as a Senior Analyst in its Financial Services Department. In this role, I assisted the Manager of Financial Services in coordinating all financial aspects of rate cases, regulatory filings, rating agency studies and numerous other projects.

In June 2004, I joined Ameren Services Company ("Ameren Services") as a Forecasting Specialist. In this role, I developed forecasting models and systems that supported the Ameren operating companies' involvement in the Midwest Independent Transmission System Operator, Inc.'s ("MISO")[1] Day 2 Energy Markets. In November 2005, I moved into the Corporate Analysis Department of Ameren Services where I was responsible for performing load research activities, electric and gas sales forecasts, and assisting with weather normalization for rate cases. In January 2007, I accepted a role I briefly held with Ameren Energy Marketing Company as an Asset and Trading Optimization Specialist before returning to Ameren Services as a Senior Commercial Transactions Analyst in July 2007. I was subsequently promoted to the position of Manager, Quantitative Analytics, where I was responsible for overseeing load research, forecasting and weather normalization activities, as well as developing prices for structured wholesale transactions.

In April 2015, I accepted a position with Ameren Illinois as its Director, Rates & Analysis. In this role, I was responsible for the group that performed Class Cost of Service, revenue allocation and rate design activities for Ameren Illinois, as well as maintained and administered that company's tariffs and riders. In December 2016, I accepted a position with the same title at Ameren Missouri.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your direct testimony in this proceeding?

A. My direct testimony in this proceeding describes the Company's proposal to initiate a new service offering ("Renewable Choice Program" or "Green Tariff"),

[1] Now known as the Midcontinent Independent System Operator, Inc.

under which qualifying customers can elect to participate in a subscription-based renewable energy program. I would emphasize that this is an optional program that customers can join based on their assessment of their own value and economic considerations. My testimony will lay out the Company's motivation for providing this offering, the mechanics of the proposed tariff, and some accounting considerations relevant to the proposal.

III. PROGRAM MOTIVATION

Q. Why is Ameren Missouri proposing a Green Tariff at this time?

A. There is clearly an increasing customer appetite for renewable energy to meet customer-specific sustainability goals. Ameren Missouri is well positioned to help its customers achieve these goals in a cost effective manner without impacting the service or costs of other customers who choose not to participate or are ineligible to do so.

The Company's recently filed Integrated Resource Plan ("IRP") noted favorable trends in the economics of wind generation, leading to the Company's adoption of a preferred resource plan for meeting its customers' energy needs that includes the addition of approximately 700 Megawatts ("MW") of new wind generation. At the same time, the Company stated that "The potential exists to add even more wind generation in the coming years as a result of improving technology and economics, as well as renewable energy initiatives with large customers." (IRP, Chapter 1 - "Executive Summary," Page 2). The juxtaposition of the customer demand for renewable energy and the favorable economics of wind generation discussed at length in the IRP presents an opportunity for the Green Tariff to advance the deployment of clean energy resources in a manner that meets customer needs and expectations. The wind generation added as a result of the Green Tariff is incremental to the 700 MW identified in the Company's preferred resource plan, which is needed in order for Ameren Missouri to comply with the increased renewable portfolio requirements under Missouri's Renewable Energy Standard ("RES").

Q. What is the basis for your statement that there is increasing customer appetite for such a program?

A. One need to look no further than statements and actions of many large commercial and industrial consumers, both within Ameren Missouri's service territory and across the country, for evidence of this demand. Just a few examples include public statements issued by AB InBev, Walmart, and Google indicating their goals related to renewable energy. All three of these companies have issued public press releases, reports, or statements describing corporate goals to have 100% of their energy consumption provided by renewable sources. Google and Walmart in particular have specifically referenced programs like the Green Tariff Ameren Missouri is proposing as means to drive development of new renewable projects. While I cited just three examples above, the corporate movement to support renewable energy is much broader than that. A group of 65 companies, many of whom have operations in Ameren Missouri's service territory, have signed on to the "Corporate Renewable Energy Buyers' Principles." This group self-describes their activities and mission on their website[2] with the statement, "A group of large energy buyers developed the Buyers' Principles to spur progress on renewable energy and to add their perspective to the future of the U.S. energy and electricity system."

[2] buyersprinciples.org/about-us

Local governments such as municipalities and counties are also increasing their support for renewable energy, including a number of such entities within Ameren Missouri's service territory. At least seven local municipalities[3] have had their mayors sign on to a Sierra Club pledge to support a vision of 100% renewable energy. The City of St. Louis' Board of Alderman recently adopted a resolution that would pledge the city's commitment to 100% renewable energy by 2035. All of these communities would be able to leverage the Green Tariff as a means of fulfilling their goals.

Finally, conversations Ameren Missouri has had directly with many of its largest power users have revealed interest in the Green Tariff concept as envisioned in this filing. It is the Company's expectation that a number of customers would be prepared to quickly engage in a dialogue about the Green Tariff upon its approval by the Commission and potentially enroll.

Q. You reference the fact that companies across the country are interested in renewable programs like this. Are other utilities offering similar services to meet this demand?

A. Yes, there are a number of utilities across the country that have begun offering similar programs to meet the stated needs of such customers. Recent tariffs filed by Duke Energy Carolinas, NV Energy, Rocky Mountain Power, and Puget Sound Energy, among others, contain different variants on voluntary renewable energy programs that large customers may elect to participate in.

[3] Chesterfield, Dellwood, Florissant, Maplewood, St. Peters, University City, and Wentzville have signed on to the pledge per http://www.sierraclub.org/ready-for-100/mayors-for-clean-energy

IV. PROGRAM DETAILS

Q. Please describe how the program would operate to meet these customer objectives.

A. In support of the program, Ameren Missouri will participate in the development of one or more new wind generation resources, depending on the ultimate demand for the program.[4] Once constructed and commercially operational, the output of the wind resource will be dedicated to the subscribing customers for a term of 15 years. The Company will be responsible for ensuring that the wind energy is sold in the wholesale markets.[5] The Renewable Energy Credits ("RECs") created by the generation of energy from the renewable resource will be retired by the Company in the North American Renewables Registry ("NARR") system on behalf of subscribing customers. The Company will not use the RECs retired for subscribing customers to meet Company RES compliance obligations or in any other manner.

Q. What customers are eligible to participate in the program?

A. The Company is proposing two categories for participation. Any non-residential customer served under rate classifications 3(M) – Large General Service, 4(M) – Small Primary Service, or 11(M) – Large Primary Service that has at least 2.5 MW of demand, either at a single location or aggregated across a number of accounts, may enroll. In addition, any account of a governmental entity (i.e., county, city, town, or village) regardless of size, may enroll. The Company is proposing to limit participation to

[4] The Company plans to either contract for wind generation through Purchased Power Agreements ("PPA") or to own the wind generation assets.

[5] The Company expects the wind resource to be sited in the MISO market, but depending on the amount of capacity needed to meet the total demand for the program and the available projects, generation in other regional markets may also be contemplated. Throughout the remainder of this testimony, MISO located projects will be assumed for examples.

larger customers (except in the case of governmental entities) for a number of reasons. The long-term commitment that is being undertaken to develop the renewable resource requires a relatively stable and sophisticated customer base. It would be significantly more difficult to ensure a good match of supply and demand if mass market accounts that tend to have higher rates of turnover were included in the pool. Additionally, the cost of administering and billing the program would likely be considerably higher with a very large number of mass market accounts eligible to participate. Smaller customers are less likely to have dedicated energy managers or other employees with experience dealing with energy markets, and therefore may be a poor fit for a program that requires them to make decisions to lock in their participation contractually for a 15-year term. Finally, the 2.5 MW aggregate demand threshold is consistent with the size of customer that is allowed by law in Missouri to opt out of participation in energy efficiency programs, so there is some precedent for using this as a delineation point for energy program eligibility. Smaller accounts may still benefit from renewable energy through the Company's existing Pure Power program.

There is an exception to the size limitation for accounts associated with governmental entities, and as I mentioned previously, there are a number of municipalities in the Company's service territory, including the City of St. Louis, that have made public commitments to renewable energy. The Company believes that this program will provide a great option for these entities to fulfill their stated objectives. These governmental accounts are also more likely to be stable, long-term accounts that are unlikely to terminate service during the 15-year program term. Also, when developing their public statements, these customers have given significant thought and consideration to energy issues, and may be better suited than many other small customers to enter into long-term commitments.

Q. How will the process for customer enrollment and wind resource development take place to ensure that supply and demand are balanced in the program?

A. Once the tariff is approved by the Commission, the Company will solicit participation from eligible customers. Interested customers will submit a non-binding expression of interest in the program to cover a percentage of their load with renewable energy. The percent of load subscribed may be any level from 0 to 100% at the customer’s discretion based on their own goals and value considerations. That percent will be applied to their most recent 12 months of usage to determine a targeted number of megawatt-hours (“MWh”) to produce annually from renewable energy as a part of the program on behalf of that customer. That MWh value will then be used to determine the installed MW of wind capacity needed in order to produce the targeted MWh of renewable energy for that customer (“RE Service Level”), based on the expected production characteristics of wind projects that may be developed. The Company will aggregate the RE Service Levels of the non-binding expressions of interest to determine the MW of wind generation capacity that is needed to meet the demand for renewable energy in the program.

Next, the Company will engage developers to get initial pricing for wind projects that will meet the initial interest level, retaining some flexibility to size the final project based on final enrollment. Based on the pricing received, the Company will return to customers who submitted an expression of interest and provide them with a fixed price offer to participate in the program, which will reflect the levelized cost of the wind generation along with a small administrative cost recovery component. Customers that continue to be interested at the price level indicated will confirm their commitments by entering into a Renewable Energy ("RE") Service Agreement, which will include a 15-year commitment to a fixed price renewable service offering. The price reflected in the RE Service Agreement will be referred to as the RE Price and will be used to bill the program. The Company will then work with the developer(s) to establish the final amount of wind generation to be constructed based on the commitments contained in executed RE Service Agreements. In this somewhat iterative fashion of working with interested customers and wind developers, the supply and demand will be matched as closely as possible. To the extent that the match is still imperfect, customers' enrollments will be prorated based on their subscribed service level to achieve a match with the available wind resource. The tariff refers to the total capacity to be developed for a group of customers under the program in MWs as an RE Block. Each customer's share of that block is referred to as their RE Allocation Factor, which will also be used for billing.

Q. What rates will be applicable to subscribing customers' bills for this service?

A. Subscribing customers will still be responsible for all base charges associated with their existing service classification, as well as applicable riders, such as the Fuel Adjustment Clause ("FAC") and Energy Efficiency Investment Charge ("EEIC").[6] In addition to those existing charges, a new line item that may be a charge or credit, the "Customer Monthly RE Adjustment," will appear on subscribing customers' bills. This line item represents the net financial settlement of each customer's subscribed portion of the wind resource in wholesale energy markets, plus the small administrative cost recovery component.

Q. Please explain how the Customer Monthly RE Adjustment will be determined.

A. Each calendar month, the wind generation output will be metered and sold into wholesale markets. The Company will separately track all of the market-based revenues and costs associated with the wholesale energy transactions related to the wind generation.[7] The total monthly net revenues will be divided by the total monthly output to come up with a monthly Wholesale Market Price ("WMP"). This reflects the market value of the wind generation. The WMP will be compared to the RE Price to determine a credit or charge for a MWh of renewable service in that month. This difference will be the net of the fixed purchase price of the wind energy and the variable sale price that energy receives in the wholesale market, on a per MWh basis. The MWhs attributable to a customer, on which the charge or credit will be based, will be equal to the total resource output for the month multiplied by the customer's RE Allocation Factor – this represents the amount of energy that was produced by the customer's share of the wind resource. This charge or credit will appear on the first monthly customer bill issued after the

[6] Certain customers do not pay Rider EEIC charges due to their election to opt out of participation in energy efficiency programs, as allowed by the Missouri Energy Efficiency Investment Act ("MEEIA")

[7] The Company intends to register the resource with MISO under a new "asset owner" designation, which will isolate it from other Company settlement transactions with MISO. This will allow for ease of tracking to ensure that all impacts associated with the program remain with the program for billing and accounting purposes.

settlement process has been completed for the first month of operation of the wind generation, and will continue monthly thereafter.[8]

Q. Can you please walk through an example of this?

A. Table 1 below shows calculations that would be used to bill a hypothetical customer on the program for a given month based on a number of illustrative assumptions.

Table 1: Illustrative Customer RE Monthly Adjustment Calculation

Line	Description	Value	Source/Calculation
1	Customer Annual Usage (MWh)	100,000	Illustrative assumption
2	RE Subscription Level	50%	Illustrative assumption
3	Wind Resource Capacity Factor	40%	Illustrative assumption
4	RE Service Level (MW)	14.3	(Line 1 x Line 2) / (8,760 hours per year x Line 3)
5	RE Block (MW)	100	Illustrative assumption
6	RE Allocation Factor	14.3%	Line 4 / Line 5
7	RE Price ($/MWh)	$30	Illustrative assumption
8	WMP ($/MWh)	$28	Illustrative assumption
9	Monthly Resource Output (MWh)	29,760	Line 5 x Line 3 x 744 Hours per month
10	Customer Allocation of Monthly Renewable Energy	4,247	Line 6 x Line 9
11	Customer Monthly RE Adjustment	$8,493	(Line 7 - Line 8) x Line 10

The hypothetical customer in Table 1 has annual usage of 100,000 MWh, and has elected to subscribe 50% of its load for renewable service. Based on an assumed resource capacity factor of 40%, the customer's RE Service Level (or the amount of wind capacity to be developed and dedicated to the customer, sufficient to serve their 50,000 MWh of

[8] MISO settlements of wholesale transactions for each operating day occur at least four times, on the 7th, 14th, 55th, and 105th day after the operating day, always using the best available data. Early settlements are sometimes based on some estimated data. The Company will use "best available" settlement data when calculating charges for a given operating month, and will true up those charges when later settlement data becomes available. The true-ups for prior months will be reflected along with new monthly charges until final (S105) settlement data is reflected in the customer's bill surcharge or credit for each operating month.

subscribed load annually) is 14.3 MW. For this hypothetical, the total resource needed to meet the subscriptions for the entire program is 100 MW, so the customer's RE Allocation Factor (or share of the resource) is 14.3% (14.3 MW / 100 MW). If the customer subscribed at an RE Price of $30/MWh and the power sold (net of market costs) for $28/MWh in a given month, each MWh generated for the customer will result in a $2 charge to the customer ($30 fixed purchase price - $28 net sale price). In this given month, the resource may have generated 29,760 MWh (based on 100 MW generation at a 40% capacity factor for a 744 hour month). The customer's 14.3% allocation of that power is therefore 4,247 MWh (29,760 MWh x 14.3%). At $2/MWh based on the net settlement of the energy (RE Price – WMP), this customer's bill will reflect a surcharge for participation in the program of $8,493 ($2/MWh x 4,247 MWh) for the month.

In a month where the power generated was in-the-money (i.e., the WMP exceeded the RE Price), the Customer Monthly RE Adjustment would reflect a bill credit.[9] It is reasonable to assume that this program could result in charges, credits, or a combination of charges and credits over the term of the program. Each customer must consider all of these possible outcomes at the time of enrollment, because they will be contractually committed to the RE Price and the financial outcomes that result.

Q. Please elaborate on how the program would work if the Company were to own the wind generation assets rather than contract for energy and capacity produced by them through a PPA.

A. For Company-owned wind generation, prior to enrolling customers Ameren Missouri will calculate the levelized cost of generation to be incurred over the life of the wind assets. That calculation will incorporate costs including depreciation expense, property taxes, operation and maintenance expenses, Production Tax Credits, and the returns and associated income taxes required on the investments supporting the net plant for the life of the project. The levelized cost will become the basis for the RE Price offered to subscribing customers. Once customers make their final commitments to subscribe to the resource at the established RE Price, project details will be finalized so that Ameren Missouri can seek a Certificate of Convenience and Necessity ("CCN") to construct the project. After receiving Commission approval of the CCN, the project will be constructed and placed into service. The same costs associated with the wind generation that make up the levelized cost calculation described above will then be included in the calculation of revenue requirement in any subsequent rate proceeding. Revenues derived from the Green Tariff program, calculated using the fixed RE Price applied to the normalized output of the currently subscribed portion of the generation resource,[10] would be included as an offset against revenue requirement, but not included in the determination of the Base Factor (“BF”) to be included in the FAC tariff. For any portion of the generation resource that was not currently subscribed at the time of the true-up date in a general rate proceeding, the revenues from the program offsetting the revenue requirement would be calculated using the normalized price of off-system sales in that case multiplied by the normalized output of the unsubscribed portion of the generation assets and included in the determination of the FAC term BF. Because the useful life of owned assets exceeds the term of the program, after the 15 years, the wind

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[9] E.g., that if the power had sold (net of market costs) for $32/MWh in a given month, the customer would receive a credit in the same amount -- $8,493.

[10] Revenues associated with the market value of the energy would not come into play in the calculation of revenue requirement, as the market revenues flow to subscribers.

assets would continue to be reflected in revenue requirement with no offsetting program revenues and would be used in the portfolio of generation assets used to serve all customers and all benefits of the generation would flow to customers.

Q. Is there any potential mismatch between the revenue requirement of the wind assets and the program revenues that would be included as an offset in a rate proceeding that would result in rate impacts to non-subscribing customers in a scenario where the Company owns the wind generation?

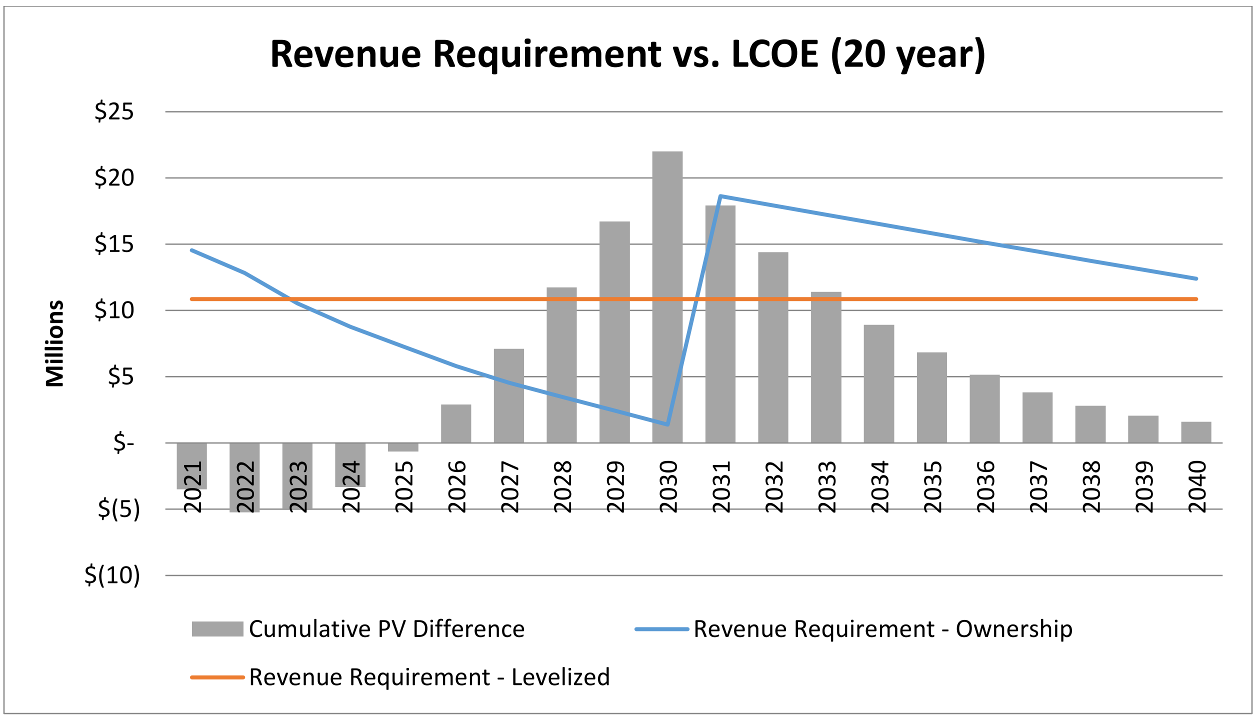
A. By the nature of the levelized cost calculation, it is designed to result in no impact on non-subscribing customers over the life of the program, but the act of levelizing the costs that are billed to subscribers results in the potential for timing mismatches relative to actual revenue requirement. Those timing differences could cause transitory rate impacts for non-subscribers. Also, as described above, the term of the program does not exactly match the expected useful life of the assets. Consequently, there would be residual impacts on revenue requirement to non-subscribing customers after the program term, but also significant residual value to those non-subscribing customers. However, because of the pattern of the revenue requirement over time and the details of the Company's resource plans, both of these issues can produce favorable outcomes for non-subscribing customers.

Q. How so?

A. Typically, revenue requirements are higher than the levelized cost of an asset in the early years of its operations and decline over time as the asset depreciates. However, the impact of Production Tax Credits available for the first 10 years of operation alters that dynamic for wind projects that may be developed for this program.

As it turns out, timing differences are likely to result in rate reductions for non-subscribing customers for most of the first 10 years, which then reverse over the latter part of the program period until subscribers and non-subscribers are once again neutral overall. Figure 1 below shows the modeled revenue requirement of a generic 100 MW wind project over its life compared against the levelized cost over the program term.

Figure 1 – Generic Wind Project Revenue Requirement vs. Levelized Cost



Note in Figure 1 that by the third year of operation the levelized cost (the red line) exceeds the revenue requirement (the blue line), which means that the revenue requirement (which ultimately translates into rates, including those charged to non-subscribing customers) would be lower with this program than without it in a rate proceeding conducted at or after that time. Rate benefits to non-subscribers would continue to accumulate, to an aggregate amount of over $20 million in this example, until year 10 of the program. At the tail end of the program, rates would be higher than if the program had not existed, but the cumulative impact (shown by the gray bars) on customers would continue to be favorable through the end of the asset life because of the front-loaded benefits.

Q. How does the residual asset life at the end of the program benefit non-subscribing customers in the context of the Company's resource plan?

A. A wind project developed for this program in the 2020 timeframe in order to maximize the impact of Production Tax Credits that are available would be subscribed through 2035 under the 15-year term of the Green Tariff. Non-subscribing customers would begin benefitting directly from any Company-owned wind assets after that. In the Company's IRP, significant coal plant capacity is expected to be retired in that timeframe, with the Sioux plant currently slated for a 2033 retirement and two units at the Labadie plant targeted for closure in 2036. The combined effect of those retirements will be over 2,000 MW of generating capacity that will no longer be available to serve Ameren Missouri's retail load. Incremental wind generation that became available from this program in the 2035 timeframe would provide energy to partially offset the reduction in energy output associated with those expected retirements. While the Production Tax Credits would have expired, the assets would be largely depreciated and would be likely to cost substantially less than new generation investments that otherwise might need to be made at the time, thereby potentially providing significant value to non-subscribers.

Q. Are there any other benefits of the program generally to non-subscribers?

A. Yes. Recall that the Company's motivation for offering the program is to meet very real customer demand for renewable energy, in particular from large electricity users. If the Company is unable to satisfy that demand, the issue will not simply go away. Instead, those customers will look for other means to achieve their renewable goals, which ultimately may result in some or all of their load being taken off of the system as alternative solutions are pursued. Because the large customers in question make a significant contribution to the recovery of the fixed costs in the Company's revenue requirement, the potential for unsatisfied customers reducing their utilization of the system could result in higher costs to all remaining customers since the fixed costs incurred to provide service to all customers would not disappear if these large customers reduce their system loads. To that end, there should be alignment of the interests of all customers – subscribers and non-subscribers alike – in seeing the launch of a successful program that meets the demand for renewable energy products on Ameren Missouri's system.

Q. What are the administrative costs that are intended to be covered by the adder to the RE Price mentioned previously?

A. The Company will incur some costs both to set up the program and to implement the program on an ongoing basis. Set up costs include IT systems needed to offer the generation into the market and to perform customer accounting and billing, as well as internal personnel costs to negotiate and execute plans with wind developers to build the resource. Ongoing costs include back office, accounting, and customer billing internal labor needed to administer the program on a monthly basis, as well as fees for recording and retiring RECs on behalf of customers. The Company estimates such costs to be approximately $0.10/MWh.

Q. What will happen under the terms of the program if a customer terminates service with the Company, or otherwise seeks to exit the program?

A. The customer's enrollment is a contractual commitment and they remain responsible for charges and have rights to credits arising from the net settlement of the renewable energy for the entire 15-year term. However, customers are permitted to transfer their subscription to new or different service accounts that they hold with the Company that have sufficient usage to warrant subscription to the RE Service Level being transferred, or to other similar customers if interested parties can be identified. In the event that a customer cannot be identified to take over the RE service, the terminating customers will continue to be billed/credited by the Company under the program unless they pay a termination fee. The termination fee is calculated by looking at the average of the Customer Monthly RE Adjustments the customer experienced over the 12-month period prior to termination and multiplying that monthly average by the number of months remaining in the term of the agreement. If the terminating customer, on average, has received credits over the previous 12 months, their termination fee is zero. No credits will be issued for exiting the program.

Q. Does this program have any impacts on the costs incurred by or service provided to non-participating customers?

A. By design, no – other than the potential timing issues and residual value consideration discussed earlier if the Company owns the wind generation assets. The program is intended to be unsubsidized, where subscribing customers pay all of the costs caused by the program and receive all of the benefits generated by it. In practice, there are a few more reasons that the program cost recovery may not perfectly insulate participants and non-participants, but those instances are expected to have a negligible effect on both groups. For example, the estimated rate for administration costs built in to the RE Price upfront is unlikely to be exactly equal to the support costs incurred. But given the total level of these costs (recall the estimate of $0.10/MWh mentioned previously), this is not anticipated to be a material issue. Another potential area is the termination provisions discussed just above. While requiring the customer to pay for the remaining term based on the recent historical experience of the program is designed to make the program whole, changes in future wholesale market energy prices over the remaining term may cause additional costs or benefits that cannot be recovered from or provided to the terminated customer. Finally, as with any service offering, customer defaults may result in uncollectible expenses. The RE Service Agreement contains credit provisions to help mitigate against this potential risk. Overall, though, the program is designed to, in all material aspects, keep non-participating customers completely neutral to its operation.

V. ACCOUNTING CONSIDERATIONS

Q. Are there any accounting issues raised by the program that need to be addressed by the Commission?

A. Yes. There are issues around the interaction of this program with the Company's FAC that need special consideration. The program may entail the Company entering into a PPA to purchase power from a third party, and will certainly involve incremental energy sales into the MISO market. These transactions are of a nature that would normally pass through the FAC. However, because these costs and revenues are incurred specifically on behalf of subscribing customers and will be collected from/credited to those customers through the Customer Monthly RE Adjustment, it would be inappropriate double-counting to allow them to also flow through the FAC. Some type of accommodation needs to be made to avoid that outcome.

Q. What accommodation do you propose?

A. The easiest means of addressing this would be to add simple language to the FAC tariff itself to carve the costs and revenues of this program out of the costs and revenues that pass through the formulas in the FAC. However, my understanding is that by law, FAC tariffs can likely only be modified in the context of a general rate case, so I am not proposing that remedy be implemented in this case. Fortunately, because of the lead time needed to subscribe customers, engage developers, and complete construction of the wind resource, it is likely that there may be time to implement this solution in the Company's next general rate case, prior to power flowing and billing commencing under the Green Tariff. My recommendation is that the Commission approve, as part of this docket, the changes that would be necessary to carve out the program's costs and revenues from the FAC, which can then be implemented in the Company's next general rate proceeding. I have attached as Schedule SMW-DIR-1 the changes that would be necessary to resolve this issue.

Q. You said there "may" be time to implement this in the next rate case. Why the uncertainty and what do you propose if there is not adequate time for that solution?

A. The timing of both the next general rate case of the Company and the initiation of commercial operation of this program are uncertain. There is some risk that power will flow in this program prior to new rates taking effect following a new rate case. To mitigate that risk, the Company has included with this filing an application to the Commission seeking an order granting authority to use a regulatory accounting mechanism to defer the impacts of the program that would otherwise result in double-counting of costs or benefits of the program until the FAC modifications can be implemented. I recommend that the Commission approve the accounting authority necessary to do so as part of its order approving the Green Tariff in this case to temporarily address the double-counting issue, and as noted, approve appropriate adjustments to the FAC tariff language for implementation in the Company's next general rate proceeding to permanently address it.

Q. Please summarize your testimony.

A. The Company's proposed Green Tariff is an innovative means to provide new energy products that are in demand from today's customers, with the result of more and quicker deployment of clean energy resources than would otherwise occur. Because the program is entirely voluntary for customers to participate in, and non-participants are in all material senses not impacted, there is really no discernable downside to providing this option. The Green Tariff is a win-win for customers interested in participating and for the advancement of renewable energy and I request the Commission's approval of it consistent with the terms and provisions described herein.

Q. Does this conclude your direct testimony?

A. Yes, it does.

**BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI**

In the Matter of the Application of Union Electric Company d/b/a Ameren Missouri for Approval of 2017 Green Tariff.	)))	File No. ET-2018-0063

AFFIDAVIT OF STEVEN M. WILLS

STATE OF MISSOURI)
) **ss**
CITY OF ST. LOUIS)

Steven M. Wills, being first duly sworn on his oath, states:

1. My name is Steven M. Wills. I work in the City of St. Louis, Missouri, and I am employed by Union Electric Company d/b/a Ameren Missouri as Director of Rates & Analysis.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of Union Electric Company d/b/a Ameren Missouri consisting of 21 pages and Schedule(s) SMW-DIR-1, all of which have been prepared in written form for introduction into evidence in the above-referenced docket.

3. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded are true and correct.

Steven M. Wills
STEVEN M. WILLS

Scribed and sworn to before me this 27th day of November, 2017.

Cathleen A. Dehne
Notary Public

My commission expires
March 7, 2021

CATHLEEN A DEHNE
Notary Public – Notary Seal
St. Louis City – State of Missouri
Commission Number 17119727
My Commission Expires Mar 7, 2021

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE

(Applicable To Service Provided On The Effective Date Of This Tariff Sheet And Thereafter)

APPLICABILITY

*This rider is applicable to kilowatt-hours (kWh) of energy supplied to customers served by the Company under Service Classification Nos. 1(M), 2(M), 3(M), 4(M), 5(M), 6(M), 11(M), and 12(M).

Costs passed through this Fuel and Purchased Power Adjustment Clause (FAC) reflect differences between actual fuel and purchased power costs, including transportation and emissions costs and revenues, net of off-system sales revenues (OSSR) (i.e., Actual Net Energy Costs (ANEC)) and Net Base Energy Costs (B), calculated and recovered as provided for herein.

The Accumulation Periods and Recovery Periods are as set forth in the following table:

Accumulation Period (AP)	Recovery Period (RP)
February through May	October through May
June through September	February through September
October through January	June through January

AP means the four (4) calendar months during which the actual costs and revenues subject to this rider will be accumulated for the purposes of determining the Fuel Adjustment Rate (FAR).

RP means the billing months during which the FAR is applied to retail customer usage on a per kWh basis, as adjusted for service voltage.

The Company will make a FAR filing no later than sixty (60) days prior to the first billing cycle read date of the applicable Recovery Period above. All FAR filings shall be accompanied by detailed workpapers supporting the filing in an electronic format with all formulas intact.

FAR DETERMINATION

Ninety five percent (95%) of the difference between ANEC and B for each respective AP will be utilized to calculate the FAR under this rider pursuant to the following formula with the results stated as a separate line item on the customers' bills.

*Indicates Change.

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FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
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FAR DETERMINATION (Cont'd.)

For each FAR filing made, the FAR_{RP} is calculated as:

$$FAR_{RP} = [(ANEC - B) \times 95\% \pm I \pm P \pm T]/S_{RP}$$

Where:

* ANEC = FC + PP + E ± R – OSSR

* FC = Fuel costs and revenues associated with the Company's generating plants that are listed in Federal Energy Regulatory Commission ("FERC") Account 151 and recorded in FERC Accounts 501 or 547, and all costs and revenues that are recorded in FERC Account 518. These include the following:

1. For fossil fuel plants:

*A. the following costs and revenues (including applicable taxes) arising from steam plant operations: coal commodity, gas, alternative fuels, Btu adjustments assessed by coal suppliers, quality adjustments related to the sulfur content of coal assessed by coal suppliers, railroad transportation, switching and demurrage charges, railcar repair and inspection costs, railcar depreciation, railcar lease costs, similar costs associated with other applicable modes of transportation, fuel hedging costs, fuel oil adjustments included in commodity and transportation costs, fuel additive costs included in commodity or transportation costs, oil costs, and expenses resulting from fuel and transportation portfolio optimization activities; and

*B. the following costs and revenues (including applicable taxes) arising from non-steam plant operations: natural gas generation costs related to commodity, oil, transportation, storage, capacity reservation, fuel losses, hedging, and revenues and expenses resulting from fuel and transportation portfolio optimization activities, but excluding fuel costs related to the Company's landfill gas generating plant known as Maryland Heights Energy Center; and

*2. The following costs and revenues (including applicable taxes) arising from nuclear plant operations: nuclear fuel commodity expense, waste disposal expense, and nuclear fuel hedging costs.

PP = Purchased power costs and revenues and consists of the following:

*1. The following costs and revenues for purchased power reflected in FERC Account 555, excluding (a) amounts associated withportions of Power Purchase Agreements dedicated to specific customers under the Renewable Choice Program tariff, (b) all charges under Midcontinent Independent System Operator, Inc. ("MISO") Schedules 10, 16, 17 and 24 (or any successor to those MISO Schedules), and (c) generation capacity charges for contracts with terms in excess of one (1) year. Such costs and revenues include:

*Indicates Change.

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FAR DETERMINATION (Cont'd.)

A. MISO costs or revenues for MISO's energy and operating reserve market settlement charge types and capacity market settlement clearing costs or revenues associated with:
   i. Energy;
   ii. Losses;
   iii. Congestion management:
      a. Congestion;
      b. Financial Transmission Rights; and
      c. Auction Revenue Rights;
   iv. Generation capacity acquired in MISO's capacity auction or market; provided such capacity is acquired for a term of one (1) year or less;
   v. Revenue sufficiency guarantees;
   vi. Revenue neutrality uplift;
   vii. Net inadvertent energy distribution amounts;
   viii. Ancillary Services:
      a. Regulating reserve service (MISO Schedule 3, or its successor);
      b. Energy imbalance service (MISO Schedule 4, or its successor);
      c. Spinning reserve service (MISO Schedule 5, or its successor);and
      d. Supplemental reserve service (MISO Schedule 6, or its successor); and
   ix. Demand response:
      a. Demand response allocation uplift; and
      b. Emergency demand response cost allocation (MISO Schedule 30, or its successor);

B. Non-MISO costs or revenues as follows:
   i. If received from a centrally administered market (e.g. PJM/SPP), costs or revenues of an equivalent nature to those identified for the MISO costs or revenues specified in subpart A of part 1 above;
   ii. If not received from a centrally administered market:
      a. Costs for purchases of energy; and
      b. Costs for purchases of generation capacity, provided such capacity is acquired for a term of one (1) year or less; and

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FAR DETERMINATION (Cont'd.)

C. Realized losses and costs (including broker commissions and fees) minus realized gains for financial swap transactions for electrical energy that are entered into for the purpose of mitigating price volatility associated with anticipated purchases of electrical energy for those specific time periods when the Company does not have sufficient economic energy resources to meet its native load obligations, so long as such swaps are for up to a quantity of electrical energy equal to the expected energy shortfall and for a duration up to the expected length of the period during which the shortfall is expected to exist; and

*2. One and 71/100 percent (1.71%) of transmission service costs reflected in FERC Account 565 and one and 71/100 percent (1.71%) of transmission revenues reflected in FERC Account 456.1 (excluding (a) amounts associated with portions of Power Purchase Agreements dedicated to specific customers under the Renewable Choice Program tariff and (b) costs or revenues under MISO Schedule 10, or any successor to that MISO Schedule). Such transmission service costs and revenues included in Factor PP include:

A. MISO costs and revenues associated with:
   i. Network transmission service (MISO Schedule 9 or its successor);
   ii. Point-to-point transmission service (MISO Schedules 7 and 8 or their successors);
   iii. System control and dispatch (MISO Schedule 1 or its successor);
   iv. Reactive supply and voltage control (MISO Schedule 2 or its successor);
   v. MISO Schedule 11 or its successor;
   vi. MISO Schedules 26, 26A, 37 and 38 or their successors;
   vii. MISO Schedule 33; and
   viii. MISO Schedules 41, 42-A, 42-B, 45 and 47;

B. Non-MISO costs and revenues associated with:
   i. Network transmission service;
   ii. Point-to-point transmission service;
   iii. System control and dispatch; and
   iv. Reactive supply and voltage control.

*Indicates Change.

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FAR DETERMINATION (Cont'd.)

E = Costs and revenues for SO_2 and NO_X emissions allowances in FERC Accounts 411.8, 411.9, and 509, including those associated with hedging.

** R = Net insurance recoveries for costs/revenues included in this Rider FAC (and the insurance premiums paid to maintain such insurance), and subrogation recoveries and settlement proceeds related to costs/revenues included in this Rider FAC.

* OSSR = Costs and revenues in FERC Account 447 excluding (a) amounts associated with portions of Power Purchase Agreements dedicated to specific customers under the Renewable Choice Program tariff, and (b) amounts associated with generation assets dedicated, as of the date BF was determined, to specific customers under the Renewable Choice Program tariff for:

1. Capacity;
2. Energy;
3. Ancillary services, including:
   A. Regulating reserve service (MISO Schedule 3, or its successor);
   B. Energy Imbalance Service (MISO Schedule 4, or its successor;
   C. Spinning reserve service (MISO Schedule 5, or its successor); and
   D. Supplemental reserve service (MISO Schedule 6, or its successor);
4. Make-whole payments, including:
   A. Price volatility; and
   B. Revenue sufficiency guarantee; and
5. Hedging.

* Indicates Change. ** Indicates Addition.

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FAR DETERMINATION (Cont'd.)

For purposes of factors FC, E, and OSSR, “hedging” is defined as realized losses and costs (including broker commissions and fees associated with the hedging activities) minus realized gains associated with mitigating volatility in the Company’s cost of fuel, off-system sales and emission allowances, including but not limited to, the Company’s use of futures, options and over-the-counter derivatives including, without limitation, futures contracts, puts, calls, caps, floors, collars, and swaps.

*Costs and revenues not specifically detailed in Factors FC, PP, E, or OSSR shall not be included in the Company's FAR filings; provided however, in the case of Factors PP or OSSR the market settlement charge types under which MISO or another centrally administered market (e.g., PJM or SPP) bills/credits a cost or revenue need not be detailed in Factors PP or OSSR for the costs or revenues to be considered specifically detailed in Factors PP or OSSR; and provided further, should the MISO or another centrally administered market (e.g. PJM or SPP) implement a market settlement charge type or schedule not listed in the FAC Charge Type Table included in this rider (a “new charge type”):

A. The Company may include the new charge type cost or revenue in its FAR filings if the Company believes the new charge type cost or revenue possesses the characteristics of, and is of the nature of, the costs or revenues listed in factors PP or OSSR, as the case may be, subject to the requirement that the Company make a filing with the Commission as outlined in B below and also subject to another party’s right to challenge the inclusion as outlined in E. below;

B. The Company will make a filing with the Commission giving the Commission notice of the new charge type no later than 60 days prior to the Company including the new charge type cost or revenue in a FAR filing. Such filing shall identify the proposed accounts affected by such change, provide a description of the new charge type demonstrating that it possesses the characteristics of, and is of the nature of, the costs or revenues listed in factors PP or OSSR as the case may be, and identify the preexisting market settlement charge type(s) which the new charge type replaces or supplements;

C. The Company will also provide notice in its monthly reports required by the Commission's fuel adjustment clause rules that identifies the new charge type costs or revenues by amount, description and location within the monthly reports;

D. The Company shall account for the new charge type costs or revenues in a manner which allows for the transparent determination of current period and cumulative costs or revenues; and

* Indicates Change.

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FAR DETERMINATION (Cont'd.)

E. If the Company makes the filing provided for in B above and a party challenges the inclusion, such challenge will not delay approval of the FAR filing. To challenge the inclusion of a new charge type, a party shall make a filing with the Commission based upon that party’s contention that the new charge type costs or revenues at issue should not have been included, because they do not possess the characteristics of the costs or revenues listed in Factors PP or OSSR, as the case may be. A party wishing to challenge the inclusion of a charge type shall include in its filing the reasons why it believes the Company did not show that the new charge type possesses the characteristics of the costs or revenues listed in Factors PP or OSSR, as the case may be, and its filing shall be made within 30 days of the Company’s filing under B above. In the event of a timely challenge, the Company shall bear the burden of proof to support its decision to include a new charge type in a FAR filing. Should such challenge be upheld by the Commission, any such costs will be refunded (or revenues retained) through a future FAR filing in a manner consistent with that utilized for Factor P; and

F. A party other than the Company may seek the inclusion of a new charge type in a FAR filing by making a filing with the Commission no less than 60 days before the Company’s next FAR filing. Such a filing shall give the Commission notice that such party believes the new charge type should be included because it possesses the characteristics of, and is of the nature of, the costs or revenues listed in factors PP or OSSR, as the case may be. The party’s filing shall identify the proposed accounts affected by such change, provide a description of the new charge type demonstrating that it possesses the characteristics of, and is of the nature of, the costs or revenues listed in factors PP or OSSR as the case may be, and identify the preexisting market settlement charge type(s) which the new charge type replaces or supplements. If a party makes the filing provided for by this paragraph F and a party (including the Company) challenges the inclusion, such challenge will not delay inclusion of the new charge type in the FAR filing or delay approval of the FAR filing. To challenge the inclusion of a new charge type, the challenging party shall make a filing with the Commission based upon that party’s contention that the new charge type costs or revenues at issue should not have been included, because they do not possess the characteristics of the costs or revenues listed in Factors PP or OSSR, as the case may be. The challenging party shall make its filing challenging the inclusion and stating the reasons why it believes the new charge type does not possess the characteristic of the costs or revenues listed in Factors PP or OSSR, as the case may be, within 30 days of the

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FAR DETERMINATION (Cont'd.)

filing that seeks inclusion of the new charge type. In the event of a timely challenge, the party seeking the inclusion of the new charge type shall bear the burden of proof to support its contention that the new charge type should be included in the Company's FAR filings. Should such challenge be upheld by the Commission, any such costs will be refunded (or revenues retained) through a future FAR filing in a manner consistent with that utilized for Factor P.

Should FERC require any item covered by factors FC, PP, E or OSSR to be recorded in an account different than the FERC accounts listed in such factors, such items shall nevertheless be included in factor FC, PP, E or OSSR. In the month that the Company begins to record items in a different account, the Company will file with the Commission the previous account number, the new account number and what costs or revenues that flow through this Rider FAC are to be recorded in the account.

B = BF x S_{AP} + RCP

*BF = The Base Factor, which is equal to the normalized value for the sum of allowable fuel costs (consistent with the term FC), plus cost of purchased power (consistent with the term PP), and emissions costs and revenues (consistent with the term E), less revenues from off-system sales (consistent with the term OSSR) divided by corresponding normalized retail kWh as adjusted for applicable losses. The normalized values referred to in the prior sentence shall be those values used to determine the revenue requirement in the Company's most recent rate case. The BF applicable to June through September calendar months (BF_{SUMMER}) is $0.01565 per kWh. The BF applicable to October through May calendar months (BF_{WINTER}) is $0.01536 per kWh.

*S_{AP} = kWh during the AP that ended immediately prior to the FAR filing, as measured by taking the most recent kWh data for the retail component of the Company's load settled at its MISO CP node (AMMO.UE or successor node), plus the metered net energy output of any generating station operating within its certificated service territory as a behind the meter resource in MISO, the output of which served to reduce the Company's load settled at its MISO CP node (AMMO.UE or successor node).

RCP = Termination fees (as defined in the Renewable Choice Program tariff) recovered from subscribers to the Renewable Choice Program.

*Indicates Change.

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S_{RP} = Applicable RP estimated kWh representing the expected retail component of the Company's load settled at its MISO CP node (AMMO.UE or successor node) plus the metered net energy output of any generating station operating within its certificated service territory as a behind the meter resource in MISO, the output of which served to reduce the Company’s load settled at its MISO CP node (AMMO.UE or successor node).

I = Interest applicable to (i) the difference between ANEC and B for all kWh of energy supplied during an AP until those costs have been recovered; (ii) refunds due to prudence reviews (“P”), if any; and (iii) all under- or over-recovery balances created through operation of this FAC, as determined in the true-up filings (“T”) provided for herein. Interest shall be calculated monthly at a rate equal to the weighted average interest rate paid on the Company’s short-term debt, applied to the month-end balance of items (i) through (iii) in the preceding sentence.

P = Prudence disallowance amount, if any, as defined below.

T = True-up amount as defined below.

The FAR, which will be multiplied by the Voltage Adjustment Factors (VAF) set forth below is calculated as:

$$FAR = FAR_{RP} + FAR_{(RP-1)}$$

where:

FAR = Fuel Adjustment Rate applied to retail customer usage on a per kWh basis starting with the applicable Recovery Period following the FAR filing.

FAR_{RP} = FAR Recovery Period rate component calculated to recover under- or over-collection during the Accumulation Period that ended immediately prior to the applicable filing.

$FAR_{(RP-1)}$ = FAR Recovery Period rate component for the under- or over-collection during the Accumulation Period immediately preceding the Accumulation Period that ended immediately prior to the application filing for FAR_{RP}.

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FAR DETERMINATION (Cont'd.)

*To determine the FAR applicable to the individual Service Classifications, the FAR determined in accordance with the foregoing will be multiplied by the following Voltage Adjustment Factors (VAF):

Secondary Voltage Service (VAF_{SEC})	1.0549
Primary Voltage Service (VAF_{PRI})	1.0238
Transmission Voltage Service (VAF_{TRAN})	0.9921

The FAR applicable to the individual Service Classifications shall be rounded to the nearest $0.00001 to be charged on a $/kWh basis for each applicable kWh billed.

TRUE-UP

After completion of each RP, the Company shall make a true-up filing on the same day as its FAR filing. Any true-up adjustments shall be reflected in T above. Interest on the true-up adjustment will be included in I above.

The true-up adjustments shall be the difference between the revenues billed and the revenues authorized for collection during the RP.

GENERAL RATE CASE/PRUDENCE REVIEWS

The following shall apply to this FAC, in accordance with Section 386.266.4, RSMo. and applicable Missouri Public Service Commission Rules governing rate adjustment mechanisms established under Section 386.266, RSMo:

The Company shall file a general rate case with the effective date of new rates to be no later than four years after the effective date of a Commission order implementing or continuing this FAC. The four-year period referenced above shall not include any periods in which the Company is prohibited from collecting any charges under this FAC, or any period for which charges hereunder must be fully refunded. In the event a court determines that this FAC is unlawful and all moneys collected hereunder are fully refunded, the Company shall be relieved of the obligation under this FAC to file such a rate case.

Prudence reviews of the costs subject to this FAC shall occur no less frequently than every eighteen months, and any such costs which are determined by the Commission to have been imprudently incurred or incurred in violation of the terms of this rider shall be returned to customers. Adjustments by Commission order, if any, pursuant to any prudence review shall be included in the FAR calculation in P above unless a separate refund is ordered by the Commission. Interest on the prudence adjustment will be included in I above.

*Indicates Change.

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FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)

***FAC CHARGE TYPE TABLE**

MISO Energy & Operating Reserve Market Settlement Charge Types and Capacity Market Charges and Credits

DA Asset Energy Amount;
DA Congestion Rebate on Carve-out GFA;
DA Congestion Rebate on Option B GFA;
DA Financial Bilateral Transaction Congestion Amount;
DA Financial Bilateral Transaction Loss Amount;
DA Loss Rebate on Carve-out GFA;
DA Loss Rebate on Option B GFA;
DA Non-Asset Energy Amount;
DA Ramp Capability Amount;
DA Regulation Amount;
DA Revenue Sufficiency Guarantee Distribution Amount;
DA Revenue Sufficiency Guarantee Make Whole Payment Amount;
DA Spinning Reserve Amount;
DA Supplemental Reserve Amount;
DA Virtual Energy Amount;
FTR Annual Transaction Amount;
FTR ARR Revenue Amount;
FTR ARR Stage 2 Distribution;
FTR Full Funding Guarantee Amount;
FTR Guarantee Uplift Amount;
FTR Hourly Allocation Amount;
FTR Infeasible ARR Uplift Amount;
FTR Monthly Allocation Amount;
FTR Monthly Transaction Amount;
FTR Yearly Allocation Amount;
FTR Transaction Amount;
Net Revenue from Voluntary Capacity Auction;
Net Purchase for Voluntary Capacity Auction;

RT Asset Energy Amount;
RT Congestion Rebate on Carve-out GFA;
RT Contingency Reserve Deployment Failure Charge Amount;
RT Demand Response Allocation Uplift Charge;
RT Distribution of Losses Amount;
RT Excessive Energy Amount;
RT Excessive\Deficient Energy Deployment Charge Amount;
RT Financial Bilateral Transaction Congestion Amount;
RT Financial Bilateral Transaction Loss Amount;
RT Loss Rebate on Carve-out GFA;
RT Miscellaneous Amount;
RT Ramp Capability Amount;
Real Time MVP Distribution;
RT Net Inadvertent Distribution Amount;
RT Net Regulation Adjustment Amount;
RT Non-Asset Energy Amount;
RT Non-Excessive Energy Amount;
RT Price Volatility Make Whole Payment;
RT Regulation Amount;
RT Regulation Cost Distribution Amount;
RT Resource Adequacy Auction Amount;
RT Revenue Neutrality Uplift Amount;
RT Revenue Sufficiency Guarantee First Pass Dist Amount;
RT Revenue Sufficiency Guarantee Make Whole Payment Amount;
RT Spinning Reserve Amount;
RT Spinning Reserve Cost Distribution Amount;
RT Supplemental Reserve Amount;
RT Supplemental Reserve Cost Distribution Amount;
RT Virtual Energy Amount;

MISO Transmission Service Settlement Schedules

MISO Schedule 1 (System control & dispatch);
MISO Schedule 2 (Reactive supply & voltage control);
MISO Schedule 7 & 8 (point to point transmission service);
MISO Schedule 9 (network transmission service);
MISO Schedule 11 (Wholesale Distribution);
MISO Schedules 26, 26A, 37 & 38 (MTEP & MVP Cost Recovery);
MISO Schedule 33 (Black Start Service);

MISO Schedule 41 (Charge to Recover Costs of Entergy Strom Securitization);
MISO Schedule 42A (Entergy Charge to Recover Interest);
MISO Schedule 42B (Entergy Credit associated with AFUDC);
MISO Schedule 45 (Cost Recovery of NERC Recommendation or Essential Action);
MISO Schedule 47 (Entergy Operating Companies MISO Transition Cost Recovery);

MISO Charge Types Which Appear On MISO Settlement Statements Represent Administrative Charges And Are Specifically Excluded From The FAC

DA Market Administration Amount;
DA Schedule 24 Allocation Amount;
FTR Market Administration Amount;
Schedule 10 - ISO Cost Recovery Adder;

RT Market Administration Amount;
RT Schedule 24 Allocation Amount;
RT Schedule 24 Distribution Amount;
Schedule 10 - FERC - Annual Charges Recovery;

* Indicates Addition.

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***FAC CHARGE TYPE TABLE (Cont'd.)**

PJM Market Settlement Charge Types

Auction Revenue Rights;
Balancing Operating Reserve;
Balancing Operating Reserve for Load Response;
Balancing Spot Market Energy;
Balancing Transmission Congestion;
Balancing Transmission Losses;
Capacity Resource Deficiency;
Capacity Transfer Rights;
Day-ahead Economic Load Response;
Day-Ahead Load Response Charge Allocation;
Day-ahead Operating Reserve;
Day-ahead Operating Reserve for Load Response;
Day-ahead Spot Market Energy;
Day-ahead Transmission Congestion;
Day-ahead Transmission Losses;
Demand Resource and ILR Compliance Penalty;
Emergency Energy;
Emergency Load Response;
Energy Imbalance Service;
Financial Transmission Rights Auction;
Generation Deactivation;
Generation Resource Rating Test Failure;
Inadvertent Interchange;
Incremental Capacity Transfer Rights;
Interruptible Load for Reliability;
Load Reconciliation for Inadvertent Interchange;
Load Reconciliation for Operating Reserve Charge;
Load Reconciliation for Regulation and Frequency Response Service;
Load Reconciliation for Spot Market Energy;
Load Reconciliation for Synchronized Reserve;
Load Reconciliation for Synchronous Condensing;
Load Reconciliation for Transmission Congestion;
Load Reconciliation for Transmission Losses;
Locational Reliability;
Miscellaneous Bilateral;
Non-Unit Specific Capacity Transaction;
Peak Season Maintenance Compliance Penalty;
Peak-Hour Period Availability;
PJM Customer Payment Default;
Planning Period Congestion Uplift;
Planning Period Excess Congestion;
Ramapo Phase Angle Regulators;
Real-time Economic Load Response;
Real-Time Load Response Charge Allocation;
Regulation and Frequency Response Service;
RPM Auction;
Station Power;
Synchronized Reserve;
Synchronous Condensing;
Transmission Congestion;
Transmission Losses;

PJM Transmission Service Charge Types

Black Start Service;
Day-ahead Scheduling Reserve;
Direct Assignment Facilities;
Expansion Cost Recovery;
Firm Point-to-Point Transmission Service;
Internal Firm Point-to-Point Transmission Service;
Internal Non-Firm Point-to-Point Transmission Service;
Load Reconciliation for PJM Scheduling, System Control and Dispatch Service;
Network Integration Transmission Service Offset;
Non-Firm Point-to-Point Transmission Service;
Non-Zone Network Integration Transmission Service;
Other Supporting Facilities;
PJM Scheduling, System Control and Dispatch Service Refunds;
PJM Scheduling, System Control and Dispatch Services;
Qualifying Transmission Upgrade Compliance Penalty;
Reactive Services;

* Indicates Addition.

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FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)

***FAC CHARGE TYPE TABLE (Cont'd.)**

PJM Transmission Service Charge Types (Cont'd.)

Load Reconciliation for PJM Scheduling, System Control and Dispatch Service Refund;
Load Reconciliation for Reactive Services;
Load Reconciliation for Transmission Owner Scheduling, System Control and Dispatch Service;
Network Integration Transmission Service;
Network Integration Transmission Service (exempt);
Reactive Supply and Voltage Control from Generation and Other Sources Service;
Transmission Enhancement;
Transmission Owner Scheduling, System Control and Dispatch Service;
Unscheduled Transmission Service;

PJM Charge Types Which Appear On The Settlement Statements Represent Administrative Charges Are Specifically Excluded From The FAC

Annual PJM Building Rent;
Annual PJM Cell Tower;
FERC Annual Charge Recovery;
Load Reconciliation for FERC Annual Charge Recovery;
Load Reconciliation for North American Electric Reliability Corporation (NERC);
Load Reconciliation for Organization of PJM States, Inc. (OPSI) Funding;
Load Reconciliation for Reliability First Corporation (RFC);
Market Monitoring Unit (MMU) Funding;
Michigan - Ontario Interface Phase Angle Regulators;
North American Electric Reliability Corporation (NERC);
Organization of PJM States, Inc. (OPSI) Funding;
PJM Annual Membership Fee;
PJM Settlement, Inc.;
Reliability First Corporation (RFC);
RTO Start-up Cost Recovery;
Virginia Retail Administrative Fee;

* Indicates Addition.