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Witness:	Steven M. Wills
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MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ER-2024-0319

DIRECT TESTIMONY

OF

STEVEN M. WILLS

ON

BEHALF OF

UNION ELECTRIC COMPANY

D/B/A AMEREN MISSOURI

St. Louis, Missouri

June, 2024

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DIRECT TESTIMONY

OF

STEVEN M. WILLS

FILE NO. ER-2024-0319

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 Senior Director of Regulatory Affairs.

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 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 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. In July of 2022, I was promoted to Director, Regulatory Affairs, and in January 2024 promoted to Senior Director, Regulatory Affairs. In this role, I oversee the teams responsible for contributing to all aspects of the Company's state regulated activities, including the Rates and Analysis team I previously directed.

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

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your direct testimony?

A. My testimony discusses the Company's inclusion of costs associated with new renewable energy centers in the revenue requirement in this case, including the Cass County Energy Center, for which the Company has commitments to address certain topics in this case that arise from the Stipulation and Agreement pursuant to which the Commission granted a Certificate of Convenience and Necessity ("CCN") for the Company to acquire/construct that energy center.[2] Next, I discuss the Renewable Solutions Program ("RSP" or "Program") and the affordability benefit that arises from the success of the Program in generating new revenues that contribute toward the revenue requirement of certain of the new renewable resources that will go into service prior to the true up date proposed in this case. I also discuss the current status of Economic Development Incentives ("EDI") offered by the Company pursuant to state law. Finally, I address the Commission's order in File No. ER-2022-0337 for the Company to study the potential to integrate distributed energy resources (i.e., net metering) with its Time of Use ("TOU") rate offerings.

III. CASS COUNTY ENERGY CENTER

Q. Is the Company including in rate base in this proceeding investment associated with new renewable generation resources?

A. Yes. The Company expects to place into service, prior to the true-up date in this case, three new solar energy centers for which the Commission has granted CCNs

[2] File No. EA-2023-0286. Order Approving Stipulation and Agreement and Granting Certificates of Convenience and Necessity, April 20, 2024.

in the last year and a half – the Huck Finn Energy Center ("Huck Finn"), the Boomtown Energy Center ("Boomtown"), and the Cass County Energy Center ("Cass County").

Q. Are there any conditions associated with those CCN approvals that you will be addressing?

A. Yes. The approval of the CCN for Cass County was subject to certain conditions that were agreed to by the Company and certain parties to the CCN case (File No. EA-2023-0286) as a part of a Stipulation and Agreement resolving the issues in that case ("Solar Stipulation"). Some of those conditions require information to be provided in the first case in which the investments in Cass County are requested to be included in the Company's rate base, which is this case.[3] I will address these conditions from the Solar Stipulation in this section of my testimony.

Q. What is the first condition from the Solar Stipulation that you will discuss?

A. The Solar Stipulation required that the treatment of tax credits arising from Cass County be determined in a future rate proceeding under the Inflation Reduction Act ("IRA") tracker established in File No. ER-2022-0337. The treatment of tax credits is not ripe for consideration at this time, because the Company has not received the benefits of any of those tax credits, and it is unlikely that those benefits will have materialized by the true-up date in this case. While the terms of the IRA tracker guarantees that customers will receive 100% of the benefits realized by the Company from those tax credits, the treatment of those credits cannot be determined until the benefits have materialized in the test year

[3] These commitments also apply to the other projects for which CCNs were approved in the Solar Stipulation, but those other projects are not being placed in service prior to the true-up date in this case and thus will be addressed in a future rate review.

or prior to the true-up date in a rate review. Company witness Hipkiss discusses other tax-related considerations the Company has built into its revenue requirement in this case in recognition of the expectation of future tax credits from Cass County (and the Boomtown Energy Center) in the IRA tracker.[4]

Q. Please address the second condition from the Solar Stipulation.

A. The Solar Stipulation required that, if the capital cost of the facility exceeds ***_____*** of the cost modeled by the Company for the project in the case where the Cass County CCN was approved, the Company would provide certain information explaining why the Company proceeded with the acquisition of the facility. While, at the time of this writing, the acquisition has not closed and Cass County has not been placed into service, and therefore the final total capital cost of the facility has not been determined, it is currently not anticipated that the cost will exceed the threshold from the Solar Stipulation. Therefore, there are no additional requirements related to that provision of the Solar Stipulation for Cass County.

Q. What is the next condition from the Solar Stipulation you will address?

A. Paragraph 5c) of the Solar Stipulation included the five items below, which the Company agreed to address in the first rate case in which the Company's investment in Cass County was proposed to be included in the Company's rate base.

(1) satisfaction of the in-service criteria (addressed below) and documentation that those criteria have been met to the extent possible at the time of that direct filing;

[4] Tax credits arising from Huck Finn are tracked under the Renewable Energy Standard Rate Adjustment Mechanism.

As of the filing of this case, the facility has not been placed in service, so in-service criteria have not been met at this time. Documentation of the in-service criteria will be provided to Staff once the facility is placed into service, prior to the final inclusion of the investment in Cass County being reflected in the trued-up rate base.

(2) an explanation of the capital costs incurred;

As of this writing, the acquisition of Cass County has not been closed and the facility has not been placed into service, so final capital costs are not known with certainty. The Company has included a pro forma adjustment to the rate base underlying its filed revenue requirement in this case for the investment expected in Cass County by the true-up date. That pro forma adjustment reflected an expected investment in the facility of ***__________***.

(3) an explanation of the tax treatments to be pursued;

As noted above, the Company cannot make an election of tax treatments at least until the Project is owned and has been placed into service. At this time, it is expected that the Company will elect to receive investment tax credits ("ITCs") for the Cass County facility. Because the Internal Revenue Service has recently issued guidance that indicates that ITCs under the IRA will not be subject to normalization requirements when transferred to a third-party entity in exchange for cash considerations, claiming ITCs for Cass County will have greater economic value than claiming production tax credits ("PTCs") for Cass County, which could be chosen in lieu of ITCs. Part of this economic value arises from the location of the Project in an "energy community" as defined in the IRA, which allows for incremental ITCs in the amount of 10% of the eligible capital costs of the project. In other words, the "energy community" permits claiming ITCs in the amount of 40% of the eligible capital costs of the Project instead of 30%. While the Company will continue to evaluate any changes in the dynamics of the project and the tax landscape that would suggest a different tax strategy (unlikely at this time), current expectations are that it will elect the ITC and transfer it to a third-party to allow customers to benefit from those credits as fully and as soon as practical.

(4) an explanation of the property tax treatment to be pursued;

This condition was directed toward the possibility that payments in lieu of taxes might be negotiated for a Missouri project (of which there were three included in the CCNs granted pursuant to the Solar Stipulation), given the possible availability of Chapter 100 financing. However, the Cass County facility is located in the state of Illinois and is thus not eligible for Chapter 100 financing allowed by Missouri state law. Therefore, the Company will simply be subject to any property taxes levied by the relevant taxing authority in Illinois. Payments of such property taxes will be included in the Company's property tax tracker.

(5) an explanation of all related expenses and offsetting revenues and a discussion of the factors that will impact those expenses going forward as estimated at the time of filing.

Expenses associated with the facility include depreciation expense, the return on the Company's net investment in the facility at the Company's weighted average cost of capital ("WACC") plus applicable income taxes, land lease costs, interconnection costs, property taxes, facility maintenance costs, and the cost of property insurance. The factors impacting these expenses going forward will be capital market conditions that impact interest rates and the Company's WACC, income and property tax rates, and general inflation as it impacts our other categories of operations and maintenance ("O&M") expense. The pro forma test year amounts of O&M expense associated with Cass County reflected in the revenue requirement in this case are $2,365,974. The Company anticipates additional information about some categories of O&M expenses to become known and measurable by the true-up date and will update those O&M values as part of the true-up phase of the case.

Offsetting revenues will include revenues generated by the sale of energy and capacity into the MISO market, in addition to revenues generated by customer subscriptions to Cass County under the RSP, which will be discussed in more detail in the next section of my testimony. Estimated energy revenues of $17.1 million and estimated capacity revenues of $0.4 million associated with Cass County are included as an offset to net energy costs in the Company's revenue requirement in this case. Factors influencing future levels of these offsetting revenues include the level the production (energy) and accreditation (capacity) of the facility, as well as changes in energy and capacity market prices in the future. Although not technically a revenue, expenses associated with Cass County will also be offset by ITCs when the benefit from them is realized and provided back to customers through the IRA tracker.

IV. RENEWABLE SOLUTIONS PROGRAM

Q. What is the Renewable Solutions Program?

A. The RSP is a program that was approved by the Commission in File No. EA-2022-0245, under which interested customers can subscribe to receive the output of new renewable energy generation facilities in order to meet their individual sustainability goals. Under the program, subscribers are still subject to all charges under the standard

Company retail tariff applicable to their service classification, but also pay an additional amount under the RSP program tariff in exchange for the title to the renewable energy credits ("RECs") from a particular facility. The monthly amount customers pay is the net impact of a charge – the Renewable Resource Charge under which the customer pays a fixed monthly amount based on the kilowatts of capacity to which they are subscribed – and a credit - the Renewable Benefits Credit which is based on the output of customers' subscribed portion of the renewable resource (determined as a pro rata share of total generation from the facility in the month based on the share of the resource's capacity that is dedicated to that customer's subscription) in that month times a tariffed rate. The net of the charge and credit is expected to be a charge in most months (any given month is dependent on the output of the resource) and will provide incremental revenue for the Company that offsets the need for some amount of additional base rate revenues to pay toward covering the revenue requirement of the Program resources. In this manner, the program directly benefits non-subscribers by enhancing the affordability of new renewable generation sources that support the Program while also providing energy and capacity to serve all of our customers.

Q. Are any Program resources expected to be in service by the true-up date in this case?

A. Yes. There are two solar facilities – the Boomtown Energy Center and the Cass County Energy Center – each of which was fully subscribed by interested customers and which represent distinct phases of the RSP with unique pricing, that are expected to go into service prior to the true-up date, resulting in new revenues under the Program. I have estimated expected annual first year net revenues from these Program phases going forward and provided them to Company witness Stephen Hipkiss for purposes of making a pro forma adjustment to the Company's operating revenues that offset the revenue requirement used to establish base retail rates.

Q. How did you estimate the annual level of net revenues expected as of the true up date?

A. As I mentioned, each facility is nominally 150 MW and is fully subscribed. Therefore, I calculated the total monthly revenues associated with the Renewable Resource Charge by multiplying 150,000 kW (150 MW converted into kW by multiplying by 1,000 kW/MW) by the Renewable Resource Rate associated with the first Program year for each phase - $8.27/kW for Boomtown and $10.34/kW for Cass County. I then multiplied the monthly revenues by 12 in order to determine the annual revenues. I also estimated the total annual credits under the Renewable Benefits Credit provision of the tariff for each Program phase. To do this, I received expected annual energy production estimates from Company witness Mark Peters and multiplied the total kWh of production by the first year Renewable Benefits Rate for the respective phase. The net revenues I calculated for each Program phase – Boomtown and Cass County – are provided in Table 1 below:

Table 1 – RSP Net Revenues by Program Phase

Boomtown RSP Subscriber Net Revenue	
Subscriptions (kW)	150,000
Renewable Resource Rate ($/kW-Month)	$8.27
Months	12
Total RRC Revenue	$14,886,000
Annual Production (kWh)	333,473,420
Renewable Benefits Credit ($/kWh)	$0.0388
Total RBC Credits	$12,938,769
Net Subscriber Revenue	**$1,947,231**

Cass County RSP Subscriber Net Revenue	
Subscriptions (kW)	150,000
Renewable Resource Rate ($/kW-Month)	$10.34
Months	12
Total RRC Revenue	$18,612,000
Annual Production (kWh)	338,050,180
Renewable Benefits Credit ($/kWh)	$0.0400
Total RBC Credits	$13,522,007
Net Subscriber Revenue	**$5,089,993**
Total RSP Net Subscriber Revenue	**$7,037,224**

Q. Are actual net revenues under the Program subject to tracking?

A. Yes. As a part of the Company's original RSP proposal, the Company was committed to ensuring that all Program net revenues would be used to enhance affordability for all customers – meaning that the Company proposed that it should not experience beneficial regulatory lag on these revenues but would track all Program net revenues and use them to offset future revenue requirements. The Commission ultimately ordered such tracking. The Program net revenues that I calculated just above are proposed for inclusion as an offset to the revenue requirement in this case and should therefore also become the base amount for tracking future Program net revenues against when rates arising from the case are in effect, in order to ensure that all net Program revenues benefit all customers.

Q. What factors will lead to variability in Program net revenues in the future?

A. There are two major factors that will impact the net revenues over time. First, variability in the output of Program resources will result in corresponding variability in the Renewable Benefits Credits earned by subscribers, which impacts the net revenues generated by the Program. Second, the Renewable Resource Rate and Renewable Benefits

Credits are subject to pre-determined annual updates for each Program year, as stated in the RSP tariff associated with each Program phase.[5] Additionally, while there are Program safeguards against subscribers exiting the Program - including transferability provisions and potential termination fees if subscriptions cannot be transferred - events around changes in individual subscriber circumstances could impact the timing and amount of future Program net revenues.

V. ECONOMIC DEVELOPMENT INCENTIVE

Q. Please describe the Company's EDI program.

A. Pursuant to legislation passed and signed into law in 2018 and amended in 2022,[6] certain incremental load additions of customers or prospective customers are subject to the availability of discounts from the Company's standard retail tariff rates for terms of 5 years.[7] Prior to the amendment of the EDI, discounts were required to average 40% over the five-year term of an EDI agreement. I will refer to EDI incentives committed under these terms as phase 1 of the EDI program. Subsequent to the amendment of EDI (phase 2 of the EDI program), discounts are now either 35% over the entire term, or customized based on customer-specific calculations of the expected revenues from the new load and expected incremental cost to serve the new load as of the time the Company receives the EDI application.

[5] The Cass County phase of the Program (Phase II) is not reflected in a Commission approved tariff yet, but the pricing has been established through the Solar Stipulation in File No. EA-2023-0286 and the auction process that resulted from it. The Company will file the Program Phase II tariff sheet in the near future reflecting the approved pricing.
[6] Section 393.1640, RSMo (Cum. Supp. 2024).
[7] Under certain conditions, a sixth year of discount is available to some customers, and the revised EDI statute also makes ten-year discounts available in certain circumstances.

Q. How many EDI agreements has the Company entered with customers?

A. As of the end of the test year, the Company had entered into a total of 34 EDI agreements that had realized discounts within the test year, 28 in phase 1 of the program and 6 in phase 2. All of the phase 2 agreements are 5 years in term, and there are no 10-year term agreements.

Q. Are all of those agreements still in effect?

A. No. Certain EDI agreements were subject to early termination due to customers not hitting the statutorily required thresholds associated with the load factor and/or minimum qualifying demand for the incremental load addition or as a result of terminating service. Six EDI contracts have been terminated early, leaving a total of 28 active EDI agreements with test year usage as of the filing of this testimony.

Q. Have you updated analysis of the EDI incremental revenues and costs for this case?

A. Yes. In order to enter into an EDI agreement with a customer, the Company is required by the statute to estimate the expected incremental revenues and costs that it will experience by serving the new load at the discounted rates. Each of these agreements passed this screening test prior to the Company's offer to enter into each EDI agreement. In other words, as of the time the customer applied, each new load was expected to provide revenues, even at the discounted levels reflected in the customer's EDI agreement, that fully covered the incremental costs of serving those loads and therefore made some contribution to covering the Company's fixed costs, and therefore positively contributed to affordability for all customers. However, conditions in energy and capacity markets that give rise to the Company's present incremental costs have changed (i.e., risen) since the time that most of the EDI applications were received and evaluated. For the 13 EDI customers with a full year of billing in the test year, the incremental revenue contributions were realized at an average rate of 4.32 cents per kWh, but the incremental costs of serving those loads are estimated to be 5.79 cents per kWh. For customers that were taking service under EDI agreements for only a part of the test year, incremental revenues were realized at an average rate of 3.22 cents per kWh, and the estimated incremental cost of serving the loads was 5.54 cents per kWh. Please note that calculations for customers that have revenues and costs over only a part of the test year are not an accurate view of full year impacts, due to differences in the seasonality of customer operations, rates, and incremental costs.

VI. NET METERING AND TIME OF USE RATES

Q. Please describe the background of the next issue you will discuss related to net metering and TOU rates.

A. In the Company's 2019 electric rate review (File No. ER-2019-0335), the Company proposed, and the Commission ultimately approved (with some modifications as agreed to by the parties to the case in a Stipulation and Agreement), a suite of rate options for residential customers that gives customers greater levels of choice and the potential for more control over their energy usage and costs. Each of the new rate options include TOU pricing, under which usage is priced differently during different parts of the day/week/year based on the differences in the typical level of demand experienced on the electric grid during those times. These TOU rates, however, were not offered by the Company to customers with net metering agreements related to customer-sited solar generation, due to inherent complexities in the interaction of TOU rates and net metering. The Company interprets the state of Missouri's Net Metering and Easy Connection Act to require certain billing methodologies (i.e., all kWh of customer usage and generation within the billing month be allowed to net against each other, and that a bill with zero or negative net usage for the month in full include zero energy charge) that created challenges and potential conflicts in applying TOU rates in a manner that retains the price signals intended by TOU rates. In the Company's most recent prior electric rate review (File No. ER-2022-0337), intervening party Renew Missouri advocated for making all residential TOU rate options available to net metered customers. I had an exchange with Renew Missouri's attorney, and also with Commissioner Holsman, during the evidentiary hearing on this topic that ultimately resulted in the Commission ordering the Company to "conduct a study on integrating distributed generation technologies and TOU rate plans."[8]

Q. Has the Company conducted the required study?

A. Yes. A report related to the study is attached to my testimony as Schedule SMW-D1.

Q. Please describe the areas examined by the Company's study along with an overview of the study's findings.

A. The Company designed the study to examine the four objectives below:

- Identify any technical barriers to metering or billing net metered customers on TOU rates,
- Evaluate the different potential treatments of net metered usage under TOU rates,
- Review residential customer usage and solar generation patterns to evaluate the potential impacts of different TOU billing paradigms, and
- Evaluate billing paradigms in the context of Missouri's Net Metering and Easy Connection Act's requirements.

[8] File No. ER-2022-0337, *Report and Order,* p. 38, issued June 14, 2023.

In pursuing these objectives, the Company did not identify any metering or billing barriers to offering TOU rates to net metering customers. However, the Company did evaluate four different potential sets of business rules for how netting could be conducted under TOU rates to illustrate the challenges to developing billing rules that respect the TOU price signals and also meet the dual mandate of the Net Metering and Easy Connection Act to allow netting of all kWh of usage and generation within the billing period, and to result in a zero bill (related to variable charge elements) when net usage is zero or negative. Ultimately, the one methodology studied that appears to fully comply with the law's dual mandate severely distorts or eliminates the usage-related price signal intended by the TOU rate. Other methodologies for netting maintain strong or adequate price signals but fail one or both of the statutory requirements – most notably, they do not result in a zero bill (related to variable charge elements) when usage is zero. This makes sense, since under TOU rates, kWh in different time periods have a different value, and a peak kWh netting with an off-peak kWh should not be expected to net to a zero charge given the different price applicable to each. One potential path to using such a methodology that respects the price signals would be to create an arbitrary condition on top of the TOU billing paradigm that simply requires the energy-related portion of the bill to be zero under the statutorily mandated conditions. See Schedule SMW-D1 for details.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Report on Challenges and Opportunities in Integrating Distributed Energy Resources with Time of Use Rates June 2024

Background

The Commission's order in File No. ER-2022-0337 directed Ameren Missouri to "conduct a study on integrating distributed generation technologies and [time of use] TOU rate plans." This issue arose from questions raised by Renew Missouri regarding the Company's position that net metering under Missouri's Net Metering and Easy Connection Act did not contemplate TOU rates, which were uncommon in Missouri at the time of the law's passage, and the specific requirements of the statute did not permit the billing of net metered customers in an economically rational manner.

In that case, Ameren Missouri expressed its interests in offering TOU rates to net metered customers, if and only if the billing mechanism could be conducted in a manner that resulted in the TOU price signals having their intended economic effect to encourage load shifting by residential customers to times other than peak periods, and were not subject to potential gaming strategies that would allow customers to reduce their bills (thereby increasing other customers' rates) in ways that did not provide commensurate system benefits. To that end, the Company in complying with the Commission's directive, commenced the study discussed in this Report.

Study Objectives

- Identify any technical barriers to metering or billing net metered customers on TOU rates,
- Evaluate the different potential treatments of net metered usage under TOU rates,
- Review residential customer usage and solar generation patterns to evaluate the potential impacts of different TOU billing paradigms, and
- Evaluate billing paradigms in the context of Missouri's Net Metering and Easy Connection Act's requirements.

Technical Barriers - Metering

Full deployment of the Company's electric AMI meters is expected in the near future. These AMI meters have the capability to record 15-minute interval measurements of kilowatt-hours delivered from the grid to the customer and kilowatt-hours received by the grid from a customer. Therefore, the data required to bill net metered customers according to any available TOU rate schedule is accessible. The only caveat is for the small number of customers who have opted out of AMI metering and elected to pay for non-standard metering. Non-standard meters employed by the Company have neither the capability to measure time differentiated usage nor inflows and outflows of electricity. Therefore, customers served by non-standard meters cannot access net metering or TOU rates.

Technical Barriers – Billing

TOU rates and net metering are both complex billing paradigms, and interacting the two concepts increases the complexity. As discussed in the section immediately below, there are numerous methodologies that could be imagined to calculate net usage during each TOU period and to handle excess generation in various TOU periods. The details of any specific billing methodology would have to be carefully analyzed to determine the programming and testing requirements to implement it. Nevertheless, the Company's systems are capable of performing the calculations that would be necessary to implement most billing mechanisms that could be developed. As such, the ability to bill TOU rates for net metered customers is not a barrier that would prevent offering the combination of these concepts, but would simply require evaluation of the specific proposal being implemented in order to determine the lead time and cost of programming and testing that would be required.

Potential treatments of net metering under TOU rates

The Company identified four potential sets of business rules for calculating and billing net usage by TOU time period, as described below.[1] The examples developed for each of these contemplate a three-period TOU rate, like the Company's Smart Savers rate, but the same logic could be implemented for any number of TOU periods.

Method 1 – kWh net only within discrete TOU periods

Net kWh are calculated separately for each TOU period by taking the difference between kilowatt-hours delivered from the grid to the customer and kilowatt-hours received by the grid from a customer within each TOU period. If the value of net usage in any period (e.g., peak) is positive, it is billed at the rate associated with that period. All negative net usage from each TOU time period is accumulated and credited at the avoided cost rate.

> Strengths – Maintains the strongest usage price signals within TOU periods, relatively simple billing/programming.
>
> Weaknesses – Does not (except by pure chance) produce a zero bill for variable charge components when net usage is zero or negative, and therefore is not compatible with the statute's requirement that zero net usage produce a bill reflecting only a customer charge. Also, may credit more kWh as avoided cost than the total monthly negative net usage (i.e., not all kWh of usage and generation within the monthly billing period "net" with each other).

Method 2 - kWh net "downhill"

Under this methodology, net usage is calculated first for the highest price (peak) period. If net peak usage is greater than zero, then that net peak usage is subject to the peak rate. If the net peak usage is less than zero, then there are zero kWh billed at the peak rate, and any net negative peak usage is passed down to the next highest price (intermediate) period to net with any positive net usage in that period. Next, net usage for the intermediate period (including any excess kWh passed down from the peak period) is calculated. If the resultant value is greater than zero, then that net usage is subject to the intermediate rate. If the net negative peak plus net intermediate usage is less than zero, then there are zero kWh billed at the intermediate rate, and any net negative usage is passed down to the lowest price (off) period. The off-peak usage billed is the amount needed to make the sum of the net billed usage in all periods equals the total monthly net kWh (across all periods) or

[1] References to bills in this section refer to bills associated with variable usage charges. All customers under net metering still pay monthly fixed customer charges, which are not discussed further in this Report.

zero, whichever is greater. If the total monthly net usage is less than zero, then the kWh of total monthly negative net usage are credited at the avoided cost rate.

Strengths – Maintains usage price signals within each TOU period.

Weaknesses –Does not (except by pure chance) produce a zero bill for variable charge components when net usage is zero or negative, and therefore is not compatible with the statute's requirement that zero net usage produce a bill reflecting only a customer charge. Also complex to bill/program.

<u>Method 3 – Pro-rata application of exported kWh to TOU periods</u>

Total kWh delivered to the grid by the customer/generator are allocated to TOU periods consistent with the proportion of total usage (kWh delivered from the grid to the customer) in each TOU period.

Strengths – Relatively easy to bill. Maintains some degree (but less than method 1 or 2) of usage-related price signal. Is consistent with the methodology the Company uses to allocate Community Solar Program (Rider CSP) kWh to subscriber bills on TOU rates. Results in zero bill when net zero or negative usage, complying with statute.

Weaknesses – Provides no recognition of the time period within which kWh are generated (the Company's position that TOU and net metering are not compatible under the statute is premised in part on the presumption that generation must also be measured and billed based on the TOU periods in which it occurred).

<u>Method 4 – kWh net bi-directionally</u>

Net usage is calculated for each TOU period that has positive net usage (zero assigned to that period if there exists negative net usage). Any negative usage that existed in the peak period is applied as a reduction to any positive intermediate net usage that exists. Any net negative intermediate usage (including spillover kWh from peak period) reduces off-peak kWh. Any negative off-peak usage resulting from this step 1) is redistributed to offset any intermediate, then peak positive net usage remaining from prior steps until usage in those steps reaches zero and 2) to the extent that there is still negative net off-peak usage after peak and intermediate usage reach zero, additional kWh receive a credit at the avoided cost rate and there is zero usage billed at the off-peak rate.

Strengths –Results in zero bill for variable charge components when net zero or negative usage exists, complying with statute.

Weaknesses –This approach severely undermines price signals in the TOU rates, as intermediate or off-peak generation can be used to offset peak usage, reducing or eliminating the incentive to reduce peak usage for customers with generation sized to meet their total load. Also, highly complex billing methodology that would be challenging and potentially resource intensive to program and test.

Summary of Four Billing Methodology Attributes

Method	Maintains Usage Price Signal	Billing Complexity	Reflects net generation (exports to the grid) by TOU Period	Complies with statutory requirement for zero bill	Consistent with Community Solar
1	Strong	Low	Yes	No	No
2	Good	High	Yes	No	No
3	Fair	Low	No	Possibly, subject to interpretation	Yes
4	Poor	Very High	Yes	Yes	No

Residential Usage and Solar Generation TOU Period Analysis

An analysis was conducted to determine the expected proportion of usage and generation in each TOU period under the Company's existing residential TOU rates using a sample of residential customers' interval data and a solar generation profile. Results of the analysis are presented in the table below. Residential load by TOU period is shown for the customer in the sample with the highest proportion of usage in that period (max), for the average customer (avg), and for customer with the lowest proportion of use in the TOU period (min).

	Smart Saver											
	Peak				Intermediate				Off-peak			
Month / Season	Solar Gen	Res-Max	Res-Avg	Res-Min	Solar Gen	Res-Max	Res-Avg	Res-Min	Solar Gen	Res-Max	Res-Avg	Res-Min
1	0.2%	24.2%	13.2%	6.5%	99.8%	74.9%	54.6%	37.6%	0.0%	51.1%	32.2%	9.7%
2	0.8%	26.2%	13.0%	6.2%	99.2%	75.4%	55.3%	36.5%	0.0%	53.2%	31.7%	7.2%
3	0.9%	27.5%	12.8%	4.5%	99.1%	81.2%	56.0%	25.2%	0.0%	70.3%	31.2%	9.1%
4	2.0%	28.3%	13.0%	6.0%	98.0%	77.3%	56.1%	32.2%	0.0%	61.0%	30.9%	10.5%
5	2.9%	27.0%	12.4%	2.3%	97.1%	89.4%	62.9%	20.8%	0.0%	76.9%	24.7%	7.5%
6	18.2%	28.4%	16.4%	0.5%	81.8%	77.5%	58.5%	16.2%	0.0%	83.4%	25.1%	6.8%
7	19.2%	33.4%	15.9%	0.2%	80.8%	82.0%	58.8%	15.8%	0.0%	84.0%	25.3%	5.6%
8	16.8%	33.4%	16.4%	0.0%	83.2%	78.3%	58.1%	23.9%	0.0%	75.4%	25.5%	4.9%
9	14.8%	28.6%	14.9%	0.2%	85.2%	77.2%	59.8%	30.0%	0.0%	69.8%	25.3%	5.3%
10	0.3%	36.7%	14.1%	5.5%	99.7%	82.9%	57.7%	21.9%	0.0%	62.8%	28.2%	10.3%
11	0.7%	38.9%	13.0%	6.2%	99.3%	79.2%	55.9%	28.8%	0.0%	57.6%	31.1%	9.7%
12	0.1%	23.9%	11.4%	4.4%	99.9%	79.9%	57.6%	30.8%	0.0%	55.6%	31.1%	9.8%
Summer	17.4%	26.9%	15.9%	0.4%	82.6%	77.9%	58.7%	22.0%	0.0%	77.6%	25.3%	5.9%
Winter	1.3%	20.9%	12.8%	5.3%	98.7%	77.7%	56.9%	36.6%	0.0%	51.7%	30.2%	12.2%
Annual	8.8%	20.2%	14.0%	8.2%	91.2%	77.8%	57.6%	33.8%	0.0%	56.7%	28.3%	11.3%

	Ultimate Saver							
	Peak				Off-Peak			
Month / Season	Solar Gen	Res-Max	Res-Avg	Res-Min	Solar Gen	Res-Max	Res-Avg	Res-Min
1	0.2%	24.2%	13.2%	6.5%	99.8%	93.5%	86.8%	75.8%
2	0.8%	26.2%	13.0%	6.2%	99.2%	93.8%	87.0%	73.8%
3	0.9%	27.5%	12.8%	4.5%	99.1%	95.5%	87.2%	72.5%
4	2.0%	28.3%	13.0%	6.0%	98.0%	94.0%	87.0%	71.7%
5	2.9%	27.0%	12.4%	2.3%	97.1%	97.7%	87.6%	73.0%
6	18.2%	28.4%	16.4%	0.5%	81.8%	99.5%	83.6%	71.6%
7	19.2%	33.4%	15.9%	0.2%	80.8%	99.8%	84.1%	66.6%
8	16.8%	33.4%	16.4%	0.0%	83.2%	100.0%	83.6%	66.6%
9	14.8%	28.6%	14.9%	0.2%	85.2%	99.8%	85.1%	71.4%
10	0.3%	36.7%	14.1%	5.5%	99.7%	94.5%	85.9%	63.3%
11	0.7%	38.9%	13.0%	6.2%	99.3%	93.8%	87.0%	61.1%
12	0.1%	23.9%	11.4%	4.4%	99.9%	95.6%	88.6%	76.1%
Summer	17.4%	26.9%	15.9%	0.4%	82.6%	99.6%	84.1%	73.1%
Winter	1.3%	20.9%	12.8%	5.3%	98.7%	94.7%	87.2%	79.1%
Annual	8.8%	20.2%	14.0%	8.2%	91.2%	91.8%	86.0%	79.8%

	Evening/Morning Saver							
	Peak				Off-Peak			
Month / Season	Solar Gen	Res-Max	Res-Avg	Res-Min	Solar Gen	Res-Max	Res-Avg	Res-Min
1	96.0%	73.0%	49.8%	31.1%	4.0%	68.9%	50.2%	27.0%
2	93.0%	75.8%	50.2%	23.9%	7.0%	76.1%	49.8%	24.2%
3	95.9%	72.7%	50.5%	20.2%	4.1%	79.8%	49.5%	27.3%
4	94.4%	75.4%	50.4%	24.8%	5.6%	75.2%	49.6%	24.6%
5	92.6%	86.4%	60.9%	9.5%	7.4%	90.5%	39.1%	13.6%
6	91.9%	85.6%	61.2%	5.3%	8.1%	94.7%	38.8%	14.4%
7	93.0%	85.7%	61.1%	4.7%	7.0%	95.3%	38.9%	14.3%
8	94.2%	83.1%	60.8%	11.3%	5.8%	88.7%	39.2%	16.9%
9	94.9%	82.4%	60.7%	15.3%	5.1%	84.7%	39.3%	17.6%
10	96.0%	80.9%	54.7%	19.7%	4.0%	80.3%	45.3%	19.1%
11	93.2%	72.8%	50.9%	29.4%	6.8%	70.6%	49.1%	27.2%
12	96.8%	70.6%	51.1%	18.3%	3.2%	81.7%	48.9%	29.4%
Summer	93.5%	83.5%	60.9%	9.6%	6.5%	90.4%	39.1%	16.5%
Winter	94.5%	70.4%	52.2%	32.6%	5.5%	67.4%	47.8%	29.6%
Annual	94.1%	75.3%	55.6%	28.2%	5.9%	71.8%	44.4%	24.7%

	Overnight							
	Peak				Off-Peak			
Month / Season	Solar Gen	Res-Max	Res-Avg	Res-Min	Solar Gen	Res-Max	Res-Avg	Res-Min
1	100.0%	90.3%	67.8%	48.9%	0.0%	51.1%	32.2%	9.7%
2	100.0%	92.8%	68.3%	46.8%	0.0%	53.2%	31.7%	7.2%
3	100.0%	90.9%	68.8%	29.7%	0.0%	70.3%	31.2%	9.1%
4	100.0%	89.5%	69.1%	39.0%	0.0%	61.0%	30.9%	10.5%
5	100.0%	92.5%	75.3%	23.1%	0.0%	76.9%	24.7%	7.5%
6	100.0%	93.2%	74.9%	16.6%	0.0%	83.4%	25.1%	6.8%
7	100.0%	94.4%	74.7%	16.0%	0.0%	84.0%	25.3%	5.6%
8	100.0%	95.1%	74.5%	24.6%	0.0%	75.4%	25.5%	4.9%
9	100.0%	94.7%	74.7%	30.2%	0.0%	69.8%	25.3%	5.3%
10	100.0%	89.7%	71.8%	37.2%	0.0%	62.8%	28.2%	10.3%
11	100.0%	90.3%	68.9%	42.4%	0.0%	57.6%	31.1%	9.7%
12	100.0%	90.2%	68.9%	44.4%	0.0%	55.6%	31.1%	9.8%
Summer	100.0%	94.1%	74.7%	22.4%	0.0%	77.6%	25.3%	5.9%
Winter	100.0%	87.8%	69.8%	48.3%	0.0%	51.7%	30.2%	12.2%
Annual	100.0%	88.7%	71.7%	43.3%	0.0%	56.7%	28.3%	11.3%

Key takeaways from the analysis suggest:

- Residential usage is more concentrated in the peak period than solar generation is for the Smart and Ultimate Savers Plan, consistent with the late afternoon peak exhibited by system and residential class loads as compared to the solar generation profile that is in fairly rapid decline at that time of day. There would be little economic incentive (i.e., potential for bill reduction) for most solar generating customers to adopt these TOU rates when a flat rate is available that is higher than the intermediate and off-peak rates that would apply to the majority of solar generation under Smart and Ultimate Savers rate options.
- For TOU rate options with long peak periods (i.e., Evening/Morning Savers and Overnight Savers), almost all generation is during peak periods, meaning that any net metering billing framework that allowed credits for excess generation at the applicable TOU period's retail rate (such as Method 4) would amount to buying kWh back from customers at premium rates, substantially above the typical wholesale value. To the extent that net metering in general represents a subsidy (an intended subsidy created deliberately by the legislature that passed the statute), that subsidy would grow significantly for customers on the Overnight Savers rate (i.e., nearly 100% of generation would potentially receive the peak retail rate, which is currently approximately 18% higher than the current flat summer rate that is available to net metered customers).
- Disparities in customer usage patterns (observed as differences between the maximum, average, and minimum percentages of usage in different TOU periods) mean that different customers would be impacted differently by possible net metering paradigms.

TOU Billing for Net Metered Customers Under the Net Metering and Easy Connection Act

Missouri's Net Metering and Easy Connection Act defines the requirements of billing for net metering customers as follows:

5. Consistent with the provisions in this section, the net electrical energy measurement shall be calculated in the following manner:

(1) For a customer-generator, a retail electric supplier shall measure the net electrical energy produced or consumed during the billing period in accordance with normal metering practices for customers in the same rate class, either by employing a single, bidirectional meter that measures the amount of electrical energy produced and consumed, or by employing multiple meters that separately measure the customer-generator's consumption and production of electricity;

(2) If the electricity supplied by the supplier exceeds the electricity generated by the customer-generator during a billing period, the customer-generator shall be billed for the net electricity supplied by the supplier in accordance with normal practices for customers in the same rate class;

(3) If the electricity generated by the customer-generator exceeds the electricity supplied by the supplier during a billing period, the customer-generator shall be billed for the appropriate customer charges for that billing period in accordance with subsection 3 of this section and shall be credited an amount at least equal to the avoided fuel cost of the excess kilowatt-hours generated during the billing period, with this credit applied to the following billing period;

(4) Any credits granted by this subsection shall expire without any compensation at the earlier of either twelve months after their issuance or when the customer-generator disconnects service or terminates the net metering relationship with the supplier;

Item 2 in that definition requires that netting of generation and usage be performed for all kWh within the billing period, despite the fact that, under TOU rates, different kWh have different values (i.e., retail rates). Rules for netting kWh of delivered to the customer and kWh of generation exported by the customer are required to accomplish this. Further, Item 3 in the definition requires a billing period with net zero or negative usage to produce a zero bill for variable charge components. Four paradigms for this have been examined. One (and possibly two) of them achieve both of these requirements, but each with weaknesses. The first method that accomplishes this dual mandate (Method 4) allows kWh generated in lower priced periods to net with usage in higher price periods (our usage analysis demonstrates that this would occur with great regularity for the Smart Savers and Ultimate Savers rate), which distorts and/or eliminates the price signals in the rate, creating economically irrational outcomes where TOU rates do not promote shifting of usage. In fact, the ability to reduce on peak billable usage with off or intermediate peak exports allows the customer the opportunity to increase on peak usage with zero effect on their bill. The other method that may meet the dual mandate (Method 3) causes kWh generated by the customer to lose their identity with respect to the TOU period in which they are generated. Neither of these outcomes is obviously desirable in order to make TOU rates available to net metered customers. The other two methodologies examined (Methods 1 and 2) result in the maintenance of strong or at least adequate price signals for residential usage, and respect the TOU period in which generation occurs. But neither of these methods results in a zero bill for variable charge components when net usage is zero or negative as required by the statue. It is presumably possible to overlay a secondary condition on these frameworks that simply and arbitrarily sets the bill to zero when that condition (i.e., zero or negative net usage) exists. But careful consideration of each proposed method, and of customer usage and generation patterns, validates the perspective that as drafted, the Net Metering and Easy Connection Act does not set up the conditions to bill net metering customers on TOU rates while maintaining the price signals intended by the rate structures by design.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Adjust Its Revenues for Electric Service.	)))	Case No. ER-2024-0319

AFFIDAVIT OF STEVEN WILLS

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

Steven Wills, being first duly sworn states:

My name is Steven Wills, and on my oath declare that I am of sound mind and lawful age; that I have prepared the foregoing *Direct Testimony*; and further, under the penalty of perjury, that the same is true and correct to the best of my knowledge and belief.

/s/ Steven Wills
Steven Wills

Sworn to me this 26th day of June, 2024.