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Issue(s):	Production Cost Modeling
Witness:	Mark J. Peters
Sponsoring Party:	Union Electric Company
Type of Exhibit:	Direct Testimony
File No.:	ER-2024-0319
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MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ER-2024-0319

DIRECT TESTIMONY

OF

MARK J. PETERS

ON

BEHALF OF

UNION ELECTRIC COMPANY

D/B/A AMEREN MISSOURI

St. Louis, Missouri
June, 2024

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DIRECT TESTIMONY

OF

MARK J. PETERS

FILE NO. ER-2024-0319

I. INTRODUCTION

Q. Please state your name and business address.

A. Mark J. Peters, One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri 63103.

Q. By whom and in what capacity are you employed?

A. I am employed by Ameren Services Company ("Ameren Services") as a Manager in the Corporate Planning Analysis Department, where I am responsible for the supervision and guidance of the group responsible for running production cost model studies used in developing budgets and financial forecasts, fuel burn projections, emissions estimates, and other generation station project analyses, and which is used in the preparation of and as evidentiary support for rate reviews, such as this one.

Q. Please describe your educational and professional background.

A. I received a Bachelor of Arts degree in Liberal Arts & Sciences (Concentration in Economics) in August of 1985 from the University of Illinois (Urbana-Champaign).

I began employment with Illinois Power Company in August of 1985, holding a variety of roles prior to its acquisition by Ameren Corporation. Since Illinois Power's acquisition, I have been involved with Ameren's Illinois utility subsidiaries' post-2006 energy supply acquisition process, the guidance and supervision of a group that provided analytical support to the Ameren Missouri trading group, which is now managed by Ameren Missouri witness Andrew Meyer, and the guidance of load forecasting and load research activities, in addition to my current duties.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to sponsor the determination of the normalized value for the sum of allowable fuel costs plus the cost of net purchased power, which was used by Company witness Steve Hipkiss in determining Ameren Missouri's revenue requirement for this case and in calculating the Net Base Energy Costs ("NBEC") utilized in the Company's Fuel Adjustment Clause ("FAC"). These costs consist of the delivered cost of nuclear fuel, coal, oil, and natural gas associated with producing electricity from the Ameren Missouri generation fleet, plus the variable component of net purchased power.

My testimony will also include the determination of:

1) The real-time load and generation deviation adjustment that has been included in the determination of NBEC over the last several Ameren Missouri electric rate reviews;
2) The level of real-time revenue sufficiency guarantee make-whole payment ("RT RSG MWP") margins;
3) The percentage of transmission costs and revenues to be included in the FAC; and
4) The normalized value for market energy and capacity revenues for the High Prairie and Atchison County Renewable Energy Centers to be included in

the base amounts established in this proceeding for the Company's Renewable Energy Standard Rate Adjustment Mechanism ("RESRAM") and excluded from the NBEC.

Company witness Andrew Meyer is also filing direct testimony to address other NBEC components, including off-system sales revenues which are netted against the costs that I have modeled, which are used by witness Hipkiss in determining NBEC.

Q. Please summarize your testimony and conclusions.

A. I have determined the following normalized values to be used by witness Hipkiss in determining Ameren Missouri's revenue requirement for this case and in calculating the ("NBEC") utilized in the Company's FAC:

1) Fuel costs of $474.7 million;
2) Net purchased power costs of $110.1 million;
3) Real-time load and generation deviation credit adjustment (reduction in NBEC) of $7.6 million; and
4) RT RSG MWP margins of $0.863 million (reduction in NBEC).

I have also determined the normalized market energy and capacity revenues related to the existing High Prairie and Atchison County Renewable Energy Centers, and the Huck Finn Renewable Energy Center which is expected to be in service prior to the end of the true up period, to be used by witness Hipkiss in determining the revenue requirement and in calculating the base amount for the RESRAM. Those amounts are, in total for the three facilities, $110.8 million for energy and $10.4 million for capacity.

Finally, I have determined that the generation weighted average locational marginal price ("LMP") to be used in the Company's production cost modeling is $41.05 per megawatt-hour ("MWh"), and that the appropriate percentage of transmission costs and revenues to be used in determining NBEC is 9.46%.

I would also note that given that the test year includes 29 days in February, appropriate leap year adjustments have been made to reflect a normalized, 365-day year.

III. PRODUCTION COST MODELING

Q. What is a production cost model?

A. A production cost model is a computer application used to simulate an electric utility's generation system and load obligations. One of the primary uses of the production cost model is to develop production cost estimates used for planning and decision making, including the development of a normalized level of net energy costs upon which a utility's revenue requirement can be based.

"Net energy costs" as used in this testimony are the normalized values for the sum of allowable fuel costs, including transportation, plus the cost of net purchased power. These are a subset of the total fuel and net purchased power costs, including transportation and emissions costs and revenues and net of net off-system sales revenues, which are used to establish NBEC in the Company's Rider FAC tariff sheets.[1] As noted, the NBEC is discussed in witness Hipkiss's direct testimony.

Q. How is PowerSIMM used by Ameren Missouri?

A. PowerSIMM is used by Ameren Missouri to model generation output, and when compared to load, to model net off-system sales and net purchased power. The results of this modeling are used for operational, financial, and regulatory purposes.

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[1] There are other components of NBEC that are not produced by the production cost modeling, as discussed by witnesses Meyer and Hipkiss in their direct testimonies.

Q. What are the major inputs to the PowerSIMM model run used for calculating a normalized level of net energy costs?

A. The major inputs are: normalized hourly loads, unit operating characteristics, unit availabilities, prices for the primary variable cost components (fuel by type and by plant, variable operating and maintenance costs, opportunity cost of emissions), and the market price of electrical energy.

Q. What are the major outputs of the PowerSIMM model run used for calculating a normalized level of net energy costs?

A. The major outputs are: generation output by unit expressed in MWh, millions of British thermal units ("MMBtu"), and the cost in dollars; net purchases of energy, expressed in both MWh and dollars; and net off-system sales of energy, expressed in both MWh and dollars.

Q. Please generally describe how net off-system sales and net purchases of energy are determined by the model.

A. For any given hour, the model increases the generation output for units that have a dispatch cost below the hourly market price for energy and decreases the output for those units whose dispatch cost is above the hourly market price. The model accomplishes this while recognizing the unit operating limits and characteristics, and after the model has determined unit commitment. In this manner, the model determines the output of each generator in MWh for each hour. This output is then compared to the load assumption in MWh for each hour to determine whether there is a net purchase or a net off-system sale for that hour.

In that regard, the model emulates the Company's market settlements with the Midcontinent Independent System Operator, Inc.'s ("MISO") markets. In actual operations, the Company purchases energy for its entire load from the MISO market and separately sells all of the MWhs generated by its generating units into the MISO market.[2] However, it is my understanding that the Federal Energy Regulatory Commission ("FERC") requires that these amounts be netted against each other for each hour for reporting purposes. This netting results in the recording of either a net off-system sale or a net power purchase for that hour, depending on whether the volume of total sales exceeds total purchases (net off-system sale) or if the volume of total purchases exceeds total sales (net power purchase). A $1 increase in off-system sales revenue has the same impact on NBEC as a $1 reduction in purchased power expense (and vice versa).

IV. PRODUCTION COST MODEL INPUTS

Q. What load data assumptions were used in the PowerSIMM model run used for calculating a normalized level of net fuel costs?

A. We used normalized hourly loads, including applicable losses, developed from the actual loads for the test year of April 1, 2023, through March 31, 2024.

Q. What operational data assumptions were used in the PowerSIMM model run used for calculating a normalized level of net energy costs?

A. Operational data assumptions reflecting the characteristics of the generating units were used for this purpose, including: unit input/output curve, which calculates the

[2] The only exception are the MWhs produced by the Atchison County Renewable Energy Center, with that power being sold into the Southwest Power Pool's ("SPP") energy market, since Atchison is connected to the transmission system under SPP's functional control. Those power sales, along with those for the High Prairie Renewable Energy Center, are included in the Company's RESRAM. The Huck Finn solar facility's sales will also be included in the RESRAM.

fuel input required for a given level of generator output; unit minimum and maximum load levels; ramp rates; minimum up and down times; unit commit status; identification of specific fuel used for startup and generation, including the ratio of those fuels if more than one for a given unit; emission limitations, and fuel blending. Schedule MJP-D1 lists the operational data used for this review.

Q. Are there any changes of note in the unit operating characteristics included in the PowerSIMM model as compared to the modeling submitted in the Company's last electric rate review?

A. Yes.

First, all units of the Rush Island Energy Center have been removed from the modeling to reflect its retirement by October 15 of this year.

Profiled energy output for the Boomtown and Cass County Renewable Energy Centers has been added to reflect their anticipated in-service dates before the end of year 2024. Separately, profiled energy output for the Huck Finn Renewable Energy Center, which is also expected to be in service by year end, has been included in the calculation of RESRAM energy and capacity revenues.

The model assumptions also reflect limits on the output of its combustion turbines sited in the State of Illinois to conform to the emission limits in that State's Climate and Equitable Jobs Act ("CEJA"), enacted in September 2021.

Additionally, the Sioux Energy Center is modeled assuming operation of the Selective Non-Catalytic Reduction ("SNCR") system for the entirety of the summer Ozone Season (May 1 – September 30), to reflect compliance activities associated with the

Missouri Department of Natural Resources' attainment plan for the 2015 Ozone Standard for the St. Louis Moderate Attainment Area.

It should be noted that the normalized output of the High Prairie, Atchison County and Huck Finn Renewable Energy Centers have been excluded from the production cost model, as the revenue associated with these facilities are excluded from NBEC. Instead, the normalized revenues associated with these resources are included in the base amounts established for the RESRAM.

Q. What unit availability data assumptions were used in the PowerSIMM model run used for calculating a normalized level of net energy costs?

A. Unit availability data assumptions were developed to annualize planned outages, unplanned outages, and de-ratings. Planned outages are major unit outages that are scheduled in advance. The length of the scheduled outage depends on the type of work being performed. Planned outage intervals vary due to factors such as the type of unit, unplanned outage rates during the maintenance interval, and plant modifications. A normalized planned outage length was used for this rate review, as reflected in Schedule MJP-D2. The lengths of the planned outage assumptions, except for the Callaway Energy Center, are based on a six-year average of actual planned outages that occurred between April 1, 2018, and March 31, 2024. The outage assumption for the Callaway Energy Center was based on an annualized average of the four most recent re-fueling outages: numbers 21 through 24.

In addition to the length of the planned outage, the time period when the planned outage occurs is also important. The planned outage schedule assumption used in modeling Ameren Missouri's generation with the PowerSIMM model in this proceeding is shown in

Schedule MJP-D3. This assumption was developed in consideration of historical practices and market prices, whereby such outages are generally scheduled in the spring and fall, when the negative financial consequences of removing a unit from service are lower.

Unplanned outages are short outages when a unit is completely off-line, which are not scheduled in advance. These outages typically last from one to seven days and occur between the planned outages. Unplanned outages, by definition, are unforeseen events whose timing cannot be predicted, and thus are modeled as random events. The normalized unplanned outage rate assumption for this proceeding is based on a six-year average of unplanned outages that occurred between April 1, 2018, and March 31, 2024, and is reflected in Schedule MJP-D4. It should be noted that consistent with its treatment in File No. ER-2022-0337, the extended forced outage at the Callaway Nuclear Energy Center immediately following the late 2020 refueling was excluded, as that was considered to be a non-recurring event.

A unit de-rate occurs when a generating unit cannot reach its maximum output due to operational considerations. The magnitude of the de-rating varies based on the operating issues involved. As with the unplanned outage assumption, these are unforeseen events whose timing cannot be predicted, and thus are modeled as random events. The de-rate assumption used in this case is based on a six-year average of de-rates that occurred between April 1, 2018, and March 31, 2024, and is reflected in Schedule MJP-D5.

Q. What fuel data assumptions were used in the PowerSIMM model run used for calculating a normalized level of net energy costs?

A. Ameren Missouri's units burn four general types of fuel: nuclear fuel, coal, natural gas (including landfill gas), and oil. The specific fuels (and the applicable ratio of those fuels if more than one) used by each generating unit for both normal generation and unit startup are identified in the model, and an incremental and average cost assumption is developed for each. The incremental cost assumptions are used by the model in its dispatch logic—determining when and at what output level a specific unit should run. Average costs represent the accounting costs incurred for the fuel consumed by generation and are used to calculate the fuel cost for each generating unit:

- The natural gas and oil price assumptions are based on the average daily spot market prices for the 36-month period ending March 31, 2024;
- The nuclear fuel cost assumption is based on the average nuclear fuel cost associated with Callaway Refuel 26;
- The incremental coal cost assumptions are based on the average spot market prices for the 36-month period ending March 31, 2024; and
- The average (accounting) coal cost assumptions reflect coal and transportation costs based upon coal and transportation prices that will be effective as of January 1, 2025.

We have not included a cost assumption for landfill gas, as those costs represent Renewable Energy Standard ("RES") compliance costs and are accounted for in the operations and maintenance costs reflected in the RES rebase, as addressed by Company witness Hipkiss in his direct testimony.

Q. What market energy price assumptions were utilized for the production cost modeling?

A. Consistent with past practice, the price assumptions used to model dispatch were the average hourly energy prices for the 36-month period ending December 21, 2024.

These prices averaged $41.05 per MWh, on an around-the-clock basis. The energy prices for the period of January 1, 2022, through March 31, 2024, are the actual generation weighted average day-ahead locational marginal LMPs in the MISO energy market for those Ameren Missouri generating units. Given that the Rush Island Energy Center units will be retired in 2024, they were excluded from this calculation.

Consistent with past practice, the energy prices for the remaining months through the true-up are basis-adjusted forward energy prices, which serve as a reasonable proxy until they are replaced with actual generation weighted energy prices as part of the true-up in this case.

Q. Please explain why you chose to utilize day-ahead LMPs at the generator nodes.

A. The use of the day-ahead LMPs is consistent with longstanding practice. As mentioned before, the PowerSIMM model simulates the dispatch of the Company's generators based on a series of inputs. This dispatching logic is similar to the one followed by the MISO to determine its day-ahead commitment of all of the generators in its footprint. The result of the MISO process is, among other things, the determination of individual LMPs for each generator. It is most appropriate to use the historical prices applicable to Ameren Missouri generation for the day-ahead markets since day-ahead prices determined the generation levels that produced the vast majority of Ameren Missouri's historic net off-system energy sales. In fact, day-ahead prices determine about 97% of Ameren Missouri's generation commitment and dispatch.

Q. Please describe the emission limitations placed upon the Illinois based combustion turbine generators ("CTGs") by CEJA.

A. In September 2021, the State of Illinois enacted CEJA. Provisions of this Act limit the level of emissions that a specific generating unit can produce over any rolling twelve-month period of time to no more than the annual average for that same emission, produced by that same unit, over Calendar Years 2018-2020.

Q. How did you model these limits?

A. Given that emissions are directly correlated to unit output, we modeled these limits by placing maximum MWh limits on each individual unit corresponding to the annual average for the 2018-2020 time period that was used to establish the CEJA limits. These annual limits were then allocated to individual months.

Q. Are there costs and revenues other than those established by the PowerSIMM production cost model which should be considered in the determination of NBEC?

A. Yes. In addition to the real-time load and generation deviation and RT RSG MWP margin adjustments discussed below, there are other costs and revenues that should be considered in determining NBEC, which are addressed in witness Meyer's and witness Hipkiss's direct testimonies.

Q. Please list the items that are modeled in PowerSIMM that should be trued-up using data as of the end of the anticipated true-up date in this rate review.

A. The following PowerSIMM input assumptions should be updated as of the applicable true-up date:

- Ameren Missouri's normalized retail kilowatt-hour ("kWh") sales and distribution line losses;
- Coal, nuclear, natural gas, and oil costs;
- Unit availability factors, including Callaway refueling;
- Energy prices;
- Known and measurable changes to unit operating characteristics, if any; and
- Known and measurable changes in emission limitations.

V. REAL-TIME LOAD AND GENERATION DEVIATION AND REAL-TIME RSG MAKE WHOLE PAYMENT MARGIN ADJUSTMENTS

Q. Please describe how the real-time load and generation deviation was calculated.

A. The deviation was calculated in a manner consistent with that used in File No. ER-2022-0337, Ameren Missouri's last rate review, using data for the 36 months ending March 31, 2024. Consistent with past practice, the CTGs and the Taum Sauk Energy Center were excluded. Additionally, all units at the Meramec Energy Center, which was retired in 2022, and the Rush Island Energy Center, which is retiring this year, were excluded.

Consistent with past practice, we intend to update this amount as part of the true-up process.

Q. Please describe how the RT RSG MWP margins were calculated?

A. These margins were calculated in a manner consistent with that used in the true-up in File No. ER-2022-0337, Ameren Missouri's last rate review, using market settlement and fuel data for the 36 months ending March 31, 2024, with the exception that Meramec CTG1 and Meramec CTG2 were excluded due to retirement in 2022.

Consistent with past practice, we intend to update this amount as part of the true-up process.

Q. Does the RT RSG MWP Margin apply to other make whole payments?

A. No. This calculation only applies to the Real Time RSG Make Whole Payments. All other make whole payments are properly normalized to a value of zero.

VI. PERCENTAGE OF TRANSMISSION COST TO BE INCLUDED IN FAC

Q. With respect to transmission charges recorded in Account 565 and transmission revenues recorded in Account 456.1, have you determined what portion of these charges should be included in the determination of NBEC used to determine the Base Factors ("BF") in Rider FAC?

A. Yes. I have determined that amount to be 9.46%. Those amounts excluded from the calculation of NBEC and BF should be included in base rates.

Q. Is this the same percentage that should be utilized to determine the portion of total transmission charges to be included in the FAC in any given period?

A. Yes.

Q. How was the 9.46% determined?

A. 9.46% is the result obtained by dividing the total MWh of net purchased power in the production cost model run for this case by the total load assumption used in that model. This calculation is consistent with that utilized in the true up for File No. ER-2014-0258, and the direct and true up in each rate review since.

VII. MARKET ENERGY AND CAPACITY SALES REVENUES TO BE INCLUDED IN THE RESRAM AND EXCLUDED FROM THE FAC

Q. What is the level of market energy sales revenue that is appropriate to include in the base amount established for the RESRAM?

A. I have determined that the normalized market energy sales revenues to be used in calculating the base amount for the RESRAM are $110.8 million. This value was obtained by multiplying the profiled hourly unit output for the High Prairie, Atchison, and Huck Finn Renewable Energy Centers by the applicable hourly LMPs. These LMPs are the same LMPs that were used in our production cost modeling.

These amounts are excluded from the calculation of NBEC as required by Rider FAC.

Q. What is the level of capacity sales revenue that is appropriate to include in the base amount of the RESRAM?

A. I have determined that the normalized capacity sales revenues to be used in calculating the base amount of the RESRAM to be $10.4 million.

The amount attributable to High Prairie was calculated using the actual Seasonal Accredited Capacity ("SAC") for each of four seasons in the past two MISO capacity auctions, and the actual seasonal Auction Clearing Prices ("ACP") for zone 5 those same periods.

The amount attributable to Huck Finn was calculated using MISO's published accreditation rate for solar resources for each of the four seasons in the past two MISO capacity auctions, and the actual seasonal ACP for zone 5 those same periods.

The amount attributable to Atchison County reflects actual bilateral capacity transactions entered for capacity in the SPP market.

These amounts are excluded from the calculation of NBEC as required by Rider FAC.

Q. Why did you only use two years for this normalization, instead of the three that were used in File No. ER-2022-0337?

A. As discussed in the Direct Testimony of Ameren Missouri Witness Andrew Meyer, MISO changed its capacity market design from an annual construct to a seasonal construct beginning Planning Year 2023-2024. As such, only two capacity auctions have been held under this new construct. By excluding results from Planning Year 2022-2023, these values are a better representation of normalized values under the new construct, in this proceeding.

Q. Does this complete your direct testimony?

A. Yes, it does.

Input / Out

Unit Name	Minimum - Net MW	12 Month Avg Net MW	Must Run	Ramp Rate MW/Hr	Minimum Up Time Hours	Minimum Down Time Hours	Primary Fuel Type	EDF	A
Callaway	1,236	1,217	Yes	- -	- -	6	Nuclear	0.966	0.000
Labadie 1	240	607	No	480	72	72	PRB Coal	0.992	0.000
Labadie 2	240	607	No	480	72	72	PRB Coal	0.992	0.000
Labadie 3	240	607	No	300	72	72	PRB Coal	0.992	0.001
Labadie 4	240	607	No	480	72	72	PRB Coal	0.992	0.001
Sioux 1	200	425	No	240	72	72	PRB/IL Coal	0.976	0.000
Sioux 2	200	425	No	240	72	72	PRB/IL Coal	0.976	0.000
Audrain CT 1	75	80	No	- -	2	2	Natural Gas	1.000	0.000
Audrain CT 2	75	80	No	- -	2	2	Natural Gas	1.000	0.000
Audrain CT 3	75	80	No	- -	2	2	Natural Gas	1.000	0.000
Audrain CT 4	75	80	No	- -	2	2	Natural Gas	1.000	0.000
Audrain CT 5	75	80	No	- -	2	2	Natural Gas	1.000	0.000
Audrain CT 6	75	80	No	- -	2	2	Natural Gas	1.000	0.000
Audrain CT 7	75	80	No	- -	2	2	Natural Gas	1.000	0.000
Audrain CT 8	75	80	No	- -	2	2	Natural Gas	1.000	0.000
Fairgrounds CT	55	60	No	- -	2	1	Oil	1.000	0.026
Goose Creek CT 1	72	79	No	- -	2	2	Natural Gas	1.000	0.000
Goose Creek CT 2	72	79	No	- -	2	2	Natural Gas	1.000	0.000
Goose Creek CT 3	72	79	No	- -	2	2	Natural Gas	1.000	0.000
Goose Creek CT 4	72	79	No	- -	2	2	Natural Gas	1.000	0.000
Goose Creek CT 5	72	79	No	- -	2	2	Natural Gas	1.000	0.000
Goose Creek CT 6	72	79	No	- -	2	2	Natural Gas	1.000	0.000
Kinmundy CT 1	104	112	No	- -	2	4	Natural Gas	1.000	0.013
Kinmundy CT 2	104	112	No	- -	2	4	Natural Gas	1.000	0.013
Mexico CT	54	60	No	- -	1	1	Oil	1.000	0.000
Moberly CT	54	60	No	- -	1	1	Oil	1.000	0.038
Moreau CT	54	60	No	- -	1	1	Oil	1.000	0.000
Peno Creek CT 1	41	46	No	- -	1	1	Natural Gas	1.000	0.000
Peno Creek CT 2	41	46	No	- -	1	1	Natural Gas	1.000	0.000
Peno Creek CT 3	41	46	No	- -	1	1	Natural Gas	1.000	0.000
Peno Creek CT 4	41	46	No	- -	1	1	Natural Gas	1.000	0.000
Pinkneyville CT 1	31	42	No	- -	1	1	Natural Gas	1.000	0.000
Pinkneyville CT 2	31	42	No	- -	1	1	Natural Gas	1.000	0.000
Pinkneyville CT 3	31	42	No	- -	1	1	Natural Gas	1.000	0.000
Pinkneyville CT 4	31	42	No	- -	1	1	Natural Gas	1.000	0.000
Pinkneyville CT 5	35	38	No	- -	1	1	Natural Gas	1.000	0.000
Pinkneyville CT 6	35	38	No	- -	1	1	Natural Gas	1.000	0.000
Pinkneyville CT 7	35	38	No	- -	1	1	Natural Gas	1.000	0.000
Pinkneyville CT 8	35	38	No	- -	1	1	Natural Gas	1.000	0.000
Raccoon Creek CT 1	75	82	No	- -	2	2	Natural Gas	1.000	0.000
Raccoon Creek CT 2	75	82	No	- -	2	2	Natural Gas	1.000	0.000
Raccoon Creek CT 3	75	82	No	- -	2	2	Natural Gas	1.000	0.000
Raccoon Creek CT 4	75	82	No	- -	2	2	Natural Gas	1.000	0.000
Venice CT 2	43	47	No	- -	1	1	Natural Gas	1.000	0.000
Venice CT 3	169	178	No	- -	2	4	Natural Gas	1.000	0.013
Venice CT 4	169	178	No	- -	2	4	Natural Gas	1.000	0.013
Venice CT 5	104	112	No	- -	2	4	Natural Gas	1.000	0.000
Maryland Hts (Fred Weber)	9	9.0	Yes	- -	1	1	Landfill Gas	1.000	- -
Ofallon	Modeled using fixed profile						Solar		
Lambert	Modeled using fixed profile						Solar		
BJC	Modeled using fixed profile						Solar		
High Prairie	Modeled using fixed profile						Wind		
Atchison County	Modeled using fixed profile						Wind		
Boomtown	Modeled using fixed profile						Solar		
Huck Finn	Modeled using fixed profile						Solar		
Cass County	Modeled using fixed profile						Solar		
Montgomery County	Modeled using fixed profile						Solar		
South St. Louis	Modeled using fixed profile						Solar		
Cape Girardeau	Modeled using fixed profile						Solar		
Fee Fee	Modeled using fixed profile						Solar		
North Metro	Modeled using fixed profile						Solar		
Delmar	Modeled using fixed profile						Solar		
House Springs	Modeled using fixed profile						Solar		
Osage	Modeled using fixed profile						Hydro		
Keokuk	Modeled using fixed profile						Hydro		
Taum Sauk 1		200	No				Pumped Storage		
Taum Sauk 2		200	No				Pumped Storage		

Note: # 1 Input Output equation: mmbtu = (A + B x Pnet + C x Pnet^2) x EDF, where Pnet = Net power level

NORMALIZED PLANNED OUTAGES

Actual	Apr-Dec 2018 (hrs)	2019 (hrs)	2020 (hrs)	2021 (hrs)	2022 (hrs)	2023 (hrs)	Jan-Mar 2024 (hrs)	Total (hrs)	Total (days)	Total (annualized days)
Labadie 1	169	2,215			517		385	3,286		
Labadie 2	70	2,137			665			2,872		
Labadie 3	2,724			438				3,162		
Labadie 4				605		561		1,167		
Labadie 1-4								10,487	**437**	**73**
Sioux 1			1,724	695	988			3,408		
Sioux 2			639	1,561		966		3,166		
Sioux 1-2								6,574	**274**	**46**

Callaway

	Refuel Days	
2019	Refuel 23	47.6
2020	Refuel 24	55.8
2022	Refuel 25	56.8
2023	Refuel 26	30.0
	Average	47.5

RC PO Year	PO Days
12/18	31.7

*** Annualized Refuel Outage Length = Avg Days / Refuel Outage x 2/3**

Schedule MJP-D2

2 0 2 3 2 0 2 4

		APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR
Mws		2 9 16 23	30 7 14 21	28 4 11 18 25	2 9 16 23	30 6 13 20 27	3 10 17 24	1 8 15 22	29 5 12 19 26	3 10 17 24	31 7 14 21	28 4 11 18	25 3 10 17 24
	CAL 1							Callaway 1					
	RUSH 1												
	RUSH 2												
	LAB 1	Labadie 1											
	LAB 2												
	LAB 3												
	LAB 4												
	SX 1	Sioux 1											
	SX 2												
		2 9 16 23	30 7 14 21	28 4 11 18 25	2 9 16 23	30 6 13 20 27	3 10 17 24	1 8 15 22	29 5 12 19 26	3 10 17 24	31 7 14 21	28 4 11 18	25 3 10 17 24
		APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR

Cal 1	10/7/23 1:00 AM				
	31.7	Days	761 Hours		
	11/7/23 5:48 PM				
		Days	L1	73	10
			S1	46	7
Lab 1	4/1/23 1:00 AM				
	72.8	Days			
	6/12/23 8:12 PM				
Sx 1	4/9/23 1:00 AM				
	45.7	Days			
	5/24/23 5:48 PM				

Normalized Unplanned Outage Rates - Full Outages

	Apr-Dec 2018	2019	2020	2021	2022	2023	Jan-Mar 2024	**Weigted Average**
Callaway 1	0.0%	0.2%	6.1%	0.0%	1.2%	5.9%	6.9%	**2.4%**
Labadie 1	4.6%	1.8%	2.5%	5.8%	3.8%	4.0%	0.0%	**3.6%**
Labadie 2	5.6%	6.9%	2.7%	5.0%	8.9%	4.2%	5.1%	**5.4%**
Labadie 3	9.6%	2.9%	5.8%	8.1%	4.6%	6.7%	8.9%	**6.0%**
Labadie 4	7.8%	7.1%	11.1%	7.2%	8.1%	14.1%	15.3%	**9.5%**
Sioux 1	20.1%	14.8%	17.3%	20.7%	17.4%	25.8%	22.5%	**19.5%**
Sioux 2	7.2%	45.8%	7.9%	4.5%	13.8%	21.3%	34.8%	**18.9%**

Normalized Derating

	Apr-Dec 2018	2019	2020	2021	2022	2023	Jan-Mar 2024	Weighted Average
Callaway 1	0.2%	1.4%	0.5%	0.1%	0.1%	0.2%	0.5%	**0.4%**
Labadie 1	2.0%	2.8%	3.0%	3.3%	1.4%	1.3%	1.3%	**2.3%**
Labadie 2	1.5%	5.9%	1.7%	0.4%	1.4%	0.8%	1.0%	**1.7%**
Labadie 3	3.0%	2.0%	3.6%	1.8%	1.2%	2.4%	2.0%	**2.3%**
Labadie 4	0.9%	5.0%	3.0%	1.5%	1.6%	3.5%	0.8%	**2.6%**
Sioux 1	0.5%	1.3%	4.4%	6.2%	3.6%	3.0%	5.6%	**3.1%**
Sioux 2	0.2%	2.1%	2.6%	3.1%	1.1%	1.1%	5.1%	**1.8%**

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	)	Case No. ER-2024-0319
Its Revenues for Electric Service.	)	

AFFIDAVIT OF MARK J. PETERS

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

Mark J. Peters, being first duly sworn states:

My name is Mark J. Peters, 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/ Mark J. Peters
Mark J. Peters

Sworn to me this 20th day of June, 2024.