

Exhibit No.:
Issue(s): Production Cost
Modeling
Witness: Michael S. Flanagan
Type of Exhibit: Direct Testimony
Sponsoring Party: Union Electric Company
File No.: ER-2026-0291
Date Testimony Prepared: June 26, 2026

MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ER-2026-0291

DIRECT TESTIMONY

OF

MICHAEL S. FLANAGAN

ON

BEHALF OF

UNION ELECTRIC COMPANY

D/B/A AMEREN MISSOURI

**St. Louis, Missouri
June, 2026**

TABLE OF CONTENTS

I.	INTRODUCTION	1
II.	PURPOSE AND SUMMARY OF TESTIMONY	2
III.	PRODUCTION COST MODELING	4
IV.	PRODUCTION COST MODEL INPUTS	6
V.	REAL-TIME LOAD AND GENERATION DEVIATION AND MAKE WHOLE PAYMENT MARGIN ADJUSTMENTS.....	13
VI.	PERCENTAGE OF TRANSMISSION COST TO BE INCLUDED IN FAC.....	13
VII.	MARKET ENERGY AND CAPACITY SALES REVENUES TO BE INCLUDED IN THE RESRAM AND EXCLUDED FROM THE FAC	14

DIRECT TESTIMONY
OF
MICHAEL S. FLANAGAN
FILE NO. ER-2026-0291

I. INTRODUCTION

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19

Q. Please state your name and business address.

A. My name is Michael S. Flanagan, and my business address is One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri 63103.

Q. What is your position with Ameren Missouri?

A. I am Manager, Generation Analysis for Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri" or the "Company"), 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 analyses.

Q. Please describe your educational background and employment experience.

A. I earned a Bachelor of Science degree in Industrial Engineering at the University of Missouri – Columbia in 1997, and a Master's degree in Business Administration at Southern Illinois University – Edwardsville in 2005.

I worked in various engineering, operations, analysis, and project support roles and positions with Nooter Fabricators, Olin Brass, and Sara Lee Bakery Group from 1997 through 2005. Since joining Ameren in 2006, I've held roles related to project support, execution, and management, capital planning, program management, and generation

1 strategy development. Generation strategy development included responsibility for
2 generation reliability analyses, and utilization of a commercial unit commitment and
3 dispatch model.

4 **II. PURPOSE AND SUMMARY OF TESTIMONY**

5 **Q. What is the purpose of your Direct Testimony?**

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

14 My testimony will also include the determination of:

- 15 1) The real-time load and generation deviation adjustment that has been
16 included in the determination of NBEC over the last several Ameren
17 Missouri electric rate reviews;
- 18 2) The level of make-whole payment (MWP) margins to be included in the
19 off-system sales component of NBEC included in witness Andrew Meyer's
20 testimony;
- 21 3) The percentage of transmission costs and revenues to be included in the
22 FAC; and

1 4) The normalized value for market energy and capacity revenues for the Huck
2 Finn, High Prairie, and Atchison County Renewable Energy Centers to be
3 included in the base amounts established in this proceeding for the
4 Company's Renewable Energy Standard Rate Adjustment Mechanism
5 ("RESRAM"), which are excluded from the NBEC used for the FAC.

6 Company witness Meyer is also filing Direct Testimony to address other FAC
7 components, including off-system sales revenues which are netted against the costs and
8 used by witness Hipkiss in determining NBEC.

9 **Q. Please summarize your testimony and conclusions.**

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

- 13 1) Fuel costs of \$494.7 million;
- 14 2) Net purchased power costs of \$95.5 million;
- 15 3) Real-time load and generation deviation credit adjustment (reduction in
16 NBEC) of \$0.6 million; and
- 17 4) MWP Margins of \$1.9 million (reduction in NBEC).

18 I have also determined that the normalized market energy and capacity revenues
19 related to the Huck Finn, High Prairie, and Atchison County Renewable Energy Centers to
20 be used by witness Hipkiss in determining the revenue requirement and in calculating the
21 base amount for the RESRAM are, in total for the three facilities, \$97.5 million for energy
22 and \$14.6 million for capacity.

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

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

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

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

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

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

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

12 **IV. PRODUCTION COST MODEL INPUTS**

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

15 A. We used normalized hourly loads, including applicable losses, developed
16 from the actual loads for the test year of April 1, 2025 through March 31, 2026.

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

19 A. Operational data assumptions reflecting the characteristics of the generating
20 units were used for this purpose, including: unit input/output curves, which calculate 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 and Huck Finn Renewable Energy Centers, are included in the Company's RESRAM.

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

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

9 A. Yes. Profiled energy output for the Vandalia, New Florence, Bowling
10 Green, and Split Rail Renewable Energy Centers has been added to reflect their anticipated
11 in-service dates before end of the true-up period, which runs through the end of 2026.

12 **Q. Are there other modeling assumptions you wish to highlight?**

13 A. Yes, all of which are consistent with modeling in Ameren Missouri's most
14 recent rate review. First, the model assumptions reflect limits on the output of its
15 combustion turbines sited in the State of Illinois to conform to the emission limits in that
16 State's Climate and Equitable Jobs Act (CEJA), enacted in September 2021.

17 Second, the Sioux Energy Center is modeled assuming operation of the Selective
18 Non-Catalytic Reduction (SNCR) system for the entirety of the summer Ozone Season
19 (May 1 – September 30), to reflect compliance activities associated with the Missouri
20 Department of Natural Resources' attainment plan for the 2015 Ozone Standard for the St.
21 Louis Moderate Attainment Area.

22 Finally, as discussed earlier, the normalized output of the Huck Finn, High Prairie,
23 and Atchison County Renewable Energy Centers has been excluded from the production

1 cost model, as the revenue associated with these facilities is excluded from NBEC. Instead,
2 the normalized revenues associated with these resources are included in the base amounts
3 established for the RESRAM.

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

6 A. Unit availability data assumptions were developed to annualize planned
7 outages, unplanned outages, and de-ratings. Planned outages are major unit outages that
8 are scheduled in advance. The length of the scheduled outage depends on the type of work
9 being performed. Planned outage intervals vary due to factors such as type of unit,
10 unplanned outage rates between the maintenance intervals, and plant modifications. A
11 normalized planned outage length was used for this rate review, as reflected in Schedule
12 MSF-D2. The lengths of the planned outage assumptions, except for the Callaway Energy
13 Center, are based on a six-year average of actual planned outages that occurred between
14 April 1, 2020 and March 31, 2026. The outage assumption for the Callaway Energy Center
15 was based on an annualized average of the four most recent re-fueling outages, numbers
16 24 through 27.

17 In addition to the length of the planned outage, the time period when the planned
18 outage occurs is also important. The planned outage schedule assumption used in modeling
19 Ameren Missouri's generation with the PowerSIMM model in this proceeding is shown in
20 Schedule MSF-D3. This assumption was developed in consideration of historical practices
21 and market prices, whereby such outages are generally scheduled in the spring and fall,
22 when the negative financial consequences of removing a unit from service are lower.

1 Unplanned outages are generally short outages when a unit is completely off-line,
2 which are not scheduled in advance. These outages typically last from a few to several days
3 and occur between the planned outages. Unplanned outages, by definition, are unforeseen
4 events whose timing cannot be predicted and thus are modeled as random events. The
5 normalized unplanned outage rate assumption for this proceeding is based on a six-year
6 average of unplanned outages that occurred between April 1, 2020 and March 31, 2026,
7 and is reflected in Schedule MSF-D4. It should be noted that consistent with its treatment
8 in File No. ER-2024-0319, the extended forced outage at the Callaway Nuclear Energy
9 Center immediately following the late 2020 refueling was excluded, as that was considered
10 to be a non-recurring event.

11 A unit de-rate occurs when a generating unit cannot reach its maximum output due
12 to operational considerations. The magnitude of the de-rating varies based on the operating
13 issues involved. As with the unplanned outage assumption, these are unforeseen events
14 whose timing cannot be predicted and thus are modeled as random events. The de-rate
15 assumption used in this case is based on a six-year average of de-rates that occurred
16 between April 1, 2020 and March 31, 2026, and is reflected in Schedule MSF-D5.

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

19 A. Ameren Missouri's units burn four general types of fuel: nuclear fuel, coal,
20 natural gas (including landfill gas), and oil. The specific fuels (and the applicable ratio of
21 those fuels if more than one) used by each generating unit for both normal generation and
22 unit startup are identified in the model, and an incremental and average cost assumption is
23 developed for each. The incremental cost assumptions are used by the model in its dispatch

1 logic—determining when and at what output level a specific unit should run. Average costs
2 represent the accounting costs incurred for the fuel consumed by generation and are used
3 to calculate the fuel cost for each generating unit:

- 4 • The natural gas and oil price assumptions are based on the average daily
5 spot market prices for the 36-month period ending March 31, 2026;
- 6 • The nuclear fuel cost assumption is based on the average nuclear fuel cost
7 associated with Callaway Refuel 28;
- 8 • The incremental coal cost assumptions are based on the average spot market
9 prices for the 36-month period ending March 31, 2026; and
- 10 • The average (accounting) coal cost assumptions reflect coal and
11 transportation costs based upon coal and transportation prices that will be
12 effective as of January 1, 2027.

13 We have not included a cost assumption for landfill gas, as those costs represent
14 Renewable Energy Standard (RES) compliance costs and are accounted for in the rebase
15 of operations and maintenance costs reflected in the RES tracker, as addressed by Company
16 witness Hipkiss in his Direct Testimony.

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

19 A. Consistent with past practice, the price assumptions used to model dispatch
20 were the average hourly energy prices for the 36-month period ending December 31, 2026.
21 These prices averaged \$38.01 per MWh, on an around-the-clock basis. The energy prices
22 for the period of January 1, 2024 through March 31, 2026 are the actual generation

1 weighted average day-ahead LMPs in the MISO energy market for those Ameren Missouri
2 generating units.

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

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

9 A. The use of the day-ahead LMPs is consistent with longstanding practice. As
10 mentioned before, the PowerSIMM model simulates the dispatch of the Company's
11 generators based on a series of inputs. This dispatching logic is similar to the one followed
12 by the MISO to determine its day-ahead commitment of all of the generators in its footprint.
13 The result of the MISO process is, among other things, the determination of individual
14 LMPs for each generator. It is most appropriate to use the historical prices applicable to
15 Ameren Missouri generation for the day-ahead markets since day-ahead prices determine
16 the generation levels that produce the vast majority of MISO market activity settlements.

17 **Q. Please describe the emission limitations placed upon the Illinois based**
18 **Combustion Turbine Generators (CTGs) by CEJA.**

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

23 **Q. How did you model these limits?**

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

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

8 A. Yes. In addition to the real-time load and generation deviation and MWP
9 margin adjustments discussed below, there are other costs and revenues that should be
10 considered in determining NBEC, which are addressed in witness Meyer's and witness
11 Hipkiss' Direct Testimonies.

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

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

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

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

3 A. Yes.

4 **Q. How was the 9.22% determined?**

5 A. 9.22% is the result obtained by dividing the total MWh of net purchased
6 power in the production cost model run for this case by the total load assumption used in
7 that model. This calculation is consistent with that utilized in the true up for File No. ER-
8 2014-0258, and the direct and true up in each rate review since.

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

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

13 A. I have determined that the normalized market energy sales revenues to be
14 used in calculating the base amount for the RESRAM are \$97.5 million. This value was
15 obtained by multiplying the profiled hourly unit output for the Huck Finn, High Prairie,
16 and Atchison Renewable Energy Centers by the applicable hourly LMPs. These LMPs are
17 the same LMPs that were used in our production cost modeling.

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

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

22 A. I have determined that the normalized capacity sales revenues to be used in
23 calculating the base amount of the RESRAM to be \$14.6 million.

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

5 Due to its in-service date, the amount attributable to Huck Finn was calculated
6 using a combination of the methodology above for the past two MISO capacity auctions
7 (PY 25/26 and PY 26/27), and a proxy calculation for the PY24/25 auction using the actual
8 seasonal ACP's and MISO's published accreditation rate for solar resources by season.

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

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

13 **Q. Does this conclude your Direct Testimony?**

14 A. Yes, it does.

Input / Output Curve #1

Unit Name	Minimum - 12 Month Avg		Must Run	Ramp	Minimum	Minimum	Primary Fuel	EDF	A	B	C
	Net MW	Net MW		Rate	Up Time	Down Time					
				MW/Hr	Hours	Hours	Type				
Callaway	1,190	1,217	Yes	--	--	6	Nuclear	0.966	0.000	8,547	1,915.876
Labadie 1	240	607	No	180	2	2	PRB Coal	0.994	0.000	9,072	607.790
Labadie 2	240	607	No	180	2	2	PRB Coal	0.994	0.000	9,072	607.790
Labadie 3	240	607	No	180	2	2	PRB Coal	0.994	0.001	8,729	573.160
Labadie 4	240	607	No	180	2	2	PRB Coal	0.994	0.001	8,729	573.160
Sioux 1	200	425	No	240	72	72	PRB/IL Coal	1.029	0.000	8,796	562.560
Sioux 2	200	425	No	240	72	72	PRB/IL Coal	1.029	0.000	8,796	562.560
Audrain CT 1	75	83	No	--	2	2	Natural Gas	1.000	0.053	2,514	430.330
Audrain CT 2	75	83	No	--	2	2	Natural Gas	1.000	0.053	2,514	430.330
Audrain CT 3	75	83	No	--	2	2	Natural Gas	1.000	0.053	2,514	430.330
Audrain CT 4	75	83	No	--	2	2	Natural Gas	1.000	0.053	2,514	430.330
Audrain CT 5	75	83	No	--	2	2	Natural Gas	1.000	0.053	2,514	430.330
Audrain CT 6	75	83	No	--	2	2	Natural Gas	1.000	0.053	2,514	430.330
Audrain CT 7	75	83	No	--	2	2	Natural Gas	1.000	0.053	2,514	430.330
Audrain CT 8	75	83	No	--	2	2	Natural Gas	1.000	0.053	2,514	430.330
Fairgrounds CT	55	60	No	--	2	1	Oil	1.000	0.060	4,712	270.080
Goose Creek CT 1	72	81	No	--	2	2	Natural Gas	1.000	0.000	8,323	277.800
Goose Creek CT 2	72	81	No	--	2	2	Natural Gas	1.000	0.000	8,323	277.800
Goose Creek CT 3	72	81	No	--	2	2	Natural Gas	1.000	0.000	8,323	277.800
Goose Creek CT 4	72	81	No	--	2	2	Natural Gas	1.000	0.000	8,323	277.800
Goose Creek CT 5	72	81	No	--	2	2	Natural Gas	1.000	0.000	8,323	277.800
Goose Creek CT 6	72	81	No	--	2	2	Natural Gas	1.000	0.000	8,323	277.800
Kinmundy CT 1	104	113	No	--	2	4	Natural Gas	1.000	0.018	5,629	337.300
Kinmundy CT 2	104	113	No	--	2	4	Natural Gas	1.000	0.018	5,629	337.300
Mexico CT	54	60	No	--	1	1	Oil	1.000	0.000	9,504	135.150
Moberly CT	54	60	No	--	1	1	Oil	1.000	0.000	9,504	135.150
Moreau CT	54	60	No	--	1	1	Oil	1.000	0.000	9,504	135.150
Peno Creek CT 1	42	47	No	--	1	1	Natural Gas	1.000	0.000	8,192	113.470
Peno Creek CT 2	42	47	No	--	1	1	Natural Gas	1.000	0.000	8,192	113.470
Peno Creek CT 3	42	47	No	--	1	1	Natural Gas	1.000	0.000	8,192	113.470
Peno Creek CT 4	42	47	No	--	1	1	Natural Gas	1.000	0.000	8,192	113.470
Pinkneyville CT 1	43	44	No	--	1	1	Natural Gas	1.000	0.000	6,953	102.740
Pinkneyville CT 2	43	44	No	--	1	1	Natural Gas	1.000	0.000	6,953	102.740
Pinkneyville CT 3	43	44	No	--	1	1	Natural Gas	1.000	0.000	6,953	102.740
Pinkneyville CT 4	43	44	No	--	1	1	Natural Gas	1.000	0.000	6,953	102.740
Pinkneyville CT 5	35	39	No	--	1	1	Natural Gas	1.000	0.000	7,394	139.920
Pinkneyville CT 6	35	39	No	--	1	1	Natural Gas	1.000	0.000	7,394	139.920
Pinkneyville CT 7	35	39	No	--	1	1	Natural Gas	1.000	0.000	7,394	139.920
Pinkneyville CT 8	35	39	No	--	1	1	Natural Gas	1.000	0.000	7,394	139.920
Raccoon Creek CT 1	75	83	No	--	2	2	Natural Gas	1.000	0.000	8,001	321.560
Raccoon Creek CT 2	75	83	No	--	2	2	Natural Gas	1.000	0.000	8,001	321.560
Raccoon Creek CT 3	75	83	No	--	2	2	Natural Gas	1.000	0.000	8,001	321.560
Raccoon Creek CT 4	75	83	No	--	2	2	Natural Gas	1.000	0.000	8,001	321.560
Venice CT 2	42	47	No	--	1	1	Natural Gas	1.000	0.000	8,271	106.400
Venice CT 3	169	178	No	--	2	4	Natural Gas	1.000	0.012	5,837	523.320
Venice CT 4	169	178	No	--	2	4	Natural Gas	1.000	0.012	5,837	523.320
Venice CT 5	104	113	No	--	2	4	Natural Gas	1.000	0.000	8,042	302.850
Maryland Hts (Fred Weber)	9	10.0	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				
Vandalia	Modeled using fixed profile						Solar				
New Florence	Modeled using fixed profile						Solar				
Bowling Green	Modeled using fixed profile						Solar				
Split Rail	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: $mmbtu = (A + B \times P_{net} + C \times P_{net}^2) \times EDF$, where P_{net} = Net power level

NORMALIZED PLANNED OUTAGES

Actual	April-Dec					Jan-Mar		Total (hrs)	Total (days)	Total (annualized days)
	<u>2020</u> (hrs)	<u>2021</u> (hrs)	<u>2022</u> (hrs)	<u>2023</u> (hrs)	<u>2024</u> (hrs)	<u>2025</u> (hrs)	<u>2026</u> (hrs)			
Labadie 1			662		551			1,213		
Labadie 2			665			1,174		1,840		
Labadie 3		438			2,618	292		3,348		
Labadie 4		605		561			782	1,949		
Labadie 1-4								8,350	348	58
Sioux 1	1,724	695	988			1,088		4,496		
Sioux 2	639	1,561		966				3,166		
Sioux 1-2								7,662	319	53

Callaway

Refuel Days	
2020 Refuel 24	55.8
2022 Refuel 25	56.8
2023 Refuel 26	30.0
2025 Refuel 27	34.5
Average	44.3

RC PO Year	PO Days
12/18	29.5

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

Normalized Unplanned Outage Rates - Full Outages

	April-Dec						Jan-Mar	Weighted Average
	<u>2020</u>	<u>2021</u>	<u>2022</u>	<u>2023</u>	<u>2024</u>	<u>2025</u>	<u>2026</u>	
Callaway 1	6.9%	0.0%	1.2%	5.9%	1.7%	25.6%	0.0%	6.5%
Labadie 1	3.0%	5.7%	3.3%	4.0%	1.3%	1.5%	12.2%	3.6%
Labadie 2	2.0%	5.0%	8.8%	4.1%	6.4%	3.8%	8.6%	5.3%
Labadie 3	7.0%	8.0%	4.3%	6.5%	5.3%	3.7%	10.9%	6.2%
Labadie 4	13.2%	6.8%	8.0%	14.0%	15.4%	12.6%	12.0%	11.8%
Sioux 1	9.5%	17.9%	13.0%	19.5%	16.8%	18.2%	37.4%	17.3%
Sioux 2	4.4%	3.8%	10.6%	15.4%	13.5%	20.0%	15.7%	12.1%

Normalized Derating

	April-Dec						Jan-Mar	Weighted
	<u>2020</u>	<u>2021</u>	<u>2022</u>	<u>2023</u>	<u>2024</u>	<u>2025</u>	<u>2026</u>	<u>Average</u>
Callaway 1	0.51%	0.09%	0.14%	0.19%	0.16%	0.58%	0.21%	0.2%
Labadie 1	3.17%	2.71%	1.37%	1.26%	0.62%	2.53%	1.65%	1.9%
Labadie 2	1.91%	0.37%	1.33%	0.79%	0.91%	2.33%	0.90%	1.2%
Labadie 3	3.61%	1.84%	1.21%	2.35%	2.61%	4.96%	2.26%	2.7%
Labadie 4	2.76%	1.50%	1.57%	3.48%	1.10%	2.51%	4.14%	2.1%
Sioux 1	1.81%	5.38%	2.41%	2.25%	4.03%	1.84%	0.25%	3.0%
Sioux 2	1.12%	2.60%	0.83%	0.79%	2.71%	2.92%	4.60%	2.0%