Exhibit No.:	
Issue(s):	Production Cost Model
Witness:	Mark J. Peters
Type of Exhibit:	Direct Testimony
Sponsoring Party:	Union Electric Company
File No.:	ER-2021-0240
Date Testimony Prepared:	March 31, 2021

MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ER-2021-0240

DIRECT TESTIMONY

OF

MARK J. PETERS

ON

BEHALF OF

UNION ELECTRIC COMPANY

D/B/A AMEREN MISSOURI

St. Louis, Missouri
March, 2021

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DIRECT TESTIMONY

OF

MARK J. PETERS

FILE NO. ER-2021-0240

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 developing fuel budgets, reviewing and updating economic dispatch parameters for the generating units owned by Ameren Missouri, running production cost model studies supporting power plant project-justification studies, and performing other special studies, including those supporting our rate reviews.

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 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 Mitchell Lansford 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.

Ameren Missouri witness Andrew Meyer is also filing direct testimony to address other FAC components, including net off-system sales revenues which are netted against the costs that I have modeled and used by Mr. Lansford in determining NBEC.

My testimony will also include the determination of a 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 and the percentage of transmission costs and revenues to be included in the FAC.

Q. Please summarize your testimony and conclusions.

A. Ameren Missouri's normalized annual fuel costs and net purchased power costs were calculated using the PowerSimm production cost model.

The normalized annual fuel costs are $592 million and net purchased power costs are $20.1 million.

The normalized annual value for the real-time load and generation deviation adjustment is a credit (reduction of cost) of $5.0 million.

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 our 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 Mr. Lansford's direct testimony.

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

Q. How is PowerSimm used by Ameren Missouri?

A. PowerSimm is used by Ameren Missouri to model generation output. The results of this modeling are used for operational, financial, and regulatory purposes. The model's output provides information used in developing budgets and financial forecasts, fuel burn projections, emissions estimates, and other generation station project analyses, and is used in the preparation of and as evidentiary support for rate reviews, such as this one.

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 megawatt-hours ("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).

[2] The only exception are the MWhs produced by the Atchison wind energy facility, 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 are included in off-system sales revenues tracked in the Company's FAC.

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 January 1, 2020 through December 31, 2020. Given that the test year has 366 days and true up period only has 365 days, a leap day adjustment was made to remove 1/29th of the February, 2020 loads from the results.

Q. Were other model results similarly adjusted for the output?

A. Yes. A similar adjustment was made to the results for fuel cost, purchased power cost, and off-system sales revenue.

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 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; 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.

We have removed the must run unit commitment status for the Labadie, Rush Island and Sioux coal fired generating units, thus allowing the model to place these units in reserve shutdown.

Additionally, unit ramp rates, heat rates and minimum load levels were updated to reflect current operating practice.

We also normalized the hourly purchase volumes under the Pioneer Prairie power purchase agreement ("PPA") using the same methodology that we used to normalize the output of the Keokuk and Osage Energy Centers. This methodology is consistent with the methodology proposed by Staff Witness Shawn Lange, in File No. ER-2016-0179.

Finally, our modeling reflects the addition of the High Prairie and Atchison Renewable Energy Centers, as well as the removal of Meramec combustion turbine generator ("CTG") 1 and CTG 2, (the former due to retirement, and the latter as a result of being placed in suspended status with the MISO).

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 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

January 1, 2015 and December 31, 2020. 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 January 1, 2015 and December 31, 2020, and is reflected in Schedule MJP-D4.

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 January 1, 2015 and December 31, 2020, 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 December 31, 2020;
- The nuclear fuel cost assumption is based on the average nuclear fuel cost associated with Callaway Refuel 24;
- The incremental coal cost assumptions are based on the average spot market prices for the 36-month period ending December 31, 2020; and
- The average (accounting) coal cost assumptions reflect coal and transportation costs based upon coal and transportation prices that will be effective as of September 30, 2021.

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 RES cost re-base operations and maintenance expense portion of the revenue requirement.

Q. What market price of energy assumptions were used in the PowerSimm model run used for calculating a normalized level of net energy costs?

A. The model was run using average hourly energy prices for the 36-month period ending September 30, 2021. The development of these prices is discussed in Mr. Meyer's testimony.

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 adjustment discussed below, there are other costs and revenues that should be considered in determining NBEC, which are addressed in Mr. Meyer's and Mr. Lansford'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 retail kilowatt-hour ("kWh") sales and distribution line losses;
- Coal, nuclear, natural gas, and oil costs;
- Unit availability factors;
- Energy prices; and
- Known and measurable changes to unit operating characteristics, if any.

V. REAL-TIME LOAD AND GENERATION DEVIATION ADJUSTMENT

Q. Please describe the purpose of the real-time load and generation deviation adjustment.

A. The real-time load and generation deviation adjustment is intended to capture the difference in revenue (or expense) between the production cost model (which is a day-ahead only model) and the operation of the MISO market, which has both a day-ahead and real-time component.

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

A. The deviation was calculated in a manner consistent with what was used in File No. ER-2019-0335, Ameren Missouri's last rate review, using data for the 36 months ending December 31, 2020. Consistent with past practice, the combustion turbine generators ("CTGs") and the Taum Sauk Energy Center were excluded, as were Meramec Energy Center Units 1 & 2, for the period following their conversion to natural gas. I recommend that this calculation be updated as part of the true-up process.

Q. What is the rationale for excluding the CTGs, Taum Sauk, and Meramec Units 1 & 2?

A. The CTGs are excluded due to the high number of reliability starts required by the MISO that occur separately from the economic dispatch process, and for which they receive Revenue Sufficiency Guarantee Make-Whole Payments.

The Taum Sauk Energy Center is excluded from the calculation due to the manner in which these generating units are offered and cleared in the MISO market. As a pumped hydroelectric unit, the incremental cost basis for generating at the Taum Sauk facility is the cost of purchasing energy from the MISO market at the applicable Taum Sauk CpNode[3] to pump water back up into the reservoir. Neither MISO market operations nor settlements consider this pumping energy to constitute load that could be cleared as part of Ameren Missouri's load in the day-ahead market. Rather, MISO considers pumping energy to constitute "negative generation" at the facility. Negative generation cannot be offered or cleared in the day-ahead market. As a result, pumping energy is only cleared in the real-time market. It is not possible to determine what pumping cost would have been had Taum Sauk's output exactly matched its day-ahead award in any given hour.

Meramec Units 1 & 2 were excluded given their limited number of hours of operation following their conversion to natural gas.

VI. PERCENTAGE OF TRANSMISSION COST 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 1.87%. 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.

[3] A CpNode or Commercial Pricing Node, is a component of the MISO commercial model used to schedule and settle market activity at a specified location.

Q. How was the 1.87% determined?

A. 1.87% 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 Case No. ER-2014-0258, and the true up in each rate review since.

Q. Does this complete your direct testimony?

A. Yes, it does.

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-2021-0240

AFFIDAVIT OF MARK J. PETERS

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

Mark J. Peters, being first duly sworn on his oath, states:

My name is Mark J. Peters, and on his oath declare that he is of sound mind and lawful age; that he has 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 29th day of March, 2021.

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	Input / Output Curve #1 A	B	C
Callaway	1,190	1,217	Yes	- -	- -	6	Nuclear	1.000	- -	9.961	- -
Labadie 1	200	607	No	480	72	72	PRB Coal	0.983	721.4	8.087	0.00100
Labadie 2	200	607	No	480	72	72	PRB Coal	0.983	743.9	8.346	0.00056
Labadie 3	240	607	No	480	72	72	PRB Coal	0.983	596.5	8.177	0.00122
Labadie 4	240	607	No	480	72	72	PRB Coal	0.983	552.0	8.460	0.00100
Rush 1	170	602	No	300	72	72	PRB Coal	1.039	523.0	8.513	0.00045
Rush 2	200	602	No	240	72	72	PRB Coal	1.039	813.4	7.549	0.00123
Sioux 1	200	415	No	240	72	72	PRB Coal	1.070	514.8	8.429	0
Sioux 2	200	415	No	240	72	72	PRB Coal	1.070	533.7	8.505	0
Meramec 1	20	122	No	90	24	24	Natural Gas	1.000	179.4	9.362	0.00700
Meramec 2	20	122	No	90	24	24	Natural Gas	1.000	179.4	9.362	0.00700
Meramec 3	115	263	No	120	120	24	PRB Coal	0.981	525.8	8.371	0.00543
Meramec 4	100	345	No	120	120	48	PRB Coal	0.981	298.0	9.085	0.00181
Audrain CT 1	62	82	No	- -	2	2	Natural Gas	1.000	164.7	10.116	0.00000
Audrain CT 2	62	82	No	- -	2	2	Natural Gas	1.000	164.7	10.116	0.00000
Audrain CT 3	62	82	No	- -	2	2	Natural Gas	1.000	164.7	10.116	0.00000
Audrain CT 4	62	82	No	- -	2	2	Natural Gas	1.000	164.7	10.116	0.00000
Audrain CT 5	62	82	No	- -	2	2	Natural Gas	1.000	164.7	10.116	0.00000
Audrain CT 6	62	82	No	- -	2	2	Natural Gas	1.000	164.7	10.116	0.00000
Audrain CT 7	62	82	No	- -	2	2	Natural Gas	1.000	164.7	10.116	0.00000
Audrain CT 8	62	82	No	- -	2	2	Natural Gas	1.000	164.7	10.116	0.00000
Fairgrounds CT	60	60	No	- -	2	1	Oil	1.000	179.0	7.692	0.02409
Goose Creek CT 1	50	81	No	- -	2	2	Natural Gas	1.000	259.1	8.603	-
Goose Creek CT 2	50	81	No	- -	2	2	Natural Gas	1.000	259.1	8.603	-
Goose Creek CT 3	50	81	No	- -	2	2	Natural Gas	1.000	259.1	8.603	-
Goose Creek CT 4	50	81	No	- -	2	2	Natural Gas	1.000	259.1	8.603	-
Goose Creek CT 5	50	81	No	- -	2	2	Natural Gas	1.000	259.1	8.603	-
Goose Creek CT 6	50	81	No	- -	2	2	Natural Gas	1.000	259.1	8.603	-
Kinmundy CT 1	77	112	No	- -	2	4	Natural Gas	1.000	269.6	7.099	0.01300
Kinmundy CT 2	77	112	No	- -	2	4	Natural Gas	1.000	269.6	7.099	0.01300
Meramec CT 1											
Meramec CT 2											
Mexico CT	60	60	No	- -	1	1	Oil	1.000	193.9	5.896	0.05235
Moberly CT	60	60	No	- -	1	1	Oil	1.000	175.3	7.014	0.03814
Moreau CT	60	60	No	- -	1	1	Oil	1.000	144.5	9.061	0.00758
Peno Creek CT 1	51	51	No	- -	1	1	Natural Gas	1.000	117.8	8.268	-
Peno Creek CT 2	51	51	No	- -	1	1	Natural Gas	1.000	117.8	8.268	-
Peno Creek CT 3	51	51	No	- -	1	1	Natural Gas	1.000	117.8	8.268	-
Peno Creek CT 4	51	51	No	- -	1	1	Natural Gas	1.000	117.8	8.268	-
Pinkneyville CT 1	42	42	No	- -	1	1	Natural Gas	1.000	91.1	7.330	-
Pinkneyville CT 2	42	42	No	- -	1	1	Natural Gas	1.000	91.1	7.330	-

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	Input / Output Curve #1 A	B	C
Pinkneyville CT 3	42	42	No	- -	1	1	Natural Gas	1.000	91.1	7.330	-
Pinkneyville CT 4	42	42	No	- -	1	1	Natural Gas	1.000	91.1	7.330	-
Pinkneyville CT 5	39	39	No	- -	1	1	Natural Gas	1.000	174.0	6.584	-
Pinkneyville CT 6	39	39	No	- -	1	1	Natural Gas	1.000	174.0	6.584	-
Pinkneyville CT 7	39	39	No	- -	1	1	Natural Gas	1.000	174.0	6.584	-
Pinkneyville CT 8	39	39	No	- -	1	1	Natural Gas	1.000	174.0	6.584	-
Raccoon Creek CT 1	42	82	No	- -	2	2	Natural Gas	1.000	286.2	8.327	-
Raccoon Creek CT 2	42	82	No	- -	2	2	Natural Gas	1.000	286.2	8.327	-
Raccoon Creek CT 3	54	82	No	- -	2	2	Natural Gas	1.000	286.2	8.327	-
Raccoon Creek CT 4	42	82	No	- -	2	2	Natural Gas	1.000	286.2	8.327	-
Venice CT 2	52	52	No	- -	1	1	Natural Gas	1.000	120.8	7.835	-
Venice CT 3	130	178	No	- -	2	4	Natural Gas	1.000	535.0	5.155	0.01288
Venice CT 4	130	178	No	- -	2	4	Natural Gas	1.000	535.0	5.155	0.01288
Venice CT 5	77	112	No	- -	2	4	Natural Gas	1.000	230.0	10.043	-
Maryland Hts (Fred Weber)	10	8.0	Yes	- -	1	1	Landfill Gas	1.000	- -	13.653	- -
Ofallon	Modeled using fixed profile										
Lambert	Modeled using fixed profile										
BJC	Modeled using fixed profile										
High Prairie	Modeled using fixed profile										
Atchison	Modeled using fixed profile										
Osage	Modeled using fixed profile										
Keokuk	Modeled using fixed profile										
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	2015 (hrs)	2016 (hrs)	2017 (hrs)	2018 (hrs)	2019 (hrs)	2020 (hrs)	Total (hrs)	Total (days)	Total (annualized days)
Labadie 1		160		169	2,215		2,544		
Labadie 2		757		70	2,137		2,964		
Labadie 3	1,217	7	1,207	2,724			5,155		
Labadie 4		1,873					1,873		
Labadie 1-4							12,536	**522**	**87**
Meramec 1		284		218			502		
Meramec 2		377		213			590		
Meramec 1-2							1,092	**46**	**8**
Meramec 3			432	1,218	2,406		4,055	**169**	**28**
Meramec 4			1,673	2,503	312	390	4,878	**203**	**34**
Rush Island 1	875			2,026		664	3,565		
Rush Island 2		2,355		455		536	3,346		
Rush 1-2							6,910	**288**	**48**
Sioux 1	987	2,378				1,724	5,090		
Sioux 2	460		1,947			639	3,047		
Sioux 1-2							8,137	**339**	**57**

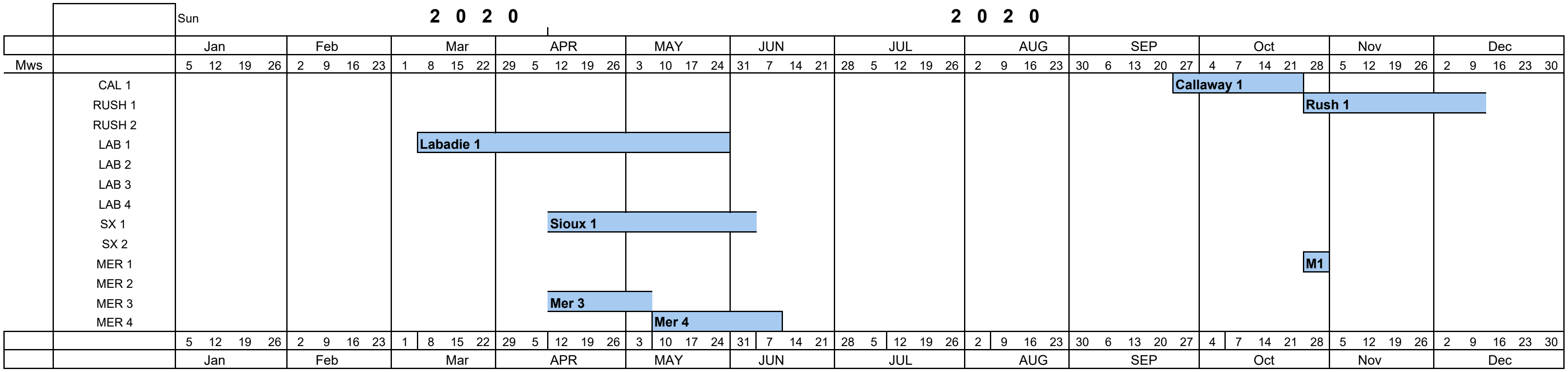
Callaway

	PO Days
Refuel 21	38.52
Refuel 22	60.04
Refuel 23	47.59
Refuel 24	79.32
Average	56.37

RC PO Year	PO Days
12/18	37.58

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

Schedule MJP-2



Cal 1	9/26/20 1:00 AM		
	37.6	Days	902 Hours
	11/2/20 2:52 PM		
Rush 1	10/27/20 1:00 AM		
	48.0	Days	
	12/14/20 12:44 AM		
Mer 3	4/11/20 1:00 AM		
	28.2	Days	
	5/9/20 4:53 AM		
Mer 4	5/9/20 1:00 AM		
	33.9	Days	
	6/11/20 9:58 PM		
Lab 1	3/5/20 1:00 AM		
	87.1	Days	
	5/31/20 2:16 AM		
Sx 1	4/11/20 1:00 AM		
	56.5	Days	
	6/6/20 1:07 PM		
Mer 1	10/27/20 1:00 AM		
	7.6	Days	
	11/3/20 3:03 PM		

Schedule MJP-D3

Normalized Unplanned Outage Rates - Full Outages

	2015	2016	2017	2018	2019	2020	Weigted Average
Callaway 1	1.3%	0.0%	4.4%	0.0%	0.2%	6.1%	**1.8%**
Labadie 1	2.6%	10.5%	5.4%	3.9%	1.8%	2.5%	**4.6%**
Labadie 2	6.5%	6.6%	7.6%	6.4%	7.0%	2.7%	**6.1%**
Labadie 3	7.7%	13.7%	7.6%	8.5%	2.9%	5.8%	**7.7%**
Labadie 4	3.8%	3.4%	5.7%	5.9%	7.1%	11.1%	**6.3%**
Meramec 1	15.6%	25.2%	0.0%	35.5%	43.4%	2.0%	**21.8%**
Meramec 2	11.0%	26.8%	55.1%	61.6%	71.9%	33.1%	**35.1%**
Meramec 3	35.8%	23.8%	24.9%	43.5%	73.3%	56.9%	**40.4%**
Meramec 4	26.8%	34.7%	27.7%	17.6%	35.8%	33.6%	**29.4%**
Rush Island 1	3.4%	5.2%	5.9%	7.6%	8.5%	6.4%	**6.1%**
Rush Island 2	7.7%	5.8%	6.6%	1.3%	9.9%	4.5%	**6.0%**
Sioux 1	19.0%	19.8%	12.4%	17.5%	14.7%	17.0%	**16.5%**
Sioux 2	16.5%	9.5%	12.0%	6.8%	46.1%	8.0%	**16.9%**

Normalized Derating

	2015	2016	2017	2018	2019	2020	Weighted Average
Callaway 1	1.0%	1.5%	1.6%	0.4%	1.4%	0.5%	**1.0%**
Labadie 1	2.7%	1.7%	4.2%	2.1%	2.8%	3.0%	**2.8%**
Labadie 2	2.6%	1.6%	1.8%	1.6%	5.9%	1.7%	**2.4%**
Labadie 3	3.7%	2.9%	2.1%	2.9%	2.0%	3.6%	**2.9%**
Labadie 4	7.4%	3.9%	1.8%	1.3%	5.0%	3.0%	**3.7%**
Meramec 1	1.9%	0.3%	0.0%	0.0%	0.0%	0.0%	**0.9%**
Meramec 2	3.9%	1.5%	0.0%	13.8%	36.5%	25.0%	**11.5%**
Meramec 3	6.2%	5.3%	0.5%	0.5%	26.4%	81.9%	**13.1%**
Meramec 4	18.3%	0.8%	8.5%	9.4%	27.0%	81.2%	**15.0%**
Rush Island 1	2.9%	4.9%	4.0%	2.8%	2.8%	1.9%	**3.3%**
Rush Island 2	6.5%	14.2%	1.8%	1.7%	2.5%	0.8%	**4.2%**
Sioux 1	1.4%	0.5%	1.2%	0.5%	1.3%	4.3%	**1.3%**
Sioux 2	0.6%	3.0%	4.8%	0.2%	2.1%	2.7%	**2.1%**