STATE OF MISSOURI
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held at its office in Jefferson City on the 9th day of March, 2022.

In the Matter of the Request of The Empire District Electric Company d/b/a Liberty for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in its Missouri Service Area	)	**File No. ER-2021-0312**

ORDER APPROVING STIPULATIONS AND AGREEMENTS

Issue Date: March 9, 2022 Effective Date: March 19, 2022

On May 28, 2021, The Empire District Electric Company d/b/a Liberty filed tariff sheets designed to implement a general rate increase for electric service. On January 28, 2022, the Staff of the Commission (Staff), Liberty, Midwest Energy Consumers Group, and Renew Missouri Advocates filed a *Non-Unanimous Partial Stipulation and Agreement* that resolves many of the issues between the parties. On January 31, 2022, Staff, the Office of the Public Counsel (OPC) and Liberty filed a *Second Partial Stipulation and Agreement.* Under the first partial stipulation the signatories agree to a starting rate base amount of $2,049,632,599. The signatories agree to a starting net operating income available of $104,315,916. The signatories agree that the Asbury generation plant Accounting Authority Order ordered in File No ER-2019-0374 will continue, but upon the effective date of new rates in this case, the baseline balances will be reset to zero. Rate schedules consistent with the Commission approved settlement in ET-2020-0390, Liberty's Transportation Electrification Pilot Program, will be calculated and implemented. Green Button will be implemented allowing customers online access to view and download their usage data. The second partial stipulation resolves some billing and reporting issues, as well as requiring the parties to meet concerning certain issues like substation security expenditures. In short, the first two partial stipulations resolve most rate base issues, income statement issues, amortization issues, fuel adjustment clause issues, advanced metering infrastructure issues, depreciation issues, and billing issues.

On February 4, 2022, Liberty and the Empire District Retired Members & Spouses Association, LLC (EDRA) filed a *Stipulation and Agreement as to EDRA* that resolves issues concerning retiree benefits.

On February 4, 2022, Liberty, Staff, and OPC filed a *Fourth Partial Stipulation and Agreement*. The fourth stipulation removes the Asbury generation plant issue and the Winter Storm Uri issue. Liberty will not seek rate case recovery for Asbury and Uri, but will instead seek to securitize those costs (File Nos. EO-2022-0040 and EO-2022-0193). The fourth partial stipulation also resolves the voltage optimization study issue, plant in service accounting issues, the emergency conservation plan issue, low-income programs and weatherization program issues, wind project issues, market price protection mechanism issues, and allowance for funds used during construction issues. Under the fourth partial stipulation, Liberty agrees to reduce its late fees from 0.5 percent to 0.25 percent.

The fourth partial stipulation also resolves rate of return, capital structure, and cost of debt. The signatories agree that for purposes of the calculation of rates, Liberty's revenue requirement increase is an annual increase of $35,515,913.

The four partial stipulations and agreements (Agreements) taken together resolve all the disputed issues between the parties with the exception of the class cost of service issue. Not all parties signed the Agreements, but each partial stipulation represents that the non-signatory parties do not oppose any of the partial stipulations. Commission Rule 20 CSR 4240-2.115(2) allows seven days to object to the stipulation and agreement. If no party files a timely objection to a stipulation and agreement, the Commission may treat it as a unanimous stipulation and agreement. More than seven days have passed since the Agreements were filed, and no party has objected. Therefore, the Commission will treat the Agreements as unanimous.

An evidentiary hearing to address the remaining cost of service issue was conducted February 7, 2022, and the class cost of service issue will be resolved by the Commission in a future report and order. An on-the-record presentation regarding the Agreements was held on February 10, 2022.

The Agreements are in part a black box settlement, meaning the parties have agreed that Liberty should be authorized to file tariffs designed to increase the company's annual revenues by $35,515,913. The parties do not, however, agree to any particular revenue or cost amounts to be used to calculate that revenue increase. Similarly the Agreements establishes Liberty's rate base at a specified amount without describing how that amount was calculated.

The Agreements also establish other amounts to be used in various regulatory calculations and provides for the continuation of some existing tracker mechanisms (the Riverton O&M tracker will cease). The class cost of service issues, including the allocation of rates among customer classes, are not resolved in the Agreements and remain for resolution by the Commission.

After reviewing the Agreements, the Commission determines that their terms are reasonable resolutions of the issues addressed in each partial stipulation and agreement. Further, the Commission determines that each partial stipulation and agreement should be approved and the respective signatories of each stipulation ordered to comply with its terms.

As no party objected to any of the stipulations, and to give the parties certainty as to the conclusion of the issues addressed by the Agreements, the Commission will make this order effective in less than thirty days.

THE COMMISSION ORDERS THAT:

1. The *Non-Unanimous Partial Stipulation and Agreement* is approved. It is attached to this order, and its terms are incorporated by reference. The signatories to that stipulation and agreement are ordered to comply with its terms.

2. The *Second Partial Stipulation and Agreement* is approved. It is attached to this order, and its terms are incorporated by reference. The signatories to that stipulation and agreement are ordered to comply with its terms.

3. The *Stipulation and Agreement as to EDRA* is approved. It is attached to this order, and its terms are incorporated by reference. The signatories to that stipulation and agreement are ordered to comply with its terms.

4. The *Fourth Partial Stipulation and Agreement* is approved. It is attached to this order, and its terms are incorporated by reference. The signatories to that stipulation and agreement are ordered to comply with its terms.

5. This order shall become effective on March 19, 2022.

BY THE COMMISSION

Morris L. Woodruff
Secretary

Silvey, Chm., Rupp, Coleman, Holsman, and
Kolkmeyer CC., concur.

Clark, Senior Regulatory Law Judge

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Request of The Empire District Electric Company d/b/a Liberty for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in its Missouri Service Area	)))))	**Case No. ER-2021-0312**

NON-UNANIMOUS PARTIAL STIPULATION AND AGREEMENT

COME NOW the Staff of the Missouri Public Service Commission ("Staff"), The Empire District Electric Company ("Empire"), Midwest Energy Consumers Group ("MECG"), and Renew MO ("Renew MO"), by and through their respective counsel, and for their Non-Unanimous Partial Stipulation and Agreement ("Stipulation"),[1] respectfully state as follows to the Missouri Public Service Commission ("Commission"):

RATE BASE AND NET OPERATING INCOME AGREEMENTS

1. While not agreeing to the specific methodologies and arguments used to derive the balance, the Signatories agree to a starting rate base amount of $2,049,632,599, which represents Staff's rate base reflected in its case as of the surrebuttal filing minus any rate base item reflected in Staff's case related to Asbury. Any rate base issue that is still to be addressed during the hearing will reduce the starting rate base amount, therefore reducing overall revenue requirement, if the issue is decided differently than what is reflected in Staff's rate base.
2. While not agreeing to the specific methodologies and arguments used to derive the balance, the Signatories agree to a starting net operating income available of $104,315,916, which

[1] The City of Ozark, Missouri ("Ozark"), The Office of the Public Counsel ("OPC"), the Empire District Retired Members & Spouses Association, LLC ("EDRA"), and The Empire District Electric Company SERP Retirees, LLC ("EDESR") are also parties to this proceeding. Although not signatories, Ozark, OPC, EDRA, and EDESR do not object to the approval of this Stipulation. As such, the Commission may treat it as unanimous.

represents Staff's net operating income available reflected in its case as of the surrebuttal filing, including Staff's billing determinants as of May 2021, minus any expenses and associated taxes reflected in Staff's case related to Asbury. Any expense issue that is still to be addressed during the hearing will increase the starting net operating income amount, therefore reducing overall revenue requirement, if the issue is decided differently than what is reflected in Staff's net operating income available.

3. As stated, if issues are decided differently than what is reflected in Staff's EMS run for the agreed to rate base and net operating income amount, it will reduce the overall revenue requirement, with the exception of Rate of Return, Return on Equity, Capital Structure, and Cost of Debt, as well as Asbury and Storm Uri costs, if litigated, which may increase, or decrease, the overall revenue requirement.

4. The Signatories further agree that Staff's EMS run included with its surrebuttal filing reflects a quantification for the items included in the Commission's AAO issued in Case No. ER-2019-0374 through June 30, 2021. The Asbury AAO authorized in Case No ER-2019-0374 will continue, but upon the effective date of new rates in this case, the baseline balances will be reset to zero, as Asbury will not be reflected in those rates.

5. This resolves the following issues in the January 25, 2022 List of Issues filed in this case: 15-Rate Base Issues (a), (b), (c), (d), (e), (g), and (h); 16 Income Statement Issues-Payroll and Benefits; 17 Income Statement Issues-Other (a), (b), (d), and (e); 18 Amortization Issues (Revenue Requirement); 19 Rate Case Expense (Revenue Requirement); 20 Wind Projects (b), (c), and (d); 23 Fuel Adjustment Clause ("FAC") (e), (o); 28 AMI, and 29 Depreciation Issues (a), (b), (c), and (d), 31 Asbury (c).

6. **EADIT Tracker**: A tracker will be created to capture the differences between protected EADIT returned to customers as part of the revenue requirement in this case, and the actual amortization recorded by the Empire using ARAM for protected EADIT balances and a 3 year amortization period for non-stub period unprotected EADIT balances.

7. **Riverton 12 O&M Tracker:** The Riverton O&M Tracker will cease on the effective date of rates in this case. The Riverton O&M Tracker balance as of June 30, 2021 is $12,460,102, which is to be amortized over a five-year period starting with the effective date of rates in this case. Recovery of the amounts tracked from July 1, 2021 to the effective date of rates in this case will be addressed in Empire's next general rate proceeding.

8. **Pension/OPEB**: The Signatories request that the Commission authorize the continuation of a tracker mechanism for pension and OPEB expenses. The annual level of ongoing Missouri jurisdictional pension and OPEBs expense is $7,978,512 and $4,641,848, respectively. This includes the actuarially determined expenses of $7,549,450 for pensions and $4,811,940 for OPEBs, and the five (5) year amortization of Missouri jurisdictional amounts of $429,062 for pensions and ($170,092) for OPEBs. The Missouri jurisdictional regulatory liability as of June 30, 2021, is a total of $7,502,082 for pensions and $850,461 for OPEBs. The prepaid pension asset balance as of June 30, 2021 is $24,548,069, Missouri jurisdictional. The Accounting Standards 715-30 and 715-60 (FAS 87/106) tracker language shall continue in effect.

REVENUES AND BILLING DETERMINANTS

9. For the purpose of establishing rates in these cases, the Signatories agree to use Staff's Billing Determinants and Revenues, which have been provided as Attachment A.

This resolves the following issues in the January 25, 2022 List of Issues filed in this case: 27 Class Cost of Service and Rate Design Issues (j), (k), and (l).

RATE DESIGN AND CLASS COST OF SERVICE AGREEMENT

10. The Signatories agree to the following provisions, which resolve following issues in the January 25, 2022 List of Issues filed in this case: 10 Green Button; 27 Class Cost of Service and Rate Design Issues (d), (e), (f), (g), (h), (i), and (m).
11. **Rider OTOU** - will remain available and open to further enrollment for eligible customers.
12. **Transmission Rate Schedule** – To be structured and designed as proposed by Empire in testimony, with the addition of the value of the monthly credit being listed in the tariff and tariff provisions requiring new customer contracts be filed for Commission review.
13. **ET-2020-0390-**Rate schedules consistent with the settlement in ET-2020-0390 to be calculated and implemented. The generally-applicable time-variant rates developed in this case do not constitute time-variant rates for purposes of EV tariff requirements, however, the Empire-proposed optional time-variant rates do satisfy such requirements.
14. **Lighting -** rate changes to occur as an equal percent adjustment to each charge.
15. **PFM** – to be consolidated with CB/SH to the new "Small General" rate schedule. To the extent that customers exceed the 40 kW cap, Empire is obligated to enforce its tariff and move customers off of this rate schedule in the future, if applicable.
16. **CB/SH/PFM rate schedules**: The parties' intent is to consolidate these rate schedules. Further, the parties' intent is to transition the generally applicable rate for this rate schedule to a time-variant rate structure for service on and after October 15, 2022. After that time, the non-time-variant rate structure will remain available to customers who elect to opt-out of the time-variant rate structure, and this option will be indicated within the rate schedule.

a. To produce the Non-Time-Variant rates, the following procedure will be followed:
    i. Step 1: Existing CB/SH/PFM rate schedules shall be consolidated by applying the existing CB rates to all determinants. This consolidation is not revenue neutral.

    ii. Step 2: To implement the increase applicable to this consolidated class in this case in excess of the revenues generated by consolidation, all rate elements will be multiplied by the same factor (1 + x%). The rates produced will be published in a new rate schedule, "Small General Service."

a. To produce the Non-Time-Variant rates, the following procedure will be followed:

    i. Step 1: A calculation will be performed under which the kWh rates produced by the Non-Time-Variant energy charges will be increased by $0.02,

    ii. Step 2: A new charge, "Off-peak discount Rider", will be introduced, at a rate of -$0.02 per kWh, applicable to usage between the hours of 10 pm and 6 am,

    iii. Step 3: The amounts produced by Time-Variant Step 1 in line "i." will be adjusted so that the total revenue recovered through the energy charges including the rider are equal to the total revenue produced by the Non-Time-Variant energy charges.

17. **GP and TEB rate schedules**:
    a. The parties' intent is to consolidate these rate schedules, and then to create separate rate schedules for customers served at a primary voltage and for customers served at a secondary voltage. Further, the parties' intent is to transition the generally-applicable rate for each of these schedules to a time-variant rate structure for service on and after October 15, 2022. After that time, the non-time-variant rate structures will remain available to customers who elect to opt-out of the time-variant rate structure, and this option will be indicated within the rate schedules.
    b. To produce the Non-Time-Variant rates, the following procedure will be followed:
        i. Step 1: Existing GP and TEB rate schedules shall be consolidated as provided below using Staff's direct-filed billing determinants.

		Rate GP	Rate TEB	Initial Consolidated rates
	Customer Charge	$ 69.49	$ 69.49	$ 69.49
	Facilities Charge	$ 2.07	$ 2.13	$ 2.13
Summer	Demand Charge	$ 7.33	$ 3.50	$ 7.33
Winter	Demand Charge	$ 5.71	$ 2.88	$ 5.71
Summer	1st 150	$0.086940	$0.104530	$ 0.086940
Summer	Next 200	$0.067450	$0.080980	$ 0.067450
Summer	All Additional	$0.060560	$0.072860	$ 0.060560
Winter	1st 150	$0.074640	$0.078970	$ 0.074640
Winter	Next 200	$0.060780	$0.063240	$ 0.060780
Winter	All Additional	$0.060270	$0.061970	$ 0.060270

This consolidation is not revenue neutral – it produces an increase of $1.462 million using these billing determinants.

ii. Step 2: To implement the increase applicable to this consolidated class in this case:
   1. 70% of the revenue increase in excess of that produced by consolidation will be recovered from increasing the monthly billing demand charges and 30% from increasing energy charges;
   2. the 30% revenue increase for energy charges will be recovered based on kWh billing determinants of the specific block as a percent of total kWh billing determinants, such that each block is multiplied by the same factor (1 + x%).

iii. Step 3: Two rate schedules will be created – "Small Primary Service" for customers served at a primary voltage and "Large General Service" for customers served at a secondary voltage. The kWh and kW rates of the Large General Service schedule will be multiplied by 0.9806 to derive the rates for the Small Primary Service rate schedule. The Small Primary Service rate schedule will include the Transformer Ownership provisions currently provided on the existing Schedule GP.

c. To produce the Time-variant rates, the following procedure will be followed:

i. Step 1: A calculation will be performed under which the kWh rates produced by Non-Time-Variant Step 3 will be increased by $0.005,

ii. Step 2: A new charge, "Off-peak discount Rider", will be introduced, at a rate of -$0.005 per kWh, applicable to usage between the hours of 10 pm and 6 am,

iii. Step 3: The non-rider per-kWh rates produced by Time-Variant Step 1 will be adjusted so that the total revenue recovered through the energy charges including the rider are equal to the total revenue produced by the energy charges produced by the Non-Time-Variant energy charges.

18. **LP** – Existing structure and general design is retained.

a. To implement the increase applicable to the rate schedule in this case:

i. 70% of the increase will be recovered from increasing the monthly billing demand charges and 30% from increasing energy charges;

ii. the 30% increases for energy charges will be recovered based on kWh billing determinants of the specific block as a percent of total kWh billing determinants, such that each block is multiplied by the same factor (1 + x%).

19. Residential Rate Schedule: The parties' intent is to transition the generally-applicable rate for this rate schedule to a time-variant rate structure for service on and after October 15, 2022. After that time, the non-time-variant rate structure will remain available to customers who elect to opt-out of the time-variant rate structure, and this option will be indicated within the rate schedule.

a. To produce the Non-Time-Variant rates, the following procedure will be followed:

i. Step 1: The customer charge will remain at $13.00.

ii. Step 2: To implement the increase applicable to the energy charges in this case, all rate elements will be multiplied by the same factor (1 + x%).

b. To produce the Non-Time-Variant rates, the following procedure will be followed:

i. Step 1: A calculation will be performed under which the kWh rates produced by the Non-Time-Variant energy charges will be increased by $0.02,

ii. Step 2: A new charge ,"Off-peak discount Rider", will be introduced, at a rate of -$0.02 per kWh, applicable to usage between the hours of 10 pm and 6 am,

iii. Step 3: The non-rider per-kWh rates produced by Time-Variant Step 1 will be adjusted so that the total revenue recovered through the energy charges including the rider are equal to the total revenue produced by the Non-Time-Variant energy charges.

20. Empire can offer their proposed structure/design of opt-in ToU, to begin October 15, 2022, with participation caps proposed by Empire. No ToU tracker, no ToU changes to the FAC, no best bill guarantee will be implemented in this case. FAC proposal to be tracked/studied in real time between rate cases.

21. Other Provisions and Future Filings:

a. Empire commits to propose time-variant demand charges in the next rate case, with supporting billing determinants. Empire commits to retain data sufficient for other parties to recommend variations to Empire's proposal, such as shifting the hours to which the demand charge is applicable.

b. Empire shall perform robust education of its customers regarding the cost-basis of time-variant rates, which shall include but not be limited to concepts such as the availability of wind energy and relatively low load conditions of off peak hours, and the nature of load requirements and generation capacity and energy costs during other hours. Such education shall not be limited to marketing of bill savings potential. This education shall focus on the generally-applicable time-variant rates, as opposed to marketing of the opt-in ToU proposed by Empire. Empire agrees to meet with Staff, OPC, and Renew Missouri to discuss its education, marketing and progress to date (including customer participation and feedback) of TOU rates on a quarterly basis until its next rate case.

c. Empire will file testimony and provide data in its next case describing:

i. how investments and charges are tracked for internal accounting purposes, and how facilities and related costs, expenses, and revenues are flowed through Empire's class cost of service study related to "Special or Excess Facilities Rider XC," and "Transformer Ownership" and interaction with facilities extension policies,

ii. identifying the presence/level of customer-specific investment in each transmission and distribution account, and identifying an average amount of customer-specific infrastructure per account associated with each size of meter.

d. Empire will maintain all sales data, to the extent that such data currently exists and in the same degree of specificity, on a class basis, for February 2021.

22. **REP Tariff**

The parties agree to update the Empire-proposed REP Tariff in the following manner

a. Update the 30 day effective date for REC rate changes to at least 60 days

b. Incorporate the provisions intended for the service agreement
c. Include a cap on the number of RECs available to the program. Initially the cap should be set at 15% of the expected RECs produced from the three wind projects, North Fork Ridge, Neosho Ridge, and Kings Point Wind Farms. The cap may be evaluated and adjusted on an annual basis. Empire shall provide Staff with the cap and all supporting calculations on an annual basis.
d. Incorporate a requirement that the wind resources from which the RECs would be sourced are specified, and that Empire be required to provide an attestation to each participating customer specifically delineating the RECs retired on behalf of that customer.

23. **Green Button**: Customers served with an Advanced Metering Infrastructure ("AMI") meter will have online access to data from their AMI meter and be able to download data for all accounts by March 31, 2024, with the Empire having a goal to provide such access by March 31, 2023. If determined to be economically feasible, these capabilities will include the ability to download data for all customer accounts."

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ATTORNEYS FOR THE EMPIRE DISTRICT ELECTRIC COMPANY

Residential Service		Current Rates		Billing Units	Current Revenue
Summer					
Customer Charge		$ 13.00		536,516	$ 6,974,708
Energy Charge					
1st 600		$ 0.12535		274935563	$ 34,463,173
Over 600		$ 0.12535		315,610,819	$ 39,561,816
Total kWh				590,546,382	
Winter					
Customer Charge		$ 13.00		1073032	$ 13,949,416
Energy Charge					
1st 600		$ 0.12535		542979770	$ 68,062,514
Over 600		$ 0.10093		593401156	$ 59,891,979
Total kWh				1,136,380,926	
Pre-MEEIA		$ 0.00045			$ 777,117
Total Residential					$ 223,680,723

		Current Rates		Billing Units	Current Revenue
Commercial Service					
Summer					
Customer Charge		$22.69		74,200	$ 1,683,598
Energy					
1st 700		0.12712		35,369,416	$ 4,496,160
Over 700		0.12712		85,792,993	$ 10,906,005
Total kWh				121,162,409	
Winter					
Customer Charge		$22.69		148,400	$ 3,367,196
Energy					
1st 700		0.12712		109,531,349	$ 13,923,625
Over 700		0.11377		89,255,961	$ 10,154,651
Total kWh				198,787,310	
Pre-MEEIA		0.00045		318,771,288	$ 143,447
Total Commercial					$ 44,674,682

		Current Rates		Billing Units	Current Revenue	
Small Heating Service						
Summer						
Customer Charge		$22.69		12,204	$	276,909
Energy						
1st 700		0.12441		6,436,900	$	800,815
Over 700		0.12441		19,153,826	$	2,382,927
Total kWh				25,590,726		
Winter						
Customer Charge		$22.69		24,408	$	553,818
Energy						
1st 700		0.12441		13,210,668	$	1,643,539
Over 700		0.09172		40,998,181	$	3,760,353
Total kWh				54,208,849		
Pre-MEEIA		0.00045		78,378,257	$	35,270
Total Small Heating					$	9,453,631

	Current Rates	Billing Units	Current Revenue
General Power Service			
Summer			
Customer Charge	$69.49	7,196	$ 500,050
Energy			
1st 150	0.08694	193,555,878	$ 16,827,748
Next 200	0.06745	192,341,255	$ 12,973,418
All Additional	0.06056	111,208,980	$ 6,734,816
Total kWh		497,106,113	
Demand Charge	$7.33	848,551	$ 6,219,881
Facilities Charge	$2.07	1,083,428	$ 2,242,696
Winter			
Customer Charge	$69.49	14,392	$ 1,000,100
Energy			
1st 150	0.07464	136,922,927	$ 10,219,927
Next 200	0.06078	130,063,877	$ 7,905,282
All Additional	0.06027	48,076,513	$ 2,897,571
Total kWh		315,063,318	
Demand Charge	$5.71	1,589,381	$ 9,075,365
Facilities Charge	$2.07	2,170,997	$ 4,493,965
Pre-MEEIA	0.00045	724,467,943	$ 326,011
Trans and minimum revenue			$ 488,687
Total General Power			$ 81,905,516

		Current Rates		Billing Units	Current Revenue	
Total Electric Building						
Summer						
Customer Charge		$69.49		3,744	$	260,171
Energy						
1st 150		0.10453		50,963,761	$	5,327,242
Next 200		0.08098		45,191,013	$	3,659,568
All Additional		0.07286		12,966,715	$	944,755
Total kWh				109,121,489		
Demand Charge		3.50		352,428	$	1,233,499
Facilities Charge		$2.13		565,534	$	1,204,587
Winter						
Customer Charge		$69.49		7,488	$	520,341
Energy						
1st 150		0.07897		98,855,072	$	7,806,585
Next 200		0.06324		72,551,106	$	4,588,132
All Additional		0.06197		39,412,961	$	2,442,421
Total kWh				210,819,138		
Demand Charge		2.88		797,985	$	2,298,196
Facilities Charge		$2.13		1,124,112	$	2,394,358
Pre-MEEIA		0.00045		306,773,101	$	138,048
Total Total Electric Building					$	32,817,903

PFM

	Units	Rates	Revenue
Customer	120	$27.65	$3,318
Summer			
1st 700	21718	$0.17527	$3,807
over 700	138016	$0.17527	$24,190
Winter			
1st 700	46750	$0.17527	$8,194
over 700	271014	$0.15871	$43,013
			$82,521

Large Power	**Current Rates**	**Usage**	**Revenue**
Summer			
Customer charge	$ 283.55	212	$ 60,113
Demand Charge (per kW)	$ 15.69	434504.5374	$ 6,817,376
Facilities Charge (per kW)	$ 1.88	476,697	$ 896,190
Energy Charge (first 350 hours)	$ 0.07	148,228,599	$ 9,698,597
All additional kWh	$ 0.03	74,984,383	$ 2,549,469
Total Revenue			**$ 20,021,745**
Winter			
Customer Charge	$ 283.55	294	$ 83,364
Demand Charge (per kW)	$ 8.66	1,305,098	$ 11,302,145
Facilities Charge (per kW)	$ 1.88	1,522,901	$ 2,863,054
Energy Charge (first 350 hours)	$ 0.06	443,198,167	$ 25,607,990
All additional kWh	$ 0.03	208,748,346	$ 6,826,071
Total Revenue			**$ 46,682,624**

Miscellaneous Service				
	Billing Units	Current Rates	Current Revenue
Customer Charge	24	$ 19.51	$ 468.24
Energy per kWh	135540	$ 0.0994	$ 13,472.68
Total Charges			$ 13,940.92

Special Lighting Service			
	Billing Units	Current Rates	Current Revenue
Customer Count	1457		
First 1000 kwh	335454	$ 0.16838	$ 56,483.74
Additional kwh	266483	$ 0.13057	$ 34,794.69
Total Charges			$ 91,278.43

Private Lighting Service			
	Billing Units	Current Rates	Current Revenue
Step_Desc			
110,000 Lumen MetalH FL	2545	$ 70.64	$ 179,778.80
12,000 Lumen MetalH FL	615	$ 24.76	$ 15,227.40
12,000 Lumen Std MetalH	1293	$ 23.87	$ 30,863.91
140,000 Lumen Sodium FL	4150	$ 69.39	$ 287,968.50
16,000 Lumen Std Sodium	39206	$ 20.59	$ 807,251.54
20,000 Lumen Mercury FL	475	$ 35.74	$ 16,976.50
20,000 Lumen Std Mercury	3223	$ 25.50	$ 82,186.50
20,500 Lumen MetalH FL	13	$ 32.79	$ 426.27
20,500 Lumen Std MetalH	1576	$ 31.86	$ 50,211.36
27,500 Lumen Sodium FL	5493	$ 34.62	$ 190,167.66
27,500 Lumen Std Sodium	2878	$ 29.76	$ 85,649.28
36,000 Lumen MetalH FL	2168	$ 48.34	$ 104,801.12
36,000 Lumen Std MetalH	1683	$ 35.74	$ 60,150.42
50,000 Lumen Sodium FL	4304	$ 47.49	$ 204,396.96
50,000 Lumen Std Sodium	4729	$ 34.52	$ 163,245.08
54,000 Lumen Mercury FL	424	$ 59.01	$ 25,020.24
54,000 Lumen Std Mercury	299	$ 48.88	$ 14,615.12
6,000 Lumen Std Sodium	79145	$ 14.15	$ 1,119,901.75
6,800 Lumen Std Mercury	38890	$ 15.32	$ 595,794.80
Total Charges			$ 4,034,633.21

Municipal Street Lighting Service			
	Billing Units	Current Rates	Current Revenue
Step_Desc			
11,000 Lumen Mercury	10302	$ 102.21	$ 87,747.29
12,000 Lumen MetalH	4355	$ 124.89	$ 45,324.66
13,000-16,000 LED	1198	$100.02	$ 9,985.33
130,000 Lumen HP Sodium	39	$ 299.00	$ 971.75
16,000 Lumen HP Sodium	100752	$ 99.90	$ 838,760.40
19,000-22,000 LED	8	$148.35	$ 98.90
20,000 Lumen Mercury	2898	$ 146.33	$ 35,338.70
20,500 Lumen MetalH	9465	$ 153.05	$ 120,718.19
27,500 Lumen HP Sodium	25652	$ 130.01	$ 277,918.04
36,000 Lumen MetalH	1502	$ 204.74	$ 25,626.62
4,000 Lumen Incandescent	104	$ 62.71	$ 6,521.84
50,000 Lumen HP Sodium	3113	$ 185.28	$ 48,064.72
53,000 Lumen Mercury	52	$ 246.88	$ 1,069.81
6,000 Lumen HP Sodium	21438	$ 79.80	$ 142,562.70
7,000 Lumen Mercury	99205	$ 85.16	$ 704,024.82
7,500-9,500 LED	7594	$ 74.03	$ 46,848.65
Total Charges			$ 2,391,582.42

Transmission Service			
	Billing Units	Current Rates	Current Revenue
Customer Charge		$ 259.01	$ 3,108.12
On-Peak Period	26793242	$ 0.0541	$ 1,045,010.62
Shoulder Period	6515055	$ 0.0437	$ 270,374.78
Off-Peak Period	37172785	$ 0.0337	$ 1,121,689.31
Billed Demand kW	98374.3	$ 25.16	$ 1,945,782.68
Facility Demand kW	98640.9	$ 0.50	$ 49,320.45
Total Charges			$ 4,435,285.96

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Request of The Empire District Electric Company d/b/a Liberty for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in its Missouri Service Area	)))))	Case No. ER-2021-0312

SECOND PARTIAL STIPULATION AND AGREEMENT

COME NOW the Staff of the Missouri Public Service Commission ("Staff"), the Office of the Public Counsel ("OPC"), and The Empire District Electric Company d/b/a Liberty ("Empire"), by and through their respective counsel, and for the parties' Second Partial Stipulation and Agreement ("Second Stipulation"),[1] respectfully state as follows the Missouri Public Service Commission ("Commission"):

1. Issue No. 3 of the Amended List of Issues reads as follows: "Should the Commission order Empire to report additional details of its reliability investment programs?"

2. With this Second Stipulation, Issue No. 3 is resolved as follows: Empire agrees to update the status of its reliability improvement projects and expenditures in a format similar to Schedule JW-1 of Jeff Westfall's direct testimony, with Staff and Empire to meet first to discuss the goals of the increased reporting. The additional information will be included with the reliability improvement program annual report currently required by the Commission's rule and will be submitted as a non-case filing in EFIS.

3. Issue No. 5 of the Amended List of Issues, Project Guardian, reads as follows: (a) Should the Commission order Empire to meet with Staff and OPC on Project Guardian? (b) Should the Commission order Empire to meet with Staff and OPC on all other "pilots" the Company is currently running or plans to run.

4. With this Second Stipulation, Issue No. 5 is resolved as follows: Empire will meet with Staff and OPC on Project Guardian.

5. Issue No. 12 of the Amended List of Issues, Billing, reads as follows:

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[1] Midwest Energy Consumers Group ("MECG"), Renew Missouri Advocates ("RenewMO"), the City of Ozark, Missouri ("Ozark"), Empire District Retired Members & Spouses Association, LLC ("EDRA"), and The Empire District Electric Company SERP Retirees, LLC ("EDESR") are also parties to this proceeding. Although not signatories, these parties do not object to the approval of this Second Stipulation. As such, the Commission may treat it as unanimous.

(a) Should the Commission order Empire to meet with Staff and OPC at least twice before its next rate case regarding input on the feasibility of future bill revisions with the intent to update the bill's contents in a cost-effective and customer informative manner moving forward?
(b) Should Empire be ordered to update its bill and its website with the following information within one month (or sooner) of rates going into effect in this case?
- Provide a link to the SAFHR website https://www.mohousingresources.com/safhr and not the Company's website;
- Include some supporting messaging containing relevant information (i.e., what it is, how one can participate, etc.) regarding Project Help;
- Include language containing contact information regarding Low-Income Weatherization Assistance Program ("LIWAP") enrollment; and
- Add language that directs further billing questions to a hyperlink to the Company's website which provides an FAQ of greater billing detail (e.g., this is what a MEEIA surcharge is, this is what the FAC is, what do TOU rates mean, etc.).

6. With this Second Stipulation, Issue No. 12 is resolved as follows: Empire to update its bill with references to SAFHR or the website with easy to use information, within 60 days of rates going into effect in this case.

   - Provide a link to the SAFHR website https://www.mohousingresources.com/safhr and not the Company's website;
   - Include a link to supporting messaging containing relevant information (i.e., what it is, how one can participate, etc.) regarding Project Help;
   - Include a link to language containing contact information regarding Low-Income Weatherization Assistance Program ("LIWAP") enrollment; and
   - Add language that directs further billing questions to a hyperlink to the Company's website which provides an FAQ of greater billing detail (e.g., this is what a MEEIA surcharge is, this is what the FAC is, what do TOU rates mean, etc.).

7. Issue No. 16(d) of the Amended List of Issues reads as follows: "Should the Commission order Empire District Electric Company to provide additional information regarding the bearing deformation associated with turbine-79 of the Neosho Ridge wind farm?"

8. With this Second Stipulation, Issue 16(d) is resolved as follows: Empire agrees to provide to Staff: (1) quarterly summary results of the Bearing Monitoring Plan, as provided to the Class A members; (2) annual costs to comply with Section 6.10(v) of the LLCA; (3) notice of exceedance of tolerances identified by the Bearing Monitoring plan and bearing failure; (4) notice of warranty expirations for the component; and (5) in the event of a failure, identification of all costs to remedy the T-79 bearing deformation, including but not limited to: replacement cost, labor costs, identification of other components that require replacement as a result of the bearing issue, PTC replacement costs, all "Damages," as defined by the LLCA, paid to Class A members, and total cost to remedy the bearing issue.

Respectfully submitted,

ATTORNEYS FOR THE EMPIRE DISTRICT ELECTRIC COMPANY

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CERTIFICATE OF SERVICE

I hereby certify that the above document was filed in EFIS on this 31st day of January, 2022, and sent by electronic transmission to all counsel of record.

__/s/ Diana C. Carter______

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Request of The Empire District Electric Company d/b/a Liberty for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in its Missouri Service Area	)))))	Case No. ER-2021-0312

STIPULATION AND AGREEMENT AS TO EDRA

COME NOW The Empire District Electric Company ("Empire") and the Empire District Retired Members & Spouses Association, LLC ("EDRA") (together, the "Signatories"), by and through their respective counsel, and for their Stipulation and Agreement as to EDRA ("Stipulation"),[1] respectfully state as follows to the Missouri Public Service Commission ("Commission"):

1. Issue 25 on the Amended List of Issues submitted herein on January 28, 2022, reads as follows: Is Empire meeting the merger stipulation employee benefit obligations to its retired employees?

2. The Signatories hereto agree to resolve the issue as follows:

> Empire will not make any change to any benefit offering (defined as the health benefit design and cost sharing mechanism) that would be materially adverse to any person qualifying for such benefit as of January 1, 2017, so long as (1) there is no material change of applicable state or federal law, rule or regulation, or the application of existing law, that would impair the ability of Empire to provide the benefit or substantially increases the cost to Empire of providing the benefit; or (2) there is no change to the Commission's current practice authorizing the tracking and cost recovery of benefit offerings and including such costs in cost of service for ratemaking purposes. Empire agrees to use its best efforts to include in cost of service the expense of the benefit offerings. The parties agree that Empire may cease to maintain a stand-alone retiree health plan covering Empire retirees exclusively and that Empire, at any time, may integrate the Empire retirees into another retiree plan offered by Liberty.

[1] The Staff of the Commission, the Office of the Public Counsel, Midwest Energy Consumers Group, Renew Missouri Advocates, the City of Ozark, and The Empire District Electric Company SERP Retirees are also parties to this proceeding. Although not signatories, these parties do not object to the approval of this Stipulation and Agreement as to EDRA. As such, the Commission may treat it as unanimous.

Notice of any disputes or controversy concerning the continued availability of a benefit offering shall be provided to the opposing party in writing not less than thirty (30) days prior to the initiation of any adjudicative action or proceeding to enforce this commitment, including arbitration.

Arbitration will only be used to resolve any dispute by the mutual agreement of the parties. If arbitration is agreed to by the parties, then the American Arbitration Association (AAA) rules shall govern such proceeding, with a petition to be filed with the AAA unless the parties mutually agree to waive such requirement. Each party shall select one (1) AAA approved arbitrator, and the two (2) party selected AAA arbitrators shall then select a neutral third AAA approved arbitrator, with such third neutral AAA approved arbitrator costs to be shared by the parties. All arbitrators shall be experts in the field of the dispute. Each party shall bear the costs associated with the arbitration, including, but not limited to, legal fees and arbitrator costs for the arbitrator that party selects. All arbitrations shall be held in Joplin, Missouri or in such other location as the parties may agree. All procedural schedules shall be set by the arbitration panel, with the final order issued no later than one-hundred fifty (150) days from the date of the written notice of dispute. All arbitration awards are binding on the parties.

The parties agree that section 386.315, RSMo., ("A public utility which uses Financial Accounting Standard 106 shall be required to use an independent external funding mechanism that restricts disbursements only for qualified retiree benefits") and the Empire VEBA Trust Agreements, specifically the fourth "whereas" paragraph ("WHEREAS, the funds held by the Trustee pursuant to this Agreement will be held for the exclusive benefit of existing and future beneficiaries in accordance with the terms of the Company's health and welfare plan documents;") require that the assets of the Empire VEBA Trust be segregated from other VEBA assets of Liberty and that such Empire VEBA Trust assets be used for the exclusive benefit of eligible Empire retirees. EDRA shall be notified anytime of the intent to modify or amend the Empire VEBA Trust Agreements.

Subject to compliance with applicable privacy and consent laws, the Company shall provide to EDRA on a quarterly basis a spreadsheet listing the name and mailing address of all new Empire retirees or changes in the status of current Empire retirees and surviving spouses.

3. To the extent the above language conflicts with Section (2) of the STIPULATION AND AGREEMENT AS TO EDRA, Retirees Plan, approved by the Commission in Case EM-2016-0213, the Signatories seek modification or waiver of the prior stipulation. All other provisions of the STIPULATION AND AGREEMENT AS TO EDRA, Case EM-2016-0213, remain unchanged.

WHEREFORE, the Signatories hereto recommend that the Commission approve this Stipulation and Agreement.

Respectfully submitted,

By: /s/ Diana C. Carter
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ATTORNEYS FOR EDRA

CERTIFICATE OF SERVICE

I hereby certify that the above document was filed in EFIS on this 4th day of February, 2022, and sent by electronic transmission to all counsel of record.

_/s/ Diana C. Carter________

List of Sub-Accounts Included and Excluded for FAC

GL	Descriptions
501	**Included:**
501042	Fuel -Coal
501045	Fuel -Oil
501054	Fuel -Natural Gas
501183	Sales Of Ash
501211	Ineffect (Gain)Loss Deri Steam
501212	Effective (Gn)Lss Deriv Steam
501216	NonFAS133Deriv(Gain)/LossSteam
501300	Fuel -Tires
501401	Ops Mtls-Fuel Handling
501607	Fuel Adm E Trader Commission
501	**Excluded:**
501011	Conv & Seminar-Fuel
501400	Ops Labor-Fuel Handling
501601	Fuel Administration -Asbury
501604	Fuel Administration -Riverton
501605	Fuel Administration Plum Point
547	**Included:**
547205	Natural Gas SLCC Tolling
547206	Nat Gas-Tollng SLCC Ineffectiv
547207	Nat Gas-Tolling SLCC Effective
547208	Comb Turb Fuel Sales -Nat Gas
547210	Combust Turb Fuel Natural Gas
547211	Ineffect (Gain)Loss Deriv Gas
547212	Effective (Gain)Loss Deriv Gas
547213	Fuel -No 2 Oil Fuel
547301	NonFAS133 Deriv (Gain)/Loss
547607	Fuel Adm E Traders Commission
547	**Excluded:**
547605	Fuel Adm State Line
547606	Fuel Adm Energy Center
547210	Natural Gas Fixed Transportation and Fixed Storage Only
411	**Included:**
411800	Gains-Disposition Emmiss Allow
509	**Included:**
509052	Emission Allowance Exp

GL	Descriptions
506	**Included:**
506127	Limestone Expense -Iatan
506128	Powdered Activated Carbon
506129	Ammonia Expense
506201	Limestone Expense
506202	Ammonia Expense
506203	Powdered Activated Carbon
506204	Lime Expense
548	**Included:**
548202	Ammonia Expense
447	**Included:**
447113	Gen Ark Off-Sys Sale-Resale
447124	Gen Ks Off-System Sale-Resale
447133	Gen Mo Off-Sys Sale-Resale
447143	Gen Ok Off-Sys Sales-Resale
447810	SPP IM Revenue -AR
447820	SPP IM Revenue -KS
447830	SPP IM Revenue -MO
447840	SPP IM Revenue -OK
447849	SPP IM Revenue -Wind [*]
447850	SPP IM Revenue
447860	Bilateral/Off Line Aux Revenue
447851	MJMEUC Revenue
447861	MJMEUC FAC Revenue Excluding Long-Term
447	**Excluded:**
447430	Aec -Off-Sys-Missouri
447540	Oklahoma G R D A Off-System
447610	Energy Imbalance -Arkansas
447620	Energy Imbalance -Kansas
447861	MJMEUC FAC Revenue Long-Term Capacity Only [#]
447630	Energy Imbalance -Missouri
447640	Energy Imbalance -Oklahoma
457	**Excluded:**
457131	Oth El Rev-Sched Sys Ctrl&Disp
457137	Ot El RvOffSys LTFSTF PTP Trns [#]
457138	Ot El RvOffSys NnFrm PTP Trns [#]
457139	Ot El RvOffSys NITS Rev
457140	Oth El Rev-Off-Sys Losses
457141	Sch 11 NITS
457142	Sch 11 PTP
457160	Sch 1 PTP

GL	Descriptions
555	**Included:**
555430	Direct Purchases
555431	Purchase Power Tolling Fees
555432	Energy Imbalance
555437	Interrupt Svc Compensation
555800	DA Asset Energy
555810	DA Non-Asset Energy
555820	DA Virtual Energy
555840	DA Reg-Up
555850	DA Reg-Down
555860	DA Spinning
555870	DA Supplemental
555880	DA Other PP Expense
555900	RT Asset Energy
555910	RT Non-Asset Energy
555920	RT Virtual Energy
555940	RT Reg-Up
555950	RT Reg-Down
555960	RT Spinning
555970	RT Supplemental
555980	RT Other PP Expense
555990	TCR Activity
555995	ARR Activity
565	**Included:**
565413	Trans Of Electricity By Others
565414	SPP Fixed Chg -Native Load Exclude S1-A
565415	SPP Var Chg Exclude Schedule 12 Only
565416	Non SPP Fixed Chg -Native Load
565417	PP Non SPP Var -Native Load
565418	Gen Non SPP Var -Native Load
565419	Off Sys Sales Trans Costs
565	**Excluded:**
565414	SPP Schedule 1-A only
565415	SPP Schedule 12 Only
575	**Excluded:**
575700	IM Market Facilitation, Monitor [*]
456	**Included:**
456071	Misc Elec Rev-Green Credits-AR
456072	Misc Elec Rev-Green Credits-KS
456073	Misc Elec Rev-Green Credits-MO
456074	Misc Elec Rev-Green Credits-OK
456075	REC Revenue
456215	REC Revenue - Wind Post-Stub Period [*]

Footnotes: **[*] indicates new account.**
[#] indicates account previously excluded from FAC.

Definitions of Accounts Included and Excluded from Empire's FAC

GL	Descriptions	Details	
501042	Fuel - Coal	Coal costs used in steam generation - includes coal, freight, railcar lease, property tax on railcars, railroad maintenance (material and labor), railcar maintenance, coal handling costs (equipment, repairs, fuel, labor)	
501045	Fuel - Oil	Oil costs used in steam generation - includes oil, freight, handling costs	
501054	Fuel - Natural Gas	Natural gas costs used in steam generation - includes gas, pipeline transportation cost	
501183	Sales Of Ash	Proceeds form the sale of coal ash	
501211	Ineffect (Gain)Loss Deri Steam	Ineffective gain/loss on FAS133 derivatives for steam generation - **currently not used**	
501212	Effective (Gn)Less Deriv Steam	Effective gain/loss on FAS133 derivatives for steam generation - **currently not used**	
501216	NonFAS133Deriv(Gain)/LossSteam	Gain/loss on Non-FAS133 derivatives for steam generation	
501300	Fuel - Tires	Tire costs used in steam generation	
501401	Ops Mtls-Fuel Handling	Fuel Handling materials costs - Plum Point	
501607	Fuel Adm E Trader Commission	Commission expense for derivatives for steam generation - **currently not used**	
547205	Natural Gas SLCC Tolling	Natural gas costs used in combustion turbine generation - SLCC Tolling - **currently not used**	
547206	Nat Gas-Tollng SLCC Ineffectiv	Ineffective gain/loss on FAS133 derivatives for combustion turbine generation - SLCC Tolling - **currently not used**	
547207	Nat Gas-Tolling SLCC Effective	Effective gain/loss on FAS133 derivatives for combustion turbine generation - SLCC Tolling - **currently not used**	
547208	Comb Turb Fuel Sales - Nat Gas	Sales of natural gas	
547210	Combust Turb Fuel Natural Gas	Natural gas costs used in steam generation - includes gas, pipeline transportation cost	
547211	Ineffect (Gain)Loss Deriv Gas	Ineffective gain/loss on FAS133 derivatives for combustion turbine generation - **currently not used**	
547212	Effective (Gain)Loss Deriv Gas	Effective gain/loss on FAS133 derivatives for combustion turbine generation - **currently not used**	
547213	Fuel - No 2 Oil Fuel	Oil costs used in combustion turbine generation	
547301	NonFAS133 Deriv (Gain)/Loss	Gain/loss on Non-FAS133 derivatives for combustion turbine generation	
547607	Fuel Adm E Traders Commission	Commission expense for derivatives for combustion turbine generation - **currently not used**	
411800	Gains-Disposition Emmiss Allow	Gain on disposition of Emission Allowances	
456071	Misc Elec Rev-Green Credits-AR	Revenue for sale of Renewable Energy Credits -allocated to Arkansas	
456072	Misc Elec Rev-Green Credits-KS	Revenue for sale of Renewable Energy Credits -allocated to Kansas	
456073	Misc Elec Rev-Green Credits-MO	Revenue for sale of Renewable Energy Credits -allocated to Missouri	
456074	Misc Elec Rev-Green Credits-OK	Revenue for sale of Renewable Energy Credits -allocated to Oklahoma	
457137	Ot El RvOffSys LTFSTF PTP Trns	Firm Point-to-Point Revenue	
457138	Ot El RvOffSys NnFrm PTP Trns	Non-Firm Point-to-Point revenue	
457141	Sch 11 NITS	Network transmissions service revenue	
457142	Sch 11 PTP	Point-to-point Schedule 11 revenue (through & out)	
457160	Sch 1 PTP	Schedule 1 Point-to-point revenue	
506127	Limestone Expense - Iatan	AQCS limestone expense - Iatan	
506128	Powdered Activated Carbon	AQCS powdered activated carbon expense	
506129	Ammonia Expense	AQCS ammonia expense	
506201	Limestone Expense	AQCS limestone expense - Iatan	
506202	Ammonia Expense	AQCS ammonia expense	
506203	Powdered Activated Carbon	AQCS powdered activated carbon expense - Iatan	
506204	Limestone Expense	AQCS limestone expense - Plum Point	
509052	Emission Allowance Expense	Emissions Allowance Expense	
548202	Ammonia Expense	AQCS ammonia expense - SLCC	
447113	Gen Ark Off-Sys Sale-Resale	Off-System Sales of energy - allocated to Arkansas - **currently not used**	
447124	Gen Ks Off-System Sale-Resale	Off-System Sales of energy - allocated to Kansas - **currently not used**	
447133	Gen Mo Off-Sys Sale-Resale	Off-System Sales of energy - allocated to Missouri - **currently not used**	
447143	Gen Ok Off-Sys Sales-Resale	Off-System Sales of energy - allocated to Oklahoma - **currently not used**	
447851	MJMEUC Revenue	Revenue from MJMEUC Contract	
447861	MJMEUC FAC Revenue	MJMEUC FAC Revenue Excluding Long-Term Capacity	
447860	Bilateral Sales	Off-System Sales of energy - allocated to Oklahoma	
555430	Direct Purchases	Long-term PPA's, MISO congestion and losses, AECI Line losses, MISO Inadvertent, MISO Schedule 24, MISO ARR Distribution, MISO ARR Transaction, MISO Miscellaneous	
555431	Purchase Power Tolling Fees	Energy/Capacity fee for Combined Cycle - Westar - **currently not used**	
555432	Energy Imbalance	Purchases for EIS - **currently not used**	
555437	Interrupt Svc Compensation	Compensation given to interruptible customers for interrupting their service related to load shedding events	
555800	DA Asset Energy	Net Day Ahead Asset Energy, netted by MWh position (purchase or sale) per settlement interval - Settlement of the net Day Ahead Market energy position at an Asset Owner's resources and loads.	Integrated Market energy charge types performed on an hourly basis for each operating day and based on the results of the Day Ahead Market clearing.

555810	DA Non-Asset Energy	Net Day Ahead Non Asset Energy, netted by MWh position (purchase or sale) per settlement interval - Settlement of the net Day Ahead Market energy position at interchange locations into and out of SPP footprint.	
555820	DA Virtual Energy	Net Day Ahead Virtual Energy, netted by MWh position (purchase or sale) per settlement interval - Settlement of the net Day Ahead Market energy position of cleared virtual transactions, financial only now mwhs.	
555840	DA Reg-Up	Net Day Ahead Regulation-Up Amount & Day Ahead Regulation-Up Distribution Amount, netted by dollars (revenue or expense) per settlement interval - settlement for Regulation-Up cleared to an asset owner's zonal obligation.	Integrated Market operating reserve charge types, these help to ensure reliability within the market. Regulation-up and regulation-down maintain the balance between load and generation. Spinning and supplemental are available in the event of outages.
555850	DA Reg-Down	Net Day Ahead Regulation-Down Amount & Day Ahead Regulation-Down Distribution Amount, netted by dollars (revenue or expense) per settlement interval - settlement for Regulation-Down cleared to an asset owner's zonal obligation.	
555860	DA Spinning	Net Day Ahead Spinning Amount & Day Ahead Spinning Distribution Amount, netted by dollars (revenue or expense) per settlement interval - settlement for Spinning cleared to an asset owner's zonal obligation.	
555870	DA Supplemental	Net Day Ahead Supplemental Amount & Day Ahead Supplemental Distribution Amount, netted by dollars (revenue or expense) per settlement interval - settlement for Supplemental cleared to an asset owner's zonal obligation.	
555880	DA Other	Other Day Ahead charges that settle at the EDE_EDE Load node including: DA Make Whole Payment (MWP), DA MWP Distribution, DA Over-collected losses Distribution Amount, DA Demand Reduction (DR), DA DR Distribution Amount, DA Grandfathered Agreement (GFA) Carve-Out Daily, DA GFA Carve-Out Monthly, DA GFA Carve-Out Yearly, GFA Carve-Out Distribution Daily Amount, GFA Carve-Out Distribution Monthly Amount, GFA Carve-Out Distribution Yearly Amount, DA Virtual Transaction Fee Amount, Day-Ahead Combined Interest Resource Adjustment Amount; DA and Reliability Unit Commitment (RUC) Make-Whole Payment (MWP); Revenue Neutrality Uplift (RNU) Distribution Amount; DA Combined Interest Resource Adjustment Amounts, Day-Ahead Ramp Capability Up Amount, Day-Ahead Ramp Capability Down Amount,Day-Ahead Ramp Capability Up Distribution Amount, Day-Ahead Ramp Capability Down Distribution Amount	See Below
555900	RT Asset Energy	Net Real Time Asset Energy, netted by MWh position (purchase or sale) per settlement interval - Settlement of the net Real Time Market energy position at an Asset Owner's resources and loads.	Integrated Market energy charge types performed on a dispatch interval basis (5 minutes)for each operating day and are based on the difference between the results of the Real Time Balancing Market process and the Day Ahead Market Clearing..
555910	RT Non-Asset Energy	Net Real Time Non Asset Energy, netted by MWh position (purchase or sale) per settlement interval - Settlement of the net Real Time Market energy position at interchange locations into and out of SPP footprint.	
555920	RT Virtual Energy	Net Real Time Virtual Energy, netted by MWh position (purchase or sale) per settlement interval - Settlement of the net Real Time Market energy position of cleared virtual transactions, financial only now mwhs.	
555940	RT Reg-Up	Net Real Time Regulation-Up Amount & Real Time Regulation-Up Distribution Amount, netted by dollars (revenue or expense) per settlement interval - settlement for Regulation-Up cleared to an asset owner's zonal obligation.	Integrated Market operating reserve charge types, these help to ensure reliability within the market. Regulation-up and regulation-down maintain the balance between load and generation. Spinning and supplemental are available in the event of outages.
555950	RT Reg-Down	Net Real Time Regulation-Down Amount & Real Time Regulation-Down Distribution Amount, netted by dollars (revenue or expense) per settlement interval - settlement for Regulation-Down cleared to an asset owner's zonal obligation.	
555960	RT Spinning	Net Real Time Spinning Amount & Real Time Spinning Distribution Amount, netted by dollars (revenue or expense) per settlement interval - settlement for Spinning cleared to an asset owner's zonal obligation.	
555970	RT Supplemental	Net Real Time Supplemental Amount & Real Time Supplemental Distribution Amount, netted by dollars (revenue or expense) per settlement interval - settlement for Supplemental cleared to an asset owner's zonal obligation.	
555980	RT Other	Other RT charges that settle at the EDE_EDE Load node including: Reliability Unit Commitment (RUC) MWP, RUC MWP Distribution Amount, RT Over Collected Losses Distribution Amount, RT Regulation Non-performance, RT Regulation Non-performance Distribution, RT Contingency Reserve Deployment Failure, RT Contingency Reserve Deployment Failure Distribution Amount, RT Regulation Deployment Adjustment, RT Out of Merit, RT Joint Operating Agreement, RT Reserve Sharing Group (RSG), RT RSG Distribution Amount, RT Demand Response, RT Demand Response Distribution Amount, RT Revenue Neutrality Uplift Distribution, RT Miscellaneous, RT Pseudo-Tie Congestion Amount, RT Pseudo-Tie Losses Amount, RT unused Reg-up mileage make whole payment, RT unused Reg-down mileage make whole payment, Real-Time Combined Interest Resource Adjustment Amount, Real-Time Ramp Capability Up Amount, Real-Time Ramp Capability Down Amount, Real-Time Ramp Capability Up Distribution Amount, Real-Time Ramp Capability Down Distribution Amount, Real-Time Capability Non-Performance Amount, Real-Time Capability Non-Performance Distribution Amount	See Below
555990	TCR Activity	All Transmission Congestion Rights charges including: TCR Funding Amount, TCR Daily Uplift Amount, TCR Monthly Payback Amount, TCR Annual Payback Amount, TCR Annual Closeout Amount, TCR Auction Transaction Amount	See Below
555995	ARR Activity	All ARR Charges including: Auction Revenue Rights Funding Amount, ARR Uplift Amount, ARR Monthly Payback Amount, ARR Annual Payback, ARR Annual Closeout Amount,	See Below
555999	Purchased Power - Net Metering	Purchased power expense from net system credits to net metering customers	
565413	Trans Of Electricity By Others	Transmission clearing account, balance is always zero.	
565414	SPP Fixed Chg - Native Load	Charges related to SPP activities allocated largely on load ratio share. Charges are primarily comprised of Schedule 1A Tariff administration, Schedule 11 Base Plan Funding (Zonal & Regional), Schedule 1 System Control Scheduling, and Dispatch, and any other SPP charges related to network service	
565415	SPP Var Chg - Native Load	Charges related to SPP activities that are largely allocated on native load. Charges primarily consist of Schedule 12 FERC administration and any other SPP charges related to Point-to-point service	
565416	Non SPP Fixed Chg -Native Load	Charges related to activity from non-SPP RTO/ISO/entities. Charges primarily consist of MISO charges: Schedule 7 PTP service, Schedule 26 Transmission expansion, Schedule 1 Scheduling, System Control and Dispatch, Schedule 2 Reactive Power, Schedule 10 FERC fees, and Schedule 33 Black Start Service, and Schedule 45 NERC fees	
565417	PP Non SPP Var -Native Load	The Non-SPP variable transmission charges are those charges assessed to Empire for the delivery of electricity from generation resources located outside of the SPP footprint into the SPP footprint and then into Empire's transmission buss for native load.	

565418	Gen Non SPP Var -Native Load	These charges include transmission charges for both owned generation and purchased generation that is used to serve Empire's native load wholesale and retail customers. The majority of these charges are associated to Empire's ownership and purchase positions with respect to Plum Point.	
565419	Off Sys Sales Trans Costs	Transmission expense for off-system sales. - c**urrently not used**	
575700	Schedule 1A2-1A4 -- Market Facilitation	SPP Administrative expense related to recovering the costs of running the TCR, Real-Time, and Day-Ahead Markets-**New Charge Account**	
447810	SPP IM Revenue - AR	The Arkansas share of any and all of the above charge types that net to a revenue per the appropriate netting procedure(s) - **currently not used**	
447820	SPP IM Revenue - KS	The Kansas share of any and all of the above charge types that net to a revenue per the appropriate netting procedure(s) - **currently not used**	
447830	SPP IM Revenue - MO	The Missouri share of any and all of the above charge types that net to a revenue per the appropriate netting procedure(s) - **currently not used**	
447840	SPP IM Revenue - OK	The Oklahoma share of any and all of the above charge types that net to a revenue per the appropriate netting procedure(s) - **currently not used**	
447849	SPP IM Revenue - Wind	SPP IM Revenue associated to the Empire owned Wind	
447850	SPP IM Revenue	Any and all of the above charge types that net to a revenue per the appropriate netting procedure(s)	
456075	REC Revenue	Revenue from the sae of Renewable Energy Credits (excludes Empire owned Wind Projects).	
456215	REC Revenue - Wind Post-Stub Period	Revenue from the sale of Renewable Energy Credits from Empire owned Wind Projects (NR, KP, NFR)	

Day Ahead Other Charges

Day Ahead Make Whole Payment	Any resource that is committed by SPP during the Day Ahead market is eligible to recover the eligible costs associated with the commitment period.
Day Ahead Make Whole Payment Distribution	Cost allocation of Make Whole Payments for resources committed in the Day Ahead market to cleared loads.
Day Ahead Over Collected Loss Distribution	Rebate of surplus collected as a result of the marginal pricing of losses.
Day Ahead Demand Reduction	Charge or credit required in order to remove the settlement impact of grossing up the host load by the amount of the Demand Response Reduction output.
Day Ahead Demand Reduction Distribution	Charge or credit for each asset owner in which a Demand Response Reduction was cleared in order to fund the credits paid for the Demand Response Reduction.
Day Ahead Virtual Transaction Fee	Fee for virtual bids and offers.
Day Ahead Grandfathered Agreement (GFA) Carve-Out Daily Amount	Day-ahead credit or charge for the exclusion of transactions associated with GFA's from market settlement of congestion, losses, and hedging instruments.
Day Ahead Grandfathered Agreement (GFA) Carve-Out Monthly Amount	Monthly credit or charge for the exclusion of transactions associated with GFA's from market settlement of congestion hedging instruments.
Day Ahead Grandfathered Agreement (GFA) Carve-Out Yearly Amount	Yearly credit or charge for the exclusion of transactions associated with GFA's from market settlement of congestion hedging instruments.
Day Ahead Grandfathered Agreement (GFA) Carve-Out Daily Distribution Amount	A GFA carve-out credit or charge determined by the Asset Owners load ratio share for GFA revenue inadequacy.
Day Ahead Grandfathered Agreement (GFA) Carve-Out Monthly Distribution Amount	A monthly charge or credit to ensure SPP revenue neutrality relating to the reversal of credits of GFA carve-outs through monthly TCR and ARR Payback.
Day Ahead Grandfathered Agreement (GFA) Carve-Out Yearly Distribution Amount	A monthly charge or credit to ensure SPP revenue neutrality relating to the reversal of credits of GFA carve-outs through yearly TCR payback, TCR Closeout, ARR Payback, ARR Closeout.
Day-Ahead Combined Interest Resource Adjustment Amount	Charge or Credit representing the Day-Ahead Balancing Market charges and credits associated with the CIR designated Resource calculated based on the Interest Percent Share for each AO's registered individual share.
Day-Ahead and Reliability Unit Commitment (RUC) Make-Whole Payment (MWP)	These charge types have been updated to ensure SPP assesses the revenue and cost associated with the Ramp Capability products
Revenue Neutrality Uplift (RNU) Distribution Amount	This charge type sums up all the charge types in its calculation. SPP must modify this charge type to include the Ramp Capability
DA Combined Interest Resource Adjustment Amounts	Combined Interest Resources are treated as one resource. Therefore, these charge types have to be modified to split the exact amount of Ramp Capability
Day-Ahead Ramp Capability Up Amount	Market settle or charge for DA Ramp Up capability
Day-Ahead Ramp Capability Down Amount	Market settle or charge for DA Ramp Down capability
Day-Ahead Ramp Capability Up Distribution Amount	Market charge or credit by asset owner per reserve zone for DA Ramp Capability Up supplied
Day-Ahead Ramp Capability Down Distribution Amount	Market charge or credit by asset owner per reserve zone for DA Ramp Capability Down supplied

Real Time Other Charges

Reliability Unit Commitment Make Whole Payment	Revenue guarantee to resources committed economically in the Real Time to cover eligible costs.
Reliability Unit Commitment Make Whole Payment Distribution	Cost allocation of Make Whole Payment for resources committed in RUC to an asset owner's Real Time deviations.

Real Time Over Collected Loss Distribution	Rebate of surplus collected as a result of the marginal pricing of losses.
Real Time Regulation Deployment Adj Amount	Adjustment to resource revenue for the combined impact of Energy and Regulation deployment.
Real Time Regulation Non-Performance	Charge when a resource with cleared Real Time Regulation-up and or Regulation-down operates outside of the operating tolerance
Real Time Regulation Non-Performance Distribution	Cost allocation of penalties collected for Regulation Non-Performance
Real Time Contingency Deployment Failure	Penalty for failing to provide Contingency Reserve amount when deployed.
Real Time Contingency Deployment Failure Distribution	Cost allocation of penalties collected for Contingency Reserve failure.
Out of Merit	Adjustment to compensate resources for additional cost incurred as a result of being manually dispatched away from the optimal point.
Real Time Joint Operating Agreement	Settlement for price coordination of a co-managed reciprocal flowgatge.
Real Time Reserve Sharing Group Amount	Settlement for response to Contingency Reserve event.
Real Time Reserve Sharing Group Distribution Amount	Asset owners payment, based on real time load ratio share, for response to a contingency event, by an RSG entity.
Real Time Demand Reduction	Credit or charge relating to the difference between the actual demand response reduction output and what was cleared in the day-ahead market.
Real Time Demand Reduction Distribution	Credit or charge to asset owners for each hour in which a demand response resource was dispatched.
Real Time Revenue Neutrality Uplift	Credit of charge calculated at each settlement location for each asset owner for each hour in order for SPP to remain revenue neutral.
Unused Reg-Up Mileage Make Whole Payment	A credit for each asset owner that is charged for unused regulation-up mileage at a rate that is in excess of the asset owners regulation-up mileage offer to the extent the resources regulation-up service margin is not sufficient to offset the charge induced by the difference in the two rates.
Unused Reg-Down Mileage Make Whole Payment	A credit for each asset owner that is charged for unused regulation-down mileage at a rate that is in excess of the asset owners regulation-down mileage offer to the extent the resources regulation-down service margin is not sufficient to offset the charge induced by the difference in the two rates.
Real Time Misc	Charge or credits that cannot be handled through standard Settlement billing.
Real Time Pseudo-Tie Congestion Amount	Real time congestion amount for resource or load that is pseudo-tied out of SPP balancing authority.
Real Time Pseudo-Tie Losses Amount	Real time loss amount for resource or load that is pseudo-tied out of SPP balancing authority.
Real-Time Combined Interest Resource Adjustment Amount	Charge or Credit representing the Real-Time Balancing Market charges and credits associated with the CIR designated Resource calculated based on the Interest Percent Share for each AO's registered individual share.
Real-Time Ramp Capability Up Amount	A RTBM charge or credit for deviations between cleared RTBM Ramp Capability Up and cleared DR Market Ramp Capability Up
Real-Time Ramp Capability Down Amount	A RTBM charge or credit for deviations between cleared RTBM Ramp Capability Down and cleared DR Market Ramp Capability Down
Real-Time Ramp Capability Up Distribution Amount	A RTBM charge or credit equal to asset owner's real-time load ratio share of the net RTBM ramp capability up procurement amounts
Real-Time Ramp Capability Down Distribution Amount	A RTBM charge or credit equal to asset owner's real-time load ratio share of the net RTBM ramp capability down procurement amounts
Real-Time Capability Non-Performance Amount	A RTBM charge or credit calculated for each asset owner for each interval when a resource with cleared RT ramp up or RT ramp down, or both, operates outside of its operating tolerance
Real-Time Capability Non-Performance Distribution Amount	A RTBM charge or credit equal to asset owner's real-time load ratio share of the RT ramp capability non-performance amount

TCR Activity

Transmission Congestion Rights (TCR) Auction Transaction	Settlement of the purchase or sale of a TCR instrument at auction.
TCR Funding	Credit or charge calculated for each TCR instrument held by an asset owner incurred by load bid into the Day Ahead market.
TCR Daily Uplift	Allocation of the deficit between congestion collections and TCR funding in Day Ahead.
TCR Monthly Payback	Use of excess congestion in a month to payback uplift in that month.
TCR Annual Payback	Use of excess congestion in a year to payback remaining uplift in that year.
TCR Annual Closeout	Allocation of the net difference between Auction Revenue Rights value and the daily settlement of TCR Auctions

ARR Activity

Auction Revenue Right (ARR) Funding	Settlement of an ARR instrument by the TCR auction price.
ARR Daily Uplift	Allocation of the net difference between ARR value and the daily settlement of TCR auctions.
ARR Monthly Payback	Use of excess auction revenue in a month to payback uplift in that month.
ARR Annual Payback	Use of excess auction revenue in a year to payback uplift in that year.
ARR Annual Closeout	Allocation of the net difference between Auction Revenue Rights value and the daily settlement of TCR Auctions

Mapping of FAC Subaccounts

[redacted]

#	Description	Accounts
1	Coal Commodity and railroad transportation	501042, 501400, 501401, 501601, 501604, 501605
2	switching and demurrage charges	501042
3	applicable taxes	501042
4	natural gas costs	501054
5	alternative fuels	501300
6	fuel additives	501042
7	Btu adjustments assessed by coal suppliers	501042
8	Quality adjustments assessed by coal suppliers	501042
9	Fuel hedging costs	501211, 501212, 501216
10	fuel adjustments included in commodity and transportation costs	501042
11	broker commissions and fees associated with price hedges	501607
12	oil costs	501045
13	propane costs	
14	combustion product disposal revenues and expenses	501183
15	consumables related to AQCS (ammonia, lime, limestone, powder activated carbon, urea, sodium bicarbonate, & trona)	506127, 506128, 506129, 506201, 506202, 506203, 506204
16	settlement proceeds	
17	insurance recoveries	
18	subrogation recoveries for increased fuel expenses in Account(s) 501	
19	Conv & Seminar-Fuel	501011

[redacted]

#	Description	Accounts
1	Natural gas generation costs related to commodity	547205, 547206, 547207, 547208, 547210, 547605, 547606
2	oil	547213
3	transportation	547210
4	storage	547210
5	capacity reservation	547210
6	fuel losses	547210
7	hedging costs for natural gas	547211, 547212, 547301
8	oil	547213
9	natural gas used to cross-hedge purchased power	
10	fuel additives/consumables	548202
11	settlement proceeds	
12	insurance recoveries	
13	subrogation recoveries for increase fuel expenses	
14	broker commissions	547607
15	fees and revenues and expenses resulting from fuel and transportation portfolio optimization activities	
16		

[redacted]

#	Description	Accounts
1	Net Emission Allowances	411800, 509042

[redacted]

#	Description	Accounts
1	Revenue from off-system sales, including MJMEUC contract	447113, 447124, 447133, 447143, 447810, 447820, 447830, 447840, 447849, 447850, 447851 ,447860, 447861, 447430, 447540, 447610, 447620, 447630, 447640

[redacted]

#	Description	Accounts
1	Renewable Energy Credit Revenue	456071, 456072, 456073, 456074, 456075,456215
2		
3		
4		
5		

[redacted]

#		Description	Accounts
1		Purchased Power costs	555430
2		PPA demand (capacity) cost (< 1 Year PPA)	Have not incurred any costs of this kind since the inception of the IM and future costs are variable and thus unable to be estimated
3		settlements	Have not incurred any costs of this kind since the inception of the IM and future costs are variable and thus unable to be estimated
4		insurance recoveries	Have not incurred any costs of this kind since the inception of the IM and future costs are variable and thus unable to be estimated
5			
6		subrogation recoveries for purchased power expenses	Have not incurred any costs of this kind since the inception of the IM and future costs are variable and thus unable to be estimated
7		virtual energy charges	555820, 555920
8		generating unit price adjustments	Have not incurred any costs of this kind since the inception of the IM and future costs are variable and thus unable to be estimated
9		load/export charges	555910, 555810
10		energy position charges	555800, 555900
11		ancillary services including penalty & distribution charges	555840, 555850, 555860, 555870, 555940, 555950, 555960, 555970
12		broker commissions	Have not incurred any costs of this kind since the inception of the IM and future costs are variable and thus unable to be estimated
13		fees and margins	Have not incurred any costs of this kind since the inception of the IM and future costs are variable and thus unable to be estimated
		SPP energy marketing charges including but not limited to:	
14	14a	Energy	555800, 555810, 555820, 555900, 555910, 555920
	14b	Ancillary Services	555840, 555850, 555860, 555870, 555940, 555950, 555960, 555970
	14c	Revenue Sufficiency	555880
	14d	Losses	Losses are now handled through the market and are a component of the LMP which will be reflected in the Energy (555800-555820 & 555900-555920)
	14e	Revenue Neutrality	555880
	14f	Congestion Management	555990, 555995
	14g	Demand Reduction	555880
	14h	Grandfathered Agreements	555880
	14i	Virtual Transaction Fee	555880
	14j	Psuedo Tie	555980
	14k	Miscellaneous	555980
	14l	Day-Ahead Combined Interest Resource Adjustment Amount	555880
	14m	Real-Time Combined Interest Resource Adjustment Am	555980
	14n	DA Ramp Products	555880
	14o	RT Ramp Products	555980
		Non-Spp costs/revenues (MISO, PJM, etc)	555430
17		Costs not received from centrally administrated market including:	
18	16a	Costs for purchases of energy	Have not incurred any costs of this kind since the inception of the IM and future costs are variable and thus unable to be estimated
	16b	Costs for purchases of generation capacity (< 1 year)	Have not incurred any costs of this kind since the inception of the IM and future costs are variable and thus unable to be estimated
	16c		
		SPP NITS service Charges (Schd 11)	565413, 565414, 457141, 457142
19		SPP Point-to-point revenue	
20		Oth El Rev-Sched Sys Ctrl&Disp	457131
21	18a	Schedule 7 - Firm PTP	457137
22	18b	Schedule 8 Non-firm PTP	457138
23	18c	Oth El Rev-Off-Sys Losses	457140
	18d	Schedule 1 Sc	565414, 457160
		Schedule 1a - SPP Tariff Administration	565414
		SPP Schedule 12 - FERC Assesssment	565415
		Non SPP costs/revenues associated with:	
	21a	Network transmission service	565418
	21b	Point-to-point transmission	565416, 565417, 565419
24	21c	System control & dispatch	565416
25	21d	Reactive supply & voltage control	565416
		SPP Schd1A Market Facilitation Expense	575700
		Purchased power from net metering	555999

FUEL & PURCHASE POWER ADJUSTMENT CLAUSE
RIDER FAC
For service on and after ~~September 16, 2020~~

The two six-month accumulation periods, the two six-month recovery periods and filing dates are set forth in the following table:

Accumulation Periods	**Filing Dates**	**Recovery Periods**
September–February	By April 1	June–November
March–August	By October 1	December–May

The Company will make a Fuel Adjustment Rate ("FAR") filing by each Filing Date. The new FAR rates for which a filing is made will be applicable starting with the Recovery Period that begins following the Filing Date. All FAR filingsshall be accompanied by detailed workpapers with subaccount detail supporting the filing in an electronic format withall formulas intact.

DEFINITIONS

ACCUMULATION

PERIOD:
The six calendar months during which the actual costs and revenues subject to this rider will be accumulated for the purpose of determining the FAR.

RECOVERY PERIOD:
The billing months during which a FAR is applied to retail customer usage on a per kilowatt-hour ("kWh") basis.

BASE ENERGY COST:
Base energy cost is ordered by the Commission in the last rate case consistent with the costs and revenues included in the calculation of the Fuel and Purchase Power Adjustment ("FPA").

BASE FACTOR ("BF"):
The base factor is the base energy cost divided by net generation kWh determined by the Commission in the lastgeneral rate case. BF = $0.0~~2338~~0870 per kWh for each accumulation period.

FUEL & PURCHASE POWER ADJUSTMENT CLAUSE
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APPLICATION

FUEL & PURCHASE POWER ADJUSTMENT

$$FPA = \{[(FC + PP + E - OSSR - REC - B) * J] * 0.95\} + T + I + P$$

Where:

FC = Fuel c~~C~~osts, excluding decommissioning and retirement costs, i~~I~~ncurred to ~~S~~support ~~S~~sales and revenues associated with the Company's in-service generating plants, consisting of the following:

The following costs reflected in Federal Energy Regulatory Commission ("FERC") Accounts 501 and 506: coal commodity and railroad transportation, switching and demurrage charges, applicable taxes, natural gas costs, alternative fuels (i.e. tires, and bio-fuel), fuel additives, Btu adjustments assessed by coal suppliers, quality adjustments assessed by coal suppliers, fuel hedging costs, fuel adjustments included in commodity and transportation costs, broker commissions and fees associated with price hedges, oil costs, combustion product disposal revenues and expenses, consumable costs related to Air Quality Control Systems ("AQCS") operation, such as ammonia, lime, limestone, and powdered activated carbon, and settlement proceeds, insurance recoveries, subrogation recoveries for increased fuel expenses in Account 501.

The following costs reflected in FERC Accounts 547 and 548: natural gas generation costs related to commodity, oil, transportation, fuel losses, hedging costs for natural gas and oil, fuel additives, and settlement proceeds, insurance recoveries, subrogation recoveries for increased fuel expenses, broker commissions and fees.

PP = Purchased Power Costs:

1. Costs and revenues for purchased power reflected in FERC Account 555, excluding 1) all charges under Southwest Power Pool ("SPP") Schedules 1a and 12, and 2) amounts associated with energy purchased from the SPP market to serve research and development projects of the Company. Such costs include:

FUEL & PURCHASE POWER ADJUSTMENT CLAUSE
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For service on and after ~~September 16, 2020~~

A. SPP costs or revenues for SPP's energy and operating market settlement charge types and market settlement clearing costs or revenues including:

i. Energy;
ii. Ancillary Services;
 a. Regulating Reserve Service
 b. Energy Imbalance Service
 c. Spinning Reserve Service
 d. Supplemental Reserve Service
iii. Revenue Sufficiency;
iv. Revenue Neutrality;
v. Demand Reduction;
vi. Grandfathered Agreements;
vii. Virtual Energy including Transaction Fees;
viii. Pseudo-tie;
ix. Combined Interest Resource Adjustments;
~~viii.~~x. Ramp Products; and
~~ix.~~xi. Miscellaneous;

B. Non-SPP costs or revenue as follows:

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

C. Settlements, insurance recoveries, and subrogation recoveries for purchased power expenses.

2. Costs of purchased power will be reduced by expected replacement power insurance recoveries qualifying as assets under Generally Accepted Accounting Principles.

3. Transmission service costs reflected in FERC Account 565:

FUEL & PURCHASE POWER ADJUSTMENT CLAUSE
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A. ~~Thirty-four~~Nineteen point three nine percent (~~34~~19.39%) of SPP costs associated with Network Transmission Service:
   i. SPP Schedule 2 – Reactive Supply and Voltage Control from Generation or Other Sources Service;
   ii. SPP Schedule 3 – Regulation and Frequency Response Service; and
   iii. SPP Schedule 11 – Base Plan Zonal Charge and Region-wide Charge.

B. Fifty percent (50%) of Mid-Continent Independent System Operator ("MISO") costs associated with:

   i. Network transmission service;
   ii. Point-to-point transmission service;
   iii. System control and dispatch; and
   iv. Reactive supply and voltage control.

~~4. Costs and revenues not specifically detailed in Factors FC, PP, E, or OSSR shall not be included in the Company's FAR filings; provided however, in the case of Factors PP or OSSR the market settlement charge types under which SPP or another market participant bills / credits a cost or revenue need not be detailed in Factors PP or OSSR for the costs or revenues to be considered specifically detailed in Factors PP or OSSR; and provided further, should the SPP or another market participant implement a new charge type, exclusive of changes in transmission revenue. The list of sub-accounts included will be provided in the FAC Monthly Reports.~~

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

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

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

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

FUEL & PURCHASE POWER ADJUSTMENT CLAUSE
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For service on and after ~~September 16, 2020~~

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

~~F. A party other than the Company may seek the inclusion of a new charge type in a FAR filing by making a filing with the Commission no less than 60 days before the Company's next FAR filing. Such a filing shall give the Commission notice that such party believes the new charge type should be included because it possesses the characteristics of, and is of the nature of, the costs or revenues listed in factors PP or OSSR, as the case may be. The party's filing shall identify the proposed accounts affected by such new charge type cost or revenue, provide a description of the new charge type demonstrating that it possesses the characteristics of, and is of the nature of, the costs or revenues listed in factors PP or OSSR as the case may be, and identify the preexisting market settlement charge type(s) which the new charge type replaces or supplements. If a party makes the filing provided for by this paragraph F and a party (including the Company) challenges the inclusion, such challenge will not delay inclusion of the new charge type in the FAR filing or delay approval of the FAR filing. To challenge the inclusion of a new charge type, the challenging party shall make a filing with the Commission based upon that party's contention that the new charge type costs or revenues at issue should not have been included, because they do not possess the characteristics of the costs or revenues listed in Factors PP or OSSR, as the case may be. The challenging party shall make its filing challenging the inclusion and stating the reasons why it believes the new charge type does not possess the characteristic of the costs or revenues listed in Factors PP or OSSR, as the case may be, within 30 days of the filing that seeks inclusion of the new charge type. In the event of a timely challenge, the party seeking the inclusion of the new charge type shall bear the burden of proof to support its contention that the new charge type should be included in the Company's FAR filings. Should such challenge be upheld by the Commission, any such costs will be refunded (or revenues retained) through a future FAR filing in a manner consistent with that utilized for Factor P.~~

FUEL & PURCHASE POWER ADJUSTMENT CLAUSE
RIDER FAC
For service on and after ~~September 16, 2020~~

E = Net Emission Costs: The following costs and revenues reflected in FERC Accounts 509 and 411 (or any other account FERC may designate for emissions expense in the future): emission allowance costs offset by revenues from the sale of emission allowances including any associated hedging.

OSSR = Revenue from Off-System Sales (Excluding revenue from full and partial requirements sales to municipalities with the exception of the revenue received net of cost from the sale of energy to the Southwest Missouri Power Electric Pool for service from the effective date of new rates in ER-2021-0312~~June 1, 2020~~ through~~-~~ May 31, 2025):

The following revenues or costs reflected in FERC Account 447: all revenues from off-system sales and SPP energy and operating market including (see Note A. below):

i. Energy;
ii. Capacity Charges associated with Contracts shorter than 1 year;
iii. Ancillary Services including;
  a. Regulating Reserve Service
  b. Energy Imbalance Service
  c. Spinning Reserve Service
  d. Supplemental Reserve Service
iv. Revenue Sufficiency;
v. Losses;
vi. Revenue Neutrality;
vii. Demand Reduction;
viii. Grandfathered Agreements;
ix. Pseudo-tie;
x. Miscellaneous; and
xi. Hedging.

REC = Renewable Energy Credit Revenue reflected in FERC Account 456 from the sale of Renewable Energy Credits that are not needed to meet the Renewable Energy Standard.

Costs and revenues not specifically detailed in Factors FC, PP, E, or OSSR shall not be included in the Company's FAR filings; provided however, in the case of Factors PP or OSSR the market settlement charge types under which SPP or another market participant bills / credits a cost or revenue need not be detailed in Factors PP or OSSR for the costs or revenues to be considered specifically detailed in Factors PP or OSSR; and provided further, should the SPP or another market participant implement a new charge type, exclusive of changes in transmission revenue.

HEDGING COSTS:

Hedging costs are defined as realized losses and costs (including broker commission fees and margins) minus realized gains associated with mitigating volatility in the Company's cost of fuel, fuel additives, fuel transportation, emission allowances and purchased power costs, including but not limited to, the Company's use of derivatives whether over-the-counter or exchanged traded including, without limitation, futures or forward contracts, puts, calls, caps, floors, collars and swaps.

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

~~With respect to the Company's North Fork Ridge, Neosho Ridge, and Kings Point wind projects, costs associated with the wind projects and revenue generated from the wind projects shall not be passed through to customers via the Fuel Adjustment Clause before the wind projects' revenue requirements are included in rates.~~

FUEL & PURCHASE POWER ADJUSTMENT CLAUSE
RIDER FAC
For service on and after ~~September 16, 2020~~

B = Net base energy cost is calculated as follows:

$B = (S_{AP} * \$0.0$~~2338~~0870)

S_{AP} = Actual net system input (“NSI”), excluding the energy used by Company research and development projects, at the generation level for the accumulation period.

J = $\frac{\text{Missouri retail kWh sales}}{\text{Total system kWh sales}}$

Where Total system kWh sales includes sales to municipalities that are associated with Empire and excludes off-system sales.

T = True-up of over/under recovery of FAC balance from prior recovery period as included in the deferred energy cost balancing account. Adjustments by Commission order pursuant to any prudence review shall also be placed in the FPA for collection unless a separate refund is ordered by the Commission.

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

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

FUEL ADJUSTMENT RATE

The FAR is the result of dividing the FPA by estimated recovery period S_{RP} kWh, rounded to the nearest $0.00000. The FAR shall be adjusted to reflect the differences in line losses that occur at primary and secondary voltage by multiplying the average cost at the generator by the voltage adjustment factors (“VAF”) of 1.0429 and 1.0625, respectively. Any FAR authorized by the Commission shall be billed based upon customers’ energy usage on and after the authorized effective date of the FAR. The formula for the FPA is displayed below

$$FAR = \frac{FPA}{S_{RP}}$$

FUEL & PURCHASE POWER ADJUSTMENT CLAUSE
RIDER FAC
For service on and after ~~September 16, 2020~~

Where:

S_{RP} = Forecasted Missouri NSI kWh for the recovery period excluding energy projected to be used by Company research and development projects.

= Forecasted total system NSI * $\frac{\text{Forecasted Missouri retail kWh sales}}{\text{Forecasted total system kWh sales}}$

Where Forecasted total system NSI ~~kWh sales~~ includes kWh sales to municipalities that are associated with Empire and excludes off-system sales and energy projected to be used by Company research and development projects.

GENERAL RATE CASE/PRUDENCE REVIEW

The following shall apply to this FAC, in accordance with Section 386.266.5, RSMo. and applicable Missouri Public Service Commission Rules governing rate adjustment mechanisms established under Section 386.266, RSMo:

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

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

TRUE-UP OF FPA

In conjunction with an adjustment to its FAR, the Company will make a true-up filing with an adjustment to its FAC on the first Filing Date that occurs after completion of each Recovery Period. The true-up adjustment shall be the difference between the FPA revenues billed and the FPA revenues authorized for collection during the true-up recovery period, i.e. the true-up adjustment. Any true-up adjustments or refunds shall be reflected in item T above and shall include interest calculated as provided for in item I above.

THE EMPIRE DISTRICT ELECTRIC COMPANY d.b.a. LIBERTY

P.S.C. Mo. No. 6 Sec. 4 2nd Revised Sheet No. 17g

Canceling P.S.C. Mo. No. 6 Sec. 4 1st Original Sheet No. 17g

For ALL TERRITORY

FUEL & PURCHASE POWER ADJUSTMENT CLAUSE
RIDER FAC
For service on and after ~~June 1, 2021~~

	Accumulation Period Ending		~~February 28~~August 31, 2022
1	Total Energy Cost (TEC) = (FC + PP + E – OSSR - REC)		~~255,868,458~~0
2	Net Base Energy Cost (B)	-	~~60,428,674~~0
	2.1 Base Factor (BF)		0.0~~2344~~0870
	2.2 Accumulation Period NSI (S_{AP})		~~2,578,334,000~~0
3	(TEC-B)		~~195,439,784~~0
~~4~~	~~Missouri Energy Ratio (J)~~	~~*~~	~~90.18[1]~~
4~~5~~	Sum of Monthly (TEC - B) * J		~~176,248,936[2]~~0
5~~6~~	Fuel Cost Recovery	*	95.00%
6~~7~~	Sum of Monthly (TEC - B) * J * 0.95		~~167,436,489~~0
7~~8~~	Deferred Amount		~~(168,720,211)~~0
8~~9~~	True-Up Amount (T)	+	~~1,293,237~~0
9~~10~~	Prudence Adjustment Amount (P)	+	0
10~~1~~	Interest (I)	+	~~(9,515)~~0
11~~2~~	Fuel and Purchased Power Adjustment (FPA)	=	0
12~~3~~	Forecasted Missouri NSI (S_{RP})	÷	~~2,273,827,774~~0
1~~4~~3	Current Period Fuel Adjustment Rate (FAR)	=	0.00000
1~~5~~4	Current Period FAR_{PRIM} = FAR x VAF_{PRIM}		0.00000
15~~6~~	Current Period FAR_{SEC} = FAR x VAF_{SEC}		0.00000
1~~7~~6	VAF_{PRIM} = 1.0464		1.0464
17~~8~~	VAF_{SEC} = 1.0657		1.0657

~~[1]The Missouri Energy Ratio (J), on line 4, is calculated by dividing the Missouri retail kWh sales by the Total system kWh sales for the current accumulation period as specified by the tariff.~~

~~[2]The (TEC-B)*J, on line 5, is calculated by taking the sum of (TEC-B)*J for each month of the accumulation period. Therefore, because each month is weighted differently, the amount on line 5 will not necessarily equal the product of lines three and four.~~

THE EMPIRE DISTRICT ELECTRIC COMPANY d.b.a. LIBERTY

DATE OF ISSUE ~~April 1, 2021~~ DATE EFFECTIVE ~~June 1, 2021~~

ISSUED BY ~~Sheri Richard, Director Rates and Regulatory Affairs, Joplin, MO~~

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Request of The Empire District Electric Company d/b/a Liberty for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in its Missouri Service Area	)))))	Case No. ER-2021-0312

FOURTH PARTIAL STIPULATION AND AGREEMENT

COME NOW the Staff of the Missouri Public Service Commission ("Staff"), the Office of the Public Counsel ("OPC"), and The Empire District Electric Company d/b/a Liberty ("Empire") (collectively, the "Signatories"), by and through their respective counsel, and for the parties' Fourth Partial Stipulation and Agreement ("Fourth Stipulation"),[1] the Signatories respectfully state as follows the Missouri Public Service Commission ("Commission"):

1. The Signatories withdraw subpart (a) of Issue 13 (charitable contributions), without prejudice as to future proceedings, and Issues 14 (rate base issue), 15 (income statement issue), 18 (MPPM), 20 (transmission tracker), 26 (Asbury), 27 (resource adequacy), and 28 (Storm Uri) from the Amended Issues List and with the understanding that all components of Asbury and Storm Uri will be addressed in securitization proceedings.
2. When taken together, the stipulations resolve all issues in this proceeding other than 23 (class revenues responsibilities).
3. Issue #2, Voltage Optimization Study, of the Amended List of Issues reads as follows: (a) Should the Commission order Empire to issue a request for proposals for an independent, third-

[1] Midwest Energy Consumers Group ("MECG"), Renew Missouri Advocates ("RenewMO"), the City of Ozark, Missouri ("Ozark"), Empire District Retired Members & Spouses Association, LLC ("EDRA"), and The Empire District Electric Company SERP Retirees, LLC ("EDESR") are also parties to this proceeding. Although not signatories, these parties do not object to the approval of this Fourth Stipulation. As such, the Commission may treat it as unanimous.

party consultant to conduct a study in calendar year 2022 of its distribution system designed to gauge the costs and benefits of a voltage optimization program in Empire's service territory? (b) Should Empire be ordered to select a consultant based on ranked majority voting from Empire, Staff and OPC to have the cost/benefit study performed? (c) Should Empire be ordered to file the cost/benefit study in Empire's PISA docket with a target date on or before December 31, 2022?

4. With this Fourth Stipulation, Issue #2 is resolved as follows: Empire will issue a request for proposals for an independent, third-party consultant to conduct a study in calendar year 2022 of its distribution system designed to gauge the costs and benefits of a voltage optimization program in Empire's service territory. Empire will meet with Staff and OPC to discuss the RFP responses and possible next steps.

5. Issue #4, PISA, reads as follows: (a) Should the Commission order Empire to file cost-benefit analyses for investments greater than $1 million and outcome-based objective metrics (benchmarks) that include both baseline and target metrics in Case No. EO-2019-0046 by the end of the calendar year 2022? (b) If so, should Empire be ordered to meet with interested parties to discuss the parameters and assumptions surrounding the filing at least twice leading up to the filing? (c) Should Empire be ordered to update the studies and metrics on an annual basis as long as PISA is in place for Empire?

6. With this Fourth Stipulation, Issue #4 is resolved as follows: Empire will meet with Staff and OPC at least twice regarding "parameters and assumptions" and will provide to Staff and OPC, with HC confidentiality protection, cost-benefit analyses and performance metrics for planned capital investments of greater than $1 million. Empire agrees to file the cost-benefit analyses and performance metrics in its PISA docket and update annually.

7. Issue #6, Empire's Emergency Conservation Plan, reads as follows: Should Empire's Emergency Conservation Plan be modified to trigger phase I of the plan when SPP wholesale market energy prices reach $500/MWh ($0.50/kWh) and phase II when SPP wholesale market energy prices reach $1000/MWh ($1.00/kWh)? Issue #7, Value of Lost Load Study, reads as follows: Should Empire be required to engage with interested stakeholders at least twice for input regarding the scope, methodology, questions and goals of a value of lost load study to be conducted in calendar year 2022 before the cold weather season by an independent third party retained by Empire for purposes of recommending changes to Empire's Emergency Conservation Plan embodied in its tariff?

8. With this Fourth Stipulation, Issues 6 and 7 are resolved as follows: Empire, in consultation with Staff and OPC, will engage a consultant to develop a Value of Lost Load ("VOLL") study. Empire will issue a competitive request for proposal. Staff and OPC will have input on the selection of the consultant and the scope and timing of the study. Empire will be allowed to recover the costs of the study. Staff, OPC, and Empire, jointly, may elect not to pursue a VOLL study in the event the cost outweighs the expected benefits of such a study. When the study is complete, the Signatories may recommend to the Commission changes to Empire's tariff they believe are supported by the study's results. The Signatories also agree that Empire will immediately begin a review of its Emergency Conservation Plan and determine if any enhancements or improvements would be beneficial. Following that review, Empire will make a filing with the Commission proposing tariff changes or stating that Empire believes no such changes are needed.

9. In resolution of Issue #9, Late Fee, Empire's late fee will be reduced from 0.5% to 0.25%.

10. Issue #8 Low-Income Programs and Issue #10 Low-Income Weatherization Program ("LIWAP") respectively read as follows:

(a) Should the LIPP continue?
(b) If so, what, if any, modifications should be made?
(c) Should the Commission order Empire to implement a Keeping Current and Keeping Kool-like bill assistance program?
(d) If so, should the Commission order Empire to provide shareholder funding of $750,000 annually?
(e) Should the Commission order Empire to create a Critical Needs Program consistent with the Critical Needs Program the Commission approved in Case Nos: GR-2021-0108 and ER-2021-0240?
(f) If so, should the Commission order annual funding of $200,000, with funding split 50/50 between customers and shareholders, and with unspent funding allocated to Empire's bill assistance program?
(g) Should the Commission order Empire to fund a one-time independent 3rd party needs assessment study that should not exceed $100,000 in funding from Empire's bill assistance program.

and

(a) Should the budget for the LIWAP program be increased by $500,000?
(b) If so, should Empire be ordered to provide shareholder funding for this amount?
(c) Should the Commission order Empire to give the three agencies—Economic Security Corporation, Ozark Area Community Action Corporation, and West Central Missouri Community Action Agency—more discretion in how they may utilize funds from Empire?
(d) Should the Commission order Empire's Annual Low-Income meetings to continue to occur?

11. In resolution of both Issue #8, Low-Income Programs, and Issue #10, Low-Income Weatherization Program ("LIWAP"), the Signatories agree as follows:

a. Low-Income Pilot Program ("LIPP")
    i. Empire's LIPP will continue, with shareholders matching the $250,000 customer funding.
    ii. The requirement for payments to stay current within 60 days of bill date will be waived.
    iii. The LIPP discount will increase to two times the customer charge during the peak heating months of December through February and peak cooling months of June through August.
    iv. There will be a 2,000 customer cap.
    v. Unspent funds will rollover annually to Empire's low-income weatherization program.

vi. Updates will be provided twice a year to Staff and to OPC.

b. Low-Income Study
   i. Empire will perform a one-time study at a cost not to exceed $100,000.
   ii. Empire will work with stakeholders to discuss the study design and RFP.

c. Critical Needs Program
   i. Empire will establish a critical needs program consistent with the direct testimony of Geoff Marke in this docket funded annually with $50,000 by customers and $50,000 by shareholders.
   ii. Unspent funds will rollover annually to Empire's low-income weatherization program.

d. Low-Income Weatherization Program
   i. Total funding increased from $250,000 to $550,000 annually, with shareholders contributing $300,000.
   ii. Funding under this program will be momentarily freed up to include the option for pass-over, marketing, hiring, training, health and safety; relaxation of funding restrictions to be revisited in the next rate case.
   iii. Missouri Division of Energy will continue to have administrative oversight of this low-income weatherization program under these new terms.

e. Liberty Utilities Service Corp. will establish an employee position devoted to low-income programs in the Central Region (which includes Empire).

f. Customers who call in for bill assistance will be given the option to be referred to one of the three community action agencies ("CAAs") if they are interested in free weatherization.

g. Empire will continue to meet annually with stakeholders and the CAAs.

12. Issue #11 reads as follows: Should Empire be required to file its future annual company-specific J.D. Power Reports (not just the scores) in this docket together with memoranda that detail how Empire is improving its relationships with its customers in light of the J.D. Power Report scores of Empire relative to its peers, as well as its relative rank across the United States, and specifically as it pertains to its cost of service.

13. With this Fourth Stipulation, Issue #11 is resolved as follows: Until Empire files its next general rate case, Empire to provide an Empire-specific report on J.D. Power results (not just

the scores) in this docket, along with a pleading/memorandum responding to the report as the reports become available.

14. Issue #13(b) of the Amended List of Issues reads as follows: Should the Commission order Empire to remove the statement on its website about the $500,000 level of funding customers received from Liberty for COVID-19 relief?
15. In resolution of Issue 13(b), Empire will remove the statement on its website about the $500,000 level of funding customers received from Liberty for COVID-19 relief.
16. Issue #16 of the Amended List of Issues, Wind Projects, reads as follows: (a) Should rate base be reduced based on test generation wind revenue? (b) Should the amount of the rate base addition of the wind projects include reductions by the net revenues, RECs, and PTCs generated by the wind projects (including for test power) until the date new rates from this case become effective? (c) Should the amount of the rate base addition of the wind projects include reductions for the payments to Tenaska pursuant to the Purchase and Sale Agreement when it elected to terminate its role as contractor for two of the wind projects?
17. Issue #16 is resolved as follows: The first partial stipulation provided for a starting rate base amount of $2,049,632,599. Empire agrees to a $20 million reduction in rate base from that $2,049,632,599 to $2,029,632,599.
18. Issue #17 of the Amended List of Issues reads as follows: (a) Should Paygo be included as an FAC revenue? (b) Should Paygo be included in the general revenue requirement? (c)Should an estimated amount of Paygo be included in revenue requirement and the balance tracked and adjusted in the next general rate case?
19. In resolution of Issue #17, PAYGO, the Signatories agree that Paygo is not a FAC component for this case, and that a base amount of $4 million Paygo is contemplated in Empire's overall

revenue requirement. Empire will track its actual Paygo revenue amounts against the base amount and record them in a regulatory tracker account. Actual amounts of Paygo revenue received will be tracked against the base amount, which in this case is set at $4 million.

20. Issue #18 of the Amended List of Issues reads as follows: (a) Is it necessary and appropriate for the Commission to make changes to the MPPM in this case? (b) If so, (i) Should the rate base revenue requirement component remain formulaic or only change with the effective dates of new rates? (ii) What costs should be included? (iii)What revenues should be included? (iv) How should the PPA replacement value be calculated? (v) When should a jurisdictional allocation factor be applied? (vi)Should the MPPM include interest on the cumulative costs/gains? (vii)If the cumulative value at the end of ten years is a net cost, how should the net cost be shared between customers and Empire? (c)How should the components in Empire's MPPM be tracked?

21. In resolution of Issue #18, Market Price Protection Mechanism ("MPPM"), the Signatories agree as follows:

    a. Clarification only.

    b. -

        i. Rate base revenue requirement component only changes with the effective date of new rates.

        ii. All wind project costs recovered from customers will be included, not including the PISA costs.

        iii. All wind project revenues returned to customers, including SPP IM revenues, revenues from the sale of RECs, Paygo, the value of the production tax credits, and all miscellaneous revenues.

iv. A PPA replacement value will be calculated:

- For any renewable compliance standard not met by the existing wind PPAs through life of the MPPM;
- Based on the energy from the wind projects being used to meet the renewable standards that is not met by existing solar requirements (e.g., currently 2% of Missouri RES).

v. Costs and revenues included at the Missouri jurisdictional level.

vi. Interest at Empire's long-term debt rate (e.g., long-term debt will be the carrying costs) will be included.

vii. 50/50 split with soft cap of $52.5 million on customers' losses with Commission making determination on how additional losses, if any, are treated at the conclusion of the MPPM.

(c) All costs and revenue components shall be tracked including the revenues included in the FAC to assure that all costs and/or revenues are appropriately treated. Balances as of the end of each MPPM year will be submitted to the Commission 60 days following the end of each MPPM year. Since Paygo has a base amount included in the Wind Revenue Requirement, any amount above/below the base amount will be incorporated into the MPPM calculation to ensure a timely capturing of costs and/or revenues.

22. Issue #19 Fuel Adjustment Clause ("FAC") reads:

(a) Should the revised FAC subaccount testimony schedule submitted by Empire be adopted?
(b) Which FERC subaccounts, if any, should be added to Empire's FAC?
(c) Which FERC subaccounts, if any, should be removed from Empire's FAC?
(d) What should be included in the FAC base factor for this case?
(e) What is the percentage of SPP and MISO transmission expense that should be recovered through the FAC?

(f) What percentage of the SPP transmission revenues should be included in the FAC? What is the amount of transmission revenues that should be included in the FAC base factor calculation?
(g) What amount of REC revenues from the Wind Projects shall be included in the FAC base factor calculation?
(h) Should the wind project costs that Empire calls hedging costs/gains be included in the FAC?
   i. If yes, what amount of costs/gains should be included in the calculation of the FAC base factor?
(i) Should the paygo component of the wind project contracts be included in the FAC?
   i. If yes, what amount of paygo should be included in the calculation of the FAC base factor?
(j) Should the value of the wind project production tax credits transferred to Empire be included in the FAC?
(k) What additional FAC reporting requirements should the Commission require of Empire?
(l) How should the FAC tariff sheets be revised?
   i. Should the FAC tariff sheets include language that allows the Commission to allow a variance from any provision of the FAC?
   ii. Should the FAC tariff sheets include language that would allow for extended recovery periods?
   iii. Should the FAC tariff sheets explicitly prohibit recovery of retirement and/or decommissioning costs related to the retirement of a generation plant? If so, what language should be adopted?
   iv. Should the FAC tariff sheets explicitly prohibit recovery of fuel and purchased power costs for research and development? If so, what language should be adopted?

23. In resolution of Issue #19, Fuel Adjustment Clause ("FAC"), the Signatories agree as follows (listed by subissue):

(a) The revised FAC subaccount testimony schedule submitted by Empire will not be adopted.

(b)&(c) FERC subaccounts will be added and removed pursuant to Fourth Stipulation **Attachment A**.

(d) The FAC base factor for this case is $8.70 per MWh, Staff's base factor adjusted for the transmission expense change and the REC change described herein.

(e) The percentage of SPP and MISO transmission expense that should be recovered through Empire's FAC shall be based on those expenses in Staff's base factor calculation of 19.39% for SPP transmission expenses and 50% for MISO expenses.

(f) No SPP transmission revenues shall be recovered through Empire's FAC; therefore, no transmission revenues shall be included in the base factor of Empire's FAC.

(g) The amount of REC revenues from the wind projects in Empire's FAC base factor shall be based on a REC value of $2.44/REC.

(h) & (h)i. The Signatories agree that the wind project costs labeled as hedging costs/gains is not a FAC component for this case, and that a base amount of $0 is contemplated in Empire's overall revenue requirement. Empire will track its actual hedging costs/gains against the base amount and record them in a regulatory tracker account. Actual amounts of hedging costs/gains will be tracked against the base amount, which in this case is set at $0.

(i) & (i)i. The Paygo component of the wind project contracts will not be included in Empire's FAC; instead, it will be tracked against the base amount of $4 million included in revenue requirement in this case. The treatment of the tracked amount will be determined in Empire's next general rate case.

(j) The Signatories agree that the wind project production tax credits are not a FAC component for this case, and that a base amount of $0 is contemplated in Empire's overall revenue requirement. Empire will track its actual wind project production tax credits against the base amount and record them in a regulatory tracker account. Actual amounts of wind project production tax credits received will be tracked against the base amount, which in this case is $0.

(k) Empire will continue its existing reporting. Empire will provide copies of the reported notices and additional information to OPC and Staff; and the deadlines for Empire's quarterly FAC surveillance reports shall be the following:

Quarter Ending	Submission Deadline
March 31	May 30
June 30	August 31
September 30	November 30
December 31	February 28

(e) & (l)i-iv. Empire will revise its FAC tariff sheets to include the changes shown in Fourth Stipulation **Attachment B**, which are all of the agreed to changes.

24. Issue #21 Rate of Return, Return on Equity; Capital Structure; Cost of Debt reads:

(a) What return on common equity should be used for determining the rate of return?
(b) What capital structure should be used for determining the rate of return?
(c) What cost of debt should be used for determining rate of return?

25. Issue #22 Allowance for Funds Used During Construction reads: What metric should be used for Empire's carrying cost rate for funds it uses during construction that are capitalized?

26. Issue #21, Rate of Return, and Issue #22, Allowance for Funds Used During Construction, are resolved as follows:

The Signatories agree that AFUDC shall be calculated in accordance with the Federal Energy Regulatory Commission's ("FERC") Uniform System of Accounts for Electric Utilities formula (short-term debt receives 100% weighting until Construction Work in Progress Balances exceed short-term debt balances). For purposes of the calculation of rates, Empire's revenue requirement increase is an annual increase of $35,515,913.

27. Issue #24 reads as follows: Should the Commission allow Empire to book assets for general plant in accordance with the Federal Energy Regulatory Commission Accounting Release 15?

28. In resolution of Issue #24, Empire agrees to the following conditions for use of general plant amortization:

a. Empire will continue to specify the original cost and associated retirement units for all additions to the accounts where it is using General Plant Amortization accounting treatment.

b. Empire will regularly retire all assets that exceed the amortization period on at least a bi-annual basis.

c. Empire will retire the assets for plant-in-service and accumulated depreciation reserves that exceed the amortization period.

General Plant Amortization Account	**Total Company** **Fully Accrued Plant to be Retired**
391.1 - Office Furniture & Equip.	1,557,007
391.3 – Computer	9,814,564
393 - Stores Equip.	82,634
394 - Tools, Shop & Garage Equip.	1,910,684
395 - Laboratory Equip.	859,093
397 - Communication Equip.	4,697,886
398 - Misc. Equip.	28,997

d. Empire will provide a report to Staff and OPC when it implements general plant amortization that details any additional plant items Empire deems needs to be retired based on the implementation of FERC Accounting Release-15 that was not previously provided in response to OPC data request 8536 in Case No. ER-2021-0312. This report will detail each plant account where additional retirements are to take place, the asset retirement units to be retired, the original transaction year, and the original cost of the retirement units to be retired from service.

General Terms

29. Admission of Testimony: The Signatories consent to the admission of, and request that the Commission admit into the record in this proceeding, without the need for witnesses to take the stand, all written testimony that has been filed herein concerning the Issues addressed by this Fourth Stipulation.

30. Unless otherwise explicitly provided herein, none of the Signatories shall be deemed to have approved or acquiesced in any ratemaking or procedural principle, including, without limitation, any method of cost of service or valuation determination or cost allocation, rate design, revenue recovery, or revenue-related methodology. Except as explicitly provided herein, none of the Signatories shall be prejudiced or bound in any manner by the terms of this stipulation in this or any other proceeding. This stipulation has resulted from extensive negotiations among the Signatories, and the terms hereof are interdependent and non-severable. If the Commission does not approve this stipulation unconditionally and without modification, or if the Commission approves this stipulation with modifications or conditions to which a party objects, then this stipulation shall be void and none of the Signatories shall be bound by any of the agreements or provisions hereof.

31. In the event the Commission accepts the specific terms of this stipulation without condition or modification, as to the issues addressed by this stipulation, the Signatories waive their respective rights to present oral argument and written briefs pursuant to RSMo. §536.080.1, their respective rights to the reading of the transcript by the Commission pursuant to §536.080.2, their respective rights to seek rehearing pursuant to §386.500, and their respective rights to judicial review pursuant to §386.510. These waivers apply only to a Commission order approving this stipulation without condition or modification issued in this proceeding and only to the issues that

are resolved hereby. These waivers do not apply to any issues explicitly not addressed by this stipulation. The Signatories agree that any and all discussions, suggestions, or memoranda reviewed or discussed, related to this stipulation shall be privileged and shall not be subject to discovery, admissible in evidence, or in any way used, described or discussed.

32. This Fourth Stipulation contains the entire agreement of the Signatories concerning the issues addressed herein.

33. This Fourth Stipulation does not constitute a contract with the Commission. Acceptance of this Stipulation by the Commission shall not be deemed as constituting an agreement on the part of the Commission to forego the use of any discovery, investigatory powers or other statutory powers which the Commission presently has. Thus, nothing in this Fourth Stipulation is intended to impinge or restrict in any manner the exercise by the Commission of any statutory right, including the right to access information.

WHEREFORE, the Signatories respectfully request the Commission to issue an Order approving this Fourth Partial Stipulation and Agreement and authorizing Empire to file tariff sheets to implement the terms hereof.

Respectfully submitted,

ATTORNEYS FOR THE EMPIRE DISTRICT ELECTRIC COMPANY

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CERTIFICATE OF SERVICE

I hereby certify that the above document was filed in EFIS on this 5th day of February, 2022, and sent by electronic transmission to all counsel of record.

_/s/ Diana C. Carter______

STATE OF MISSOURI

OFFICE OF THE PUBLIC SERVICE COMMISSION

I have compared the preceding copy with the original on file in this office and I do hereby certify the same to be a true copy therefrom and the whole thereof.

WITNESS my hand and seal of the Public Service Commission, at Jefferson City, Missouri, this 9th day of March, 2022.

Morris L. Woodruff
Secretary

MISSOURI PUBLIC SERVICE COMMISSION

March 9, 2022

File/Case No. ER-2021-0312

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Enclosed find a certified copy of an Order or Notice issued in the above-referenced matter(s).

Sincerely,

Morris L Woodruff

Morris L. Woodruff
Secretary

Recipients listed above with a valid e-mail address will receive electronic service. Recipients without a valid e-mail address will receive paper service.