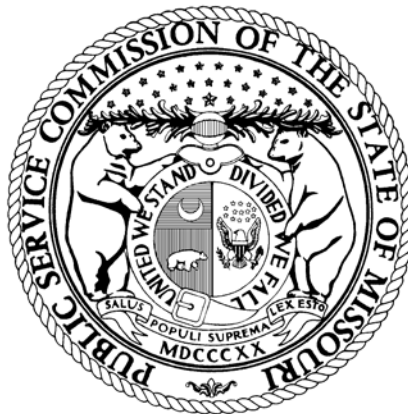


MISSOURI PUBLIC SERVICE COMMISSION

STAFF REPORT COST OF SERVICE



THE EMPIRE DISTRICT ELECTRIC COMPANY

CASE NO. ER-2019-0374

*Jefferson City, Missouri
January 15, 2020*

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1 **True-Up:** A true-up date generally is established when significant changes in a utility's
2 cost of service occur after the end of the update period, but prior to the operation-of-law date, and
3 one or more of the parties has decided these significant changes in cost of service should be
4 considered for cost-of-service recognition in the current case. True-up audits may involve the
5 filing of additional testimony and, if necessary, additional hearings beyond the initial testimony
6 filings and evidentiary hearings scheduled for a case. The true-up cut-off date ordered in this case
7 is January 31, 2020. Staff will file its true-up audit revenue requirement and recommendations as
8 part of its surrebuttal filing scheduled for March 27, 2020.

9 **Isolated Adjustment:** Isolated adjustments are adjustments proposed to capture the
10 financial impact of known and measurable events occurring outside of a test year/update
11 period/true-up period that will have a significant or material impact on the cost of service. The
12 inclusion of isolated adjustments in rates should not impact the overall matching of rate base,
13 revenues and expense items. In this case, Staff is proposing that certain isolated adjustments
14 associated with the impending retirement of the Asbury Unit be reflected in Empire's cost of
15 service.

16 **Normalization:** Utility rates are intended to reflect normal ongoing operations.
17 A normalization adjustment is required when the test year reflects the impact of an abnormal event.
18 For example, overtime expense may be normalized to remove an unusual weather event, and
19 revenue may be normalized to remove abnormal weather conditions.

20 **Annualization:** Annualization adjustments are the most common adjustment made to test
21 year results to reflect the utility's most current annual level of revenue and expenses.
22 Annualization adjustments are required when changes have occurred during the test year and/or
23 update period, which are not fully reflected in the unadjusted test year results. For example,
24 signing a new labor contract would necessitate annualizing the new level of wages to expense.
25 Similarly, an addition of a large industrial customer would necessitate an annualization of billing
26 determinants and revenues.

27 **Disallowances:** In examining test year results, Staff makes disallowances to costs that
28 should not be recovered in rates. Examples of these types of costs are certain advertising costs
29 and donations made to charitable organizations.

30 **Return on Equity:** The ROE is the return allowed in rates on the shareholders' equity
31 investment in a regulated utility.

1 **Rate of Return:** The rate of return (“ROR”) is the overall cost of capital; that is, the cost
2 of debt and the Commission-selected ROE weighted by the capital structure.

3 *Staff Expert/Witness: Kimberly K. Bolin*

4 **II. Background**

5 Empire provides electric utility service in Missouri, Kansas, Arkansas, and Oklahoma. As
6 of September 30, 2019, Empire serves approximately 174,625 retail electric customers throughout
7 its system of which approximately 155,567 are Missouri customers. Empire also provides water
8 utility services in Missouri. Empire owns and services The Empire District Gas Company
9 (“EDG”), an affiliated Missouri natural gas distribution business. Empire also owns and
10 services The Empire District Industries, Inc. (“EDI”) an affiliated Missouri non-regulated fiber
11 optic business.

12 Empire merged with Liberty Utilities (Liberty) on January 3, 2017. Empire and Liberty
13 are subsidiaries of Liberty Utilities, Co (“LUCo”). LUCo is wholly owned by Algonquin Power
14 & Utilities Company (APUC). Liberty provides gas, water and sewer service in Missouri and
15 other jurisdictions.

16 Empire last sought to change its Missouri jurisdictional electric retail rates in Case No.
17 ER-2016-0023. As a result of the Missouri Public Service Commission (“Commission”) Order
18 Approving Stipulation and Agreement in that proceeding, Empire was granted an annual rate
19 increase of \$20,390,000, effective September 9, 2016.

20 *Staff Expert/Witness: Kimberly K. Bolin*

21 **III. Test Year/True-Up Period**

22 Empire filed its case based upon a test year of the twelve-month period ending
23 March 31, 2019, and made adjustments to its case to reflect the impacts of anticipated changes
24 through the true-up period ending January 31, 2020. These dates were adopted by the Commission
25 in its Order Setting Procedural Schedule and Other Procedural Requirements issued on
26 October 17, 2019, which set the test year as the 12 months ending March 31, 2019, updated
27 through September 30, 2019, and trued-up to include known and measurable information through
28 January 31, 2020.

1 Based on currently available information, Staff’s revenue requirement as presented in its
2 Accounting Schedules includes a measurement of all major cost of service components. Staff’s
3 quantification of Empire’s revenue requirement as of September 30, 2019 is shown on Line 10 of
4 Staff Accounting Schedule 1, Revenue Requirement. Staff’s current estimate of the impact of the
5 future true-up audit through January 31, 2020 and certain Asbury retirement isolated adjustments
6 out through March 1, 2020 can be found on Line 11 of Staff Accounting Schedule 1, Allowance
7 for Known and Measurable Changes/True-up Estimate.

8 For purposes of the true-up audit, Staff will update the following items through
9 January 31, 2020; plant in service, depreciation reserve, other rate base items, payroll expense,
10 payroll-related benefits, fuel and purchased power costs, depreciation and amortization expense,
11 rate case expense, property taxes, related income tax effects, customer growth for revenues,
12 SPP transmission revenues and expense, capital structure, and debt costs used in determining the
13 rate of return.

14 *Staff Expert/Witness: Kimberly K. Bolin*

15 **IV. Rate of Return (Capital Structure, Cost of Debt, Cost of Equity)**

16 **A. Summary**

17 Staff estimated the market based cost of common equity (“COE”), and calculated an
18 authorized return on equity (“ROE”) recommendation, for Empire vertically integrated electric
19 utility operations using a comparative COE analysis. Staff’s analysis takes into account changes
20 in economic and capital market conditions by employing several widely used COE estimation
21 methodologies: the constant-growth discount cash flow model (“DCF”) and the capital asset
22 pricing model (“CAPM”). The comparative analysis method allowed Staff to calculate changes
23 in authorized ROE from period to period by using the Commission’s decision in the most recent
24 Spire Missouri, Inc. (“Spire Missouri”) rate cases¹ as a benchmark. To account for risk
25 differentials between the regulated electric and regulated gas industries, Staff utilized two proxy
26 groups: an electric proxy group and a gas proxy group. Staff’s gas proxy group is the same gas
27 proxy group Staff presented in the Spire Missouri rate cases.

¹ *In the matter of Spire Missouri*, Case Nos. GR-2017-0215 and GR-2017-0216 (*Report & Order*, issued February 21, 2018) at page 35.

1 In the Spire Missouri rate cases, the Commission authorized Spire Missouri an ROE of
 2 9.80%. At the time, Staff estimated a 6.96% COE for the gas proxy group, using market data from
 3 the period April, May, and June 2017. Staff’s updated COE for the gas proxy group, using market
 4 data from the period September, October, and November 2019, is 6.21%, indicating that the COE
 5 for the gas proxy group has decreased approximately 75 basis point (“bps”) since the Spire rate
 6 cases decision. Staff’s current COE estimated for Staff’s electric proxy group of 6.39% implies
 7 that the COE for the electric proxy group is 18 bps higher than for the gas proxy group. Based on
 8 its review of this information, Staff recommends an authorized ROE of 9.25%² for Empire District
 9 Electric Company. Staff also recommends that the Commission set Empire’s allowed Rate of
 10 Return (“ROR”) based on Empire’s capital structure as of September 30, 2019. The summary of
 11 Staff’s ROR recommendation is in the following Table:

12 **Table 1. Allowed Rate of Return**

Capital Component	Percentage of Capital	Embedded Cost	Allowed Rate of Return Using Common Equity Return of:		
			9.05%	9.25%	9.80%
Common Stock Equity	52.90%	-----	4.79%	4.89%	5.18%
Long-Term Debt	47.10%	4.76%	2.24%	2.24%	2.24%
Total	<u>100.00%</u>		<u>7.03%</u>	7.14%	7.43%

13
 14 The details of Staff’s analysis and recommendations are presented in Schedules PC-1 – PC-13 in
 15 Confidential Appendix 2.

16 **B. Analytical Parameters**

17 The determination of a fair ROR is guided by principles of economic and financial
 18 theory and by certain minimum Constitutional standards. Investor-owned public utilities such
 19 as Empire are private property that the state may not confiscate without appropriate

² 9.80% minus 57 (=75-18) bps = 9.23%, rounded up to 9.25%.

1 compensation. The United States Supreme Court has described the minimum characteristics of a
2 Constitutionally-acceptable rate of return in two frequently-cited cases:³ *Bluefield Water Works*
3 *& Improvement Co. v. Public Service Commission of West Virginia*, and *Federal Power*
4 *Commission v. Hope Natural Gas Co.*

5 From these two decisions, Staff derives and applies the following principles to guide it in
6 recommending a fair and reasonable ROR:

- 7 1. A return consistent with returns of investments of comparable risk;
- 8 2. A return sufficient to assure confidence in the utility's financial
9 integrity; and
- 10 3. A return that allows the utility to attract capital.

11 Embodied in these three principles is the economic theory of the opportunity cost of investment.
12 The opportunity cost of investment is the return that investors forego in order to invest in similar
13 risk investment opportunities that vary depending on market and business conditions.

14 Methodologies of financial analysis have advanced greatly since the *Bluefield* and *Hope*
15 decisions.⁴ Additionally, today's utilities compete for capital in a global market rather than a
16 local market. Nonetheless, the parameters defined in those cases are readily met using current
17 methods and theory. The principle of commensurate return is based on the concept of risk.
18 Financial theory holds that the return an investor may expect is reflective of the degree of risk
19 inherent in the investment, risk being a measure of the likelihood that an investment will not
20 perform as expected by that investor. Any line of business carries with it its own risks and it
21 follows, therefore, that the return Empire shareholders may expect is equal to that required for
22 comparable-risk utility companies.

23 COE is a market-determined minimum return investors are willing to accept for their
24 investment in a company compared to returns on other available investments. An authorized ROE,
25 on the other hand, is a Commission-determined return granted to monopoly industries, allowing
26 them the opportunity to earn fair and reasonable compensation for their investments.

³ *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679, 43 S.Ct. 675, 67 L.Ed. 1176 (1923); *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 64 S.Ct. 281, 88 L.Ed. 333 (1943).

⁴ Neither the Discounted Cash Flow ("DCF") nor the Capital Asset Pricing Model ("CAPM") methods were in use when those decisions were issued.

1 Staff has relied primarily on the analysis of a comparable group of companies to estimate
2 the COE for Empire, applying this comparable-company approach through the use of both the DCF
3 method and the CAPM. Properly used and applied in appropriate circumstances, both the DCF
4 and the CAPM can provide accurate estimates of utilities' COE. It is well-accepted economic
5 theory that a company that earns its cost of capital will be able to attract capital and maintain
6 its financial integrity; therefore, Staff's recommended authorized ROE based on the COE,
7 derived from comparison of peer companies, is consistent with the principles set forth in *Hope*
8 and *Bluefield*.

9 C. Current Economic and Capital Market Conditions

10 Determining whether a COE estimate is fair and reasonable requires a good understanding
11 of economic and capital market conditions, with the former having a significant impact on the
12 latter. With this in mind, Staff emphasizes that an estimate of a utility's COE should pass the
13 "common sense" test when considering broader economic and capital market conditions.

14 1. Economic Conditions

15 The current economic climate is punctuated by a weakening global economy and volatility
16 emanating from trade disagreements between the USA and China, and the pending withdrawal
17 ("Brexit") of the UK from the European Union ("EU"). According to Bureau of Labor Statistics,
18 gross domestic product ("GDP") grew 3.1%, 2.0% and 2.1% in the first, second and third quarters
19 of 2019, respectively. Real GDP growth in 2017 and 2018 were 2.2% and 2.9%, respectively.⁵
20 Because of the aforementioned concerns in the economy, the projections for economic activity
21 point to a continued slowdown. In 2019, real GDP is expected to slow down to between 2.0% and
22 2.4%.⁶ International Monetary Fund ("IMF") and Organization for Economic Co-operation and
23 Development ("OECD") project averages of between 2.05% and 1.84% real GDP growths for
24 2020 and 2021, respectively. Long-run projections for real GDP is about 1.9% according to the
25 Federal Open Market Committee ("FOMC").

26 Inflation, measured by Personal Consumption Expenditures ("PCE") for 2017 and 2018
27 was 1.7% and 1.8%, respectively.⁷ Inflation is expected to be about 1.80% for the year 2019

⁵ <https://www.bea.gov/news/2019/initial-gross-domestic-product-4th-quarter-and-annual-2018>.

⁶ FED: <https://www.federalreserve.gov/monetarypolicy/fomcproptabl20190619.htm>.

⁷ <https://www.cbo.gov/sites/default/files/115th-congress-2017-2018/reports/53651-outlook-appendixd.pdf>.

1 according to the Federal Reserve Bank of Philadelphia.⁸ Long-term inflation should be expected
2 to be near the Federal Reserve (“FED”) 2% target.⁹ The unemployment rate has continued to
3 decline from 4.7% in January 2017 to 3.5% in November 2019.¹⁰

4 FOMC increased the FED target funds rate (“funds rate”) nine times since December 2015,
5 from 0 to 2.5%. In July, 2019 the FED cut the target rate by 25 basis points, its first rate cut since
6 2008, followed by two more in September and October. Slowdown in the global economy has
7 necessitated such a move by the FED. The broad market experienced a sharp decline by the end
8 of 2018. Dow Jones ended 2018 down 3.5% and S&P 500 ended 2018 down 4.4%. The Edison
9 Electric Institute Index (“EEI Index”) ended 2018 up 3.7%, indicating electric utilities’ resilience
10 as compared to S&P 500. Some analysts attributed the economic concern in part to the trade
11 tariffs.¹¹ Brexit also continues to be a drag on the global economy. The FED has explicitly
12 mentioned Brexit uncertainty as one potential factor weighing on the U.S. outlook, and it’s
13 certainly possible that a “no deal” Brexit could cause a period of volatility in global financial
14 markets which, if it was sustained, might weigh on U.S. growth.¹²

15 30-year treasury yields fell throughout 2017 before rising in 2018 and then falling again in
16 2019. 30-year treasury yields were 3.02% in January 2017 and 2.77% by December 2017.
17 2018 saw yields rising from 2.88% in January to 3.10% in December 2018 before falling to 2.28
18 by November 2019 (*see* Schedule PC-3-2). Abroad, negative yields are common. In the European
19 Union, bonds of up to 20-year maturity have negative yields.¹³ Japan has had negative yields for
20 over a decade. Low interest rates abroad have the effect of pushing down U.S. interest rates
21 through the force of supply and demand. Lower yields abroad increase demand for U.S. debt
22 securities with the effect of lowering yields in the U.S. The average 30-year Treasury bond yield
23 for the 3-month period (April, May and June 2017) of Spire rate case analysis was 2.90%. The
24 average 30-year Treasury bond yield was 2.21% in the 3-month period (September, October and
25 November 2019) the period of analysis for the current rate case. That is a decrease of 69 basis
26 points (“bps”) (*see* Schedule PC-3-2).

⁸ <https://www.philadelphiafed.org/research-and-data/real-time-center/survey-of-professional-forecasters/2019/survq419>.

⁹ FED: <https://www.federalreserve.gov/monetarypolicy/fomcproptabl20190619.htm>.

¹⁰ <https://fred.stlouisfed.org/series/UNRATE>.

¹¹ EEI Q2 2019 Financial Update, at page 4.

¹² <https://www.cnbc.com/2019/07/18/brexit-impact-on-the-us.html>.

¹³ https://www.ecb.europa.eu/stats/financial_markets_and_interest_rates/euro_area_yield_curves/html/index.en.html.

1 Interest rates have a strong relationship with GDP and the inflation rate. Weakening GDP
2 growth will prompt the Fed to cut interest rates as the Fed tries to stimulate the economy.
3 Weakening GDP also signals to investors of a weakening economy, which causes investors to cut
4 demand for treasury bonds and other debt securities. Low demand for treasury bonds causes prices
5 to rise and yields to fall, creating a low cost of capital environment. Weak inflation also causes
6 concern about economic growth, which prompts the Fed to cut interest rates. Because of weak
7 economic growth and short-term interest rate cuts, long-term interest rates have fallen to levels
8 lower than experienced during the period of Spire rate cases. With projected low GDP growth,
9 interest rates are set to remain low and continue to support a low COE environment.

10 **2. Capital Market Conditions**

11 **a. Utility Debt Markets**

12 Interest rates are a key factor in determining a utility's COE, as stock investors demand a
13 premium return over those offered by lower-risk, interest-bearing securities, such as U.S. Treasury
14 bonds. An increase [decrease] in interest rates therefore, will increase [decrease] a utility's cost
15 of equity, all else being equal.¹⁴ The current utility debt market indicates a lower cost-of-capital
16 than the period when the Commission ordered a 9.80% authorized ROE for Spire. Utility bond
17 yields have been on a steady decline since January 2019. Average utility bond yields, as reported
18 by Mergent Bond Record, declined from 4.48% in January 2019 to 3.5% in November 2019
19 (*see* Schedule PC-3-1).

20 Staff compared average utility bond yields in a three month period (April, May and
21 June 2017) within the timeframe of the Spire Missouri rate case analysis, to a three month
22 period (September, October and November, 2019) within the timeframe of the current case. The
23 three-month average utility bond yield was 4.13% in the Spire rate case compared to 3.46% in the
24 current rate case, a drop of 67 bps (*see* Schedule PC-3-1). As noted in the Edison Electric Institute,
25 lower interest rates have boosted utilities stocks, “[d]riven by falling interest rates, the EEI Index
26 gained nearly 16% through June.”¹⁵

27 Although utilities' COE is not perfectly correlated to changes in utility debt yields, it is
28 widely recognized in the investment community that regulated utility stocks are a close alternative

¹⁴ Electricity Markets & Policy Group: <https://emp.lbl.gov/sites/all/files/lbnl-1003952.pdf>.

¹⁵ Edison Electric Institute, Q2 2019 Financial Update, page 5.

1 to bond investments and, therefore, that the two values are highly correlated over time. As interest
2 rates fall, utility stock prices rise, pushing COE down as investors substitute debt for utility stock
3 in search for higher yields. In an article on September 3, 2019 CNBC reported that falling bond
4 yields have lifted two sectors: real estate and utilities.¹⁶

5 **b. Utility Equity Markets**

6 Utility equities have outperformed the S&P 500 in the recent past. Over the past 4 years
7 ending November 30, 2019, the S&P 500 Utilities sector outperformed the overall S&P 500
8 69.38% to 63.84%, respectively. Staff's electric and gas proxy groups had total returns of 67.47%
9 and 73.83%, respectively, over the four-year period, well above the 63.84% for the S&P 500. As
10 noted in the Edison Electric Institute in its Q2 2019 Financial Update, sustained low interest rates
11 have caused the utilities to outperform the overall market "[t]he utility sector, widely seen as a
12 defensive sector, typically underperforms a broad market advance. But the first half of 2019 also
13 produced a surprising and steady decline in long-term interest rates in the U.S. and overseas"
14 (EEI Q2 2019 Financial Update, page 4). In the long-term, total returns on the S&P 500 are
15 expected to be greater than total returns on utility stocks because overall, companies in the S&P
16 500 have higher growth rates than utilities. In times of volatility and economic uncertainty,
17 investors move their investments into utilities, increasing demand and consequently pushing
18 utilities' valuations higher than the overall market.

19 To further gain insight on what is happening in the utility equity market, Staff analyzed
20 utility price to earnings ("PE") ratios and dividend yields. Staff's electric proxy group's PE ratio
21 for the time period (April, May and June, 2017), corresponding to the time period during the Spire
22 rate cases, was 23.49x compared to 31.45x in the current period (September, October and
23 November, 2019), corresponding to the time period of Staff's analysis for the current case. The
24 gas proxy group's PE ratio in the same periods increased from 25.26x to 32.10x. Dividend yields
25 for electric and gas proxy groups fell from 3.74% to 3.00% and from 2.64% to 2.46%, respectively.

26 There is an inverse relationship between PE ratios and COE. At any given point in time,
27 the PE ratio gives you the price of the company (per share) divided by earnings per share. The
28 reciprocal of this is called earnings yield – a metric comparable to dividend yield. At a high PE

¹⁶ <https://www.cnbc.com/2019/09/03/plunging-bond-yields-have-lifted-these-two-stock-sectors-to-record-levels.html>.

1 ratio, earnings yield (dividend yield) is low, which translates into low COE. Higher PE ratios and
2 lower dividend yields today than the period of Spire rate cases indicate a lower COE.

3 **D. Empire Operations**

4 Empire provides electric service in an area of approximately 10,000 square miles in
5 southwest Missouri and the adjacent corners of the states of Arkansas, Oklahoma, and Kansas.
6 Empire's revenue components are as follows: 93.3% electric, 5.7% gas and 1% other. According
7 to Moody's Investors Service, Empire is regulated by Missouri Public Service Commission,
8 Kansas Corporation Commission, the Corporation Commission of Oklahoma, the Arkansas Public
9 Service Commission and the Federal Energy Regulatory Commission ("FERC").¹⁷ Empire's
10 service area encompasses 133 incorporated communities in 26 counties in the four state area. Most
11 of the communities in the Company's service area are small, with only 35 containing a population
12 in excess of 1,500. Only 12 communities have a population in excess of 5,000, and the largest
13 city, Joplin, Missouri, has a population of approximately 50,000. Empire serves approximately
14 155,000 customers. The economy in the Company's service area is diversified, and includes
15 small to medium manufacturing operations, medical, agricultural, entertainment, tourism, and
16 retail interests.

17 On January 1, 2017, Empire was acquired by Liberty Utilities, Co. ("LUCo") which is
18 owned by Algonquin Power & Utilities Corp. ("APUC"). APUC serves approximately 800,000
19 customers in twelve states across the United States through its electric, gas, water and waste water
20 utilities. In addition to its regulated utility business, APUC also operates its Liberty Power
21 business, which owns approximately 1.36 GW of renewable generation in the United States
22 and Canada.

23 While most of its day-to-day operations remain the same, there have been some changes in
24 the Company's operations since the LUCo acquisition. For example, the Company is no longer
25 publicly traded, although APUC is listed on the New York and Toronto Stock Exchanges. Another
26 difference is that Empire is now part of a larger corporate family that operates other electric, gas,
27 and water utilities, providing opportunities for collaboration across the business to share best
28 practices and expertise.

¹⁷ Moody's Investors Service, Credit Opinion, January 16, 2019.

1 With the passage of Senate Bill 564 in 2018, Empire will have the opportunity to
2 improve its operations by cutting its regulatory lag. Moody's noted in its Credit Opinion on
3 January 16, 2019, "On a positive note, Missouri Senate Bill 564, passed in June 2018, is expected
4 to provide a more supportive regulatory framework, thereby reducing regulatory lag and opening
5 the possibility of greater spend in Missouri."(Empire's Moody's Credit Opinion, January 16, 2019)
6 The bill provides the ability for electric utilities to update their rates in between general rate cases
7 to account for changes in customer usage due to weather or conservation. Alternatively, utilities
8 can institute plant in service accounting to defer and recover 85% of total depreciation expense
9 and return on qualifying electric plant placed in-service."¹⁸

10 **E. Cost of Capital**

11 In order to arrive at Staff's recommended ROR, Staff specifically examined (1) an
12 appropriate ratemaking capital structure, (2) the Company's embedded cost of debt, and (3) an
13 evaluation of a fair and reasonable authorized ROE.

14 **1. Capital Structure**

15 Staff analyzed Empire's capital structure since its acquisition by LUCo. LUCo is the
16 primary debt issuer for the entire LUCo family. All existing Empire debt was retained by Empire
17 when the merger happened. New debt and refinancing of maturing debt will occur on the LUCo
18 bond platform. Liquidity is to be provided via a single consolidated credit facility at LUCo.

19 In the 'Stipulation and Agreement' in the merger case, No. EM-2016-0213, Empire agreed
20 that if its per books capital structure is different from the per books capital structure of the entity
21 on which it relies for financing, Empire shall be required to provide evidence in subsequent rate
22 cases as to why its per book capital structure is the most economical for purposes of determining
23 its revenue requirement. Empire's consolidated capital structure is composed of 52.90% equity
24 and 47.10% debt as of September, 30, 2019. Liberty's capital structure is composed of 53.00%
25 equity and 47.00% debt. Staff accepts Empire's per books capital structure.

¹⁸ Moody's, in its credit opinion on January 16, 2019.

1 **2. Embedded Cost of Debt**

2 Staff recommends the use of Empire’s consolidated embedded cost of debt for purposes of
3 setting its ROR, which is 4.76% as of September 30, 2019.

4 **3. Cost of Common Equity**

5 Staff estimated Empire’s cost of common equity through a comparable company
6 cost-of-equity analysis using the proxy group of electric utility companies, applying DCF and
7 CAPM analyses. Staff also estimated the current cost of equity for the gas utility proxy group
8 Staff presented in the Spire rate case to determine any change in the COE since the Commission
9 authorized a 9.80% ROE. Combining the estimates and applying them proportionately allowed
10 Staff to estimate a reasonable authorized ROE (*see* Schedule PC-13). Staff compared its
11 recommendation to recent authorized ROEs of other Commissions as a check on the
12 reasonableness of Staff’s ROE recommendation.

13 **a. The Proxy Group**

14 Staff used a proxy group consisting of companies that are predominantly vertically
15 integrated, regulated, electric utilities to estimate changes in the cost of equity since Spire’s last
16 rate case. Staff ensured companies in the proxy group are confined to vertically integrated,
17 regulated, electric utility operations by starting with the list included in the Edison Electric
18 Institute’s¹⁹ (“EEI”) regulated electric utility index, and then screened these companies further by
19 ensuring that they:

- 20 • are publicly traded
21 • have investment grade credit ratings from two of the three major U.S. credit rating
22 agencies
23 • have long-term growth coverage from at least 2 analysts
24 • have no pending merger or acquisitions
25 • have not reduced dividends since 2016
26 • have 50% of plant from electric utility
27 • have at least 25% of plant from electric generation

¹⁹ EEI is an association that represents all U.S. investor-owned electric companies. It classifies electric public utilities as ‘regulated’ and ‘mostly regulated’, with ‘regulated’ having 80% or more total assets regulated.

- generate at least 80% of income from regulated utility operations
(see Schedule PC-5)

b. The Constant-growth DCF

Staff started its evaluation of the electric utility industry’s COE by applying values derived from the proxy group to the constant-growth DCF model. The constant-growth DCF model is widely used by investors to evaluate stable-growth investment opportunities, such as regulated utility companies. It may be expressed algebraically as follows:

$$k = D_1/P_0 + g$$

- Where:
- k is the cost of equity;
 - D_1 is the expected next 12 months dividend;
 - P_0 is the current price of the stock; and
 - g is the dividend growth rate.

The term D_1/P_0 , the expected next 12-months' dividend divided by current share price, is the dividend yield. Staff calculated the dividend yield for each of the comparable companies by dividing the consensus analysts’ expected dividend per share over the next four quarters (see Schedule PC-10-1) by the average daily closing stock prices for the three months ending November 30, 2019.²⁰ The projected average dividend yield for the electric utility proxy group is approximately 3.14%.

c. The Inputs

In the DCF method, the cost of equity is the sum of the dividend yield and a growth rate ("g") that represents the projected capital appreciation of the stock. In estimating a growth rate, Staff considered the 10-Year and 5-Year historical earnings per share (“EPS”) for each of the comparable companies and also the 5-Year SNL projected EPS. The 10-year and 5-year historical average were 3.66% and 3.11%, respectively (see Schedule PC-9-3). The average

²⁰ The monthly high/low averaging technique minimizes the effects of short-term stock market volatility on the calculation of dividend yield. P_0 is calculated by averaging the highest and the lowest price for each month during the selected period.

1 consensus long-term growth rates in EPS for the companies was 5.16% as of November 30, 2019.
2 (*see* Schedule PC-9-3).

3 While Staff may accept the argument that electric utilities' EPS can grow over the next five
4 years at a growth rate of approximately 5.16%, a rate which is higher than the consensus GDP
5 long-term growth rate estimates of about 4.4%²¹, 3.8%²² and 3.9%²³, it would be unreasonable to
6 conclude that this higher growth rate is sustainable in perpetuity. This growth rate does not give
7 consideration to empirical and logical information that suggests that utility companies should grow
8 at a rate less than that of the overall economy over the long term. Since 2009, companies in the
9 S&P 500 have retained about 65% of their earnings for reinvestment.²⁴ Staff's electric proxy
10 group has had about 20% earnings retention rate. During the same time period, the electric utilities
11 in general have retained an average 26% of their earnings for reinvestment. Utilities should not
12 be expected to grow at rates as robust as the S&P 500's growth rate because of their lower retention
13 rates. With authorized ROEs in the 9.00% to 10.00%²⁵ range, sustainable growth model indicates
14 growth rates in the 2.34% to 2.60%²⁶, a far cry from an average of 5.16%. Staff's electric proxy
15 group has an average of 3.11% EPS growth rate in the past five years (*see* Schedule PC-9-3).

16 There are stark statistics that point to a continued slowdown in electricity usage, and
17 consequently, growth. Growth in electric use is tied to economic and population growths. World
18 Bank recently estimated U.S. population growth to be around 0.60%²⁷ annually. The U.S.
19 economy is projected to grow at a nominal rate of about 4.00%²⁸ annually. For developed
20 countries like the United States, electricity usage is projected to be even lower than economic
21 growth due to decrease in the use of electricity. The U.S. and other developed countries are moving
22 away from manufacturing-based economies to service-based economies. Service-based
23 economies tend to use less electricity than economies with high levels of industrial activity. This
24 further dismisses the notion that electric utilities will grow at 5.16%, perpetually.

²¹ <https://data.oecd.org/gdp/nominal-gdp-forecast.htm>.

²² CBO estimates 1.8% for the next decade plus 2% projected CPI.

²³ EIA projects 3.9% through 2050.

²⁴ Aswath Damodaran: http://pages.stern.nyu.edu/~adamodar/New_Home_Page/datafile/spearn.htm.

²⁵ Average authorized ROEs have ranged between 9.00% and 10.00% in the last 5 years.

²⁶ Using the 26% retention rate. Growth = .26*.09 = 2.34% and, .26*.1 = 2.60%.

²⁷ https://data.worldbank.org/indicator/SP.POP.GROW?most_recent_year_desc=false.

²⁸ Nominal growth rate which is real growth rate (about 1.9%) plus expected inflation (about 2.0%).

1 A projected long-term nominal GDP growth rate²⁹ should be conservatively ascribed as an
2 upper constraint when testing the reasonableness of growth rates used to estimate the cost of equity
3 for a regulated electric utility. A high-end estimate for nominal GDP of 4.4% is reasonable.

4 It is important to consider actual experience in dividend growth achieved by electric utility
5 companies and the basic characteristics of electric utility stocks when determining a reasonable
6 expected growth rate in the DCF. It is critical to remember that the growth rate used in the DCF
7 is supposed to represent the expected capital gains (growth in the stock price) of the utility.
8 Considering that over long-term holding periods a majority of utility investors' return from
9 investing in utility stocks have been from the payment of the dividend, it is simply illogical to
10 expect the growth component of the return to be higher than the dividend yield. Results of the
11 DCF place the electric utility proxy group's dividend yield currently at 3.14%. Making the
12 assumption that capital gains could equal the dividend yield implies electric utility investors are
13 requiring a total return of 6.28% for electric utility stocks. While this may seem low for purposes
14 of setting the authorized ROE, it is definitely in the realm of reasonableness for COE for regulated
15 utility stocks. Although Staff considers it unlikely that the fundamental characteristics of electric
16 utility stocks will cause returns from capital gains to be much higher than dividend returns, because
17 historical dividend growth has been approximately 4.0% and expected dividend growth over the
18 next five years is expected to be higher, Staff used a constant growth rate of 4.20% to 5.00% to
19 arrive at a COE estimate of between 7.34% to 8.14% (*see* Schedule PC-10-1). Staff also used this
20 growth rate to maintain consistency with the growth rate range assumed in the Spire rate cases.

21 **d. The CAPM**

22 The CAPM is built on the premise that the variance in returns is the appropriate measure
23 of risk, but only the non-diversifiable variance (systematic risk) is rewarded. Systematic risks,
24 also called market risks, are unanticipated events that affect almost all assets to some degree
25 because the effects are economy wide. Systematic risk in an asset, relative to the average, is
26 measured by the Beta of that asset. Unsystematic risks, also called asset-specific risks, are
27 unanticipated events that affect single assets or small groups of assets. Because unsystematic risks
28 can be freely eliminated by diversification, the reward for bearing risk depends on the level of
29 systematic risk. The CAPM shows that the expected return for a particular asset depends on the

²⁹ The nominal GDP growth rate, contrasted to the real GDP growth rate introduced earlier, is not adjusted for inflation.

1 pure time value of money (measured by the risk free rate), the reward for bearing systematic risk
 2 (measured by the market risk premium), and the amount of systematic risk incurred by the asset
 3 (measured by Beta). The general form of the CAPM is as follows:

$$k = R_f + \beta(R_m - R_f)$$

4
 5 Where: k is the expected return on equity for a security;

6 R_f is the risk-free rate;

7 β is Beta; and

8 $R_m - R_f$ is the market risk premium.

9 For inputs, Staff relied on historical capital market return information through the end
 10 of 2018. For the risk-free rate (R_f), Staff used the average yield on 30-year U.S. Treasury bonds
 11 for the three-month period ending November 30, 2019; that figure was 2.21%. For beta (β), Staff
 12 relied on Market Intelligence betas³⁰.

13 The average beta for the proxy group was 0.54. For the market risk premium ($R_m - R_f$)
 14 estimates, Staff relied on the historical difference between earned total returns on stocks and earned
 15 total returns on bonds.³¹ The first risk premium (6.00%) was based on the long-term arithmetic
 16 average of historical return differences from 1926-2018. The second risk (4.50%) premium was
 17 based on the long-term geometric average of historical return differences from 1926 to 2018. The
 18 results using the long-term arithmetic average risk premium and the long-term geometric risk
 19 premium are 4.63% to 5.43% (*see* Schedule PC-11-1) for the electric proxy group and 4.91% to
 20 5.81% for the gas proxy group (*see* Schedule PC-11-2). The gas proxy group's CAPM results
 21 from the period of Spire rate cases was 6.08% geometric and 7.14% arithmetic, for an average
 22 decrease of 125 bps from that point to the current period (*see* Schedule PC-12).

23 **F. Tests of Reasonableness**

24 Staff has tested the reasonableness of its recommendation by reviewing past authorized
 25 ROEs in other jurisdictions.

³⁰ Staff used Market Intelligence Excel beta generator template.

³¹ From Duff & Phelps *2019 Valuation Handbook: A Guide to the Cost of Capital*.

Average Authorized Returns

Although Staff believes it has appropriately considered this Commission's recent authorized ROE and capital structure decisions for purposes of its recommendation in this case, Staff recognizes that the Commission may also be interested in recent authorized ROEs and capital structure decisions for other electric utility and gas utility companies throughout the country. For consideration of authorized ROEs and capital structures for other electric utility and gas utility companies, the chart below presents information compiled and published by Regulatory Research Associates (RRA) which details the average authorized ROEs by Commissions around the U.S. in rate cases from 2015 – 2019, along with the percentage of common equity to total capital. These are averages for fully litigated vertically integrated electric and gas cases.

Table 2: Past 5 Years Authorized ROEs

Year	Electric		Gas	
	ROE%	Equity%	ROE%	Equity%
2015	9.85%	49.54%	9.60%	49.94%
2016	9.77%	48.91%	9.54%	50.07%
2017	9.74%	48.90%	9.725	49.885
2018	9.68%	45.66%	9.57%	50.63%
2019	9.36%*	49.15%	9.73%	51.13%

*Data through December 4, 2019 for fully litigated and vertically integrated cases

Source: Regulated Research Associates, an offering of S&P Global Market Intelligence

G. Conclusion

In light of recent Commission decisions, Staff believes an authorized ROE in the range of 9.05% to 9.80% is fair and reasonable for Empire. Considering information Staff has reviewed, Staff recommends the Commission authorize a ROE of 9.25.

A ROE range of 9.05% – 9.80% leads to an ROR range of 7.07% to 7.43% for Empire (see Schedule PC-13). Using the point recommended authorized ROE of 9.25%, results in an allowed ROR of 7.14% for Empire. Empire's ROR was calculated by applying an embedded cost

1 of long-term debt of 4.76% and an allowed return on common equity of 9.25% to a capital structure
2 consisting of 52.90% common equity and 47.10% long-term debt

3 *Staff Expert/Witness: Peter Chari*

4 **V. Rate Base**

5 **A. Plant in Service**

6 Accounting Schedule 3, plant in service, reflects the rate base value of Empire's plant
7 in service by account, updated through September 30, 2019, to be later trued-up through
8 January 31, 2020. Empire records its water, non-utility operating, Empire District Gas, fibercom,
9 MO water, and MO Midstates gas general plant in service balances on its electric books. To ensure
10 that Empire's electric customers only pay for rates associated with Empire's electric service, Staff
11 adjusted Empire's plant in service to remove Empire Water, Empire District Gas, Empire District
12 Industries, Inc. (EDI) Liberty Water, Liberty Midstates Gas and non-utility operations portions
13 from the Company's general plant for electric rate case purposes.

14 *Staff Expert/Witness: Courtney Barron*

15 **B. Depreciation Reserve**

16 Accounting Schedule 6, Depreciation Reserve, reflects the rate base value of Empire's
17 depreciation reserve by account, updated through September 30, 2019, to be later trued-up through
18 January 31, 2020. Since Staff removed portions of the general plant that are allocated to Empire
19 Water, Empire District Gas, Empire District Industries, Inc. (EDI), Liberty Water, Liberty
20 Midstates Gas and non-utility operations portions, Staff also removed portions of the associated
21 depreciation reserve for these plant accounts.

22 *Staff Expert/Witness: Courtney Barron*

23 **C. Cash Working Capital**

24 Cash Working Capital ("CWC") is the amount of funding necessary for a utility to pay
25 day-to-day expenses incurred in providing utility services to its customers. Cash inflows from
26 payments received by the Company and cash outflows for expenses incurred by the Company are
27 analyzed using a lead/lag study. The lead/lag study involves analysis of the timing of when funds

1 are paid to suppliers and when the utility receives the good or service compared to when the utility
2 receives revenues from customer bills for the utility services it provides. Analysis is also
3 performed for pass-through expenses where funds are collected and remitted such as sales taxes
4 and employee payroll withholdings.

5 The CWC requirement can be negative or positive. If the requirement is negative, it
6 demonstrates that the utility's customers are providing the working capital for the test year, which
7 indicates customers paid for the utility's expenses before the Company incurred them. Under this
8 circumstance, CWC would represent a reduction to rate base. A positive CWC requirement
9 indicates that the utility pays its expenses before receiving payment from the customers, which
10 means that the shareholders are providing the funds. In this instance, CWC would represent a rate
11 base addition.

12 In this case, Staff performed a full lead/lag study specific to costs incurred during the
13 12 month period ending March 31, 2019, and also reviewed the lead/lag study sponsored by the
14 Company's consultant Timothy Lyons. In addition to the revenue lag, Staff reviewed the
15 following expenses for the lead/lag study: cash vouchers, power plant fuel expenses, purchased
16 power, payroll, employer payroll taxes, employee vacation time, 401k, life/Accidental Death &
17 Dismemberment (AD&D) insurance, pension and OPEB expense, incentive compensation,
18 interest expense, property taxes, Federal and State income taxes, Public Service Commission
19 (PSC) assessment expense, employee payroll withholdings, federal and state unemployment taxes,
20 sales taxes, use taxes, and municipal gross receipts taxes.

21 Staff accepted the Company's proposed revenue lag and its proposed expense lags for the
22 following: payroll, Federal Unemployment Tax (FUTA) and State Unemployment Tax (SUTA).
23 Staff performed an analysis of these items and determined the Company's calculation was
24 reasonable.

25 Staff performed a thorough analysis and adjusted the following expense lags: employer
26 payroll taxes, employee payroll withholdings, coal, natural gas, oil, purchased power,
27 PSC assessment, property taxes, pension and OPEB expense, 401k, incentive compensation,
28 accrued vacation, life/Accidental Death & Dismemberment (AD&D) insurance premiums, Federal
29 and State income taxes, interest expense and cash vouchers. Staff also accounted for bad debt
30 expense by removing the dollar amount from cash vouchers and listing a zero day lag since this is
31 a non-cash item.

1 When Staff calculates an expense lag the date the utility makes the payment is used to
2 calculate the lag. Staff has an outstanding request for the payment dates for oil and purchased
3 power invoices. For purposes of this filing, Staff used the due dates to calculate the expense lag
4 for oil and purchased power. Staff will review the oil and purchased power expense lags once the
5 payment dates are received and address any changes in rebuttal testimony.

6 Sales tax and gross receipts taxes are collected by Empire District Electric Company
7 and then remitted to the taxing authorities based on the taxing authorities' due date. These taxes
8 are included on ratepayer bills and the Company collects and remits the tax for the taxing
9 authority. Since a service is not provided to the ratepayer by the Company, measurement of the
10 revenue and expense lag calculations start with the beginning point of the collection lag for sales
11 and gross receipts taxes. The collection lag is the period of time between the day the bill is
12 placed in the mail by the Company and the day the Company receives payment from the
13 ratepayers. As a result, Staff recommends a shortened revenue and expense lag for the sales tax
14 and gross receipts tax.

15 All of Staff's recommended revenue and expense lags can be found in Schedule 8 of
16 Staff's Accounting Schedules. Staff's overall lead/lag study resulted in a negative CWC
17 requirement for Empire District Electric Company. This means that the ratepayers are
18 currently providing the cash working capital, in the aggregate, to Empire District
19 Electric Company. Therefore, the ratepayers will be compensated for the cash working
20 capital provided through a reduction to rate base.

21 *Staff Expert/Witness: Jared Giacone*

22 **D. Prepayments**

23 Staff's recommended treatment of prepayments is to examine each prepayment account
24 individually in order to determine an appropriate measure that most accurately predicts the ongoing
25 future expense of a particular prepayment account, and then to include the prepayments in
26 Empire's rate base. Prepayments are the costs a company incurs and pays in advance. Prepayments
27 are treated as an asset and are reflected in the utility's rate base. Due to the lack of a discernable
28 trend, Staff has included a 13-month average, ending September 30, 2019 in the rate base in the
29 amount of \$6,954,889.

1 In the prior rate case, ER-2016-0023, KCP&L Land Lease (165352) was excluded from
2 investments. KCP&L Land Lease is a cash account, not an actual investment in utility assets. It is
3 excluded in this case for prepayments as well.

4 *Staff Expert/ Witness: Angela Niemeier*

5 **E. Materials and Supplies**

6 Staff's recommended treatment of materials and supplies (M&S) is to examine each
7 account individually in order to determine an appropriate level that most accurately reflects the
8 ongoing future expense of a particular account. M&S represent an investment in inventory for
9 items such as spare parts, electric cables, poles, meters, and other miscellaneous items used in
10 daily operations and maintenance activities by Empire to maintain Empire's production facilities
11 and electric system. Empire holds a variety of M&S in inventory so the items can be readily
12 available when needed in performing its utility operations. Staff analyzed these M&S accounts
13 from September 30, 2018 to September 30, 2019. Staff reviewed and analyzed historical balances
14 from 2015 to current for M&S to determine if there is a discernible trend. Data reveals an overall
15 upward trend. After reviewing the data, Staff included the most current 13-month average of
16 \$31,582,948 in rate base.

17 Empire's electronic recording system included both water and electric utility inventory;
18 therefore, an adjustment entry was made to remove the water portion of M&S from Empire's
19 electric M&S. Staff used a 13-month average of Empire's water inventory to determine the level
20 of the M&S inventory that needed to be eliminated from Empire's rate base in this proceeding.

21 *Staff Expert/ Witness: Angela Niemeier*

22 **F. Customer Advances**

23 Customer advances are funds typically provided to Empire in order to ensure that Empire
24 builds electric infrastructure in areas that have potential for future development. These advances
25 are also used by the utility to establish electric service for potential future customers without
26 investing a substantial amount of money at the risk of the utility and its other customers. Customer
27 advances are included in the rate base as an offset, reducing the amount of overall investment that
28 customers must supply as a return to the utility.

1 Staff reviewed historical balances for customer advances and performed an analysis to
2 determine if there is a discernible trend; data from 2015 to current revealed that there is a
3 slight upward trend. Staff included the 13-month average of customer advances, ending
4 September 30, 2019, as an offset to Empire's rate base.

5 *Staff Expert/Witness: Angela Niemeier*

6 **G. Customer Deposits**

7 Customer deposits are funds required to be provided by certain customers taking electrical
8 service from Empire as a security against potential loss arising from failure to pay for utility
9 service. These funds are deducted from Empire's rate base, as they are cost-free funds received
10 from Empire customers. Staff reviewed historical balances for customer deposits and performed
11 an analysis to determine if there was a discernible trend. There was a gradual upward trend in
12 Customer Deposits. Staff included a representative ongoing level of \$13,610,695 as an offset to
13 rate base, which is based on a 13-month average from September 30, 2018 to September 30, 2019.

14 Staff calculated interest expense based on the level of customer deposits included in Staff's
15 rate base schedule. Staff utilized the formula included in the tariff (JE-2003-0707) to calculate the
16 customer deposit interest; this formula is the most current prime interest rate, as published in the
17 Wall Street Journal, as being in effect on the last business day of December of the prior year,
18 plus 1%. The prime rate listed in December 2018 was 5.50%. Therefore, the reasonable rate
19 applied to customer deposits, prime rate plus 1%, is 6.50%. The amount of interest, \$886,274, is
20 included as an adjustment in Staff Accounting Schedule 10.

21 *Staff Expert/Witness: Angela Niemeier*

22 **H. Fuel Inventories**

23 **Coal Inventory** - Staff used the results of its fuel model to calculate the annual amount of
24 coal used by each Empire generating plant to meet its total company normalized native load.
25 Empire operates in four retail jurisdictions: Missouri, Arkansas, Kansas, and Oklahoma.
26 "Native load" is the kilowatt or megawatt demand placed upon Empire's electric system by its
27 regulated retail electric customers. To determine the amount of coal inventory, the average daily
28 burn by unit must be calculated. The average daily burn by unit is derived by dividing the
29 annualized tons burned by the difference between 365 days and the number of annual

1 planned outage days. Then, the average daily burn is multiplied by an appropriate number of days
2 of inventory for each plant resulting in a burn inventory. The number of days of inventory of
3 Powder River Basin (“PRB”), or “western” coal, for the Asbury 1 unit was set by Empire at or
4 around 60 days. The PRB coal in 2019 was to be supplied by western coal suppliers Peabody Coal
5 Sales through December 31, 2019.

6 Staff has also used a 60-day calculation to establish Empire’s rate base investment in
7 the coal inventory maintained both at KCPL’s Iatan Generating Stations (Empire is a 12% owner
8 of Iatan 1 and 2) and Plum Point Energy Associates, LLC’s Plum Point Energy Station (Empire is
9 a 7.52% owner of Plum Point).

10 Staff multiplied the resulting burn inventory for each unit by the delivered cost of coal per
11 ton for that unit as calculated by Staff. To this total, Staff added the fixed cost of basemat coal
12 established in the prior Empire rate case, Case No. ER-2011-0004, for each unit, except for Plum
13 Point. Basemat coal is the bottom portion of a coal pile that is not usable as fuel due to
14 contamination by soil, clay, and other contaminants. The basemat coal for the Plum Point unit is
15 capitalized as part of plant in service costs. The total cost of the burn inventory and basemat coal
16 was multiplied by Staff’s energy jurisdictional factor to arrive at the Missouri allocated amount,
17 with the result reflected as part of Fuel Inventories in Accounting Schedule 2, Rate Base.

18 **Fuel Oil Inventory** - Staff used the 13-month average inventory quantities and a weighted
19 average price for oil inventory levels as reported in the Company’s Coal and Oil Inventory Reports
20 provided in response to Staff’s Data Request No. 0018.

21 **Gas Stored Underground** – Empire did not renew its natural gas storage agreement with
22 Southern Star Central Gas Pipeline, Inc. (“SSCGP”) when it expired on March 31, 2016.
23 Therefore, Staff will not include any inventory cost for Gas Stored Underground in rate base.

24 *Staff Expert/Witness: Amanda C. McMellen*

25 **I. Accumulated Deferred Income Taxes (“ADIT”)**

26 Empire's ADIT represents, in effect, a net prepayment of income taxes by customers prior
27 to tax payment by Empire. For example, because Empire is allowed to deduct depreciation expense
28 on an accelerated basis for income tax purposes, the amount of depreciation expense used as a
29 deduction for income taxes purposes by Empire is considerably higher than the amount of
30 depreciation expense used for ratemaking purposes. This results in what is referred to as a

1 “book-tax timing difference,” and creates a deferral of income tax reserves to the future. The net
2 credit balance in the ADIT accounts reserve represents a source of cost-free funds to Empire.
3 Therefore, Empire’s rate base is reduced by the ADIT balance to avoid having customers pay a
4 return on funds that are provided cost-free to the Company. Generally, deferred income taxes
5 associated with all book-tax timing differences created through the ratemaking process should be
6 reflected in rate base. Staff has decided to take this approach in calculating the ADIT rate base
7 offset amount in this case.

8 The deferred tax impact associated with the past tax timing differences reflected in
9 Staff’s rate base offset include amounts associated with the following major components:
10 Accelerated Depreciation, Loss on Hedge Transactions, Gain on Hedge Transactions, License
11 Software Amortization, Loss on Reacquired Debt, Ice Storm Expenses, Deferred Federal Tax
12 Asset-Miscellaneous, Deferred Tax Liability-Iatan Deferred Charges, Contributions in Aid of
13 Construction, Post-retirement Benefits – Pensions, Capitalized Interest, and Deferred Tax Net
14 Operating Loss.

15 *Staff Expert/Witness: Keith D. Foster*

16 **J. Vegetation Management Tracker Regulatory Asset**

17 Per the Stipulation and Agreement in Case No. ER-2016-0023, the
18 Vegetation/Infrastructure tracker was discontinued and a regulatory asset was established in the
19 amount of \$2,182,407 (the balance as of March 31, 2016). The asset was to be amortized over
20 five years. The annual amortization of this asset is \$436,381. The unamortized balance as of
21 September 30, 2019 is \$854,776.

22 *Staff Expert/Witness: Kimberly K. Bolin*

23 **K. Iatan and Plum Point Carrying Costs**

24 **Iatan 1**

25 Pursuant to Empire’s regulatory plan approved by the Commission in Case No.
26 EO-2005-0263, Empire deferred certain “carrying costs” associated with the Iatan I AQCS
27 investment past its in-service date into Account 182308, Iatan Deferred Carrying Costs. (The
28 deferral of carrying costs after a projects’ in-service date is also known as “construction
29 accounting”). In the *Report and Order* in KCPL’s Case No. ER-2010-0355, the Commission

1 disallowed certain costs that had been booked to the Iatan accounts. The effect of these
2 disallowances reduced the balance of the Iatan I AQCS plant balance. In Empire's Case No.
3 ER-2012-0345, Staff removed any construction accounting allowances associated with the portion
4 of Iatan 1 AQCS approved disallowances that were allocated to Empire from its rate base and
5 expense amortization calculations. In the current case, Staff used the September 30, 2015 balance
6 (\$4,306,937) from the most recent rate case, Case No. ER-2016-0023 and the annual amortization
7 expense included in Staff's Accounting Schedules in Case No. ER-2012-0345, to determine the
8 unamortized balance of \$3,968,021 as of September 30, 2019 to include in rate base.

9 **Iatan 2**

10 Pursuant to Empire's regulatory plan approved by the Commission in Case No.
11 EO-2005-0263, Empire deferred certain "carrying costs" associated with the Iatan 2 generation
12 unit investment past its in-service date into Account 182332, MO IatanII Df Chr ER-2010-0130.
13 In the *Report and Order* in KCPL's Case No. ER-2010-0355, the Commission disallowed certain
14 costs that had been booked to the Iatan accounts. Staff has removed any construction accounting
15 allowances associated with the portion of Iatan 2 disallowances that were allocated to Empire from
16 its rate base and expense amortization calculations. The balance of Iatan 2 carrying costs was also
17 reduced by Empire's deferral of fuel and purchased power expense savings it had incurred due to
18 the addition of Iatan 2 to its generating system from the unit's in-service date through
19 June 30, 2012. Staff used the September 30, 2015 balance (\$2,342,397) from the most recent rate
20 case, Case No. ER-2016-0023, and the annual amortization expense included in Staff's Accounting
21 Schedules in Case No. ER-2012-0345, to determine the unamortized balance of \$2,163,085 as
22 of September 30, 2019 to include in rate base.

23 **Plum Point**

24 Pursuant to Commission approval of the *Non-Unanimous Stipulation and Agreement and*
25 *Joint Proposal Regarding Certain Procedural Matters* dated February 25, 2010, in Case No.
26 ER-2010-0130, Empire deferred certain "carrying costs" associated with the Plum Point
27 generating unit investment past its in-service date into Account 182331, MO PlumPT Df Chgs
28 ER-2010-0130. Based on the results of its Construction Audit and Prudence Review for Plum
29 Point (submitted in Case No. ER-2011-0004), Staff recommended one disallowance to Empire's
30 Plum Point plant balances. Staff used the September 30, 2015 balance (\$109,533) from the most

1 recent rate case, Case No. ER-2016-0023, and the annual amortization expense included in Staff's
2 Accounting Schedules in Case No. ER-2012-0345, to determine the unamortized balance of
3 \$101,585 as of September 30, 2019 to include in rate base.

4 *Staff Expert/Witness: Kimberly K. Bolin*

5 **L. SWPA Hydro Reimbursement**

6 On September 16, 2010, Empire received a payment in the amount of \$26,563,700 from
7 the Southwestern Power Administration (SWPA) to compensate Empire for the expected financial
8 impact of a future reduction in capacity at its Ozark Beach hydroelectric plant. The reduction in
9 capacity at Ozark Beach is due to the federal Energy and Water Development Act of 2006, which
10 requires a decrease in available head waters at Ozark Beach. In Case No. ER-2011-0004, Empire
11 agreed to flow the SWPA payment back to the customers over a ten-year period via a tracker
12 mechanism. Staff has included the unamortized balance of \$2,100,623 of this regulatory liability
13 as an offset to rate base.

14 *Staff Expert/Witness: Angela Niemeier*

15 **VI. Allocations**

16 **A. Corporate Allocations**

17 **1. Background**

18 Empire's last electric rate case, ER-2016-0023, was settled among the parties. There was
19 a provision made in the settlement that within two weeks of the filing (6/20/16) of the Stipulation
20 And Agreement, Empire, Staff, and OPC would jointly propose a procedural schedule in Empire's
21 Cost Allocation Manual ("CAM") docket, Case No. AO-2012-0062. Empire, Staff, and OPC did
22 so in a filing on July 29, 2016. After the conclusion of Case No. ER-2016-0023, in Case No.
23 EM-2016-0213, the Commission approved the sale of all of the common stock of Empire to Liberty
24 Utilities (Central) Co. and Liberty Sub Corp.,³² subsidiaries of Algonquin Power & Utilities
25 Corporation ("APUC"). On October 19, 2016, in Case No. AO-2012-0062, Empire, Staff, and
26 OPC, via a *Unanimous Stipulation and Agreement and Joint Request to Suspend Procedural*

³² Liberty Sub Corp. was a special purpose corporation formed for the sole purpose of merging with and into Empire, with Empire emerging as the surviving corporation.

1 *Schedule* (“Unanimous Stipulation And Agreement”), advised the Commission that if the
2 acquisition approved in Case No. EM-2016-0213 closed, Empire should initiate a new proceeding
3 by filing a proposed CAM within six (6) months. The acquisition closed on January 1, 2017, and
4 the Commission closed Case No. AO-2012-0062 on July 5, 2017.³³

5 On June 30, 2017, Empire; The Empire District Gas Company (“EDG”); Liberty Utilities
6 (Midstates Natural Gas) Corp. (“Liberty Midstates”); and Liberty Utilities (Missouri Water), LLC
7 (“Liberty Water”) filed an Application for Approval of CAM, Conditional Request for Variance,
8 and, if Necessary, Request for Waiver in Case No. AO-2016-0360. The CAM attached to the
9 parties’ Application is applicable to APUC and its subsidiaries, and includes an Appendix 9, which
10 contains additional terms and conditions specifically applicable to Empire, EDG, and Liberty
11 Midstates. While the Commission has yet to approve the CAM filed in Case No. AO-2017-0360,
12 since January 1, 2017, the various services directly or indirectly provided to Empire by APUC and
13 its subsidiaries have been allocated based on the allocation procedures described within that CAM.

14 This CAM was also the basis for corporate allocations by Midstates Natural Gas in their
15 most recent rate case (Case No. GR-2018-0013). Many of the issues raised by Staff in the
16 GR-2018-0013 case relative to corporate allocations were deferred to the CAM case. Therefore,
17 Staff does not intend to revisit those issues in this rate case.

18 However, on June 27, 2018, Staff filed a motion to open a working docket, File No.
19 AW-2018-0394, for a review and consideration of rewriting and writing of existing and new
20 Affiliate Transaction Rules. Numerous comments were received concerning the draft affiliate
21 transaction rules, and on July 17, 2019, the Commission ordered Staff to file a new draft rule for
22 its consideration; Staff did so on September 16, 2019. Consequently, on December 30, 2019, the
23 parties to Case. No. AO-2017-0360 filed a *Status Report and Joint Motion to Stay Proceeding*
24 until completion of the workshop docket and a formal rulemaking respecting the Affiliate
25 Transaction Rules. The Commission, in its January 10, 2020, *Order Staying Proceeding*, granted
26 the parties’ joint request.

³³ Paragraph 11 of the Unanimous Stipulation and Agreement in Case No. AO-2012-0062 states as follows:

11. Neither the Staff nor OPC will file a complaint against EDE and/or EDG or provide support for any claim or allegation against EDE and/or EDG on the basis that EDE and/or EDG is or has been non-compliant with the Commission's affiliate transactions rules because EDE and/or EDG are conducting and/or have conducted affiliate transactions without Commission approved CAMs.

1 **2. Allocations**

2 The Corporate Allocation process for Empire flows from many different levels of the
3 corporation and yet, the processes followed at each level are very similar. At its simplest, there
4 are two types of allocation: direct and indirect. Direct allocations to Empire, and other affiliates,
5 occur when the work performed by a corporate entity can be directly related to a specific affiliate,
6 regulated utility, or unregulated utility. On the other hand, indirect allocations occur when the
7 services performed by a corporate entity benefit more than one affiliate, regulated utility, or
8 unregulated utility. The following describes, in general, the allocation process for each of the
9 corporate entities.

10 **Algonquin Power & Utilities Corporation (“APUC”)**

11 As described in APUC’s CAM, there are several services APUC provides as a benefit to
12 its subsidiaries: financing, financial control, legal, executive and strategic management, and
13 related services. Any expenses associated with these services are billed at cost, with fully burdened
14 labor rates. All labor costs that are directly related to a specific subsidiary are charged directly to
15 that entity. With the exception of corporate capital, indirect costs are totaled for a month and then
16 allocated using a Corporate Allocation Method described in the CAM between Liberty Utilities
17 Canada (“LUC”) and Liberty Power. The indirect costs allocated to LUC are further allocated to
18 the individual utilities, which includes Empire, using a Utility Four-Factor allocation
19 methodology. Both direct and indirect allocations are billed monthly to each affected subsidiary.

20 Staff applied an adjustment for the Bonus (Short Term Incentive Plan), Long Term
21 Incentive Plan (“LTIP”), and Stock Options expenses for APUC executives allocated by APUC to
22 its business units. Staff’s review of how these incentives are awarded to the executives found that
23 they were awarded for increasing shareholder value, not as a benefit to the ratepayers. Therefore,
24 Staff applied adjustments to remove from the test year the portions of these expenses that were
25 both directly and indirectly allocated to Empire.

26 **Liberty Utilities (Canada) Corporation (“LUC”)**

27 As described in APUC’s CAM, LUC provides services separately to Liberty Utilities
28 (“LU”) and Liberty Power, and together as shared services. Shared services are provided within
29 LUC under the business unit of Liberty Algonquin Business Services (“LABS”).

1 The services provided to LU include: executive, regulatory strategy, energy procurement,
2 operations, utility planning, administration, and customer experience. All costs incurred that are
3 directly related to a specific utility are charged directly to that utility. Costs that are not directly
4 related to a utility are indirectly allocated to its regulated utilities using a Utility Four-Factor
5 Methodology described in the CAM. These indirect allocations include labor, non-labor, and
6 capital costs.

7 The services provided to Liberty Power include: executive, energy services, asset
8 management, business development, and operations. These services are provided by specific LUC
9 employees who support Liberty Power and, therefore, all associated costs are directly allocated to
10 Liberty Power.

11 Shared services from LUC are the costs that benefit both the group of subsidiary companies
12 owned by LU and Liberty Power and administered under the LABS-Canada business unit. All
13 costs incurred that are directly related to a specific affiliate company or business unit are directly
14 charged to that company or business unit. Costs that are not directly related to a specific utility
15 are indirectly allocated between the regulated and unregulated business units using two Corporate
16 Allocation Methods described in the CAM: one for Business Services indirect costs and another
17 for Corporate Services indirect costs. The Utility Four-Factor Methodology described in the CAM
18 is then used to allocate the indirect costs for the regulated businesses to the individual regulated
19 utilities.

20 Both direct and indirect allocations are billed monthly to each affected subsidiary.

21 **Liberty Utilities Service Corporation (“LUSC”)**

22 LUSC employs most of the U.S.-based utility employees, who are assigned to specific
23 utilities. As such, the majority of employees’ fully loaded labor costs are directly charged to the
24 utility for whom each supports, via timesheet tracking. There are some employees who provide
25 shared services that benefit both LU and Liberty Power through the LABS U.S. business unit.
26 A sampling of these shared services includes customer care and billing, Information Technology
27 (IT) support, and human resources. As with LUC, all costs incurred that are directly related to a
28 specific affiliate company or business unit are directly charged to that company or business unit.
29 Costs that are not directly related to a specific utility are indirectly allocated between the regulated
30 and unregulated business units using two Corporate Allocation Methods described in the CAM:

1 one for Business Services indirect costs and another for Corporate Services indirect costs. The
2 Utility Four-Factor Methodology described in the CAM is then used to allocate the indirect costs
3 for the regulated businesses to the individual regulated utilities.

4 Both direct and indirect allocations are billed monthly to each affected subsidiary.

5 **Empire District Electric**

6 As is discussed earlier in this Report, Empire is engaged in both regulated and
7 non-regulated business operations. Included in Appendix 9 to the CAM, are the additional
8 allocation procedures to be followed by each of the Missouri Regulated Utilities which is the
9 collection of Empire (including its water operations), EDG, and Liberty Midstates. Appendix 9
10 describes the methods for assigning and allocating costs to the regulated electric, gas, and water
11 operations, as well as to the various non-regulated operations. With some exceptions, this has
12 many of the same allocation procedures that existed prior to APUC's acquisition of Empire. Under
13 the Missouri Regulated Utilities' cost allocation system, costs are either directly assigned to
14 business units (referred to as "The Direct Bill Method"), indirectly allocated to the business units,
15 or allocated through use of a general allocation factor.

16 Under the direct assignment approach, Empire directly assigns certain costs to its regulated
17 electric operations either by use of vendor invoices or by labor charges. In the case of assignment
18 by vendor invoice, each vendor invoice that includes charges for goods and services that directly
19 benefit a specific business unit has the invoiced costs directly assigned to the appropriate
20 corresponding business unit. In the case of assignment by labor, all employees are required to
21 record their time electronically based on the amount of time each employee spends each month
22 working for each business unit. The system then allocates a portion of that employee's salary,
23 including associated payroll taxes and fringe benefits, to the appropriate business unit.

24 Empire's indirect allocation factor is based upon a "unit of service method," which is
25 employed by the Company in the event that incurred costs cannot be directly billed to the
26 individual business units as described above. Empire uses the unit service method based on certain
27 unit drivers. Examples of Empire's unit drivers are as follows: number of vouchers, number of
28 active customers, number of purchase orders, and number of personal computers. An allocation
29 rate is then calculated based on information obtained from various general ledger entries and
30 adjusted periodically.

1 For costs that cannot be directly assigned, or that have no unit drivers, the Company uses
2 a modified “Massachusetts Formula” as a general allocation method it refers to as a “Corporate
3 Allocation Method.” A “Massachusetts Formula” is a general allocation factor based upon three
4 (3) separate measurements of directly assigned costs, which is used to allocate a company’s
5 common costs that cannot be reasonably directly assigned or indirectly allocated to a company’s
6 business units. The modified “Massachusetts Formula” used by Empire consists of the averages
7 of (1) profit margin, (2) payroll, and (3) net property, plant, and equipment. It is used to allocate
8 common costs that apply to the regulated activities of Empire, EDG, and Empire’s water
9 operations. Staff modified some of the various allocation factors to reflect Staff’s adjusted
10 numbers that were included in its cost of service. Please reference Staff’s Exhibit Modeling
11 System (“EMS”) that was filed with its cost of service report in this case for the allocation factors
12 used by Staff.

13 Staff has a concern regarding Empire’s allocation methodologies. It appears that Empire
14 may not properly assign a portion of its common costs to its non-regulated operations. Such a
15 methodology would overstate the costs to provide electric service while understating the cost to
16 provide non-regulated operations. Staff has proposed an adjustment to account for these common
17 costs, which is described below.

18 **3. Corporate Expenses**

19 Due to Staff’s concern with the reliability of Empire’s current approach of allocating its
20 corporate costs to its non-regulated activities, as described in Corporate Allocations, Staff has
21 proposed an adjustment to remove a portion of costs related to Empire District Industries, Inc.
22 (“EDI”) allocated to Empire in the test year.

23 *Staff Expert/Witness: Keith D. Foster*

24 **B. Jurisdictional Allocations**

25 Jurisdictional allocation factors are used to allocate demand-related and energy-related
26 costs to the applicable jurisdictions. Fixed costs, such as the capital costs associated with
27 generation and transmission plant, are allocated on the basis of demand. Variable costs, such as
28 fuel, are more appropriately allocated on the basis of energy consumption. In this case,
29 demand-related and energy-related costs are divided among three jurisdictions: Missouri Retail

1 Operations, Non-Missouri Retail Operations and Wholesale Operations. The particular allocation
2 factor applied is dependent upon the type of cost that is being allocated.

3 **1. Demand Allocation Factor**

4 Demand refers to the rate at which electric energy is delivered to a system to match the
5 requirements of its customers (“load”), generally expressed in kilowatts (“kW”) or megawatts
6 (“MW”), either at an instant in time or averaged over a specified time interval. System peak
7 demand is the largest electric requirement (“load”) that occurs within a specified period of time,
8 (e.g. hour, day, month, season and year) on a utility’s system. Since generation units and
9 transmission lines are planned, designed, and constructed to meet a utility’s anticipated system
10 peak demands, plus required reserves, the contribution of each of Empire’s three jurisdictions:
11 Missouri Retail Operations, Non-Missouri Retail Operations and Wholesale Operations,
12 coincident to the system peak demand, *i.e.*, each jurisdiction’s demand at the time of the system
13 peak, is the appropriate basis on which to allocate these facilities. Thus, the term coincident peak
14 (“CP”) refers to the load, generally in kW or MW, in each of the jurisdictions that coincides with
15 Empire’s overall system peak recorded for the time period in the corresponding analysis. Staff is
16 utilizing a Twelve Coincident Peak (“12 CP”) methodology to determine demand allocation
17 factors for Empire. This methodology is appropriate for an electric utility, such as Empire, that
18 experiences similar system peak demands in both summer and winter months. An electric utility
19 that experiences dominant peaks only in the summer months might consider the use of a Four
20 Coincident Peak (“4 CP”) methodology.

21 Staff determined the demand allocation factor for each jurisdiction using the following
22 process:

- 23 a. Identify Empire’s peak hourly load in each month for the test year,
24 April 2018 through March 2019, and sum the hourly peak loads.
- 25 b. Sum the particular jurisdiction’s corresponding loads for the hours
26 identified in (a). above.
- 27 c. Divide (b). by (a). above.

1 The result is the allocation factor for each of Empire’s jurisdictions:

2 Retail Operations:

3 Missouri - .8393

4 Non – Missouri - .1065

5 Wholesale Operations: .0542

6 **2. Energy Allocation Factor**

7 Variable expenses, such as fuel, are allocated to the jurisdictions based on energy
8 consumption. The energy allocation factor, for each individual jurisdiction, is the ratio of the
9 normalized annual kilowatt-hour (“kWh”) usage of each particular jurisdiction to the total
10 normalized Empire kWh usage. The kWh usage data includes adjustments for anticipated growth,
11 annualizations, and non-normal weather. Staff witness Michelle A. Bocklage provided the growth
12 and annualization adjustments. Staff witness Michael L. Stahlman provided the weather and
13 days adjustments. Staff has calculated the following energy allocation factors for the
14 particular jurisdictions:

15 Retail Operations:

16 Missouri - .8240

17 Non – Missouri - .1109

18 Wholesale Operations - .0651

19 Staff witness Keith D. Foster used these demand and energy jurisdictional allocation
20 factors in determining Staff’s recommended cost of service for Empire in this case.

21 *Staff Expert/Witness: Alan J. Bax*

22 **VII. Income Statement**

23 **A. Rate Revenues**

24 **Introduction**

25 Since the largest component of operating revenues results from rates charged to Empire’s
26 Missouri retail customers, a comparison of operating revenues with cost of service is
27 fundamentally a test of the adequacy of the currently effective Missouri jurisdictional retail
28 electricity rates. If the overall cost of providing service to Missouri retail customers exceeds

1 operating revenues, an increase in the current rates that Empire charges to Missouri retail
2 customers for electricity is appropriate.

3 One of the major tasks in a rate case is not only to determine whether a deficiency
4 (or excess) between cost of service and operating revenues exists, but also to determine the
5 magnitude of any such deficiency (or excess). Any deficiency (or excess) identified can only be
6 made up (or otherwise addressed) by adjusting Missouri retail rates (i.e., rate revenues)
7 prospectively, on a going-forward basis.

8 *Staff Expert/Witness: Caroline Newkirk*

9 **Definitions**

10 Operating Revenues are composed of Retail Rate Revenue and Other Operating Revenue.
11 Each is defined respectively as follows:

12 **Retail Rate Revenue:** Test year rate revenues consist solely of the revenues derived from
13 the current rates Empire charges for providing electric service to its Missouri retail customers
14 (i.e., native load and customer charges). Empire’s charges are determined by multiplying each
15 customer’s usage by the per unit rates established in its tariff. Empire’s tariff provides that different
16 rates apply to different types of charges (demand vs. energy) and different times of the year
17 (summer vs. winter); and to customers in different rate classes (differentiation by type and amount
18 of use). Revenues from the Fuel Adjustment Clause (“FAC”) represent collections or refunds of
19 prior period fuel costs and are excluded in determining the annualized level of ongoing
20 rate revenues.

21 **Other Operating Revenue:** This category includes revenues from such items as forfeited
22 discounts, reconnect charges, rent from electric property, and other miscellaneous charges.

23 *Staff Expert/Witness: Caroline Newkirk*

24 **The Development of Rate Revenue in this Case**

25 The objective of this section is to determine normalized and annualized test year usage
26 and revenues by rate class. The intent of Staff’s adjustments to test year Missouri usage and
27 rate revenues is to determine the level of revenue that the Company would have collected on an
28 annual, normal-weather basis, based on information “known and measurable” at the end of the
29 update period.

1 The two major categories of revenue adjustments are known as “normalization” and
2 “annualization.” Normalization adjustments eliminate the impact from revenues of test year events
3 that are unusual and unlikely to be repeated in the years when the new rates from this case are in
4 effect. To eliminate the impact of test year weather on revenues is an example of a normalization
5 adjustment. Annualizations are adjustments that re-state test year results as if conditions known
6 at the end of the update period had existed throughout the entire test year. Adjustment for customer
7 growth is an example of an annualization.

8 *Staff Expert/Witness: Caroline Newkirk*

9 **1. Update Period Adjustment**

10 For purposes of this case, Empire used the test year ending March 31, 2019 as a starting
11 point for any usage and revenue adjustments. Empire then updated usage and corresponding
12 revenues for changes in customer growth. Although Staff will also use the retail revenues from the
13 test year ending March 31, 2019, as a starting point, Staff will update the retail revenues and usage
14 for changes in normalized and annualized sales through the end of July 31, 2019, to provide a more
15 current basis for the revenue calculation.

16 On October 17, 2019, the Commission issued the Order Setting Procedural Schedule and
17 Other Procedural Requirements setting the test year as “the twelve-month period ending with
18 March 31, 2019, updated to September 30, 2019, and trued-up to include known and measurable
19 information through January 31, 2020”. Due to delays in receiving data from Empire directly
20 impacting revenue calculations, Staff was unable to fully calculate revenues through the entirety
21 of the update period. Therefore, in Staff’s direct filing revenues are updated through July 31, 2019.
22 Staff anticipates updating revenues for the remainder of the update period and true up period.

23 *Staff Expert/Witness: Michelle A. Bocklage*

24 **2. Normalization and Annualization of Billing Determinants**

25 Staff normalized and annualized billing determinants for the Residential Service (RG),
26 Commercial Service (CB), Small Heating Service (SH), Total Electric Building Service (TEB),
27 and General Power Service (GP) rate classes, based on the normalized and annualized kWh

1 factor.³⁴ For example, if the normalized and annualized kWh factor is 0.97 for the month of
2 September in the RG rate class, then the total actual usage for that month and that rate class is
3 decreased by 0.03, or 3%.

4 Staff adjusted actual billing determinants to equal the normalized and annualized monthly
5 kWh using the relationship between actual average usage per customer and normalized and
6 annualized average usage per customer. Staff also used the relationship between percentage of
7 usage priced in the first rate block and the second rate block to distribute normalized and
8 annualized monthly kWh to the rate blocks for rate classes RG, CB and SH. This calculation
9 resulted in normalized usage by rate block, which was then converted to total normalized and
10 annualized revenues by multiplying rate block usage by the appropriate rates.

11 The GP and TEB class billing units were similarly adjusted; however, the rate classes were
12 subdivided by voltage with separate normalization and annualization adjustments being applied to
13 each voltage level.

14 The overall difference between Empire's actual billing determinants and rate revenue and
15 Staff's recommended normalized and annualized billing determinants and rate revenue results in
16 Staff's normalized and annualized kWh and revenue adjustments.

17 *Staff Expert/Witness: Michelle A. Bocklage*

18 **3. Adjustments for Non-Missouri classes**

19 Staff adjusted the RG, CB, SH, TEB, and GP classes' usage for non-Missouri customers
20 for weather both to provide normalized kWh and for the days adjustment. Once Staff applied the
21 growth adjustment, the final normalized and annualized usage was provided to Staff witness
22 Michael L. Stahlman for inclusion in calculations for Net System Input ("NSI"), and to Staff
23 witness Alan J. Bax for inclusion in calculations for jurisdictional allocations.

24 *Staff Expert/Witness: Michelle A. Bocklage*

³⁴ The normalized and annualized factors represent the impact of the weather normalization adjustment and the 365 day adjustment on actual usage calculated by Staff witness Michael L. Stahlman.

4. Rate Switching

During the test year, excluding residential customers, there was a net switch of approximately 4 customers who switched rate classes. Table 1, below, shows a summary of the number of all customers that switched between RG, CB, SH, TEB, and GP classes.

Update Period	Rate Switchers	2018			2018			2018			2018			2019		
		Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec	Jan	Feb	Mar			
Res Gen	RG	2	2	2	2	0	0	0	0	0	0	0	0	0	0	
Comm	CB	-10	-9	-8	-4	-3	-1	0	4	1	0	0	0	0	0	
Comm SH	SH	-2	-1	0	0	0	1	0	0	0	0	0	0	0	0	
Gen Pow	GP(ALL)	8	8	9	8	7	4	1	0	-4	-1	0	0	0	0	
TEB	TEB (ALL)	2	2	-1	-2	-3	-1	-1	0	0	0	0	0	0	0	

The calculation of rate switchers could only be completed for the test year and not the update period because Staff did not receive the update period information from Empire until December 11, 2019, which did not allow sufficient time for Staff to calculate the rate switcher adjustment for the update period.

Those customers who switched into and out of each of these classes were handled separately in order to reflect the rate class to which the customer switched. The billing units and revenues of these customers were removed from their original rate code and their usage was added to their final rate code where it was re-priced to match rates in the final rate code.

Staff Expert/Witness: Michelle A. Bocklage

5. Customer Growth (Annualization)

Staff made customer growth adjustments to test year kWh sales and rate revenue to reflect the additional kWh sales and rate revenue that would have occurred if the number of customers taking service at the end of July 31, 2019 had existed throughout the entire test year. Staff calculated customer growth for the RG, CB, SH, TEB, and GP customer classes.

The only retail customer rate classes for which this approach is not taken is the Large Power (“LP”) group and the Feed Mill and Grain Elevator Service (“PFM”) group. The process used for the LP and PFM rate classes is described in the below subsection (7.) of the Report. Staff’s customer growth adjustment to test year usage and resulting revenues for all retail customer groups combines the results of the analysis described above for RG, CB, SH, TEB, and GP in order to provide the annualized level of sales and revenues through the end of July 2019.

Staff Expert/Witness: Michelle A. Bocklage

1 **6. Annualization of Excess Facility Charge Revenues**

2 These revenues result from charges to customers for additional distribution facilities, such
3 as utility poles, transformers, etc., provided in excess of the distribution facilities normally made
4 available to similarly sized customers. Staff annualizes these revenues for changes in the
5 distribution facilities provided during the update period to determine the revenue that the Company
6 would have earned had these additional facilities been in use the entire update period.

7 *Staff Expert/Witness: Michelle A. Bocklage*

8 **7. Large Power and Feed Mill and Grain Elevators Customer**
9 **Annualization**

10 Staff normalized and annualized billing determinants for the LP and PFM rate classes on
11 an individual customer basis. As mentioned by Staff witness Michael L. Stahlman, the LP class
12 was not weather normalized.

13 The annualization adjustments are for the period of August 1, 2018, through
14 September 30, 2019. There were 36 customers in the Missouri LP rate class at the beginning of
15 the update period: 4 customers switched from the GP class during the update period leaving
16 40 customers in the LP class at the end of July, 2019. Staff annualized the LP customers that
17 entered the LP class in order to reflect 12 months of usage for each customer. There were no
18 customers who left or entered the PFM class during the 12 months of the update period.

19 Staff will review the LP and PFM rate classes again for changes in the number of customers
20 in each class during true-up. The overall difference between Empire’s actual billing determinants
21 and rate revenue and Staff’s normalized and annualized billing determinants and rate revenue
22 results in Staff’s normalized and annualized kWh and revenue adjustments.

23 *Staff Expert/Witness: Byron M. Murray*

24 **8. System Energy Losses**

25 When determining the hourly loads used as an input in Staff’s recommended fuel model,
26 Staff accounts for system energy losses, which largely consist of the losses occurring in the
27 electrical equipment (e.g., transmission and distribution lines, transformers, etc.) between an
28 electric utility’s generating sources and its customers' meters. In addition, Staff includes small,

1 fractional amounts of energy that are either diverted (stolen) or unmetered (unmetered usage) as
2 system energy losses.

3 Staff's basis for calculating system energy losses is that Net System Input (NSI) equals the
4 sum of "Retail Sales" + "Wholesale Sales" + "Company Use" and "System Energy Losses." This
5 can be expressed mathematically as:

$$6 \quad \text{NSI} = \text{Retail Sales} + \text{Wholesale Sales} + \text{Company Use} + \text{System Energy Losses}$$

7 NSI, Retail and Wholesale Sales and Company Use are known quantities; therefore, system
8 energy losses may be calculated as follows:

$$9 \quad \text{System Energy Losses} = \text{NSI} - (\text{Retail Sales} + \text{Wholesale Sales} + \text{Company Use})$$

10 The system energy loss percentage is the ratio of system energy losses to NSI multiplied
11 by 100:

$$12 \quad \text{System Energy Loss Percentage} = (\text{System Energy Losses} \div \text{NSI}) \times 100$$

13 NSI is also equal to the sum of the Company's net generation and net interchange.
14 Net interchange is the difference between off-system purchases and off-system sales.
15 Net generation is the total energy output of each generating plant minus the energy consumed
16 internally to enable the production of electricity at each plant. The output of each generating plant
17 is monitored and metered continuously. The net of off-system purchases and off-system sales
18 (Net Interchange) is also similarly monitored.

19 Staff calculated the loss percentage of Empire's system, for the twelve months ending
20 March 2019, as 5.92% of NSI. Staff witness Michael L. Stahlman used this loss percentage in the
21 development of hourly loads used in Staff's recommended fuel model.

22 *Staff Expert/Witness: Alan J. Bax*

23 **9. Normal Weather**

24 **365-Days Adjustment to Usage**

25 Calendar months and revenue months differ from one another because the periods they
26 cover begin and end at different times. Calendar months coincide with the calendar, beginning on
27 the first day of the month and ending on the last day of the month. Staff calculated a normalization

1 adjustment to Empire's kWh usage to reflect a calendar year's (i.e., 365 days') worth of usage.
2 Empire's customers' usage is measured and rate revenues are collected over a period known as a
3 revenue month, which is the interval over which Empire reads customers' meters and issues bills.
4 A bill rendered for a given revenue month may charge for usage in parts of two calendar months.
5 Revenue months usually take their names from the calendar month in which the customer's bill is
6 rendered. For example, assume a customer's meter was read and usage determined on June 8 and
7 then again on July 8 and that the bill was sent to the customer on July 15. The revenue month for
8 this bill is July even though 22 days of the usage measured for this bill occurred from June 9
9 through June 30 and it contained only eight days of usage in July.³⁵

10 The length of a revenue month is dependent upon the interval between meter readings and
11 does not necessarily have the same number of days that occur in a given calendar month of the
12 same name; that is, a revenue month may have more than or less than the number of days for the
13 same-named calendar month. For the example given above, the usage is for 30 days (June 9
14 through July 8), even though the revenue month is July, which has 31 days. When revenue month
15 usage is totaled over the year, the resulting revenue year will include usage from the immediately
16 prior calendar year and assign usage to the next calendar year, meaning a revenue year may contain
17 more than or less than 365 days' usage. Therefore, since the costs and expenses are accounted over
18 a calendar year, Staff calculates an annualization adjustment to bring the revenue year kWh into a
19 365-days interval. This adjustment is stated in kWh and is referred to as the 365-Days Adjustment.
20 Staff calculated the 365-Days Adjustment by adjusting individual bill cycles that had more than
21 or less than 365 days' usage from the first date in that cycle's revenue test year to the last meter
22 read date in that cycle's revenue test year. The overall average usage per day of that cycle was
23 then multiplied by the days over/under 365 days to determine the kWh adjustment.

24 The 365-Days Adjustment for RES, SGS, LGS, SPS, and LPS were provided to Staff
25 witness Michelle A. Bocklage, who used the 365-Days Adjustment to adjust the revenues of the
26 weather-normalized class revenues months to the twelve months ended June 30, 2019.

27 *Staff Expert/Witness: Michael L. Stahlman*

³⁵ Primary months are used to distinguish in which month the usage is billed under and whether summer or winter rates apply. For example, a customer's sixth bill of the year is deemed the customer's June bill even if it is billed to the customer on May 29. In this example, the primary month is June and the summer rate will apply to all usage on the bill, even though the revenue month would be May.

Weather Normalization of Usage

In many of the classes of service, electricity consumption is highly responsive to the weather, specifically temperature. As the temperature reaches higher levels, the demand for cooling, air conditioning and fans increases the customers' consumption of electricity. As the weather becomes cold and temperature falls, the demand for additional heating, electric space heating for example, also forces an increase in electricity consumption. Electric air conditioning and space heating is prevalent in Empire's service territory, therefore, it follows that Empire's electric load is linked with and responsive to temperature.

Empire's test year ran from April 1, 2018, through March 31, 2019. In an attempt to capture a more likely forward-looking indicator of non-weather electricity usage per customer, Staff used the most recent temperature and load data available and, therefore, based its analysis on a period of August 1, 2018, through July 31, 2019. Although Staff has subsequently received information through September 2019, preliminary review of the data did not suggest that it was likely to change the level of normalized usage per customer and there was insufficient time for Staff to complete and update the analysis.

Also at the time of this writing, Staff did not have billing cycle data per rate class through the update period. To better explain the importance of this data, in a rate case, Staff will get revenues based on a revenue month rather than a calendar month (e.g., you may get a bill on June 17th which is for usage between May 15th and June 15th, and all that usage is treated as the June revenue month). The sample mean data, which is a sample of rate class's usage for a given day, that Empire provided allows for a statistical relationship between weather and use to be determined for any given calendar day. Staff then uses the meter read schedule to apply that calendar day relationship to get the weather factor for any one of the twenty-one bill cycles in a revenue month. But without the billing cycle information, there is no really good method of determining the proper weight that bill cycles have to get a single weather factor for the entire revenue month (i.e. if there are more customers in one bill cycle than another, that one with the most customers should have more importance in determining the overall weather factor adjustment). Thus, in the absence of better information, Staff weighted each billing cycle equally. Staff Data Request No. 0142.2 is still pending on this subject.

The method and model used by Staff is similar to those used by Empire. Staff's model and methodology contained elements important in the class-level weather normalization process: use

1 of daily sample means data to determine non-linear, class-specific responses to changes in
2 temperature with the incorporation of different base usage parameters to account for different days
3 of the week, months of the year and holidays. The results of Staff's analysis were provided to Staff
4 witness Michelle Bocklage to be used in the normalization of revenues for weather sensitive
5 classes, Residential (RES), Commercial Service (CB), Small Heating Service (SH), General Power
6 Service (GP), and Total Electric Building Service (TEB).

7 *Staff Expert/Witness: Michael L. Stahlman*

8 **Weather Variables**

9 **Historical Data Used to Calculate Weather Variables** - Each year's weather is unique;
10 consequently, test year usage, hourly loads, revenue, and fuel and purchased power expense need
11 to be adjusted to "normal" weather so that rates will be designed on the basis of normal weather
12 rather than any anomalous weather in the test year. In the quantification of the relationship
13 between test year weather and energy sales, Staff used weather observations of Springfield
14 Regional Airport ("SGF") in Springfield, Missouri for the period of August 1, 2018, through
15 July 31, 2019.

16 Weather Variables - Staff obtained weather data from the Midwest Regional Climate
17 Center (MRCC). Weather data of Springfield Regional Airport ("SGF") was used for the service
18 territory of Empire. The weather data sets consist of actual daily maximum temperature ("Tmax")
19 and daily minimum temperature ("Tmin") observations. Staff used these daily temperatures to
20 develop a set of mean daily temperature ("MDT") values.

21 **Normal Weather** - According to the National Oceanic and Atmospheric Administration
22 ("NOAA"), a climate "normal" is defined as the arithmetic mean of a climatological element
23 computed over three consecutive decades.³⁶ In developing climate normal temperatures, the
24 NOAA focuses on the monthly maximum and minimum temperature time series to produce the
25 serially-complete monthly temperature ("SCMT") data series.³⁷

26 Staff utilized the SCMT published in July 2011 by the National Climatic Data Center
27 ("NCDC") of the NOAA. For the purposes of normalizing the test year electric usage and

³⁶ Retrieved on October 17, 2013, <https://www.ncdc.noaa.gov/data-access/land-based-station-data/land-based-datasets/climate-normals>.

³⁷ Retrieved on October 17, 2013, <http://www1.ncdc.noaa.gov/pub/data/normals/1981-2010/source-datasets/>. The SCMT, computed by the NOAA, includes adjustments to make the time series of daily temperatures homogeneous.

1 revenues, Staff used the adjusted T_{\max} and T_{\min} daily temperature series for the 30-year period of
2 January 1, 1987, through December 31, 2016, at SGF. The series is consistent with NOAA's
3 SCMT during the most recent NOAA 30-year normal period ending 2010.

4 There may be circumstances under which inconsistencies and biases in the 30-year time
5 series of daily temperature observations occur, (e.g. such as the relocation, replacement, or
6 recalibration of the weather instruments). Changes in observation procedures or in an instrument's
7 environment may also occur during the 30-year period. The NOAA accounted for documented
8 and undocumented anomalies in calculating its SCMT.³⁸ The meteorological and statistical
9 procedures used in the NOAA's homogenization for removing documented and undocumented
10 anomalies from the T_{\max} and T_{\min} monthly temperature series is explained in a peer-reviewed
11 publication.³⁹

12 Subsequent to determining the homogenized monthly temperature time series described
13 above, the NOAA also calculates monthly normal temperature variables based on a 30-year normal
14 period, e.g. maximum, minimum, and average temperatures. These monthly normals are not
15 directly usable for Staff's purposes, because the NOAA daily normal temperatures values are
16 derived by statistically "fitting" smooth curves through these monthly values. As a result, the
17 NOAA daily normal values reflect smooth transitions between seasons and do not directly relate
18 to the 30-year time series of MDT as used by Staff. However, in order for Staff to develop
19 adjustments to normal weather for electric usage, Staff must calculate a set of normal daily
20 temperature values that reflect the actual daily and seasonal variability.

21 Staff used a ranking method to calculate normal weather estimates of daily normal
22 temperature values, ranging from the temperature that is "normally" the hottest to the temperature
23 that is "normally" the coldest, thus estimating "normal extremes." Staff ranked MDTs for each
24 month of the 30-year history from hottest to coldest and then calculated the normal daily
25 temperature values by averaging the ranked MDTs for each rank, irrespective of the calendar date.
26 The ranking process results in the normal extreme being the average of the most extreme
27 temperatures in each month of the 30-year normals period. The second most extreme temperature

³⁸ Arguez, A., I. Durre, S. Applequist, R. S. Vose, M. F. Squires, X. Yin, R. R. Heim, Jr., and T. W. Owen, 2012: NOAA's 1981-2010 U.S. Climate Normals: An Overview. *Bulletin of the American Meteorological Society*, 93, 1687-1697.

³⁹ Menne, M.J., and C.N. Williams, Jr., (2009) Homogenization of temperature series via pairwise comparisons. *J. Climate*, 22, 1700-1717.

1 is based on the average of the second most extreme day of each month, and so forth. Staff's
2 calculation of daily normal temperatures is not the same as NOAA's calculation of smoothed daily
3 normal temperatures because Staff calculated its normal daily temperatures based on the rankings
4 of the actual temperatures of the test year, and the test year temperatures do not follow smooth
5 patterns from day to day.⁴⁰ More details of a ranking method for normal weather are explained in
6 a peer-reviewed publication.⁴¹ Using these normal daily temperatures, Staff calculated normal
7 MDT for each day of the test year. I then used this information for weather normalization of the
8 test year kWh usage and update period hourly loads.

9 *Staff Expert/Witness: Michael L. Stahlman*

10 **Load Requirement at Transmission**

11 Hourly load requirement is the hourly electric supply necessary to meet the energy
12 demands of both the company's customers and the company's own needs. The hourly loads used
13 in the analysis of the period August 2018, through July 2019, were obtained from Empire's data
14 provided in accordance with 20 CSR 4240-3.190 (1)(C).

15 Due to the high saturation of air conditioning, and the presence of significant electric space
16 heating in Empire's electric service territory, the magnitude and shape of Empire's load
17 requirement are directly related to daily temperatures. The actual daily temperatures for the update
18 period differed from normal conditions. Therefore, to reflect normal weather, daily peak and
19 average load requirement are adjusted independently, but using the same method.

20 Independent adjustments are necessary because average loads and peak loads respond
21 differently to weather. Daily average load is calculated as the daily energy divided by twenty-four
22 hours and the daily peak is the maximum hourly load for the day. Separate regression models
23 estimate both a base component, which is allowed to fluctuate across time, and a weather sensitive
24 component, which measures the response to daily fluctuations in weather for daily average loads
25 and peak loads. The regression parameters, along with the difference between normal and actual
26 cooling and heating measures, are used to calculate weather adjustments to both the average and

⁴⁰ It is important to note that Staff's calculation of daily weather normal temperatures do not assign a temperature to a specific calendar date; the method assigns a rank to a normal temperature which is matched to the rank of the actual temperature for a given period.

⁴¹ Won, S. J., Wang, X. H., & Warren, H. E. (2016). Climate normals and weather normalization for utility regulation. *Energy Economics*, 54, 405-416.

1 peak loads for each day. The adjustments for each day are added respectively to the actual average
2 and peak loads for each day. Staff witness Michael L. Stahlman provided actual and normal daily
3 temperatures used in this analysis.

4 The starting point for allocating both the weather-normalized daily peak and the
5 weather-normalized average loads to the hours is the actual hourly loads. A unitized load curve
6 is calculated for each day as a function of the actual peak and average loads for that day.
7 The corresponding weather-normalized daily peak and average loads, along with the unitized load
8 curves, are used to calculate weather-normalized hourly loads. This process includes many checks
9 and balances, which are included in the spreadsheets that are used. In addition, the analyst is
10 required to examine the data at several points in the process. For more information, the process is
11 described in greater detail in the document “Weather Normalization of Electric Loads, Part A:
12 Hourly Net System Loads”.⁴²

13 After weather-normalizing and annualizing usage for Empire’s Missouri jurisdictional
14 retail customer classes is completed, weather-normalized wholesale usage, as well as any
15 non-Missouri jurisdictional usage, is added to produce an annual sum of the hourly net system
16 loads that equals the adjusted test year usage, plus losses, and is consistent with Staff’s Missouri
17 jurisdictional normalized revenues.

18 A factor was applied to each hour of the weather-normalized loads to produce an annual
19 sum of the hourly load requirement that equals the adjusted test year usage, plus losses, and is
20 consistent with normalized revenues. Once completed, the test-year hourly normalized system
21 loads were given to Staff witness Charles T. Poston, PE to be used in developing the test year fuel
22 and purchased-power expense.

23 *Staff Experts/Witnesses: Michael L. Stahlman and Shawn E. Lange*

24 **10. Economic Development Riders**

25 Staff calculated the normalized level of revenue forgone by Empire, by class, due to
26 discounts provided under the Economic Development Rider (“EDR”) and Limited Large Customer
27 Economic Development Rider⁴³ (“LLCEDR”) tariffs. Staff calculated this amount by applying

⁴² “Weather Normalization of Electric Loads, Part A: Hourly Net System Loads” (November 28, 1990), written by Dr. Michael Proctor, Manager of the Economic Analysis Department.

⁴³ The purpose of the Limited Large Customer Economic Development Rider is to comply with Mo. Rev. Stat. Section 393.1640 (2018).

1 the discount percentage applicable under each customer's contract for each of the 12 months
2 ending September 2019. Staff will update this calculation and resulting revenue adjustment as part
3 of true-up. The dollars of revenue reduced due to the EDR/ LLCEDR discount was provided by
4 rate schedule to Staff's revenue witness to be accounted for in Staff's total revenue calculated.⁴⁴

5 Staff did not find any customers which currently need to be excluded from the
6 EDR/ LLCEDR calculation, however, customers may be excluded in the future in the following
7 instances: where documentation of the EDR/ LLCEDR contract is not provided, where a review
8 of documentation provided indicates the customer did not qualify for the EDR/ LLCEDR
9 or continued receipt of the EDR/ LLCEDR, or where the form of the EDR/ LLCEDR provided
10 is improper.⁴⁵

11 Staff recommends that Empire continue to review compliance with the EDR/ LLCEDR
12 tariffs for each customer receiving the discount, including but not limited to the following terms:

- 13 1. Ensuring that the local, regional, or state governmental economic development
14 incentives that are provided as qualification under the Availability provisions of Tariff
15 Sheet Nos. 22, 22d, and 22e are actually awarded and accepted. Some of the EDR/
16 LLCEDR documents provided to the Commission include only an offer letter from a
17 governmental economic development agency with no indication the incentives were
18 ultimately accepted and conditions associated with the receipt of such incentives have
19 been met and maintained.
- 20 2. Ensuring that an annual load factor of 50% or greater has been maintained in years
21 three through five of service under the EDR, as applicable, pursuant to Tariff Sheet No.
22 22, Applicability Paragraph 1; or under the LLCEDR, 55% or greater has been
23 maintained in years three through five of service, as applicable, pursuant to Tariff Sheet
24 No. 22c, Availability/Eligibility Paragraph 4.
- 25 3. Review expansion customers to determine whether load shifting has occurred, pursuant
26 to EDR Tariff Sheet No. 22a Incentive Provision Paragraph 2 or LLCEDR Tariff Sheet

⁴⁴ Per page 3, paragraph 12 of the Non-Unanimous Stipulation and Agreement filed in ER-2012-0345, Empire agrees to hold customers harmless in future general rate increase requests from any rates collected by Empire pursuant to the Economic Development Rider that are less than the rates a similarly situated customer would be charged pursuant to the applicable tariff rate.

⁴⁵ Limited Large Customers have just begun receiving the discount outside the test period or have not completed expansion work at this time. Those still in the expansion phase have provided projections for Annual Load Factor. Actual Load Factor will be reviewed in future rate cases as appropriate. Customers will need to remain in compliance continuously to receive discounts.

1 No. 22d Applicability Paragraph 5. If shifting has occurred, metering arrangements
2 must be made to exclude shifted amounts from the metered amount subject to the
3 EDR/ LLCEDR discount.

- 4 4. Ensure market value of capacity analysis is performed, monitored, and reported to
5 Commission Staff and the Office of Public Counsel pursuant to SBEDR Tariff Sheet
6 No. 22e Incentive Provisions Paragraph 4.

7 As part of the review, Empire should present documentation confirming the continued
8 eligibility of each EDR/ LLCEDR customer under each item provided above. Pursuant to this
9 review, customers not meeting continued eligibility requirements to receive the EDR/ LLCEDR
10 discounts should be removed from the EDR/ LLCEDR calculation. At this time, Staff did not find
11 any customers which currently need to be excluded based on EDR/ LLCEDR qualifications for
12 discounts. Staff will continue to review and monitor the EDR/ LLCEDR customer program and
13 may make further recommendations in this case or future cases.

14 **Empire EDR Adjustments**

15 The Empire EDR tariff prescribes a yearly rate discount schedule for the first through the
16 fifth service contract years. Staff excluded \$6,173.80 from the second year discount allowed for
17 customer ** _____ **. Billing for this
18 customer's first two years of new service were reviewed by Staff. The February and September
19 2019 billing adjustments for the EDR discount exceeded the 25% second year discount rate by the
20 excluded amount. All other EDR discount billing adjustments for this customer's first and second
21 year were in compliance with the EDR tariff. There is only one customer receiving a discount
22 under the EDR tariff.

23 There were no customers receiving discounts under the LLCEDR tariff for the
24 12 months ending September 2019. Three customers have completed applications and will qualify
25 for LLCEDR discounts based on projected new load demand. One of these
26 customers, ** _____ **, just began new service at the time of this review and Empire should
27 be able to provide billing and LLCEDR discount data in the future. The other two qualifying
28 customers have not started new or expanded service with Empire at this time.

1 Finally, Staff has verified that all Empire customers are currently participating in another
2 Missouri Economic Development program or are approved for participation pursuant with the
3 EDR/LLCEDR tariff requirement.

4 *Staff Expert/Witness: Nancy L. Harris*

5 **11. Stub Period Tax Cut/Removal of Tax Impact**

6 The test year rate revenues do not reflect the full amount of the reduction to Empire's
7 tariffed rates ordered by the Commission on August 30, 2018 in Case No. ER-2018-0366, as a
8 result of the federal tax rate reduction that became law earlier in 2018. As a result, test year
9 revenues were overstated by the difference between the amount that was actually billed to
10 customers during the test year and the amount that would have been billed if the federal tax rate
11 reduction had been in effect throughout the entire test year. Staff has proposed an adjustment to
12 remove the income tax impact to revenues for each rate class by multiplying the actual test year
13 kWh for the months of April 2018 through August 2018 by the appropriate class' tax credit as
14 established in the above case. Staff also removed amounts that were recorded as an offset to
15 revenues during the test year for the stub period tax benefits.

16 *Staff Expert/Witness: Kimberly K. Bolin*

17 **B. Other Revenues**

18 **1. FAC Revenues**

19 Staff removed from test year revenues, the Fuel Adjustment Clause ("FAC") revenues.
20 This adjustment is necessary to in order to calculate new retail rates. Brooke Mastrogiannis
21 addresses Staff's recommendations for the FAC in Section XI of this report.

22 *Staff Expert/Witness: Caroline Newkirk*

23 **2. Unbilled Revenues**

24 Staff has eliminated unbilled revenue from its determination of revenue requirement to
25 ensure only 365 days of revenue are included and to reflect revenues on an "as billed" basis.
26 The recording of unbilled revenue on the books of the Company recognizes sales of electricity that
27 have occurred, but have not yet been billed to the customer. Therefore, it is necessary for Staff to

1 remove unbilled revenue in order to reach an accurate revenue requirement based upon electricity
2 sales billed to and revenues collected from Missouri customers.

3 *Staff Expert/Witness: Caroline Newkirk*

4 **3. Gross Receipts Revenues**

5 For this item, Empire acts merely as a collecting agent and remits the taxes collected from
6 customers to the appropriate taxing entities. The Gross Revenue Taxes (“GRT”), also known as
7 city franchise taxes, included on a customer’s bill are collected by the Company and remitted to
8 the appropriate taxing authority. The GRT included on a customer’s bill is recorded as revenue on
9 the books of the Company, with a corresponding charge booked to GRT expense. Theoretically,
10 the revenue and expense offset one another and, therefore, have no effect on net income. GRT are
11 reported as both a revenue and expense item on Empire’s books. Staff has made adjustments to
12 eliminate both the revenue and expense associated with GRT.

13 *Staff Expert/Witness: Caroline Newkirk*

14 **4. Renewable Energy Credits (“REC”)**

15 Empire is currently receiving wind energy from the following counterparties: Greenlight
16 Energy, Swiss Carbon, and Renewable Choice Energy. As a result of these contracts, Empire
17 receives Renewable Energy Credits or Certificates (“RECs”), which are credits issued under the
18 Center for Resource Solutions’ “green-e” program to certify that one megawatt-hour of electricity
19 has been generated by a facility engaged in the production of renewable energy, such as wind,
20 solar or biomass. RECs are tradable and can be bought and sold. Since the REC Revenue for the
21 12 months ending September 30, 2019 was unusually low when compared to the two previous
22 years, Staff normalized the three years ending September 30, 2019. Staff also removed any non-
23 Missouri jurisdictional accounts from REC revenues.

24 *Staff Expert/Witness: Caroline Newkirk*

25 **5. Coal Fly Ash Revenues**

26 “Coal fly ash” is a byproduct created as a result of the burning of coal in generating stations
27 to produce electricity. Fly ash has a number of possible industrial uses, primarily as an ingredient
28 in concrete products. Over the past several years, Empire has been selling its fly ash to several

1 different industrial companies to be used in concrete. By recycling fly ash, Empire not only
2 receives a profit, but also provides positive environmental benefits. During the test year Empire
3 collected \$43,879 of revenue for the sale of this product. Staff analyzed three years of data based
4 on the updated test year period of 12-months ending September 30, 2019. Since there has been a
5 downward trend over the past three years, Staff left fly ash revenue amounts at test year.

6 *Staff Expert/Witness: Caroline Newkirk*

7 **6. Miscellaneous Revenues**

8 Empire's miscellaneous other revenues consist of forfeited discounts, rents from property,
9 reconnect, and surge arrester fees.

10 Staff's analysis reflected a review of these revenue levels over a three-year period ending
11 September 30, 2019. Based upon Staff's review, the miscellaneous revenue levels at a 12-month
12 period ending September 30, 2019, appear reasonable for inclusion in customer cost of service.

13 *Staff Expert/Witness: Caroline Newkirk*

14 **C. Amortizations**

15 **1. Amortization of Ice Storm Costs**

16 In reviewing the records provided by Empire, Staff noted that it booked ice storm
17 amortizations from other states, which are not recoverable in Missouri rates. Staff could not find
18 any booked costs associated with ice storms in Missouri. Staff made an adjustment to eliminate
19 the amounts of the ice storm amortizations from other states.

20 *Staff Expert/Witness: Angela Niemeier*

21 **2. Southwestern Power Administration ("SWPA") Hydro** 22 **Reimbursement and Amortization**

23 As described previously in this Report, in Case No. ER-2011-0004, Empire agreed to flow
24 the SWPA payment back to its customers over a ten-year period via a tracker mechanism. This
25 yearly amortization, unlike other amortizations discussed in this Report, does not increase the
26 Company's expense levels, but is a reduction or offset to expenses. Staff included an adjustment
27 of \$109,385 as an offset to expenses.

28 *Staff Expert/Witness: Angela Niemeier*

1 **3. DSM Cost Recovery**

2 Empire’s Account 182318 contains costs of the Company’s demand-side management
3 (“DSM”) programs that are in various stages of development and implementation. Staff
4 participated in the previously authorized (and now expired) Customer Programs Collaborative
5 (“CPC”) and participates in the current authorized DSM advisory group established to assist
6 Empire in the development of DSM programs. Based upon Staff’s participation in these groups,
7 as well as Staff’s review of the costs in Account 182318, Staff has amortized the amounts incurred
8 by Empire prior to the end of its Regulatory Plan (June 15, 2011) over ten years. Any amounts
9 incurred after the end of the Regulatory Plan to date are amortized over a period of six years,
10 consistent with the terms of the Commission’s *Report and Order* in Case No. ER-2014-0351.
11 Staff has removed the amortization of program expenditures from 2007 and 2011 since they
12 expired in December 2017 as well as the amortization of the expenditures from 2008 and 2012
13 since they expired in December 2018. The DSM costs include the payments to Empire’s customers
14 that participate in the programs.

15 *Staff Expert/Witness: Caroline Newkirk*

16 **4. Amortization of Electric Plant**

17 Staff has adjusted the amortization reserve for electric plant intangible assets to reflect the
18 updated balances through September 30, 2019, the end of the update period for this case.
19 The amortization reserve balance as of September 30, 2019, is \$21,933,340 and was included as
20 an offset to rate base in Staff’s Accounting Schedules. Staff will review this recommendation again
21 in true-up.

22 *Staff Expert/Witness: Courtney Barron*

23 **5. Amortization of PeopleSoft Intangible Asset**

24 Staff has adjusted the intangible asset for the PeopleSoft software costs to reflect the
25 updated balances through September 30, 2019. The regulatory asset balance, as of the end of the
26 update period September 30, 2019, is \$93,909 and was included as an addition to rate base in
27 Staff’s Accounting Schedules. Staff will review this recommendation again in true-up.

28 *Staff Expert/Witness: Courtney Barron*

1 **6. Amortization Expense**

2 When Empire converted to PowerPlan, all the one hundred accounts were grouped into a
3 single account number (111000) in the company’s general ledger. The company provided the
4 sub-ledger that broke out each individual account grouped under account number 111000. Staff
5 reviewed all of Empire’s amortization expense booked under account number 111000. Staff made
6 an adjustment to increase this expense to reflect the annualized amortization based on updated
7 information through September 30, 2019.

8 *Staff Expert/Witness: Courtney Barron*

9 **7. Tornado Accounting Authority Order (“AAO”) Amortization**

10 The Commission issued an order on November 30, 2011, that approved and incorporated
11 the Stipulation and Agreement in Empire’s Application for an Accounting Authority Order, Case
12 No. EU-2011-0387. In that Stipulation and Agreement, the parties agreed to allow Empire to defer
13 to Account 182.3 Other Regulatory Assets the following items: incremental operations and
14 maintenance expenses associated with the repair, restoration and rebuild activities associated with
15 the May 22, 2011 tornado; and depreciation and carrying charges equal to its ongoing Allowance
16 for Funds Used During Construction rates associated with tornado-related capital expenses. The
17 company agreed that if it filed a general rate case in Missouri by June 1, 2013 (which it did), then
18 Empire would begin to amortize over a ten year period the deferral balance beginning at the earlier
19 of: 1) the effective date of new rates implemented in its next general rate case or rate complaint
20 case; or 2) June 1, 2013. As of September 30, 2019, Empire had a deferred balance of \$1,408,802
21 in Account 182.3 for tornado related expenses. Staff has not included this in rate base because of
22 the Commission’s long-standing policy of “sharing” the financial impact of extraordinary events,
23 such as tornado expenses, through exclusion of the unamortized portion of an accounting authority
24 order deferral from rate base. The annual amortization calculated in the last rate case,
25 ER-2016-0023, has not changed, therefore, Staff included the same annualized amount in this case.

26 *Staff Expert/Witness: Kimberly K. Bolin*

27 **8. Iatan Carrying Costs Amortization**

28 Pursuant to earlier agreements, Empire deferred certain carrying costs (monthly debt
29 and equity-derived carrying charges) and monthly depreciation for its Iatan 1 AQCS

1 Account 182308 – Iatan Deferred Carrying Costs, Iatan 2 Account 182332 – MO IatanII Df Chg
 2 ER-2010-0130, and Plum Point Account 182331 – MO PlumPt Df Chgs ER-2010-0130. This
 3 deferral of carrying costs on the Iatan 1 AQCS, Iatan 2, and Plum Point investments was authorized
 4 under previous agreements approved by the Commission. In Empire’s Case No. ER-2012-0345,
 5 Staff recommended amortization of these carrying costs into the cost of service using a composite
 6 amortization rate derived from dividing the total depreciation expense for each plant by the total
 7 plant balance for each plant. Staff used these composite rates and calculated amortization amounts
 8 of \$84,729 for Iatan 1 AQCS, \$44,828 for Iatan 2, and \$1,987 for Plum Point. Staff used the same
 9 amortization amounts in this case.

10 *Staff Expert/Witness: Kimberly K. Bolin*

11 **9. Iatan and Plum Point O&M Tracker Regulatory Asset**

12 Per the Stipulation and Agreement in Case No. ER-2016-0023, the Iatan and Plum Point
 13 O&M trackers were discontinued and regulatory assets were established in the following amounts;
 14

Discontinued Tracker	Asset as of March 31, 2016	Annual Amortization
Iatan Common	\$759,080	\$253,027
Iatan 2	(\$196,421)	(\$65,474)
Plum Point	\$110,308	\$36,769

15
 16 All three regulatory assets were to be amortized over three years. Amortizations began
 17 mid-September 2016. These assets were fully amortized mid-October 2019. Staff removed this
 18 amortization expense from the test year and Staff did not include any balances for these assets in
 19 rate base since they have expired.

20 *Staff Expert/Witness: Kimberly K. Bolin*

21 **10. Amortization of Excess ADIT**

22 The Tax Cuts and Jobs Act was signed into law in December 2017, and as part of that a
 23 reduction in the corporate tax rate required the revaluation of accumulated tax timing differences
 24 that were previously valued at 35% to be revalued at 21%. This excess deferred tax value is
 25 required to be returned to customers based on whether the excess deferred taxes are protected or
 26 unprotected. Protected excess ADIT is the portion associated with accelerated depreciation tax

1 timing differences that must be “normalized” for rate making purposes and where the flow back
2 of excess ADIT cannot be returned to customers any more quickly than over the estimated life of
3 the assets that gave rise to the ADIT. Unprotected excess ADIT is the portion of the deferred tax
4 reserve that resulted from normalization treatment of tax timing differences other than accelerated
5 depreciation.

6 The Commission ordered Empire in Case No. ER-2018-0366, to record a regulatory
7 liability for the difference between the excess ADIT balances at 35% versus 21%. Recovery of
8 the deferred amounts was to be determined in Empire’s next general rate proceeding. Staff
9 recommends inclusion of the amortization of the return of excess ADIT in rates for Empire electric
10 customers in this rate proceeding. The impact of this issue is reflected on the Income Tax Schedule
11 in Staff’s Accounting Schedules.

12 *Staff Expert/Witness: Kimberly K. Bolin*

13 **11. Stub Period Amortization**

14 On January 1, 2018, the Tax Cuts and Jobs Act (TCJA) became effective. Among other
15 impacts, the TCJA dramatically reduced the federal income tax rates applicable to businesses,
16 including regulated utilities.

17 In 2018, the Missouri Legislature approved a law that, among other provisions, allowed
18 the Commission to reduce rates on a single-issue basis for electric utilities on account of the TCJA
19 federal income tax rate reduction. (Single-issue treatment of TCJA impacts was only allowed for
20 utilities, such as Empire, not already before the Commission in a general rate case filing at the
21 time.) In Case No. ER-2018-0366, the single-issue rate proceeding opened for Empire, the
22 Commission ordered Empire District Electric to reduce its rates by approximately \$17.5 million
23 effective August 28, 2018 in order to pass on to customers the annual ongoing savings related to
24 the TCJA tax rate change. However, another issue was litigated in Case No. ER-2018-0366:
25 how should the tax benefit from the TCJA that inured to Empire’s benefit from January 1 to
26 August 28, 2018 (i.e., the “stub period”) be treated for accounting purposes? After hearings,
27 the Commission ordered Empire to defer approximately \$11.7 million of stub period tax savings
28 benefits on its balance sheet as a regulatory liability for potential flow-back to customers, but
29 with the ratemaking treatment of the regulatory liability reserved to Empire’s next general
30 rate proceeding.

1 In its Report and Order issued for Case No. ER-2018-0366, the Commission referred to the
2 TCJA as an “extraordinary event,” and noted that none of the parties appeared to contest that
3 characterization during the case. The Commission has often in the past ordered deferrals of costs
4 or savings associated with extraordinary events, and subsequently passed on those costs/savings
5 to customers in rates through amortizations of regulatory assets (deferred costs or expenses) or
6 regulatory liabilities (deferred revenues or savings).

7 Staff agrees with the Commission that enactment of the TCJA as a whole was an
8 extraordinary event, and for that reason recommends that the entire amount of benefit that accrued
9 to Empire in the stub period from the lower TCJA income tax rates should be flowed back to
10 customers in rates through an amortization.

11 At this time, Staff finds an amortization period of five years appears to be appropriate for
12 this item. Consistent with the common practice afforded in the past to regulatory assets and
13 liabilities, Staff is not proposing to include the unamortized balance of the TCJA stub period
14 regulatory liability in rate base.

15 *Staff Expert/Witness: Mark L. Oligschlaeger*

16 **D. Fuel and Purchased Power Expense**

17 **1. Fixed Costs**

18 Staff does not calculate within its fuel model those fuel and purchased power costs that
19 do not vary directly with the amount of fuel burned. These costs are determined separately. The
20 non-variable fuel costs included in fuel expense are typically referred to as fuel adders, described
21 in the section below. The non-variable purchased power costs are referred to as capacity charges
22 and these costs are annualized separately from purchased power energy costs.

23 *Staff Expert/Witness: Amanda C. McMellen*

24 **a. Fuel Adders**

25 The costs of fuel adders are determined separately from fuel model costs and are added to
26 the level of fuel expense calculated by the model to determine overall fuel expense. The fuel
27 adders in this case are natural gas transportation costs and freeze treatment costs for coal deliveries.
28 Staff annualized the natural gas transportation expense based on Empire’s current
29 contractual obligations with SSGCGP, which began on January 1, 2010. In regard to freeze

1 treatment costs, all PRB coal delivered by rail to Asbury is subject to being sprayed with a side
2 release for freeze conditioning during the winter months. However, Staff could not confirm
3 that the treatment was applied consistently in order to determine an annualized cost. Therefore,
4 Staff used the actual costs for freeze treatment incurred for the twelve months ending
5 September 30, 2019 (the update period), to add to the total fuel costs.

6 *Staff Expert/Witness: Amanda C. McMellen*

7 **b. Purchased Power – Capacity Charges**

8 In addition to its ownership interest in the Plum Point unit through Plum Point Energy
9 Associates, LLC, Empire has contracted for a reservation of an additional 51 MW capacity from
10 Plum Point through a purchased power contract. For this 51 MW of power, Empire pays a fixed
11 component and an energy component. The fixed amounts Empire pays are referred to as capacity
12 charges. Generally, there is an amount for Plum Point operation and maintenance costs included
13 within the energy charge. The fixed component is paid as a “demand charge,” generally on a
14 monthly basis, regardless of the level of power actually purchased. This amount is for the “right”
15 to purchase the power in much the same way that natural gas utilities purchase reservation of
16 capacity from pipelines through reservation payments. The demand charges are intended to cover
17 part of the fixed expenses of operating a generating facility.

18 Staff’s adjustment to purchased power expense in this case annualizes demand charges for
19 Empire’s Plum Point Purchase Power Agreement.

20 *Staff Expert/Witness: Amanda C. McMellen*

21 **c. Fuel Prices**

22 Generally, Staff computed its level of fuel expense using prices and quantities contracted
23 by Empire for delivery in 2019, including prices and quantities agreed to in fuel contracts effective
24 through December 31, 2019 (with one exception described in the “Coal Prices” section below),
25 and for current freight contracts. These fuel prices include prices for coal, natural gas, and oil, as
26 well as associated transportation charges.

27 *Staff Expert/Witness: Amanda C. McMellen*

1 **d. Coal Prices**

2 Staff determined its coal price by generation facility based on a review and analysis
3 of Empire’s current coal purchase and coal transportation contracts. Staff’s recommended
4 PRB coal prices reflect Empire’s actual contracted coal purchase prices effective through
5 December 31, 2019, and a 12-month average of transportation costs incurred through the update
6 period, September 30, 2019. Staff’s local bituminous coal price reflects Empire’s actual contracted
7 coal purchase price in effect December 31, 2019. According to Empire, they are not purchasing
8 this coal in 2020, but are using what remains on the ground due to the retirement of Asbury. For
9 the Plum Point unit, Staff’s recommended coal prices reflect the actual contracted coal purchase
10 and transportation prices in effect for 2019. For the Iatan 1 and 2 units, Staff’s recommended coal
11 prices reflect KCPL’s projected weighted average contracted coal purchase and transportation
12 prices for 2019.

13 *Staff Expert/Witness: Amanda C. McMellen*

14 **e. Natural Gas Prices**

15 The natural gas price recommended in this case by Staff of \$2.46 per MMBtu is composed
16 of two components: hedged and non-hedged (“spot”) prices. Staff calculated the non-hedged
17 component of natural gas prices using a twelve-month weighted average of Empire’s actual
18 commodity cost of natural gas purchased on the spot market during the twelve months ending
19 September 30, 2019. The weighted average price for the non-hedged component is \$2.265
20 per MMBtu. Staff calculated the hedged component of natural gas costs by applying a weighted
21 average for the actual hedged purchases contracted for at September 30, 2019, that is applicable
22 to Empire’s forecasted gas needs for the twelve months ending September 30, 2019. The
23 weighted average price for the hedged component is \$2.643 per MMBtu. Staff weighted the
24 hedged gas price at 52% of its overall gas price recommendation, as Empire has contracted to
25 meet approximately 52% of its projected natural gas usage from October 1, 2018 through
26 September 30, 2019, with hedged gas supplies. Empire’s natural gas transportation costs are
27 annualized and normalized separately as a part of fuel adders.

28 *Staff Expert/Witness: Amanda C. McMellen*

1 **f. Fuel Oil Prices**

2 Staff used a weighted average price of 1,560.48 cents per MMBtu to determine the fuel oil
3 cost input in the fuel model in this case. Staff calculated this weighted average price by:
4 (1) converting each month's number of barrels purchased over a 13-month period into gallons;
5 (2) dividing a total month's purchase in gallons by that month's total purchase costs to derive an
6 average monthly price per gallon; (3) summing the totals for the 13-month period to calculate a
7 weighted 13-month average cost per gallon, which in this case is \$2.175311; and (4) converting
8 this per gallon price into the cents per MMBtu, which is 1,560.48. Empire burns fuel oil mainly
9 as a secondary fuel or, in some instances, for flame stabilization. Empire does maintain onsite
10 storage at its various facilities in sufficient capacity that only occasional purchases are necessary.
11 As a result, Empire does not contract for or hedge oil costs.

12 *Staff Expert/Witness: Amanda C. McMellen*

13 **2. Entergy Transmission Contract**

14 Empire has a contract with Entergy Solutions, Inc. for firm point-to-point transmission
15 service to transmit power generated from the Plum Point Energy Station to Empire. Staff included
16 an adjustment that annualizes the cost of this service at the current contract rate effective
17 September 1, 2019.

18 *Staff Expert/Witness: Ashley Sarver*

19 **3. Heat Rate and Efficiency Testing**

20 Whenever an electric utility requests that a rate adjustment mechanism ("RAM") such as a
21 Fuel Adjustment Clause ("FAC") be continued or modified, Commission Rule 20 CSR 4240-3.161
22 (3)(Q) specifies that the electric utility shall file specific information as part of its direct testimony
23 in a general rate proceeding:

24 (Q) The results of heat rate tests and/or efficiency tests on all the electric
25 utility's nuclear and non-nuclear steam generators, Heat recovery steam
26 generators, steam turbines, and combustion turbines conducted within the
27 previous twenty-four (24) months;

28 The commission first authorized Empire's FAC in Case No. ER-2008-0308. The FAC was
29 continued with modifications in Case Nos. ER-2010-0130, ER-2011-0004, ER-2012-0345,

1 ER-2014-0351, and ER-2016-0023. Liberty-Empire is requesting that its FAC again be continued
2 with modifications in this current general rate case proceeding.

3 Staff has conducted a review of the most recent heat rate/efficiency tests for Empire's
4 generating units and found them to be reasonable based on comparisons with data filed in previous
5 general rate case proceedings and known changes in power plant operating parameters. All of the
6 testing dates submitted by Empire were found to be in accordance with the twenty-four (24) month
7 requirement of 20 CSR 4240-3.161(3)(Q).

8 *Staff Expert/Witness: Jordan Hull*

9 **4. Market Prices**

10 For Case No. ER-2019-0374, Staff updated its production cost model to use multiple sets
11 of market prices. This represents a change in method from Case No. ER-2016-0023.⁴⁶ The prices
12 used are based on a three year average of the day-ahead prices for Empire's generating nodes and
13 load node within the Southwest Power Pool Integrated Marketplace. Within the model, the unique
14 market prices associated with each of the generating facilities are one of the determining factors
15 for economic dispatching. This simulates how the actual market dispatches generation resources
16 based on prices set by regional load requirements. The three year average calculated by Staff was
17 incorporated into the production cost model as a reasonable forecast of market prices.

18 **5. Planned and Forced Outages**

19 Planned and forced outages are infrequent in occurrence and variable in duration. In order
20 to capture this variability, the generating unit outages were normalized by averaging seven years
21 of data that Empire provided to comply with 20 CSR 4240-3.190 and supplemental information
22 provided in response to a Staff data request. For each thermal generating unit an equivalent forced
23 outage rate and scheduled maintenance outage durations were calculated based on that data.

24 The outages defined for each thermal generating unit represent times that they are
25 unavailable for dispatch within the market. Planned outages are scheduled during times of
26 expected lower energy demand in order to minimize the impact of the temporary loss of generating

⁴⁶ Empire's generation portfolio includes a number of generating facilities that are geographically distant from each other and from Empire's service territory. Staff's decision to use multiple sets of market prices is intended to better account for the differences in market conditions experienced at each of those facilities.

1 capacity. Unplanned outages are applied in a random pattern to mimic the unforeseen nature of
2 faults that may force a power plant offline.

3 **6. Contract Prices and Energy**

4 Staff's fuel model includes Empire's energy contracts with the Meridian Way and
5 Elk River wind farms in Kansas and the Plum Point coal power plant in Arkansas. For the wind
6 farms, Staff developed hourly energy production profiles by averaging historic generation records.
7 The prices paid for the energy from Meridian Way and Elk River are set by the contracts Empire
8 enters into with the wind farm owners. Generation for the coal power plant was calculated through
9 the use of the production cost model. The energy price for the coal plant contract was adopted
10 from Empire's fuel model workpapers.

11 **7. Variable Fuel Expense**

12 Staff uses the PLEXOS production cost model to perform an hour-by-hour chronological
13 simulation of a utility's generation, energy sales, and energy purchases. Staff uses this model to
14 determine annual fuel consumption, fuel expense, and the costs and revenues associated with the
15 purchases and sales of energy. Staff applies constraints to the model in order to reasonably align
16 power plant behavior with historical performance. This is done to simulate Empire's bidding
17 strategy within the integrated market.

18 In this case, Staff's model meets all load requirements through market purchases at a
19 defined load node. Simultaneously, each thermal generating facility is dispatched according to its
20 own set of market prices. In each hour, the total generation from all sources is then summed and
21 compared against the purchased energy required to satisfy load. If total generation exceeds
22 purchased energy, then net sales are recorded for that hour. Conversely, if total generation is less
23 than purchased energy, net purchases are recorded. In that way, net sales and purchases within the
24 market are determined for each hour of the simulation.

25 Staff relied on data provided in Empire's workpapers for many of the operating
26 characteristics of the thermal generating units in Empire's portfolio. These include maximum and
27 minimum capacity, heat rate, primary fuel type, start-up fuel type, ramp rates, start-up costs,
28 minimum up time, minimum down time, and variable operating and maintenance expense. Staff
29 updated or separately calculated values for operating characteristics on an "as-needed" basis.

1 Staff estimates the variable fuel and purchased power expense for Empire for the update
2 period, ending September 30, 2019, to be \$117,419,091. This value includes revenue from net
3 sales made in the integrated market.

4 Staff assumed continued operation of Empire's Asbury plant in its model to calculate
5 variable fuel expense. Please see Section XIII of the Report, "Isolated Adjustments – Retirement
6 of Asbury," for a discussion of Staff's overall position regarding rate treatment of Asbury in this
7 proceeding.

8 *Staff Expert/Witness: Charles T. Poston, PE*

9 **E. Payroll and Benefits**

10 **1. Payroll, Payroll Taxes and 401K**

11 Staff adjusted Empire's test year payroll expense to reflect annualized levels of payroll,
12 payroll taxes, and 401(k) benefit costs as of September 30, 2019. Staff calculated a reasonable
13 overtime payroll level for Empire by multiplying an overtime percentage computed for the non-
14 union and union employees based upon a two-year average of overtime hours actually incurred by
15 the current rate paid for overtime as of September 30, 2019. Staff then divided that product by
16 Staff's pro forma base payroll amount.

17 Staff determined an allocation rate for distributing the payroll adjustments by using the
18 percentage of Empire's total electric payroll costs. After allocation between expense and
19 construction based on a three (3) year Operation & Maintenance (O&M) average, Staff distributed
20 the total amount of the adjustment to individual Federal Energy Regulatory Commission Uniform
21 System of Accounts (FERC USOA) based upon the actual distribution by FERC account Empire
22 experienced for the twelve months ending March 31, 2019. Staff's Accounting Schedule 10,
23 Adjustments to the Income Statement, reflects all payroll adjustments, segregated by the FERC
24 USOA Account, to reflect Staff's total adjustment required to restate the test year payroll to an
25 annualized level as of September 30, 2019.

26 Staff calculated payroll taxes based upon September 30, 2019, wage levels and current tax
27 rates. This included Federal Unemployment Taxes ("FUTA"), State Unemployment Taxes
28 ("SUTA"), and Federal Insurance Contributions Act ("FICA") tax. The Company's 401(k) benefit
29 costs were annualized by applying Empire's actual 401(k) match rate for each employee to the
30 annualized payroll as of September 30, 2019.

31 *Staff Expert/Witness: Ali Arabian*

1 **2. Payroll Benefits**

2 Empire currently offers its employees Dental, Vision, Healthcare, and Life Insurance
3 benefits. Staff performed an analysis of the employee benefit costs included in Account 926 from
4 the general ledger. Staff annualized each expense by examining the individual costs over a
5 36 month period to determine the appropriate amount to include for each expense. Staff
6 performed a three year average through the update period to annualize these expenses ending
7 September 30, 2019.

8 *Staff Expert/Witness: Ali Arabian*

9 **3. FASB Accounting Standards Codification (“ASC”) 715-60 (formerly**
10 **FAS 106) – Other Post-Employment Benefit Costs (“OPEBs”)**

11 In Case No. ER-2006-0315, the signatory parties entered into a *Non-Unanimous*
12 *Stipulation and Agreement as to Certain Issues*, addressing the ratemaking treatment for
13 annual other post-employment benefit costs (also known as “OPEBs”) under FASB ASC Subtopic
14 715-60, formerly known as Financial Accounting Standard No. 106 (“FAS 106”). OPEBs
15 primarily relate to medical benefits owed by Empire to Company retirees. The 2006
16 agreement was later modified by the *Stipulation and Agreement as to Certain Issues* reached in
17 Case No. ER-2008-0093, ER-2010-0130, ER-2011-0004, ER-2012-0345, ER-2014-0351 and
18 ER-2016-0023. (Collectively, Staff will refer to the *Stipulations and Agreements* regarding OPEB
19 expense ratemaking from the 2006 rate case to current as the “OPEB Agreements.”) These OPEB
20 Agreements were intended to ensure that the amount collected in rates for OPEBs were based on
21 the FAS 106 cost recognized by the Company for financial reporting purposes, using a
22 methodology similar to that used to determine FAS 87 pension cost. In addition, the OPEB
23 Agreements were intended to ensure that Empire contributed the full amount of the OPEB
24 expenses it collected in rates into an external trust fund. The OPEB Agreements also called for the
25 use of a OPEBs tracker mechanism to quantify the difference over time in the OPEBs rate
26 allowance provided to the Company, and the Company’s annual actual OPEBs expenses under
27 FAS 106.

28 In this case, Staff has complied with the terms agreed upon by the signatories to OPEB
29 Agreements approved by the Commission in Empire’s last six electric rate cases for ratemaking
30 treatment of OPEBs costs. Empire’s OPEB costs in this case were based upon the Company’s

1 actuary report from CBIZ Cottonwood for the fiscal period ending December 31, 2018. Staff will
2 update the OPEB costs, tracker balance and amortization in its True-Up testimony. The results of
3 Staff's review of Empire's OPEB costs to date are as follows:

4 1. The Company's ongoing FAS 106 cost recognized in rates in this
5 case is \$333,619.

6 2. Empire has over-recovered its FAS 106 expense in rates compared
7 to its actual level of expense since the Company's last rate case. The balance in the
8 Regulatory Liability account as of September 30, 2019, was (\$4,768,543), which is
9 to be amortized over five years as a reduction to expense in the amount of
10 (\$953,709).

11 3. Rate base is reduced by the level of regulatory liability associated
12 with Empire's ongoing OPEBs tracker mechanism, \$4,768,543.

13 *Staff Expert/Witness: Ashley Sarver*

14 **4. Accounting Standards Codification ("ASC") 715-30 (Formerly FAS**
15 **87 and FAS 88) Pension Costs**

16 In Case No. ER-2004-0570, the Staff, Empire and other parties entered into a
17 *Stipulation and Agreement as to Certain Issues*, addressing, among other items, the ratemaking
18 treatment for annual pension cost under FASB's ASC Subtopic 715-30, formerly known as
19 Financial Accounting Standard No. 87 ("FAS 87"). Staff will refer to pensions as FAS 87 and FAS
20 88 in this report. This agreement, and thus treatment of annual pension cost, was later modified by
21 each of the later *Stipulation and Agreement as to Certain Issues* entered into in Case Nos.
22 ER-2006-0315, ER-2008-0093, ER-2010-0130, ER-2011-0004, ER-2012-0345, ER-2014-0351
23 and ER-2016-0023. (Collectively, Staff will refer to the *Stipulations and Agreements* regarding
24 pension expense ratemaking from the 2004 rate case to current as the "Pension Agreements.")
25 These above-referenced Pension Agreements provide for Empire to generally have its pension rate
26 allowance set equal to its most current annual level of pension expense as calculated under FAS 87.
27 Furthermore, these agreements established a tracker mechanism for Empire's pension expense, in
28 which any excess or deficit in the Company's pension rate allowance, as compared to its ongoing
29 levels of FAS 87 expense, is to be treated as a regulatory asset or liability. The resulting pension
30 tracker regulatory asset or pension tracker regulatory liability is then to be included in Empire's
31 rate base, and amortized as an addition or reduction to pension expense over a five-year period.

1 Pension cost under FAS 87 has been reflected in Staff's income statement for this case in
2 a manner consistent with the ratemaking treatment agreed upon by the signatories to all of the
3 stipulation and agreements approved by the Commission in Empire's last seven electric rate cases.
4 Empire's rate base, as determined by the Staff, includes the FAS 87 Regulatory Asset, which
5 represents the cumulative difference between FAS 87 pension costs recovered in rates and FAS 87
6 pension costs recognized in the financial statements between rate cases.

7 FAS 88 deals with the current recognition of gains and losses related to settlements and
8 curtailments of pension plans. The Company's employees have the option at retirement to accept
9 annuity payments or a lump sum distribution. A lump sum distribution, for purposes of FAS 88, is
10 a settlement requiring the recognition of a gain or a loss. According to Case No. ER-2010-0130,
11 Appendix C of the Stipulation and Agreement for treatment of special events for pensions and
12 OPEB states this regulatory asset or liability will not be added to rate base (since it is not a cash
13 item), and it will be amortized over five years beginning when new rates are implemented in the
14 Company's next general electric rate increase or decrease proceeding before the Commission.
15 Therefore, Staff did not include rate base treatment for FAS 88. The FAS 88 test year cost was
16 averaged over a two year period in order to determine ongoing FAS 88 expense.

17 Additionally, Staff has included a prepaid pension asset ("PPA") in rate base in the amount
18 of \$18,865,955. The PPA represents the cumulative amount of pension contributions in excess of
19 actual costs as of September 30, 2019. These contributions were made to prevent the pension plan
20 from becoming "at-risk" as defined under the Pension Protection Act, and to meet the obligations
21 of the Pension Benefit Guarantee Corporation.

22 Empire's pension costs in this case were based upon the Company's actuary report from
23 CBIZ Cottonwood as of January 1, 2019. Staff will update the pension costs, tracker balance and
24 amortization in its True-Up testimony. The results of the Staff's review to date of Empire's
25 pension costs are as follows:

- 26 1. The Company's ongoing FAS 87 expense recognized in
27 rates in this case is \$1,275,179 and FAS 88 \$6,573,354.
- 28 2. Empire has under-recovered its FAS 87 expense in rates
29 compared to its actual level of expense since the Company's last rate
30 case. The balance in the Regulatory Asset account at September 30,
31 2019, was \$457,014, which is to be amortized over five years as an
32 expense in the amount of \$91,403.

1 3. FAS 88 settlement adjustment in the amount of \$11,576,868
2 is to be amortized over five years as an expense in the amount of
3 \$2,315,374.

4 4. The amount to be included in rate base for Empire's ongoing
5 pension expense tracker mechanism as a Regulatory Liability is
6 (\$182,978).

7 5. An amount of \$18,865,955 is included in Empire's rate base
8 as a prepaid pension asset.

9 *Staff Expert/Witness: Ashley Sarver*

10 **5. Incentive Compensation**

11 Staff reviewed Empire's portfolio of incentive compensation plans offered to
12 its employees. In the past, Empire had one incentive plan called the Management Incentive
13 Compensation Program ("MIP"). The MIP offered awards to Empire senior officers for the
14 achievement of certain pre-set goals. However, with the Liberty merger, the program has changed.
15 There is now one Long Term Incentive Plan ("LTIP"), and three different short term
16 incentive plans: the "Empire Legacy Bonus/Incentive Plan", the Shared Bonus Plan ("SBP"), and
17 the Short Term Incentive Plan ("STIP"). The name for the incentive plan associated with Empire's
18 original employees is the "Empire Legacy Bonus/Incentive Plan." As a part of the Liberty merger
19 transition process, employees who have Directors and above within their title (such as Department
20 Heads) were moved to the Liberty Utilities Short Term Incentive Plan ("LU STIP") in 2017.
21 The Liberty-Empire Information Technology team has also moved to the Liberty Utilities short
22 term bonus plans (STIP and SBP). It is expected that the rest of the LU-Empire employees will be
23 moved to the Liberty Bonus Plans for the 2020 payout. Based upon this review, Staff is proposing
24 adjustments to the Company's incentive compensation expense.

25 **a. Short Term Incentive Plans**

26 In order to determine the appropriate amount to include, Staff reviewed the incentive
27 metrics used to measure parent and divisional goals and the actual award received. Staff disallowed
28 all the actual awards associated with the performance measure of meeting earnings per share
29 targets. Any incentive goals associated with enhancing the value of a utility's stock price and the
30 achievement of these goals benefits Empire's shareholders, not Empire's ratepayers; therefore,
31 Staff has removed this expense from inclusion in rates.

The STIP and SBP award calculations are as follows:

STIP Incentive Plan Calculations:

STIP Payout \$= Eligible Annual Base Salary X Target Bonus % X Pro-ration Factor X STIP Weighting.

STIP Weighting= 70%*(Parent Scorecard Result) +10%*(Divisional Objective Result) +20%*(Personal Objective Achievement)

SBP Bonus Plan Calculations:

SBP Payout \$= Eligible Annual Base Salary X Target Bonus % X Pro-ration Factor X SBP Weighting.

SBP Weighting= [85%*(Parent Scorecard Result) +15%*(Divisional Objective Result)] * Individual Multiplier

Parent Scorecard:

Both the STIP and the SBP weighting calculations reference a “parent scorecard”. The unified parent scorecard for APUC, Liberty Utilities, and Liberty Power is the same for both plans and is broken down as follows:

Objectives	Definitions	Weighted %
Customers and Communities	Conduct Operations Safely and Responsibly	15%
	Deliver a Satisfactory Customer Experience	10%
Our People and Team	Foster Employee Engagement through Effective Leadership	10%
Our Processes	Efficient and Effective Management of Capital Re-Investment Programs	10%
	Advance "Customer First" business Process Overhaul	5%
Our Efficiencies	Maximize Operating Efficiency by Managing to Budgets	30%
	Reduce Cost of Capital through Prudent Investments	20%
		100%

Staff has disallowed the 50% percent associated with the “Our Efficiencies” objective of the parent scorecard so that they are assigned to shareholders.

1 **Divisional and Personal Scorecard:**

2 While all employees under the STIP and SBP plan use the same parent scorecard,
3 the divisional scorecard varies for each of the following eight divisions: LABS, Renewable
4 Generation, Corporate Development, Transformation, Regulated Utilities- Head office, Regulated
5 Utilities- East, Regulated Utilities- Central, and Regulated Utilities- West. Staff reviewed each
6 divisional scorecard to disallow any incentive metric associated with the performance measure of
7 meeting earnings per share targets or enhancing the value of a utility's stock price. Although the
8 personal achievement/individual multiplier varies by employee, Staff is using a conservative
9 flat rate of 20% across all employees for its calculation of incentive pay. Staff has asked the
10 Company to provide the exact percentages by employee and may update the 20% to actuals if they
11 are provided.

12 **Payout:**

13 The payout for both STIP and SBP reference a "target bonus percentage". Staff averaged
14 the target bonus percentage for the employees that were provided and applied that across all
15 employees. Staff has asked the Company to provide the target bonus percentage for every
16 employee and may update the average to actuals if they are provided.

17 **b. Long Term Incentive Plan ("LTIP")**

18 In Empire's past rate cases, Staff also recommended a disallowance of long-term stock
19 incentive compensation awarded to Empire's executive management, which results in the
20 issuance of stock annually that is considered to be part of the senior officer's total compensation.
21 The senior officers do not have any specific goals to meet in order to be granted these stock options.
22 Awarding these stock options benefits Empire's shareholders, not Empire's ratepayers.
23 Additionally, unlike other expense recognition in the income statement, expense recognition for
24 equity-based incentive compensation does not result in a cash outlay by Empire. Staff has
25 eliminated stock options recognized as an expense in this case consistent with the Commission's
26 *Report and Order* in Case No. ER-2006-0315.

27 *Staff Expert/Witness: Caroline Newkirk*

1 **6. Supplemental Executive Retirement Plan (“SERP”)**

2 Certain management employees receive benefits under Empire’s Supplemental Employee
3 Retirement Program (“SERP”). The provisions of Accounting Standards Codification 715-30,
4 formerly FAS 87, are used to calculate the annual financial reporting expense accrual for this plan.
5 Due to the fact that the benefits from this retirement program are not available to a broad range of
6 employees, the Internal Revenue Service (“IRS”) designated this program as a “non-qualified”
7 plan. In a non-qualified plan, the expense is not “pre-funded” and only the amounts paid to
8 beneficiaries are tax deductible. Therefore, Staff’s policy has been to limit utilities’ rate recovery
9 of this item to actual benefit payments to employees, if reasonable. Staff reviewed a five year
10 period ending September 30, 2019 to determine the reasonable ongoing level for SERP. Due to an
11 upward trend in actual payments, Staff used the 12 months of actual payments ending with the end
12 of the update period (September 30, 2019) to determine the annual costs of the SERP for inclusion
13 in rates for this case.

14 *Staff Expert/Witness: Ashley Sarver*

15 **F. Southwest Power Pool Revenues and Expenses**

16 **1. SPP Transmission Revenues**

17 Empire receives revenues from the Southwest Power Pool (“SPP”) to reimburse it for costs
18 associated with transmission of electricity to other SPP members. Staff reviewed the monthly
19 amount of revenues received from SPP since April 2014 for any trends in the data that would
20 indicate a revenue amount other than the test year revenue amount would be appropriate to include
21 in the cost of service. Staff’s review determined the total amount of revenues received in the
22 period of October 2018 through September 2019, which is the end of the update period in this case,
23 is the most appropriate amount to use to normalize the SPP Transmission revenues.

24 **2. SPP Transmission Expenses**

25 The SPP is a not-for-profit, regional transmission organization (“RTO”) which maintains
26 functional control over the transmission assets of its members and provides transmission service
27 through its Federal Energy Regulatory Commission (“FERC”) approved open access transmission
28 tariff (“OATT”). SPP’s costs of providing transmission service must be recovered from its
29 member companies, including Empire. As with the SPP Transmission Revenues, Staff reviewed

1 the monthly amount of SPP transmission expense since April 2014 for any trends in the data that
2 would indicate an expense amount other than the test year expense amount would be appropriate
3 to include in the cost of service. Staff’s review determined the total amount of expense incurred
4 for twelve months ending September 2019, which is the end of the update period in this case, is
5 the most appropriate amount to use to normalize the SPP Transmission expense.

6 **3. Ancillary Services Market Revenue and Expense**

7 Empire began participating in SPP’s Ancillary Services Market (“ASM”) in March 2014.
8 Empire entered the ASM to acquire ancillary services for its retail load and also to be able to
9 provide these services to other SPP members from its own generation when available. Ancillary
10 services generally refer to the services necessary to support the transmission of capacity and energy
11 from resources to loads while maintaining reliable operation of the transmission system.⁴⁷
12 Staff reviewed the monthly amount of ASM revenues and expenses since April 2014 for any
13 trends in the data and determined the average of the three-year period ending September 2019, the
14 end of the update period for this case, is the most appropriate method for annualizing ASM
15 revenues and expenses.

16 **4. Miscellaneous SPP Related Revenues and Expenses**

17 Empire also has received certain miscellaneous revenues and incurred expenses as a result
18 of participating in SPP’s Integrated Market (“IM”) beginning in March 2014. Staff reviewed the
19 monthly amount of these revenues and expenses since April 2014 for any trends in the data and
20 determined the average of the three-year period ending September 2019, the end of the update
21 period for this case, is the most appropriate method for annualizing these revenues and expenses.

22 *Staff Expert/Witness: Keith D. Foster*

23 **G. Operations and Maintenance (“O&M”) Normalized Adjustments**

24 Empire’s operation and maintenance expenses for its generating facilities (production
25 stations) tend to fluctuate from year to year, since unscheduled outages occur at irregular and
26 unpredictable times, and major planned outages do not occur annually. Each maintenance account
27 was reviewed and analyzed separately for each production station. The production facilities

⁴⁷ As defined, per the glossary on the SPP website, such as Operating Reserves.

1 examined included Iatan 1, Iatan 2, Iatan Common, Asbury, Riverton, State Line Combined Cycle,
2 State Line 1, Energy Center, Ozark Beach, and Plum Point. These units were examined
3 individually because each of them is on a different maintenance cycle and to group them would
4 have either overstated or understated the final annualized maintenance costs. These adjustments
5 were then combined where possible in an effort to reduce the volume of adjustments.

6 The Staff's proposed production operation and maintenance normalization adjustments
7 pertain to Empire's non-labor maintenance costs only; labor maintenance costs are handled as part
8 of the Staff's overall payroll adjustments.

9 **1. Iatan 1**

10 Staff noted the Iatan 1 production station is on a six-year major operation and maintenance
11 cycle. For that reason, Staff used a six-year average of operation and maintenance costs to develop
12 its adjustment for Iatan 1 maintenance expense. Empire owns only 12% of the Iatan 1 unit.

13 **2. Asbury**

14 The Asbury maintenance expense is based on a five-year overhaul schedule of the
15 boiler and turbine. Staff's adjustment is based upon a five-year average of operation and
16 maintenance costs.

17 **3. Riverton**

18 A tracker for Riverton's O&M costs was originally established in Case No. ER-2014-0351.
19 In Case No. ER-2016-0023, the Stipulation and Agreement "recommended a continuation of the
20 use of the tracker mechanism for Riverton 12 O&M expense, because it was recently converted
21 from a simple cycle to a combined cycle unit, there is no operational history by which to determine
22 an appropriate level of Riverton O&M costs. As such, the parties agree that this is an extraordinary
23 situation that allows for the use of a tracker mechanism."

24 For this case, Staff is recommending a discontinuation of the O&M tracker. Riverton 12
25 was converted to a combined cycle unit on May 1, 2016. Therefore, there are over three years
26 of actual cost information for non-labor O&M costs as of the end of the test year period for
27 this proceeding.

28 Staff reviewed five years of data; however, it is most appropriate to use a three-year average
29 due to the fluctuation in cost due to Riverton 12 being converted to a combined cycle unit on

1 May 1, 2016. Therefore, Staff's adjustment is based upon a three-year average of operation and
2 maintenance costs as of March 31, 2019, the end of the test year period.

3 **4. Riverton 12 O&M Tracker**

4 Additionally, in this case, Staff analyzed the Riverton 12 O&M costs beginning
5 August 1, 2015, when the tracker started, through September 30, 2019, the update period for
6 this case. For this same time period, Staff then calculated the total O&M costs, which were above
7 the established tracker base and included the total in rate base as a regulatory asset. Staff
8 recommends a five year amortization of the regulatory liability incurred for Riverton 12.

9 **5. State Line Combined Cycle ("SLCC") and State Line Common**

10 The SLCC operation and maintenance expense is based on a five-year overhaul schedule
11 of the boiler and turbine. Empire owns 60% of the SLCC unit, with Westar Energy ("Westar")
12 owning the remaining 40%. Staff subtracted 40% of SLCC expenses incurred in the period ended
13 September 30, 2015, to adjust out Westar's portion of test year expenses. Staff then applied an
14 adjustment based on a five-year average of Empire's portion of operation and maintenance costs.
15 Empire is responsible for 66.7% of the State Line Common operation and maintenance expenses,
16 while Westar Energy is responsible for the remaining 33.3%. Staff removed 33.3% of State Line
17 Common expenses to adjust out Westar's portion of test year expenses. Staff then applied an
18 adjustment based on a five-year average of Empire's portion of operation and maintenance costs.

19 **6. State Line 1**

20 Empire has had a contract with Siemens group related to the operation and maintenance of
21 this production unit since June 29, 2001. The terms of the contract require Siemens to conduct
22 maintenance service for the turbines, which are required to run for a specified number of hours per
23 year. If a turbine does not meet the annual hour's requirement, a credit is due to Empire from
24 Siemens; if the turbine exceeds the hours, then the Company incurs additional costs from Siemens.
25 The nature of this expense varies greatly from year to year and, therefore, Staff is recommending
26 using a five-year average to normalize this expense.

1 **7. Energy Center and Ozark Beach**

2 The Energy Center and Ozark Beach operation and maintenance expense is based on a
3 five-year overhaul schedule of the boiler and turbine. Staff’s adjustment is based upon a five-year
4 average of operation and maintenance costs.

5 *Staff Expert/Witness: Ashley Sarver*

6 **H. Other Expenses**

7 **1. Rate Case Expense**

8 Staff reviewed Empire’s actual rate case expense amounts incurred as of January 6, 2020,
9 directly related to this case, based upon the traditional criteria of allowing rate recovery of all
10 reasonable and prudent expenses, normalized over an appropriate period of time. On two
11 occasions, Empire chartered a plane to attend meetings in Jefferson City at a cost of \$3,070.88 and
12 \$3,357.50. Staff has disallowed these requested amounts due to prudence. Instead Staff determined
13 what costs Empire would have incurred if Empire employees would have driven to Jefferson City
14 the night before the meetings. Staff included the costs for hotel rooms, breakfast and lunch for
15 four employees for an allowed amount of \$560 for each occasion.

16 Staff has normalized rate case expense over a two (2) year period. The ultimate amount of
17 rate case expense incurred by Empire in this proceeding will be directly associated with the length
18 of the case through the settlement conference and hearing process.

19 Empire is required to submit a depreciation study every five years. In Case No.
20 ER-2016-0023, the last rate case, Empire submitted a depreciation study. This cost is being
21 normalized over a five-year period.

22 *Staff Expert/ Witness: Angela Niemeier*

23 **2. Rate Case Expense Sharing**

24 Rate case expense is a sum of the incremental costs a utility incurs in preparing and filing
25 a rate case. In the instant case, Empire has incurred expenses in conjunction with outside
26 consultants. Staff recommends assigning Empire’s discretionary rate case expense to both
27 ratepayers and shareholders based upon a 50/50 split and full recovery of the depreciation study

1 over five years. This allocation was utilized by the Commission in the recent Spire Missouri Inc.
2 (“Spire Missouri”) rate cases, Case Nos. GR-2017-0215 and GR-2017-0216.

3 Staff’s recommended cost sharing methodology is based on the following rationale:

- 4 1) Rate case expense sharing creates an incentive and eliminates a
5 disincentive on the utility’s part to control rate case expenses to
6 reasonable levels;
- 7 2) Both ratepayers and shareholders benefit from the rate case process.
8 The ratepayer is receiving the opportunity to be provided safe and
9 adequate service at a just and reasonable rate and the shareholder is
10 receiving an opportunity to receive an adequate return on investment;
- 11 3) It is fair and equitable to expect shareholders to carry a reasonable
12 portion of the rate case burden; and
- 13 4) There is a high probability that some recommendations advocated by
14 utilities through the rate case process will ultimately be found by the
15 Commission to not be in the public interest.

16 Rate case expense is defined as all incremental costs incurred by a utility directly related
17 to an application to change its general rate levels. These applications are usually initiated by the
18 utility, but rate case expenses may also be incurred as a result of the filing of an earnings complaint
19 case by another party. The largest amounts of rate case expenses usually consist of costs associated
20 with use of outside witnesses, consultants, and external attorneys hired by the utility to participate
21 in the rate case process.

22 Generally, utility management has a high degree of control over rate case expense.
23 Attorneys, consultants, and other services can either be provided by in-house personnel or can be
24 acquired from an outside party. Rate case expenses subject to a sharing mechanism do not include
25 internal labor costs as these are included in the cost of service through the payroll annualization
26 and are not incremental expenses resulting from the rate case process. These costs are fully paid
27 for by ratepayers.

28 In 2011, the Commission established Case No. AW-2011-0330 to investigate current rules
29 and practices regarding recovery of rate case expense by Missouri utility companies. Both of the
30 options of sharing rate case expense 50/50 and sharing based on the percentage ordered rate
31 increase versus requested the rate increase sought by the utility were discussed in that report.

1 The Commission ordered a sharing of Kansas City Power & Light's (KCPL) rate case
2 expenses in its Report and Order in Case No. ER-2014-0370:

3 The Commission finds that in order to set just and reasonable rates under
4 the facts of this case, the Commission will require KCPL shareholders to
5 cover a portion of KCPL's rate case expense. One method to encourage
6 KCPL to limit its rate case expenditures would be to link KCPL's
7 percentage recovery of rate case expense to the percentage of its rate
8 increase request the Commission finds just and reasonable. The
9 Commission determines that this approach would directly link KCPL's
10 recovery of rate case expense to both the reasonableness of its issue
11 positions and the dollar value sought from customers in this rate case.

12 The Commission concludes that KCPL should receive rate recovery of its
13 rate case expenses in proportion to the amount of revenue requirement it is
14 granted as a result of this Report and Order, compared to the amount of its
15 revenue requirement rate increase originally requested. This amount should
16 be normalized over three years. The Commission also finds that it is
17 appropriate to require a full allocation to ratepayers of the expenses for
18 KCPL's depreciation study, recovered over five years, because this study is
19 required under Commission rules to be conducted every five years.
20 [Footnotes omitted]⁴⁸

21 The footnote omitted in the above reference further clarifies the Commission's conclusions
22 concerning recovery of rate case expenses:

23 It is understood that some of the issues litigated in this case do not directly
24 affect the overall revenue requirement granted by the Commission; but it is
25 also clear that the vast majority of litigated issues do have a direct or indirect
26 impact on the revenue requirement. Accordingly, percentage sharing is a
27 reasonable approach to correlating recovery of rate case expense to the
28 relationship between the amount of litigation that benefited both ratepayers
29 and shareholders and that which benefited only shareholders⁴⁹.

30 More recently, in the Spire Missouri rate cases, the Commission ordered a 50/50 split of rate case
31 expenses:

32 Therefore, it is just and reasonable that the shareholders and the ratepayers,
33 who both benefited from the rate case, share in the rate case expense. The
34 Commission finds that in order to set just and reasonable rates under the
35 specific facts in this case, the Commission will require Spire Missouri
36 shareholders to cover half of the rate case expense and the ratepayers to

⁴⁸ *Report and Order*, Case No. ER-2014-0370 page 72.

⁴⁹ *Report and Order*, Case No. ER-2014-0370 page 72, Footnote 251.

1 cover half with the exception of the cost of customer notices and the
2 depreciation study.⁵⁰

3 Staff examined the facts and circumstances in Empire's filing and recommends the Commission
4 order a 50/50 sharing of rate case expense.

5 *Staff Expert/Witness: Kimberly K. Bolin*

6 **3. Dues and Donations**

7 Staff reviewed the list of membership dues paid and donations made to various
8 organizations that Empire charged to its utility accounts during the test year. For the starting point
9 in this case, Staff recommends adjustments to exclude various dues and donations that were
10 included by Empire in its above-the-line expense accounts. In *Re: Missouri Public Service,*
11 *a Division of UtiliCorp United, Inc.,* Case Nos. ER-97-394, *et al., Report and Order,*
12 7 Mo.P.S.C.3d 178, 212 (1998), the Commission stated:

13 The Commission has traditionally disallowed donations such as these. The
14 Commission finds nothing in the record to indicate any discernible
15 ratepayer benefit results from the payment of these donations. The
16 Commission agrees with the Staff in that membership in the various
17 organizations involved in this issue is not necessary for the provision of safe
18 and adequate service to the MPS ratepayers.

19 Staff excluded dues that do not have any direct benefit to ratepayers and were not necessary
20 for the provision of safe and adequate service. Allowing Empire to recover these expenses through
21 rates causes the ratepayer to involuntarily contribute to these organizations. Examples of dues
22 excluded from recovery in the rate case, based on the Commission's *Report and Order* mentioned
23 above, are dues paid to Amazon, Sam's Club, and Twin Hills Golf and Country Club. Area
24 Chamber of Commerce dues were allowed, but National and State Chamber of Commerce dues
25 were disallowed as being duplicative costs to the local Chamber of Commerce organizations.
26 An example of a donation that was excluded was a donation to Missouri S&T Alumni Association.
27 No further adjustments are necessary for this case.

28 *Staff Expert/Witness: Courtney Barron*

⁵⁰ *Report and Order*, Case Nos. GR-2017-0215 and GR-2017-0216, page 52.

1 **4. Edison Electric Institute (“EEI”) Dues**

2 According to information obtained from the EEI website (www.eei.org), EEI is an
3 association of investor-owned electric utilities and industrial affiliates. I determined that a primary
4 function of EEI is to represent the interests of the electric utility industry in the legislative and
5 regulatory arenas. This role includes EEI’s engagement in lobbying activities.

6 In Case No. ER-83-49, a KCPL rate increase case, the Commission stated its determination
7 that EEI dues:

8 ...would be excluded as an expense until the company could better quantify
9 the benefit accruing to both the company’s ratepayers and shareholders.

10 This position has been re-affirmed by the Commission in subsequent rate proceedings.

11 In *Re: Kansas City Power & Light Co.*, Case Nos. EO-85-185 *et al.*, Report and Order,
12 28 Mo.P.S.C. (N.S.) 228, 259 (1986), the Commission stated:

13 . . . The argument that allocation is not necessary if the benefits lessen the
14 cost of service to the ratepayers by more than the cost of the dues misses
15 the point.

16 It is not determinative that the quantification of benefits to the ratepayer is
17 greater that the EEI dues themselves. The determining factor is what
18 proportion of those benefits should be allocated to the ratepayer as opposed
19 to the shareholder. It is obvious that the interests of the electric industry are
20 not consistently the same as those of the ratepayers. The ratepayers should
21 not be required to pay the entire amount of EEI dues if there is benefit
22 accruing to the shareholders from EEI membership as well. The
23 Commission finds this to be the case. The Company has been informed in
24 prior rate cases that it must allocate its quantified benefits from membership
25 in EEI. That has not been done herein. Therefore, no portion of EEI dues
26 will be allowed in this case.

27 Empire failed to quantify ratepayer and shareholder benefits from its participation in EEI;
28 therefore, I removed total EEI dues included in the test year of \$179,693 from Empire’s cost of
29 service. No further adjustment is necessary for this case.

30 *Staff Expert/Witness: Courtney Barron*

31 **5. Insurance Expense**

32 Insurance expense is the cost of protection obtained from third parties by utilities
33 against the risk of financial loss associated with unanticipated events or occurrences. Utilities, like

1 non-regulated entities, routinely incur insurance expense in order to minimize their liability (and,
2 potentially that of their customers) associated with unanticipated losses. Staff made an adjustment
3 to annualize Empire’s insurance expense to reflect the premiums paid as of July 2019.

4 *Staff Expert/Witness: Ali Arabian*

5 **6. Customer Deposit Interest Expense**

6 See the discussion in Section V.G. concerning Rate Base - Customer Deposits.

7 *Staff Expert/Witness: Angela Niemeier*

8 **7. Property Tax Expense**

9 Utility companies are required to file a valuation of their utility property with their
10 respective taxing authorities at the beginning of each assessment year, which is January 1st. Based
11 on the information provided by the utility, the taxing authority will in turn send the company its
12 “assessed values” for every category of the company’s property. The taxing authority will then
13 issue to the utility company a property tax rate later in the year. The final step in the process is
14 when the taxing authority issues a property tax bill to the company late in each calendar year.
15 The billed amount of property taxes is based on the property tax rate applied to the previously
16 determined assessed values of the utility’s plant in service balances as of January 1st of the
17 same year.

18 Staff determined its adjustment for property taxes by developing a property tax rate to be
19 applied to total property as of December 31, 2018. Staff calculated the property rate by dividing
20 the 2018 property taxes paid by the 2017 total property. This property tax rate was then applied to
21 the total property as of December 31st, 2018, to arrive at the annualized property tax. Then the
22 annualized property tax was added to the 2018 Plum Point taxes paid to arrive at total annualized
23 property tax. The total annualized property tax was then subtracted from the total test year property
24 taxes to derive the adjustment.

25 The owners of the Plum Point unit, including Empire, have an agreement with the City of
26 Osceola, Arkansas; Mississippi County, Arkansas; Osceola School District No. 1 of Mississippi
27 County, Arkansas; and Mississippi County Community College District of Arkansas, to make an
28 annual Payment in Lieu of Taxes (“PILOT”) instead of paying property taxes on the Plum Point
29 unit in the normal manner. A PILOT agreement allows the owners of the Plum Point unit to pay

1 one flat amount of property taxes on the Plum Point unit for 30 years with the potential for an
2 extension at the end of the 30-year term, regardless of any additions or retirements made to the
3 unit since its in-service date. To appropriately calculate the overall property tax amount for Empire,
4 the amount of Empire's share of the Plum Point plant had to be subtracted from total plant in
5 service so as not to be included in the development of the annualized property taxes. The set
6 amount of PILOT taxes that Empire has agreed to pay for Plum Point was then added to the
7 annualized property tax calculation to determine the total property tax adjustment. Staff will update
8 its recommended level of property taxes as part of the true-up audit in this proceeding.

9 *Staff Expert/Witness: Courtney Barron*

10 **8. Uncollectible/Bad Debt Expense**

11 Bad debt, or uncollectible expense, is the portion of retail revenue that Empire is unable to
12 collect from retail customers due to non-payment of bills. The final bill is due 21 days from the
13 statement mailing date. If unpaid, on the second day after the due date, a collection notice is sent
14 advising the customer the account will be turned over to a collection agency if unpaid or suitable
15 arrangements are not made within 10 days. After the 10 days, any accounts that remain unpaid are
16 written off and sent to a collection agency.

17 Staff examined the most recent five-year (April 2014 – March 2019) history of Empire's
18 bad debt write-offs that were never collected (i.e., write-offs net of amounts subsequently
19 collected). It is apparent from a review of this data that Empire's bad debt expense fluctuates from
20 one year to the next. Therefore, Staff calculated a five-year average of the uncollectable percentage
21 of bad debt to revenue, which was then applied to Staff's annualized and adjusted level of test year
22 retail rate revenues to obtain the normalized level of bad debt expense.

23 *Staff Expert/Witness: Caroline Newkirk*

24 **9. Advertising Expense**

25 Staff evaluated Empire's advertising invoices and supporting information and classified
26 its advertising into the five categories, as set forth in the Commission's April 23, 1986 ruling in
27 *In re Kansas City Power and Light Company*, Case Nos. EO-85-185, EO-85-224. These

1 five categories are general, safety, institutional, promotional, and political. They are described
2 as follows:

- 3 1. General - informational advertising that is useful in the provision of adequate service;
- 4 2. Safety - advertising which conveys the ways to safely use electricity and to avoid
5 accidents;
- 6 3. Promotional - advertising used to encourage or promote the use of electricity;
- 7 4. Institutional - advertising used to improve the company's public image; and
- 8 5. Political - advertising associated with political issues.

9 Institutional and Political advertising are always disallowed by Staff. General and Safety
10 advertising are always allowed by Staff. Promotional advertising can be allowed to the extent that
11 the utility can provide cost justification for the advertisement.

12 Following this guidance, to calculate the adjustment Staff categorized each advertisement
13 into one of the five above types and then excluded institutional, promotional and political
14 advertising expenses.

15 *Staff Expert/Witness: Angela Niemeier*

16 **10. Software Maintenance Expense**

17 Empire has contracts, operating licenses, and agreements with vendors that provide
18 maintenance, upgrades to software, and support for its computer software. Staff annualized the
19 expense for each of the suppliers based on the current rate for each as recorded on the
20 General Ledger as of September 30, 2019. Therefore, Staff made an adjustment of (\$179,386) in
21 Account 921 - Office Supplies to decrease the software maintenance expense to reflect the
22 annualized amount of \$826,000 as of September 30, 2019.

23 *Staff Expert/Witness: Ashley Sarver*

24 **11. Lease Expense**

25 Lease costs are those costs incurred by Empire for the leasing of its equipment and building
26 space. Staff submitted Data Request No. 0048 to Empire asking for a list of all lease agreements
27 (office, vehicle, computers, etc.) charged to Missouri electric operations, along with the lease costs
28 and information concerning all changes to the lease amounts since October 2015. Staff examined
29 these costs for the test year, updated through September 30, 2019. Staff included \$5,392 annually

1 for the Missouri Chamber of Commerce Educational Foundation lease. Staff determined this
2 amount after allocating a portion of the lease to Empire water and gas. Staff included \$392 annually
3 for the AmeriCold lease. Staff determined this amount by annualizing the most current lease
4 payment.

5 *Staff Expert/Witness: Courtney Barron*

6 **12. Public Service Commission Assessment**

7 The adjustment of \$55,908 represents the difference between Staff's annualized PSC
8 Assessment and the assessment amount included in the test year. The most recent PSC Assessment
9 in effect for the fiscal year, July 1, 2019 to June 30, 2020, was used in the Staff's annualization.

10 *Staff Expert/ Witness: Angela Niemeier*

11 **13. Injuries and Damages and Workers' Compensation**

12 Empire maintains workers' compensation insurance for the benefit of its employees. The
13 workers' compensation adjustment proposed by Staff annualizes this expense based upon the
14 premiums in effect at July 2019 to reflect an ongoing and normal expense level for Empire.

15 From time to time, claimants sue Empire seeking payment of damages. If Empire loses the
16 lawsuit, Empire will likely make a payout to the aggrieved party. Alternatively, it may choose to
17 enter into an out-of-court settlement, also resulting in a payout.

18 Based upon generally accepted accounting principles, Empire is required to charge to
19 current expense an estimate of its future payouts for injuries and damages claims. To determine a
20 normalized level of this expense, Staff used a five-year average of actual injuries and damages and
21 workers' compensation payments in its cost of service report, instead of relying upon accounting
22 estimates. Staff applied an allocation of 50.00 percent to the five-year average of actual payments
23 made for injuries and damages. The allocation of 50.00 percent represents the electric expense
24 portion of the payments. The remaining amounts of the payments 50.00% are allocated to the
25 Company's construction, water operations and below-the-line activities. Below the line refers
26 to line items in the income statement that do not directly impact a company's reported profits. A
27 five-year average of actual payments was used to normalize this expense because Staff's analysis
28 shows a considerable fluctuation in the annual amount of payments from one year to the next.

29 *Staff Expert/Witness: Ali Arabian*

1 **14. Postage**

2 Staff annualized Empire’s test year postage expense to reflect the postal increase that went
3 into effect on January 27, 2019. Staff included a postal expense adjustment in the amount of
4 \$110,671 in its recommendation.

5 *Staff Expert/ Witness: Angela Niemeier*

6 **15. Credit Card Fees**

7 Currently, each Empire customer who pays her/his utility bill with a credit card is charged
8 a transaction fee. Empire has proposed to begin recovering in rates the per-transaction fee
9 associated with processing a customer credit card payment instead of the individual customer
10 paying the fee. Staff recommends this cost be allowed recovery in rates. Staff has included an
11 annualized amount for credit card processing fees for Empire, based on the number of actual credit
12 card payments occurring during the test year, multiplied by the current fee per-transaction.

13 *Staff Expert/Witness: Kimberly K. Bolin*

14 **16. Outside Services**

15 Various outside (independent) contractors and vendors provide legal, auditing, and other
16 services to Empire to carry out its operational activities as needed. Staff reviewed Empire’s outside
17 services expenses booked to Accounts 923045 and 923047 for the test year through the update
18 period ending September 30, 2019. Staff normalized the amounts of outside services on a going
19 forward basis by calculating a five-year average of incurred costs for these accounts in the amount
20 of \$2,326,254. Staff subtracted the five-year average of incurred costs from the test year total to
21 determine the adjustment. This adjustment does not include outside services related to rate case
22 expense. Outside services incurred for rate case purposes are booked in a separate account.

23 *Staff Expert/Witness: Courtney Barron*

24 **17. Weatherization Program**

25 Empire began administering its Weatherization Program, a low-income program
26 (“Program”), throughout its service area following Case No. ER-2004-0570⁵¹. The Company

⁵¹ Case No. ER-2004-0570, *In the Matter of the tariff filing of The Empire District Electric Company to Implement a General Rate Increase for Retail Electric Service Provided to Customers in its Missouri Service Area.*

1 worked with Empire’s Demand Side Management Advisory Group (“DSMAG”) composed of the
2 Public Service Commission Staff, the Office of the Public Counsel, and the Department of Natural
3 Resources-Division of Energy, providing the reporting data as to the portion of the budget spent
4 and number of homes weatherized on a quarterly basis.

5 The program was given Commission approval in each following rate case, with the current
6 program design ordered in Case No. ER-2016-0023. The current design arose from a Stipulation
7 and Agreement filed on June 20, 2016, which the Commission approved August 10, 2016 in which
8 the Signatories agreed:

9 Empire would continue the program with an annual budget of \$250,000
10 (increased from \$225,000)⁵². The Signatories also agreed a process
11 evaluation to be conducted of the Company’s program by an independent
12 evaluator to determine why funds for the program remain unspent, whether
13 barriers exist to full utilization of Company funded weatherization fund, and
14 will recommend solutions to remedy these barriers. The cost of the process
15 evaluation was agreed should not exceed \$15,000, funded through the
16 Company’s weatherization program funding.

17 Following the conclusion of Case No. ER-2016-0023, on August 4, 2016, a Stipulation and
18 Agreement was filed in Case No. EM-2016-0213, *In the Matter of The Empire District Electric*
19 *Company, Liberty Utilities (Central) Co. and Liberty Sub Corp. Concerning an Agreement and*
20 *Plan of Merger and Certain Related Transactions*, where the signatories agreed:

21 Empire and The Empire District Gas Company agree to provide DE an
22 annual payment totaling up to 5% of the agreed to weatherization funds for
23 a pilot program concerning the administration and monitoring of the funds
24 (not to exceed an annual cap of \$12,500) to the extent DE is utilized for the
25 management of those funds. Said funds will be provided for a period of five
26 years and be considered below the line and not recovered in future rates.
27 Nothing in this paragraph will affect Staff’s and OPC’s ability to oppose
28 funding for DE in future cases whether for Empire or any other utility. DE
29 shall work with the OPC, Staff, and Empire to develop reporting standards
30 for its administration and monitoring activities to be presented at the annual
31 meetings with each location Community Action Agency.

32 Following Commission approval of the Stipulation and Agreement on September 7, 2016,
33 the Company transitioned the administration of the program over to DE effective
34 November 1, 2017 and the oversight of program fund allocations to the three Community Action

⁵² *In the Matter of The Empire District Electric) Company for Authority to File Tariffs Increasing) Rates for Electric Service Provided to Customers) Case No. ER-2016-0023 in the Company’s Missouri Service Area, Stipulation and Agreement, June 20, 2016, page 8, paragraph 16.*

1 Agencies (“CAA”) within the Company’s territory, the Economic Security Corporation, the Ozark
2 Area Community Action Corporation, and the West Central Missouri Community Action Agency.

3 With the assistance of the Community Action Agencies, Empire provides the agreed upon
4 annual program report in EFIS. The report addresses progress of the Program, and provides an
5 accounting of the funds received and spent on the Program during the preceding calendar year.

6 Since DE has administered the program the portion of the budget spent has increased along
7 with the number of homes weatherized compared to the administration by the Company. During
8 the 2018 calendar year, the Company provided \$250,000 to DE for funding the weatherization
9 program and an additional \$12,500 for administration. Of the annual program budget \$233,036
10 was spent by the CAAs for a total of 83 homes weatherized.

11 Staff recommends the Commission order 1) the continuation of the program at the current
12 funding level until the Company’s next general rate case and 2) the Commission order the
13 Company to update the weatherization program tariff so it reflects the current program structure
14 with program administration.

15 *Staff Expert/Witness: Kory J. Boustead*

16 **18. Low Income Pilot Program**

17 The Low-Income Pilot Program (“LIPP”) is a currently approved tariffed program effective
18 February 28, 2017 with a total program budget of \$250,000 that shall run until either the budget is
19 exhausted or until rates are implemented in Empire’s next general rate case – i.e., this rate case,
20 whichever occurs first. LIPP is an experimental program providing a 100 percent discount of the
21 customer charge for Low Income Heat Energy Assistance Program (“LIHEAP”) eligible
22 customers as proposed in Case No. ER-2016-0023.

23 The Program was agreed upon, if Commission ordered, in the Stipulation and Agreement
24 filed on June 20, 2016⁵³ followed by an approved order of the Commission on August 10, 2016⁵⁴.
25 The order set goals for the program to: 1) provide electric bill payment assistance to customers
26 meeting the Program’s eligibility requirements, and 2) evaluate the impact of the Program and to

⁵³ Case No. ER-2016-0023 *In the Matter of The Empire District Electric Company for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company’s Missouri Service Area*. Stipulation and Agreement, paragraph 13, h.

⁵⁴ Case No. ER-2016-0023 *In the Matter of The Empire District Electric Company for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company’s Missouri Service Area*, Order Approving Stipulation and Agreement, page 5-6. paragraph 5.

1 evaluate the impact a customer charge discount for program participants can have on the
2 disconnection and bad debt rates for Empire both during and after participation in the program.

3 As of May 2019, 1,218 customers have participated in the program. 647 customers
4 were disqualified from the program after an average of eight months as a result of defaulting
5 on payments and 597 customers are still participating in the program for a total program length
6 of 19 months. There were also losses of 277 participants which discontinued their service
7 and received final bills (154 of which have been left unpaid).⁵⁵ Enrollment into the program is
8 allowed at any time, however the majority of the enrollments took place during two timeframes
9 1) May-July 2017 and 2) January – March 2018. The Company attributes these surges in
10 enrollments to peak weather and the timeframe they send applicant pool communication.

11 In Case No. EM-2016-0213, the Empire-Liberty Merger, filed August 23, 2016, the
12 Company agreed to an annual in-person meeting with each of the local Community Action
13 Agencies for the next five years in Joplin, at Empire’s headquarters, with extended invitations to
14 (at least) the Commission Staff, OPC, and the DE to discuss progress to date along with the
15 Strengths, Weaknesses, Opportunities and Threats to Empire’s low-income population. Empire
16 has held three annual meetings to date 1) October 26, 2017; 2) November 2, 2018; and
17 3) November 8, 2019.

18 Staff recommends the Commission order 1) the continuation of the LIPP program at the
19 current funding level until the Company’s next general rate case; and 2) to remove the program
20 spending cap at \$250,000 and authorize Empire to use a regulatory asset or regulatory liability
21 account to track incurred program expenses above or below the \$250,000 program total as it is
22 currently structured.

23 *Staff Expert/Witness: Kory J. Boustead*

24 **VIII. Income Taxes**

25 **A. Current and Deferred Income Tax**

26 **1. Current Income Taxes**

27 Current income tax for this case has been calculated by Staff largely consistent with the
28 methodology used in Empire’s most recent rate case, Case No. ER-2016-0023. Adjustments are

⁵⁵ Liberty Utilities Low-Income Program Stakeholder Annual Meeting, November 8, 2019, PowerPoint presentation.

1 made to net income to compute the current income tax expense. These adjustments are effectuated
2 by taking adjusted net income and either adding to or subtracting from the net income various
3 timing differences to obtain net taxable income for ratemaking purposes. (The term “timing
4 differences” refers to the differences in time when certain costs can be deducted for purposes of
5 determining financial statement net income and taxable income, respectively.) The adjustments
6 are the result of various financial statement (“book”) and tax timing differences as well as their
7 implementation under separate tax ratemaking methods: flow-through versus normalization. The
8 resulting net taxable income for ratemaking is then multiplied by the appropriate federal and state
9 tax rates to obtain the current provision for income taxes. Staff used the current federal tax rate of
10 21 percent and the Missouri state income tax rate of four (4) percent effective January 1, 2020, in
11 calculating Empire’s income tax liability. The difference between the calculated current income
12 tax provision and the per book income tax provision is the current income tax provision adjustment.

13 The tax timing differences used in calculating taxable income for computing current
14 income tax are as follows:

15 Add Back to Operating Income Before Taxes:

- 16 Book Depreciation Expense
- 17 Non-Deductible Expense – Non-deductible meals and dues
- 18 Contributions In Aid of Construction
- 19 Book Amortization

20 Subtractions from Operating Income:

- 21 Interest Expense – Weighted Cost of Debt times Rate Base
- 22 Tax Depreciation – Straight-Line
- 23 Tax Depreciation – Excess

24 **2. Deferred Income Taxes**

25 When a tax timing difference is reflected for ratemaking purposes in the deferred tax
26 adjustment consistent with the timing used in determining taxable income for the calculation of
27 current income tax payable to the IRS, the timing difference is given a “flow-through” treatment.

28 When a current year timing difference is deferred and recognized for ratemaking purposes
29 consistent with the timing used in calculating pre-tax operating income in the financial statements,
30 then that timing difference is given “normalization” treatment for ratemaking purposes. Deferred

1 income tax expense for a regulated utility reflects the tax impact of “normalizing” tax timing
2 differences for ratemaking purposes. Current IRS rules for regulated utilities, in effect, require
3 normalization treatment for the timing difference related to accelerated depreciation.

4 For most utilities, it is necessary to break out a utility’s tax depreciation into two separate
5 components: tax straight-line depreciation and excess tax depreciation. Tax straight-line
6 depreciation is different from book straight-line depreciation due to the different tax basis of
7 property allowed under the tax code. Excess tax depreciation differs from straight-line book
8 depreciation due to the higher depreciation rates allowed in the early years of an asset’s life under
9 the current tax code as compared to “straight-line” book depreciation rates. To calculate excess
10 tax depreciation, Staff used the total tax depreciation amount included in the Company’s filing in
11 this case. Most tax basis differences were eliminated for assets placed into service after 1986 due
12 to the Tax Reform Act (“TRA”) enacted that year.

13 *Staff Expert/Witness: Keith D. Foster*

14 **IX. Renewable Energy**

15 **A. Renewable Energy Standard (“RES”)**

16 The Missouri Renewable Energy Standard (“RES”)⁵⁶ was enacted as a voter initiative
17 petition in November 2008. Provisions of the resulting statute and regulations require Empire
18 (and the other investor-owned utilities) to meet certain requirements regarding the use of
19 renewable energy while not exceeding the one percent (1%) retail rate impact limit. The investor-
20 owned utilities demonstrate compliance by retiring Renewable Energy Credits (“REC”) in the
21 commission-approved tracking system, the North American Renewables registry. A REC
22 represents that 1 MWh of electricity has been generated from a renewable energy resource. A REC
23 expires three years from the date the electricity associated with that REC was generated, however,
24 a REC may be used for compliance in the calendar year it expired as long as it was valid at any
25 time in that year.⁵⁷ When the investor-owned utilities retire a REC it means that action has been
26 taken to remove the REC from circulation within the NAR system, in other words, it no longer can
27 be traded, sold, or transferred to another party.

⁵⁶ Mo. Rev. Stat. Section 393.1020 (2000).

⁵⁷ 20 CSR 4240-20.100(1)(M) and 20 CSR 4240-20.100(2)(B).

1 The RES requires Empire to provide a rebate to its retail customers for installation of solar
2 electric systems on their premises. Empire was previously believed to be exempt from offering
3 solar rebates to its customers and exempt from the solar RES requirements. The exemption was
4 challenged and on February 10, 2015, the Missouri Supreme Court issued an opinion that Empire
5 was not exempt from these requirements. This resulted in Empire filing proposed solar rebate tariff
6 sheets to offer solar rebates to its customers on May 5, 2015, that became effective May 16, 2015.⁵⁸

7 For calendar years 2018 through 2020, the RES requires Empire to generate or purchase
8 ten percent (10%) of its retail sales using renewable energy resources.⁵⁹ Empire must derive two
9 percent (2%) of the renewable energy requirement from solar energy.⁶⁰ RECs can be banked for
10 three (3) years and utilized for future compliance purposes.⁶¹ Empire files annually a RES
11 Compliance Plan and RES Compliance Report.⁶² Each RES Compliance Plan
12 provides information regarding the utility's plan for the current calendar year and the subsequent
13 two (2) calendar years. The RES Compliance Report is a status report on the utility's compliance
14 for the preceding calendar year. For the 2018 calendar year, Empire retired RECs from
15 Ozark Beach Hydroelectric Project and the Elk River Windfarm for the non-solar requirement and
16 S-RECs obtained from its customer-generators for solar compliance.⁶³

17 *Staff Expert/Witness: Claire M. Eubanks, PE*

18 **B. Solar Rebates**

19 On May 5, 2015, Empire issued tariffs to establish solar rebate payments procedures, and
20 to revise its net metering tariffs to accommodate the payment of solar rebates.⁶⁴ The tariff
21 submitted under YE-2015-0322 became effective on May 16, 2015. Staff has amortized the costs
22 over a ten-year period, based upon Staff's review of the costs recorded to date in Account 182377.
23 Staff is using the September 30, 2019, balance of this regulatory asset in rate base in this case.
24 Staff has also included an adjustment in the Income Statement to amortize these costs to expense.

⁵⁸ See Case No. ET-2015-0285.

⁵⁹ Mo. Rev. Stat. Section 393.1030 .1(1) (2000).

⁶⁰ Mo. Rev. Stat. Section 393.1030.1 (2000).

⁶¹ "An unused credit may exist for up to three years from the date of its creation." Mo. Rev. Stat. § 393.1030.2 (2000).

⁶² Empire filed its RES Plan for 2019-2021 and its RES Report for calendar year 2018 in EE-2019-0305; its 2019 RES Plan and RES Report is due on April 15, 2020.

⁶³ EE-2019-0305, *2018 Annual Renewable Energy Standard Compliance Report*, page 8.

⁶⁴ Order Approving Expedited Tariff, MoPSC File No. ET-2015-0285, page 1.

1 Staff will make further adjustments in the true-up audit in order to address any additional solar
2 rebate spending through that point in time.

3 *Staff Expert/Witness: Caroline Newkirk*

4 **X. Depreciation**

5 **A. Depreciation Study**

6 20 CSR 4240-3.160(1)(A) requires that a depreciation study, database and property unit
7 catalog be submitted with a general rate increase request unless Staff received these items during
8 the three (3) years prior to the rate increase request or before five (5) years have elapsed since last
9 receiving said items. Empire references a depreciation study submitted in Case No. ER-2016-0023
10 on October 16, 2015, as meeting the requirement of 20 CSR 4240-3.160(1)(A). The depreciation
11 study referenced by Empire was filed as Supplement Schedule TJS-2 to the Direct Testimony of
12 Thomas J. Sullivan in Case No. ER-2016-0023. The study was updated through
13 December 31, 2014. Empire has stated that it will file a depreciation study with the rate case
14 planned to be filed for the 3rd quarter of 2020.⁶⁵ Empire is not requesting to change currently
15 ordered depreciation rates in this case. Staff does not take issue with the current depreciation
16 study, database and property unit catalog as long as a new depreciation study is submitted by
17 October 16, 2020.

18 Empire has requested approval to utilize a 5% depreciation rate for new charging station
19 assets that do not have a previously ordered rate. In response to Staff Data Request No. 0189,
20 Empire stated that the expected service life of the equipment is 20 years and that there would likely
21 be no salvage value according to the equipment vendor. With the limited history of electric vehicle
22 charging and rapid advancement of technology in this area, the 20-year service life assumption
23 seems reasonable, but this assumption should be revisited in the next general rate case, when the
24 next depreciation study is available.

25 *Staff Expert/Witness: Cedric E. Cunigan*

⁶⁵ Direct Testimony of Sheri Richard page 7, lines 19 and 20.

1 **B. Clearing Accounts**

2 During the test year, Empire incurred depreciation for transportation equipment that was
3 charged to expense through a clearing account. Empire has vehicles and power operated
4 equipment in its fleets to maintain existing operations as well as to be used in construction related
5 activities. The depreciation expense associated with assets is recorded in clearing accounts. The
6 clearing accounts are then allocated to the various construction projects and other operations and
7 maintenance expense accounts. In this current rate case, because depreciation expense is
8 accounted for in Staff’s Accounting Schedule 5, Staff made an adjustment to remove the
9 depreciation amount booked to the clearing account for construction activities. The removed costs
10 are charged to construction projects that will eventually be plant in service, in which the costs will
11 be recovered through depreciation over the life of the assets.

12 *Staff Expert/Witness: Kimberly K. Bolin*

13 **XI. Fuel Adjustment Clause (“FAC”)**

14 **A. Policy**

15 In summary, Staff makes the following recommendations regarding Empire’s Fuel
16 Adjustment Clause (“FAC”):

- 17 • Continue Empire’s FAC with modifications;
- 18 • Include a revised Base Factor⁶⁶ in the FAC tariff sheets calculated from the Base
19 Energy Cost⁶⁷ that the Commission includes in the revenue requirement upon
20 which it sets Empire’s general rates in this case;
- 21 • Order Empire to continue to provide monthly filings that will aid the Staff in
22 performing FAC tariff, prudence, and true-up reviews;
- 23 • Clarify that the only transmission costs and revenues that are included in Empire’s
24 FAC are those that Empire incurs for Purchased Power and Off-System Sales; and

⁶⁶ Base Factor is defined in Empire’s Original Tariff Sheet No. 17u as “BASE FACTOR (“BF”): The base factor is the base energy cost divided by net generation kWh determined by the Commission in the last general rate case.”

⁶⁷ Base Energy Cost is defined in Empire’s Original Revised Tariff Sheet No. 17u as “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 Purchased Power Adjustment (“FPA”).”

- Order Empire to include Schedule E from the Stipulation and Agreement that was approved by Commission Order in Case. No ER-2016-0023 on August 10, 2016, either within the tariff or as an attachment to the tariff, to clarify the list of sub-accounts included and excluded within the Fuel Adjustment Clause.

At this time Staff does not have its estimate for the Base Factor for the FAC, but will provide it and a discussion on the calculation of the Base Factor when Staff files its Class Cost of Service/Rate Design Report on January 29, 2020. Staff will use the Base Energy Cost and the kWh at the generator from its fuel run to develop the Base Factor.

B. History

The Commission first authorized a FAC for Empire in its *Report and Order* in Empire's 2008 rate case, Case No. ER-2008-0093, and approved FAC tariff sheets in that case with an effective date of September 1, 2008. In general rate cases Case Nos. ER-2010-0130, ER-2011-0004, ER-2012-0345, ER-2014-0351, and ER-2016-0023, the Commission authorized continuation, with modifications, of Empire's FAC. The primary features of Empire's present FAC (tariff sheet numbers 17u through 17ac) include:

- Two 6-month accumulation periods: March through August and September through February;
- Two 6-month recovery periods: December through May and June through November;
- Fuel Adjustment Rate ("FAR") filings semi-annually not later than April 1 and October 1;
- One Base Factor for all calendar months of the year;
- A 95%/5% sharing mechanism;
- FAR rates for individual service classifications adjusted for the two Empire service voltage levels, rounded to the nearest \$0.00001, and charged on each kWh billed; and
- True-up of any over- or under-recovery of revenues following each recovery period with a true-up amount being included in the determination of FAR for a subsequent recovery period.

1 The resulting changes to the Empire FARs ordered by the Commission are summarized in
2 the **Continuation of FAC** section of this report. The Base Factor was originally set in Empire’s
3 2008 general rate case and was changed as a result of the negotiated settlements in Empire’s 2010,
4 2011, 2012, and 2016 general rate cases, and by Commission *Report and Order* in the 2014 general
5 rate case.

6 Staff has filed seven prudence review reports⁶⁸ (File Nos. EO-2010-0084, EO-2011-0285,
7 EO-2013-0114, EO-2014-0057, EO-2015-0214, EO-2017-0065, and EO-2018-0244) discussing
8 its review of the costs and revenues of the Company’s FAC. Staff found no evidence of imprudent
9 decisions by the Company’s management related to fuel, purchased power and net emission costs,
10 off-system sales revenues and renewable energy credits revenues for the time periods reviewed⁶⁹.

11 **C. Continuation of FAC**

12 Staff recommends that the Commission approve, with modifications, the continuation of
13 Empire’s FAC.

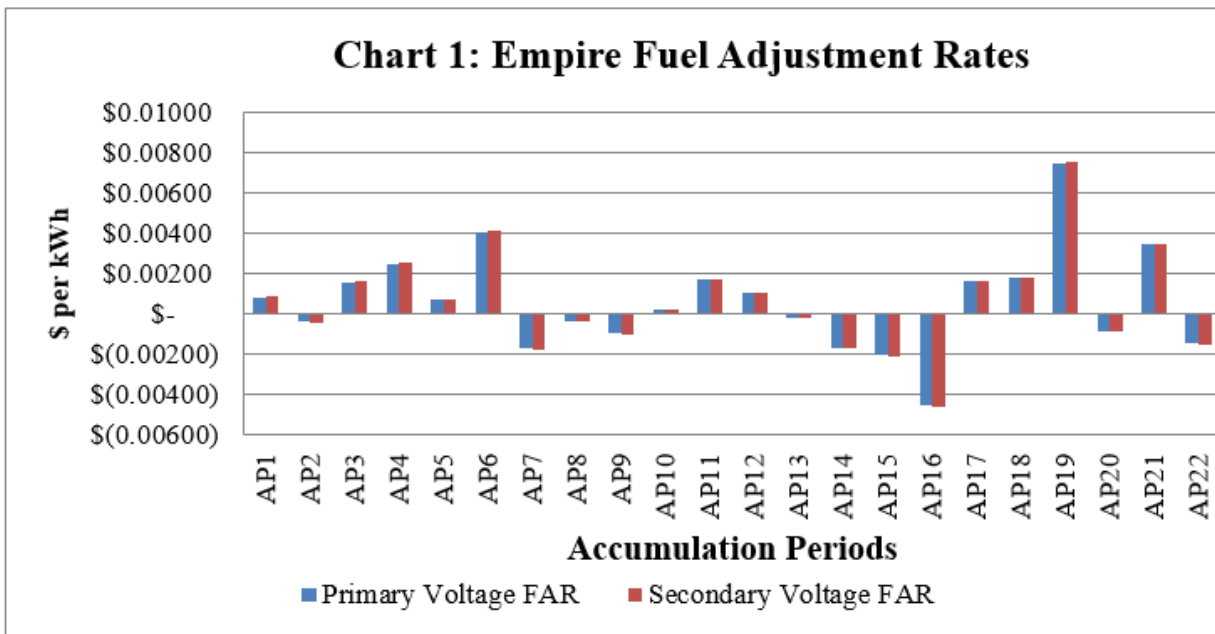
14 The Company has filed for and received approval of changes to its fuel adjustment rates
15 (“FARs”) for Twenty-Two (22) completed accumulation periods (“AP”) (AP1 through AP22).
16 The primary and secondary voltage FARs for each accumulation period are reflected in Chart 1.

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26 *continued on next page*

⁶⁸ 20 CSR 4240-20.090(11) Prudence Reviews Respecting RAMs [rate adjustment mechanisms]. A prudence review of the costs subject to the FAC shall occur no less frequently than every eighteen months.

⁶⁹ In Staff’s Sixth Prudence Audit Report, Case No. EO-2017-0065, OPC challenged Empire’s financial losses on natural gas hedging including their hedging strategy, however the Commission’s Amended Report and Order issued on February 28, 2018 states on page 22, “the Commission finds and concludes that Empire’s natural gas hedging policy was prudent”.

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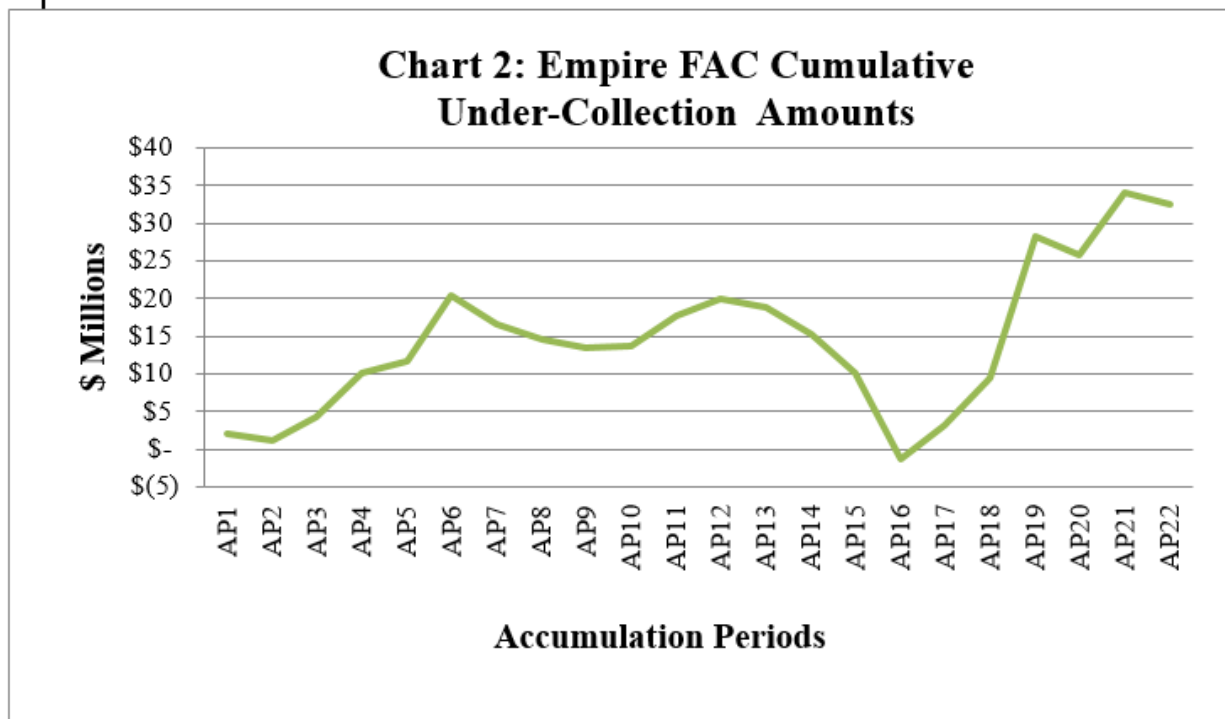
3 The Company’s actual Total Energy Cost exceeded the then-effective Base Factors
 4 multiplied by monthly usage billed to Empire’s customers’ in twelve out of twenty-two completed
 5 accumulation periods. Actual Total Energy Cost include: 1) Empire’s total booked costs as
 6 allocated to its Missouri retail jurisdiction for fuel consumed in the Company’s generating units,
 7 including the costs associated with the Company’s fuel hedging program; 2) purchased power
 8 energy charges, including applicable transmission fees; 3) Southwest Power Pool variable costs;
 9 and 4) air quality control system consumables, such as anhydrous ammonia, limestone, and powder
 10 activated carbon, and emission allowance costs. Actual Total Energy Cost does not include the
 11 purchased power demand costs, since these are considered to be fixed costs. Actual FAC costs are
 12 off-set by actual Revenue from Off-System Sales, actual Net Emission Costs, and actual
 13 Renewable Energy Credit Revenues. During ten accumulation periods (AP2, AP7, AP8, AP9,
 14 AP13, AP14, AP15, AP16, AP20, and AP22), Empire’s Base Energy Cost exceeded actual Total
 15 Energy Cost; 95% of such excess amounts was returned to customers during ten recovery periods
 16 (“RP”) (RP2, RP7, RP8, RP9, RP13, RP14, RP15, RP16, RP20, and RP22). In twelve of its
 17 accumulation periods (AP1, AP3, AP4, AP5, AP6, AP10, AP11, AP12, AP17, AP18, AP19,
 18 and AP21), Empire under-collected its actual Total Energy Costs, and 95% of the amounts of

1 under-collection was recovered from Empire’s Missouri customers during twelve RPs (RP1, RP3,
 2 RP4, RP5, RP6, RP10, RP11,RP12, RP17, RP18, RP19, and RP21).

3 At the conclusions of its general electric rate cases, during AP3, AP6, AP10, AP14,
 4 and AP17 – Case Nos. ER-2010-0130, ER-2011-0004, ER-2012-0345, ER-2014-0351, and
 5 ER-2016-0023, respectively – the Base Factors in Empire’s FAC were re-set.

6 Charts 2 and 3 illustrate the following information for the twenty-two (22) accumulation
 7 periods: 1) cumulative under collection amount which is equal to Total Energy Cost (“TEC”) less
 8 Net Base Energy Cost (“B”) for Empire’s Missouri jurisdiction,⁷⁰ and 2) percentage of cumulative
 9 under-collection amount which is equal to $100 * (TEC - B) / TEC$.

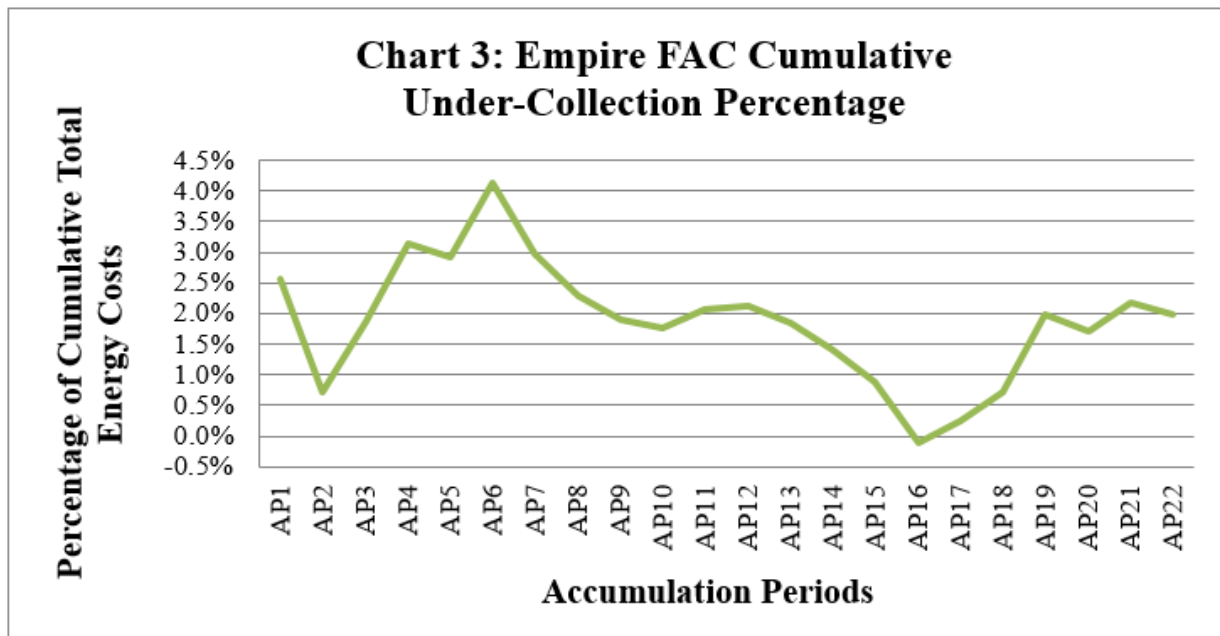
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⁷⁰ For AP22, this is the amount on line 5 of Empire’s 7th Revised Sheet No. 17ac.

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3 Chart 1 illustrates the variability of the FARs as a result of variations in each accumulation
 4 period’s billed Base Energy Cost and actual Total Energy Cost. From Charts 2 and 3, Staff
 5 observes that the FAC cumulative under-collected amount over eleven years is approximately
 6 \$33 million, or about 2.0 percent of total actual Total Energy Cost of \$1.632 million during AP1
 7 through AP22.

8 Staff recommends continuation of Empire’s FAC with modifications. As shown in the
 9 previous charts and discussion, Empire’s actual Total Energy Costs continue to be relatively
 10 large,⁷¹ volatile, and beyond the control of the Company. In addition, the Southwest Power Pool
 11 (“SPP”) conversion to the Integrated Marketplace (“IM”) on March 1, 2014, represents a
 12 fundamental change in how Empire’s generation is dispatched and how Empire serves its native
 13 load. By having an FAC that includes IM costs, the effects of the IM will flow through the FAC
 14 to both the Company and its customers in a timely manner.

15 **D. Revising the Base Factor**

16 Correctly setting the Base Factor in Empire’s FAC tariff sheets is critical to both a
 17 well-functioning FAC and a well-functioning FAC sharing mechanism. For the reasons below,

⁷¹ Empire’s proposed Base Energy Cost for this case represents 24% of the requested total revenue requirement.

1 Staff recommends the Commission require the Base Factor in Empire's FAC be set based on the
 2 Base Energy Cost that the Commission includes in the revenue requirement which it sets Empire's
 3 general rates in this case.

4 Table 1 below shows three scenarios in which the FAC Base Energy Cost used to set the
 5 FAC Base Factor are equal to, less than, or greater than the Base Energy Cost in the revenue
 6 requirement upon which the Commission sets general rates:

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Table 1: Base Energy Cost Case Studies				
		Case 1	Case 2	Case 3
Line	95%/5% Sharing Mechanism	Energy Cost in FAC Equal To Base Energy Cost in Rev. Req.	Energy Cost in FAC Less Than Base Energy Cost in Rev. Req.	Energy Cost in FAC Greater Than Base Energy Cost in Rev. Req.
a	Revenue Requirement	\$ 10,000,000	\$ 10,000,000	\$ 10,000,000
b	Base Energy Cost in Rev. Req.	\$ 4,000,000	\$ 4,000,000	\$ 4,000,000
c	Base Energy Cost in FAC	\$ 4,000,000	\$ 3,900,000	\$ 4,100,000
	Outcome 1: Actual Energy Cost <u>Greater Than</u> Base Energy Cost in Revenue Requirement			
d	Actual Total Energy Cost	\$ 4,200,000	\$ 4,200,000	\$ 4,200,000
	Billed to Customer:			
= b	in Permanent Rates	\$ 4,000,000	\$ 4,000,000	\$ 4,000,000
$e = (d - c) \times 0.95$	through FAC	\$ 190,000	\$ 285,000	\$ 95,000
$f = b + e$	Total Billed to Customers	\$ 4,190,000	\$ 4,285,000	\$ 4,095,000
$g = f - d$	Kept/(Paid) by Company	\$ (10,000)	\$ 85,000	\$ (105,000)
	Outcome 2: Actual Energy Cost <u>Less Than</u> Base Energy Cost in Revenue Requirement			
h	Actual Energy Cost	\$ 3,800,000	\$ 3,800,000	\$ 3,800,000
	Billed to Customer:			
= b	in Permanent Rates	\$ 4,000,000	\$ 4,000,000	\$ 4,000,000
$i = (h - c) \times 0.95$	through FAC	\$ (190,000)	\$ (95,000)	\$ (285,000)
$j = b + i$	Total Billed to Customers	\$ 3,810,000	\$ 3,905,000	\$ 3,715,000
$k = j - h$	Kept/(Paid) by Company	\$ 10,000	\$ 105,000	\$ (85,000)

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 9 Case 1 illustrates that if the FAC Base Energy Cost used for the Base Factor is equal to the
 10 Base Energy Cost in the revenue requirement used for setting general rates, the utility does not
 11 over or under-collect as a result of the level of total actual energy costs. The FAC works as it is
 12 intended to work.

13 Case 2 illustrates that if the FAC Base Energy Cost used for the Base Factor is less than
 14 the Base Energy Cost in the revenue requirement used for setting general rates, the utility will

1 collect more than was intended and customers pay more than the FAC was designed for them to
2 pay, regardless of the level of actual energy costs.

3 Case 3 illustrates that if the FAC Base Energy Cost used for the Base Factor is greater than
4 the Base Energy Cost in the revenue requirement used for setting general rates, the utility will not
5 collect all of the costs that were intended in the FAC design, and customers pay less than the entire
6 amount intended, regardless of the level of actual energy costs.

7 These three cases illustrate the importance of setting the Base Factor in the FAC correctly,
8 *i.e.*, revising the Base Factor to match the Base Energy Cost in the revenue requirement used for
9 setting general rates. Case 1 is the preferred case, and illustrates how the FAC is intended to work.

10 Confidential Table 2 below contains a comparison of Empire’s FERC account expenses
11 and revenues, annual kWhs, cents per kWh, and Base Energy Cost approved in the last general
12 rate case, Case No. ER-2016-0023, and Empire’s proposed⁷² Base Energy Cost in this case.
13 Empire’s proposed overall total Fuel and Purchased Power for the FAC base increased a total of
14 2.59% compared to the total fuel and purchased power for FAC base approved in Case No.
15 ER-2016-0023.

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⁷² This proposed FAC Base Factor calculation can be found in Todd Tarter’s Direct Testimony, Schedule TWT-3. This proposed FAC Base Factor calculation was also updated with Aaron Doll’s Supplement Direct Testimony filed on December 20, 2019.

Confidential Table 2 - FAC BASE FACTOR CALCULATION

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1 **E. Additional Reporting Requirements**

2 Due to the accelerated Staff review process necessary with FAC adjustment filings,⁷³
3 similar to what it did in the last Empire rate case (Case No. ER-2016-0023), Staff recommends the
4 Commission order Empire to continue providing the following information in between rate cases,
5 to aid Staff in performing FAC tariff, prudence, and true-up reviews:

- 6 • Monthly Southwest Power Pool (“SPP”) market settlements and revenue neutrality
7 uplift charges;
- 8 • Notification to Staff within 30 days of entering a new long-term contract for
9 purchased power, transportation, coal, natural gas or other fuel (natural gas spot
10 transactions are specifically excluded);
- 11 • Notification to Staff within 30 days of changes to a purchased power contract;
- 12 • Monthly natural gas fuel reports that include all transactions (spot and longer term),
13 including terms, volumes, price and analysis of number of bids;
- 14 • Every Empire hedging policy in effect at the time the tariff changes ordered by the
15 Commission in this rate case go into effect;
- 16 • Notification to Staff within 30 days of any material change in Empire’s fuel hedging
17 policy and Staff access to new policies;
- 18 • Missouri Fuel Adjustment Interest calculation workpapers in electronic format with
19 all formulas intact when Empire files for a change in its cost adjustment factor;
- 20 • Notification to Staff within 30 days of any revisions to Empire’s internal policies
21 for participating in the SPP and Staff access to the new policies;
- 22 • Access to all natural gas, nuclear fuel, coal, and transportation contracts and
23 policies upon Staff’s request, at Empire’s corporate office in Joplin, Missouri; and
- 24 • Notification to Staff within 30 days of the effective date of every natural gas
25 contract Empire enters into and Staff opportunity to review the contract at Empire’s
26 corporate office in Joplin, Missouri.

27 *Staff Expert/Witness: Brooke Mastrogiannis*

⁷³ The company must file its FAC adjustment 60 days prior to the effective date of its proposed tariff sheet. Staff has 30 days to review the filing and make a recommendation to the Commission. The Commission then has 30 days to approve or deny Staff’s recommendation.

1 **F. FAC Voltage Adjustment Factors and Loss Study**

2 Empire filed a request to continue its Fuel Adjustment Clause (“FAC”) in the current case.
 3 Commission Rule 20 CSR 4240-20.090(13) requires an electric utility that desires to continue
 4 using a Commission authorized Rate Adjustment Mechanism (“RAM”), such as an FAC, to
 5 complete a jurisdictional system loss study of the corresponding system energy losses experienced
 6 in its delivery of electricity. This study must be based upon a consecutive twelve-month period,
 7 preferably a calendar year, and be conducted at least once every four years following the
 8 Commission’s initial approval of the company’s FAC.⁷⁴ Empire included a loss study in its
 9 workpapers submitted with its request that is in compliance with this regulation. This loss study
 10 contains system loss calculations/determinations based on data collected during calendar year
 11 2017. Staff used the information in this loss study in developing the following recommended
 12 primary and secondary voltage level adjustment factors:

Voltage Level	Voltage Adjustment Factor
Primary	1.0429
Secondary	1.0625

16 These voltage adjustment factors account for the energy losses experienced in the delivery
 17 of electricity from the generator to the customer. These factors will be utilized in Staff’s
 18 determination of Fuel Adjustment Rates (“FARs”) that are applicable to an individual voltage
 19 service classification of a particular customer in the corresponding FAC tariff to be filed based on
 20 the Commission’s order in this matter.

21 *Staff Expert/Witness: Alan J. Bax*

⁷⁴ 20 CSR 4240-20.090(13) states:

(13) Rate Design of the RAM. The design of the RAM rates shall reflect differences in losses incurred in the delivery of electricity at different voltage levels for the electric utility’s different rate classes as determined by periodically conducting Missouri jurisdictional system loss studies.

(A) When the electric utility initially seeks authority to use a RAM, the end of the twelve- (12-) month period of actual data collected that is used in its Missouri jurisdictional system loss study must be within twenty-four (24) months of the date the utility files its general rate proceeding first requesting a RAM.

(B) When the electric utility seeks to continue or modify its RAM, the end of the twelve- (12-) month period of actual data collected that is used in its Missouri jurisdictional system loss study must be no earlier than four (4) years before the date the utility files the general rate proceeding seeking to continue or modify its RAM.

Therefore, the electric utility shall conduct a Missouri jurisdictional system loss study within twenty-four (24) months prior to the general rate proceeding in which it requests its initial RAM. The electric utility shall conduct a Missouri jurisdictional loss study no less often than every four (4) years thereafter, on a schedule that permits the study to be used in the general rate proceeding necessary for the electric utility to continue to utilize a RAM.

1 **XII. Customer Service**

2 **A. Overview Since Merger with Liberty Utilities**

3 **Background**

4 In Case No. ER-2004-0570, the Missouri Public Service Commission (“Commission”) ordered Empire District Electric Company (“Company” or “Empire”) to provide monthly contact center data to the Commission Staff.⁷⁵ This data included staffing levels, call volumes, average speed of answer, and abandoned call rate. In addition, Company staff periodically met with Commission Staff to discuss contact center performance and customer service activity.

9 **Empire’s Continued Commitment to Contact Center Performance**

10 In the Staff Stipulation and Agreement filed in its merger case with Liberty Utilities (Central) Co. and Liberty Sub Corp., Empire reiterated its commitment to providing quality contact center performance. A provision in this Stipulation and Agreement states that “Empire and Liberty will strive to meet or exceed the customer service and operational levels currently provided to their customers.”⁷⁶ The Stipulation and Agreement also states that Company and Commission Staff personnel would meet on a periodic (such as quarterly) basis to review contact center and other service quality performance.⁷⁷ Commission Staff monitored contact center performance data in the monthly reports submitted by Empire and noted that 2017 and 2018 performance fell below premerger levels.

19 **Company Meetings with Commission Staff Related to Contact Center Performance**

20 Company personnel apprised Commission Staff of contact center performance at each periodic meeting held, as needed, since the merger docket. At the most recent meeting on November 6, 2019, the Company provided detailed information about the 2017 and 2018 decline in contact center performance, the remedial actions it has taken, and the improvements that have transpired.⁷⁸ In response to a Commission Staff data request, the Company described its remedial actions:

⁷⁵ Report and Order, dated March 10, 2005, approving Stipulation and Agreement as to Certain Issues, filed Dec. 22, 2004 in Case No. ER-2004-0570.

⁷⁶ Page 10 of Staff Stipulation and Agreement, dated Aug 4, 2016 in Case No. EM-2016-0213.

⁷⁷ Page 10 of Staff Stipulation and Agreement, dated Aug 4, 2016 in Case No. EM-2016-0213.

⁷⁸ See Schedule 1, “Periodic Meeting with PSC, Case No. EM-2016-0213”.

- 1 • In the last six months Liberty-Empire has added two additional CSR positions at the contact
2 center and have posted an additional four positions in November 2019.
- 3 • An additional supervisor was added in October 2019, this addition will help support the
4 new CSR's day to day interactions with our customers.
- 5 • Creation of Digital Customer Experience Team. This team responds to customer service
6 inquiries through Facebook and Twitter during the hours of 7:00 a.m. to 10:00 p.m.
- 7 • In an attempt to reduce customer calls regarding meter estimations the Company has
8 utilized contract employees to backfill meter reading as several meter readers have taken
9 other positions with the Company.⁷⁹

10 Statistics provided for the month of September 2019 indicated an abandoned call rate of
11 4% and an average speed of answer of 44 seconds.⁸⁰ The Company has an abandoned call rate
12 goal of 5% or less and a goal for answering all calls within 30 seconds.⁸¹

13 **Commission Staff's Analysis**

14 Commission Staff opines that the Company is taking appropriate actions to address the
15 unacceptable contact center performance that began in 2017, subsequent to the merger with Liberty
16 Utilities. While it is unfortunate that performance fell, it was not until 2018 that the unsatisfactory
17 performance became a concern warranting Commission Staff's attention. Based on its experience,
18 Commission Staff agrees that turnover attributable to the Empire-Liberty merger is a common
19 consequence of mergers and that replacement contact center staff productivity must increase
20 before satisfactory performance levels are restored. Improvement trends are encouraging, and the
21 Company has an opportunity to achieve its performance goals in the near-term future.

22 **Commission Staff Recommendation**

23 Commission Staff recommends that the Company management establish a deadline for
24 meeting its contact center performance goals and communicate its progress toward reaching those
25 goals in its monthly reports and periodic meetings with Commission Staff. Developing a deadline
26 to achieve contact center goals should help ensure that satisfactory performance occurs in a timely
27 manner. Commission Staff will monitor the Company's actions and progress toward restoring
28 contact center performance to pre-merger levels.

29 *Staff Expert/Witness: Gary Bangert*

⁷⁹ Response to Commission Staff Data Request No. 0182 in Case No. ER-2019-0374.

⁸⁰ See Schedule 2, "Report 09-2019".

⁸¹ See Schedule 1, "Periodic Meeting with PSC, Case No. EM-2016-0213".

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B. Credit Card Fees

Current Payment Methods

Currently, customers may pay their bills from Empire by cash, check, money order, debit or credit card, and electronic bank draft through the customer’s checking or savings account. Payments can be made in person at Empire’s office locations, at Western Union (or another authorized collector service), at the Company’s kiosk machines, by wire transfer, at third-party locations such as grocery stores, through online banking, or on the Company’s website. At the website, customers may also set up paperless billing and make automatic payments from a checking or savings account.

Empire currently uses a third-party payment vendor, Western Union Speedpay, to process payments made by credit card.⁸² Individual residential customers pay a \$2.25 convenience fee for each transaction using this service.

Customer Survey Results

Customers are periodically given surveys and asked to provide feedback of their overall satisfaction with Liberty Utilities.⁸³ The Company stated that it uses these surveys to prioritize customer service issues needing improvement.⁸⁴ ** _____

_____ **⁸⁵ Company Witness Brent Baker also stated in his direct testimony that “Customers have consistently reported that ease of bill payment is a priority, including having no fees for card payments.”⁸⁶

Empire’s Request

In this case, the Company proposes to eliminate credit card convenience fees for individual customers and to recover the costs associated with processing credit card payments in its overall cost of service, similar to the way bank fees are recovered.⁸⁷

⁸² Data Request No. 0176.
⁸³ Direct Testimony Brent Baker, Empire District Electric Company, page 9.
⁸⁴ Direct Testimony Brent Baker, Empire District Electric Company, page 9.
⁸⁵ Data Request No. 0175.
⁸⁶ Direct Testimony Brent Baker, Empire District Electric Company, page 9.
⁸⁷ Direct Testimony Brent Baker, Empire District Electric Company, page 10.

Staff Analysis

1
2 The Company cannot project the number of customers that may pay bills by credit card if
3 no convenience fee is charged to them,⁸⁸ but based on the high level of current participation, Staff
4 anticipates that the total number of customers using this payment option will increase if there is
5 no convenience fee. Mr. Baker notes a 36% increase in the number of credit card payments
6 between 2016 (379,329 transactions) and 2018 (511,195 transactions).⁸⁹ Additionally, payment
7 by credit card is consistently the second most utilized payment option for Empire customers,
8 behind payment by mail.⁹⁰

9 Empire conducted a request for proposal to obtain competitive costs for credit card
10 processing. Ten companies were reviewed, and Kubra was selected as the Company's payment
11 vendor. The Company anticipates Kubra will begin processing payments beginning the first or
12 second quarter of 2020. In addition, Empire reviewed how other companies such as ComEd,
13 Paymentus and Fiserv handle fees for paying by credit card, but did not offer insight into their
14 findings.⁹¹ Staff is awaiting response to a data request requesting more information of the current
15 contract and the contract with Kubra.⁹²

16 The Company has not analyzed the cost savings that may result if customers are able to
17 pay by credit card with no convenience fee.⁹³ However, the Company states that it does expect
18 more customers to take advantage of the option of bill payment by credit card with no fee charged.
19 By doing so, the Company expects that it could reduce resources for processing payments by mail,
20 customer walk-ins or phone calls, as well as collection efforts.⁹⁴

21 Staff agrees that there is potential for savings in other areas if customers no longer pay a
22 convenience fee for making a payment by credit card. However, the Company was unable to
23 provide Staff with estimated savings to the Company, as well as what portion of the increased
24 Company costs associated with credit card fees would be offset by operational savings.

⁸⁸ Data Request No. 0178.1.

⁸⁹ Direct Testimony Brent Baker, Empire District Electric Company, page 9.

⁹⁰ Data Request No. 0177.

⁹¹ Data Request No. 0180.

⁹² Data Request No. 0180.1.

⁹³ Data Request No. 0179.

⁹⁴ Data Request No. 0179.

Recommendations

1
2 The Commission has previously approved requests to eliminate credit card convenience
3 fees with the utility absorbing credit card processing services in the cost of service.⁹⁵ As discussed
4 in Section VII.H., subsection 15 of this Report sponsored by Staff witness Kimberly K. Bolin,
5 Staff is recommending in this case that convenience fees for customers paying bills by credit card
6 be eliminated, with the cost of processing such payments to be included in the Company's cost of
7 service. If the Commission approves this treatment, Staff recommends that the Company be
8 ordered to track performance and savings to the Company and its customers from this initiative.
9 Staff further recommends that Empire be required to monitor the level of customers using the
10 credit card option, along with other questions such as: Have the number of payments by credit
11 card increased? If so, by how much? Has eliminating a fee to pay by credit card resulted in savings
12 to the customer and/or to the Company? If so, how much? How will the Company inform
13 customers that there is no fee to pay their bill by credit card? Staff witness Kimberly K. Bolin is
14 sponsoring the adjustments proposed by Staff in regard to inclusion in cost of service of customer
15 credit card payment processing costs.

16 *Staff Expert/Witness: Dana R. Parish*

XIII. Isolated Adjustment – Retirement of Asbury

17
18 Ordinarily, appropriate ratemaking practice calls for measurement of all of the major
19 components of utility cost of service (revenues, expenses, rate base) at a consistent point in time
20 for ratemaking purposes (generally the true-up audit cut-off date for a rate case). However, the
21 Commission has recognized there may be exceptions to this general rule, and for a long time has
22 allowed parties to argue for inclusion in utility rates of “isolated adjustments” for events occurring
23 after the true-up period. The Commission has stated that, for an isolated adjustment to be
24 considered, the underlying event must have a known and measurable financial impact, and that
25 inclusion in rates of the isolated adjustment would not inappropriately affect the overall matching
26 in time of utility revenues, expenses and rate base.

27 In its direct testimony filed on August 14, 2019, Empire stated that it planned to retire the
28 Asbury generating plant by no later than June 30, 2020, which was approximately five months

⁹⁵ Case No. GR-2017-0215 & GR-2017-0216, “In the Matter of Spire Missouri, Inc.’s Request to Increase Its Revenues for Gas Service.”

1 after the true-up cut-off date that was later ordered in this proceeding. Empire did not include any
2 adjustments reflecting the retirement of Asbury in its case. However, Empire stated in its
3 testimony that an AAO was an option that could be used to address changes in operations and
4 maintenance (“O&M”) expense due to the retirement of the plant, for potential reflection of the
5 changes in Asbury O&M expense in its next general rate case.

6 In Case No. EA-2019-0010, Empire’s application for certificates of convenience and
7 necessity to acquire interest in three wind project holding companies, Empire entered into a
8 stipulation and agreement calling for use of an AAO to measure the changes in the types of Asbury
9 capital costs, expenses and revenues that have been included in Empire’s cost of service that
10 Empire will no longer incur after retiring Asbury. However, in its Report and Order in that
11 proceeding, the Commission did not approve that provision as it stated that it was too early to issue
12 an AAO for the retirement of Asbury because the sale or retirement of the unit was not certain at
13 that time. The Commission also said there was not sufficient evidence to show the sale or
14 retirement would be extraordinary in nature, and thus eligible for an AAO. The Commission said
15 when the retirement or sale of the unit did occur, parties could present proposals for deferrals of
16 some or all Asbury costs and savings as part of a formal request for an AAO.

17 On November 13, 2019, Empire filed in this case an updated Asbury informational notice
18 stating that the retirement of Asbury would occur no later than March of 2020. After this notice
19 and further discussions with Empire, Staff has learned that Empire is planning on retiring the
20 Asbury plant no later than March 1, 2020. The test year in this case is the 12 months ending
21 March 31, 2019, updated through September 30, 2019, with a true-up audit cut-off date of
22 January 31, 2020. The planned retirement of Asbury is outside of the true-up period by
23 approximately one month.

24 Staff recommends that isolated adjustments to certain rate base related financial impacts of
25 the retirement of the Asbury plant be included in this case. The amount of these adjustments will
26 be known and measurable at the time of the Asbury retirement, well before the operation-of-law
27 date in this proceeding. Accordingly, Staff intends to adjust plant-in-service and the accumulated
28 depreciation reserve to reflect the retirement of the Asbury plant. Staff also intends to remove
29 Asbury depreciation expense from this case. In addition, Staff will also remove any fuel inventory
30 associated with Asbury from rate base. These adjustment amounts will be quantified and
31 supported in Staff’s surrebuttal/true-up testimony filing scheduled for March 27, 2019.

1 Empire's O&M expenses will also be affected by the retirement of Asbury, but many of
2 these cost changes may not be fully known and measurable within the pendency of this rate case.
3 For that reason, Staff recommends that a tracker mechanism be ordered by the Commission in this
4 case to quantify the changes in the amounts of O&M expenses incurred by Empire associated due
5 to the retirement of Asbury, with the tracked amount potentially includable in rates in Empire's
6 next general rate proceeding. The items to be tracked include the portion of the change in Asbury
7 net fuel/purchased power expense not flowing through the FAC, Asbury maintenance expense,
8 and Asbury payroll expense and payroll related benefits.

9 *Staff Expert/Witness: Kimberly K. Bolin*

10 **XIV. Appendices**

11 **Appendix 1 - Staff Credentials**

12 **Appendix 2 - Support for Staff Cost of Capital Recommendation**

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric)
Company's Request for Authority to) Case No. ER-2019-0374
Implement a General Rate Increase for)
Electric Service)

AFFIDAVIT OF ALI ARABIAN

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

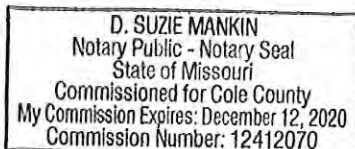
COMES NOW ALI ARABIAN and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing *Staff Cost of Service Report*; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

Ali Arabian
ALI ARABIAN

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 14th day of January 2020.



D. Suzie Mankin
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric)
Company's Request for Authority to) Case No. ER-2019-0374
Implement a General Rate Increase for)
Electric Service)

AFFIDAVIT OF GARY BANGERT

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW GARY BANGERT and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing *Staff Cost of Service Report*; and that the same is true and correct according to his best knowledge and belief.

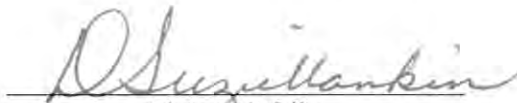
Further the Affiant sayeth not.


GARY BANGERT

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 14th day of January 2020.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2020
Commission Number: 12412070


Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric)
Company's Request for Authority to) Case No. ER-2019-0374
Implement a General Rate Increase for)
Electric Service)

AFFIDAVIT OF COURTNEY BARRON

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW COURTNEY BARRON and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing *Staff Cost of Service Report*; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Courtney Barron
COURTNEY BARRON

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 14th day of January 2020.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2020
Commission Number: 12412070

D. Suzie Mankin
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric)
Company's Request for Authority to) Case No. ER-2019-0374
Implement a General Rate Increase for)
Electric Service)

AFFIDAVIT OF ALAN J. BAX

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW ALAN J. BAX and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing *Staff Cost of Service Report*; and that the same is true and correct according to his best knowledge and belief.

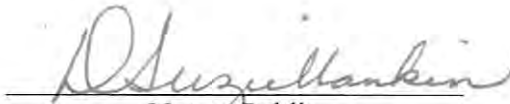
Further the Affiant sayeth not.


ALAN J. BAX

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 14th day of January 2020.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2020
Commission Number: 12412070


Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric)
Company's Request for Authority to) Case No. ER-2019-0374
Implement a General Rate Increase for)
Electric Service)

AFFIDAVIT OF MICHELLE A. BOCKLAGE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

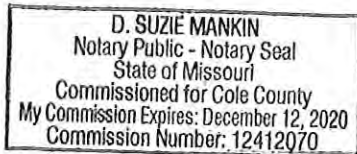
COMES NOW MICHELLE A. BOCKLAGE and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing *Staff Cost of Service Report*; and that the same is true and correct according to her best knowledge and belief.

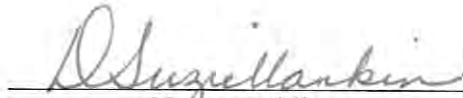
Further the Affiant sayeth not.


MICHELLE A. BOCKLAGE

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 14th day of January 2020.




Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric)
Company's Request for Authority to) Case No. ER-2019-0374
Implement a General Rate Increase for)
Electric Service)

AFFIDAVIT OF KIMBERLY K. BOLIN

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

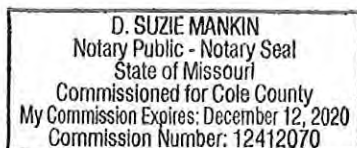
COMES NOW KIMBERLY K. BOLIN and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing *Staff Cost of Service Report*; and that the same is true and correct according to her best knowledge and belief.

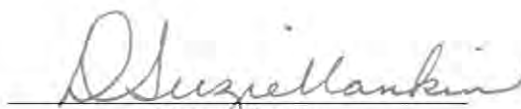
Further the Affiant sayeth not.


KIMBERLY K. BOLIN

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 14th day of January 2020.




Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric)
 Company's Request for Authority to) Case No. ER-2019-0374
 Implement a General Rate Increase for)
 Electric Service)

AFFIDAVIT OF KORY J. BOUSTEAD

STATE OF MISSOURI)
) ss.
 COUNTY OF COLE)

COMES NOW KORY J. BOUSTEAD and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing *Staff Cost of Service Report*; and that the same is true and correct according to her best knowledge and belief.

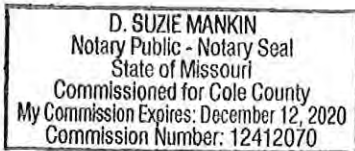
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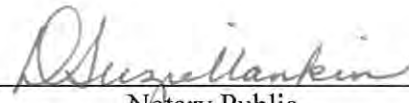


KORY J. BOUSTEAD

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 14th day of January 2020.





 Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric)
Company's Request for Authority to) Case No. ER-2019-0374
Implement a General Rate Increase for)
Electric Service)

AFFIDAVIT OF PETER CHARI

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW PETER CHARI and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing *Staff Cost of Service Report*; and that the same is true and correct according to his best knowledge and belief.

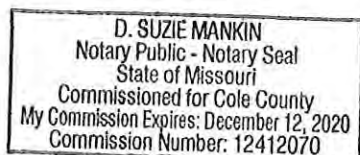
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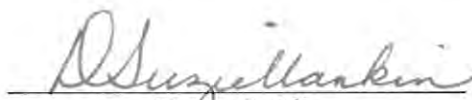


PETER CHARI

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 14th day of January 2020.





Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric)
Company's Request for Authority to) Case No. ER-2019-0374
Implement a General Rate Increase for)
Electric Service)

AFFIDAVIT OF CEDRIC E. CUNIGAN

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW CEDRIC E. CUNIGAN and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing *Staff Cost of Service Report*; and that the same is true and correct according to his best knowledge and belief.

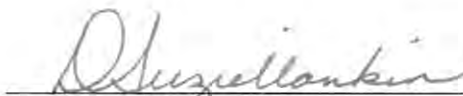
Further the Affiant sayeth not.


CEDRIC E. CUNIGAN

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 14th day of January 2020.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2020
Commission Number: 12412070


Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric)
Company's Request for Authority to) Case No. ER-2019-0374
Implement a General Rate Increase for)
Electric Service)

AFFIDAVIT OF CLAIRE M. EUBANKS, PE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

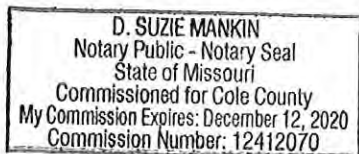
COMES NOW CLAIRE M. EUBANKS, PE and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing *Staff Cost of Service Report*; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Claire M Eubanks
CLAIRE M. EUBANKS, PE

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 14th day of January 2020.



D. Suzie Mankin
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

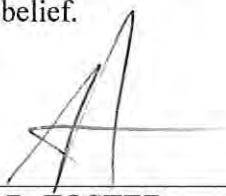
In the Matter of The Empire District Electric)
Company's Request for Authority to) Case No. ER-2019-0374
Implement a General Rate Increase for)
Electric Service)

AFFIDAVIT OF KEITH D. FOSTER

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW KEITH D. FOSTER and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing *Staff Cost of Service Report*; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

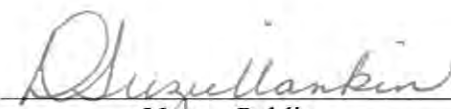


KEITH D. FOSTER

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 14th day of January 2020.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2020
Commission Number: 12412070



Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric)
Company's Request for Authority to) Case No. ER-2019-0374
Implement a General Rate Increase for)
Electric Service)

AFFIDAVIT OF JARED GIACONE

STATE OF MISSOURI)
) ss.
COUNTY OF JACKSON)

COMES NOW JARED GIACONE and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing *Staff Cost of Service Report*; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.



JARED GIACONE

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Jackson, State of Missouri, at my office in Kansas City, on this 13th day of January 2020.



Notary Public



BEVERLY M. WEBB
My Commission Expires
April 14, 2020
Clay County
Commission #12464070

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric)
Company's Request for Authority to) Case No. ER-2019-0374
Implement a General Rate Increase for)
Electric Service)

AFFIDAVIT OF NANCY L. HARRIS

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW NANCY L. HARRIS and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing *Staff Cost of Service Report*; and that the same is true and correct according to her best knowledge and belief.

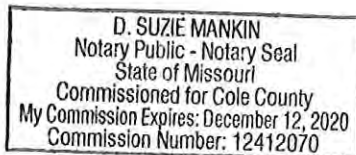
Further the Affiant sayeth not.

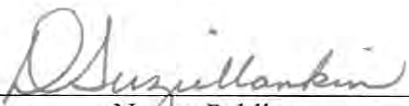


NANCY L. HARRIS

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 14th day of January 2020.





Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

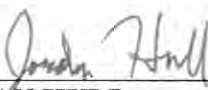
In the Matter of The Empire District Electric)
Company's Request for Authority to) Case No. ER-2019-0374
Implement a General Rate Increase for)
Electric Service)

AFFIDAVIT OF JORDAN HULL

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW JORDAN HULL and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing *Staff Cost of Service Report*; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

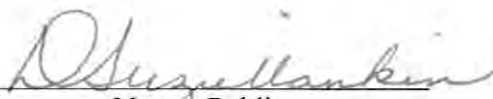


JORDAN HULL

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 14th day of January 2020.





Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI


In the Matter of The Empire District Electric)
Company's Request for Authority to) Case No. ER-2019-0374
Implement a General Rate Increase for)
Electric Service)

AFFIDAVIT OF BROOKE MASTROGIANNIS

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

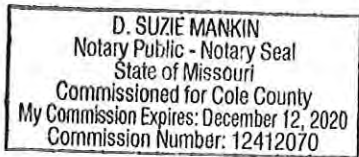
COMES NOW BROOKE MASTROGIANNIS and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing *Staff Cost of Service Report*; and that the same is true and correct according to her best knowledge and belief.

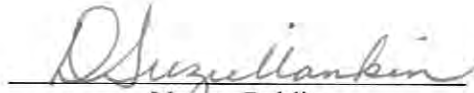
Further the Affiant sayeth not.


BROOKE MASTROGIANNIS

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 14th day of January 2020.




Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric)
Company's Request for Authority to)
Implement a General Rate Increase for)
Electric Service)

Case No. ER-2019-0374

AFFIDAVIT OF AMANDA C. MCMELLEN

STATE OF MISSOURI)
)
COUNTY OF COLE) ss.

COMES NOW AMANDA C. MCMELLEN and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing *Staff Cost of Service Report*; and that the same is true and correct according to her best knowledge and belief.

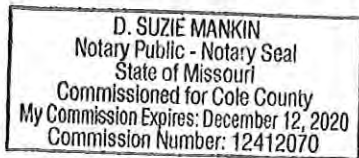
Further the Affiant sayeth not.

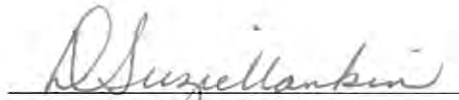


AMANDA C. MCMELLEN

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 14th day of January 2020.





Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

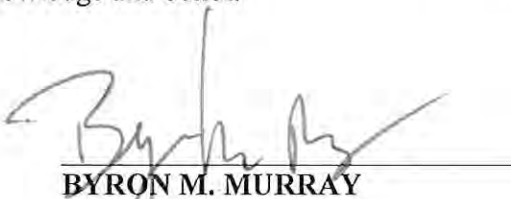
In the Matter of The Empire District Electric)
Company's Request for Authority to) Case No. ER-2019-0374
Implement a General Rate Increase for)
Electric Service)

AFFIDAVIT OF BYRON M. MURRAY

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW BYRON M. MURRAY and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing *Staff Cost of Service Report*; and that the same is true and correct according to his best knowledge and belief.

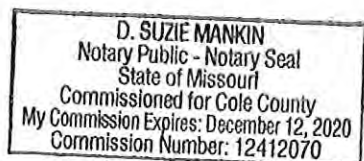
Further the Affiant sayeth not.




BYRON M. MURRAY

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 14th day of January 2020.





Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric)
Company's Request for Authority to) Case No. ER-2019-0374
Implement a General Rate Increase for)
Electric Service)

AFFIDAVIT OF CAROLINE NEWKIRK

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

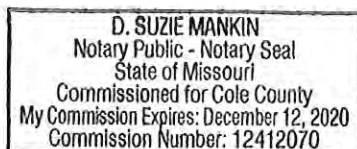
COMES NOW CAROLINE NEWKIRK and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing *Staff Cost of Service Report*; and that the same is true and correct according to her best knowledge and belief.

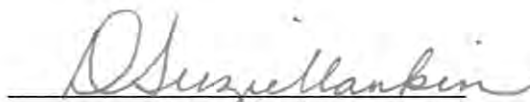
Further the Affiant sayeth not.


CAROLINE NEWKIRK

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 14th day of January 2020.




Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric)
Company's Request for Authority to) Case No. ER-2019-0374
Implement a General Rate Increase for)
Electric Service)

AFFIDAVIT OF ANGELA NIEMEIER

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW ANGELA NIEMEIER and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing *Staff Cost of Service Report*; and that the same is true and correct according to her best knowledge and belief.

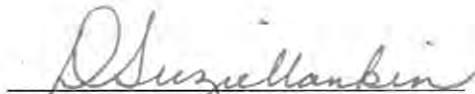
Further the Affiant sayeth not.


ANGELA NIEMEIER

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 14th day of January 2020.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2020
Commission Number: 12412070


Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric)
Company's Request for Authority to) Case No. ER-2019-0374
Implement a General Rate Increase for)
Electric Service)

AFFIDAVIT OF MARK L. OLIGSCHLAEGER

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

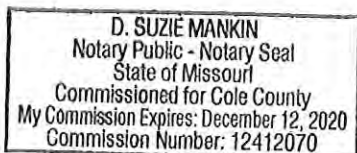
COMES NOW MARK L. OLIGSCHLAEGER and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing *Staff Cost of Service Report*; and that the same is true and correct according to his best knowledge and belief.

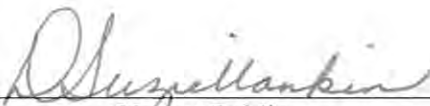
Further the Affiant sayeth not.


MARK L. OLIGSCHLAEGER

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 14th day of January 2020.




Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric)
Company's Request for Authority to) Case No. ER-2019-0374
Implement a General Rate Increase for)
Electric Service)

AFFIDAVIT OF DANA R. PARISH

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW DANA R. PARISH and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing *Staff Cost of Service Report*; and that the same is true and correct according to her best knowledge and belief.

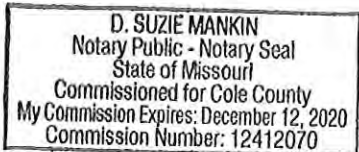
Further the Affiant sayeth not.



DANA R. PARISH

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 14th day of January 2020.





Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric)
Company's Request for Authority to) Case No. ER-2019-0374
Implement a General Rate Increase for)
Electric Service)

AFFIDAVIT OF CHARLES T. POSTON, PE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW CHARLES T. POSTON, PE and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing *Staff Cost of Service Report*; and that the same is true and correct according to his best knowledge and belief.

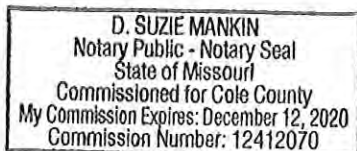
Further the Affiant sayeth not.

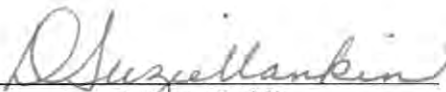


CHARLES T. POSTON, PE

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 14th day of January 2020.





Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric)
Company's Request for Authority to) Case No. ER-2019-0374
Implement a General Rate Increase for)
Electric Service)

AFFIDAVIT OF ASHLEY SARVER

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW ASHLEY SARVER and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing *Staff Cost of Service Report*; and that the same is true and correct according to her best knowledge and belief.

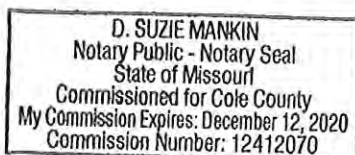
Further the Affiant sayeth not.

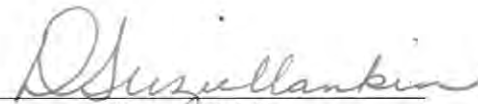


ASHLEY SARVER

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 14th day of January 2020.





Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric)
Company's Request for Authority to) Case No. ER-2019-0374
Implement a General Rate Increase for)
Electric Service)

AFFIDAVIT OF MICHAEL L. STAHLMANN

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW MICHAEL L. STAHLMANN and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing *Staff Cost of Service Report*; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

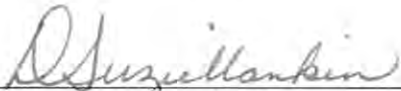


MICHAEL L. STAHLMANN

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 14th day of January 2020.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2020
Commission Number: 12412070



Notary Public