Exhibit No. 101P

Staff – Exhibit 101P
Staff cost-of-service report
File No. ER-2021-0312

MISSOURI PUBLIC SERVICE COMMISSION

STAFF REPORT

COST OF SERVICE

THE EMPIRE DISTRICT ELECTRIC COMPANY

d/b/a Liberty

CASE NO. ER-2021-0312

Jefferson City, Missouri
October *29, 2021*

** **Denotes Confidential Information** **

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COST OF SERVICE REPORT OF

THE EMPIRE DISTRICT ELECTRIC COMPANY
d/b/a Liberty

CASE NO. ER-2021-0312

STAFF'S COST OF SERVICE REPORT OF
The Empire District Electric Company
Case No. ER-2021-0312

I. Executive Summary

Staff conducted a review in Case No. ER-2021-0312 of all revenue requirement cost of service components (capital structure and return on rate base, rate base, depreciation expense and other operating expenses) which comprise The Empire District Electric Company, d/b/a Liberty's ("Empire" or "Company") revenue requirement. This audit was in response to Empire's filing made on May 28, 2021, seeking to increase its retail rates approximately $79,945,556 with Winter Storm Uri costs and $50,062,217 without Winter Storm Uri costs on an annual basis.

In February 2021, most of the Midwest, including Missouri, experienced extreme cold temperatures, wind chill, and snow. Such temperatures resulted in rolling electrical blackouts and extreme natural gas price spikes. As a result of this weather crisis, demand for electricity on Empire's local distribution system and demand for natural gas in the region escalated and prices rose on the spot and daily index markets. Empire incurred extraordinary fuel and purchased power costs for this period.

On April 1, 2021, Empire filed a Fuel Adjustment Clause (FAC) Fuel Adjustment Rate (FAR) tariff change in Case No. ER-2021-0032. Within this filing, Empire was allowed to defer $168,720,211 (95% of the extraordinary fuel and purchased power costs for the February 2021 winter storm).

On June 2, 2021, Empire filed an Application for an accounting authority order (AAO) permitting Empire to track and defer, beginning February 2021, to a regulatory asset: (1) the remaining 5% of extraordinary fuel and purchased power costs ($9,266,670) from February 2021 that was not deferred as a result of Case No. ER-2021-0032; (2) carrying costs on the total February 2021 fuel and purchased power expenditures at the Company's weighted average cost of capital; and (3) other costs specially related to Winter Storm Uri, including outside legal fees. Staff has recommended that the Commission approve Empire's request for an AAO permitting Empire to track and defer to a regulatory asset certain costs associated with Winter Storm Uri with any ratemaking decisions to be determined in a later proceeding.

On August 28, 2021, Empire filed a notice of intent in Case No. EO-2022-0040 with regard to its intended petition to obtain a financing order that authorizes the issuance of securitized utility tariff bonds regarding the extraordinary costs incurred due to Winter Storm Uri.

In Empire's direct filing for this case, Empire requested to recover an incremental increase of $29,883,338 for the Winter Storm Uri costs. However, Empire filed its direct testimony in this case on May 28, 2021, before the other cases (Case No. EO-2022-0040 and Case No. EU-2021-0274) were filed. Due to Empire's bond securitization filing, Staff is not including any recovery of Winter Storm Uri costs in this rate case, and recommends any review of the prudence of costs and other recovery issues for these costs be addressed in Case No. EO-2022-0040.

Staff's recommended increase of $6,366,574 in revenue requirement is based upon a test year for the twelve months ending September 30, 2020 with the use of an update period ending June 30, 2021. Staff recommends a return on equity (ROE) of 9.50% for Empire. This ROE combined with recommended capitalization ratios and senior capital cost rate results in an overall return or cost of capital for Empire of 6.49%.

The impact of Staff's recommended revenue requirement for each retail rate customer class will be addressed in Staff's rate design direct testimony and report that is scheduled to be filed on November 17, 2021.

Below are definitions of technical terms that will frequently be used in the Cost of Service Report:

Test Year: The test year income statement is the starting point for determining a utility's existing annual revenues, operating costs, and net operating income. In this case, the test year is the 12 months ending September 30, 2020.

Update: An update period considers factors that occur subsequent to test year through a specific date. Updating a case does not change the test year, but adjusts the test year to reflect the audited results associated with factors considered through the update period. The update period represents the last date through which historical data is available to be audited by Staff prior to the filing of direct testimony.

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

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

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

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

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

Staff Expert/Witness: Amanda C. McMellen

II. Background

Empire provides electric utility service in Missouri, Kansas, Arkansas, and Oklahoma. As of June 30, 2021, Empire serves approximately 178,449 retail electric customers throughout its system of which approximately 158,892 are Missouri customers. Empire also provides water utility services in Missouri. Empire owns and services The Empire District Gas Company ("EDG"), an affiliated Missouri natural gas distribution business. Empire also owns and services The Empire District Industries, Inc. ("EDI") an affiliated Missouri non-regulated fiber optic business.

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

Empire last sought to change its Missouri jurisdictional electric retail rates in Case No. ER-2019-0374. As a result of the Missouri Public Service Commission ("Commission") *Amended Report and Order* in that proceeding, Empire was granted an annual rate increase of $992,367, effective September 16, 2020.

Staff Expert/Witness: Amanda C. McMellen

III. Test Year/True-Up Period

Empire filed its case based upon a test year of the twelve-month period ending September 30, 2020, and made adjustments to its case to reflect the impacts of through the update period ending June 30, 2021. These dates were adopted by the Commission in its *Order Establishing Procedural Schedule and Other Procedural Requirements* issued on August 4, 2021, which set the test year as the 12 months ending September 30, 2020, updated through June 30, 2021.

Based on currently available information, Staff's revenue requirement as presented in its Accounting Schedules includes a measurement of all major cost of service components. Staff's quantification of Empire's revenue requirement as of June 30, 2021 is shown on Line 10 of Staff Accounting Schedule 1, Revenue Requirement.

Staff Expert/Witness: Amanda C. McMellen

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

A. Summary

Staff estimated the market based cost of common equity (COE), and calculated an authorized ROE recommendation for Empire vertically-integrated electric utility operations using a comparative COE analysis. Staff's analysis takes into account changes in economic and capital market conditions by employing widely-used COE estimation methodologies: the constant-growth discounted cash flow (DCF) model and the capital asset pricing model

(CAPM). The comparative analysis method allowed Staff to calculate the change in authorized ROE based on the change in its COE estimate from period to period by using the Commission's decision in the most recent Empire rate case[1] as a benchmark. That case was fully litigated before the Commission, including rate of return/capital structure issues.

In the last Empire rate case, the Commission authorized an ROE of 9.25%. The corresponding COE estimate for that Empire rate case is 7.88% in a range of 6.05% to 8.62% (see PC-8-1). Staff's DCF COE estimate for the current case is 8.30% in a 6.83% to 9.37% range (see PC-8-2), which indicates that COE has increased by up to 42[2] basis points (bps) since the Commission's decision in the last Empire rate case (refer to Schedule PC-11). However, Staff believes that current utility COE estimates are unusually and unsustainably high due to the effects of the coronavirus pandemic ("COVID-19"). When COVID-19 hit in 2020, it caused massive volatility in the economy - gross domestic product (GDP) fell sharply, followed by an equally sharp recovery.[3] The recovery from the COVID-19 pandemic is spurring fears of higher inflation and, consequently, higher market risk.[4] The effects of the high market risk are most notable in the CAPM where the beta coefficient is unusually and unsustainably high compared to the period of the last Empire rate case.[5] Inflation fears can increase market risk for utilities as investors believe that regulators will not adjust revenues fast enough to compensate for rising input costs.[6] Higher market risk means that investors require higher returns (COE) for their investments. However, Staff agrees with many economic and financial experts that inflation concerns and, consequently, the current high market risks, are likely to be transitory.[7]

Based upon the above discussion, Staff's position is that it is reasonable that Empire's ROE be increased by 25 bps, instead of 42 bps; from the 9.25% ROE authorized for Empire in

[1] ***In the matter of Empire District Electric Company***, Case Nos. ER-2019-0374 (***Report & Order,*** issued February 21, 2018) at page 35.

[2] 8.30% minus 7.88%.

[3] https://www.cnbc.com/2020/07/30/us-gdp-q2-2020-first-reading.html.

[4] https://www.spglobal.com/en/research-insights/featured/inflation.

[5] Staff's Beta was 0.54 in the Empire rate case. Empire's witness used an average Beta of 0.54. Currently the Beta coefficient is about 0.88 per Company witness's Value Line Beta.

[6] https://www.hartfordfunds.com/dam/en/docs/pub/whitepapers/WP597.pdf.

[7] https://www.cbsnews.com/news/interest-rates-inflation-federal-reserve-transitory/ and https://www.spglobal.com/en/research-insights/featured/inflation.

the last Empire rate case, to 9.50%, in a reasonable range of 9.25% to 9.70%. Staff set the zone of reasonableness by adding 42 bps (the total increase in COE since the last Empire rate case) to the Commission's authorized ROE (9.25%) in the Empire rate case, for a total of 9.67%, rounded up to 9.70%. For the lower limit of the range of reasonableness, Staff used the Commission authorized ROE, 9.25%, in the last Empire rate case.

Staff also recommends that the Commission set Empire's allowed ROR based on the more economical capital structure, Empire's stand-alone pro forma capital structure composed of 52.44% common equity and 47.56% long-term debt, as of September 30, 2021.[8] Likewise, Staff recommends Empire's stand-alone cost of debt of 3.76% for setting ROR in this proceeding.[9] The summary of Staff's ROR recommendation is in the following Table:

Table 1

Capital Components	Percentage of Capital	Embedded Cost	Allowed Rate of Return Using Common Equity Return of:		
			9.25%	**9.50%**	9.75%
Long-Term Debt	47.56%	3.76%	1.79%	**1.79%**	1.79%
Common Equity	52.44%	---	4.85%	**4.98%**	5.11%
Total	100%		6.64%	**6.77%**	6.90%

In the remainder of this testimony, Staff will present economic and capital market evidence to show that COE has increased since the period of Staff's analysis for the last Empire rate case. Staff will also present evidence to support the reasonableness of using Empire's own capital structure and cost of debt to set ROR in this proceeding. The details of Staff's analysis and recommendations are presented in Schedules PC-1 – PC-12 in Appendix 2 attached.

B. Analytical Parameters

The determination of a fair rate of return is guided by principles of economic and financial theory and by certain minimum Constitutional standards. Investor-owned public

[8] Response to Staff Data Request No. 0258, Case No. ER-2021-0312.
[9] Todd Mooney's Direct Testimony, Case No. ER-2021-0312, Schedule TM-4.

utilities such as Empire are private property that the state may not confiscate without appropriate compensation. The United States Supreme Court has described the minimum characteristics of a constitutionally-acceptable rate of return in two frequently-cited cases:[10] ***Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia***, and ***Federal Power Commission v. Hope Natural Gas Co***.

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

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

Embodied in these three principles is the economic theory of the opportunity cost of investment. The opportunity cost of investment is the next best return that investors forego in order to invest in their chosen investment. Investors' opportunity costs vary depending on market and business conditions.

Methodologies of financial analysis have advanced greatly since the ***Bluefield*** and ***Hope*** decisions.[11] Additionally, today's utilities compete for capital in a global market rather than a local market. Nonetheless, the parameters defined in those cases are readily met using current methods and theory. The principle of commensurate return is based on the concept of risk. Financial theory holds that the return an investor may expect is reflective of the degree of risk inherent in the investment, with risk measured as the likelihood an investment will not perform as expected. Any line of business carries with it its own risks and it follows, therefore, that the return Empire shareholders may expect is equal to that required for comparable-risk utility companies.

[10] ***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).

[11] Neither the DCF nor the CAPM methods were in use when those decisions were issued.

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

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

C. Current Economic and Capital Market Conditions

Determining whether a cost of capital estimate is fair and reasonable requires an understanding of economic and capital market conditions, with the former having a significant impact on the latter. Staff emphasizes that estimates of a utility's COE and ROE recommendations should pass the "common sense" test considering broader economic and capital market conditions.

1. Economic Conditions

The economy is currently recovering from the COVID-19 pandemic recession of 2020. Although the Delta variant of the COVID-19 has created some concerns about the sustainability of the recovery, economic growth has so far remained robust.[12] Fears of inflation, though still high, remain temporary in the view of experts.[13] Fears of increased inflation expectations are raising concern among investors that they will not be able to earn enough return on their investments to cover the increased expected inflation.[14] High inflation reduces real returns from

[12] https://www.brookings.edu/research/11-facts-on-the-economic-recovery-from-the-covid-19-pandemic/.
[13] https://www.reuters.com/business/why-fed-chair-powell-still-thinks-high-inflation-is-temporary-2021-08-27/.
[14] https://www.cnbc.com/2021/05/13/heres-why-stock-investors-are-watching-inflation-so-closely.html.

investments.[15] To compensate for the high expected inflation, investors demand higher returns for their investments.[16, 17] Higher returns mean a higher cost of capital. However, as Staff already pointed out, the fears of inflation are probably somewhat overblown and transitory, which means that current COE estimates are likely exaggerated.

In the period since the last Empire rate case, the economy experienced enormous volatility. Real GDP fell by 32.9%, on an annual basis, in the second quarter of 2020, after a 5% decline in the first quarter.[18] Third and fourth quarters of 2020 saw real GDP increase by 33.4% and 4.3%; sharp increases that coincided with the opening up of the economy after the shutdown induced by efforts to combat the COVID-19 pandemic. First and second quarters of 2021 real GDP growths were 6.3% and 6.6%, respectively.[19] It is expected that the year 2021 will wind up with GDP growth rate of about 6.0%.[20] In 2019, when Staff last conducted analysis for an Empire rate case, real annual GDP rose by 2.3%, down from the 2018 increase of 2.9%.[21] Real GDP is projected to grow at 3.1%, and 1.1% in 2022 and 2023, respectively.[22] The Federal Reserve ("Fed") projects a long-term real GDP growth rate of 1.6% to 2.2%.[23] The U.S. Energy Information Administration (EIA) projects a long-term real GDP growth rate of 2.1%.[24] The Congressional Budget Office (CBO) projects a nominal GDP growth rate of 3.70%.[25] The long-running real GDP growth rate projection was 1.89%, estimated in 2019 close to when Staff presented testimony in the last Empire rate case. Availability of vaccines, increased vaccination rates and the Fed's assurances to continue to support the economy are boosting prospects for continued economic recovery. During economic recovery, utilities tend

[15] https://www.usbank.com/financialiq/invest-your-money/investment-strategies/effects-of-inflation-on-investments.html.
[16] Inflation is one of the building blocks of cost of capital/equity – the higher the inflation, the higher the COE, and vice-versa.
[17] https://www.cnbc.com/2021/05/13/heres-why-stock-investors-are-watching-inflation-so-closely.html.
[18] Bureau of Economic Analysis: Gross Domestic Product, 2nd Quarter 2020 (Advance Estimate) and Annual Update | U.S. Bureau of Economic Analysis (BEA).
[19] https://www.kiplinger.com/economic-forecasts/gdp.
[20] Ibid.
[21] Gross Domestic Product, 2nd Quarter 2020 (Advance Estimate) and Annual Update | U.S. Bureau of Economic Analysis (BEA).
[22] https://www.cbo.gov/system/files/2021-07/57218-Outlook.pdf.
[23] https://www.federalreserve.gov/monetarypolicy/files/fomcprojtabl20210616.pdf.
[24] https://www.eia.gov/outlooks/aeo/data/browser/#/?id=18-AEO2021&sourcekey=0.
[25] https://www.cbo.gov/system/files/2021-07/57218-Outlook.pdf.

to underperform the broader market which, consequently, pushes COE for utilities higher. Compounded by the current fears of transitory inflation, the share price of utility equities are currently depressed and COE elevated. As Staff alluded to, inflation fears are likely to subside in the near future, meaning that COE should come down to more reasonable levels. Already there is evidence that inflation fears are subsiding. Long-term interest rates (yields) have come down from the high of about 2.45% reached in March 2021, to about 1.94% in September 2021. All else the same, high inflation expectations means higher interest rates (yields).[26, 27, 28]

Fears of increased inflation are real, though likely overstated. Larry Summers, a noted economist and former Treasury Secretary, noted that, "The Federal Reserve shouldn't raise interest rates today but should at least start to express more concern about the inflation outlook."[29] Warren Buffet added his voice, on May 1, 2021, to the concern about rising inflation, saying that they, at Berkshire Hathaway, are seeing substantial inflation.[30] The Fed, led by Jerome Powell, has made assurances that it is ready to act to make sure inflation will not get out of hand. The general opinion is that high inflation will be transitory and therefore, that fears are exaggerated.[31] It is important to note that current COE estimates are developed assuming exaggerated fears of inflation.[32] The impact of the high inflation expectation has been notable in the increase in interest rates between December 2020 and May 2021 when long-term interest rates (30-year Treasury yields) steadily rose from 1.67% to 2.32% (see PC-3-1).[33]

The Fed predicted an annual inflation rate of 4.2% by the end of 2021, up from 3.4% they forecasted in June.[34] The Fed still expects inflation to slow down to 2.2% next year, slightly above the Fed's long-term target of 2.0%.[35] The current high inflation is attributed to

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[26] https://www.investopedia.com/articles/bonds/09/bond-market-interest-rates.asp.

[27] https://www.thebalance.com/the-impact-of-inflation-on-bonds-417071.

[28] https://www.cnbc.com/2021/02/25/why-stock-investors-are-starting-to-really-worry-about-rising-bond-yields.htm.

[29] https://www.marketwatch.com/story/summers-says-fed-should-express-more-concern-over-inflation-outlook-11619029595?siteid=yhoof2.

[30] https://www.cnbc.com/2021/05/03/warren-buffett-says-berkshire-hathaway-is-seeing-very-substantial-inflation-and-raising-prices.html.

[31] https://www.cnn.com/2021/04/09/perspectives/inflation-fears-us-economy-covid/index.html.

[32] https://www.cnbc.com/2021/05/13/heres-why-stock-investors-are-watching-inflation-so-closely.html.

[33] https://www.cnbc.com/2021/07/13/us-bonds-treasury-yields-rise-ahead-of-inflation-data-update.html.

[34] https://www.npr.org/2021/09/22/1039317128/federal-reserve-inflation-economy-taper-interest-rates#:~:text=At%20the%20conclusion%20of%20a,to%20about%202.2%25%20next%20year.

[35] Ibid.

supply-chain bottlenecks and shortages, resulting from the pandemic. From the perspective that investors' current sentiments are affected by higher expectations of inflation than in 2019, it is reasonable to accept that COE has increased, albeit by not as much as indicated by the DCF and CAPM results, since Staff presented testimony in the last Empire rate case.

Long-term interest rates were 3.04% in January 2019 before they moved up and down throughout 2019, to finally settle at 2.30% in December 2020. With COVID-19 causing widespread economic shutdown and pushing interest rates higher, the Fed intervened in March 2020 to cut the federal discount rate to a range of 0% to 0.25%. In addition to cutting the federal discount rate, the Fed announced it would purchase an additional $700 billion worth of Treasury bonds and mortgage-backed securities.[36] The Fed also struck a deal with five other foreign central banks, the Bank of Canada, the Bank of England, the Bank of Japan, the European Central Bank, and the Swiss National Bank, to lower their rates on currency swaps to keep the financial markets functioning normally.[37] Lowering rates on currency swaps makes borrowing U.S dollars by banks around the world cheaper. The aggregate effect of the Fed's actions was a decline in interest rates from 1.97% in February 2020 to a low of 1.31% in July 2020. 30-year Treasury yields rose from 1.36% in August 2020 to about 2.34% in March 2021, before falling to about 1.94% as of the end of September 2021. Utilities stock prices have traditionally moved negatively with interest rates; that is not the case in this period. The effects of COVID-19, such as high inflation fears, have increased market risk and consequently, pushed utilities' COE higher. As the Fed signals that it is about to start scaling back (Quantitative Easing (QE) tapering) on the COVID-19 economic measures, it is expected that interest rates will begin to rise.[38] With interest rates expected to rise as a result of the tapering, it is reasonable to expect utilities' COE to remain elevated, though on a downward trend. The current unemployment rate remains higher, at 5.2%, currently, than the pre-pandemic level of 3.5%.[39] The higher unemployment rate means that the economy is yet to fully recover to its pre-pandemic level and that supports a reasonable belief that the Fed will maintain the

[36] https://www.wsj.com/articles/fed-faces-crucial-decisions-to-alleviate-virus-shock-11584303662.

[37] https://www.federalreserve.gov/newsevents/pressreleases/monetary20200315c.htm.

[38] https://www.usatoday.com/story/money/2021/09/22/federal-reserve-fed-signals-taper-bond-purchases-year/5808736001/.

[39] https://www.bls.gov/news.release/pdf/empsit.pdf.

near-zero interest rates to continue to support economic growth. The Fed has a dual mandate: maximum employment and stable prices.[40] As Staff already mentioned, currently the Fed's task is harder: if they step in to restrain inflation, it means slowing economic growth. Either way the Fed goes in the event of inflation ramping up, COE will rise. Given the current and projected economic climate, it is reasonable to allow Empire the opportunity to earn a somewhat higher authorized ROE than the 9.25% authorized for Empire in 2020.

2. Capital Market Conditions

a. Utility Debt Markets

Average public utility yields fell from a high of 4.48% in January 2019, to a low of 3.16% (see PC-4-1) in February 2020. The downward trend in public utility bond yields reversed when yields rose sharply by 43 bps to 3.59% in March 2020 (see PC-4-1). The sharp rise in public utility bond yields in March 2020 coincided with the closure of the economy and the subsequent sharp decline in the GDP. Public utility bond yields started to fall again in April 2020 after the Fed cut the federal funds rate to 0.0% to 0.25%, and ramped up Treasury bond-buying activity. By August 2020, public utility bond yields had fallen to 2.76% (see PC-4-1). The changes in public utility bond yields mirrored the changes in the 30-Year Treasury bond yields. 30-Year Treasury bond yields have historically, with a few exceptions, been positively correlated with public utility bond yields (see PC-4-2). The biggest factor currently driving interest rates is the fear of a rise in expected inflation. In an article in Kiplinger's on March 18, 2021, economist David Payne noted that, "Despite the Federal Reserve's latest commitment to low short-term interest rates and easy-money policies into 2023, long-term rates rose again on continued inflation fears."[41]

Staff has, in the past, highlighted that interest rates were the main driver of COE change, but the current economic climate is so dislocated that the impact of interest rates on utilities performance is atypical.[42, 43] Lower interest rates would normally mean lower COEs, all else

[40] https://www.federalreserve.gov/faqs/what-economic-goals-does-federal-reserve-seek-to-achieve-through-monetary-policy.htm.

[41] Kiplinger's: https://www.kiplinger.com/economic-forecasts/interest-rates.

[42] Edison Electric Institute (EEI) 2020 Financial Review, page 2.

[43] 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.

the same. Staff compared interest rates during the last Empire rate case period (September, October and November 2019) to the current rate case period (June, July and August 2021) and noticed that interest rates as measured by the Mergent public utility yields decreased by about 20 basis points.[44] Important in understanding the current economic dynamics is increased risk as measured by "Beta". Beta is a measure of the volatility or systematic risk of a security or portfolio compared to the market as a whole. Current Betas for Staff's electric proxy group are about 0.88 compared to 0.54 in the period of the last Empire rate case analysis. Higher Betas, all else the same, mean higher COEs.

b. Utility Equity Markets

In the period between December 2019 and August 2021,[45] the utilities sector underperformed the broader market (S&P 500). The S&P 500 had total returns of 48.29% compared to 15.44% for the utilities sector (see Figure 1 below). Staff's electric proxy group of companies similarly under-performed, returning 14.22% in the same period. A detailed analysis of the performance of the equity market since December 2019 reveals tremendous volatility. Figure 1 shows the volatility experienced by the stock market since December 2019. At the onset of the economic shutdown in March 2020, the S&P 500 and the Dow Jones Industrial fell 12.5% and 13%, respectively.[46] Utilities were 35% off (down) their January 2020 high.[47] The decline of the utilities was unusual given that utilities are historically considered a defensive sector – when the capital market goes down, utilities rise as investors 'run for the safety' of utilities. "The utilities sector did not act as defensively as we have seen in previous market downturns."[48] The stock market recovered immediately and sharply from the March 2020 sharp decline (see Figure 1 below), with the utilities sector briefly leading the broader market. Starting in May 2020, the utilities sector has lagged the broader market. Total returns for utilities, in general, for the entire year 2020 were negative 0.6%.[49] The Edison

[44] Three-month average interest rates for the Empire rate case was 2.21% compared to 2.01% for the current rate case.

[45] This is the period between Staff's last analysis for the Empire rate case and the current rate case. Staff is focusing on the changes in capital markets that impacted COE.

[46] The stock market crash of March 12, 2020, was of the same proportion as the crash of 1987.

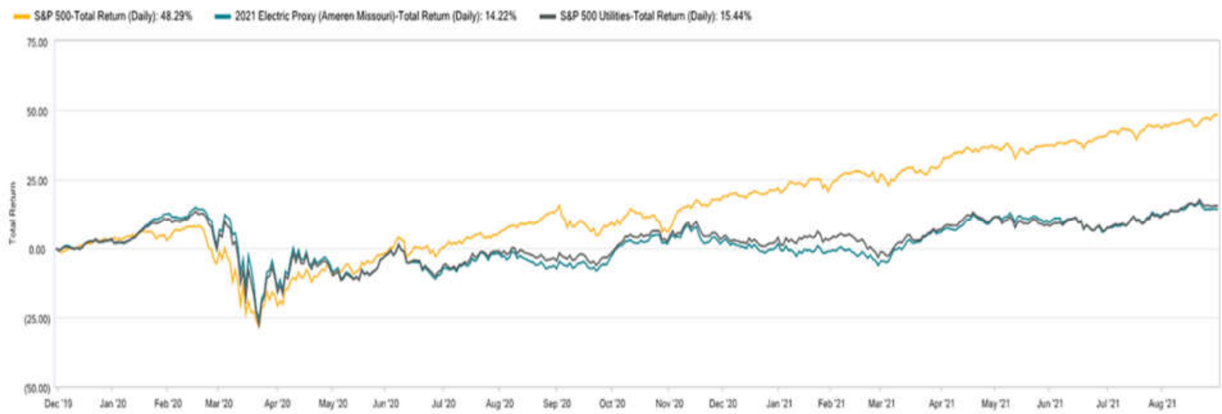
[47] EEI Financial Review, page 1.

[48] https://www.edwardjones.com/sites/default/files/acquiadam/2021-08/investing-in-the-utilities-sector.pdf.

[49] EI Financial Review, page 1.

Electric Institute (EEI) Index returned negative 1.6% compared to the Dow Jones' and S&P 500's positive 9.7% and 18.4%, respectively, for the year 2020.

Figure 1 - Total Returns Between December 2019 and August 2021



The combined effect of the utility sector's unusual decline in 2020, and the subsequent sluggish recovery, is that the utilities have not recovered fully from the COVID-19 recession. Average stock prices for Staff's proxy group of companies is at $67.66, as of August 31, 2021, compared to the pre-COVID-19 recession high of about $72.40 reached in January 2020. Declining stock prices, all else the same, means increasing COE.[50] The principal reason for stock prices to decline is adverse perception about the stock's risk and or risk in the economy. Currently, the utilities sector faces two major risks that have the potential to keep stock prices depressed and COE elevated – fears of high inflation and increasing interest rates.[51] As a consequence, the current economic climate justifies increasing authorized ROE by 25 bps to 9.50% from the 9.25% authorized Empire in February 2020.

As Staff alluded to above, the two potential downsides for utilities, currently and in the near future, are increased inflation and increasing interest rates. It is important to understand the dynamics of these two potential risks to utilities in order to have a reasonable estimation of the trajectory of COE. Firstly, the fear of increased inflation means that investors will try to

[50] In the DCF COE model, declining stock prices, all else the same, leads to higher dividend yields. Dividend yields are a component of COE.

[51] Whether inflation fears materialize or not, current utility stock prices are pricing in the fear that inflation will be higher.

avoid low-return utilities because they fear that utilities will not provide a high enough return to compensate for the increased expected inflation. "… [S]ome sectors prove more durable during inflationary times than others, but the utilities sector is usually not a place to seek shelter from inflation."[52] The belief that utilities are 'not a place to seek shelter from inflation' stems from the general belief, among investors, that regulators are not flexible enough with adjusting rates to compensate for increasing inflation.[53] The fear of increased inflation will potentially keep utility stock prices depressed, and COE elevated.

Secondly, the fear of increased inflation has suddenly brought about talk about increasing interest rates sooner than expected.[54] Increasing interest rates is one of the tools at the disposal of the Fed to curtail inflation. Controlling inflation by increasing interest rates inadvertently causes COE to rise. Historically, utilities have moved in the opposite direction of interest rates, meaning that as interest rates rose, utilities stock prices fell.[55] As Staff already pointed out, the lower the stock prices, all else the same, the higher the COE.

Staff has already shown that utilities' stock prices are currently lower than they were when Staff presented testimony for the last Empire rate case in 2019. Lower stock prices, all else the same, means higher COE. Staff also analyzed other variables that affect change in COE – dividend yields and expected growth rates. Higher dividend yields, all else the same, means higher COE. Staff compared dividend yields from the period (September, October, and November 2019) of the last Empire rate case to the dividend yields of the current period (June, July, and August 2021). Average dividend yields were 3.14% (see PC-9-2) during the period of last Empire rate case, compared to 3.49% (see PC-9-1) in the current period – that is an increase of 35 bps. The analysts' estimated growth rates for Staff's proxy group increased from 5.16%, estimated during the period (September, October, and November 2019). Staff's analysis of estimated growth rates in the current Empire rate case shows a result of 5.30% (June, July, and August 2021). Higher estimated growth rates, all else the same, signal a higher required return to investors. The net effect of the changes in stock prices, dividend yields, and growth

[52] https://finance.zacks.com/utilities-stocks-perform-well-during-inflationary-periods-8933.html.

[53] https://finance.zacks.com/utilities-stocks-perform-well-during-inflationary-periods-8933.html.

[54] https://www.wsj.com/articles/federal-reserve-meeting-interest-rates-bond-purchases-june-2021-11623777582.

[55] Because utilities are a capital-intensive industry that borrows huge sums of money to fund its operations, an increase in cost of capital directly reduces revenues.

rates is that COE increased by up to 42 bps (unadjusted for expected inflation, see PC-11) since Staff conducted its analysis for the last Empire rate case.

D. Empire Operations

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

On January 1, 2017, Empire was acquired by LUCo which is owned by APUC. APUC serves approximately 800,000 customers in twelve states across the United States through its electric, gas, water, and wastewater utilities. In addition to its regulated utility business, APUC also operates its Liberty Power business, which owns approximately 1.36 GW of renewable generation in the United States and Canada.

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

With the passage of Senate Bill 564 in 2018, Empire has had the opportunity to improve its operations by cutting its regulatory lag. Moody's noted in its Credit Opinion on January 16, 2019, "[o]n a positive note, Missouri Senate Bill 564, passed in June 2018, is expected to provide a more supportive regulatory framework, thereby reducing regulatory lag and opening the possibility of greater spend in Missouri." (Empire's Moody's Credit Opinion, January 16, 2019). The bill provides the ability for electric utilities to update their rates in between general rate cases to account for changes in customer usage due to weather or conservation. Alternatively, utilities can institute plant-in-service accounting to defer and recover 85% of total depreciation expense and return on qualifying electric plant placed in-service." In 2020, Empire opted to use plant-in-service accounting (PISA), and is seeking to begin recovery of PISA deferrals in this rate case.

E. Rate of Return

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

1. Capital Structure

For recommendation of an appropriate capital structure for ratemaking in this proceeding, Staff considered the merger conditions of the Case No. EM-2016-0213, in which APUC's acquisition of Empire was authorized by the Commission. Specifically, Staff considered merger condition number 5, which reads as below:

> If Empire's per books capital structure is different from that of the entity or entities in which Empire relies for its financing needs, Empire shall be required to provide evidence in subsequent rate cases as to why Empire's per book capital structure is the most economical for purposes of determining a fair and reasonable allowed rate of return for purposes of determining Empire's revenue requirement.

Per merger condition 5, Staff looked at the capital structures of the two entities, LUCo and APUC, on which Empire relies for its financing, in addition to Empire's capital structure, to determine which one is more [most] economical. To determine which capital structure is more economical, Staff looked at which capital structure has the lowest equity ratio among the three (Empire's, LUCo's and APUC's). In addition to condition 5 above, Staff was guided by the Commission's Order in the last Empire rate case (ER-2019-0374). In that case, the Commission accepted The Office of the Public Counsel's ("OPC") adjustments to LUCo's capital structure to add off-balance sheet debts guaranteed by LUCo to long-term debt, and subtract similar amount of debt from the equity portion of LUCo's capital structure.[56] Currently, LUCo guarantees a total of $628,500,000 in long-term debt held by its financing affiliate, Liberty Utilities Financing, GP1.[57]

The Company's capital structure witness in this case, Mr. Todd Mooney, recommended a pro forma capital structure, as of September 30, 2021, for Empire composed of 52.44% common equity and 47.56% long-term debt to be used to set Empire's ROR in this proceeding. Mr. Mooney presented LUCo's and APUC's pro forma capital structures, as of September 30, 2021, alongside Empire's pro forma capital structure for comparison to determine the most economical capital structure for ratemaking. The pro forma capital structures of the three entities (Empire, LUCo, and APUC), as of September 30, 2021, with adjustments for the $628,500,000 in LUCo's off-balance sheet debts, are as follows:

Table 2

	Empire	LUCo	APUC
Long-term Debt	**47.56%**	**47.21%**	**40.30%**
Preferred Stock	**0.00%**	**0.00%**	**0.79%**
Redeemable Non-Controlling Interest held by Related Party		0.32%	2.64%
Redeemable Non-Controlling Interest			0.18%
Common Stock	**52.44%**	**52.47%**	**56.10%**
Total	100%	100%	100%

Based on the pro forma capital structures as of September 30, 2021, Empire has a capital structure that contains the lowest equity ratio and consequently, the more economical capital structure. At the moment, Staff recommends Empire's pro forma standalone capital structure composed of 52.44% common equity and 47.56% long-term debt, for ratemaking in this proceeding. Given that Empire will update its capital structure, as of September 30, 2021, during the proceeding of this case, Staff would like to point out that its capital structure recommendation is subject to change depending on Empire's updated capital structure data as of true-up date of September 30, 2021.

[56] Amended Report and Order, Case No. ER-2019-0374, pages 34 and 35.
[57] Todd Mooney's Direct Testimony, ER-2021-0312, Schedule TM-4.

2. Embedded Cost of Debt

Staff recommends Empire's own standalone long-term debt cost of 3.76%, as of the true-up date of September 30, 2021.[58]

3. Cost of Common Equity

Staff estimated Empire's cost of common equity through a comparable company cost-of-equity analysis using the proxy group of electric utility companies, applying the DCF analysis.

a. The Proxy Group

Staff used a proxy group consisting of companies that are predominantly vertically-integrated, regulated, electric utilities to estimate changes in the cost of equity since Empire's last rate case. Staff ensured companies in the proxy group are confined to vertically-integrated, regulated, electric utility operations by starting with the list included in the EEI's regulated electric utility index, and then screened these companies further by ensuring that they:

- are publicly traded
- have investment grade credit ratings from two of the three major U.S. credit rating agencies
- have long-term growth coverage from at least 2 analysts
- have no pending merger or acquisitions
- have not reduced dividends since 2016
- have 50% of plant from electric utility
- have at least 25% of plant from electric generation
- generate at least 80% of income from regulated utility operations

continued on next page

[58] Direct Testimony of Todd Mooney, Case No. ER-2021-0312, Schedule TM-3.

The 15 electric utilities that met these criteria are presented in Table 3 below:

Table 3

Number	Company Name	Ticker Symbol
1	Alliant Energy Corporation	LNT
2	Ameren Corporation	AEE
3	American Electric Power Company, Inc.	AEP
4	Avista Corporation	AVA
5	CMS Energy Corporation	CMS
6	Duke Energy Corporation	DUK
7	Evergy, Inc.	EVRG
8	IDACORP, Inc.	IDA
9	NorthWestern Corporation	NWE
10	OGE Energy Corp.	OGE
11	Pinnacle West Capital Corporation	PNW
12	PNM Resources, Inc.	PNM
13	Portland General Electric Company	POR
14	Southern Company	SO
15	Xcel Energy, Inc.	XEL

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 PC-9-1) by the average daily opening and closing stock prices for the three months ending

August 31, 2021.[59] The projected average dividend yield for the electric utility proxy group is approximately 3.49%.

i. The Inputs

In the DCF method, the cost of equity is the sum of the expected dividend yield and a growth rate ("*g*") that represents the projected capital appreciation of the stock. Expected dividend yield equals the expected dividend for the next twelve months divided by the current stock price. Staff used the analysts' annual projected dividends for the next twelve months divided by the average of the recent three months closing stock prices. The average expected dividend for Staff's electric comparable group of companies is $2.33 (see PC-9-1). The average closing stock price for the recent three months ending August 31, 2021, is $67.66 (see PC-9-1).

In estimating a growth rate, Staff reviewed Value Line's 10-year and 5-year historical earnings per share (EPS), book value per share (BVPS), dividend per share (DPS) and analysts' projected EPS for each of the comparable companies. 10-year historical EPS, DPS, and BVPS averaged 5.79%, 5.39% and 3.88%, respectively (see PC-8-1). The average of the averages of EPS, DPS, and BVPS was 4.96% for the electric comparable group of companies. The 5-year historical averages were 5.14%, 6.07% and 4.12%, respectively. The average of averages was 5.21%. It is a common practice in financial analysis to average the averages of the three growth measures, EPS, DPS, and BVPS, to discern the appropriate growth rate for the DCF model. Historical averages of 4.96% and 5.21% for 10-year and 5-year, respectively, are not materially different, indicating some consistency in growth rates. Staff also reviewed projected EPS estimates from Market Intelligence and Value Line. Analysts' average projected EPS estimate, as of August 31, 2021, was 5.30%, (see PC-8-2), also consistent with the historical growth rates.

The growth rates that Staff has reviewed are short-term, less than ten years for the historical growth rates and less than five years for the analysts' projected growth rates. Short-term growth rates are unsuitable for use, exclusively, in the constant-growth DCF, because the constant-growth DCF assumes a long-term investment horizon. In addition, short-term growth rates, especially the analysts' projected growth rates, are often too high to be sustainable forever. Utilities are not expected to grow at the 5-year projected growth rates such

[59] 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.

as the 5.30% growth rate projected for Staff's proxy group of companies for a long period of time. One of the determinants of growth for business is the growth rate of the economy as a whole, measured by the GDP growth rate. It is therefore reasonable to assume that businesses' perpetual growth rate cannot exceed the long-term growth rate of the economy. In the long-run, it is expected that growth rates of all businesses will converge to the level of the GDP's long-run growth rate. To reflect the long-term assumption in the growth rates for use in the constant-growth DCF, Staff combined the analysts' projected growth with the long-term projected GDP growth rate at two-thirds analysts' projected growth rates plus one-third projected long-term GDP growth rate to form one perpetual growth rate. It is a common practice among analysts and ROR witnesses to combine analysts' projected growth rates with projected long-term GDP growth rates to estimate a reasonable growth rate for use in the constant-growth DCF.[60] The Federal Reserve projects a long-term real GDP growth rate of 1.6% to 2.2%.[61] The EIA projects a long-term real GDP growth rate of 2.1%.[62] The CBO is projecting a nominal GDP growth rate of 3.70%.[63] A reasonable long-term GDP growth rate is the average (3.83%) of the aforementioned three long-term GDP growth rates.[64] Analysts' average projected 5-year growth rate for Staff' proxy group of companies is 5.30%[65] (see PC-8-2). Combining the two growth rates results in a reasonable growth rate of 4.81% (see PC-8-2). Adding the expected dividend yield of 3.49% to the estimated growth rate of 4.81% results in mean COE estimate of 8.30% with a range of 6.83% to 9.37% for the electric proxy group.

F. Tests of Reasonableness

Staff has tested the reasonableness of its COE estimates and the recommended authorized ROE using the CAPM, bond yield-plus risk premium method, and a survey of the nationally authorized ROEs.

[60] The FERC ordered that analysts' estimated growth rates be combined with long-term GDP growth rates for a reasonable growth rate that reflects the long-term horizon assumed in the constant-growth DCF model.

[61] https://www.federalreserve.gov/monetarypolicy/files/fomcprojtabl20210616.pdf.

[62] https://www.eia.gov/outlooks/aeo/data/browser/#/?id=18-AEO2021&sourcekey=0.

[63] https://www.cbo.gov/system/files/2021-07/57218-Outlook.pdf.

[64] (1.6%+2.2% +2.1%)/3+2.00%(inflation target)+3.70%.

[65] Average of SNL and Value Line estimates.

a. CAPM

The CAPM is built on the premise that variance in returns is the appropriate measure of risk, but only the non-diversifiable variance (systematic risk) is rewarded. Systematic risks, also called market risks, are unanticipated events that affect almost all assets to some degree because the effects are economy wide. Systematic risk in an asset, relative to the average, is measured by the Beta of that asset. Unsystematic risks, also called asset-specific risks, are unanticipated events that affect single assets or small groups of assets. Because unsystematic risks can be freely eliminated by diversification, the reward for bearing risk depends on the level of systematic risk. The CAPM shows that the expected return for a particular asset depends on the pure time value of money (measured by the risk free rate), the reward for bearing systematic risk (measured by the market risk premium), and the amount of systematic risk incurred by the asset (measured by Beta). The general form of the CAPM is as follows:

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

Where: k is the expected return on equity for a security;
R_f is the risk-free rate;
β is Beta; and
$R_m - R_f$ is the market risk premium.

For the risk-free rate (R_f), Staff used the average yield on 30-year U.S. Treasury bonds for the three-month period ending August 31, 2021; that figure was 2.01%. For Beta (β), Staff relied on Value Line Betas; the average Beta for the electric comparable group of companies is 0.89.[66] For the market risk premium ($R_m - R_f$) estimates, Staff relied on the historical difference between earned total returns on stocks and earned total returns on bonds.[67] The first risk premium (6.07%) was based on the long-term arithmetic average of historical return differences from 1926-2020. The second risk premium (4.62%) was based on the long-term geometric average of historical return differences from 1926 to 2020. The CAPM COE results range from 6.02% to 7.62%, with an average of 6.70% (see schedule PC-10) for Staff's electric comparable group of companies.

[66] Staff averaged Value Line Betas provided at different times in 2021, for companies in the proxy group.
[67] From Duff & Phelps *2019 Valuation Handbook: A Guide to the Cost of Capital.*

To the extent that the CAPM COE estimate range (6.02% to 7.62%) overlaps with Staff's DCF COE model estimate range of 6.83% to 9.37%, it confirms the reasonableness of Staff's COE estimates.

b. Bond Yield Plus Risk Premium

Staff conducted a simple test of reasonableness on its COE estimates using the bond yield-plus risk premium. The bond yield-plus risk premium estimates the required return on an equity by adding an equity risk premium to the yield-to-maturity on a company's long-term debt. Since Staff is using a proxy group of companies to estimate COE in this case, the appropriate yield-to-maturity to use is the average yield-to-maturity of the companies in the Staff's proxy group. Staff's proxy group of companies have credit ratings ranging from A- to BBB+, with a mean of about BBB+. Moody's public utility bond yields on A-rated bonds and Baa-rated bonds had a three-month average of 2.95% and 3.19%, respectively, as of August 31, 2021. The average of the two yields is 3.07%. While opinions vary on the appropriate risk premium to use for the U.S capital market, a range of 3% to 5% is considered acceptable. Adding 3.07% to 3% and 5% yields a COE estimate range of 6.07% to 8.07%. To the extent that the bond yield-plus risk premium COE estimate range overlaps with the DCF model, it supports the reasonableness of Staff's COE estimates.

c. Average Authorized ROE

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 ROE decisions for other utility companies throughout the country. For consideration of recent authorized ROEs, the Table 4 below presents information compiled and published by Regulatory Research Associates (RRA), which details the average electric and gas utility authorized ROEs awarded by public utility commissions around the U.S in rate cases from 2010 to 2021:

continued on next page

Table 4[68]

	Natural Gas						Electric					
	Fully Litigated		Settled		Natural Gas Total		Fully Litigated		Settled		Electric Total	
Year	ROE (%)	Case (No.)	ROE (%)	Case (No.)	ROE (%)	Case (No.)	ROE (%)	Case (No.)	ROE (%)	Case (No.)	ROE (%)	Case (No.)
2010	10.08	27	10.30	12	10.15	39	10.35	27	10.39	34	10.37	61
2011	9.76	8	10.08	8	9.92	16	10.39	26	10.12	16	10.29	42
2012	9.92	21	9.99	14	9.94	35	10.28	29	10.06	29	10.17	58
2013	9.59	12	9.80	9	9.68	21	9.85	17	10.12	32	10.03	49
2014	9.98	15	9.51	11	9.78	26	10.05	21	9.73	17	9.91	38
2015	9.58	5	9.60	11	9.60	16	9.66	16	10.04	15	9.84	31
2016	9.61	10	9.50	16	9.54	26	9.74	25	9.80	17	9.77	42
2017	9.82	7	9.68	17	9.72	24	9.73	24	9.75	29	9.74	53
2018	9.59	17	9.59	23	9.59	40	9.63	22	9.57	26	9.60	48
2019	9.74	12	9.70	20	9.71	32	9.58	27	9.76	20	9.66	47
2020	9.44	12	9.47	22	9.46	34	9.43	32	9.46	23	9.44	55
2021	9.61	6	9.63	10	9.62	16	9.44	15	9.48	9	9.46	24

Of particular relevance to the current case are ROEs authorized in 2020 and 2021. In 2020, the average authorized ROE was 9.43%. In the year-to-date 2021, as of August 25, the average authorized ROE is 9.44%. Staff's recommended authorized ROE of 9.50% is generally consistent with ROEs recently authorized for other utilities around the country. Staff believes that in order for Empire to be competitive on the capital market, it has to be given the opportunity to earn an ROE that is reasonably consistent with ROEs awarded to other utilities around the country.

G. Conclusion

Using the widely-accepted methods of financial analysis, Staff believes that the cost of common equity has increased by up to 42 basis points since Staff presented testimony in 2019/2020, in the last Empire rate case. Based on the evolving current economic conditions, Staff believes that it is reasonable to increase the authorized ROE by 25 basis points, from the 9.25% ROE authorized for Empire by the Commission in 2020, to 9.50%. Therefore, Staff recommends that the Commission authorize Empire an ROE of 9.50%, which is the midpoint of Staff's reasonable range of 9.25% to 9.70%.

[68] The national authorized ROEs were retrieved from Regulatory Research Associates ("RRA") on August 25, 2021.

Using the recommended authorized ROE of 9.50%, Staff recommends an authorized ROR of 6.77%, calculated by applying an embedded cost of long-term debt of 3.76%, to a capital structure of 52.44% common equity and 47.56% long-term debt.

Staff Expert/Witness: Peter Chari

H. Regulatory Lag and Risk Mitigation

Staff's position on rate of return, including return on equity, is bolstered by the risk reduction associated with the Empire electing plant in service accounting ("PISA") in Case No. EO-2019-0046 on August 12, 2020. By electing PISA, Empire is able to defer 85% of depreciation expenses and return associated with certain plant-in service to a regulatory asset for future recovery under RSMo. Section 393.1400.5. Staff will expound upon this supporting position as part of its rebuttal testimony as well as address the direct testimony of Empire witness John J. Reed on this topic.

Staff Expert/Witness: Kimberly K. Bolin

V. Rate Base

A. Plant in Service

Accounting Schedule 3, Plant-in-Service, reflects the rate base value of Empire's plant-in-service by account, updated through June 30, 2021.

Staff Expert/Witness: Angela Niemeier

1. Stranded Meters

Due to the Empire's installation of AMI meters, there were meters that are no longer used and useful. Staff has made an adjustment to plant in service to remove the amounts associated with the meters that were replaced.

Staff Expert/Witness: Amanda C. McMellen

2. Asset Retirement Obligations

An asset retirement obligation (ARO) is an obligation, legal or non-legal, associated with the retirement of a tangible, long-lived asset for the cost of returning a piece of property to its original condition. Retirement obligations can be recognized either when the asset is placed in service or during the operational life when its removal obligation is incurred. An asset retirement cost (ARC) is the offsetting asset that is created when an ARO is recognized.

Empire's depreciation rates include net salvage. Net salvage equals the gross salvage value of an asset minus the cost of removing the asset from service. Cost of removal is defined as the costs of demolishing, dismantling, tearing down or otherwise removing plant. Staff's understanding is that the cost of removal traditionally included in customer rates would include ARO items, but would not be limited to AROs.

In Empire's last rate case, (ER-2019-0374), the Commission ruled:

> The Commission has not generally allowed for the recovery of ARO's because without a legal obligation, these future costs were not known and measurable. However, the evidence in this case shows that the costs at issue to remove asbestos at the Asbury and Riverton generating units, as well as, costs paid to settle obligations for the coal ash ponds at Asbury, Iatan, and Riverton are not ARO's. Instead, these costs have already been paid by Empire, but not yet recovered in rates. The cost of removal of asbestos at Asbury and costs associated with the operation of certain ash ponds at Asbury and Iatan shall be charged to accumulated depreciation reserve of each respective generation facility. However, for the Riverton ash pond, which has already been retired, the costs shall be captured in a regulatory asset to be considered in Empire's next rate case.

In this case, Empire has requested that the costs associated with the Riverton ash pond closing and the removal of asbestos from Riverton be amortized over a 3-year period and included in the unamortized balance in rate base. Staff agrees with this adjustment and has reflected this amortization in the amount of $1,133,275.

For the environmental costs related to Iatan and Polychlorinated Biphenyls (PCB) transformers, Empire has made an adjustment to add these costs to the accumulated depreciation reserve as directed in the Report and Order from Case No. ER-2019-0374. Staff also made the same adjustments to the accumulated depreciation reserve.

Empire has recorded an ARC in plant-in service for the newly constructed wind farms. These amounts need to be removed from plant in service as they will be recovered through depreciation rates through the cost of removal. Staff has made an adjustment to remove the ARCs from plant in service.

Staff Expert/Witness: Kimberly K. Bolin

3. Transmission and Distribution Investment

Staff reviewed Empire's transmission and distribution investment. In particular Staff looked at the decision to follow the Missouri reliability inspection standards in all states. This review helped to determine how and to what degree that decision would be impacting costs and benefits for Missouri ratepayers. Staff also reviewed the applicable National Electric Safety Code for the investments in Empire's transmission and distribution system to verify that these investments were justified and prudent. Staff also reviewed the metrics employed by Empire to determine what projects where funded and the approved budget and final cost values for the projects to help determine if the projects had prudent fiscal management. During this review Staff relied upon responses to Staff Data Request Nos. 0219-0227 as well as the testimony and workpapers of Empire witness Jeffery Westfall. As a result of this review, Staff is not recommending a disallowance.

Staff Expert/Witness: Shawn E. Lange, PE

4. Advanced Metering Infrastructure

Empire began installing Advanced Metering Infrastructure (AMI) in Missouri in June 2020. AMI encompasses not only physical meters, but also the supporting communications networks and data management systems. These components work together to enable two-way communications between the utility and its customers.

Empire researched its requirements for AMI and possible vendors. Additionally, Empire considered maintaining its existing metering infrastructure. As a part of its research, Empire received pricing estimates from Itron, ** [redacted], ** ultimately selecting Itron as its vendor and the Itron Openway Riva meters for electric customers.

In addition to enabling two-way communications, the selected Itron meters support more granular usage measurement, bidirectional metering (i.e., for renewable generation or vehicle to grid systems), and remote disconnects/reconnects. Additionally, Empire has committed to retaining data to enhance the accuracy and applicability of its load research data.[69]

[69] Global Stipulation and Agreement, ER-2019-0374, page 8.

Empire completed the installation of its supporting communication networks in December 2020. As of June 30, 2021, Empire has installed 155,062 AMI meters in Missouri representing approximately 98 % of its customer base. Staff recommends inclusion of installed meters in rate base.

Staff Expert/Witness: Claire M. Eubanks, PE

5. In-service Criteria Overview

In order for Staff to recommend inclusion of generating units, including solar or wind facilities in rate base, the plant must be "fully operational and used for service." A new facility usually will not have any historical operating information from which Staff can make a recommendation to the Commission as to whether the new unit is fully operational and used for service; therefore, operational tests must be established and performed by the utility. Staff refers to these operational tests or requirements as in-service criteria.

The Commission has used in-service testing since at least 1978, after Section 393.135 went into effect in 1976, to determine whether the inclusion of a facility in rates is just and reasonable. Section 393.135, RSMo. 2016 states:

> Any charge made or demanded by an electrical corporation for service, or in connection therewith, which is based on the costs of construction in progress upon any existing or new facility of the electrical corporation, or any other cost associated with owning, operating, maintaining, or financing any property before it is <u>fully operational and used for service</u>, is <u>unjust and unreasonable, and is prohibited</u>. [Emphasis added.]

In-service testing has been completed on a wide range of generating plant types and specific plant upgrades, such as environmental retrofits. Staff typically recommends similar tests across types of generating plant types (i.e., base load, intermediate, and peaking), however each specific plant type may also have different tests unique to the specific generating unit. Staff also commonly recommends criteria that applies to all generating plants and environmental retrofits, for example, that all major construction work is complete.

In recommending in-service criteria, Staff includes certain tests that will give an indication of how a new unit will perform under various conditions. Additionally, Staff recommends several criterion, which in combination are needed to determine that a unit is both fully operational and used for service. Certain fundamental tests are included to prove whether the unit can start properly, shut down properly, operate at its full design capacity, operate for a period of time without tripping off line, operate at multiple load points, or operate at its design minimum load point. Other items Staff would consider are whether the unit can meet the emissions requirements, and whether the full output of the unit can be delivered into the electrical distribution/transmission system. An additional factor Staff will consider is whether contractual testing has been performed prior to the company accepting the unit.

There have been instances where the Commission determined a generating plant was used for service but not fully operational. An early case in which the Commission considered in-service criteria specifically was Case No. ER-79-60, a rate case in which the date of Jeffery Energy Center Unit 1 becoming fully operational and used for service was at issue. In that case, the Commission found that even though the Jeffery Energy Center Unit 1 was used for service, it must also be fully operational prior to inclusion in rates.

Staff Expert/Witness: Claire M. Eubanks, PE

Wind In-Service

As a part of the certificate of convenience and necessity (CCN) case, Staff and Empire agreed to in-service criteria to be used to determine whether the North Fork Ridge, Kings Point, and Neosho Ridge wind farms are fully operational and used for service.[70] Staff witnesses Charles T. Poston, PE, J Luebbert, and Claire M. Eubanks, PE present the status of Engineering Analysis' evaluation and recommendation in the attached Construction Audit report, Appendix 4.

In its conclusion, Staff recommends the North Fork Ridge Project be considered fully operational and used for service as of April 21, 2021. Staff has requested additional information and verification from the Company regarding the satisfaction of the in-service criteria for Kings Point and Neosho Ridge. Staff will continue to review information provided by the Company and will provide its recommendation concerning full or partial satisfaction of the in-service criteria for Kings Point and Neosho Ridge in a subsequent round of testimony. At this time,

[70] Case No. EA-2019-0010.

Staff recommends proceeding with the development of a revenue requirement as though all three wind farms are in-service.

Staff Experts/Witnesses: Claire M. Eubanks, PE, Charles T. Poston, PE, J Luebbert

Solar In-Service

In this case, Staff recommends the solar in-service criteria contained in Appendix 3, Schedule AC-d1. The solar in-service criteria includes the typical criterion that Staff always includes, such as all major construction work is complete and whether there are sufficient distribution assets for the facility. In addition to confirmation that the solar facility is producing energy, the solar in-service testing includes a capacity test. This test evaluates the system's power generating capability. Solar generation has inherent uncertainties related to weather conditions such as temperature, irradiance, and seasonal variability. The benefit of the capacity test is that it is a shorter-duration test, which corrects for these weather conditions. The solar in-service criteria proposed by Staff in this case are comparable to the criteria used for other solar facilities, such as Ameren Missouri's O'Fallon Renewable Energy Center.

Prosperity Solar

Empire's Prosperity Solar farm was constructed to serve Empire's Community Solar Pilot Program, which was approved by the Commission on September 30, 2020 in File No. ET-2020-0259. It is located on a portion of the Oronogo-Duenweg Mining Belt Superfund site on Elm Road, in Jasper County, Missouri, on 11 acres leased by Liberty from the owner. The facility is 2.25 MW in capacity. This project allows Empire to offer 4,500 blocks (500 W each) to its subscribing community solar customers. Empire did not apply for a CCN for this facility as it intends to size the facility to meet the $3.5 million spending requirement pursuant to RSMo. 393.1665.2[71]. Empire believes the initial facility does not

[71] "An electrical corporation with one million or more Missouri electric customers shall invest in the aggregate no less than fourteen million dollars in utility-owned solar facilities located in Missouri or in an adjacent state during the period between August 28, 2018, and December 31, 2023. An electrical corporation with less than one million but more than two-hundred thousand Missouri electric customers shall invest in the aggregate no less than four million dollars in utility-owned solar facilities located in Missouri or in an adjacent state during the period between August 28, 2018, and December 31, 2023. An electrical corporation with two hundred thousand or fewer Missouri electric customers shall invest in the aggregate no less than three million five hundred thousand dollars in utility-owned solar facilities located in Missouri or in an adjacent state during the period between August 28, 2018, and December 31, 2023. If the rate impact of the electrical corporation's investment in such facilities would cause the

require CCN approval pursuant to RSMo. 393.1665.3, but will apply for CCN approval for future solar builds.

Schedule AC-1 provides the in-service criteria for this facility and Staff's review. Staff recommends the Commission find that Empire's Prosperity Solar farm is fully operational and used for service.

Staff Expert/Witness: Amanda Coffer

6. Plant-In-Service Accounting Regulatory Asset Balance

Staff has included Plant-In-Service Accounting (PISA) deferrals through June 30, 2021, as an addition to rate base. For a complete discussion on PISA, please refer to Section VII.C., subsection 10.

Staff Expert/Witness: Keith D. Foster

B. Depreciation Reserve

Accounting Schedule 6, Depreciation Reserve, reflects the rate base value of Empire's depreciation reserve by account, updated through June 30, 2021.

Staff Expert/Witness: Angela Niemeier

1. Stranded Meters

Due to the Empire's installation of AMI meters, there were meters that were replaced that were not fully depreciated. Staff has made an adjustment to depreciation reserve to remove the amounts associated with the meters that were replaced.

Staff Expert/Witness: Amanda C. McMellen

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electrical corporation to exceed the one percent maximum average retail rate increase limitation required by subdivision (1) of subsection 2 of section 393.1030, that part of such costs that would cause such one percent limitation to be exceeded shall be deferred by the electrical corporation to a regulatory asset. Carrying costs at the electrical corporation's weighted average cost of capital shall be added to the regulatory asset balance and the regulatory asset shall be recovered through rates set under section 393.150 or through a rate adjustment mechanism under section 393.1030, as soon as is practical."

C. Cash Working Capital

Cash Working Capital (CWC) is the amount of funding necessary for a utility to pay day-to-day expenses incurred in providing utility services to its customers. Cash inflows from payments received by the Company and cash outflows for expenses incurred by the Company are analyzed using a lead/lag study. The lead/lag study involves analysis of the timing of when funds are paid to suppliers and when the utility receives the good or service compared to when the utility receives revenues from customer bills for the utility services it provides. Analysis is also performed for pass-through expenses where funds are collected and remitted such as sales taxes and employee payroll withholdings.

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

During this rate proceeding, Staff did not conduct a lead/lag study. Staff recommends using the expense lead days approved by the Commission in Case No. ER-2019-0374, since there have been no substantial changes in the Company's payment processes or practices during the test year that would result in a significant change in lead days, with the exception of property taxes.

Staff determined the property tax expense lag to be 181.24 days, using the most current property tax assessments and invoices. The Company updated the revenue lag to reflect more recent collection experiences. Staff reviewed the revenue lag determined by the Company in this rate proceeding and finds it to be reasonable.

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

Staff Expert/Witness: Courtney Horton

D. Prepayments

Staff's recommended treatment of prepayments is to examine each prepayment account individually in order to determine an appropriate measure that most accurately predicts the ongoing future expense of a particular prepayment account, and then to include that prepayment expense in Empire's rate base. Prepayments are the costs a company incurs and pays in advance. Prepayments are treated as an asset and are reflected in the utility's rate base. Staff reviewed and analyzed balances from September 2018 to June 2021 for each prepayment account number to determine if there was a discernable trend. Staff used a 13-month average for the prepayment accounts that did not have a discernable trend. Staff used the June 30th, 2021 account balances for the prepayment accounts where the amount stayed the same. Staff's included a total of $7,359,543 in rate base.

Staff Expert/Witness: Courtney Horton

E. Materials and Supplies

Staff's recommended treatment of Materials and Supplies (M&S) is to examine each account individually in order to determine an appropriate level that most accurately reflects the ongoing future expense of a particular account. M&S represent an investment in inventory for items such as spare parts, electric cables, poles, meters, and other miscellaneous items used by Empire in daily operations and maintenance activities to maintain production facilities and electric system. Empire holds a variety of M&S in inventory so the items can be readily available when needed in performing its utility operations. Staff reviewed and analyzed balances from September 2018 to June 2021 for each M&S account number to determine if there was a discernable trend. Staff used a 13-month average for the M&S accounts that did not have a discernable trend. Staff used the June 30th, 2021 account balances for the M&S accounts that had a steady trend. Staff included a total of $43,846,806 in rate base.

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

Staff Expert/Witness: Courtney Horton

F. Customer Advances

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

Staff reviewed balances from September 2019 to June 2021 for customer advances and performed an analysis to determine if there is a discernible trend, for account numbers 252100 (Customer Advances for Construction- Electric) and 252110 (Customer Advances for Subdivision Construction- Electric). After analysis, the data revealed that there is a discernable upward trend for account number 252100 and a steady trend for account number 252110. Staff included the most current 13-month average ending June 30, 2021 as an offset to rate base in the amount of $6,344,360.

Staff Expert/Witness: Courtney Horton

G. Customer Deposits

Customer deposits are the funds required to be provided by certain customers taking electrical service from Empire as security against potential loss arising from failure to pay for utility service. These funds are deducted from Empire's rate base because these funds are cost-free funds received by Empire customers. Staff reviewed customer deposit balances from September 2019 to June 2021, and performed an analysis to determine if there was a discernible trend. There was a gradual upward trend in customer deposits. Staff included a 13-month average, June 2020 to June 2021, in the amount of $14,053,714 as an offset to rate base.

Staff calculated interest expense based on the level of customer deposits included in Staff's rate base schedule. Staff utilized the formula included in the tariff (YE-2021-0041 Schedule 6, Sec 3, Sheet 5) to calculate the customer deposit interest; this formula is the most current prime interest rate, as published in the Wall Street Journal, as being in effect on the last business day of December of the prior year, plus 1%. The prime rate listed in December 2020 was 3.25%. Under this formula, the reasonable rate applied to customer deposits is 4.25%. The amount of interest, $601,033, is included as an adjustment in Staff Accounting Schedules 10.

Staff Expert/Witness: Courtney Horton

H. Fuel Inventories

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

Staff used a 60-day calculation to establish Empire's rate base investment in the coal inventory maintained both at Evergy Metro's Iatan Generating Stations (Empire is a 12% owner of Iatan 1 and 2) and Plum Point Energy Associates, LLC's Plum Point Energy Station (Empire is a 7.52% owner of Plum Point).

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

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

I. Accumulated Deferred Income Taxes

Empire's Accumulated Deferred Income Taxes (ADIT) represents, in effect, a net prepayment of income taxes by customers prior to tax payment by Empire. For example, because Empire is allowed to deduct depreciation expense on an accelerated basis for income tax purposes, the amount of depreciation expense used as a deduction for income taxes purposes by Empire is considerably higher than the amount of depreciation expense used for ratemaking purposes. This results in what is referred to as a "book-tax timing difference," and creates a deferral of income tax reserves to the future. The net credit balance in the ADIT account's reserve represents a source of cost-free funds to Empire. Therefore, Empire's rate base is reduced by the ADIT balance to avoid having customers pay a return on funds that are provided cost-free to the Company. Generally, deferred income taxes associated with all book-tax timing differences created through the ratemaking process should be reflected in rate base. As it has done in prior Empire rate cases, Staff has decided to take this approach in calculating the ADIT rate base offset amount in this case.

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

Staff Expert/Witness: Keith D. Foster

J. Vegetation Management Tracker Regulatory Asset

Per the Stipulation and Agreement in Case No. ER-2016-0023, the Vegetation/Infrastructure tracker was discontinued and a regulatory asset was established in the amount of $2,182,407 (the balance as of March 31, 2016). The asset was to be amortized over five years. The annual amortization of this asset is $436,381. The unamortized balance as of June 30, 2021 is $90,994. In October 2021, the balance will be zero. Therefore, Staff recommends zero to rate base. Staff proposes an adjustment of ($436,481) to remove the amortization from test year. This adjustment includes ($61,980) from account 571998, ($357,478) from 593998, and ($17,023) from account 594998.

Staff Expert/Witness: Angela Niemeier

K. Iatan and Plum Point Carrying Costs

Iatan 1 - Pursuant to Empire's regulatory plan approved by the Commission in Case No. EO-2005-0263, Empire deferred certain "carrying costs" associated with the Iatan I Air Quality Control System investment past its in-service date into Account 182308, Iatan Deferred Carrying Costs. (The deferral of carrying costs after a projects' in-service date is also known as "construction accounting".) In the *Report and Order* in KCPL's Case No. ER-2010-0355, the Commission disallowed certain costs that had been booked to the Iatan accounts. The effect of these disallowances reduced the balance of the Iatan I AQCS plant balance. In Empire's Case No. ER-2012-0345, Staff removed any construction accounting allowances associated with the portion of Iatan 1 AQCS approved disallowances that were allocated to Empire from its rate base and expense amortization calculations. In the current case, Staff used the Januar 31, 2020, balance ($3,939,778) from the most recent rate case, Case No. ER-2019-0374, and the annual amortization expense first set and included in Staff's Accounting Schedules in Case No. ER-2012-0345, to determine the unamortized balance of $3,819,745 as of June 30, 2021, to include in rate base.

Iatan 2 - Pursuant to Empire's regulatory plan approved by the Commission in Case No. EO-2005-0263, Empire deferred certain "carrying costs" associated with the Iatan 2 generation unit investment past its in-service date into Account 182332, MO IatanII Df Chr ER-2010-0130. Similar to Case No. ER-2010-0355, Staff has disallowed certain costs that had been booked to the Iatan accounts. Staff has removed any construction accounting allowances associated with the portion of Iatan 2 disallowances that were allocated to Empire from its rate base and expense amortization calculations. The balance of Iatan 2 carrying costs was also reduced by Empire's deferral of fuel and purchased power expense savings it had incurred due to the addition of Iatan 2 to its generating system from the unit's in-service date through June 30, 2012. Staff used the January 31, 2020, balance ($2,148,142) from the most recent rate case, Case No. ER-2019-0374, and the annual amortization expense included in Staff's Accounting Schedules in Case No. ER-2012-0345, to determine the unamortized balance of $2,084,636 as of June 30, 2021, to include in rate base.

Plum Point - Pursuant to Commission approval of the *Non-Unanimous Stipulation and Agreement and Joint Proposal Regarding Certain Procedural Matters* dated February 25, 2010, in Case No. ER-2010-0130, Empire deferred certain "carrying costs" associated with the Plum Point generating unit investment past its in-service date into Account 182331, MO PlumPT Df Chgs ER-2010-0130. Based on the results of its Construction Audit and Prudence Review for Plum Point (submitted in Case No. ER-2011-0004), Staff recommended one disallowance to Empire's Plum Point plant balances in that case. Staff used the January 31, 2020, balance ($100,923) from the most recent rate case, Case No. ER-2019-0374, and the annual amortization expense included in Staff's Accounting Schedules in Case No. ER-2012-0345, to determine the unamortized balance of $98,108 as of June 30, 2021, to include in rate base.

Staff Expert/Witness: Angela Niemeier

L. SWPA Hydro Reimbursement

On September 16, 2010, Empire received a payment in the amount of $26,563,700 from Southwestern Power Administration (SWPA), to compensate Empire for the expected financial impact of the future reduction in capacity at its Ozark Beach hydroelectric plant. The reduction in capacity at Ozark beach is due to the Energy and Water Development Act of 2006, federal legislation, which requires a decrease in available head waters at Ozark Beach. In Case No. ER-2011-0004, Empire agreed to flow the SWPA payment back to the customers over a ten-year period via a tracker mechanism. The SWPA amortization ended September 2020. Therefore, Staff proposes $0 to rate base for the SWPA hydro reimbursement.

Staff Expert/Witness: Angela Niemeier

VI. Allocations

A. Corporate Allocations

1. Background

After the conclusion of Case No. ER-2016-0023, Empire was acquired by APUC in Case No. EM-2016-0213. APUC, in addition to some of its subsidiaries, provides various services, either directly or indirectly, to Empire. These services are allocated to Empire, as well as to other entities based on allocation procedures described in the Algonquin Power & Utilities Corp. Cost Allocation Manual, also referred to as the Liberty CAM. The Liberty CAM was effective January 1, 2017, including an Appendix 9 constituting additional terms and conditions applicable to Empire, EDG, Liberty Utilities Corp. ("Midstates Natural Gas"), and Liberty Utilities, LLC ("Missouri Water").

2. Allocations

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

Algonquin Power & Utilities Corporation

As described in Liberty's CAM, there are several services APUC provides as a benefit to its subsidiaries: financing, financial control, legal, executive and strategic management, and related services. Any expenses associated with these services are billed at cost, with fully burdened labor rates. All labor costs that are directly related to a specific subsidiary are charged directly to that entity. With the exception of corporate capital, indirect costs are totaled for a month and then allocated between Liberty Utilities Canada (LUC) and Liberty Power using a Corporate Allocation Method described in the CAM. The indirect costs allocated to LUC are further allocated to the individual utilities, which includes Empire, using a Utility Four-Factor allocation methodology. The Utility Four-Factor Methodology allocates costs by relative size and scope of the utilities. The methodology used by LUC involves four allocating factors, or drivers: (1) Utility Net Plant; (2) Total Customers; (3) Non-Labor Expenses; and (4) Labor Expenses. Both direct and indirect allocations are billed monthly to each affected subsidiary.

Staff applied an adjustment for the Bonus, Short Term Incentive Plan (STIP), Long Term Incentive Plan (LTIP), and Stock Options expenses for APUC executives allocated by APUC to its business units. Staff's review of how these incentives are awarded to the executives found that they were awarded for increasing shareholder value, not as a benefit to the ratepayers. A further description of these plans is included in the Incentive Compensation Section VII.E., subsection 5. Therefore, Staff applied adjustments to remove from the test year the portions of these expenses that were both directly and indirectly allocated to Empire.

Liberty Utilities (Canada) Corporation

As described in Liberty's CAM, LUC provides services separately Liberty and Liberty Power, and together as shared services. Shared services are provided within LUC under the business unit of Liberty Algonquin Business Services ("LABS").

The services provided to Liberty include: executive, regulatory strategy, energy procurement, operations, utility planning, administration, and customer experience. All costs incurred that are directly related to a specific utility are charged directly to that utility. Costs that are not directly related to a utility are indirectly allocated to its regulated utilities using the same Utility Four-Factor Methodology described above for APUC. These indirect allocations include labor, non-labor, and capital costs.

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

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

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

Liberty Utilities Service Corporation

Liberty Utilities Service Corporation ("LUSC") employs most of the U.S.-based utility personnel, who are assigned to and provide services to specific utilities. As such, the majority of employees' fully loaded labor costs are directly charged to the utility for whom each supports, via timesheet tracking. There are some employees who provide shared services that benefit both LU and Liberty Power through the LABS U.S. business unit. A sampling of these shared services includes customer care and billing, Information Technology support, and human resources. As with LUC, all costs incurred that are directly related to a specific affiliate company or business unit are directly charged to that company or business unit. Costs that are not directly related to a specific utility are indirectly allocated between the regulated and unregulated business units using two Corporate Allocation Methods described in the CAM: one for Business Services indirect costs and another for Corporate Services indirect costs. The Utility Four-Factor Methodology described in the CAM is then used to allocate the indirect costs for the regulated businesses to the individual regulated utilities.

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

Empire District Electric

As is discussed earlier in this Report, Empire is engaged in both regulated and non-regulated business operations. Included in Appendix 9 to the CAM are the additional allocation procedures to be followed by each of the Missouri Regulated Utilities, which is

Empire (including its water operations), EDG, and Liberty Midstates. Appendix 9 describes the methods for assigning and allocating costs to the regulated electric, gas, and water operations, as well as to the various non-regulated operations. With some exceptions, this has many of the same allocation procedures that existed prior to APUC's acquisition of Empire. Under the Missouri Regulated Utilities' cost allocation system, costs are either directly assigned to business units (referred to as "The Direct Bill Method"), indirectly allocated to the business units, or allocated through use of a general allocation factor.

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

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

For costs that cannot be directly assigned, or that have no unit drivers, the Company uses a modified "Massachusetts Formula" as a general allocation method it refers to as a "Corporate Allocation Method." A "Massachusetts Formula" is a general allocation factor based upon three (3) separate measurements of directly assigned costs, which is used to allocate a company's common costs that cannot be reasonably directly assigned or indirectly allocated to a company's business units. The modified "Massachusetts Formula" used by Empire consists of the averages of (1) profit margin, (2) payroll, and (3) net property, plant, and equipment.

It is used to allocate common costs that apply to the regulated activities of Empire, EDG, and Empire's water operations. Staff modified some of the various allocation factors to reflect Staff's adjusted numbers that were included in its cost of service. Please reference Staff's Exhibit Modeling System (EMS) that was filed with its cost of service report in this case for the allocation factors used by Staff.

Staff Expert/Witness: Caroline Newkirk

B. Jurisdictional Allocations

Jurisdictional allocation factors are used to allocate demand-related and energy-related costs to the applicable jurisdictions. Fixed costs, such as the capital costs associated with generation and transmission plant, are allocated on the basis of demand. Variable costs, such as fuel, are more appropriately allocated on the basis of energy consumption. In this case, demand-related and energy-related costs are divided among three jurisdictions: Missouri Retail Operations, Non-Missouri Retail Operations and Wholesale Operations. The particular allocation factor applied is dependent upon the type of cost that is being allocated.

1. Demand Allocation Factor

Demand refers to the rate at which electric energy is delivered to a system to match the requirements of its customers ("load"), generally expressed in kilowatts (kWs) or megawatts (MWs), either at an instant in time or averaged over a specified time interval.

System peak demand is the largest electric requirement ("load") that occurs within a specified period of time, (e.g. hour, day, month, season and year) on a utility's system. Since generation units and transmission lines are planned, designed, and constructed to meet a utility's anticipated system peak demands, plus required reserves, the contribution of each of Empire's three jurisdictions identified above coincident to the system peak demand, *i.e.*, each jurisdiction's demand at the time of the system peak, is the appropriate basis on which to allocate these facilities. Thus, the term coincident peak (CP) refers to the load, generally in kWs or MWs, in each of the jurisdictions that coincides with Empire's overall system peak recorded for the time period in the corresponding analysis. Staff is utilizing a Twelve

Coincident Peak (12 CP) methodology to determine demand allocation factors for Empire.[72] This methodology is appropriate for an electric utility, such as Empire, that experiences similar system peak demands in both summer and winter months. An electric utility that experiences dominant peaks only in the summer months might consider the use of a Four Coincident Peak (4 CP) methodology.[73]

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

a. Identify Empire's peak hourly load in each month for the test year, October 2019 through September 2020, and sum the hourly peak loads.
b. Sum the particular jurisdiction's corresponding loads for the hours identified in (a) above.
c. Divide (b) by (a) above.

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

Retail Operations:	
Missouri -	.8828
Non – Missouri -	.1151
Wholesale Operations:	.0021

2. Energy Allocation Factor

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

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[72] A Twelve Coincident Peak ("12 CP") Methodology considers the contribution of the monthly peaks in each of Empire's jurisdictions, which is coincident with the time of Empire's overall system peak, for each month in the test year (October 2019 through September 2020).

[73] Compared to a 12 CP, a Four Coincident Peak Methodology ("4-CP") typically considers the contribution of the monthly peaks in the respective jurisdictions of the electric utility that occur at the time of the utility's overall system peak for the four summer months (June-September) included in the 12-month test period being analyzed.

Retail Operations:	
Missouri -	.8808
Non – Missouri -	.1168
Wholesale Operations:	.0024

Staff witness Caroline Newkirk used these demand and energy jurisdictional allocation factors in determining Staff's recommended cost of service for Empire in this case.

Staff Expert/Witness: Alan J. Bax

VII. Income Statement

A. Rate Revenues

Introduction

Since the largest component of operating revenues results from rates charged to Empire's Missouri retail customers, a comparison of operating revenues with cost of service is fundamentally a test of the adequacy of the currently effective Missouri jurisdictional retail electricity rates. If the overall cost of providing service to Missouri retail customers exceeds operating revenues, an increase in the current rates that Empire charges to Missouri retail customers for electricity is appropriate.

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

Definitions

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

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

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

The Development of Rate Revenue in this Case

This section discusses Staff's normalized and annualized test year usage and revenues by rate class. The intent of Staff's adjustments is to determine the level of revenue that Empire would have collected on an annual, normal-weather basis, based on information at the end of the test year September 30, 2020 and in this case, updated through May 31, 2021, as explained below. The two major categories of revenue adjustments are known as "normalization" and "annualization." Normalizations deal with test year events that are unusual and unlikely to be repeated in the years when the new rates from this case are in effect. Test year weather is an example. Annualizations are adjustments that take conditions known at the end of the test year and apply them as if they had existed throughout the entire test year. Adjustments for customer growth are an example of an annualization.

1. Update Period Adjustment

The purpose of the update period adjustment is to provide a more current level of normalized and annualized customer usage data, referred to as billing determinants,[74] to establish rates in this case. In this case, Staff was able to update billing determinants to reflect the 12-month period ending May 31, 2021. Billing determinants are the customer counts and detailed customer usage data for each rate schedule that are necessary to calculate retail rate revenue for each rate schedule charge type. The Residential ("RES"), Commercial Service ("CB") and Small Heating Service ("SH") rate schedules consists of a customer charge billed

[74] Billing determinants are the customer counts and detailed customer usage including both kWh and kW.

per customer, and an energy charge billed per kWh. Therefore the billing determinants consist of the number of customers and the number of kWh sold at each level of the energy charge. The General Power Service ("GP") and Total Electric Building Service ("TEB") rate schedules also include a demand charge and a facilities charge; therefore, the billing determinants include the level of customer kW subject to each type of demand charge and facilities charge.

Empire provided Staff with workpapers and Data Request responses that had conflicting customer usage and customer counts. After discussions with the Company, it was determined that the data in its response to Data Request No. 0137 was determined before calculating certain manual adjustments and that the data in the Company's workpaper[75] included those manual adjustments,[76] which produced two different sets of data. As a further complication, the Company's workpaper did not provide usage by billed rate block whereas the data provided in response to Data Request No. 0137 did provide usage by billed rate block. Therefore, in order for Staff to have usage by block for the RG, CB and SH service classes, Staff utilized the percent of usage by block that was provided in Data Request No. 0137 and applied it to the total usage after the Company's manual adjustments in the workpaper. Although this is not ideal, Staff believes this results in the most accurate customer billing determinants given the data provided.

2. Weather Normalization of Revenue and 365 Day Adjustment

Staff normalized and annualized update period usage data provided by Empire for the RG, CB, SH, GP and TEB service classes. Staff witness Michelle A. Bocklage discusses the weather normalization and 365 days adjustment for the LP class.

The RG, CB, SH, GP and TEB service classes consist of a seasonal differentiated energy charge for summer and winter. The RG, CB, and SH service classes are billed using a summer energy charge (the first four monthly billing periods after June 16) at a flat non-blocked energy rate. The winter energy charge (the remaining eight billing periods of the calendar year) is billed using a declining two-block rate. For the RG rate class, the first rate block applies to the first 600 kWh used in a billing period and second block is applied to all kWh billed in excess of 600 kWh. For the CB and SH rate classes, the first rate block applies to the first 700 kWh

[75] REV ADJ 4 – Weather Normalization and COVID.
[76] Billing corrections.

used in a billing period and the second block is applied to all kWh billed in excess of 700 kWh. The GP and TEB rate classes are billed an energy and demand charge. The energy charge rate blocks are separated based on the customer's relationship between kWh usage and kW demand in each month. The energy charge is billed at the first 150 hours, next 200 hours, and all additional use of metered demand, per kWh and is differentiated by summer and winter. The demand charge is per kW of billing demand and is billed at a summer and winter rate.

Staff applied the normalized and annualized kWh factor[77] to the RG, CB, SH, GP and TEB rate classes. For example, if the normalized and annualized kWh factor is 0.97 for the month of September in the RG rate class, then the total actual usage for that month and that rate class is decreased by .03 by multiplying it by the actual usage. Mr. Stahlman explains how the factors are derived in Section VII.A., subsection 11.

Staff adjusted actual usage to equal the normalized and annualized monthly kWh using the relationship between actual average usage per customer and normalized and annualized average usage per customer. Staff also used the relationship between the percentage of usage priced in the first rate block and the second rate block to distribute normalized and annualized monthly kWh to the rate blocks for rate classes RG, CB, and SH. This computation resulted in normalized usage by rate block, which was then converted to the total normalized revenues by multiplying rate block usage by the appropriate rates found in Empire's effective tariff sheets.

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

3. Rate Switching

Table 5, below, shows a summary of the number of customers that switched between classes for the twelve months ending May 2021.

[77] 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.

Table 5: Update Period Rate Switchers

Rate	Jun -20	Jul-20	Aug-20	Sep -20	Oct-20	Nov -20	Dec -20	Jan-21	Feb-21	Mar -21	Apr -21	May -21
Residential (RG)	13	17	14	15	16	12	9	8	3	2	3	0
Commercial (CB)	-20	-21	-17	-16	-17	-13	-10	-9	-4	-2	-3	0
Small Heating (SH)	1	0	1	0	-1	-1	0	-1	-1	-1	-1	0
General Power (GP)	6	3	3	1	2	2	2	2	2	1	1	0
Total Electric Building (TEB)	0	1	-1	0	0	0	-1	0	0	0	0	0
Total Retail	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

The overall effect of rate switching on usage nets to zero (one class' increase exactly equals the other class' decrease); however, in this case, the overall effect of rate switching is a slight decrease to revenue.

Those customers who switched into and out of each of these classes were handled by rate class. 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.

4. Customer Growth Adjustment

Staff made adjustments to reflect the impact in the change of customer levels on the update period kWh sales, kW demand,[78] and revenues. Staff's customer growth adjustment reflects the level of kWh sales, kW demand and rate revenues that would have occurred if the number of customers taking service at the end of May 31, 2021, had existed throughout the entire twelve months.

Staff has calculated customer growth for the following customer classes: RG, CB, SH, GP and TEB rate classes. The customer growth adjustment takes into account normalized weather usage, as well as the adjustment for 365 days and rate changes that occurred during the test year.

[78] Class kW demand was only adjusted for the GP and TEB classes that have demand charges.

5. Adjustments for Non-Missouri classes

Staff adjusted the RG, CB, SH, TEB, and GP classes' usage for non-Missouri customers for weather by applying the combined weather factor and days factor to the monthly kWh. Staff then calculated the growth adjustment for each class noted above by applying the ending customer counts of the update period, May 2021. Staff provided the final normalized and annualized usage to Staff witness Michael L. Stahlman for inclusion in Net System Input (NSI), and to Staff witness Alan J. Bax for inclusion in jurisdictional allocations.

Total Normalized and Annualized Revenue

Below is Staff's ending revenue calculation after the adjustments discussed above were applied to the data provided by the Company.

Rate Class	Total MO Normalized Revenue
RG	$223,680,723
CB	$44,674,682
SH	$9,453,631
GP	$81,905,516
TEB	$32,817,903

Staff Expert/Witness: Kim Cox

6. Annualization of Excess Facility Charge Revenues

These revenues result from charges to customers for additional distribution facilities, such as utility poles, transformers, etc., provided in excess of the distribution facilities normally made available to similarly sized customers. Staff annualizes these revenues for changes in the distribution facilities provided at the end of the update period to determine the revenue that the Company would have earned had these additional facilities been in use the entire update period. Then, Staff uses these annualized revenues in developing its cost of service.

Staff Expert/Witness: Michelle A. Bocklage

7. Large Power and Feed Mill and Grain Elevators Adjustments

Staff determined annualized and normalized billing determinants for the LP and PFM rate classes on an individual customer basis; rather than as an entire class. As mentioned by Staff witness Michael L. Stahlman, the LP class was not weather normalized. Staff calculates the normalized and annualized kWh and revenue adjustment for the update period so that the most current data is used; rather than relying on test year data.

Staff made adjustments for the period of June 1, 2020, through May 31, 2021. Due to the significant amounts of electricity used by each LP customer and the heterogeneous nature of the electric use and load factor, the class sales and revenues were annualized on an individual customer account basis. There were 43 customers in the Missouri LP rate class at the beginning of the update period, but one rate switcher moved from the GP class to the LP class during the update period. This resulted in 44 customers in the Missouri LP rate class at the end of May 2021. Staff annualized the usage of the customer by removing the usage from the GP class and moved it to the LP class so that it reflects 12 months of usage for that customer in the LP class.

Out of the 10 PFM customers, no PFM customer's load was adjusted. No new customers entered the PFM rate class during the 12 months of the update period.

Staff Expert/Witness: Michelle A. Bocklage

8. Lighting Revenues

Staff updated lighting revenues to reflect the change in usage through a12-month period ending May 31, 2021. For the Miscellaneous Services (MS), Special Lighting Service (LS), Private Lighting Service (PL), and Municipal Street Lighting Service (SPL) lighting classes, Staff made some adjustments for incorrect meter reads as outlined in the Company's response to Data Request No. 0170. Electrical usage for lighting was determined not to be weather sensitive.

Staff Expert/Witness: Joseph P. Roling

9. Special Transmission Service Contract Customer (Praxair) Annualization

Staff calculated the revenues of the Special Transmission Service Contract (PRAXAIR) (SC-P) rate schedule on an individual customer basis.

Staff made adjustments to billing units and revenues based on the test year for the 12-months ending September 30, 2020, adjusted for changes through an update period ending May 31, 2021. After reviewing historical usage for Praxair, Staff did not find any material changes in usage through the twelve months of the update period. Staff determined that no adjustments were required in the update period.

Staff Expert/Witness: Joseph P. Roling

10. System Energy Losses

When determining the hourly loads during the test year of this case, which are used as an input in Staff's recommended fuel model, Staff accounts for system energy losses, which largely consist of the losses occurring in the electrical equipment (e.g., transmission and distribution lines, transformers, etc.) between an electric utility's generating sources and its customers' meters. In addition, Staff includes small, fractional amounts of energy that are either diverted (stolen) or unmetered (unmetered usage) as system energy losses.

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

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

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

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

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

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

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

Staff calculated the loss percentage of Empire's system, for the twelve months ending September 2020, as 6.38% of NSI. This percentage is consistent with typical expectations for an average loss factor calculation on Empire's system. The system energy loss percentage was provided to Staff witness Michael L. Stahlman in his development of hourly loads used in Staff's recommended fuel model.

Staff Expert/Witness: Alan J. Bax

11. Normal Weather

365-Days Adjustment to Usage

The purpose of a 365-Days Adjustment is to ensure that the test period reviewed has precisely 365 calendar days. Calendar months and revenue months differ from one another because of the periods they cover and the differing beginning and ending times. Calendar months coincide with the calendar, beginning on the first day of the month and ending on the last day of the month. Empire's customers' usage is measured, and rate revenues are collected, over a period known as a revenue month, which is the interval over which Empire reads customers' meters and issues bills. A bill rendered for a given revenue month may charge for usage in parts of two calendar months. Revenue months usually take their names from the calendar month in which the customer's bill is rendered. For example, assume a customer's meter was read and usage determined on June 8 and then again on July 8 and that the bill was sent to the customer on July 15. The revenue month for this bill is July even though 22 days of the usage measured for this bill occurred from June 9 through June 30 and it contained only eight days of usage in July.[79]

[79] Primary months are used to distinguish in which month the usage is billed 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

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

The 365-Days Adjustment for RES, SGS, LGS, SPS, and LPS were provided to Staff witness Kim Cox, who used the 365-Days Adjustment to adjust the revenues of the weather-normalized class revenues months to the twelve months ended April 30, 2021.

Staff Expert/Witness: Michael L. Stahlman

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 colder, the demand for additional heating, via electric space heating, also forces an increase in electricity consumption. Electric air conditioning and space heating are prevalent in Empire's service territory; therefore, it follows that Empire's electric load is linked with and responsive to temperature.

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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.

Empire's test year ran from October 1, 2019, through September 30, 2020. In an attempt to capture a more likely forward-looking indictor of non-weather electricity usage per customer, Staff decided to use the most recent temperature and load data available and, therefore, based its analysis on the twelve months of June 1, 2020, through May 31, 2021.

For the update period, Staff's weather analysis showed an overall warmer than normal year. The months of June 2020 through October 2020 were generally slightly cooler than normal and the months of November 2020 through May 2021 were generally warmer than normal with the notable exception of February 2021, which was much colder than normal.

The method and model used by Staff is similar to those used by Empire. Staff's model and method contained elements important in the class-level weather normalization process: use of daily load research data to determine non-linear, class-specific responses to changes in temperature with the incorporation of different base usage parameters to account for different days of the week, months of the year, and holidays. The results of Staff's analysis were provided to Staff witness Kim Cox to be used in the normalization of revenues for weather-sensitive classes, RES, CB, SH, GP and TEB.

Staff Expert/Witness: Michael L. Stahlman

Weather Variables

Historical Data Used to Calculate Weather Variables - Each year's weather is unique; consequently, test year usage, hourly loads, revenue, and fuel and purchased power expense need to be adjusted to "normal" weather so that rates will be designed on the basis of normal weather rather than any anomalous weather in the test year. In the quantification of the relationship between test year weather and energy sales, Staff used weather observations of Springfield Regional Airport ("SGF"), Missouri, for the twelve months of June 1, 2020, through May 31, 2021.

Weather Variables - Staff obtained weather data from the Midwest Regional Climate Center ("MRCC"). Weather data of SGF was used for the service territory of Empire due to the availability and reliability of the weather data as well as its approximate location to Empire's customer base. The weather data sets consist of actual daily maximum temperature ("T_{max}") and daily minimum temperature ("T_{min}") observations. Staff used these daily temperatures to develop a set of mean daily temperature ("MDT") values.

Normal Weather - According to the National Oceanic and Atmospheric Administration ("NOAA"), a climate "normal" is defined as the arithmetic mean of a climatological element computed over three consecutive decades.[80] In developing climate normal temperatures, the NOAA focuses on the monthly maximum and minimum temperature time series to produce the serially-complete monthly temperature ("SCMT") data series.[81]

Staff utilized the SCMT published in July 2011 by the National Climatic Data Center ("NCDC") of the NOAA. For the purposes of normalizing the test year electric usage and revenues, Staff used the adjusted T_{max} and T_{min} daily temperature series for the 30-year period of January 1, 1988, through December 31, 2017, at SGF. NOAA updated the 30-year normal period to the end of 2020 in May 2021, but Staff has not been able to analyze the SCMT for the most recent period. As discussed below, the SCMT is based on the NOAA 30-year normal period ending 2010, with observed data through 2017.

There may be circumstances under which inconsistencies and biases in the 30-year time series of daily temperature observations occur, (e.g. such as the relocation, replacement, or recalibration of the weather instruments). Changes in observation procedures or in an instrument's environment may also occur during the 30-year period. The NOAA accounted for documented and undocumented anomalies in calculating its SCMT.[82] The meteorological and statistical procedures used in the NOAA's homogenization for removing documented and undocumented anomalies from the T_{max} and T_{min} monthly temperature series is explained in a peer-reviewed publication.[83]

Subsequent to determining the homogenized monthly temperature time series described above, NOAA also calculates monthly normal temperature variables based on a 30-year normal period, e.g. maximum, minimum, and average temperatures. These monthly normals are not directly usable for Staff's purposes, because the NOAA daily normal temperatures values are

[80] Retrieved on October 17, 2013, https://www.ncdc.noaa.gov/data-access/land-based-station-data/land-based-datasets/climate-normals.

[81] 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.

[82] 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.

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

derived by statistically "fitting" smooth curves through these monthly values.[84] As a result, the NOAA daily normal values reflect smooth transitions between seasons and do not directly relate to the 30-year time series of MDT as used by Staff. However, in order for Staff to develop adjustments to normal weather for electric usage, Staff must calculate a set of normal daily temperature values that reflect the actual daily and seasonal variability.

Staff used a ranking method to calculate normal weather estimates of daily normal temperature values, ranging from the temperature that is "normally" the hottest to the temperature that is "normally" the coldest, thus estimating "normal extremes." Staff ranked MDTs for each month of the 30-year history from hottest to coldest and then calculated the normal daily temperature values by averaging the ranked MDTs for each rank, irrespective of the calendar date. The ranking process results in the normal extreme being the average of the most extreme temperatures in each month of the 30-year normals period. The second most extreme temperature is based on the average of the second most extreme day of each month, and so forth. Staff's calculation of daily normal temperatures is not the same as NOAA's calculation of smoothed daily normal temperatures because Staff calculated its normal daily temperatures based on the rankings of the actual temperatures of the test year, and the test year temperatures do not follow smooth patterns from day to day.[85] More details of a ranking method for normal weather are explained in a peer-reviewed publication.[86] Using these normal daily temperatures, Staff calculated normal MDT for each day of the test year. Staff then used this information for weather normalization of the test year kWh usage and update period hourly loads.

Staff Expert/Witness: Michael L. Stahlman

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[84] A more detailed description is discussed in Won, S. J., Wang, X. H., & Warren, H. E. (2016). Climate normals and weather normalization for utility regulation. Energy Economics, 54, 405-416.

[85] It is important to note that Staff's calculation of daily weather normal temperatures does 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.

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

Load Requirement at Transmission

Hourly load requirement is the hourly electric supply necessary to meet the energy demands of both the company's customers and the company's own needs. The hourly loads used in the analysis of the update period June 2020, through May 2021, were obtained from Empire's data provided in accordance with 20 CSR 4240-3.190 (1)(C).

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

Independent adjustments are necessary because average loads and peak loads respond differently to weather. Daily average load is calculated as the daily energy divided by twenty-four hours and the daily peak is the maximum hourly load for the day. Separate regression models estimate both a base component, which is allowed to fluctuate across time, and a weather-sensitive component, which measures the response to daily fluctuations in weather for daily average loads and peak loads. The regression parameters, along with the difference between normal and actual cooling and heating measures, are used to calculate weather adjustments to both the average and peak loads for each day. The adjustments for each day are added respectively to the actual average and peak loads for each day. Staff witness Michael L. Stahlman provided actual and normal daily temperatures used in this analysis.

The starting point for allocating both the weather-normalized daily peak and the weather- normalized average loads to the hours is the actual hourly loads. A unitized load curve is calculated for each day as a function of the actual peak and average loads for that day. The corresponding weather-normalized daily peak and average loads, along with the unitized load curves, are used to calculate weather-normalized hourly loads. This process includes many checks and balances, which are included in the spreadsheets that are used. In addition, the analyst is required to examine the data at several points in the process. For more information, the process is described in greater detail in the document "Weather Normalization of Electric Loads, Part A: Hourly Net System Loads."[87]

Once Staff's normalized, annualized test year usage for Empire's retail customer classes is completed, weather-normalized wholesale usage is added. Then, the non-LTS class annual usage was increased by the average annual loss factor supplied by Staff witness Alan J. Bax. The LTS class' annualized usage was added to the non-LTS annual usage to produce an annual sum of the hourly load requirement that equals the adjusted test year usage and is consistent with Staff's normalized revenues.

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

Staff Experts/Witness: Michael L. Stahlman

COVID-19 Usage Normalization

Staff included additional variables in the weather normalization regression analysis to estimate the impact of COVID-19 on usage. The variables used include a dummy variable for the time period after COVID-19 (i.e., a "1" for March 23, 2020, and after and a "0" for all prior dates) and other variables that were developed using Google mobility data for the state of Missouri. Google monitored the locations of cell phones and provided an estimate of how much time people spent at various locations compared to a base of February 14, 2020. This data was made available to assist public health officials in making policies concerning COVID-19.[88]

The categories provided are the change in time spent at retail/recreation, grocery/pharmacies, parks, in transit, at work, and at home. Staff included the change in time spent at home in the residential weather normalization regression analysis and the change in time spent at work in the SGS, LGS, SPS, and LPS weather normalization regression analyses to estimate the impact of COVID-19 on those customer classes. The variable was forced to

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[87] "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.

[88] COVID-19 Community Mobility Reports. (2021) https://www.google.com/covid19/mobility/ (8/11/2021).

equal 1 prior to March 15, 2020, since the changes in activity prior to that date were largely unrelated to the virus. The variable was smoothed by using the average of the prior three days (residential) or seven days (work) to account for weekends and other fluctuations. The resulting regression analysis generally indicated that COVID-19 had an impact on customer usage and that this impact is ongoing; e.g. usage has not returned to pre-COVID-19 levels.

Staff normalized the usage for COVID-19 by assuming that continuing customer usage would more likely reflect the latter months of Staff's update period (i.e., a "new normal") rather than the period before March 2020. The Google mobility data indicates that customers continue to spend less time at work and more time at home when compared to the time before the pandemic. This is likely due to many of Empire's customers continuing to have the work-from-home option through the update period. The results of this analysis were given to Staff witness Kim Cox as part of the weather normalization factors.

Staff Experts/Witness: Michael L. Stahlman

B. Other Revenues

1. FAC Revenues

Staff removed from test year revenues, the Fuel Adjustment Clause (FAC) revenues. This adjustment is necessary to in order to calculate new retail rates.

2. Unbilled Revenues

Staff has eliminated unbilled revenue from its determination of revenue requirement to ensure only 365 days of revenue are included and to reflect revenues on an "as billed" basis. The recording of unbilled revenue on the books of the Company recognizes sales of electricity that have occurred, but have not yet been billed to the customer. Therefore, it is necessary for Staff to remove unbilled revenue in order to reach an accurate revenue requirement based upon electricity sales billed to and revenues collected from Missouri customers.

3. Gross Receipts Revenues

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

4. Renewable Energy Credits

Empire is currently receiving wind energy from ** [redacted] **. As a result of these contracts, Empire receives Renewable Energy Credits or Certificates ("RECs"), which are credits issued under the Center for Resource Solutions' "green-e" program to certify that one megawatt-hour of electricity has been generated by a facility engaged in the production of renewable energy, such as wind, solar or biomass. RECs are tradable and can be bought and sold. Staff's analysis reflected a review of these revenue levels over a five-year period ending June 30, 2021. Because there is no discernable upward or downward trend, Staff has used a five-year average ending June 30, 2021. Staff also removed any non-Missouri jurisdictional accounts from REC revenues.

5. Coal Fly Ash Revenues

"Coal fly ash" is a byproduct created as a result of the burning of coal in generating stations to produce electricity. Over the past several years, Empire has been selling its fly ash to several different industrial companies to be used in concrete. Staff's analysis reflected a review of these revenue levels over a five-year period ending June 30, 2021. There has been a downward trend over the past five years, with no revenues at all in the year ending June 30, 2021. Since the Asbury coal fired plant was de-designated from the SPP market in March 2020, Empire does not expect this revenue stream to exist again in the future. Staff has reduced the test year amount to zero to reflect no revenue for sales of coal fly ash.

6. Miscellaneous Revenues

Empire's miscellaneous other revenues consist of forfeited discounts, rents from property, reconnect, and surge arrester fees. Staff's analysis reflected a review of these revenue levels over a five-year period ending June 30, 2021. Because there is no discernable upward or downward trend, Staff has used a five-year average ending June 30, 2021.

Staff Expert/Witness: Caroline Newkirk

C. Amortizations

1. Amortization of Ice Storms

Empire booked ice storm amortizations from Kansas that are not allowed for recovery in Missouri. Therefore, Staff made an adjustment of ($24,325) to eliminate the amortized amount of the ice storm amortizations from Kansas that were included in the starting point of this case.

Staff Expert/Witness: Angela Niemeier

2. SWPA Amortization

As described previously in this Report, in Case No. ER-2011-0004, Empire agreed to flow the SWPA payment back to its customers over a ten-year period via a tracker mechanism. This yearly amortization, unlike other amortizations discussed in this Report, does not increase the Company's expense levels, but is a reduction or offset to expenses. The SWPA amortization ended September 2020. Therefore, Staff proposes an adjustment of ($300,725) to remove the amortization from test year.

Staff Expert/Witness: Angela Niemeier

3. DSM Cost Recovery

Empire's Account 182318 contains costs of the Company's demand-side management (DSM) programs that are in various stages of development and implementation. The DSM costs include the payments to Empire's customers that participate in the programs. Staff participated in the previously authorized (and now expired) Customer Programs

Collaborative (CPC) and participates in the current authorized DSM advisory group established to assist Empire in the development of DSM programs. Based upon Staff's participation in these groups, as well as Staff's review of the costs in Account 182318, Staff has amortized the amounts incurred by Empire prior to the end of its Regulatory Plan (June 15, 2011) over ten years. Any amounts incurred after the end of the Regulatory Plan to date are amortized over a period of six years, consistent with the terms of the Commission's *Report and Order* in Case No. ER-2014-0351. Staff has removed the amortization of program expenditures from years that are fully expired as of June 30, 2021.

Staff Expert/Witness: Caroline Newkirk

4. Amortization of Electric Plant

Staff adjusted the amortization reserve for electric plant intangible assets to reflect the updated balances through June 30, 2021, which is the end of the update period for this case. The amortization reserve balance as of June 30, 2021, is $30,783,862 and was included as an offset to rate base in Staff's Accounting Schedule 2.

Staff Expert/Witness: Angela Niemeier

5. Amortization of PeopleSoft Intangible Asset

Staff adjusted the intangible asset for the PeopleSoft software costs to reflect the updated balances through June 30, 2021. The regulatory asset balance, as of the end of the update period June 30, 2021, is $39,129 and was included as an addition to rate base in Staff's Accounting Schedule 2.

The amortization for this asset ends September 30, 2022. Currently, Empire amortizes $2,609 monthly for PeopleSoft. Staff proposes to decrease the monthly amortization to align with the 3-year rate case cycle. When the new rates for this case take effect in April 2022, the intangible asset for PeopleSoft balance will be $15,652. Staff proposes decreasing the monthly amortization to $434 beginning April 2022. If this adjustment does not occur, the Company will over recover $78,258 before the next rate case, providing the Company files again in 3 years.

Staff Expert/Witness: Angela Niemeier

6. Amortization Expense

Staff reviewed the Company's workpapers for amortization expense. Staff analyzed these accounts and made an adjustment of $2,455,377 increase to this expense to reflect the annualized amortizations based on updated information through June 30, 2021.

Staff Expert/Witness: Angela Niemeier

7. Tornado AAO Amortization

The Commission issued an order on November 30, 2011, that approved and incorporated the Stipulation and Agreement in Empire's Application for an Accounting Authority Order ("AAO") in Case No. EU-2011-0387. In that Stipulation and Agreement, the parties agreed to allow Empire to defer to Account 182.3 Other Regulatory Assets the following items: incremental operations and maintenance expenses associated with the repair, restoration and rebuild activities associated with the May 22, 2011 tornado; and depreciation and carrying charges equal to its ongoing Allowance for Funds Used During Construction rates associated with tornado-related capital expenses. The Company agreed that if it filed a general rate case in Missouri by June 1, 2013, then Empire would begin to amortize over a ten year period the deferral balance beginning at the earlier of: 1) the effective date of new rates implemented in its next general rate case or rate complaint case; or 2) June 1, 2013. As of June 30, 2021, Empire had a deferred balance of $704,401 in Account 182.3 for tornado related expenses, which has been included in rate base. After reviewing the information provided, Staff found that the ten year amortization period will end around the time the next rate case is expected to be filed (April – May 2025). Therefore, Staff amortized the remaining balance as of the operation of law date in this case (April 2022) over three years.

Staff Expert/Witness: Amanda C. McMellen

8. Iatan Carrying Costs Amortization

Pursuant to earlier agreements, Empire deferred certain carrying costs (monthly debt and equity-derived carrying charges) and monthly depreciation for its Iatan 1 AQCS Account 182308 – Iatan Deferred Carrying Costs, Iatan 2 Account 182332 – MO IatanII Df Chg ER-2010-0130, and Plum Point Account 182331 – MO PlumPt Df Chgs ER-2010-0130.

This deferral of carrying costs on the Iatan 1 AQCS, Iatan 2, and Plum Point investments was authorized under previous agreements approved by the Commission. In Empire's Case No. ER-2012-0345, Staff recommended amortization of these carrying costs into the cost of service using a composite amortization rate derived from dividing the total depreciation expense for each plant by the total plant balance for each plant. Staff used these composite rates and calculated amortization amounts of $84,729 for Iatan 1 AQCS, $44,828 for Iatan 2, and $1,987 for Plum Point. Staff used the same amortization amounts in this case.

Staff Expert/Witness: Angela Niemeier

9. Low Income Pilot Program Amortization

In the prior rate case, Case No. ER-2019-0374, in its direct filing, Staff inadvertently omitted the unamortized balance of the Low Income Pilot Program (LIPP) carried over from Case No. ER-2016-0023 and also omitted the amortization of the asset. Staff included both of these in its true-up revenue requirement to reflect the unamortized balance as well as the amortization. Staff included $250,000 for the unamortized balance, the cap ordered by the Commission in Case No. ER-2016-0023. For the regulatory asset, Staff recommended a six-year amortization period. Per the Stipulation and Agreement in Case No. ER-2016-0023, if the Commission ordered a LIPP then the cost of the program was to receive regulatory/rate base treatment as Demand Side Management ("DSM") costs. Under the Stipulation and Agreement, the DSM costs are to be amortized over six years. Staff also recommended the $250,000 cap be removed and Empire be allowed to track costs above or below that amount. In the Global Stipulation and Agreement for the last rate case, it was agreed between the parties the Company's LIPP would remain in place with no changes made in that case, and the Company would track all costs until the next rate case.

Staff reviewed the tracked costs in this rate case and has included the correct amount of $286,109 in rate base and a new annual amortization expense amount of $47,685 in the revenue requirement. Kory J. Boustead addresses Staff's recommendations for the continuation of the program in Section VII.H., subsection 19 of this report.

Staff Expert/Witness: Keith D. Foster

10. PISA Amortization

On June 1, 2018, Senate Bill 564 was signed into law, which allows investor-owned electric utilities in the State of Missouri the option to defer 85% of all depreciation expense and return associated with qualifying electric plant that was recorded to plant-in-service as a regulatory asset on or after the date the utility elects to use PISA. PISA accounting is applicable to plant additions between the date they are booked to plant-in-service accounts and the date such additions are reflected in utility rate base in a general rate proceeding. Qualifying plant for the purposes of the PISA deferral is all rate base additions that are not new nuclear generating units, coal-fired generating units, new natural gas units or rate base additions that increase revenues by allowing service to new customer premises. In each general rate case after election of PISA, the balance of the regulatory asset must be amortized over 20 years and the unamortized balance is included in rate base and allowed to earn a return. Any utility that elects the PISA deferral must file every year on February 28th a five-year capital investment plan with the Commission, with specific capital investments detailed within the plan. Additionally, in the years after filing the first five-year capital investment plan, the utility must also submit an annual report detailing the actual capital investment from the prior year. For the first five years after the election of PISA, the purchase and installation of smart meters cannot be more than six percent of the total capital expenditures for any given year under the electric company's Capital Investment Plan. At least 25% of the capital investment included in the plan must be for grid modernization projects. PISA remains in effect until December 31, 2023; however, electric utilities may request the Commission approve a five-year continuation prior to the cutoff date. Any existing balances that remain after the expiration of the PISA option would continue to be amortized and recovered through base rates by the electric utility.

Empire filed its election to use PISA on August 12, 2020, as part of Case No. EO-2019-0046. On February 26, 2021, Empire submitted a five-year capital investment plan entitled "Liberty's Clean Transition Plan" in compliance with PISA requirements as part of Case No. EO-2019-0046. This five-year capital investment plan detailed grid modernization project expenditures that meet the minimum 25% of the planned capital expenditure for each year from 2021 to 2025.

At the time Empire filed its PISA election, it established a regulatory asset account on its books and has recorded 85% of depreciation expense on eligible plant additions as well as a return applied to the net qualifying plant balance. As part of this rate case, Staff examined the amounts included in Empire's deferred regulatory asset account during the period covering August 1, 2020, through the June 30, 2021, update period. With one potential exception, Staff determined the deferred PISA amounts comply with the new law. As a part of its review, Staff recently discovered a set of additions and retirements listed as "Eligible for PISA as Grid Modernization" related to connecting a new customer for which Staff questions its eligibility for PISA treatment. Staff submitted a Data Request No. 0240.1 to the Company to determine the nature and eligibility of these additions and retirements, and, if necessary, will update its revenue requirement for rebuttal. Staff has included an annual amortization amount of $629,868 in its cost of service calculation as part of a twenty-year amortization. Staff also included the unamortized balance of $12,597,366 of this regulatory asset in rate base consistent with the new law. Eligible PISA amounts incurred subsequent to June 30, 2021, will again be deferred in a new regulatory asset account until the true-up cutoff established by the Commission in Empire's next rate proceeding for inclusion in base rates established in that future rate case.

Staff Expert/Witness: Keith D. Foster

11. Amortization of Excess ADIT

Tax Cut and Jobs Act

The Tax Cuts and Job Act (TCJA) was signed into law in December 2017, and as part of that law, a reduction in federal corporate tax rate from 35% to 21% required the revaluation of previously recorded accumulated deferred tax timing differences. Also, effective January 1, 2020, the Missouri state corporate tax rate was reduced from 6.25% to 4%. This also caused a need for additional revaluation of accumulated tax timing differences.

The excess federal deferred tax value is required to be returned to customers over a time period determined by whether the excess deferred taxes are protected or unprotected. Protected excess accumulated deferred income tax (ADIT) is the portion associated with accelerated depreciation tax timing differences that must be "normalized" for ratemaking purposes.

The flow back of excess ADIT cannot be returned to customers any more quickly than over the estimated remaining life of the assets that gave rise to the ADIT. Unprotected federal excess ADIT is the portion of the deferred tax reserve that resulted from normalization treatment of tax timing differences other than accelerated depreciation. Unprotected federal excess ADIT is to be flowed back to customers over a period of time set by the Commission, at its discretion.

There is no distinction between protected and unprotected status for state excess ADIT. The entire balance of that amount can be flowed back to customers over a period of time set by the Commission, at its discretion.

In Empire's previous rate case (ER-2019-0374), the Commission ordered Empire to amortize the Missouri jurisdictional unprotected portion of excess ADIT ($25,661,649) over a 3 year period and the Missouri jurisdictional protected portion ($101,146,004) of excess ADIT was amortized using the average rate assumption method (ARAM) to match depreciation deductions for booked and tax purposes on each individual asset over the life of the asset. Staff recommends continuing the 3-year amortization of the unprotected portion of the excess ADIT ($8,540,550). Staff recommends including in the cost of service an annual amortization of $3,178,977 for the protected portion of the excess ADIT, which is the amount of amortization calculated using ARAM for calendar year 2022. In Empire's direct filing, Empire uses the 2021 ARAM amortization amount. However, since rates from this rate proceeding will not become effective until April 25, 2022, Staff has determined that the 2022 ARAM amortization amount is appropriate to use.

Excess ADIT for Asbury

Empire retired the Asbury generating plant on March 1, 2020. Empire reclassified the excess ADIT (EADIT) related to Asbury into a separate regulatory liability account, in the amount of $16,055,610, which is Asbury's portion of the EADIT. Empire recommends amortizing this amount over 26 years, which is also the same time period that Empire recommends amortizing the regulatory asset related to the retirement of Asbury. Staff recommends amortizing the regulatory asset for the EADIT related to Asbury over a 15-year period. This is also the same time period that Staff is recommending amortizing the regulatory asset and liability created due to the retirement of Asbury. This results in an annual amortization of $1,070,374.

TCJA tax stub period

In Empire's previous rate case (ER-2019-0374) the Commission ordered:

> The Commission finds that the stub period revenue, the TCJA $11.7 million regulatory liability established in File No. ER-2018-0366, shall be amortized as a reduction to Empire' total amortization expense over five years with no rate base offset for the unamortized amount.

During the test year, Empire recorded $97,737 in Account 403014 for this amortization. Staff has adjusted the amortization expense to reflect a full year of amortization expense ($2,345,691) for this regulatory liability.

Tax Tracker

Empire has requested a Tax Tracker for EADIT and any future tax changes. Staff recommends establishing a tracker to capture the differences between protected EADIT returned to customers as part of the revenue requirement in this case, and the actual amortization recorded by the Company using ARAM for protected EADIT balances. Staff also recommends a tracker for the unprotected 3 year amortization period for non-stub period unprotected EADIT balance. However, Staff does not recommend including any future tax changes in this tracker. If a tax change occurs, the change will need to be evaluated and the proper ratemaking can be determined in a future case. Staff proposes that the EADIT tracker work mechanically just like all other past trackers, with the tracked to be amortized over a period of time to be decided in a future case, and included in the cost of service at that time.

Staff Expert/Witness: Kimberly K. Bolin

D. Fuel & Purchased Power

1. Fixed Costs

Staff does not include fuel and purchased power costs that do not vary directly with fuel burned in its fuel model. These costs are determined separately. The non-variable fuel costs included in fuel expense are typically referred to as fuel adders. The non-variable purchased power costs are referred to as capacity charges and these costs are annualized separately from purchased power energy costs.

Staff Expert/Witness: Amanda C. McMellen

a. Fuel Adders

The costs of fuel adders are determined separately from fuel model costs and are added to the level of fuel expense calculated by the model to determine overall fuel expense. The fuel adders in this case are natural gas transportation costs. Staff annualized the natural gas transportation expense based on Empire's current contractual obligations with Southern Star Central Gas Pipeline, which began on January 1, 2010.

Staff Expert/Witness: Amanda C. McMellen

b. Purchased Power – Capacity Charges

In addition to its ownership interest in the Plum Point unit through Plum Point Energy Associates, LLC, Empire contracts for a reservation of 50 MW capacity from Plum Point. For this 50 MW of power, Empire pays for a fixed component and an energy component. The fixed amounts Empire pays are referred to as capacity charges. Generally, there is an amount for Plum Point operation and maintenance costs included within the energy charge. The fixed component is paid as a "demand charge," generally on a monthly basis, regardless of the level of power actually purchased. This amount is for the "right" to purchase the power in much the same way that natural gas utilities purchase reservation of capacity from pipelines through reservation payments. The demand charges are intended to cover part of the fixed expenses of operating a generating facility.

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

Staff Expert/Witness: Amanda C. McMellen

c. Fuel Prices

Generally, Staff computes its level of fuel expense using prices and quantities contracted by Empire for delivery during the test year and update period. These fuel prices include prices for coal, natural gas, and oil, as well as associated transportation charges.

Staff Expert/Witness: Amanda C. McMellen

d. Coal Prices

Staff determined its coal price by generation facility based on a review and analysis of Empire's current coal purchase and coal transportation contracts. For the Plum Point unit, Staff's recommended coal prices reflect the actual contracted coal purchase and transportation prices in effect for 2021. For the Iatan 1 and 2 units, Staff recommended coal prices reflect Evergy Metro's projected weighted average contracted coal purchase and transportation prices for 2021.

Staff Expert/Witness: Amanda C. McMellen

e. Natural Gas Prices

The natural gas price recommended in this case by Staff of $2.42 per MMBtu is composed of two components: hedged and non-hedged ("spot") prices. Staff calculated the non-hedged component of natural gas prices using a twelve-month weighted average of Empire's actual commodity cost of natural gas purchased on the spot market during the twelve months ending June 30, 2021. The weighted average price for the non-hedged component is $2.401 per MMBtu. Staff calculated the hedged component of natural gas costs by applying a weighted average for the actual hedged purchases contracted for at June 30, 2021, that is applicable to Empire's forecasted gas needs for the twelve months ending September 30, 2019. The weighted average price for the hedged component is $2.445 per MMBtu. Staff weighted the hedged gas price at 44% of its overall gas price recommendation, as Empire has contracted to meet approximately 44% of its projected natural gas usage from July 2020 through June 30, 2021, with hedged gas supplies. Empire's natural gas transportation costs are annualized and normalized separately as a part of fuel adders.

Staff Expert/Witness: Amanda C. McMellen

f. Fuel Oil Prices

Staff used a weighted average price of 1,337.13 cents per MMBtu to determine the fuel oil cost input in the fuel model in this case. Staff calculated this weighted average price by: (1) converting each month's number of barrels purchased over a 13-month period into gallons; (2) dividing a total month's purchase in gallons by that month's total purchase costs to derive an average monthly price per gallon; (3) summing the totals for the 13-month period to calculate a weighted 13-month average cost per gallon, which in this case is $1.863957; and (4) converting this per gallon price into the cents per MMBtu, which is 1,337.13. Empire burns fuel oil mainly as a secondary fuel or, in some instances, for flame stabilization. Empire does maintain onsite storage at its various facilities in sufficient capacity that only occasional purchases are necessary. As a result, Empire does not contract for or hedge oil costs.

Staff Expert/Witness: Amanda C. McMellen

2. Entergy Transmission Contract

Empire has a contract with Entergy Solutions, Inc. for firm point-to-point transmission service to transmit power generated from the Plum Point Energy Station to Empire. Staff included an adjustment that annualizes the cost of this service at the current contract rate effective June 30, 2021.

Staff Expert/Witness: Ashley Sarver

3. Heat Rate and Efficiency Testing

When an electric utility requests that a rate adjustment mechanism (RAM), such as a fuel adjustment clause (FAC), be continued or modified, 20 CSR 4240-20.090(2) (A) (15) states that the electric utility shall file as part of its supporting information of its general rate case direct filing:

> A level of efficiency for each of the electric utility's generating units determined by the results of heat rate/efficiency tests or monitoring that were conducted or obtained on each of the electric utility's steam generators, including nuclear steam generators, heat recovery steam generators, steam turbines and combustion turbines within twenty-four (24) months preceding the filing of the general rate increase case.

Heat rates of generating units are an indicator of each unit's performance. A heat rate is a calculation of total volume of fuel burned for electric generation multiplied by the average heat content of that volume of fuel for a given time period divided by the total net generation of electricity in kilowatt hours (kWh) for that same time period. Heat rates are inversely related to the operating efficiency of the generating unit. Increasing heat rates of specific units over time may indicate that a specific unit's efficiency is declining. Heat rates can vary greatly depending on operating conditions, including but not limited to load, hours of operation, shutdowns and startups, unit outages, derates,[89] and weather conditions. Therefore, a good indication of unit performance for a utility's frequently used units is an analysis of the trend of heat rates over time.

Empire witness Zachary Quintero filed the results of the most recent heat rate/efficiency tests for Empire's generating units in schedule ZQ-07 of his direct testimony. Staff reviewed those results and found them to be reasonable based on comparisons with data filed in previous general rate case proceedings and known changes in power plant operating parameters. Staff found all of the testing dates Empire submitted to be in accordance with the twenty-four (24) month requirement of 20 CSR 4240-20.090(2)(A)(15).

Staff Expert/Witness: Jordan T. Hull

4. Market Prices

For this proceeding, Staff continues to use multiple sets of market prices within its production cost model. Beginning in Empire's previous rate case, ER-2019-0374, Staff modified its production cost model to use different market prices at different locations within Empire's territory. That change brought Staff into greater alignment with the production cost model used by Empire and allowed for a more direct comparison of model results. Within the Southwest Power Pool (SPP) market, physical locations at which electrical equipment and components are connected are described as "nodes." Market conditions such as changing energy demand from customers, differing levels of generation at power plants, transmission constraints, and even variable weather conditions result in a range of different prices across the nodes located throughout Empire's territory. Those different market prices at different nodes represent the sale and/or purchase price for electricity on a dollar-per-megawatt-hour basis. Power plants sell their energy at those prices and customer load is purchased at those prices. For each hour of its simulation, the production cost model will economically dispatch each coal or natural gas-fired power plant based on the individual operating characteristics of each unit, the cost of fuel, and the hourly market price at the associated node. Due to the intermittent nature of renewable resources such as wind farms or hydroelectric facilities and their limited ability to be dispatched in the same way as coal or natural gas-fired power plants,

[89] Derate- To lower the rating of (a device), especially because of a deterioration in efficiency or quality.

the market prices in Staff's production cost model are not used to determine the amount of generation at those facilities. For renewable resources, Staff's model uses predefined generation profiles based on historical information when available or, in the case of new facilities, reasonable estimates based on the best available data. The market prices at the nodes associated with renewable energy facilities are only used to calculate market revenues from the sales of electricity.

In order to account for the variability of market prices, Staff developed a normalized set of prices by averaging three years of market data, ending May 31, 2021. A look-back period of three years is considered by Staff to be long enough to provide enough data to generate reasonable averages while still remaining short enough to reflect current market conditions. Starting in June 2021, SPP changed Empire's generating and load nodes. To maintain a consistent data set in which all of Empire's market nodes remained the same, Staff chose to end its three-year review of market prices in May 2021. Additionally, Staff slightly altered its method of averaging market prices due to the effects of Winter Storm Uri in February 2021. Market prices in February of 2021 were exceptionally high and resulted in unreasonable results when included in the calculation of a three year average. Therefore, Staff based the February market prices for its production cost model on the average of February market prices from 2019 and 2020 only. Using only two years of data for February for the calculation of market prices is consistent with the method used by Staff in Case No. ER-2021-0240 for Ameren Missouri. It also is consistent with the method used by Staff for the calculation of the natural gas prices used in this case.

5. Planned and Forced Outages

Planned and forced outages are infrequent in occurrence and variable in duration. In order to capture this variability, power plant outages were normalized by averaging seven years of data that Empire provided to comply with 20 CSR 4240-3.190[90] and supplemental information provided in response to a Staff data request.[91] For each coal or natural gas-fired

[90] 20 CSR 4240-3.190 requires that every electric utility in Missouri provide monthly reports to Staff that contain information about the operations of power plants, including, in part, "All generating unit outages and derates," and, "Planned outages of power production facilities."

[91] Case No. ER-2021-0312, Empire Response to Staff Data Request No. 0144.

power plant, an equivalent forced outage rate and scheduled maintenance outage duration was calculated based on that data.

The outages defined for each power plant represent times that they are unavailable for dispatch within the market. Planned outages are scheduled during times of expected lower energy demand in order to minimize the impact of the temporary loss of generating capacity. Unplanned outages are applied in a random pattern to mimic the unforeseen nature of faults that may force a power plant offline.

6. Contract Prices and Energy

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

7. Variable Fuel Expense

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

In this case, Staff's model meets all load requirements through market purchases at a defined load node. Simultaneously, each coal or natural gas-fired power plant is dispatched according to its own set of market prices. In each hour of the simulation, the total generation from all sources is then summed and compared against the purchased energy required to satisfy load. If total generation exceeds purchased energy, then net sales are recorded for that hour. Conversely, if total generation is less than purchased energy, net purchases are recorded. In that way, net sales and purchases within the market are determined for each hour of the simulation.

Staff relied on data provided in Empire's workpapers for many of the operating characteristics and dispatching strategies of the coal and natural gas-fired power plants in Empire's portfolio. These include maximum and minimum capacity, heat rate, primary fuel type, start-up fuel type, ramp rates, start-up costs, minimum up time, minimum down time, and variable operating and maintenance expense. Staff updated or separately calculated values for operating and market characteristics such as market prices, generation at renewable energy facilities, and planned and forced outage rates as described above.

Staff estimates the variable fuel and purchased power expense for Empire for the update period, ending June 30, 2021, to be $49,627,797. This value includes revenue from net sales made in the integrated marketplace.

The variable fuel and purchased power expense from Staff's production cost model is significantly lower than what was calculated in Empire's previous rate case, ER-2019-0374. This is due to the decrease in fuel expense related to the retirement of Asbury and to the addition of the revenues from the North Fork Ridge, Kings Point, and Neosho Ridge wind farms. Due to the way that production cost models operate, none of the capital expenses from power plant construction are reflected in the results. Instead, only the costs of fuel, the costs of purchased power, and the revenues from the sales of electricity are calculated. As a result, since wind farms do not have fuel expenses, only the revenues from their energy sales are factored into the final results. Necessarily, those revenues offset the costs of fuel and purchased power, decreasing the final variable fuel and purchased power expense.

Staff Expert/Witness: Charles T. Poston, PE

E. Payroll and Benefits

1. Payroll, Payroll Taxes, and 401(K)

Staff adjusted Empire's test year payroll expense to reflect annualized levels of payroll, payroll taxes, and 401(k) benefit costs as of June 30, 2021. Staff calculated a reasonable overtime payroll level for each Empire employee by multiplying the overtime percentage computed for the non-union and union employees by the base payroll as of June 30, 2021. The overtime percentage was computed based upon a two-year average of overtime hours and costs incurred compared to total hours and costs incurred.

Staff determined an allocation rate between expense and construction based on a three year operation and maintenance (O&M) average, Staff then distributed the total amount of the adjustment to individual Federal Energy Regulatory Commission Uniform System of Accounts (FERC USOA) accounts, based upon the actual distribution experienced for the twelve months ending June 30, 2021. Staff's Accounting Schedule 10, Adjustments to the Income Statement, reflects all payroll adjustments, segregated by the FERC USOA account, to reflect Staff's total adjustment required to restate the test year payroll to an annualized level as of June 30, 2021. Staff's calculation for total payroll is $50,237,598.

Staff calculated payroll taxes based upon June 30, 2021 wage levels and current tax rates. This included Federal Unemployment Taxes (FUTA), State Unemployment Taxes (SUTA), and Federal Insurance Contributions Act (FICA) tax. Staff's calculation for payroll taxes is $4,054,663.

The Company's 401(k) benefit costs were annualized by applying Empire's actual 401(k) match rate for each employee to the annualized payroll as of June 30, 2021. Staff's calculation for 401K benefit costs is $1,552,130.

Staff Expert/Witness: Caroline Newkirk

2. Employee Benefits

Empire currently offers its employees Dental, Vision, Healthcare, and Life Insurance benefits. Staff performed an analysis of the employee benefit costs included in Account 926, which is associated with employee pensions and benefits, from the general ledger. Staff annualized each expense by examining the individual costs over a 36-month period to determine the appropriate amount to include for each expense. Staff used a three-year average through the update period to annualize these expenses through June 30, 2021. Staff's adjustment for total employee benefits other than pensions and other post-employment benefit (OPEBs) is $519,259.

Staff Expert/Witness: Caroline Newkirk

3. FASB Accounting Standards Codification (ASC) 715-60 (formerly FAS 106)–Other Post-Employment Benefit Costs ("OPEBs")

In Case No. ER-2006-0315, the signatory parties entered into a *Non-Unanimous Stipulation and Agreement as to Certain Issues*, addressing the ratemaking treatment for annual other post-employment benefit costs (also known as "OPEBs") under FASB ASC Subtopic 715-60, formerly known as Financial Accounting Standard No. 106 (FAS 106). OPEBs primarily relate to medical benefits owed by Empire to Company retirees. The 2006 agreement was later modified by the *Stipulation and Agreement as to Certain Issues* reached in Case No. ER-2008-0093, *Non-Unanimous Stipulation and Agreement* in Case No. ER-2010-0130, *Global Agreement* in Case No. ER-2011-0004, *Non-Unanimous Stipulation and Agreement* in Case No. ER-2012-0345, *Revised Stipulation and Agreement* in Case No. ER-2014-0351, *Stipulation and Agreement* in Case No. ER-2016-0023 and *Amended Report and Order* in Case No. ER-2019-0374. (Collectively, Staff will refer to the *Stipulations and Agreements* regarding OPEB expense ratemaking from the 2006 rate case to the current case as the "OPEB Agreements.") These OPEB Agreements were intended to ensure that the amount collected in rates for OPEBs were based on the FAS 106 cost recognized by the Company for financial reporting purposes, using a methodology similar to that used to determine FAS 87 pension cost. In addition, the OPEB Agreements were intended to ensure that Empire contributed the full amount of the OPEB expenses it collected in rates into an external trust fund. The OPEB Agreements also called for the use of a OPEBs tracker mechanism to quantify the difference over time in the OPEBs rate allowance provided to the Company, and the Company's annual actual OPEBs expenses under FAS 106.

In this case, Staff has complied with the terms agreed upon by the signatories to OPEB Agreements approved by the Commission in Empire's last seven electric rate cases for ratemaking treatment of OPEBs costs. Empire's OPEB costs in this case were based upon the Company's actuary report from CBIZ Cottonwood for the fiscal period ending December 31, 2021 (report dated September 2021). The results of Staff's review of Empire's OPEB costs to date are as follows:

1. The Company's ongoing FAS 106 cost recognized in rates in this case is $4,811,940.

2. Empire has over-recovered its FAS 106 expense in rates compared to its actual level of expense since the Company's last rate case. The balance in the regulatory liability account as of June 30, 2021, was ($850,461), which is to be amortized over five years as a reduction to expense in the amount of ($170,092).

3. Rate base is reduced by the level of regulatory liability associated with Empire's ongoing OPEBs tracker mechanism, currently $850,461.

Staff Expert/Witness: Ashley Sarver

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

In Case No. ER-2004-0570, Staff, Empire, and other parties entered into *a Stipulation and Agreement as to Certain Issues*, addressing, among other items, the ratemaking treatment for annual pension cost under FASB's ASC Subtopic 715-30, formerly known as Financial Accounting Standard No. 87 ("FAS 87"). Staff will refer to pension accounts as FAS 87 and FAS 88 in this report. This agreement, and thus treatment of annual pension cost, was later modified by each case, *Stipulation and Agreement as to Certain Issues* reached in Case No. ER-2008-0093, *Non-Unanimous Stipulation and Agreement* in Case No. ER-2010-0130, *Global Agreement* in Case No. ER-2011-0004, *Non-Unanimous Stipulation and Agreement* in Case No. ER-2012-0345, *Revised Stipulation and Agreement* in Case No. ER-2014-0351, *Stipulation and Agreement* in Case No. ER-2016-0023 and *Amended Report and Order* in Case No. ER-2019-0374. (Collectively, Staff will refer to the *Stipulations and Agreements* regarding pension expense ratemaking from the 2004 rate case to current as the "Pension Agreements"). These above-referenced Pension Agreements provide for Empire to generally have its pension rate allowance set equal to its most current annual level of pension expense as calculated under FAS 87. Furthermore, these agreements established a tracker mechanism for Empire's pension expense, in which any excess or deficit in the Company's pension rate allowance, as compared to its ongoing levels of FAS 87 expense, is to be treated as a regulatory asset or liability. The resulting pension tracker regulatory asset or pension tracker regulatory liability is then to be included in Empire's rate base, and amortized as an addition or reduction to pension expense over a five-year period.

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

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

Additionally, Staff has included a prepaid pension asset (PPA) in rate base in the amount of $24,548,069. The PPA represents the cumulative amount of pension contributions in excess of actual costs as of June 30, 2021. These contributions were made to prevent the pension plan from becoming "at-risk" as defined under the Pension Protection Act, and to meet the obligations of the Pension Benefit Guarantee Corporation.

Empire's pension costs in this case were based upon the Company's actuary report from CBIZ Cottonwood as of December 31, 2021 (report dated September 2021). The results of Staff's review to date of Empire's pension costs are as follows:

1. The Company's ongoing FAS 87 expense recognized in rates in this case is $6,802,606.

2. Empire has under-recovered its FAS 87 expense in rates compared to its actual level of expense since the Company's last rate case. The balance in the Regulatory Asset account at June 30, 2021, was $11,792,698, which is to be amortized over five years as an expense in the amount of $2,358,540.

3. The FAS 88 settlement adjustment in the amount of $11,576,868 is to be amortized over five years as an expense in the amount of $2,315,374. As of June 30, 2021, the amortized amount is $9,647,390.

4. The amount to be included in rate base for Empire's ongoing pension expense tracker mechanisms, accounted for as a regulatory liability is ($7,502,082).

5. Staff included an amount of $24,548,069 in Empire's rate base as a prepaid pension asset.

Staff Expert/Witness: Ashley Sarver

5. Incentive Compensation

Staff reviewed Empire's portfolio of employee incentive compensation plans. In the past, Empire had one incentive plan, the Management Incentive Compensation Program (MIP). Through the MIP, Empire offered awards to its senior officers for achieving goals. However, when Liberty merged with Empire in 2017, the structure of Empire's incentive compensation plans changed. There is now one LTIP and two short term incentive plans, the Shared Bonus Pool (SBP) and the STIP. Directors are eligible for the LTIP, management level employees are eligible for the STIP, and all other employees are eligible for the SBP. Empire's information technology team is eligible for both the STIP and SBP.

Staff proposes the following adjustments to the Company's incentive compensation expense.

a. Long Term Incentive Plan

Through the LTIP, senior officers are annually issued stock as part of their total compensation. In Empire's past rate cases, Staff recommended disallowance of LTIP benefits, because senior officers do not have specific goals to meet in order to be granted these stock options. These awards benefits Empire's shareholders, not Empire's ratepayers. Additionally, unlike other recognition expense in its income statement, Empire has no cash outlay for this equity-based incentive compensation. In this case, Staff eliminated stock options recognized as an expense, consistent with the Commission's *Report and Order* in Case No. ER-2006-0315.

b. Short Term Incentive Plans (SBP and STIP)

Empire uses both parent and division scorecards to determine the amounts employees receive under the SBP and STIP. In order to determine the appropriate amount of short term incentive plan costs to include in rate base, Staff reviewed the incentive metrics used to measure parental and divisional goals and the actual award received. Staff disallowed the part of all awards associated with the objective of meeting earnings per share targets, because this objective enhances the utility's stock price and benefits Empire's shareholders, not Empire's ratepayers.

Liberty calculates the STIP and SBP awards as follows:

STIP Incentive Plan Calculations:

> ***STIP Payout $*** *= Bonus Target % x Eligible Annual Base Salary x Proration Factor x STIP Factor*
>
> ***STIP Factor*** *= (Parent Scorecard Weight x Scorecard Achievement) + (Division Scorecard Weight x Scorecard Achievement) + (Personal Objectives Weight x Personal Achievement)*

SBP Bonus Plan Calculations:

> ***SBP Payout $*** *= $ Bonus Target % x Eligible Earnings x Pro ration Factor x SBP Factor*
>
> ***SBP Factor*** *= [(85% Parent Scorecard x Scorecard Achievement) + (15% Division Scorecard x Scorecard Achievement)] x Personal Achievement*

Parent Scorecard:

Both the STIP and the SBP weighting calculations reference a parent scorecard. The parent scorecard contains objectives set by the executive team and reflect financial and operational objectives. The parent scorecard for APUC, Liberty Utilities, and Liberty Power is the same for both plans and is broken down as follows:

Objectives	Target %
Conduct Operations Safely and Responsibly	15%
Meet our Customers' Expectations	10%
Foster Employee Engagement through Effective Leadership	10%
Efficient and Effective Management of Capital Re-Investment Programs	10%
Sustainable Development Initiative	5%
Maximize Operating Efficiency by Managing to Budgets	30%
Reduce Cost of Capital through Prudent Investment	20%
	100%

Staff disallowed 50% of STIP and SBP costs associated with the financial objectives of the parent scorecard ("Maximize Operating Efficiency by Managing to Budgets" and "Reduce Cost of Capital through Prudent Investments"), because they enhance Empire's stock price and assigned these costs to shareholders.

Divisional and Personal Scorecard:

While Empire uses the same parent scorecard for all employees under the STIP or SBP plans, the divisional scorecard varies for each of the following divisions based upon the region: APUC, Information Technology, Liberty Utilities/Liberty Power (LU/LP), Corporate Development & Strategy, Legal, Liberty Utilities, Transformation, Compliance and Risk, Human Resources/Communications, Finance, Government Affairs & Sustainability, Regulated Utilities-Head Office, Regulated Utilities-East, Regulated Utilities-Central, and Regulated Utilities-West. Staff reviewed each divisional scorecard to disallow costs associated with meeting earnings per share targets or enhancing the utility's stock price. For the remaining award, Staff used the individual employee's personal achievement/individual multiplier to calculate incentive pay. Table 6 below illustrates the individual performance multiplier, which is based on employee performance.

Table 6

Performance Rating	Individual Performance Multiplier %
Noteworthy Achievement	111%-120%
Exceeds Achievement	100%-110%
Achieved	75%-100%
Partially Achieved	25%-75%
Did not Achieve	0%

Staff's calculation for Incentive Compensation is $ $1,918,501.

Staff Expert/Witness: Caroline Newkirk

6. Supplemental Executive Retirement Plan

Certain management employees receive benefits under Empire's Supplemental Employee Retirement Program ("SERP"). The provisions of Accounting Standards Codification 715-30, formerly FAS 87, are used to calculate the annual financial reporting expense accrual for this plan. Due to the fact that the benefits from this retirement program are not available to a broad range of employees, the Internal Revenue Service ("IRS") designated this program as a "non-qualified" plan. In a non-qualified plan, the expense is not "pre-funded" and only the amounts paid to beneficiaries are tax deductible. Therefore, Staff's policy has been to limit utilities' rate recovery of this item to actual benefit payments to employees, if reasonable. Staff reviewed a five-year period ending June 30, 2021 to determine the reasonable ongoing level for SERP. Staff used the 12 months of actual payments ending with the end of the update period (June 30, 2021) to determine the annual costs of the SERP for inclusion in rates for this case.

Staff Expert/Witness: Ashley Sarver

F. Southwest Power Pool Revenues and Expenses

1. SPP Transmission Revenues

Empire receives revenues from the Southwest Power Pool (SPP) to reimburse it for costs associated with transmission of electricity to other SPP members. Staff reviewed the monthly amount of revenues received from SPP since October 2015 for any trends in the data that would indicate a revenue amount other than the test year revenue amount would be appropriate to include in the cost of service. Staff's review determined the total amount of revenues received in the period of July 2020 through June 2021, which is the end of the update period in this case, is the most appropriate amount to use to normalize the SPP Transmission revenues.

2. SPP Transmission Expenses

The SPP is a not-for-profit, regional transmission organization (RTO) which maintains functional control over the transmission assets of its members and provides transmission service through its Federal Energy Regulatory Commission (FERC) approved open access transmission tariff (OATT). SPP's costs of providing transmission service must be recovered from its member companies, including Empire. Staff reviewed the monthly amount of SPP transmission expense incurred by Empire since October 2015 for any trends in the data, which would indicate that an expense amount other than the test year expense amount would be appropriate to include in the cost of service. Staff's review determined the total amount of expense incurred in the period of July 2020 through June 2021, which is the end of the update period in this case, is the most appropriate amount to use to normalize the SPP Transmission expense.

3. Ancillary Services Market Revenue and Expense

Empire began participating in SPP's Ancillary Services Market (ASM) in March 2014. Empire entered the ASM to acquire ancillary services for its retail load and also to be able to provide these services to other SPP members from its own generation when available. Ancillary services generally refer to the services necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the transmission system.[92] Staff reviewed the monthly amount of ASM revenues and expenses since

[92] As defined, per the glossary on the SPP website, such as Operating Reserves.

October 2015 for any trends in the data, which would indicate that revenue and expense amounts other than the test year revenue and expense would be appropriate to include in the cost of service. Staff's review determined the average of the three-year period ending September 30, 2020, the end of the test year period for this case, is the most appropriate method for annualizing ASM revenues and expense.

4. Miscellaneous SPP Related Revenues and Expenses

Empire also has received certain miscellaneous revenues and has incurred expenses as a result of participating in SPP's Integrated Market (IM) beginning in March 2014. Staff reviewed the monthly amount of these revenues and expenses since October 2015 for any trends in the data and determined the test year period ending September 2020, is the most appropriate method for annualizing these revenues and expenses.

Staff Expert/Witness: Keith D. Foster

G. Operations and Maintenance Normalized Adjustments

Empire's O&M expenses for its generating facilities (production stations) tend to fluctuate from year to year, since unscheduled outages occur at irregular and unpredictable times, and major planned outages do not occur annually. Each maintenance account was reviewed and analyzed separately for each production station. The production facilities examined included Iatan1, Iatan2, Iatan Common, Asbury, Riverton, State Line Combined Cycle, State Line1, Energy Center, Ozark Beach, and Plum Point. These units were examined individually because each of them is on a different maintenance cycle and to group them would have either overstated or understated the final annualized maintenance costs. These adjustments were then combined where possible in an effort to reduce the volume of adjustments.

Staff's proposed production O&M normalization adjustments pertain to Empire's non-labor maintenance costs only; labor maintenance costs are handled as part of Staff's overall payroll adjustments.

1. Iatan

The Iatan production station is on a six-year major overhaul work cycle, and for that reason, Staff used a six-year average of O&M costs to develop its adjustment for Iatan O&M

expense. Empire owns only 12% of the Iatan 1 unit. So, Staff adjusted its calculations to account for this fact.

2. Riverton

A tracker for Riverton's O&M costs was originally established in Case No. ER-2014-0351. In Case No. ER-2019-0374, Amended Report and Order states "based upon the implementation of the SPP Integrated Market, the fluctuation in the hours of unit operation, and the availability of only three years of O&M information from the time Riverton 12 was converted from a simple cycle to a combined cycle unit, the Commission finds that the Riverton 12 tracker should continue."

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

It is most appropriate to use a five-year average due to the fluctuation in cost due to Riverton 12 being converted to a combined cycle unit on May 1, 2016. Therefore, Staff's adjustment is based upon a five-year average of O&M costs as of June 30, 2021, the end of the update period.

3. Riverton 12 O&M Tracker

Additionally, in this case, Staff analyzed the Riverton 12 O&M costs beginning August 1, 2015, when the tracker started, through June 30, 2021, the update period for this case. For this same time period, Staff then calculated the total O&M costs, which were above the established tracker base and included the total in rate base as a regulatory asset. Staff recommends a five-year amortization of the regulatory asset incurred for Riverton 12.

4. State Line Combined Cycle and State Line Common

The State Line Combined Cycle (SLCC) and State Line Common O&M expense is based on a six-year major maintenance overhaul cycle.

Operations Accounts

The operations costs are based on ownership percentages. Empire owns 60% of the SLCC unit and 66.7% of State Line Common, with Westar Energy ("Westar") owning the remaining 40% and 33.3%, respectively. Staff included the five-year average of Empire's portion of operations costs in the revenue requirement.

Maintenance Accounts

Empire's maintenance cost is weighted based on Empire's ownership and net-generation percentage.[93] The ownership percentage is given a 75% weighting and net-generation is given a 25% weighting. The ownership percentage is based on ownership of Empire of 60% of the SLCC unit and 66.7% of State Line Common. For example, to calculate the weighted ownership percentage for the SLCC unit take the total cost x 75% x 60%. However, Staff had to calculate the net-generation percentage based on a calculation using the generation used between Empire and Westar. Staff used an average of the 12 months ending June 30, 2021 to calculate the net-generation calculation. For example, to calculate the 25% net-generation percentage based for SLCC is total cost x 25% x net generation ratio percentage.

5. State Line 1, Energy Center and Ozark Beach

The State Line 1, Energy Center, and Ozark Beach major turbine maintenance schedule is based on hours and/or starts for the overhaul schedule. Staff's adjustment is based upon a five-year average of O&M costs.

6. Removal of Asbury O&M from Test Year

Staff removed non-labor, non-fuel O&M amounts for Asbury generating plant as the test year is no longer representative of normal O&M as the Asbury plant was retired on March 1, 2020.

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[93] The ownership percentages reflect the investments made between Empire and Westar, with Westar owning 40% of State Line Combined Cycle and 33% of State Line Common. The net-generation percentage is a calculation using the average generation used between Empire and Westar.

7. Wind Projects O&M

Staff made an adjustment to wind (non-FAC) operating expenses and wind project O&M. For the wind operating expense, Staff reviewed the agreements and included the agreement costs to the revenue requirement. For the wind project O&M expense, Staff included the update period for operations, however, for maintenance Staff did not have 12 months of data so Staff used the 10 months available and annualized that amount to come up with the annualized total.

Staff Expert/Witness: Ashley Sarver

H. Other Expenses

1. Rate Case Expense

Empire proposed an adjustment to reflect the cost associated with the current rate case assuming a two-year amortization period.

Staff reviewed Empire's projected and actual rate case expense amounts based upon the traditional criteria of allowing rate recovery of reasonable and prudent expenses, normalized over an appropriate period of time. ** [redacted]

[redacted]

[redacted] **

Staff normalized rate case expense over a three (3) year period. Staff asserts that the rate case expense incurred in relation to a current rate proceeding should be included in rates on a "normalized" basis. The rate case expense includes a three year normalization of rate case expense at $219,163 per year; the cost of the depreciation study at $13,593, normalized over five years; the line loss study at $4,000, normalized over four years; and the Cost/Benefit Analysis, a one-time cost, normalized at $65,500 per year for five years. Thus, the total of rate case expense will be $302,256.

Staff will apply the same cost sharing technique approved by the Commission in Case No. ER-2019-0374 to all rate case expense except for the costs of the depreciation study, line loss study and Cost/Benefit Analysis. Staff's sharing proposal is discussed in the next section by Staff witness Amanda C. McMellen. Therefore, a total of $192,674 will be borne by ratepayers annually.

Staff Expert/Witness: Angela Niemeier

2. Rate Case Sharing

Rate case expense is a sum of the incremental costs a utility incurs in preparing and filing a rate case. In the instant case, Empire has incurred expenses in conjunction with outside consultants. Staff recommends assigning Empire's discretionary rate case expense to both ratepayers and shareholders based upon a 50/50 split and full recovery of the depreciation study over five years. This allocation was utilized by the Commission in the Spire Missouri Inc.

("Spire Missouri") rate cases, Case Nos. GR-2017-0215 and GR-2017-0216; and in the last Empire rate case, Case No. ER-2019-0374.

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

1) Rate case expense sharing creates an incentive and eliminates a disincentive on the utility's part to control rate case expenses to reasonable levels;

2) Both ratepayers and shareholders benefit from the rate case process. The ratepayer is receiving the opportunity to be provided safe and adequate service at a just and reasonable rate and the shareholder is receiving an opportunity to receive an adequate return on investment;

3) It is fair and equitable to expect shareholders to carry a reasonable portion of the rate case burden; and

4) There is a high probability that some recommendations advocated by utilities through the rate case process will ultimately be found by the Commission to not be in the public interest.

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

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

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

The Commission ordered a sharing of Kansas City Power & Light's[94] (KCPL) rate case expenses in its Report and Order in Case No. ER-2014-0370:

> The Commission finds that in order to set just and reasonable rates under the facts of this case, the Commission will require KCPL shareholders to cover a portion of KCPL's rate case expense. One method to encourage KCPL to limit its rate case expenditures would be to link KCPL's percentage recovery of rate case expense to the percentage of its rate increase request the Commission finds just and reasonable. The Commission determines that this approach would directly link KCPL's recovery of rate case expense to both the reasonableness of its issue positions and the dollar value sought from customers in this rate case.
>
> The Commission concludes that KCPL should receive rate recovery of its rate case expenses in proportion to the amount of revenue requirement it is granted as a result of this Report and Order, compared to the amount of its revenue requirement rate increase originally requested. This amount should be normalized over three years. The Commission also finds that it is appropriate to require a full allocation to ratepayers of the expenses for KCPL's depreciation study, recovered over five years, because this study is required under Commission rules to be conducted every five years. [Footnotes omitted][95]

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

> It is understood that some of the issues litigated in this case do not directly affect the overall revenue requirement granted by the Commission; but it is also clear that the vast majority of litigated issues do have a direct or indirect impact on the revenue requirement. Accordingly, percentage sharing is a reasonable approach to correlating recovery of rate case expense to the relationship between the amount of litigation that benefited both ratepayers and shareholders and that which benefited only shareholders.[96]

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

[94] KCPL has changed names since this case, and is now doing business as Evergy Missouri Metro, Inc.
[95] *Report and Order*, Case No. ER-2014-0370 page 72.
[96] *Report and Order*, Case No. ER-2014-0370 page 72, Footnote 251.

> Therefore, it is just and reasonable that the shareholders and the ratepayers, who both benefited from the rate case, share in the rate case expense. The Commission finds that in order to set just and reasonable rates under the specific facts in this case, the Commission will require Spire Missouri shareholders to cover half of the rate case expense and the ratepayers to cover half with the exception of the cost of customer notices and the depreciation study.[97]

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

Staff Expert/Witness: Amanda C McMellen

3. Dues & Donations

Staff reviewed the list of membership dues paid and donations made to various organizations that Empire charged to its utility accounts during the test year. In ***Re: Missouri Public Service, a Division of UtiliCorp United, Inc.***, Case Nos. ER-97-394, *et al., Report and Order,* 7 Mo.P.S.C.3d 178, 212 (1998), the Commission stated:

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

Staff excluded dues that do not have any direct benefit to ratepayers and were not necessary for the provision of safe and adequate service. Allowing Empire to recover these expenses through rates causes the ratepayer to involuntarily contribute to these organizations. Examples of dues excluded from recovery in the rate case, based on the Commission's *Report and Order* mentioned above, are dues paid to Amazon and Sam's Club. Area Chamber of Commerce dues were allowed, but National and State Chamber of Commerce dues were disallowed as being duplicative costs to the local Chamber of Commerce organizations.

There is growing concern within utility regulation as to whether investor owned utilities are ultimately passing lobbying costs through to ratepayers even when an adjustment to remove lobbying has been proposed by the utility itself (e.g. recording the lobbying portion of a

[97] *Report and Order,* Case Nos. GR-2017-0215 and GR-2017-0216, page 52.

membership expense below-the-line) or through a proposed adjustment by other parties to a rate case. There is concern that while utilities are required to remove the lobbying portion of membership dues to certain trade groups, some of the remaining membership amount paid may still be associated with these group's efforts to shape policy. Some memberships provide the utilities invoices with a lobbying percentage specifically delineated and some do not. However, in many cases there is no explanation provided of what that lobbying percentage amount is based on. Staff has analyzed Empire's memberships in certain trade groups and at this time has removed 50% of all memberships that Staff has reason to believe may involve lobbying activity or for which Staff does not know how the organization determines the invoiced lobbying percentage. Staff will continue to work with Empire to ensure a proper amount of test year membership dues are included in the cost of service in this case.

Staff disallowed the donation amounts charged to account numbers 908101, 921104, 921702, and 921712. An example of a donation that was excluded was a donation to Missouri Sports Hall of Fame. No further adjustments are necessary for this case.

Staff Expert/Witness: Courtney Horton

4. Edison Electric Institute (EEI) Dues

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

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

> …would be excluded as an expense until the company could better quantify the benefit accruing to both the company's ratepayers and shareholders.

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

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

> . . . The argument that allocation is not necessary if the benefits lessen the cost of service to the ratepayers by more than the cost of the dues misses the point.
>
> It is not determinative that the quantification of benefits to the ratepayer is greater that the EEI dues themselves. The determining factor is what proportion of those benefits should be allocated to the ratepayer as opposed to the shareholder. It is obvious that the interests of the electric industry are not consistently the same as those of the ratepayers. The ratepayers should not be required to pay the entire amount of EEI dues if there is benefit accruing to the shareholders from EEI membership as well. The Commission finds this to be the case. The Company has been informed in prior rate cases that it must allocate its quantified benefits from membership in EEI. That has not been done herein. Therefore, no portion of EEI dues will be allowed in this case.

Empire failed to quantify ratepayer and shareholder benefits from its participation in EEI in this case; therefore, Staff removed total EEI dues included in the test year of $192,260 from Empire's cost of service. No further adjustment is necessary for this case.

Staff Expert/Witness: Courtney Horton

5. Insurance Expense

Insurance expense is utilities' cost of protection, obtained from third parties, against the risk of financial loss associated with unanticipated events or occurrences. Utilities, like non-regulated entities, routinely incur insurance expense in order to minimize their liability (and, potentially that of their customers) associated with unanticipated losses. Staff made an adjustment to annualize Empire's insurance expense to reflect the premiums paid as of July 2021. Staff's adjustment for insurance expense is $1,100,414.

Staff Expert/Witness: Courtney Horton

6. Customer Deposit Interest Expense

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

Staff Expert/Witness: Courtney Horton

7. Property Tax Expense

Utility companies are required to file a valuation of their utility property with their respective taxing authorities at the beginning of each assessment year, which is January 1st. Based on the information provided by the utility, the taxing authority will send the company its "assessed values" for every category of the company's property. The taxing authority will then issue to the utility company a property tax rate later in the year. The final step in the process is when the taxing authority issues a property tax bill to the company after September in each calendar year with a "due date" of December 31st. The billed amount of property taxes is based on the property tax rate applied to the previously determined assessed values of the utility's plant in service balances as of January 1st of the same year.

Staff determined its adjustment for property taxes by developing a property tax rate to be applied to total property as of December 31, 2020. Staff calculated the property tax rate by dividing the 2020 property taxes paid by the total property as of December 31, 2019. This property tax rate was then applied to the total property as of December 31, 2020, to arrive at the annualized property tax. Then, the annualized property tax was added to the 2020 Plum Point taxes paid to arrive at total annualized property tax. The total annualized property tax was then subtracted from the total test year property taxes to derive the adjustment.

The owners of the Plum Point unit, including Empire, have an agreement with the City of Osceola, Arkansas; Mississippi County, Arkansas; Osceola School District No. 1 of Mississippi County, Arkansas; and Mississippi County Community College District of Arkansas, to make an annual Payment in Lieu of Taxes ("PILOT") instead of paying property taxes on the Plum Point unit in the normal manner. A PILOT agreement allows the owners of the Plum Point unit to pay one flat amount of property taxes on the Plum Point unit for 30 years with the potential for an extension at the end of the 30-year term, regardless of any additions or retirements made to the unit since its in-service date. To appropriately calculate the overall property tax amount for Empire, the amount of Empire's share of the Plum Point plant had to be subtracted from total plant in service so as not to be included in the development of the annualized property taxes. The set amount of PILOT that Empire has agreed to pay for Plum Point was then added to the annualized property tax calculation to determine the total property tax adjustment.

In addition, Empire has an agreement with the Board of County Commissioners of Neosho County, Kansas, to make an annual PILOT instead of paying property taxes on the Neosho Ridge wind in the normal manner. In the PILOT agreement, following the date that the Developer provides notice of completion to the County, Empire will pay $1,000,000 per year for the first 10 years by May 10th. Staff is including this in Property Tax Expense as it is a known and measurable amount going forward.

Staff Expert/Witness: Angela Niemeier

8. Uncollectible/Bad Debt Expense

Bad debt, or uncollectible expense, is the portion of retail revenue that Empire is unable to collect from retail customers due to non-payment of bills. The final bill is due 21 days from the statement mailing date. If unpaid, on the second day after the due date, a collection notice is sent advising the customer the account will be turned over to a collection agency if unpaid or suitable arrangements are not made within 10 days. After the 10 days, any accounts that remain unpaid are written off and sent to a collection agency. However, due to the economic impact to customers of the COVID-19 pandemic the Company observed a temporary exception to this policy during a portion of 2020.

Staff examined five years (April 2015 – March 2020) of Empire’s bad debt write-offs that were never collected (i.e., write-offs net of amounts subsequently collected). It is apparent from a review of this data that Empire’s bad debt expense fluctuates from one year to the next. Therefore, Staff calculated a five-year average of the uncollectable percentage of bad debt to revenue. This percentage was then applied to Staff’s annualized and adjusted level of test year retail rate revenues to obtain the normalized level of bad debt expense. Data after the date of March 2020 was not taken into consideration because COVID-19 would have directly impacted the amount of bad debt and skewed the normalization.

Staff Expert/Witness: Caroline Newkirk

9. Advertising Expense

Staff evaluated the invoices and supporting information Empire provided for advertisements and classified them into the five categories set forth in the Commission’s ruling in Kansas City Power and Light Company[98] Case No. EO-85-185 et. al., (general, safety, institutional, promotional, and political).

- General: Informational advertising that is useful in the provision of adequate service.
- Safety: Advertising that conveys safe ways to use electricity and avoid accidents.
- Institutional: Advertising used to improve the company's image.
- Promotional: Advertising that is used to promote the use of electricity, this expense is allowed if the benefits derived exceed the costs.
- Political: Advertising associated with political issues.

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

Following this guidance, Staff categorized each advertisement and calculated the adjustment excluding promotional and institutional/goodwill advertising expenses from recovery in rates in the amount of ($99,931). Institutional/goodwill advertising promotes the company's image and does not benefit customers. In addition, Staff excluded advertisements for water and gas and advertisements in newspapers greater than 50 miles outside Missouri border.

Staff Expert/Witness: Angela Niemeier

<u>10. Software Maintenance Expense</u>

Empire has contracts, operating licenses, and agreements with vendors that provide maintenance, upgrades to software, and support for its computer software. Staff annualized the expense for each of the suppliers based on the annualized contract amounts as of June 30, 2021. Therefore, Staff made an adjustment of ($640,968) in Account 921-Office Supplies to decrease the software maintenance expense to reflect the annualized amount of $503,462 as of June 30, 2021.

Staff Expert/Witness: Ashley Sarver

[98] KCPL is now known as Evergy Missouri Metro, Inc.

11. Leases Expense

Lease costs are incurred by Empire for the leasing of its equipment and building space. Staff submitted Data Request No. 0046 to Empire requesting a list of all lease agreements (office, vehicle, computers, etc.) charged to Missouri electric operations, along with the lease costs and information concerning all changes to the lease amounts since October 2019. Staff examined these costs for the test year, updated through June 30, 2021. The update period included wind farm leases for the new wind farm projects. Staff included an adjustment for the wind farm land leases, Americold, MailFinance, and the Missouri Chamber of Commerce Education Foundation lease (after allocating a portion to Liberty's water and gas companies) in its lease expenses. Staff's total annualized lease expense is $3,102,047.

Staff Expert/Witness: Courtney Horton

12. PSC Assessment

The operations of the PSC are funded by assessments levied upon regulated utility companies. The funding required from each utility is evaluated yearly and a new assessment is billed on July 1st of each year. These assessments are used to reimburse the Commission for its operating costs. The PSC assessment expense reflects the most current assessment issued on July 1, 2021, for $974,996.

Staff Expert/Witness: Angela Niemeier

13. Injuries and Damages and Workers' Compensation

Empire maintains workers' compensation insurance for its employees' benefit. Staff's proposed workers' compensation adjustment annualizes this expense based upon the premiums in effect during July 2021 to reflect an ongoing and normal expense level. However, due to the significant increase in premiums without explanation from the Company, Staff decided to use the test year amount for workers' compensation. Staff submitted a data request to the Company requesting explanation for the significant increase.

Empire occasionally pays injuries and damages and workers' compensation claims. Based upon generally accepted accounting principles, Empire must charge to current expense an estimate of its future claims payouts. To determine a normalized level of these expenses, Staff used a five-year average of actual claims for injuries and damages and workers' compensation payments in its cost of service report, instead of relying upon accounting estimates. Staff allocated to Empire Electric 50% of the five-year average of actual payments made for injuries and damages, which represents the electric expense portion of the payments. The remaining 50% of the payments is allocated to the Company's construction, water operations, and below-the-line activities. Below-the-line refers to line items in the income statement that do not directly impact a company's reported profits. A five-year average of actual payments was used to normalize this expense because Staff's analysis shows a considerable fluctuation in the annual amount of payments from one year to the next. Staff's adjustment for Injuries and Damages and Workers' Compensation is $1,456,205.

Staff Expert/Witness: Courtney Horton

14. Postage

There has been no postal rate changes from January 27, 2019 through the end of the update period of June 30, 2021. After analyzing data, Staff determined that no adjustment is needed from test year.

Staff Expert/Witness: Angela Niemeier

15. Customer Payment Fees

In previous cases, each Empire customer who paid her/his utility bill with a credit card was charged a transaction fee from an outside vendor. In Case No. ER-2019-0374, the Commission ruled that Empire should begin recovering the credit card fees in rates instead of the individual customer paying the $2.25 transaction fee. Empire began using a new company, KUBRA, for these credit card transactions in October 2020. The new vendor payment fees are $1.45 for KUBRA transactions for residential customers, $5.50 for KUBRA for commercial customers, $0.40 for KUBRA transactions that involve ACH (direct payments, electronic payments, and money transfers) for both residential and non-residential transactions, and $1 for FirsTech Kiosk Payments. Staff has included an annualized amount for credit card processing fees for Empire, based on the number of actual customer payment fees occurring during the test year, multiplied by the current fee per-transaction. This customer payment fee adjustment is $748,320.

Staff Expert/Witness: Angela Niemeier

16. Outside Services

Various outside (independent) contractors and vendors provide legal, auditing, and other services to Empire to carry out its operational activities as needed. Staff reviewed Empire's outside services expenses booked to Accounts 923045 and 923047 for the test year through the update period ending June 30th, 2021. Staff normalized the costs of outside services on a going forward basis by calculating a five-year average of incurred costs for these accounts in the amount of $2,468,686.

Staff also included the costs associated with the new AMI outside service expenses resulting in an overall total company adjustment in the amount of $487,832. This adjustment does not include outside services related to rate case expense. Outside services incurred for rate case purposes are booked in a separate account.

Staff Expert/Witness: Courtney Horton

17. Travel and Training Expense

Travel and training expense is an operating expense that includes expenses associated with employee travel and training. This is a new issue in this case due to the effects of COVID on Company adjustments. Previously, Staff did not review travel and training expense in prior rate cases, because the Company used the test year amount. However, for this rate case the Company adjusted this expense due to COVID, using a five-year average. Originally, Staff requested to review five years of invoices. However, based on the voluminous number of invoices and the amount of Company time to provide the invoices, the Company and Staff agreed to review a sample of invoices for the last five years. After reviewing the invoices and the Company's associated workpaper, Staff concluded that using the test year expenses, less any adjustments, was the most appropriate method to normalize these expenses. Staff's calculation for normalized travel and training expense is $229,966.

Staff Expert/Witness: Courtney Horton

18. Energy Efficiency Programs

Empire currently offers four energy efficiency programs to its electric customers. The Commission originally approved these programs in Case No. ER-2016-0023, and authorized the programs to continue in Case No. ER-2019-0374. These programs are:

Custom Commercial and Industrial (C&I) – P.S.C. Mo. No. 6 Sec. 4, Original Sheet Nos. 8a-8b

The Custom Commercial and Industrial (C&I) Rebate Program is designed to encourage the efficient use of energy by providing rebates to cover a portion of the costs associated with the purchase and installation of energy efficient equipment in commercial and industrial facilities.

Residential HVAC Rebate program – P.S.C. Mo. No. 6 Sec. 4, Original Sheet No. 8f

The HVAC Rebate Program is designed to encourage the efficient use of energy through the purchase and installation of energy efficient HVAC systems by providing rebates to lower the cost of such improvements for residential customers.

Multi-Family Direct Install program – P.S.C. Mo. No. 6 Sec. 4, Original Sheet No. 8e

The Multi-Family Direct Install Program is designed to improve the energy efficiency of multi-family dwellings in the Company's territory by offering kits containing direct-install measures (e.g., high-efficiency light bulbs, showerheads, sink aerators, etc.) to the owners and/or tenants of those buildings.

Income-Eligible Multi-Family Direct Install program – P.S.C. Mo. No. 6 Sec. 4, Original Sheet No. 8d

The Income-Eligible Multi-Family Direct Install Program is designed to improve the energy efficiency of low-income multi-family dwellings in the Company's service territory by offering kits containing direct-install measures (e.g., high-efficiency light bulbs, showerheads, sink aerators, etc.) to the owners of those buildings.

The Company did not propose changes to these programs, because it has filed an application for approval of a Missouri Energy Efficiency Investment Act (MEEIA)[99] portfolio.

[99] EO-2022-0078 In the Matter of the Application of The Empire District Electric Company, d/b/a Liberty to Implement Robust and Mutually-Beneficial Energy Efficiency Offerings Under the Framework Prescribed by MEEIA.

Staff recommends the Company continue its energy efficiency programs until the Commission approves its MEEIA application.

Staff Expert/Witness: Kory J. Boustead

19. Low-Income Programs

Empire currently has three low-income programs:

1. Weatherization Program – P.S.C. Mo. No. 6 Sec. 4, Original Sheet No. 8c
2. Low-Income Pilot Program – P.S.C. Mo. No. 6 Sec. 4, Original Sheet No. 24
3. Empire's Action to Support the Elderly & Project Help – P.S.C. Mo. No. 6 Sec. 4, Original Sheet No. 20

Weatherization Program

Empire's pilot Weatherization Program supplements funding low-income ratepayers receive through the Federal Department of Energy's (DOE) Low-Income Weatherization Assistance Program (LIWAP). Empire's funds are allocated to local community action agencies (CAAs), which determine customer eligibility to receive assistance for conservation, education, and weatherization initiatives to help reduce customers' energy use, thus reducing Empire's bad debts.

In the Empire merger case, Case No. EM-2016-0213,[100] the Commission approved[101] a Stipulation and Agreement[102] in which Empire and the Empire District Gas Company (EDG) agreed to provide the Department of Natural Resources, Division of Energy (DE) an annual payment totaling up to 5% of the agreed to weatherization funds for administration and monitoring of the funds (not to exceed a cap of $12,500). The agreement is for a five-year period and is considered below the line and not recovered in future rates. The Commission approved continuing this program at the same funding level in Case No. ER-2019-0374, Empire's last rate case.

[100] EM-2016-0213, *In the Matter of The Empire District Electric Company, Liberty Utilities (Central) Co. and Liberty Sub Corp. Concerning an Agreement and Plan of Merger and Certain Related Transactions.*

[101] *Order Approving Stipulations and Agreements and Authorizing Merger Transactions*, EM-2016-0213, (September 7, 2016), EFIS number 134.

[102] *Stipulation & Agreement,* EM-2016-0213, (August 23, 2016), EFIS number 105, page 8, paragraph 24.

This is the fourth year of Empire's partnership with the DE. Company witness Nathaniel W. Hackney does not state in his direct testimony who will administer this program when this pilot[103] ends at the end of its fifth year.

The Company proposed no changes to the Weatherization Program. Staff's recommendation is that the program continue as it currently is constituted and at the current funding level.

Low-Income Pilot Program

This program was initiated in Case No. ER-2016-0023 to study the impact on Empire's disconnection and bad debt rates of removing some low-income customers' customer service charges. The Commission ordered ratepayers to fund the total program budget of $250,000 and that the program run until the budget is exhausted, or until new rates are implemented, whichever occurs first.[104]

In Case No. ER-2019-0374, the Commission ordered continuation of Empire's residential Low-Income Pilot Program[105] with no changes and ordered the Company to track all costs until the next rate case.[106] Empire should have ended the program when the program spending reached the $250,000 cap. Because Empire exceeded that, Staff's position is that it should recover only the Commission-allowed $250,000 plus what has been expended since the September 16, 2020, effective date of the ER-2019-0374 Commission order. Staff witness Keith D. Foster addressed the amount included in rate base in Section VII.C., subsection 9 of this report.

The mechanics of the program are as follows. Two CAAs qualify and enroll customers in the program. Qualified customers receive a bill statement with a monthly credit equal to the monthly customer charge and a revised bill payment amount.

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[103] It is important to note that the term "pilot" is in regards to DE being provided compensation to administer the weatherization program for a 5 year period, not that the weatherization program itself is a pilot program as this program is a legacy program where in the past Empire provided the program administration.

[104] Order Approving Stipulation and Agreement, ER-2016-0023, page 4-6 (Aug 10, 2016).

[105] Tracking Number YE-2021-0041, New Tariff PSC No. 6, Sec. 4, Sheet No. 24.

[106] Amended Report and Order, ER-2019-0374, July 23, 2020.

Empire conducted a study of the Low-Income Pilot Program's effectiveness, titled Summary of Results, Low-Income Pilot Program, in Case No. ER-2019-0374.[107]

Empire, Staff, OPC, and DE met on September 2, 2020, and March 3, 2021, to discuss this program and whether it should be modified. As a result of recommendations from OPC and Staff, Empire proposes the following changes to the program in this rate case:

1. During peak months (May-July and November-January), change the stipend from the monthly customer charge to twice the monthly customer charge;
2. Limit the number of participants to 1,000 to ensure continued expenditure levels; and
3. Maintain a "waiting list" to replace customers who unenrolled from the program.

Empire states[108] the higher credit during peak periods will provide more benefit when bills are typically at their highest. Further, low-income programs are challenged to serve the needs of the targeted group, while managing costs in a manner that does not create undue burden on other customer segments. By limiting the number of participants and maintaining a waiting list, the Company can provide assistance to its most challenged customers while managing the program's impact on the remaining customer base.[109]

Staff's recommendations for its direct case are as follows:

> Staff recommends (1) the Commission approve the program continue at the current approved funding and (2) the Commission approve Empire's proposed program changes in witness Jon Harrison's Direct Testimony as follows: During peak months (May-July and November-January), change the stipend from the monthly customer charge to twice the monthly customer charge;
>
> Limit the number of participants to 1,000 to ensure continued expenditure levels; and
>
> Maintain a "waiting list" to replace customers who are no longer participating in the program.

[107] Direct Testimony of Nathaniel Hackney, Schedule NWH-2.
[108] Direct Testimony of Jon Harrison, page 20, lines 20-21.
[109] Direct Testimony of Jon Harrison.

Empire's Action to Support the Elderly & Project Help

In addition to the Weatherization and Low-Income Pilot Programs, Empire offers two other programs to assist underserved communities. The first is Empire's Action to Support the Elderly[110] (EASE). EASE allows Empire to waive late penalties and deposits, adjust due dates, and notify third parties when a registered elderly or disabled person's account becomes delinquent.

Finally, Empire works with Crosslines Churches in Joplin and receives customers' voluntary donations to offer Project Help. Project Help is an assistance program created to meet emergency energy-related expenses of the elderly and/or disabled residents in Empire's electric service area.

Empire proposed no changes to these programs in its last rate case, nor in this case. Staff's recommendation is that the programs continue as they currently are and has no proposed changes. These programs are not ratepayer-funded.

Staff Expert/Witness: Kory J. Boustead

VIII. Current and Deferred Income Tax

A. Current Income Taxes

Current income tax for this case has been calculated by Staff consistent with the methodology used in Empire's most recent rate case, Case No. ER-2019-0374. Adjustments are made to net income to compute the current income tax expense. These adjustments are effectuated by taking adjusted net income and either adding to or subtracting from the net income various timing differences to obtain net taxable income for ratemaking purposes. (The term "timing differences" refers to the differences in time when certain costs can be deducted for purposes of determining financial statement net income and taxable income, respectively.) The adjustments are the result of various financial statement ("book") and tax timing differences as well as their implementation under separate tax ratemaking methods: flow-through versus normalization. The resulting net taxable income for ratemaking is then multiplied by the appropriate federal and state tax rates to obtain the current provision for

[110] Tracking Number YE-2021-0041, New Tariff PSC No. 6, Sec. 4, Sheet No. 20.

income taxes. Staff used the current federal tax rate of 21 percent and the state income tax rate of 4 (four) percent, in calculating Empire's income tax liability. The difference between the calculated current income tax provision and the per book income tax provision is the current income tax provision adjustment.

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

Add Back to Operating Income Before Taxes:

Book Depreciation Expense

Non-Deductible Expense – Non-deductible meals and dues

Contributions In Aid of Construction

Book Amortization

Subtractions from Operating Income:

Interest Expense – Weighted Cost of Debt times Rate Base

Tax Depreciation – Straight-Line

Tax Depreciation – Excess

B. Deferred Income Taxes

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

When a current year timing difference is deferred and recognized for ratemaking purposes consistent with the timing used in calculating pre-tax operating income in the financial statements, then that timing difference is given "normalization" treatment for ratemaking purposes. Deferred income tax expense for a regulated utility reflects the tax impact of "normalizing" tax timing differences for ratemaking purposes. Current IRS rules for regulated utilities essentially require normalization treatment for the timing difference related to accelerated depreciation.

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

Staff Expert/Witness: Keith D. Foster

IX. Renewable Energy

A. Solar Rebates

On May 5, 2015, Empire issued tariffs to establish solar rebate payments procedures, and to revise its net metering tariffs to accommodate the payment of solar rebates. The tariff submitted under YE-2015-0322 became effective on May 16, 2015. Staff has amortized the costs over a ten-year period, based upon Staff's review of the costs recorded to date in Account 182377. Staff is using the June 30, 2021 balance of this regulatory asset in rate base in this case. Staff has also included an adjustment in the Income Statement to amortize these costs to expense.

Staff Expert/Witness: Caroline Newkirk

X. Depreciation

A. Recommendations

Staff reviewed the depreciation study provided in the Direct Testimony of Dane A. Watson, of Alliance Consulting Group. Staff also requested the source data for the depreciation study in Staff Data Request Nos. 0085, 0086, 0086.1, and 0087. Staff analyzed the data submitted and is proposing the rates as shown in Appendix 3, Schedule CEC-d1.

B. Discussion

Empire is required to submit a depreciation study as part of rate increase requests under rule 20 CSR 4240-3.160, unless the Commission Staff has received a study within 5 years prior to the filing for a rate increase. On May 28, 2021, Empire submitted a depreciation study prepared by Alliance Consulting Group for the capital assets of Empire, based on plant balances as of December 31, 2019. This study was submitted in the Direct Testimony of Dane A. Watson.

Depreciation is defined as:

> the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, and requirements of public authorities.[111]

Staff accounts for depreciation by recording the actual purchase cost of the asset, known as book cost, and charging depreciation expense over the expected or average service life of the asset. Average service life can be determined by plotting the percentage of assets surviving against the age of the assets in a survivor curve, and calculating the area under that curve. For an account in which all plant is retired, the full survivor curve is available and average service life can be calculated. Accounts with plant remaining have a partial curve, which is known as a stub curve. Iowa curves represent common survival rates and patterns of assets, and are widely used to estimate depreciation. The average service life can be estimated by comparing a stub curve to Iowa curves and fitting the best matched curve.

Using the data supplied by Empire and the methods below, Staff calculated its own depreciation rates of Empire's plant in service and recommends the rates as listed in Accounting Schedule 5. Staff receives data in excel or notepad format for retirements and salvage information. The data includes installment year (vintage), FERC account, type of transaction, transaction year, amount of transaction, and group or location codes. Staff uses a version of Gannett Fleming Software to complete the following actions with the company provided data. First the data is sorted and checked for errors. Next, the software allows Staff to analyze the amount of plant that has been retired at each age and plot the stub curve. Then, Staff matches an appropriate Iowa curve to the stub curve data. Curves are fitted using a mixture of

[111] 18 CFR Part 101 Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provision of the Federal Power Act Definition 12.

mathematical and visual fitting practices. Once a curve is chosen, Staff has an estimate of the average service life.

Staff calculated an estimated net salvage percentage for each account by reviewing the accounts gross salvage and cost of removal data:

$$\textit{Net Salvage} = \textit{Gross Salvage} - \textit{Cost of Removal}$$

Gross salvage is the removed market value of the retired asset. Cost of removal is the cost associated with the retirement and disposition of the asset from service. Net salvage percentages were developed by dividing the experienced net cost of removal by the original cost of plant retired during the same time period to calculate the net cost of removal percentage. Staff then charts the salvage values and analyzes using a 3-year or 5-year moving average to determine trends. The moving average smooths outlier data points by averaging them over time instead of appearing as one spike allowing trends to be shown more clearly. Staff then uses the average life and salvage percentage to calculate a depreciation rate, annual accrual, and remaining life. Where there was adequate data to support it, Staff's recommendation is informed by statistical analysis of plant retirements. For accounts that did not have adequate data to produce a reasonable result using statistical analysis, Staff relied on its engineering experience, informed judgement, and previous cases to prepare recommended rates. Staff used the straight-line method, broad group-averaging life procedure, and remaining life technique for its calculations. These are commonly accepted methods for depreciation of utility plant. These methods take into account changes and deviations from calculated accruals and apply an adjustment over the remaining life rather than requiring a larger adjustment later, reducing rate shock to customers. The straight line method allocates expense evenly over the expected life of the asset. The broad group life procedure bases annual depreciation on the average service life of the account group rather than the specific vintage year. The broad group method views each vintage of asset in the continuous group as having identical life and salvage characteristics. A remaining life accrual basis applies that depreciation over the estimated remaining useful life of the asset group. The remaining life technique calculates the depreciation rate by taking into account the depreciation reserve for the account. This corrects any under or over accrual that may have accrued in the accounts. It then applies the remaining balance over the estimated average remaining life of the assets in the accounts.

Staff used this technique for the majority of accounts with the exception of miscellaneous equipment and general plant accounts that have been amortized. The amortized accounts are accounts 391, 391.3, 393, 394, 395, 397, and 398.

Staff recommends that the Commission order the depreciation rates as listed in Appendix 3, Schedule CEC-d1.

Staff Expert/Witness: Cedric E. Cunigan, PE

C. Clearing Accounts

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

Staff Expert/Witness: Ashley Sarver

XI. Fuel Adjustment Clause

A. Policy

In summary, Staff makes the following recommendations regarding Empire's Fuel Adjustment Clause (FAC):

- Continue Empire's FAC with modifications;
- Include a revised Base Factor[112] in the FAC tariff sheets calculated from the Base Energy Cost[113] that the Commission includes in the revenue requirement upon which it sets Empire's general rates in this case;

[112] Base Factor is defined in Empire's Original Tariff Sheet No. 17i 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."

[113] Base Energy Cost is defined in Empire's Original Revised Tariff Sheet No. 17i 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")."

- Clarify that the only transmission costs and revenues that are included in Empire's FAC are those that Empire incurs for Purchased Power and Off-System Sales; and
- Order Empire to include Schedule BM-d1[114] 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.

In this rate case Empire is proposing to re-base the Base Factor to $0.01011 per kWh. At this time, Staff does not have its estimate for the Base Factor, 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 November 17, 2021. Staff will use the Base Energy Cost and the kWh at the generator from its fuel run to develop the Base Factor.

Staff witness Alan J. Bax addresses the Voltage Adjustment Factors in Section XI.F. of this Cost of Service Report.

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 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, ER-2016-0023, and ER-2019-0374, the Commission authorized continuation, with modifications, of Empire's FAC. The primary features of Empire's present FAC (tariff sheet numbers 17i through 17q) include:

- Two 6-month accumulation periods (AP)[115]: March through August and September through February;
- Two 6-month recovery periods (RP)[116]: December through May and June through November;

[114] Staff witness Brooke Mastrogiannis created Appendix 3, Schedule BM-d1 from Empire witness Zachary Quintero's Schedule zq-06, with modifications.

[115] An AP is the calendar months during which the actual costs and revenues are accumulated for the purposes of the Fuel Adjustment Rate.

[116] A RP is the billing calendar months during which the FAR is applied to retail customer usage on a per kWh basis, as adjusted for service voltage.

- Empire must file Fuel Adjustment Rate (FAR)[117] filings semi-annually, not later than April 1 and October 1 of each year;
- One Base Factor[118] for all calendar months of the year;
- A 95/5 sharing mechanism between ratepayers and Company[119];
- 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 included in the determination of FAR for a subsequent recovery period.

The resulting changes to the Empire FARs the Commission ordered are summarized in the **Continuation of FAC** section of this report. The Base Factor was originally set in Empire's 2008 general rate case and was changed as a result of the negotiated settlements in Empire's 2010, 2011, 2012, and 2016 general rate cases, and by Commission *Report and Order* in the 2014 and 2019 general rate cases.

Staff filed nine prudence review reports[120] (File Nos. EO-2010-0084, EO-2011-0285, EO-2013-0114, EO-2014-0057, EO-2015-0214, EO-2017-0065, EO-2018-0244, EO-2020-0059, and EO-2021-0281) discussing its review of the costs and revenues included in the Company's FAC. Staff found no evidence of imprudent decisions by the Company's management related to fuel, purchased power and net emission costs, off-system sales revenues, and renewable energy credits revenues for the time periods reviewed.[121]

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[117] The FAR for each accumulation period is the amount that is returned to or collected from customers as part of a decrease or an increase of the FAC Fuel and Purchased Power Adjustment per kWh rate.

[118] The Base Factor, which is equal to the normalized value for the sum of allowable fuel costs, plus costs of purchased power, and emission costs and revenues, less revenues from off-system sales, divided by corresponding normalized retail kWh as adjusted for applicable losses. 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 November 17, 2201. Staff will use the Base Energy Cost and the kWh at the generator from its fuel run to develop the Base Factor.

[119] 95% of the difference between the total energy cost and net base energy costs for each respective AP will be used to calculate the FAR.

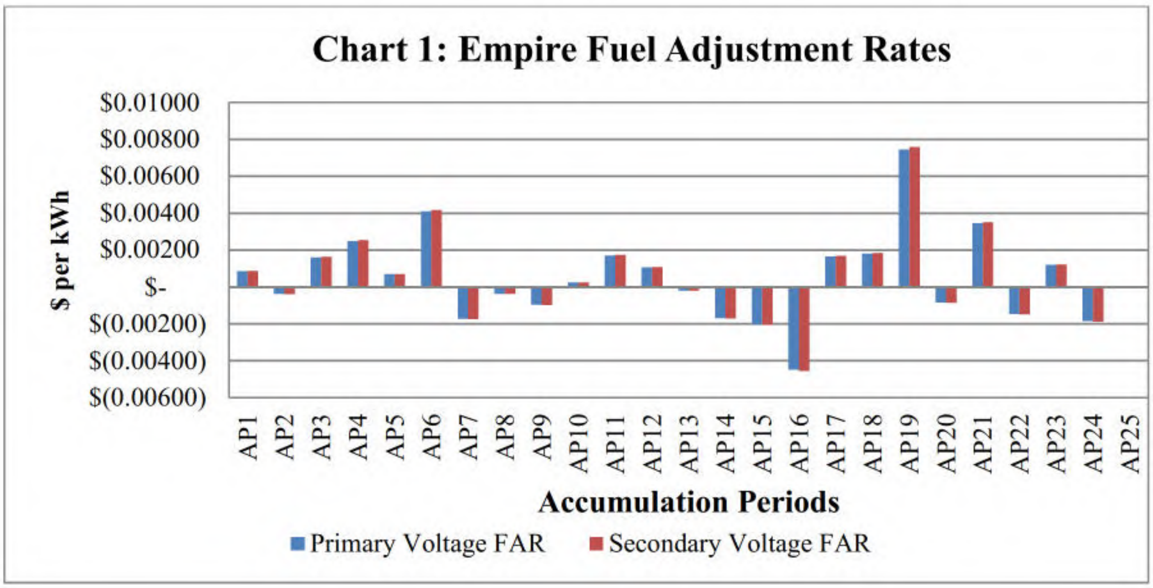
[120] 20 CSR 4240-20.090(11) Prudence Reviews Respecting RAMs [rate adjustment mechanisms]. A prudence review of the costs subject to the FAC shall occur no less frequently than every eighteen months.

[121] 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

C. Continuation of FAC

Staff recommends that the Commission approve, with modifications, the continuation of Empire's FAC.

The Company filed for and received approval of changes to its fuel adjustment rates (FARs) for twenty-five (25) completed APs (AP1 through AP25). The primary and secondary voltage FARs for each accumulation period are reflected in Chart 1.



The Company's actual Total Energy Cost exceeded the then-effective Base Factors multiplied by monthly usage billed to Empire's customers' in fourteen out of twenty-five completed accumulation periods. Actual Total Energy Cost include:

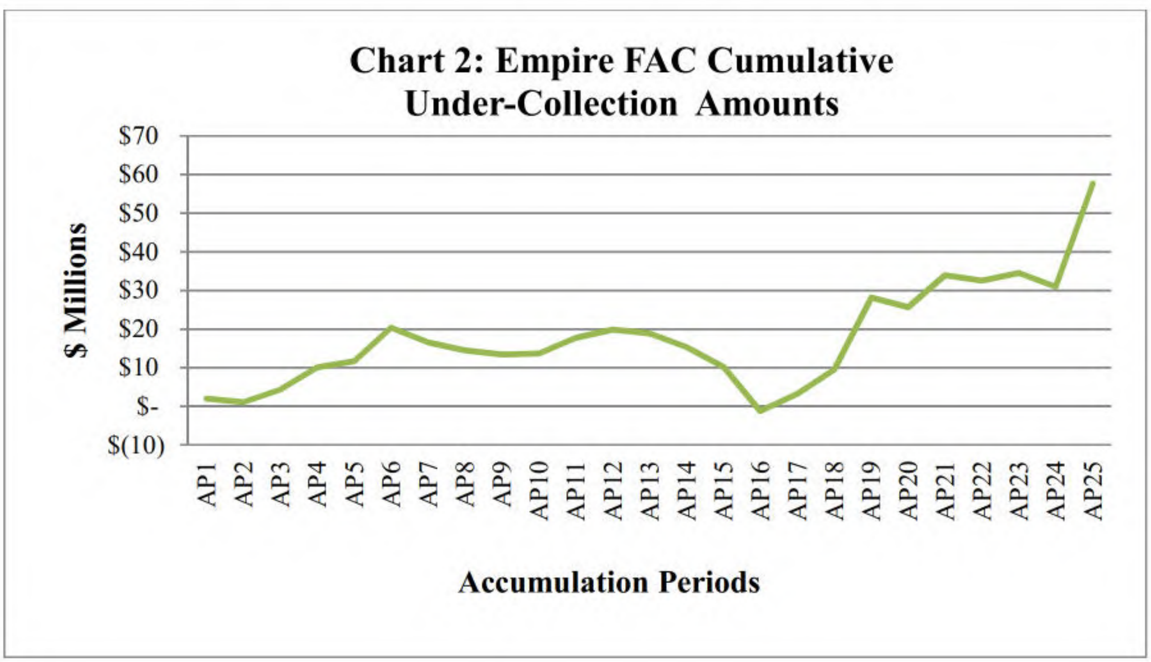
1) Empire's total booked costs as allocated to its Missouri retail jurisdiction for fuel consumed in the Company's generating units, including the costs associated with the Company's fuel hedging program;
2) Purchased power energy charges, including applicable transmission fees;
3) Southwest Power Pool variable costs; and
4) Air quality control system consumables, such as anhydrous ammonia, limestone, and powder activated carbon, and emission allowance costs.

issued on February 28, 2018 states on page 22, "the Commission finds and concludes that Empire's natural gas hedging policy was prudent".

Actual Total Energy Cost does not include the purchased power demand costs, since these are considered to be fixed costs. Actual FAC costs are off-set by actual Revenue from Off-System Sales, actual Net Emission Costs, and actual Renewable Energy Credit Revenues. In fourteen of its accumulation periods (AP1, AP3, AP4, AP5, AP6, AP10, AP11, AP12, AP17, AP18, AP19, AP21, AP23, and AP25), Empire under-collected its actual Total Energy Costs, and during eleven accumulation periods (AP2, AP7, AP8, AP9, AP13, AP14, AP15, AP16, AP20, AP22 and AP24), Empire's Base Energy Cost exceeded actual Total Energy Cost.

At the conclusions of its general electric rate cases, during AP3, AP6, AP10, AP14, AP17, and AP25 – Case Nos. ER-2010-0130, ER-2011-0004, ER-2012-0345, ER-2014-0351, ER-2016-0023, and ER-2019-0374, respectively – the Base Factors in Empire's FAC were re-set.

Charts 2 and 3 illustrate the following information for the twenty-five (25) accumulation periods: 1) cumulative under collection amount which is equal to Total Energy Cost (TEC) less Net Base Energy Cost ("B") for Empire's Missouri jurisdiction,[122] and 2) percentage of cumulative under-collection amount which is equal to 100*(TEC-B)/TEC.



[122] For AP25, this is the amount on line 5 of Empire's 2nd Revised Sheet No. 17q.

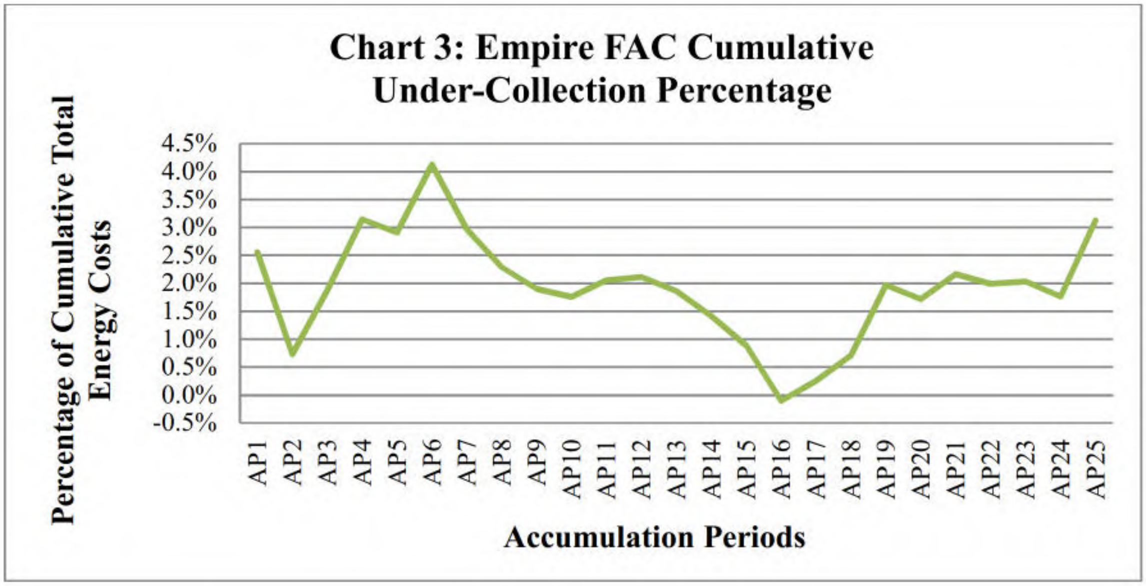


Chart 1 illustrates the FARs' variability as a result of variations in each accumulation period's billed Base Energy Cost and actual Total Energy Cost. From Charts 2 and 3, Staff observes that the FAC cumulative under-collected amount over eleven years is approximately \$58 million, or about 3.1% percent of total actual Total Energy Cost of \$1.843 million, during AP1 through AP25.

As shown in the previous charts and discussion, Empire's actual Total Energy Costs continue to be relatively large, volatile, and beyond its control. In addition, the Southwest Power Pool (SPP) conversion to the Integrated Marketplace (IM) on March 1, 2014 represents a fundamental change in how Empire's generation is dispatched and how Empire serves its native load. By having a FAC that includes IM costs, the effects of the IM will flow through the FAC to both the Company and its customers in a timely manner.

D. Revising the Base Factor

Correctly setting the Base Factor in Empire's FAC tariff sheets is critical to both a well-functioning FAC and a well-functioning FAC sharing mechanism. For the reasons stated below, Staff recommends the Commission calculate Empire's FAC Base Factor in its FAC on the Base Energy Cost that the Commission includes in the revenue requirement it sets in this case.

To demonstrate why it is critical to correctly set the Base Factor, Table 7 below shows three scenarios in which the FAC Base Energy Cost used to set the FAC Base Factor is equal to, less than, or greater than the Base Energy Cost in the revenue requirement upon which the Commission sets general rates:

Table 7: 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 Net Energy Cost **Greater Than** 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) x 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 **Less Than** 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) x 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)**

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

Case 2 illustrates that if the FAC Base Energy Cost used for the Base Factor is less than the Base Energy Cost in the revenue requirement used for setting general rates, the utility will collect more than was intended and customers pay more than the FAC was designed for them to pay, regardless of the level of actual energy costs.

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

These three cases illustrate the importance of setting the Base Factor in the FAC correctly, *i.e.,* revising the Base Factor to match the Base Energy Cost in the revenue requirement used for setting general rates. Case 1 is the preferred case, because the amount refunded to or collected from customers is closest to zero. In addition, Outcome 1 and Outcome 2 under Case 1 result in the utility collecting slightly more than was intended or the customers pay slightly less than what was intended, as opposed to the more extreme outcomes under Cases 2 and 3.

Confidential Table 8 below contains a comparison of Empire's FERC account expenses and revenues, annual kWhs, cents per kWh, and Base Energy Cost approved in the last general rate case, Case No. ER-2019-0374, and Empire's proposed[123] Base Energy Cost in this case. Empire's proposed overall total Fuel and Purchased Power for the FAC base decreased a total of 58.59% compared to the total fuel and purchased power for FAC base approved in Case No. ER-2019-0374. The primary driver that significantly reduced the proposed FAC base factor is the Company's generation mix transformation, specifically the introduction of about 600 megawatts (MW) of new wind resources to the Company's generation mix.[124] The revenues from the sale of energy from the new wind farms offset the costs of fuel and purchased power. Staff witness Charles T. Poston, PE also addresses the effects of the new wind farm revenues in his testimony concerning variable fuel expense.

continued on next page

[123] This proposed FAC Base Factor calculation can be found in Todd Tarter's Direct Testimony, Schedule TWT-3.
[124] Empire witness Todd Tarter's Direct Testimony page 5.

**

Confidential Table 8: FAC BASE FACTOR CALCULATION

[redacted]

**

E. Additional Reporting Requirements

Due to the accelerated Staff review process necessary with FAC adjustment filings,[125] similar to what it did in the last Empire rate case (Case No. ER-2019-0374), Staff recommends the Commission order Empire to continue providing the following information between rate cases, to aid Staff in performing FAC tariff, prudence, and true-up reviews:

- Monthly SPP market settlements and revenue neutrality uplift charges;
- Monthly filings that will aid the Staff in performing FAC tariff, prudence, and true-up reviews;
- Additional FAC monthly reporting, including a detailed listing of all costs and revenues incurred due to the Missouri Joint Municipal Electric Utility Commission contracts;
- Notification to Staff within 30 days of entering a new long-term contract for purchased power, transportation, coal, natural gas or other fuel (natural gas spot transactions are specifically excluded);
- Notification to Staff within 30 days of changes to a purchased power contract or entering a new long-term contract for purchased power;
- Monthly natural gas fuel reports that include all transactions (spot and longer term), including terms, volumes, price, and analysis of number of bids;
- Every Empire hedging policy in effect at the time the tariff changes ordered by the Commission in this rate case go into effect;
- Notification to Staff within 30 days of any material change in Empire's fuel hedging policy and Staff access to new policies;
- Missouri Fuel Adjustment Interest calculation workpapers in electronic format with all formulas intact when Empire files for a change in its cost adjustment factor;
- Notification to Staff within 30 days of any revisions to Empire's internal policies for participating in the SPP and Staff access to the new policies;
- Access to all natural gas, nuclear fuel, coal, and transportation contracts and policies upon Staff's request, at Empire's corporate office in Joplin, Missouri; and

[125] 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.

- Notification to Staff within 30 days of the effective date of every natural gas contract Empire enters into and Staff opportunity to review the contract at Empire's corporate office in Joplin, Missouri.

Staff Expert/Witness: Brooke Mastrogiannis

F. FAC Voltage Adjustment Factors

Empire filed a request to continue its Fuel Adjustment Clause (FAC) in this case. Commission Rule 20 CSR 4240-20.090(13) requires an electric utility that desires to continue using a Commission authorized Rate Adjustment Mechanism (RAM), such as an FAC, to complete a jurisdictional system loss study of the corresponding energy losses experienced in its delivery of electricity on its system. This study must be based upon a consecutive twelve-month period, preferably a calendar year, and be conducted at least once every four years following the Commission's initial approval of the Company's FAC.[126] Empire indicated its intention to utilize the jurisdictional system loss study that was provided in its workpapers submitted with its last rate case (ER-2019-0374) as it remains compliant with this aforementioned regulation. This loss study contains system loss calculations/determinations based on data collected during calendar year 2017. Staff used the information in this loss study in developing the following recommended primary and secondary voltage level adjustment factors:

[126] 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 the 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 then conduct a Missouri jurisdictional loss study no less often than once 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.

Voltage Level	Voltage Adjustment Factor
Primary	1.0429
Secondary	1.0625

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

Staff Expert/Witness: Alan J. Bax

XII. Customer Service

A. Overview since Merger with Liberty

Condition number one under Customer Service Conditions in the Commission approved Stipulation and Agreement in the Algonquin – Empire merger Case No. EM-2016-0213, states that, "Empire and Liberty will strive to meet or exceed the customer service and operational levels currently provided to their customers."[127] In Case No. ER-2019-0374, Staff determined, and Empire admitted, that Empire failed to meet targeted levels of performance. In that proceeding, Empire witness Brent Baker stated, "certain customer service call answering metrics were not met in 2017 and 2018. In 2017, the Company missed the target by 2%, and in 2018, the Company was 16% below 18 targeted levels of performance."[128]

Empire's unsatisfactory customer service performance was a significant issue in Empire's last general rate case, Case No. ER-2019-0374. The Commission's concerns over Empire's customer service resulted in the Commission ordering Empire to do the following tasks for the years 2020, 2021, and 2022 related to meter reading and billing:

1. Incorporate data into its monthly reports to Commission Staff.
2. Initiate quarterly reports to the Commission Staff and OPC regarding the number of estimated meter readings.

[127] EM-2016-0213, Stipulation and Agreement, August 4, 2016, page 10.
[128] ER-2019-0374, Direct Testimony of Brent Baker, August 14, 2019, page 12.

3. Initiate quarterly reports to the Commission Staff and OPC regarding the number of estimated meter readings exceeding three consecutive estimates.
4. Initiate quarterly reports to the Commission Staff and OPC regarding the number of bills with a billing period outside of 26 to 35 days.
5. Initiate quarterly reports to the Commission Staff and OPC regarding the Company and contract meter reader staffing levels.
6. Evaluate the authorized meter reader staffing level and take action to maintain adequate meter reader staffing levels in order to minimize the number of estimated bills.
7. Company will meet with Staff and OPC to discuss bill redesign possibilities for the future.
8. Ensure that all customers who receive estimated bills for three consecutive months receive the appropriate communication regarding estimated bills and their option to report usage as required by Service and Billing Practices, Rule 20 CSR 4240-13.020(3).
9. Ensure that all customers who receive an adjusted bill due to underestimated usage are offered the appropriate amount of time to pay the amount due on past actual usage as required by Service and Billing Practices, Rule 20 CSR 4240-13.025(1)(C).
10. Evaluate meter-reading practices and take action to ensure that billing periods stay within the required 26 to 35 days, unless permitted by those exceptions listed in the Commission's rules.
11. File notice within this case by September 1, 2020, containing an explanation of the actions the Company has taken to implement the above recommendations related to billing and bill estimates.[129]

Per the conditions of the Merger and the aforementioned ordered tasks in Case No. ER-2019-0374, Staff monitors on an ongoing basis Empire's customer service and operational performance related to meter reading and billing practices. Staff concludes that as of the date of this testimony, Empire has improved its customer service performance and reduced the number of estimated monthly meter reads. However, Staff identified issues with task ten (10) from the Commission's Order in Case No. ER-2019-0374 that requires Empire to evaluate

[129] ER-2019-0374, Amended Report and Order, July 23, 2020, page 145.

meter reading practices to ensure billing periods stay within the required 26 to 35 days per 20 CSR 4240-13.015(C). Staff's rebuttal testimony will respond to Empire's direct testimony regarding steps taken to comply with task ten (10) and Staff's rebuttal will also respond to Empire's testimony regarding its overall efforts to comply with the Amended Report and Order in Case No. ER-2019-0374.

Staff Expert/Witness: Contessa King

B. Credit Card Fees

Background

In Case No. ER-2019-0374, Empire proposed the elimination of credit card convenience fees for individual customers, and instead allow Empire to recover the costs associated with processing card payments in its overall cost of service. Staff recommended that the Commission grant the request but with three recommendations. The Commission found that credit card fees should be included in the Company's revenue requirement so that individual fees are no longer required. The Commission also found it reasonable to order Empire to perform the following tasks as suggested by Staff:

> *(1) Track performance and savings to the Company and its customers from this initiative;*
>
> *(2) Monitor the level of customers using the credit card option, whether the number of payments by credit card increases, and whether eliminating a fee to pay by credit card results in savings to the customer, to the Company, or to both; and*
>
> *(3) State how the Company will inform customers that there is no fee to pay their bill by credit card.*[130]

Commission Staff's Analysis

Task (1) - Empire states that in addition to customers not being charged direct fees for credit card payments, the Company has chosen a new vendor, which has lowered the overall cost to process fees. Empire asserts that the lower fees have provided savings for customers and this is further demonstrated by the amount the Company is seeking to include in the cost of

[130] ER-2019-0374, Amended Report and Order, page 76.

service."[131] Staff agrees with Empire's assessment that customers will and have seen savings. Staff witness Angela Niemeier will address the revenue requirement adjustment concerning credit card fees.

Task (2) - The Company has provided Staff with credit card usage from April 2019 through August 2021. It appears that credit card usage has increased. Empire asserted it was difficult to determine if the COVID-19 pandemic attributed to the increase and the Company will continue tracking and analyzing savings to customers and the Company.[132] Staff agrees that the Company should continue to track and analyze savings to customers and the Company.

Task (3) – In Staff Data Request No. 0229, Staff inquired about Empire's efforts to notify Commission Staff on how customers would be informed that there is no fee for credit card payments. Empire responded that on October 8, 2020, an e-mail was sent from the Company's legal counsel to Staff and OPC.[133]

Staff did receive an email with two attachments on October 8, 2020, informing Staff and OPC that an email would be sent October 9, 2020, to Empire's gas and electric customers. The purpose of the emails to be sent to customers was "To provide customers with information regarding the new look and feel by moving to the KUBRA system." Empire also informed Staff and OPC that there would be updates on Empire's website payment page starting October 16, 2020. On the email to be sent to electric customers, the change in fee was mentioned on the second page, along with a footnote on the third page stating that the change in fee started on September 16, 2020.

Summary

Staff believes that Empire has complied with the Commission's tasks (1) and (2), and that Empire complied with the notifications requirement in task (3).

However, Staff will address in rebuttal Empire's Direct Testimony regarding the adequacy of Empire's customer notifications, and whether Empire should take steps to improve its customer notice that there is no fee for credit card payments.

Staff Expert/Witness: Scott J. Glasgow

[131] ER-2021-0312, Direct Testimony Jon Harrison, page 9.
[132] ER-2021-0312, Direct Testimony Jon Harrison, pafe 10.
[133] Staff Data Request No. 0229.

XIII. Affiliate Transaction

In Case No. ER-2019-0374, the Amended Report and Order states "the Commission also finds that Empire's interactions with its affiliates should be reviewed as part of the next rate case. Staff should conduct an audit of the various types of affiliate transactions as part of this review and provide testimony to support its findings."

As part of its audit process in this case, Staff reviewed the methods used by the following Empire Electric affiliates: Empire District Industries, Inc. ("EDI"), The Empire District Gas Company ("EDG"), Algonquin Power & Utilities Corp. ("APUC"), Liberty Utilities (Canada) Corp. ("LUCC"), Liberty Utilities Service Corp. ("LUSC"), Algonquin Power Co., d/b/a Liberty Power ("APCO"), Liberty Utilities Co, and Liberty Utilities Corp ("Park Water") to assign and allocate costs to Empire Electric's operations. These services include payroll and benefits funding, direct costs, APUC indirect costs, Liberty Algonquin Business Services ("LABS") indirect costs, Liberty Utilities indirect costs and regional indirect costs.

Affiliate Transaction Rule

The Commission's Affiliate Transactions Rule (ATR) applicable to electric utilities, Commission Rule 20 CSR 4240-20.015, originally became effective February 29, 2000, and is intended to prevent regulated utilities from subsidizing their non-regulated operations. In order to accomplish this objective, the rule sets forth financial standards, evidentiary standards, and recordkeeping requirements applicable to regulated electrical corporations such as Empire.[134]

Pursuant to the ATR, an affiliate transaction is any transaction for the provision, purchase, or sale of any information, asset, product or service, or portion of any product or service, between a regulated electrical corporation and an affiliated entity, and shall include all transactions carried out between any unregulated business operation of a regulated electrical corporation and the regulated business operations of an electrical corporation.

The rule requires regulated electrical corporations to meet certain "Standards" when transacting with affiliates. The primary standard is that a regulated electrical corporation shall not provide a "financial advantage" to an affiliated entity. For purposes of the rule, a regulated electrical corporation shall be deemed to provide a financial advantage to an affiliated entity if:

[134] *See* the "Purpose Statement" of Commission Rule 20 CSR 4240-20.015.

1. It compensates an affiliated entity for goods or services above or lesser of -
    A. The fair market price; or
    B. The fully distributed cost to the regulated electrical corporation to provide the goods or services for itself; or
2. It transfers information, assets, goods or services of any kind to an affiliated entity below the greater of –
    A. The fair market price; or
    B. The fully distributed cost to the regulated electrical corporation.[135]

The only affiliate transactions provided an exception from the rule on this point are corporate support functions, which are defined as "joint corporate oversight, governance, support systems and personnel, involving payroll, shareholder services, financial reporting, human resources, employee records, pension management, legal services, and research and development activities."[136] Except as necessary to provide these corporate support services, a regulated electrical corporation shall conduct its business in such a way as not to provide any preferential service, information or treatment to an affiliate entity over another party at any time.[137] In addition to the standards outlined above, a regulated electric corporation shall include in its annual Cost Allocation Manual (CAM), the criteria, guidelines, and procedures it will follow to be in compliance with this rule.[138]

For each affiliate transaction a regulated electric corporation engages in, it must also meet certain "Evidentiary Standards." When a regulated electrical corporation purchases information, assets, goods or services from an affiliated entity, the regulated electrical corporation shall either obtain competitive bids for such information, assets, goods or services or demonstrate why competitive bids were neither necessary nor appropriate. The regulated electrical corporation shall document both the fair market price of such information, assets, goods and services and the fully distributed cost (FDC) to the regulated electrical corporation to product the information, assets, goods or services for itself. Similar standards are prescribed

[135] *See* Commission Rule 20 CSR 4240-20.015(2) (A).
[136] *See* Commission Rule 20 CSR 4240-20.015(1) (D).
[137] *See* Commission Rule 20 CSR 4240-20.015(2) (B).
[138] *See* Commission Rule 20 CSR 4240-20.015(2) (E).

for transactions where a regulated electric corporation provides information, assets, goods or services to affiliated entities. Finally, regulated electric corporations are to use a "commission-approved" CAM, which sets forth cost allocation, market valuation and internal cost methods, when transacting with affiliates.[139]

To ensure its transactions with affiliates are auditable, regulated electric corporations are also required to meet certain "Record Keeping Requirements." Regulated electric corporations are required to maintain books, accounts, and records separate from those of its affiliates. The rule further requires regulated electric corporations to maintain certain information relating to its affiliate transactions in a mutually agreed-to electronic format on a calendar year basis, and to provide that information to Staff and OPC on, or before, March 15 of the succeeding year. The information required to be provided includes: a full and complete list of all goods and services provided to or received from affiliate entities, all contracts with affiliated entities, all affiliate transactions undertaken with affiliated entities without a written contact together with a brief explanation of why there was no contract, the amount of affiliated transactions by affiliated entity and account charged, and the basis used to record each type of affiliated transactions.[140] The rule also requires certain records be kept by a regulated electric utility's affiliates, and that regulated electric corporations make those records available to the Commission when required.[141]

On July 11, 2018, the Commission opened Case No. AW-2018-0394, to assist Staff in its consideration of new and existing rules regarding the treatment of affiliate transactions and HVAC affiliate transactions by and among electrical corporations, gas corporations, heating companies, water corporations with more than 8,000 customers, and sewer corporations with more than 8,000 customer. While Staff has submitted multiple versions of draft ATRs and HVAC Affiliate Service Rules in the working case, no subsequent rulemaking has yet resulted.

Empire's Cost Allocation Manual

The allocation of costs and methods used to allocate costs from APUC to its subsidiaries are outlined in Liberty's annual CAM, which was provided via email to OPC and Staff on

[139] *See* Commission Rule 20 CSR 4240-20.015(3).
[140] *See* Commission Rule 20 CSR 4240-20.015(4).
[141] *See* Commission Rule 20 CSR 4240-20.015(5) & (6).

March 15, 2021, as part of its 2020 Affiliate Transaction Report. It was then submitted to the Commission on August 16, 2021 under Tracking No. BAFT-2022-0071 in the Commission's Electronic Filing Information System (EFIS). Liberty's CAM covers each of its Missouri subsidiaries, including Empire Electric.

While Liberty submits its CAM to the Commission annually, the CAM has not been formally approved by the Commission. On June 30, 2017, Empire Electric, Empire District Gas Company, Liberty Utilities (Midstates Natural Gas) Corp., and Liberty Utilities (Missouri Water), LLC, filed an application for approval of their CAM by the Commission in Case No. AO-2017-0360. However, the proceeding has been stayed since January 10, 2020, primarily due to the potential for revisions to the Commission's ATR through Case No. AW-2018-0394. That being said, the CAM provides a detailed explanation of services provided by APUC and its affiliates to other entities within the APUC business and describes the direct and indirect charging methodologies used for those services.

Empire is part of a multi-layered corporate structure. It is directly owned by Liberty Utilities Co., which is owned by a string of affiliated companies, and ultimately owned by APUC. Empire receives a variety of corporate, administrative, and support services from a number of upstream affiliate entities. In addition, Empire also receives support services from LUSC. Almost all of Empire's affiliated transactions involve receipt of corporate support services from its affiliates, including LUSC.

APUC provides financing, financial control, legal, executive and strategic management and related services to Liberty Utilities, Liberty Power, and its international utilities in Chile and Bermuda. APUC labor costs are directly[142] charged to the extent possible to the affiliated entity on whose behalf APUC is incurring the costs. Direct labor charges are based upon APUC employee timesheets. If APUC labor is used to benefit all subsidiaries in general, then indirect[143] allocation methods are used to allocate the costs.

[142] In the context of this testimony, direct charged costs are those incurred on behalf of a specific business unit, or that can be identified with a specific product or service.

[143] In the context of this testimony, an indirect cost is one that is incurred on behalf of more than one business unit or for all business units within a corporate structure. These costs cannot be identified with a particular service or product.

APUC incurs three types of costs that are passed to its regulated and unregulated subsidiaries. First, there are direct costs that benefit an unregulated company, which are direct assigned to that company. Second, there are APUC's costs that directly benefit a specific regulated company, which are directly assigned to that specific regulated company. If a good or service cost benefits more than one regulated company, the cost is allocated using a Utility-Four Factor Methodology.[144] Lastly, there are the remaining costs that benefit the entire multi-layered structure (both regulated and unregulated companies). All costs in the last category have to be allocated between regulated and nonregulated parts of the business. This allocation is based on the function or cost type based on various weighted factors. The factors can be a combination of the following: net plant, number of employees, revenues, or O&M. In Liberty's CAM there are tables provided to show which particular allocation factors to use based on the underlying type of cost subject to allocation.

LUCC is based in Canada and provides various services to Liberty Utilities, specific services to Liberty Power, and shared services to the entire organization. There are three types of corporate costs that are allocated to Liberty Power and regulated utilities. As with APUC, the direct cost for unregulated companies are directly assigned to the utility. Second, indirect costs that benefit all regulated operations are allocated using the Utility Four-Factor Methodology. Lastly, direct charges that are directly assigned to a utility are allocated at 100% to that utility; however, if the cost includes more than one regulated company it is allocated using the Utility Four-Factor Methodology.

LABS, a business unit within LUCC and LUSC, charges costs to regulated and unregulated subsidiaries. For example, the services include: budgeting, forecasting and issuing consolidated and stand-alone financial statements, treasury functions, development of human resources policies and procedures, information systems and equipment for account. LABS incurs three types of costs that are passed to regulated and unregulated entities. First, as with APUC, direct costs tied to unregulated subsidiaries are directly assigned to the specific unregulated subsidiary. A direct cost traceable to a regulated subsidiary is directly assigned to that specific subsidiary utility; however, if one or more regulated company is involved then the

[144] The Utility-Four Factor Methodology factors are based on the following: customer count, utility net plant, non-labor expenses, and labor expenses.

cost is allocated using the Utility Four-Factor Method. Indirect costs that benefit both unregulated and regulated subsidiaries are allocated based on a combination of the following: number of employees, O&M expense, capital expenditures, and revenue or net plant. For example, allocation of costs associated with business services for utility planning is based on the following factors: revenue, O&M expense, and net plant. If LABS costs need to be broken down between regulated operating utilities it is based on the Utility Four-Factor Methodology.

The majority of costs charged by LUSC relate to salaries for employees that perform functions for the various regulated and non-regulated entities under the APUC umbrella; these costs include benefits and insurance. When possible LUSC will directly charge the applicable utility; however, when that is not possible and the costs are indirect they are allocated using the regional four-factor allocation. Each factor (customer count, utility net plant, non-labor expense, and total expense) has a 25% weight. Empire evaluates and updates the allocation factors annually. These factors are based on the most recent audited financial statements and other actual year-end information. These factors come into effect April 1st of each year. The allocation factors are listed in the CAM. Caroline Newkirk explains the allocation procedures more in detail in Section VI.A. Corporate Allocations.

Empire Electric's Affiliate Transactions

Staff reviewed Empire's 2020 Affiliate Transaction Report, which includes the CAM and corporate organizational charts. The services provided to Empire by various affiliates include the following: pole attachments, office space rent, customer billing services, phone services, purchasing services, two way radio services, computer technical support, miscellaneous administrative and general support, use of regulated vehicles, fiber optic services, and interest on cash held. In the Affiliate Transaction Report a cost amount is provided for each category.

Under the Affiliate Transaction Rule,[145] when a regulated electrical corporation purchases information, assets, goods or services from an affiliate entity, the regulated electrical corporation shall either obtain competitive bids for such information, assets, goods or services or demonstrate why competitive bids were neither necessary nor appropriate. The transactions

[145] Commission Rule 20 CSR 4240-20.015(3).

that involve either the purchase or receipt of information, assets, goods or services by a regulated electrical corporation from an affiliated entity, the regulated electrical corporation shall document both the fair market price of such information, assets, goods, and services and the FDC to the regulated electrical corporation to produce the information, assets, goods, or services for itself.

Application of the "higher of/lower of" pricing standard to regulated – nonregulated affiliate transactions is an effective means to protect regulated customers from higher rates due to potential cross subsidy. For example, Empire received fiber optic services from Empire District Industries, Inc. during the test year and update period. While Empire did not obtain competitive bids for this service, Empire did utilize a study of Multiple Protocol Layer Services rates conducted by Teleplus Solutions on Empire's behalf to determine market price. Staff determined this process to be reasonable.

However, as stated above, Empire is directly owned by LUCO, which in turn is owned by a string of affiliated companies, and ultimately by APUC. Utilities operating under holding company structures typically involve the centralized provision of service by a "service company" to regulated and unregulated holding company affiliates. Use of service companies to obtain necessary corporate support service for multiple entities under a holding company structure is common practice for utilities, as it is believed to be an economical approach for provision of these services.

The specific item services included in the definition of "corporate support" in the ATRs are joint corporate oversight, governance, support systems and personnel involving payroll, shareholder services, financial reporting, human resources, employee records, pension management, legal services, and research and development activities. There are apparent economies of scale benefits when such services are offered on a centralized basis to affiliated entities. All of the above listed services are currently provided to Empire, at cost, by its affiliates.

The FERC currently prohibits centralized service companies under its jurisdiction from charging a profit for corporate support services to affiliated entities. Elimination of profit from service company affiliated transactions tend to make receipt of goods or services from a service company more economical to utilities than obtaining the same good or service from an unaffiliated profit-seeking entity, all other things being equal. While FERC does not require the use of service companies for holding company structures, FERC Order 667, one of several rulemaking orders amending FERC's regulations to implement the repeal of the Public Utility Holding Company Act of 1935 and enact the Public Utility Holding Company Act of 2005, provides that transactions with centralized service companies must be made at cost. LUSC, LUCC and APUC are centralized service companies, and their services to Empire Electric are valued at cost. Staff generally agrees with FERC that it not necessary to obtain market values for services obtained from service companies at cost.

As stated above, Empire is part of a multi-layered corporate structure receives a variety of corporate, administrative, and support services from a number of upstream affiliate entities. The provision of corporate services to a number of affiliates on a centralized basis, as is done for Empire by the Algonquin upstream affiliates, should be expected to be inherently more cost-effective than having each affiliate, including regulated utilities, provide the service for themselves, due to economies of scale. When multiple affiliated entities exist under the corporate umbrella, it is reasonable to support the concept of centralized provision for services to utilities, due to the cost-effectiveness.

As of the filing of its direct testimony, Staff has reviewed the transactions listed in the Affiliate Transactions Report and found the costs charged to Empire by affiliates during the test year appear to be reasonable, consistent with the intent of, and substantially in compliance with, the Commission's ATR. That being said, Staff has a Data Request No. 0297 that is due November 8, 2021, that will provide Staff additional information with regard to Empire's affiliate transactions, including the extent to which Empire obtains competitive bids for provision of market services. Staff will continue to investigate affiliate transactions throughout the case.

Staff Expert/Witness: Ashley Sarver

XIV. Retirement of Asbury

A. Asbury Generating Station Unrecovered Investment

Empire retired its Asbury Generating Station ("Asbury"), a coal-fired unit, on March 1, 2020. In Empire's last general rate case, No. ER-2019-0374, with rates effective

September 16, 2020, the capital costs and operating costs associated with Asbury were still fully reflected in the ordered customer rates. However, also in that 2019 rate case, the Commission ordered that:

> The Empire District Electric Company shall record as a regulatory asset/liability the costs and revenues identified in the body of this order as of January 1, 2020, related to the closure of the Asbury Power Plant. The regulatory asset/liability should quantify separately dollars related to the categories of costs and revenues.[146]

The intent of the Commission's directive was for Empire to track and defer all of the financial impacts of Asbury's retirement so that all savings or additional costs incurred by Empire associated with the plant retirement between the date of the retirement and Empire's next general rate proceeding would be eligible for reflection in customer rates in that next rate case. However, in the 2019 rate case order, the Commission did not directly address any issues regarding the ratemaking treatment to be afforded to any unrecovered capital investment for Asbury existing as of the date of its retirement.[147]

In this rate case, Empire is seeking to recover both a return "on" approximately $159.4 million of unrecovered investment in Asbury that existed as of its retirement date through inclusion of the amount in rate base, and a return "of" that unrecovered investment through an amortization to expense over a 26-year period (which would be valued at approximately $6.13 million). The unrecovered investment arises because Empire chose to retire Asbury earlier than the retirement date upon which its last depreciation rates for the unit were based. (The depreciation rates authorized for Asbury at the time of its retirement assumed that the unit would retire in 2035.[148]) The bulk of Asbury's unrecovered costs as of the retirement date relate to major environmental investments Empire made to the unit in 2008 (a Selective Catalytic Reduction addition) and 2014 (an Air Quality Control System addition).

Staff views the question of whether a utility should be allowed to continue to recover, in rates, costs associated with a retired plant asset as a determination to be made by the

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[146] Amended Report and Order in ER-2019-0374 at page 190 paragraph 6 (see Appendix 3, Schedule MLO-d1 attached to this report).

[147] *Id.* at 117 ("For this reason, the impacts of Asbury's retirements should be considered in their entirety in the next rate case and not as isolated adjustments in this case.").

[148] Direct Testimony of Empire Witness Tisha Sanderson, Case No. ER-2021-0312, page 21, lines 7 – 9.

Commission on a case-by-case basis. As a general rule in Missouri, recovery of plant assets that are not "used and useful" in rates has not been allowed, and Asbury since early 2020 has neither been used by Empire to generate electricity nor useful to Empire customers as a source of meeting customer demands. The issue now before the Commission is whether there are specific circumstances regarding the decision to retire Asbury that would justify a continued total or partial recovery in rates of Asbury unrecovered investment in this proceeding.

Regarding past decisions by Empire that directly resulted in the existence of unrecovered Asbury costs as of its retirement date, the most important were those decisions to add a material amount of investment in environmental upgrades in 2008 and 2014, and the subsequent decision to retire the unit in 2020. Staff is not challenging the prudence of either the environmental upgrade decisions or the retirement decision for Asbury, as those choices appear to have been reasonable based on the information relied upon by Empire at that time. However, regardless of the underlying prudence of those decisions, Staff's position is that only a partial recovery of unrecovered Asbury costs in rates by Empire in this proceeding is reasonable.

The primary reason that Empire chose to retire Asbury only a few years after making significant capital investments in the unit would be the perception that recent political, economic and regulatory changes affecting the electric utility industry made continued use of coal units to generate electricity increasing less cost-effective than competing technologies. This changing environment did not affect Empire in isolation; Staff notes a general pattern of coal unit retirements occurring across the country in the last decade. Empire's decision to retire Asbury is part of this larger trend.

There is always an inherent risk in the utility industry, as well as for unregulated businesses, that economic decisions that were prudent and reasonable at the time they were made will prove to be less than optimal at a later time due to constantly changing factors. In light of this, the pertinent question regarding the Asbury retirement decision is whether the financial consequences of retiring this plant asset should be assigned in rates in entirety to utility customers, entirely to utility shareholders, or shared between the two groups. Staff's view is that, concerning Asbury, it is appropriate to share the economic impacts resulting from the early Asbury closure between the utility and its customers. This is best accomplished by including a "return of" Asbury unrecovered investment in Empire's rates resulting from this case, but not allowing a "return on" that investment in rate base.

Staff views that the purpose of utility regulation is not to shield monopoly utilities from all economic risk, but rather to serve as best as it can as a surrogate for the competitive forces facing unregulated industries. In a more competitive environment, if an unregulated company's assets become uneconomic over time through the normal operation of market forces, the company in question is not able to pass that impact on to customers. This does not necessarily mean that regulated utilities must likewise in all circumstances bear the entire financial burden of uneconomic but prudent investments. Unlike competitive businesses, a regulated utility does have an obligation to provide safe and adequate service to all customer in its service territory.

The fallout of Empire's Asbury cost recovery position in this case would require customers to pay in entirety for recent expensive capital improvements that in some cases were only in service for a short period of time, which appears unreasonable on its face. On the other hand, a complete assignment of the remaining Asbury capital costs to shareholders might provide incentives for Empire and other electric utilities to avoid taking timely action to retire plant assets that become uneconomic due to the dynamic nature of the industry. Accordingly, a sharing of the remaining unrecovered capital costs for Asbury would on balance provide an appropriate ratemaking result for Empire and its customers in this proceedings.

Staff recommends that the Commission in this case order all costs and savings associated with the Asbury retirement that were recorded by Empire into regulatory assets and regulatory liabilities pursuant to Commission order be charged to or flowed to customers in rates through a fifteen year amortization, to recognize in rates such costs/savings over the approximate period in which Asbury was expected to continue to provide power to Empire customers, prior to the retirement decision in 2020. Staff recommends that the unrecovered remaining balance of Asbury be part of the regulatory asset to be amortized over fifteen years, with the annual amortization of the Asbury unrecovered asset balance being worth approximately $10.6 million. However, Staff also recommends that the balance of the Asbury regulatory asset associated with the unrecovered investment in the unit be excluded from Empire's rate base. Further explanation of Staff's proposed treatment of the Asbury regulatory asset and liability in this case can be found in the next section of this Report, sponsored by Staff witness Amanda C. McMellen.

Staff Expert/Witness: Mark L. Oligschlaeger

B. Asbury Retirement AAO

Per the *Amended Report and Order* in Case No. ER-2019-0374 effective August 2, 2020, the Commission found that the retirement of Asbury to be extraordinary, unusual, unique and not recurring. Therefore, the Commission held that an AAO was appropriate to defer a final decision on the financial impacts of retiring Asbury[149] based on the criteria set forth in the *Global Stipulation and Agreement* ("Agreement"). Based on the Agreement, an AAO was established, beginning January 1, 2020, to separately track and quantify changes from base amounts included in Case No. ER-2019-0374 as reflected in Appendix D to the Agreement. The items included in the AAO deferral are as follows:

a. Rate of return on Asbury Plant,
b. Accumulated Depreciation,
c. Accumulated and Excess Deferred Income Tax,
d. Fuel inventories assigned to the Asbury Plant,
e. Depreciation expense,
f. All non-fuel/ non-labor operating and maintenance expenses,
g. All labor charges for maintaining and operating the Asbury Plant,
h. Property taxes assigned to the Asbury Plant, and
i. Any costs associated with the retirement of the Asbury Plant, including dismantlement and decommissioning, non-Empire labor excluded.

At OPC's request, the following items were also included in an AAO by the Commission:

a. Cash working capital and income tax gross up associated with Asbury,
b. Any fuel or SPP revenues or expenses associated with Asbury that do not flow through the FAC, and
c. Revenue from scrap value or value of items sold.

The intent of the AAO is to track and defer the changes to cost of service items reflected in Empire's last rate case, No. ER-2019-0374 caused by the Asbury retirement so as to allow any savings associated with Asbury's retirement or additional costs associated with the retirement to be returned to or charged to customers in subsequent rate cases. The Signatories to the

[149] Amended Report and Order, Case No. ER-2019-0374, issued July 23, 2020, pages 118-120.

Agreement acknowledged that the purpose of an AAO is to defer a final decision on current costs until a future rate case and that, in that future rate case, the signatories and the Commission are not bound by the terms of the AAO in setting new rates.[150]

At page 10 of the Agreement, it states "In future proceedings, Empire retains the right to request recovery of both a return of and on the investment in Asbury…"[151] In this proceeding, Empire has added the unrecovered Asbury plant value as of the date of its retirement to its Asbury regulatory asset and has proposed to recover in rates both a return of and on that amount. Staff is not opposed to amortization treatment of the unrecovered Asbury plant value, as explained in Section XIV.A. by Staff witness Mark L. Oligschlaeger, Staff recommends that the amortization period for both the regulatory asset and regulatory liability should be 15r. A 15 year amortization period is appropriate because that was the estimated remaining life for depreciation purposes of the Asbury assets at the time it was officially de-designated (retired) from the market by Empire. However, Staff recommends that no return on unrecovered Asbury investment be allowed in rate base in this proceeding. Refer again to Section XIV.A. of this Report for an explanation of this position. Asbury last generated power in December 2019 and was officially de-designated from the SPP market as of March 1, 2020.

Staff has included $1,297,499 as an addition to rate base for amounts included in the Asbury regulatory asset not associated with the Asbury unrecovered value. This amount reflects environmental costs incurred at Asbury since its retirement, and the impact of the retirement on the Asbury CWC allowance. Staff has also included as a reduction to rate base $44,526,314 for the Asbury regulatory liability balance, which includes the following: plant in service and associated accumulated depreciation, remaining plant and associated accumulated depreciation, fuel inventories, CWC, ADIT, excess ADIT, return based on the ROE from the last case, revenue from scrap value or value of items sold, depreciation expense, all non-fuel/non-labor O&M expense, property taxes, non-labor Asbury retirement/decommissioning costs and gross-up factor. The asset and liability amounts included in rate base represent the amounts that are above or below the Asbury revenue requirement baseline set in the last rate case. Based upon a 15-year amortization period, the amortization amounts included in expenses are

[150] Global Stipulation and Agreement dated April 15, 2020 pages 9-10.

[151] Global Stipulation and Agreement dated April 15, 2020, page 10.

$7,487,864 for the asset, including the unrecovered Asbury asset, and ($2,981,421) for the liability for a total adjustment of $4,519,443.

Staff Expert/Witness: Amanda C. McMellen

C. Asbury Decommissioning

Asbury Unit 1 ("Asbury") was first operational in 1970 as an approximately 200 MW coal-fired electric power plant in Jasper County, MO. Asbury was de-designated[152] from the Southwest Power Pool (SPP) in March of 2020.

Empire has set three goals for themselves for the decommissioning and repurposing process: 1) to create a safe and compliant work location; 2) to develop a decommissioning plan for the final disposition of the unused physical facilities on site; and 3) to repurpose certain facilities onsite to support the operations and maintenance activities for the renewable generation facilities.

To meet the first goal of creating a safe and compliant work location, Empire prioritized the removal of environmentally sensitive items. Work completed includes:

a) removal of anhydrous ammonia;
b) removal of oil from equipment;
c) removal of coal combustion residuals waste within plant ductwork;
d) removal of certain chemicals stored onsite and within equipment;
e) removal of residual coal from the coal piles;
f) modifications to water discharge outfalls;
g) isolation and Lock-Out Tag-Out on certain plant systems; and
h) modifications of environmental and operating permits.

Empire states that they are continuing to comply with all safety requirements, remaining permits, and all regulations for the facility to provide a workplace that is safe for the employees, contractors, and the general public.

The second goal entails the development of a decommissioning plan for Asbury. This goal is broken into three phases. Phase 1 includes performing an initial decommissioning

[152] *Designated Resource* – Any designated generation resource owned, purchased, or leased by a transmission customer (TC) to serve load in the SPP region. Designated resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the TC's load on a non-interruptible basis. (Glossary - Southwest Power Pool (spp.org))

analysis and study of the facilities. Phase 2 to includes the development of work plans, schedules, engineering plans and specifications, expound on and execution of the Isolation Study, asbestos removal, completion of NPDES modifications, and risk register modifications. Phase 3 includes finalization of bid documents, revision of cost estimates, bid administration, construction management, demolition of the facilities, reporting, and project accounting.

Empire retained the services of Black & Veatch[153] to perform Phase 1 of the decommissioning plan, which is to perform an initial decommissioning analysis and study of the facilities. The results of the Phase 1 report are included Empire Witness Drew Landoll's Confidential Direct Schedule DWL-1. From the analysis of the options, Empire decided to demolish Asbury Unit 1.

Phase 2 of the Decommissioning plan includes: a) asbestos identification and quantification study; b) Unit 1 engineering for isolation of the utilities; c) construction work to isolate and repower the Asbury Renewable Energy Operations Center from Unit 1; d) continued compliance driven modifications; e) certain risk register mitigations; f) ongoing development of demolition plans and associated work specifications; and g) removal of asbestos. This work has yet to be completed but is anticipated to be done by the end of the first quarter of 2022.

Phase 3 is planned to include finalization of bid documents, revision of cost estimates, bid administration, construction management, demolition of facilities, reporting, and project accounting. It is tentatively scheduled to be completed in 2024.

The last goal, as established by Empire, is to repurpose existing Asbury Assets. The current plan is to repurpose some of the facilities to be used for the Renewable Energy Center. The Renewable Energy Center will be used to operate and maintain Empire's renewable energy assets and facilities. Empire has repurposed the following items for the Renewable Energy Center: administration building, maintenance building, break room building, old administrative building, land, fire suppression and detection, rail spur, warehouses, and the related infrastructure supporting these facilities. The Renewable Operations Center employees are responsible for inventory management, engineering, operations, purchasing, and maintenance of the new wind farms and Prosperity solar facility. It also is the location of the primary warehouse for inventory, tools and equipment and the Vestas long-term maintenance-contract

[153] Black & Veatch is an engineering, procurement, consulting, and construction company.

employees. In addition to the Renewable Operations Center, Empire has constructed a separate office and maintenance building located at each wind farm. In repurposing the Asbury plant for renewable operations Liberty is estimating and additional ** [redacted] ** investment to provide an alternative power supply to the facility and other utilities. As this investment will be in-service outside of the update period, Staff will review the proposed investment in a future rate proceeding.

Staff's initial review of the decommissioning of the Asbury Plant has shown no cause for concern. Staff recommends that the Commission order Empire to update Staff with any updates or changes to the decommissioning on a regular basis.

Staff Expert/Witness: David T. Buttig, PE

Appendices

Appendix 1 - Staff Credentials

Appendix 2 - Cost of Capital

Appendix 3 - Other Staff Schedules

In-Service Review - Amanda Coffer

List of Sub-Accounts Included and Excluded for FAC - Brooke Mastrogiannis

Depreciation - Cedric E. Cunigan, PE

Amended Report and Order in ER-2019-0374, Page 190 - Mark L. Oligschlaeger

Appendix 4 - Construction Audit Report

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

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

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 Report - Cost of Service*; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

Alan J Bax
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 27th day of October 2021.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: April 04, 2025
Commission Number: 12412070

D Suzie Mankin
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

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

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 Report - Cost of Service*; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Kimberly K. Bolin

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 27th day of October 2021.

D. SUZIE MANKIN
Notary Public - Notary Seal
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Commissioned for Cole County
My Commission Expires: April 04, 2025
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D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

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

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 Report - Cost of Service*; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Kory J. Boustead
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 27th day of October 2021.

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D Suzie Mankin
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AFFIDAVIT OF DAVID T. BUTTIG, PE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

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

Further the Affiant sayeth not.

David Buttig

DAVID T. BUTTIG, 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 27th day of October 2021.

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D Suzie Mankin

Notary Public

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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 Report - Cost of Service*; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

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 28th day of October 2021.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: April 04, 2025
Commission Number: 12412070

D Suzie Mankin
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

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

AFFIDAVIT OF AMANDA COFFER

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

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

Further the Affiant sayeth not.

Amanda Coffer
AMANDA COFFER

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 27th day of October 2021.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: April 04, 2025
Commission Number: 12412070

D Suzie Mankin
Notary Public

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OF THE STATE OF MISSOURI

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

AFFIDAVIT OF KIM COX

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

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

Further the Affiant sayeth not.

Kim Cox

KIM COX

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 27th day of October 2021.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: April 04, 2025
Commission Number: 12412070

D. Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

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AFFIDAVIT OF CEDRIC E. CUNIGAN, PE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

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

Further the Affiant sayeth not.

Ced E Cunigan

CEDRIC E. CUNIGAN, 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 28th day of October 2021.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: April 04, 2025
Commission Number: 12412070

D Suzie Mankin

Notary Public

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AFFIDAVIT OF CLAIRE E. EUBANKS, PE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

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

Further the Affiant sayeth not.

Claire M Eubanks

CLAIRE E. 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 28th day of October 2021.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: April 04, 2025
Commission Number: 12412070

D Suzie Mankin

Notary Public

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OF THE STATE OF MISSOURI

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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 Report - Cost of Service*; 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 27th day of October 2021.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: April 04, 2025
Commission Number: 12412070

D Suzie Mankin
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

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

AFFIDAVIT OF SCOTT J. GLASGOW

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

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

Further the Affiant sayeth not.

Scott J. Glasgow

SCOTT J. GLASGOW

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 27th day of October 2021.

D. SUZIE MANKIN
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State of Missouri
Commissioned for Cole County
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D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

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

AFFIDAVIT OF COURTNEY HORTON

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

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

Further the Affiant sayeth not.

Courtney Horton

COURTNEY HORTON

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 27th day of October 2021.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: April 04, 2025
Commission Number: 12412070

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

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

AFFIDAVIT OF JORDAN T. HULL

STATE OF MISSOURI	)	
	)	ss.
COUNTY OF COLE	)	

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

Further the Affiant sayeth not.

Jordan Hull

JORDAN T. 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 27th day of October 2021.

D. SUZIE MANKIN
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State of Missouri
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My Commission Expires: April 04, 2025
Commission Number: 12412070

D. Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

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

AFFIDAVIT OF J LUBBERT

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

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

Further the Affiant sayeth not.

J Lubbert

J LUBBERT

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 29th day of October 2021.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: April 04, 2025
Commission Number: 12412070

D Suzie Mankin
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

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AFFIDAVIT OF CONTESSA KING

STATE OF MISSOURI	)	
	)	ss.
COUNTY OF COLE	)	

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

Further the Affiant sayeth not.

Contessa King

CONTESSA KING

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 27th day of October 2021.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
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D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

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

AFFIDAVIT OF SHAWN E. LANGE, PE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

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

Further the Affiant sayeth not.

Shawn Lange

SHAWN E. LANGE, 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 28th day of October 2021.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: April 04, 2025
Commission Number: 12412070

D. Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

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

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 Report - Cost of Service*; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Brooke Mastrogiannis
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 27th day of October 2021.

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Notary Public - Notary Seal
State of Missouri
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D Suzie Mankin
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

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AFFIDAVIT OF AMANDA C. McMELLEN

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

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 Report - Cost of Service*; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Amanda C McMellen

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 27th day of October 2021.

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State of Missouri
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My Commission Expires: April 04, 2025
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D Suzie Mankin

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BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

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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 Report - Cost of Service*; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Caroline Newkirk

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 27th day of October 2021.

D. SUZIE MANKIN
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State of Missouri
Commissioned for Cole County
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Commission Number: 12412070

D. Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

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

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 Report - Cost of Service*; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Angela Niemeier
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 27th day of October 2021.

D. SUZIE MANKIN
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State of Missouri
Commissioned for Cole County
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D Suzie Mankin
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OF THE STATE OF MISSOURI

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

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 Report - Cost of Service*; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

Mark L Oligschlaeger
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 28th day of October 2021.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
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D Suzie Mankin
Notary Public

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OF THE STATE OF MISSOURI

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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 Report - Cost of Service*; 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

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AFFIDAVIT OF JOSEPH P. ROLING

STATE OF MISSOURI	)	
	)	ss.
COUNTY OF COLE	)	

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

Further the Affiant sayeth not.

Joseph P. Roling

JOSEPH P. ROLING

JURAT

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D. Suzie Mankin

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

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 Report - Cost of Service*; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Ashley Sarver

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 27th day of October 2021.

D. SUZIE MANKIN
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State of Missouri
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D Suzie Mankin

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BEFORE THE PUBLIC SERVICE COMMISSION

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

AFFIDAVIT OF MICHAEL L. STAHLMAN

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

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

Further the Affiant sayeth not.

MICHAEL L. STAHLMAN

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 27th day of October 2021.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
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D Suzie Mankin
Notary Public