BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Evergy Metro, Inc. d/b/a Evergy Missouri Metro's Request for Authority to Implement a General Rate Increase for Electric Service	))))	**File No. ER-2022-0129** Tracking Nos. YE-2022-0200 and YE-2022-0201
In the Matter of Evergy Missouri West, Inc. d/b/a Evergy Missouri West's Request for Authority to Implement a General Rate Increase for Electric Service	))))	**File No. ER-2022-0130** Tracking No. YE-2022-0202

AMENDED REPORT AND ORDER

Issue Date: December 8, 2022

Effective Date: December 18, 2022

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AMENDED REPORT AND ORDER

On November 21, 2022, the Commission issued its *Report and Order* resolving the above captioned case. On December 2, 2022, the Staff of the Commission filed its motion for clarification which raised several questions of interpretation. On December 5, 2022, Evergy filed its response to Staff's motion, a request for reconsideration regarding two areas of concern, and as an alternative to its reconsideration request, Evergy also applied for rehearing. This *Amended Report and Order* makes changes to address many of the questions and areas of concern. No other party filed a request for reconsideration or rehearing.

All requests for rehearing filed regarding the Commission's *Report and Order* issued on November 21, 2022, are moot as this *Amended Report and Order* supplants it. This *Amended Report and Order* will be given a ten-day effective date. All applications for rehearing of this *Amended Report and Order* must be filed prior to this effective date.

Procedural History

On January 7, 2022, Evergy Metro, Inc. (EMM) and Evergy Missouri West, Inc. (EMW) (together, "Evergy") each submitted tariff sheets to produce net increases in their electric base rates, resulting in the two above captioned files. EMM requested a net increase in its electric base rates of approximately $43.9 million, an increase of 5.20%. EMW requested a net increase in its electric base rates of approximately $27.7 million, an increase of 3.85%. The cases have not been consolidated, but have had joint filings and a joint evidentiary hearing.[1]

The Commission set the test year in both files to be the twelve-month period ending June 30, 2021, updated through December 31, 2021, with the true-up period ending on

[1] 20 CSR 4240-2.110(3).

May 31, 2022. To allow sufficient time to study the effect of the tariff sheets and to determine if the rates established by those sheets are just, reasonable, and in the public interest, both EMM's and EMW's submitted tariff sheets were suspended until December 6, 2022.[2]

The Commission directed notice of the filings and set an intervention deadline. The Commission granted requests to intervene in both File No. ER-2022-0129 and File No. ER-2022-0130 to the following entities: ChargePoint, Inc.; Missouri Energy Consumers Group (MECG); Renew Missouri Advocates; Sierra Club; Google, LLC; and Missouri Industrial Energy Consumers (MIEC). The following four additional parties were permitted to intervene in File No. ER-2022-0130: the City of St. Joseph; Velvet Tech Services, LLC; Dogwood Energy, LLC; and Nucor Steel Sedalia, LLC.

A series of five virtual public hearings were held from August 8 to August 10.[3] An evidentiary hearing was held from August 31 to September 9.[4] Prefiled testimony was given in addition to testimony taken during the evidentiary hearing. Initial post-hearing briefs were filed on October 14, and reply briefs on October 21.[5]

On various dates before and during the evidentiary hearing, the parties submitted four stipulations and agreements, which were approved by the Commission.[6] After the Commission approved the agreements, as presented by the parties, nine issues still remained unresolved. One issue, referenced as the Plant-In-Service Act (PISA) deferral

[2] Date references are to 2022 unless otherwise noted.
[3] Transcript Volume (Tr. Vol.) 2-6.
[4] Tr. Vol. 7-13.
[5] With the exception of MECG which was granted leave to file and filed its reply brief on October 22.
[6] *Order Approving Four Partial Stipulations and Agreements*, issued September 22, 2022.

issue, has been made moot as the Commission addressed it in a separate case, File No. ER-2023-0011.[7] This Report and Order addresses the eight remaining issues.

General Findings of Fact

1. EMM and EMW are two affiliated, certificated Missouri "electrical corporation[s]" and "public utilit[ies]" as those terms are defined at Section 386.020, RSMo (Supp. 2021). EMM and EMW generally serve the western half of Missouri.[8]

2. EMM serves approximately 301,200 customers in the Kansas City metropolitan area and surrounding cities of Missouri.[9]

3. EMW serves approximately 337,000 customers in the western and northwestern counties of Missouri, including the cities of Lee's Summit, St. Joseph, and Sedalia.[10]

4. Kansas City Power & Light (KCP&L) and Aquila were separate utilities prior to their merger in 2008. Following the merger, Aquila was renamed KCP&L Greater Missouri Operations (GMO). The former companies continued to operate as separate utilities with Great Plains Energy Inc. (GPE) acting as the holding company for the stock of both utilities. In 2018, GPE merged with Westar Energy Inc., with KCP&L and GMO being subsidiaries of the combined company. KCP&L and GMO later became Evergy Missouri Metro (EMM) and Evergy Missouri West (EMW).[11] Although some referenced documents in the present case may still include former company names, for convenience

[7] File No. ER-2023-0011, *In the Matter of the Application of Evergy Missouri West, Inc. d/b/a Evergy Missouri West for Authority to Implement Rate Adjustments Required by 20 CSR 4240-20.090(8) and the Company's Approved Fuel and Purchased Power Cost Recovery Mechanism,* Report and Order, effective November 19, 2022.
[8] Ex. 39 (EMM), Ives Direct, p. 5; and Ex. 113 (EMW), Ives Direct, p. 5.
[9] Ex. 39, Ives Direct, p. 5; and Ex. 113, Ives Direct, p. 5.
[10] Ex. 39, Ives Direct, pp. 5-6; and Ex. 113, Ives Direct, pp. 5-6.
[11] *See generally* File No. EM-2018-0012, *Report and Order* issued May 24, 2018; File No. EM-2016-0324, Staff's Investigation Report filed July 25, 2016; and File No. EM-2007-0374, *Report and Order* issued July 1, 2008.

this order will refer to the current monikers of EMM, EMW, Evergy when combined, or the Company.

5. The Office of the Public Counsel (OPC) is a party to this case pursuant to Section 386.710(2), RSMo (2016) and by Commission Rule 20 CSR 4240-2.010(10).

6. The Staff of the Commission (Staff) is a party to this case pursuant to Commission Rule 20 CSR 4240-2.010(10).

7. The parties presented eight issues for determination by the Commission, listed below:

a. Sibley;
b. AMI-SD;
c. Subscription Pricing;
d. Rate Design/Class Cost of Service;
e. Rate Base;
f. Resource Planning;
g. Streetlighting;
h. CNPPID PPA (Hydro PPA).[12]

8. By a Commission approved stipulation and agreement, the EMM revenue requirement has been set at $25.0 million and the revenue requirement for EMW has been set at $42.5 million.[13] These revenue requirement amounts may be affected by the decisions of the Commission in this Order, which the parties acknowledged in the stipulation by stating "Resolution of [the remaining disputed] issues will have an impact on the revenue requirement."[14]

9. Cost causation is the principle that costs should be borne by those who cause them to be incurred.[15]

[12] Order of Witnesses, filed August 30, 2022.
[13] Order Approving Four Partial Stipulations and Agreements, issued September 22, 2022, para. 1.
[14] Stipulation and Agreement, filed August 30, 2022, para. 1.
[15] Tr. Vol. 13, p. 943 (referencing the definition given in the book *Energy Utility Rate Setting* by Lowell E. Alt, Jr.).

General Conclusions of Law

A. EMM and EMW are public utilities and electrical corporations as those terms are defined in Subsections 386.020(15) and (43), RSMo (Supp. 2021). By the terms of the statute, EMM and EMW are electrical corporations and are subject to regulation by the Commission pursuant to Chapters 386 and 393, RSMo.

B. The Commission's subject matter jurisdiction over EMM and EMW's rate increase requests is established under Section 393.150, RSMo.

C. EMM and EMW can charge only those amounts set forth in their tariffs.[16]

D. Subsection 393.140(11), RSMo, gives the Commission authority to regulate the rates EMM and EMW may charge customers for electric service.

E. Utilities are required to provide safe and adequate service.[17]

F. In determining the rates EMM and EMW may charge their customers, the Commission is required to determine whether the proposed rates are just and reasonable.[18]

G. EMM and EMW have the burden of proving the proposed rates are just and reasonable, pursuant to Section 393.150.2, RSMo, "[a]t any hearing involving a rate sought to be increased, the burden of proof to show that the increased rate or proposed increased rate is just and reasonable shall be upon the . . . electrical corporation . . . ."

H. In order to carry their burden of proof, EMM and EMW must meet the preponderance of the evidence standard.[19] In order to meet this standard, EMM and EMW

[16] Sections 393.130 and 393.140, RSMo.
[17] Sections 393.130 and 393.140, RSMo.
[18] Section 393.150.2, RSMo.
[19] *Bonney v. Environmental Engineering, Inc.*, 224 S.W.3d 109, 120 (Mo. App. 2007); *State ex rel. Amrine v. Roper*, 102 S.W.3d 541, 548 (Mo. banc 2003); *Rodriguez v. Suzuki Motor Corp.*, 936 S.W.2d 104, 110 (Mo. banc 1996), citing to, *Addington v. Texas*, 441 U.S. 418, 423, 99 S.Ct. 1804, 1808, 60 L.Ed.2d 323, 329 (1979).

must convince the Commission it is "more likely than not" that the proposed rate increases are just and reasonable.[20]

I. Witness credibility is solely a matter for the fact-finder, "which is free to believe none, part, or all of the testimony."[21]

J. Generally, one's belief, feeling, understanding, or thought about a matter does not constitute substantial evidence justifying or permitting a finding to that effect.[22]

K. In determining whether the rates proposed by EMM and EMW are just and reasonable, the Commission must balance the interests of the investor and the consumer.[23] In discussing the need for a regulatory body to institute just and reasonable rates, the United States Supreme Court has held as follows:

> Rates which are not sufficient to yield a reasonable return on the value of the property used at the time it is being used to render the services are unjust, unreasonable and confiscatory, and their enforcement deprives the public utility company of its property in violation of the Fourteenth Amendment.[24]

In the same case, the Supreme Court provided the following guidance on what is a just and reasonable rate:

> What annual rate will constitute just compensation depends upon many circumstances and must be determined by the exercise of a fair and enlightened judgment, having regard to all relevant facts. A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or

[20] *Holt v. Director of Revenue, State of Mo*., 3 S.W.3d 427, 430 (Mo. App. 1999); *McNear v. Rhoades*, 992 S.W.2d 877, 885 (Mo. App. 1999*); Rodriguez v. Suzuki Motor Corp*., 936 S.W.2d 104, 109-111 (Mo. banc 1996); *Wollen v. DePaul Health Center*, 828 S.W.2d 681, 685 (Mo. banc 1992).
[21] *State ex rel. Public Counsel v. Missouri Public Service Comm'n*, 289 S.W.3d 240, 247 (Mo. App. 2009).
[22] *Dickey Co. v. Kanan,* 537 S.W.2d 430, 433-34 (Mo.App.1976).
[23] *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 603, (1944).
[24] *Bluefield Water Works & Improvement Co. v. Public Service Commission of the State of West Virginia*, 262 U.S. 679, 690 (1923).

> speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.[25]

The Supreme Court has further indicated:

> '[R]egulation does not insure that the business shall produce net revenues.' But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[26]

L. Furthermore, in quoting the United States Supreme Court in *Hope Natural Gas*, the Missouri Court of Appeals said:

> [T]he Commission [is] not bound to the use of any single formula or combination of formulae in determining rates. Its rate-making function, moreover, involves the making of 'pragmatic adjustments.' … Under the statutory standard of 'just and reasonable' it is the result reached, not the method employed which is controlling. It is not theory but the impact of the rate order which counts.[27]

M. An administrative agency, as fact finder, also receives deference when choosing between conflicting evidence.[28]

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[25] *Bluefield,* at 692-93.
[26] *Federal Power Commission v. Hope Natural Gas Co.,* 320 U.S. 591, 603 (1944) (citations omitted).
[27] *State ex rel. Associated Natural Gas Co. v. Pub. Serv. Comm'n*, 706 S.W. 2d 870, 873 (Mo. App. W.D. 1985).
[28] *State ex rel. Missouri Office of Public Counsel v. Public Service Comm'n of State*, 293 S.W.3d 63, 80 (Mo. App. 2009).

N. The Commission's interpretation of statutes within its purview are entitled to great weight.[29]

SIBLEY (EMW ONLY)

Findings of Fact:

Sibley Retirement Prudence

10. The Sibley Generating Station (Sibley) was a coal-fired power-generating plant consisting of three units built during the 1960s.[30]

11. Two projects extended the depreciable life for approximately 20 years – to 2040.[31] Those projects consist of a 1991 plant conversion to burn low-sulfur coal, and the installation of scrubbers to Unit 3 in 2009.[32]

12. During the time period of January 2015 through November 2016, Sibley Unit 3 supplied 35% of EMW's energy needs.[33]

13. The depreciation study filed in February 2016 in EMW's rate case, File No. ER-2016-0156, was based on the assets in service as of December 31, 2014 (2014 Depreciation Study). The 2014 Depreciation Study included a projected end of depreciable life date of December 31, 2019, for Sibley Units 1 and 2, and December 31, 2040, for Unit 3 and the Sibley common plant.[34]

14. EMW's 2012 Integrated Resource Plan (IRP) shows the retirement of Sibley Units 1 and 2 occurring in 2017 as part of EMW's Preferred Plan.[35]

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[29] *State ex rel. Sprint Mo., Inc. v. Pub. Serv. Comm'n of State*, 165 S.W.3d 160, 164 (Mo. banc 2005) (citing *Foremost–McKesson, Inc. v. Davis*, 488 S.W.2d 193, 197 (Mo. banc 1972)).
[30] Ex. 113, Ives Direct, p. 30.
[31] Ex. 113, Ives Direct, p. 30.
[32] Ex. 114, Kennedy Direct, p. 12.
[33] Ex. 308, Marke Surrebuttal, p. 65.
[34] Ex. 114, Kennedy Direct, pp. 27-28.
[35] Ex. 113, Ives Direct, p. 31.

15. EMW's 2013 and 2014 IRP Annual Updates move the proposed retirement date to 2019.[36]

16. EMW's 2015 IRP shows that Sibley Units 1 and 2 will stop burning coal in 2019.[37]

17. On January 20, 2015, Evergy issued a press release announcing that EMW would stop burning coal at Sibley Units 1 and 2 by December 31, 2019.[38]

18. EMW's 2016 IRP Annual Update restates that Sibley Units 1 and 2 will stop burning coal 2019.[39]

19. EMW's 2017 IRP Annual Update set forth a fuller retirement plan. The retirement of Sibley Units 2 and 3 (including the Unit 1 boiler and common plant) by 2019 reflected the lowest cost plan from a net present value of revenue requirement (NPVRR) perspective. Those retirements on that timeline would result in a savings of $282 million over the 2016 IRP, which would make it the lowest cost alternative on an expected value basis.[40]

20. EMW's modeling for the 2017 IRP Annual Update showed that retiring Sibley Unit 3 reduced costs for EMW customers across all 18 modeled scenarios – regardless of load, gas price, or carbon-dioxide (CO_2) price assumption.[41]

21. The economic evaluation conducted through the IRP process took EMW's projected load growth and specific generation supply portfolio into consideration when the retirement decision was made.[42]

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[36] Ex. 113, Ives Direct, p. 31.
[37] Ex. 113, Ives Direct, p. 31.
[38] Ex. 114, Kennedy Direct, pp. 24-25.
[39] Ex. 113, Ives Direct, p. 31.
[40] Ex. 113, Ives Direct, p. 31.
[41] Ex. 113, Ives Direct, p. 31.
[42] Ex. 56, Messamore Rebuttal, p. 4.

22. EMW determined through the IRP process that the retirement of Sibley would reduce the long-term NPVRR and therefore reduce costs to customers going forward as opposed to continuing to operate the plant. The retirement of Sibley Units 1 and 2 in 2017 were first shown to reduce NPVRR in Evergy's 2012 IRP. The retirement of Sibley Unit 3 in 2018 was first shown to reduce NPVRR in Evergy's 2017 IRP Annual Update.[43]

23. On June 2, 2017, EMW announced by press release it would retire Sibley Units 2 and 3 (including the Unit 1 boiler and common plant) by 2018. The stated factors for the retirement were: the reduction in wholesale electricity market prices; a reduction in the required reserve generating capacity; a decline in near-term capacity needs; the age of the Sibley units; and expected environmental compliance costs.[44]

24. In January 2018, EMW filed a general rate case which included Sibley in rate base as the plant was in operation and expected to be in operation at the true-up date of that rate case, June 30, 2018.[45]

25. EMW's 2018 IRP, filed in April of that year, states that Sibley Units 2 and 3 will retire at the end of 2018.[46]

26. On September 5, 2018, Unit 3 tripped and went off-line due to a turbine vibration event. EMW made a required non-case related filing in the Commission's Electronic Filing and Information System (EFIS) on September 6, 2018, and a follow-up

[43] Ex. 56, Messamore Rebuttal, p. 4.
[44] Ex. 113, Ives Direct, p. 32.
[45] Ex. 113, Ives Direct, p. 32. EMW's filed general rate case is File No. ER-2018-0146.
[46] Ex. 113, Ives Direct, p. 33.

non-case related EFIS filing on September 12, 2018, indicating that a preliminary analysis showed the likely impact of the turbine vibration was a repair costing over $200,000.[47]

27. EMW subsequently conducted a root cause analysis of the Sibley Unit 3 turbine vibration event which included an evaluation of the time and expense to repair the unit. The estimated cost to repair was $2.21 million.[48]

28. EMW estimated that $54 million in capital costs would have been required to keep Sibley operational in the short term, including a submerged flight conveyer, new ash pond, auxiliary boiler, and generator rewind.[49]

29. EMW estimated the operation and maintenance (O&M) costs to keep Sibley operational would have been $28 million per year.[50]

30. The costs to keep Sibley in operation exceeded the benefits. The energy benefits did not always cover total fuel costs. Sibley's average annual SPP margins from 2015 to 2017 were only approximately $4 million. The future capital investment and O&M required to keep the plant operational was forecasted to be $165 million between 2018 and 2021.[51]

31. The EMW Vice President of Generation Operations sent two internal emails regarding the retirement of Sibley on October 2, 2018.[52]

32. The first internal Evergy email of October 2, 2018, states in pertinent part, "It is our intention to cease burning coal and move to decommissioning activities. Upon receipt of this email Robert Hollinsworth will contact Eric Peterson to notify [Southwest

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[47] Ex. 113, Ives Direct, p. 33.
[48] Ex. 113, Ives Direct, p. 33.
[49] Ex. 113, Ives Direct, p. 38.
[50] Ex. 113, Ives Direct, p. 38.
[51] Ex. 56, Messamore Rebuttal, pp. 6-7.
[52] Ex. 134 Data Requests and email string from File No. EC-2019-0200, pp. 4-5 of 15.

Power Pool (SPP)] and will contact Randy Adams at Local 412. I will forward this email to the rest of the Evergy officer team."[53]

33. The second internal Evergy email of October 2, 2018, states in pertinent part, "This email is to let the Evergy officer team know the direction being taken following a turbine trip due to vibration on Sibley Unit 3. Following a comprehensive evaluation of options we have determined the safest and most economical solution is to cease burning coal at the station and to move the remaining coal currently on the ground to Iatan."[54]

34. An internal reply to the October 2 email was made on October 3, 2018, by Evergy's chief operating officer (and supervisor to the sender of the October 2 email).[55] That reply states in pertinent part, "We will plan to review such recommendation at the CEO Staff meeting on October 15 in advance of a comparable review with the Evergy Board at the Operations Committee and full Board meeting later this month. Once we've reviewed with the Board, we can then circle back with the management team to review any feedback received and make a final decision."[56]

35. On November 1, 2018, EMW held meetings with Staff and OPC to discuss the turbine vibration event and potential retirement later that month.[57]

36. On November 10, 2018, the sender of the October 2 email writes that he has received feedback from recent management and Board meetings. He states his plan to move forward with a formal retirement of Sibley, and asks that any objections be raised by the end of the business day November 12, 2018.

37. On November 13, 2018, EMW retired Sibley.[58]

[53] Ex. 134 Data Requests and email string from File No. EC-2019-0200, p. 5 of 15.
[54] Ex. 134 Data Requests and email string from File No. EC-2019-0200, p. 4 of 15.
[55] Tr. Vol. 8, p. 178.
[56] Ex. 134 Data Requests and email string from File No. EC-2019-0200, p. 3 of 15.
[57] Ex. 113, Ives Direct, p. 33.
[58] Ex. 113, Ives Direct, p. 33.

38. The manual titled "Public Utility Depreciation Rates" published by the National Association of Regulatory Utility Commissioners (NARUC) states, "Ordinary retirements are caused by such factors as wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, and changes in demand."[59]

39. EMM retired Montrose Unit 1 in 2016 and Montrose Units 2 and 3, including common plant, on December 31, 2018. These retirements were driven by results of the IRP process and were announced on June 2, 2017 (which updated the prior retirement announcement of January 20, 2015). EMW retired Sibley 1 except for the boiler in June 2017 and the remainder of Sibley 1 and Sibley 2 in 2018 when Unit 3 was retired. All of these retirements were considered in IRP filings before retirement and were demonstrated to result in the lowest NPVRR for Missouri customers.[60]

40. Sibley provided service for 50 to 60 years, representing a major portion of the expected life of the assets. At the time of retirement, the majority of remaining net book value (NBV) was related to the 1991 and 2009 environmental retrofits.[61]

41. NBV is the initial plant in service amount less accumulated depreciation.[62]

42. Increasing the accumulated depreciation reserve reduces NBV and return while decreasing the accumulated depreciation reserve would increase NBV and return.[63]

43. The pace of the developments in renewable technology; a decline in the social acceptance of coal-fired generation; and the onset of federal, state, local and customer carbon-free emission targets changed the economics of Sibley for customers.[64]

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[59] Ex. 114, Kennedy Direct, p. 18.
[60] Ex. 114, Kennedy Direct, p. 22.
[61] Ex. 114, Kennedy Direct, p. 23.
[62] Tr. Vol. 8, p. 209.
[63] Tr. Vol. 8, pp. 209-210.
[64] Ex. 114, Kennedy Direct, p. 23.

44. The retirement of Sibley Unit 3 and the Sibley common property in 2018 was the result of a number of factors including, the economics of the plant, the changes in technology providing for the economic development of cleaner generation (for example the introduction of economically feasible solar and wind generation), national environmental requirements, and the changes in the social acceptance of coal fired generation. Evergy states that all of these impacts greatly accelerated in the time between the completion of the 2014 Depreciation Study and late 2018.[65]

45. OPC witness Dr. Marke admitted that the Sibley retirement provided clear environmental and health related benefits.[66]

46. Staff does not dispute the prudence of the decision to retire Sibley.[67]

Sibley AAO

47. Since the Sibley Units 2 and 3 were formally retired after the true-up date in EMW's general rate case, File No. ER-2018-0146, EMW's authorized rates from that rate case would normally include costs, revenues, and investment associated with the Sibley units.[68]

48. The largest component of Sibley's undepreciated investment was the pollution control equipment installed in 2009 to meet clean air requirements,[69]

49. At the time of retirement, Sibley Unit 3 and the Sibley common property were no longer producing energy or expected to produce energy for Evergy. Sibley was no longer used and useful.[70]

[65] Ex. 114, Kennedy Direct, p. 28.
[66] Tr. Vol. 8, p. 267.
[67] Ex. 269, Majors Surrebuttal and True-Up Direct, p. 2.
[68] Ex. 400, Meyer Direct, p. 9.
[69] Ex. 114, Kennedy Direct, p. 27.
[70] Ex. 400, Meyer Direct, p. 10.

50. Generally, the accounting for removal from plant-in-service upon retirement would be to credit the book value of the asset and debit the accumulated reserve.[71]

51. Subsequent to the completion of the 2018 general rate case, and due to the timing of the Sibley retirement, OPC and MECG filed a request for an Accounting Authority Order (AAO) to create a regulatory deferral account for costs and revenues related to Sibley.[72]

52. The Commission granted the AAO request in File No. EC-2019-0200.[73]

53. The Report and Order in the AAO case, states: "The estimated net book value of each Sibley unit and the common assets at Sibley as of June 30, 2018, as calculated by GMO's witness, is $145.7 million. Public Counsel's witness estimated that net book value at $160 million, while MECG's witness estimated that value at $300 million."[74]

54. In the present case, the parties have presented three amounts representing the unrecovered NBV of Missouri jurisdictional Sibley plant using one of three different Commission cases as starting points: [75]

Evergy	$145.2 million at 6/30/2018	EC-2019-0200
Staff	$145.2 million at 6/30/2018	EC-2019-0200
OPC	$190.8 million at 6/30/2018	ER-2016-0156
MECG	$300 million at 6/30/2018	ER-2018-0146

[71] Ex. 218, Majors Direct, p. 13.
[72] File No. EC-2019-0200, Petition for an Accounting Order, filed January 2, 2019.
[73] File No. EC-2019-0200, Report and Order, filed October 17, 2019.
[74] EC-2019-0200, Report and Order, page 9.
[75] Ex. 310, Robinett Rebuttal, pp. 14-17; Ex. 261, Cunigan Surrebuttal, p. 10.

55. Evergy witness Spanos did not file testimony in the 2018 rate case, File No. ER-2018-0146.[76]

56. The approximate $145.2 million Sibley NBV proposed by Evergy in this rate case has not been used to set rates before.[77]

57. Evergy witness Spanos' unit and locational calculations filed in File No. EC-2019-0200 would not have impacted the aggregate balances that were used to set rates in the last rate case even if he had filed testimony.[78]

58. Evergy witness Spanos' testimony in File No. EC-2019-0200 based accumulated depreciation reserve calculations on an expected retirement of November 2018 for all Sibley units.[79]

59. The reallocation of the accumulated depreciation reserves from other EMW steam plants to Sibley by EMW occurred at the time Sibley was being removed from the account balance.[80]

60. The depreciation rate would be affected by increasing or decreasing the accumulated depreciation reserve balance given the same time frame.[81]

61. Parties in the current rate case stipulated to depreciation rates for the remaining EMW steam plants; Iatan, Jeffrey Energy Center and Lake Road identical to the depreciation rates previously authorized by the Commission.[82]

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[76] Tr. Vol. 8, p. 337.
[77] Tr. Vol. 8, p. 205.
[78] Tr. Vol. 8, p. 222.
[79] Ex. 133, Spanos Rebuttal, EC-2019-0200, p. 3.
[80] Tr. Vol. 8, p. 253-254.
[81] Tr. Vol. 8, p. 255.
[82] *Order Approving Four Partial Stipulations and Agreements*, issued September 22, 2022; and Ex. 252, Staff Accounting Schedules.

62. The True-Up Accounting Schedules in File No. ER-2018-0146 recorded plant in service and accumulated depreciation reserve at June 30, 2018, with Sibley still in service.[83]

63. Staff and Evergy workpapers are $2 different on plant-in-service (or original cost) and $1 different on accumulated depreciation reserves. Total difference between Staff and Evergy's true-up positions is $3.00.[84]

64. The total Sibley plant-in-service (or original cost) at June 30, 2018 was $478,109,210 with Missouri jurisdictional Sibley plant totaling $476,483,639.[85]

65. Depreciation rates and accumulated depreciation reserves can be calculated many ways. The remaining life technique uses the net plant of surviving plant less book depreciation reserve as the depreciable cost and uses the average remaining service life of the assets. The whole life technique is where the depreciation cost is only the original cost spread out evenly over the average service life of the assets.[86]

66. The 2014 Depreciation Study included Sibley life extensions to 2040.[87]

67. Evergy's calculations resulted in the book reserve (accumulated depreciation) associated with Sibley as of June 30, 2018, as approximately $327.2 million which produced a NBV of approximately $145.7 million.[88]

68. Evergy witness Spanos' assignment of the actual book reserve to the location level in his File No. EC-2019-0200 depreciation analysis is based on the recovery and age of those assets. The only way to calculate book reserve when shifting from the

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[83] Ex. 310, Robinett Rebuttal, p. 15 and Schedule JAR-R-3.
[84] Ex. 310, Robinett Rebuttal, p. 16.
[85] Ex.402, Meyer Surrebuttal, Schedule GRM-1, p. 1.
[86] Ex. 209, Cunigan Direct, pp. 4-5.
[87] Tr. Vol. 8, pp. 133-134.
[88] Ex. 72, Spanos Rebuttal, pp. 21-22.

location level to the vintage level is based on theoretically assigning the book reserve to the vintage level based on the age of the dollars (asset).[89]

69. A theoretical reserve calculation is a snapshot in time that does not trace any collection of depreciation expense on any asset. The calculation assumes that all the prior depreciation expense was adequate, but it does not look at what was actually collected in rates.[90]

70. Evergy witness Spanos agreed that a theoretical reserve calculation should not be the basis of calculating depreciation reserve; however, it should be a basis of how to assign the depreciation reserve to the vintage level based on the ages of the asset.[91]

71. Staff first recommended a remaining NBV of $145.6 million, but subsequently recommended $300 million if no additional evidence supportive of the $145.6 million was presented.[92]

72. Staff witness Majors testified that although Mr. Spanos briefly explains the theoretical reserve method of calculating this amount ($145.6 million), there is no clear reasoning why this method is superior to the allocated reserve amount included in the 2018 rate case.[93]

73. Staff witness Majors did a high-level analysis of Sibley plant and accumulated depreciation reserve going back to 2004 (File No. ER-2004-0034) calculating an approximate NBV of $234 million using approved depreciation rates and

[89] Tr. Vol. 8, p. 325.
[90] Tr. Vol. 8, pp. 314-315.
[91] Tr. Vol. 8, p. 325.
[92] Ex. 254, Majors Rebuttal, p. 4.
[93] Ex. 254, Majors Rebuttal, p. 5.

Staff accounting schedules plant in service amounts. His analysis ended at the 2018 rate case.[94]

74. Staff witness Majors was unable to independently calculate the approximate $145 million NBV proposed by EMW.[95]

75. The $145.7 million Sibley units net book value put forth by Evergy through Mr. Spanos calculation was determined outside of the 2018 rate case and was never contemplated when setting Evergy's rates.[96]

76. OPC witness Robinett calculated the NBV of Sibley based on the 2014 Depreciation Study to be approximately $190.8 million at June 30, 2018.[97] Under the 2014 Depreciation Study, the unrecovered balance of Sibley was approximately $227.1 million at December 31, 2014. Reducing that number by 3.5 years of depreciation expense (approximately $36.2 million) results in an NBV of $190.8 million at June 30, 2018.[98]

77. OPC witness Robinette has been analyzing depreciation rates and studies of utilities in Missouri and providing expert testimony on behalf of Staff (2010-2016) and OPC (2016 to current) since 2010.[99]

78. The 2014 Depreciation Study was the last time a depreciation study was performed that included Sibley prior to the Sibley retirement in late 2018.[100]

79. The Commission previously ordered the adoption of the life span method dating back to File Nos. ER-2010-0355 and ER-2010-0356. Under the life span method, the generating units should not be looked at as a fleet but as individual units with individual

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[94] Tr. Vol. 8, p. 216.
[95] Tr. Vol. 8, p. 216.
[96] Ex. 402, Meyer Surrebuttal, p. 7.
[97] Ex. 310, Robinett Rebuttal, p. 16.
[98] Ex. 310, Robinett Rebuttal, p. 18.
[99] Ex. 309, Robinett Direct, Schedule JAR-D-1.
[100] Ex. 310, Robinett Rebuttal, pp. 14-15.

lives, not as (or similar to) a mass asset. However, EMW continues to apply a mass asset depreciation methodology for book purposes. Because of this depreciation treatment both EMW's and Staff's depreciation analyses in this case have led to a reduction of the accumulated depreciation reserve directly tied to the Sibley property retirement.[101]

80. Evergy has decreased the accumulated depreciation reserve balances for the Jeffrey Energy Center, Iatan 1 and 2, and Lake Road steam generating units to account for a portion of the undepreciated balance from the Sibley unit retirements.[102]

81. The Commission has set depreciation rates on the principle that only known and measurable costs should be included in rates. The historical interim net salvage experienced has been included into the depreciation rates that have previously been ordered by this Commission and are in the depreciation rates currently being recommended by Staff. Only costs that are known and measurable should be included in depreciation expense.[103]

82. Evergy maintains depreciation reserve by account and by type of plant (*i.e.* steam production, nuclear production, other production, transmission, distribution, and general plant) not by generating unit. Mr. Spanos performed an allocation of depreciation reserves from a pool of all dollars for steam generation in the complaint case to arrive at his net book value of $145.7 million. Mr. Spanos assigned reserves to each of the steam generating units for the first time in the complaint case.[104]

83. Evergy witness Spanos' work papers provided in the complaint case, File No. EC-2019-0200, identify through the five major steam production plant accounts,

[101] Ex. 311, Robinett Surrebuttal, pp. 7-8.
[102] Ex. 400, Meyer Direct, p. 14.
[103] Ex. 311, Robinett Surrebuttal, pp. 8-9.
[104] Ex. 311, Robinett Surrebuttal, p. 10.

approximately $599 million of theoretical reserve. The difference in amounts between the accumulated depreciation reserve collected in rates through June 30, 2018, and the theoretical reserve, approximately $175 million, would not have been collected from customers through rates.[105]

84. Staff agrees that the O&M deferral in the AAO is approximately $39 million.[106]

85. MECG agrees that the O&M deferral in the AAO is approximately $39 million.[107]

86. The O&M deferral was updated from Evergy's direct filing to $39,020,260 based on new information from EMW.[108]

87. The return deferral should be based on the NBV calculated at June 30, 2018.[109]

88. The average filed rate of return recommendation in File Nos. ER-2018-0145 and ER-2018-0146 (EMM and EMW's most recent general rate cases, respectively) was 8.73%.[110]

89. OPC witness Robinett calculates that the return collected since Evergy's last rate case is approximately $66.6 million. This calculation relies on an NBV of Sibley based on the 2014 Depreciation Study of approximately $190.8 million at June 30, 2018, and the average filed rate of return recommendation from Evergy's 2018 rate cases of 8.73% multiplied by four years.[111]

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[105] Tr. Vol. 8, p. 322.
[106] Tr. Vol. 8, p. 196.
[107] Tr. Vol. 8, p. 197.
[108] Tr. Vol. 8, p. 196.
[109] Tr. Vol. 8, p. 196.
[110] Ex. 310, Robinett Rebuttal, p. 18.
[111] Ex. 310, Robinett Rebuttal, p. 18.

90. MECG witness Meyer calculated the return to be approximately $102.9 million based on an 8.576 percent rate of return derived from a 9.5 percent return on equity, and a $300 million NBV over four years.[112]

91. EMW elected PISA accounting on December 31, 2018.[113]

92. EMW witness Kennedy forecasted the Sibley AAO costs through November 30, 2022. EMW's return component was calculated with a rate of return of 9.87 percent. The rate base component includes a deduction for Accumulated Deferred Income Taxes (ADIT), Excess Deferred Income Taxes (EDIT), and Net Operating Losses (NOLs) and additions for materials and supplies, and fuel inventory. The subtotal rate base was calculated to be $125,483,489. When the subtotal rate base is multiplied by the 9.87 percent rate of return and calculated out to November 30, 2022, the return component totals $49,540,308.[114]

93. If the net book value of Sibley is calculated using the methods proposed by Mr. Greg Meyer or Mr. John Robinett, then the remaining steam production plant accounts would need to be rebalanced using the same method.[115]

94. The signatories to the *Stipulation and Agreement* in File No. ER-2018-0146 agreed to defer as a regulatory liability the amounts of depreciation expense included in the cost of service for the Sibley plant from the date of retirement until new customer rates are established in the current rate case. These deferrals reduce the NBV of Sibley by

[112] Ex. 400, Meyer Direct, p. 11.
[113] Ex. 308, Marke Surrebuttal, p. 42.
[114] Ex. 114, Kennedy Direct, p. 35.
[115] Ex. 261, Cunigan Surrebuttal, p. 9.

increasing the depreciation reserve. The Missouri jurisdictional balance of this deferral will be $41.4 million through November 2022.[116]

95. Evergy requests authority for recovery of and to earn a return on the incurred costs of the final decommissioning of Sibley.[117] Evergy argues the net salvage value is part of the service value of the asset, thus the decommissioning costs should be charged to the accumulated depreciation account.[118]

96. The amount of labor and non-labor O&M in the Sibley AAO is $39,020,260, as of November 30, 2022.[119]

97. The total Sibley depreciation deferred was calculated by EMW to be $41,448,308, as of November 30, 2022.[120]

Amortization Period

98. Staff witness Keith Majors supports netting the regulatory liability against the unrecovered investment in the Sibley Units and amortizing the balance over five years.[121]

99. MECG's witness, Greg Meyer, recommended a 10-year amortization period for the regulatory liability and a 20-year amortization period with no return on the unamortized balance for the unrecovered investment in the Sibley Units.[122]

100. The funds in the regulatory liability account were collected from customers over approximately four years.[123]

[116] Ex. 254, Majors Rebuttal, p. 9.
[117] Ex. 114, Kennedy Direct, p. 7, and 32.
[118] Ex. 114, Kennedy Direct, p. 33.
[119] Ex. 46, Klote Surrebuttal, p. 9
[120] Ex. 114, Kennedy Direct, p. 35.
[121] Ex. 218, Majors Direct, p.141.
[122] Ex. 400, Meyer Direct, pp. 14-15.
[123] Ex. 129, Kennedy Rebuttal, p. 13.

101. If the Commission authorizes recovery of any unrecovered investment in the Sibley Units, OPC witness Dr. Marke recommended that the amortization period match to the 2040 scheduled retirement date of Sibley Unit 3, which is seventeen years from when rates will go into effect in this case.[124]

102. A utility's authorized ROE is to allow the utility an opportunity to earn just and reasonable compensation for their investment in rate base.[125]

103. Evergy witness Ives testified that Commission decisions on the issues in these cases could result in a revenue requirement that exceeded the Compound Annual Growth Rate cap (PISA cap) and a performance penalty under Section 393.1655.3, RSMo, (Supp. 2021).[126]

Conclusions of Law:

O. In determining whether a utility's conduct was prudent, the Commission will judge that conduct by:

> asking whether the conduct was reasonable at the time, under all the circumstances, considering that the company had to solve its problem prospectively rather than in reliance on hindsight. In effect, [the Commission's] responsibility is to determine how reasonable people would have performed the tasks that confronted the company.[127]

P. The Missouri Supreme Court further affirmed the Commission's rationale in stating,

> [t]he PSC ordinarily applies a presumption of prudence in determining whether a utility reasonably incurred its expenses. This presumption of prudence will not survive a showing of inefficiency or improvidence that creates serious doubt as to the prudence of an expenditure. If such a showing is made, the presumption drops out and the applicant has the

[124] Ex. 306 - EMW, Marke Direct, p. 10
[125] Ex. 223, Won Direct, p. 7.
[126] Ex. 42, Ives Surrebuttal, pp. 19-23.
[127] *State ex rel. Associated Natural Gas Co. v. Pub. Serv. Comm'n,* 954 S.W.2d 520, 529 (Mo. App. W.D. 1997).

> burden of dispelling these doubts and proving the questioned expenditure to have been prudent.[128]

Q. In order to disallow a utility's recovery of costs from its ratepayers, a regulatory agency must find both that the utility acted imprudently and that such imprudence resulted in harm to the utility's ratepayers.[129]

R. Commission Rule 20 CSR 4240-22.010 states:

> The fundamental objective of the resource planning process at electric utilities shall be to provide the public with energy services that are safe, reliable, and efficient, at just and reasonable rates, in compliance with all legal mandates, and in a manner that serves the public interest and is consistent with state energy and environmental policies.

S. Resource planning is defined as the process by which an electric utility evaluates and chooses the appropriate mix and schedule of supply-side, demand-side, and distribution and transmission resource additions and retirements to provide the public with an adequate level, quality, and variety of end-use energy services.[130]

T. Resource plan means a particular combination of demand-side and supply-side resources to be acquired according to a specified schedule over the planning horizon, which is at least 20 years' duration.[131]

U. Resource acquisition strategy means a preferred resource plan, an implementation plan, a set of contingency resource plans, and the events or circumstances that would result in the utility moving to each contingency resource plan.

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[128] *Spire Missouri, Inc. v. Pub. Serv. Comm'n*, 618 S.W.3d 225, 232 (Mo. banc 2021) (internal citations and quotation marks omitted).
[129] *State ex rel. Associated Natural Gas Co. v. Pub. Serv. Comm'n,* 954 S.W.2d 520, 530 (Mo. App. W.D. 1997).
[130] 20 CSR 4240-22.020(53).
[131] 20 CSR 4240-22.020(43 and 52).

It includes the type, estimated size, and timing of resources that the utility plans to achieve in its preferred resource plan.[132]

V. A preferred resource plan is the resource plan contained in the resource acquisition strategy most recently adopted by the utility.[133]

W. *Depreciation,* as applied to depreciable electric plant, means 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.[134]

X. *Retirement units* means those items of electric plant which, when retired, with or without replacement, are accounted for by crediting the book cost thereof to the electric plant account in which included.[135]

Y. 12. *Records for Each Plant (Major Utility).*

> Separate records shall be maintained by electric plant accounts of the book cost of each plant owned, including additions by the utility to plant leased from others, and of the cost of operating and maintaining each plant owned or operated. The term *plant* as here used means each generating station and each transmission line or appropriate group of transmission lines.[136]

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[132] 20 CSR 4240-22.020(51).
[133] 20 CSR 4240-22.020(46).
[134] CFR 18, Part 101, *Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act,* Definitions.
[135] CFR 18, Part 101, *Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act,* Definitions.
[136] CFR 18, Part 101, *Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act,* General Instructions.

Z. 22. *Depreciation Accounting.*

A. *Method.* Utilities must use a method of depreciation that allocates in a systematic and rational manner the service value of depreciable property over the service life of the property.

B. *Service lives.* Estimated useful service lives of depreciable property must be supported by engineering, economic, or other depreciation studies.

C. *Rate.* Utilities must use percentage rates of depreciation that are based on a method of depreciation that allocates in a systematic and rational manner the service value of depreciable property to the service life of the property. Where composite depreciation rates are used, they should be based on the weighted average estimated useful service lives of the depreciable property comprising the composite group.[137]

AA. 10. *Additions and Retirements of Electric Plant.*

A. For the purpose of avoiding undue refinement in accounting for additions to and retirements and replacements of electric plant, all property will be considered as consisting of (1) retirement units and (2) minor items of property. Each utility shall maintain a written property units listing for use in accounting for additions and retirements of electric plant and apply the listing consistently.

B. The addition and retirement of retirement units shall be accounted for as follows:

(1) When a retirement unit is added to electric plant, the cost thereof shall be added to the appropriate electric plant account, except that when units are acquired in the acquisition of any electric plant constituting an operating system, they shall be accounted for as provided in electric plant instruction 5.

(2) When a retirement unit is retired from electric plant, with or without replacement, the book cost thereof shall be credited to the electric plant account in which it is included, determined in the manner set forth in paragraph D, below. If the retirement unit is of a depreciable class, the book cost of the unit retired and credited to electric plant shall be charged to the accumulated provision for depreciation applicable to such property. The cost of removal and

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[137] CFR 18, Part 101, *Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act,* General Instructions.

the salvage shall be charged or credited, as appropriate, to such depreciation account.[138]

BB. 403 *Depreciation expense*.

A. This account shall include the amount of depreciation expense for all classes of depreciable electric plant in service except such depreciation expense as is chargeable to clearing accounts or to account 416, Costs and Expenses of Merchandising, Jobbing and Contract Work.[139]

CC. Section 393.1655, RSMo (Supp. 2021) states, in pertinent part:

1. This section applies to an electrical corporation that has elected to exercise any option under section 393.1400 and that has more than two hundred thousand Missouri retail customers in 2018, and shall continue to apply to such electrical corporation until December 31, 2023.

* * *

3. This subsection shall apply to electrical corporations that have a general rate proceeding pending before the commission as of the later of February 1, 2018, or August 28, 2018. If the difference between (a) the electrical corporation's average overall rate at any point in time while this section applies to the electrical corporation, and (b) the electrical corporation's average overall rate as of the date new base rates are set in the electrical corporation's most recent general rate proceeding concluded prior to the date the electrical corporation gave notice under section 393.1400, reflects a compound annual growth rate of more than three percent, the electrical corporation shall not recover any amount in excess of such three percent as a performance penalty.

Issues Presented by the Parties:

A. Was the retirement of the Sibley generating facility before the end of its useful life prudent?

1. If no, what if any disallowance should the Commission order?

B. What is the appropriate value for the regulatory liability from Case No. EC-2019-0200?

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[138] CFR 18, Part 101, *Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act,* Electric Plant Instructions.

[139] CFR 18, Part 101, *Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act,* Income Accounts.

C. What is the amount of unrecovered investment associated with the Sibley Unit Retirements?

D. What reserve balances should be used for purposes of determining depreciation expense for EMW steam production units, consistent with the Commission's determination of Sibley's unrecovered investment?

E. What is the proper amortization period for the regulatory liability related to Sibley?

F. What is the proper amortization period for the unrecovered depreciation investment from the Sibley retirement?

G. Should the net book value be included in rate base?

H. Should the Regulatory liability for Sibley include a rate of return on the undepreciated balance from the time of retirement through the rates effective in this rate case?

I. Should the unrecovered investment in Sibley earn a weighted average cost of capital return on a going forward basis?

Decision:

Sibley Retirement Prudence

The proffered evidence purportedly showing Evergy "gamed" the system are two emails, the timing of the retirement during a rate case, and the amount of undepreciated life remaining.

Both emails of October 2 refer to being sent to the Evergy officer team. This clearly indicates a higher level of approval was necessary. The mention of contacting the SPP and the local labor union can be interpreted as either giving them a heads-up or as official notice of retirement – neither view is conclusive based on the evidence. And, only inference was offered in opposition to the idea that the October 3 email outlined a more formal retirement decision-making process. The Commission does not find the emails to be persuasive evidence that the retirement occurred on or around October 2, 2018, or that Evergy was attempting to game the system.

The planned retirement of Sibley was December 2018. The actual retirement occurred November 13, 2018, but began with the turbine vibration event of September 5, 2018. The true-up date of June 30, 2018, was the cut-off to include assets in rate base during the previous rate case, File No. ER-2018-0146. Generally, all assets used and useful as of that date were included in rate base. The turbine vibration event occurred after the applicable true-up date. EMW got estimates to fix Sibley and subsequently the repair versus retirement decision was reviewed by upper management. EMW also announced the likely retirement of Sibley Unit 3 in its 2017 IRP Annual Update. The Commission finds no persuasive evidence that EMW acted to game the system by purportedly delaying its decision to retire Sibley.

At the time of retirement, Sibley Unit 3 had a depreciation retirement date of 2040. The majority of the undepreciated investment at issue is due to the environmental upgrades occurring in 2009. However, the prudence of those investments is not at issue. Rather, the question is if the retirement of those investments with approximately 20 years of remaining depreciable life was prudent?

Sibley's retirement was the catalyst for OPC and MECG's request for an AAO in File No. EC-2019-0200. In that case, the prudence of the retirement decision was deferred until this rate case. OPC is the only party challenging the prudence of the decision to retire Sibley. OPC questions the prudency of retiring a dispatchable generating unit that was, in one recent time period, contributing approximately one third of EMW's total generation load. OPC argues this transferred too much risk to ratepayers as EMW, without Sibley, has to purchase power in order to meet customer load, which will result in higher customer rates. The Commission does not find OPC's arguments persuasive.

It is undeniable that there is financial risk in predicting power generation and some of that risk will be borne by ratepayers which can reasonably be counted as a detriment. However, in making a decision whether to close Sibley there were also significant definitive detriments to be considered, namely the cost to repair and keep Sibley operational. The estimated cost to repair Sibley Unit 3 was $2.21 million and an estimated capital investment of $54 million would have been needed to keep Sibley operational. Additionally, the $28 million in annual operations and maintenance costs to keep a 60-year-old coal-fired generation plant running had to be considered.

Even without factoring in the cost of repairing Sibley Unit 3, the information and analysis presented in Evergy's 2017 IRP plan showed that the lowest cost from a net present value of revenue requirement perspective was to retire Sibley by end of 2019. Further, even OPC acknowledged there are additional unquantifiable environmental and health benefits to reducing coal fired generation. The Commission does not find the decision to retire Sibley to be imprudent.

<u>Sibley AAO</u>

Regulatory Liability Account

The Commission authorized the deferral of Sibley related costs in File No. EC-2019-0200. The Commission now must decide the amount of regulatory liability resulting from the Sibley deferrals it will allow to flow back to customers.

The deferrals quantify the Sibley related costs that were included in rates from File No. ER-2018-0146 effective December 6, 2018, through the date rates will become effective in this rate case. The parties to the current case agree that the deferral of Sibley labor and non-labor O&M costs to be included in the regulatory liability is $39,020,260.

Establishing the NBV of the Sibley properties at June 30, 2018, is required for the determination of the return paid by customers in rates. There is generally no dispute as to the original in-service cost of the Sibley plant (total Sibley plant-$478,109,210, Missouri jurisdictional-$476,483,639). The original cost of plant in service less the applicable depreciation expense accumulated over time in the accumulated depreciation reserve equals the NBV. The NBV also represents the unrecovered depreciation expense. It is the quantification of the accumulated depreciation reserve balance that creates the NBV difference between the parties. Determining that figure is key to answering many of the other issues presented.

Parties often use the total Sibley original in-service cost, accumulated depreciation reserve amount and NBV, however for purposes of this rate case these amounts will ultimately need to be converted to Missouri jurisdictional exact dollar amounts. The use of approximate amounts and rounding was also used frequently in testimony and during the hearing.

OPC witness Robinett's calculation of the Sibley NBV at June 30, 2018, is the only approach that included the allocation of accumulated depreciation reserve balance between EMW's steam properties as determined by Spanos' 2014 Depreciation Study, which was the most recent depreciation study at the time of the 2018 rate case. The 2019 theoretical reserve analysis performed by Mr. Spanos addresses the Sibley retirement by allocating reserve dollars previously allocated to other EMW steam properties to Sibley, thus reducing Sibley's June 30, 2018, NBV and increasing the NBV of the other steam properties. Once Sibley was retired on November 13, 2018, it was no longer eligible to be included in rate base. Using the 2014 Depreciation Study as a basis to estimate the remaining unrecovered NBV gives consideration to reserve allocation changes prior to

Sibley's retirement. OPC witness Robinett's experience in the analysis of depreciation rates and studies allowed him to determine a NBV at June 30, 2018, by using the 2014 Depreciation Study allocations and applying 3 ½ years of depreciation expense to bring the unrecovered Sibley value in line with plant and reserve in File No. ER-2018-0146. The Commission finds OPC witness Robinett's calculation to be the most credible of the NBV estimates.

MECG argues that the NBV was last established in the 2018 case, File No. ER-2018-0146, and that valuation should remain at $300 million at June 30, 2018, as it represents the amount used to calculate rates. MECG's NBV position does not consider the 2014 Depreciation Study accumulated depreciation reserve allocations. While the overall return on net rate base was charged to customers through rates set in the 2018 case, no specific amount was assigned to any individual plant. The 2014 Depreciation Study provides a more precise allocation of the accumulated depreciation reserve between EMW's steam properties of which the amounts allocated to Sibley are to be included in determining the return on Sibley's NBV.

Evergy's depreciation expert argues for a NBV of $145.7 million. However, Evergy's NBV proposal starts with the amount calculated in File No. EC-2019-0200, which is based on the new-in-2018 individual retirement values that were derived using a theoretical reserve. Typically, a theoretical reserve is not used when other information is available.

The Commission is not convinced that once Sibley was retired on November 13, 2018, it was appropriate for EMW to shift Sibley's unrecovered depreciation to other steam properties. The effect of the reallocation proposed by EMW is to allow future return on Sibley stranded costs that resulted from the early retirement of the properties to be included in future customer rates. The Commission finds the appropriate NBV at June 30, 2018, for the Sibley Units is $190,833,490.

Next, the appropriate rate of return to use in calculating the return portion of the regulatory liability must be determined. OPC proposes using 8.73 percent which is the average of the rate of return proposed by parties in EMW's last rate case. MECG proposes a 8.576 percent rate of return by using a 9.5 percent return on equity which is based on the PISA statute default rate of return that would not have been applicable in EMW's 2018 rate case since that treatment was not requested by EMW until after the effective date of rates in that rate case. EMW's proposed rate of return is 9.87 percent but they provide no support or explanation of how this seemingly high percentage was derived.

The Commission will calculate the return portion of the regulatory liability based on OPC's June 30, 2018, Sibley NBV of $190,833,490 multiplied by an 8.73 percent rate of return over the period rate payers have been paying the current rates, December 6, 2018, through November 30, 2022.

The regulatory liability represents costs paid by customers since the 2018 rate case for Sibley related costs that ended upon its retirement in November 2018 that are now being credited to customers. The regulatory liability includes $39,020,260 of labor and non-labor O&M costs and a return of $66,639,055 for a total of $105,659,315.

The Stipulation and Agreement in the 2018 rate case provided for specific treatment of depreciation expense collected after Sibley's retirement. The depreciation amounts would accumulate in a regulatory liability until new customer rates were established in a subsequent rate case. The regulatory liability account would then be closed into accumulated depreciation. This treatment eliminates the need to have the depreciation expense that was included in rates included in and amortized with the other components of the regulatory liability. This increases the accumulated depreciation reserve and reduces the Sibley NBV at November 30, 2022.

Regulatory Asset

The NBV of the Sibley properties at November 30, 2022, represents the unrecovered depreciation expense or EMW's unrecovered investment. Since the Commission has found the appropriate NBV for the Sibley properties at June 30, 2018, to be $190,833,490, the NBV at November 30, 2022, can be determined by reducing the June 30, 2018, NBV by the depreciation expense closed to the accumulated depreciation reserve through November 30, 2022 (53 months of depreciation expense). This includes the recognition of depreciation expense of Sibley between June 30, 2018, and the retirement date, November 13, 2018, and the deferral provision of the. Stipulation and Agreement in the 2018 rate case. The NBV at November 30, 2022, is $145,067,295.

The Commission will also allow EMW to recover a return of its investment in decommissioning and dismantling costs associated with the retirement of the Sibley properties that were not reflected in the June 30, 2018, plant in-service balances. These costs are $37,186,380. Including the return of these costs in EMW's NBV supports the Commission's practice of not allowing terminal net salvage values in depreciation rates. Therefore, the total regulatory asset is $182,253,675.

Even though Sibley retired in November 2018, the accumulated depreciation reserve increased from July 1, 2018, and must be included in determining the NBV to be used for amortization of the return of the remaining Sibley investment. The regulatory asset being established in this case allows EMW to recover its undepreciated investment in Sibley that resulted from its early retirement.

Evergy also requests a return on the undepreciated amount of Sibley plant, acknowledging that it is no longer used and useful, and cites an academic treatise in support. Evergy also argues it should earn a return on and return of the NBV of Sibley as there is no authoritative reason not to permit it. Staff, MECG, and OPC argue against any authorized return on the undepreciated amount of Sibley.

Historically, the Commission has distinguished between recovery based on prudent investment and recovery based on the asset being used and useful. The Commission is not persuaded by Evergy's argument and sees no reason to change its prior decisions. While it is appropriate to allow a utility to recover amounts prudently invested in plant, allow it a return of amounts spent, the fact that an initial investment may have been prudent when made does not support authorizing the Company to continue earning a profit/return on that investment when the plant in question is no longer used and useful. The Commission will allow recovery of the undepreciated amount of Sibley plant as the prudency of the investment in Sibley, including the 1991 and 2009 environmental retrofits, is unchallenged. The Commission will not authorize a return on that amount as none of that investment is now used and useful. Since the Commission is not allowing a return on the undepreciated amount of Sibley plant the issue on whether to use a weighted average cost of capital return on a going forward basis is moot.

The Commission's denial of Evergy's request for a return on the undepreciated amount of Sibley plant coincides with its decision that the Sibley NBV should not continue to be included in rate base. This is not based on a judgement of imprudence but a determination that as retired plant Sibley should be removed from Evergy's books. Only the regulatory liability and asset associated with Sibley should be reflected in Evergy's rates going forward.

To avoid having the theoretical reserve developed in File No. EC-2019-0200 applied in the allocation of the accumulated depreciation reserve between EMW's steam properties, the Commission will instruct Staff to work with EMW and OPC to have the EMW steam properties accumulated depreciation reserve amounts going forward from this case correspond to the 2014 Depreciation Study analysis that led to OPC's formulation of its $190,833,490 NBV at June 30, 2018. The accumulated depreciation reserve balances for other EMW property besides the steam properties will not be affected since the reserve issue in this case applied only in the determination of the 2018 retired Sibley NBV which also then impacted the accumulated depreciation reserve of the other steam properties.

Amortization period

One Amortization or Two

The Commission does not agree with Staff that the unrecovered investment in the Sibley Units should be reduced by the regulatory liability and the balance addressed in a single amortization. It is more appropriate and transparent to keep the two accounts distinct and amortize them separately. The regulatory liability represents Sibley costs included in rates after its retirement in November 2018 that were paid by customers. The regulatory asset represents the undepreciated Sibley plant investment or NBV that the Commission will allow EMW to recover from customers.

Regulatory Liability Amortization

Next the Commission must determine the amortization period over which the regulatory liability should be returned to customers. The regulatory liability was collected from rate payers over approximately four years. MECG and Staff both support an amortization period greater than four years. MECG argued the size of the regulatory liability warrants a longer period. The Commission does not see any justification to delay rate payer recovery – that is for rate payers to recover over a longer time frame than the four years in which the amount of the regulatory liability was collected from customers. Accordingly, the Commission finds the proper amortization period over which the revenue liability should be credited to customers is the same period over which it was collected from customers, four years.

Regulatory Asset Amortization

Next, we must determine the appropriate amortization period for the regulatory asset. The length of an amortization is typically driven by how large an amount is being amortized, because of its impact on rates, and/or it may be tied to another factor, such as the regulatory liability amortization in this case being set at four years to mirror the period over which those amounts were included in rates. Evergy, OPC and MECG all propose that the amortization period for recovery of the unrecovered investment in the Sibley Units be based upon the projected remaining life of the plant had it not been closed. While the timeframes they recommend vary only based upon their estimates of that remaining useful life, their proposals are vastly different. Evergy seeks recovery over a 20-year amortization period with the assumption it will be earning a return on the unamortized balance over that time frame. OPC and MECG would have recovery over a 17- or 20-year period, without allowing a return on the unamortized balance.

As previously addressed it is not appropriate to allow Evergy to continue to earn a return on plant that is no longer in service, no longer used and useful. So, the question before the Commission is whether it is appropriate to make Evergy wait 17 to 20 years for a full return of its unrecovered investment absent any return on those amounts. The Commission does not find this result reasonable. Evergy should be allowed a return of these amounts as quickly as practicable. The only other party taking a position on this issue was Staff, who recommended first netting the asset and liability accounts before amortizing the resulting unrecovered asset balance over a five-year period. The Commission has determined it is more appropriate and transparent to treat the regulatory liability and asset accounts independently, and has determined that the regulatory liability should be recovered over a four-year period.

The regulatory asset is not so large as to necessitate use of an extended 17- to 20-year amortization period, but it is almost double the amount of the regulatory liability, which is to be recovered over a four-year period. The Commission finds it appropriate to set the amortization period for the unrecovered investment in the Sibley Units at eight years.

Further, the Commission is mindful that Evergy elected PISA accounting in 2018, and although the PISA deferral issue was made moot by the Commission's decision in File No. ER-2023-0011, Evergy's concern that the revenue requirement authorized in this case might push it over its PISA cap warrants consideration. While there is no clear evidence as to whether a shorter recovery period would push Evergy over its PISA cap, extending the recovery of the regulatory asset over a period greater than the regulatory liability recovery period will decrease the risk of Evergy surpassing the PISA cap.

AMI-SD

Findings of Fact:

104. Automated Meter Infrastructure (AMI) is an integrated system of smart meters, communication networks, and data management systems that enables two-way communication between utilities and customers.[140]

[140] Ex. 211, Eubanks Direct, p. 3.

105. AMI meters measure and record electricity usage hourly or sub-hourly. Depending on the manufacturer and model of the AMI meter, other capabilities may be available such as monitoring the on/off status of electric service, measuring voltage, and remotely disconnecting and reconnecting electric service.[141]

106. EMM and EMW initially began replacing their existing automated meter reading (AMR)[142] meters with AMI meters in portions of its service territories from 2014 to 2016.[143]

107. Evergy historically has installed AMI meters that have different capabilities.[144]

108. Evergy first began installing AMI meters with remote service disconnect and reconnect, commonly referred to as AMI-SD meters, in 2017.[145]

109. As of September of 2018, EMM's AMI meter penetration was approximately 98% and EMW's was somewhat less than 60%.[146]

110. From November 1, 2018, through May 31, 2022, 87% of the meters exchanged were less than 7 years old.[147]

111. During the test year and update period (through December 2021), EMM exchanged 49,647 meters and EMW exchanged 22,235 meters. Of the exchanged meters, 99% of meters exchanged were less than 7 years old.[148]

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[141] Ex. 211, Eubanks Direct, p. 3.
[142] AMR meters allow reading from a handheld device or vehicle, within a certain distance from the meter. To contrast, AMI meters can be read from anywhere there is an internet connection.
[143] Ex. 211, Eubanks Direct, p. 3.
[144] The specifics regarding the manufacturer and model type is confidential and is not at issue except for those meters with the service disconnect and reconnect functionality.
[145] Ex. 21, Caisley Rebuttal, p. 11.
[146] Ex. 211, Eubanks Direct, p.4.
[147] Ex. 262, Eubanks Surrebuttal and True-up Direct, p. 5.
[148] Ex. 211, Eubanks Direct, p. 5.

112. Some of the AMI-SD meters installed during 2019 and 2020 were replacing manual meters as part of the rural EMM AMI meter exchange.[149]

113. Staff raised a concern regarding Evergy's premature retirements of the AMI meters still having a significant portion of remaining life being removed and replaced with AMI-SD meters.[150]

114. At the time of the initial deployment of AMI, AMI-SD meters were cost prohibitive, more than double the cost of the meters that were installed and nearly 25% higher than prices available today for AMI-SD meters.[151]

115. The AMI meters installed in 2014 to 2016 had a design life of 20+ years.[152] Evergy testified that the AMI meters installed in 2014-2016 still had design life left.[153]

116. Based on Account 370.02 Meters - AMI Distribution in the 2018 true-up accounting schedules through June 30, 2018, EMM had a Missouri Jurisdictional plant-in-service of $33,812,886 with an accumulated reserve of $4,081,223. This compares to a plant-in-service of $61,650,283 with an accumulated depreciation reserve of $3,211,002 based on Staff's direct accounting schedules through May 31, 2022.[154]

117. Based on Account 370.02 Meters - AMI Distribution in the 2018 true-up accounting schedules through June 30, 2018, EMW had a Missouri Jurisdictional plant-in-service of $21,777,871 with an accumulated reserve of $1,230,040. This compares to a plant-in-service of $49,178,779 with an accumulated depreciation reserve of $2,472,035 based on Staff's direct accounting schedules through May 31, 2022.[155]

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[149] Ex. 306 - EMW, Marke Direct, p. 15 (see table); Ex. 306 – EMM, Marke Direct, p. 9 (see table).
[150] Ex. 211, Eubanks Direct, p. 7.
[151] Ex. 21, Caisley Rebuttal, p. 10.
[152] Ex. 211, Eubanks Direct, p. 5.
[153] Ex. 21, Caisley Rebuttal, p. 9.
[154] Ex. 310, Robinett Rebuttal, p. 6.
[155] Ex. 310, Robinett Rebuttal, p. 7.

118. OPC's witness Robinett indicated that the changes in plant in service and accumulated depreciation mean that the amount of early retirements has outpaced annual depreciation expense accrual which can be seen by a reduction in the total accumulated depreciation reserves from 2018 to 2022. This is not typical with an increase in plant-in-service over the same period. It would have been expected that depreciation reserve would have continued to increase and should have increased more with the additional plant that was added.[156]

119. Evergy has not recorded the AMI meters on the books as 'old' or 'new' nor do they intend to open up a new subaccount for the new meters.[157]

120. Evergy intends to complete the replacement of AMI meters with AMI-SD meters by the end of 2024,[158] and possibly as early as the end of 2023.[159]

121. Evergy states the AMI meters were replaced with AMI-SD meters for technology reasons.[160]

122. The current AMI meters are not being replaced because they are at the end of their useful life but instead to make it easier for customer to be disconnected.[161]

123. AMI-SD reconnect functionality allows customers to get service connected within minutes, nearly 24 hours a day, seven days a week.[162]

124. To be reconnected currently, it can take one to three days, depending on the timing of the request being after hours or including non-business days.[163]

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156 Ex. 310, Robinett Rebuttal p. 6.
157 Ex. 306 - EMW, Marke Direct, p. 20; Ex. 306 – EMM, Marke Direct, p. 14.
158 Ex. 211, Eubanks Direct, p. 7.
159 Tr. Vol. 9, p. 381.
160 Ex. 21, Caisley Rebuttal, p. 10.
161 Ex. 306 - EMW, Marke Direct, p. 22; Ex. 306 – EMM, Marke Direct, p. 16.
162 Ex. 21, Caisley Rebuttal, pp. 11-12.
163 Tr. Vol. 9, p. 390.

125. Remote disconnect and reconnect addresses safety concerns for the Evergy workers currently physically performing the disconnection, such as dogs, poison ivy, vehicle accidents, or angry confrontations.[164]

126. Before replacing the AMI meters with AMI-SD meters, Evergy reviewed the prospect by conducting a business case, and also analyzed the financial impact to customers from two different perspectives.[165]

127. The first financial review evaluating the cost to purchase and install AMI-SD meters was based on the proposed change-out schedule and the short-term and on-going O&M savings that would be realized due to the additional capabilities the AMI-SD meters could provide to make operations more efficient. The results indicate that from a financial perspective, customers would be indifferent to the AMI-SD meter change.[166]

128. The second financial review calculated the present value of the AMI meters installed in 2014 at $76 per meter plus the cost to install an AMI-SD meter in 2021 at $125 per meter. This was then compared to the cost of an AMI-SD meter in 2014 at $165 per meter. The present value comparison indicated that installing the AMI meter without SD capabilities in 2014 plus installing an AMI-SD meter in 2021 was less expensive than if the Evergy would have installed AMI-SD meters in 2014.[167]

129. Staff's assessment of the first financial review conducted by the Company is that it does not demonstrate that there are net cost savings to the AMI-SD meter rollout and it does not include the useful life remaining of the existing AMI meters in its calculations. For the second financial review, Staff assesses that the review simply

[164] Tr. Vol. 9, p. 391.
[165] Ex. 21, Caisley Rebuttal, pp. 9-10.
[166] Ex. 21, Caisley Rebuttal, pp. 15-16.
[167] Ex. 21, Caisley Rebuttal, pp. 15-16.

considers whether or not it would have been a better financial decision for the Company to install AMI-SD meters in 2014; however, no party is suggesting Evergy should have installed AMI-SD meters in 2014.[168]

130. Staff also raised concerns about the inputs assumed by Evergy in preparing its business case analysis, including the depreciation rate used, personnel needs, and contractual obligations.[169]

131. Calculating the cost of the new AMI-SD meters must include the cost of the previous AMI meter that is not fully depreciated as well as the cost of labor associated with both the installation of the previous AMI meter and the installation of the new AMI-SD meter.[170]

132. OPC witness Dr. Marke's assessment of the first financial review is that it omitted a critical variable in the analysis, which was the undepreciated balance of the old AMI meters. The exclusion of the undepreciated balance would indicate that it is no longer a cost to the customers. However, this is not as reflected in Evergy's proposed rate base, which includes the old AMI meter along with the new AMI-SD meter that replaced it, as well as software in rate base.[171]

133. Evergy presented several benefits of the AMI meters.[172]

134. None of the benefits that would flow to EMM or EMW from the use of AMI-SD meters were quantified.[173]

[168] Ex. 262, Eubanks Surrebuttal and True-up, p. 6. The 2014 installation of AMI meters is not being challenged as imprudent.
[169] Ex. 262C, Eubanks Surrebuttal and True-up Direct, pp. 7-8 (The Commission notes the particular information is confidential, and thus will not be restated).
[170] Tr. Vol. 9, p. 425
[171] Ex. 308, Marke Surrebuttal, p. 31.
[172] Ex. 49, Lutz Direct, pp. 36-39; and Ex. 117, Lutz Direct, pp. 36-39.
[173] Tr. Vol. 9, p. 435 - 436

135. The reasons for the individual meter exchanges during the test year, as provided in Evergy's field notes, were broken down by Staff into categories in descending order of the most common to least common as follows:

a. To exchange an AMI meter with an AMI-SD meter;

b. To exchange an AMI meter with an AMI-SD meter due to customer arrears;

c. Communication issues;

d. Unknown reasons;

e. Net meter installations;

f. Other (damaged or failing meters, access issues, and customer-requested exchanges).[174]

136. Staff recommended disallowances of meter exchanges where the reason identified in the field notes was for one of the three reasons - (1) the exchange was for the purpose of exchange (category a); (2) when the exchange was due to customer arrears (category b); and (3) for unknown reasons (category d).[175]

137. Evergy testified to the benefits to the customer and the Company of prioritizing customers with balances in arrears for meter exchange. Evergy forecast that post-COVID, an atypically high number of customers would have balances in arrears. Evergy was concerned that if a high number of customers were disconnected, many of them could end up waiting hours for reconnection once a payment was made or a plan established. Evergy argued that meter exchanges to AMI-SD meters for customers with balances in arrears was to ensure that they could be more quickly restored to service with an AMI-SD meter than with a technician physically present to restore service.[176]

[174] Ex. 211, Eubanks Direct, pp. 5-6.
[175] Ex. 211, Eubanks Direct, p. 6.
[176] Ex. 21, Caisley Rebuttal, pp. 18-19.

138. The meter exchanged for "unknown reasons" could come from two places – an order entered without comments or field personnel deciding on a meter exchange while on location. Field personnel making this type of exchange is considered a "pick-up" order by Evergy's system, without a way to enter the reason for the exchange.[177]

139. Staff adjusted its recommended initial disallowance to remove meter exchanges that were listed in the unknown category when there was a meter reader or field employee request for the exchange.[178]

140. While it is reasonable and necessary to replace a meter that is damaged or failing; given that the vast majority (99%) of AMI meters exchanged for AMI-SD meters were less than 7 years old, it is not reasonable to replace a meter solely to gain a new capability or when there is seemingly no reason.[179]

141. Staff recommends that the Commission disallow $6,321,846 for EMM and $2,957,124 for EMW FERC Account 370.2, respectively.[180]

142. Staff multiplied the number of meters per category of recommended disallowance by the cost per meter (depending on meter type) to arrive at its recommended disallowance.[181]

143. OPC's cursory review of Evergy's PISA filings suggest that both EMM and EMW may have exceeded the statutory limits on smart meter investment in 2020 for EMM and 2019 for EMW. OPC recommended that this be added to the list of issues where OPC can provide a recommendation in its position statement.[182]

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[177] Ex. 21, Caisley Rebuttal, p. 21.
[178] Ex. 262, Eubanks Surrebuttal and True-up Direct, pp. 4-5.
[179] Ex. 211, Eubanks Direct p. 6.
[180] Ex. 262, Eubanks Surrebuttal and True-up Direct, p. 3.
[181] Ex. 262, Eubanks Surrebuttal and True-up Direct, p. 3.
[182] Ex. 308, Marke Surrebuttal, pp. 42-43.

Conclusions of Law:

No additional Conclusions of Law are necessary.

Issues Presented by the Parties:

A. Should the Commission approve a disallowance related to the replacement of AMI meters with AMI meters that have the capability to disconnect/reconnect service (AMI-SD)?

B. Should the Commission order Evergy Metro to change its deployment strategy so that it no longer prioritizes customers in arrearage?

C. Did Evergy exceed the 6% annual PISA spend limit on AMI meters?
1. If yes, what actions, if any, should the Commission take in response?

Decision:

The Commission agrees with Staff's position that the premature retirement and replacement of AMI meters that still function with AMI-SD meters was not prudent. The Commission therefore will order a disallowance of the AMI-SD meters installed for the three reasons established in Staff's estimate, which were (1) exchange of AMI meter for AMI-SD meter; (2) exchange of AMI meter for an AMI-SD meter due to customer arrears; and (3) unknown reasons.

Evergy witnesses testified that prioritizing customers with balances in arrears for meter exchange was a benefit to customers and the Company. Evergy argued that with the possibility of large numbers of disconnections post-COVID, it was beneficial to those customers in arrears (and thus more likely to experience an involuntary shut-off) because they could more quickly have electricity restored if shut-off. The Commission does not find this rationale credible. Replacement of functioning meters with significant remaining life is, without further valid justification, not just and reasonable.

Installing an AMI-SD meter for the purpose of installing an AMI-SD meter is not a prudent reason for a meter exchange when the meter being taken out is likely only 7 years into a 20-year depreciable life. This reasoning is not improved by prioritizing customers in arrears. Similarly, after being adjusted to remove those meters exchanges initiated by the Evergy field personnel, the meters exchanged for unknown reasons were not sufficiently supported in evidence with a valid reason for the exchange of an AMI meter with substantial life remaining. The Commission finds that Evergy has not met its burden of proof regarding the meter exchanges for the three reasons outlined by Staff.

OPC recommended a disallowance of all AMI-SD meters. The Commission disagrees as OPC's recommendation is premised on the assumption that the installation of AMI-SD meters was unjustified and provided no benefit. The Commission does not question the overall benefits provided by AMI-SD meters over AMI meters. There is value in the upgraded technology and benefits provided with the AMI-SD meter. In this case, the benefits of the AMI-SD meters provide value when installed for justifiable reasons, such as replacing manual meters, or an AMI meter that is not functioning.

OPC also presented a question in surrebuttal testimony that Evergy, in purchasing the AMI-SD meters, may have exceeded its PISA limit. However, testimony stated it was based on a cursory review and only recommended further discussion. Of concern to the Commission is that the testimony only suggests that this may be an issue. The lack of evidence regarding this issue precludes a Commission decision at this time.

SUBSCRIPTION PRICING

Findings of Fact:

144. EMM and EMW proposed an opt-in Subscription Pricing Pilot Program (Subscription Pricing).[183]

[183] Ex. 37 (EMM), Hledik Direct, p. 3; and Ex. 112 (EMW), Hledik Direct, p. 3.

145. Evergy has conducted customer surveys regarding Subscription Pricing.[184]

146. The first survey consisted of 39 customers, and the second survey was online.[185]

147. One of the questions posed in Evergy's first survey was "do you want unlimited electricity for a fixed price?"[186]

148. Evergy explained that they referenced an "unlimited" electric plan so that the survey participant can draw a comparison with other "unlimited" plans consumers are traditionally familiar with, such as their subscription with Netflix or wireless phone provider. In other words, the consumer is not charged on a per unit basis (number of movies watched or number of minutes used). They are charged on a flat, monthly price.[187]

149. Evergy stated it will not market or promote subscription pricing to customers as an "unlimited" rate plan.[188]

150. Evergy also distinguished that it was the 2021 customer survey that mentioned the word "unlimited". Evergy states the June 2022 customer survey presented the option as a "Flat Pricing Plan" and was still desired by customers.[189]

151. The description of Flat Pricing that was given in the survey compared it to an unlimited plan for an unrelated subscription service, specifically using the word "unlimited".[190]

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[184] Tr. Vol. 10, p. 636.
[185] Tr. Vol. 10, p. 629.
[186] Tr. Vol. 10, pp. 636-637.
[187] Ex. 84, Winslow Surrebuttal, p. 20.
[188] Ex. 84, Winslow Surrebuttal, pp. 20-21.
[189] Ex. 84, Winslow Surrebuttal, pp. 20-21.
[190] Ex. 84, Winslow Surrebuttal, p. 20; Ex. 22, Caisley Surrebuttal, Confidential Schedule CAC-5, p. 35 of 42.

152. Subscription Pricing would provide residential customers with an entirely fixed monthly electric bill, similar to subscription-based services and club memberships.[191]

153. Subscription Pricing removes pricing signals important to programs like cost-based and time of use rates.[192]

154. Subscription Pricing's fixed bill would be based on historical usage of the previous twelve months of weather normalized usage. The customer's bill would remain unchanged for a one-year term. After each one-year term, the usage would be re-averaged for the next one-year term, but there is no true-up.[193]

155. Evergy's customer survey reflected interest in the program for moderate-income households seeking a stable electric bill but renters and low-income customers did not find this plan to fit their lifestyle.[194]

156. Evergy is a monopoly that provides an essential service and does not provide competitive non-essential services like gym memberships or streaming entertainment services.[195]

157. There are thirteen utilities in the United States offering a subscription pricing program.[196]

158. Subscription Pricing, as proposed, is a complex pricing process with a behavioral usage adder, a program cost adder, risk premium adder, efficiency incentive, and other add-on options.[197]

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[191] Ex. 37, Hledik Direct, p. 3; and Ex. 112, Hledik Direct, p. 3.
[192] Tr. Vol. 10, p. 619, 18-23.
[193] Ex. 37, Hledik Direct, p. 5 and 19; and Ex. 112, Hledik Direct, p. 5 and 19.
[194] Ex. 82, Winslow Direct, pp. 22-23.
[195] Ex. 242, King Rebuttal, p. 12.
[196] Tr. Vol. 10, p. 504.
[197] Ex. 242, King Rebuttal, p. 12; and see Tr. Vol. 10, pp. 500-503, and 580-581.

159. Subscription Pricing uses weather normalization applied by class to calculate a given Subscription Pricing enrollee's bill.[198]

160. Customers of Subscription Pricing would, on average, pay more under Subscription Pricing than they otherwise would under a standard rate.[199]

161. Evergy seeks waivers of certain mandated billing and payment standards set by Chapter 13 of the Code of State Regulations.[200]

162. Customers may not be able to understand the complex structure of all of the components which make up the ultimate flat rate offered by the Subscription Pricing program.[201]

163. A level pay tool already exists for Evergy customers in the form of the Average Payment Plan.[202]

164. Average Payment Plan participants are exposed to weather-related fluctuations changes in usage, which is different from the proposed Subscription Pricing Plan.[203]

165. OPC recommended a disallowance for the fees associated with Evergy's consultant testimony in regards to Subscription Pricing, stating it is out-of-line with Commission policy.[204]

Conclusions of Law:

No additional Conclusions of Law are necessary.

[198] Tr. Vol. 10, pp. 578-579.
[199] Ex. 323, Kremer Rebuttal, Schedule LAK-R-6; and see Tr. Vol 10, pp. 512-517.
[200] Ex.242, King Rebuttal, pp.11-12.
[201] Ex. 38, Hledik Surrebuttal, pp. 10-11.
[202] Ex. 323, Kremer Rebuttal, p. 14 and 16.
[203] Ex. 38, Hledik Surrebuttal, p. 8.
[204] Ex. 307, Marke Rebuttal, p. 21.

Issues Presented by the Parties:

A. Should the Commission approve the proposed Subscription Pricing Pilot Program?

B. Should the Commission grant Evergy's request for variances to Chapter 13.020 Billing and Payment Standards, which the Company states is needed to implement Evergy's proposed Subscription Pricing Pilot Program?

C. Should the Commission disallow costs related to consultant fees associated with Evergy's Subscription offering?

Decision:

Evergy argues that its two surveys show that customers want Subscription Pricing. A question in the first customer survey mentions unlimited energy and only involves thirty-nine customers. The second survey was conducted online. The second survey can be interpreted to show that customers prefer what the survey calls "Flat Pricing" when offered a choice among the several of Evergy's proposed rates. However, the description of Flat Pricing that was given in the survey used the word "unlimited" and compared Flat Pricing to a plan for an unrelated subscription service. In addition, the results of the survey showed the preference for this type of plan was skewed towards moderate-income households but not renters and low-income customers. While every utility offering may not be preferential for every customer type, alienating a specific customer group which is already at a disadvantage further erodes the desirability of this proposal. The Commission does not find the results of either survey to be credible support for Subscription Pricing.

Subscription Pricing, by Evergy's own admission, removes elements such as weather-related fluctuations in usage which operate as pricing signals to customers in conjunction with rate structures such as TOU rates. The success of TOU rates could be undermined by participation in a program structured like Subscription Pricing.

There is also the unchallenged fact that Subscription Pricing will likely result in higher bills for participants. Because Subscription Pricing, absent other factors, is more likely than not to result in higher bills to customers, the Commission finds it would likely result in unjust and unreasonable rates.

The Commission has set rules that offer protections to utility customers for billing structure to ensure that customers understand what they are being billed and the reasoning for those charges. Evergy asks for variances from these rules to offer customers a bill that reflects only the price of service, but not the detailed breakdown behind it. Evergy by its witness' own admission expects that customers would not comprehend all of the details comprising their bills under the Subscription Pricing program proposal. The Commission is further not persuaded that the Program or its waivers are appropriate.

OPC recommended the Commission disallow the costs of the consultant who testified and put together the Subscription Pricing proposal. OPC argues that the rate design is inherently illegal and so out-of-line with Commission policy that ratepayers should not have to pay for the consultant's testimony supporting that rate design. The Commission is not fully persuaded by OPC's argument, and finds it appropriate to divide the cost equally between shareholders and ratepayers. While this proposed pilot program was ultimately rejected, the Commission does not want to stifle innovation. Therefore, the Commission finds it appropriate that both shareholders and ratepayers should contribute to the cost of this proposal and will disallow 50% of the cost of the Subscription Pricing consultant.

RATE DESIGN/CLASS COST OF SERVICE

Findings of Fact:

166. Evergy's immediately preceding general rate case included an agreement regarding rate design issues, specifically supporting Time of Use (TOU) rates, but with no specific measurable goal or timeline.[205]

167. Starting immediately after its rate case approvals in 2018, the Company began executing on its commitments from the rate design agreement.[206]

168. Evergy then researched, developed, and implemented a 3-period, opt-in TOU rate plan (Whole House) for residential customers as a pilot.[207]

169. An opt-in structure is such that the default is a flat rate or a blocked/tiered rate and a customer may choose to have a time varying rate. The choice of remaining on the status quo flat or blocked/tiered rate is the choice of the customer.[208]

170. An opt-out structure is such that all customers are placed on a TOU rate, which requires a customer to take action to revert to the flat or blocked/tiered rate, or select another rate within the utility's portfolio of rates.[209]

171. Evergy's pilot resulted in 1.1% of the residential customers enrolled in TOU rates over a 20-month period.[210]

172. Evergy conducted surveys which showed customers wanted more rate options, but were hesitant regarding a mandatory TOU rate.[211]

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[205] Ex. 82 (EMM), Winslow Direct, p. 5; and Ex. 128 (EMW), Winslow Direct, p. 5.
[206] Ex. 82, Winslow Direct, p. 5; and Ex. 128, Winslow Direct, p. 5.
[207] Ex. 82, Winslow Direct, p. 5; and Ex. 128, Winslow Direct, p. 5.
[208] Ex. 49 (EMM), Lutz Direct, Schedule BDL-3, p. 36 of 89; Ex. 117 (EMW), Lutz Direct, Schedule BDL-3, p. 36 of 89.
[209] Ex. 49, Lutz Direct, Schedule BDL-3, p. 36 of 89; Ex. 117, Lutz Direct, Schedule BDL-3, p. 36 of 89.
[210] Ex. 49, Lutz Direct, Schedule BDL-3, pp. 36-37 of 89; Ex. 117, Lutz Direct, Schedule BDL-3, pp. 36-37 of 89.
[211] Ex. 23, Caisley Surrebuttal, pp. 6-7.

173. Evergy in this case proposed new opt-in TOU rates with the primary goals of expanding customer choice; reducing system coincident peak demand; and aligning pricing structure with cost causation.[212]

174. For the existing 3-period TOU rate, Evergy proposed two adjustments to (1) align the summer season to June 1 – September 30, and (2) reduce the non-summer price differentials to better reflect cost.[213] The non-summer season runs from October 1 through May 31.[214]

175. The existing 3-period Evergy TOU rate has a 6-times price differential between the on-peak and super off-peak rate.[215]

176. Price differentials are ratios presented to reflect the pricing relationship between the TOU periods (on-peak vs off-peak). For example, 6:1 indicates that the on-peak price is 6-times the off-peak price.[216]

177. Evergy proposes three additional opt-in residential TOU rates – (1) a 2-period TOU rate; (2) a High Differential TOU rate to accommodate the charging patterns of electric vehicle (EV) drivers (High Differential EV TOU rate); and (3) a Separately Metered Electric Vehicle TOU rate which is identical to the High Differential TOU rate with the exception that customers need to have a separate meter for EVs.[217]

178. The Evergy 2-period TOU proposal has a 4-times price differential between on-peak and super off-peak during summer and a 2-times differential between on-peak

[212] Ex. 82, Winslow Direct, p. 7; and Ex. 128, Winslow Direct, p. 7.
[213] Ex. 82, Winslow Direct, p. 18; and Ex. 128, Winslow Direct, p. 18.
[214] Ex. 49, Lutz Direct, Schedule BDL-3, p. 70 of 89; Ex. 117, Lutz Direct, Schedule BDL-3, p. 70 of 89.
[215] Ex. 82, Winslow Direct, p. 17; and Ex. 128, Winslow Direct, p. 17.
[216] Ex. 83, Winslow Rebuttal, p. 2.
[217] Ex. 82, Winslow Direct, pp. 15-16; and Ex. 128, Winslow Direct, pp. 15-16.

and off-peak during winter.[218] This is a new rate proposal that would provide customers who have less ability to shift usage throughout the year an additional TOU rate option and mitigate the bill impact of the 3-period TOU rate typically occurring for space heating customers.[219]

179. The Evergy High Differential TOU rate and the Separately Metered Electric Vehicle TOU rate would both have a 12-times price differential for EMM and a 10-times price differential for EMW.[220]

180. Under the proposed Separately Metered Electric Vehicle TOU rate, the customer is required to install a separate meter for EV charging while providing the customer the option to choose a different rate in Evergy's portfolio for its other home usage.[221]

181. Evergy sees the fundamental purposes of TOU rates to be price signaling of actual costs, and creation of elasticity in demand to improve efficiency of resources.[222]

182. Staff did not support Evergy's proposed opt-in TOU rates because Staff viewed Evergy's TOU rates as not being cost-based.[223] However, Staff stated that Evergy's 2-period TOU rate structure is the less objectionable of the residential TOU rates proposed by Evergy.[224]

183. Staff recommended the transition of EMM and EMW residential rate schedules to a default time-based rate structure consistent with two other Missouri

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[218] Ex. 82, Winslow Direct, p. 18; Ex. 128, Winslow Direct, p. 18; Ex. 49, Lutz Direct, Schedule BDL-3, pp. 66-67, 70-71 of 89; Ex. 117, Lutz Direct, Schedule BDL-3, pp. 66-67, 70-71 of 89.
[219] Ex. 82, Winslow Direct, p. 16; and Ex. 128, Winslow Direct, p. 16.
[220] Ex. 82, Winslow Direct, p. 19; and Ex. 128, Winslow Direct, p. 19.
[221] Ex. 82, Winslow Direct, p. 16; and Ex. 128, Winslow Direct, p. 16.
[222] Ex. 83, Winslow Rebuttal, p. 3.
[223] Tr. Vol. 11, p. 747.
[224] Ex. 243, Sarah Lange Rebuttal, p. 52.

utilities. The Union Electric Company d/b/a Ameren Missouri (Ameren Missouri) default TOU approach is a modest on-peak overlay included in the default residential rate design. The Empire District Electric Company d/b/a Liberty (Empire) default TOU approach employs a modest off-peak discount overlay and was also included in the default residential rate design.[225]

184. Staff's recommended TOU default rate during the summer is a one cent premium during on peak times, and an off-peak discount of one cent during off peak time. During non-summer months, the TOU is a one-quarter of one cent ($0.0025) premium during on-peak times, with the one cent off-peak discount remaining the same.[226]

185. Under Staff's recommended TOU rate, if a customer who uses approximately 1,000 kWh a month consumes a lot of their energy over night, they can expect to see their monthly bills go down by about $10 each month. If a customer who uses around 1,000 kWh a month consumes a lot of their energy in the afternoon and early evening, they can expect to see their bills go up by about $10 each month. If a customer is able to change when they use energy, they can save about $20 per month. But under Staff's plan, no customer will have a TOU-related bill increase of more than one cent per kWh in the summer, or one cent for each 4 kWh the rest of the year, and even that increase will only apply if that customer uses all of their energy between 4:00 p.m. and 8:00 p.m.[227]

[225] Ex. 229, Sarah Lange Direct, p. 17.
[226] Tr. Vol. 11, p. 746; Ex.265, Sarah Lange Surrebuttal, p. 34.
[227] Ex. 229, Sarah Lange Direct, p. 45.

186. Staff witness Sarah Lange argues that Staff's proposed TOU rates are a customer friendly approach, which will mitigate the impact of TOU rates to customers with energy-intensive HVAC units.[228]

187. Among investor-owned electric utilities in Missouri, TOU rates have been a recent addition and are not widespread.[229]

188. Even though opt-in TOU rate deployment is more common, some utilities have deployed TOU on an opt-out or mandatory basis, most of which were deployed in the last two years.[230]

189. States and commissions have adopted different approaches regarding opt-in versus opt-out TOU rates.[231]

190. Customer satisfaction under TOU remains high with either opt-in or opt-out. However, opt-out rates have higher enrollment rates relative to opt-in rates.[232]

191. The cost to provide energy to customers varies with the time of day due to demand, that is, competition for that energy. The driver of Staff's low differential TOU rate proposal is that energy generally costs more in certain time periods, and that historically ratemaking has not sufficiently recognized the cost-based difference of a kWh consumed at 6:00 p.m. versus being consumed at 2:00 a.m.[233]

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[228] Ex. 229, Sarah Lange Direct, p. 41.
[229] Ex. 83, Winslow Rebuttal, p. 6.
[230] Ex. 49, Lutz Direct, Schedule BDL-3, pp. 36-37 of 89; Ex. 117, Lutz Direct, Schedule BDL-3, pp. 36-37 of 89.
[231] Ex. 49, Lutz Direct, Schedule BDL-3, pp. 36-37 of 89; Ex. 117, Lutz Direct, Schedule BDL-3, pp. 36-37 of 89.
[232] Ex. 49, Lutz Direct, Schedule BDL-3, pp. 36-37 of 89; Ex. 117, Lutz Direct, Schedule BDL-3, pp. 36-37 of 89.
[233] Ex. 229, Sarah Lange Direct, pp. 18-19.

192. Moving customer usage from on-peak to off-peak is beneficial, but was not the driving design criteria of Staff's TOU proposal.[234]

193. Third-party reviews show half of TOU rate price differentials are at least 10 cents per kWh. Staff's recommended low differential TOU rate of one cent per kWh is an outlier in the industry.[235]

194. Analysis of TOU programs show that as the price differential increases, customers shift usage in greater amounts.[236]

195. TOU rate designs are not well suited for customers with loads that cannot be shifted.[237]

196. Customers who do not save money at the level they expect under a TOU rate did not remain in the program.[238]

197. Among investor-owned electric utilities in Missouri, the price differentials are conservative – Ameren Missouri's introductory rate was described as a low differential, and Empire began offering a two-cent differential in October of 2022.[239]

198. One of the primary benefits of AMI meters is the ability to price electricity closet to the true cost of service through TOU rates.[240]

199. Evergy witness Miller recommends Evergy's summer inclining block rate with no further change for the default residential rate structure.[241]

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[234] Tr. Vol. 11, pp. 781-782.
[235] Ex. 83, Winslow Rebuttal, pp. 4-5.
[236] Ex. 83, Winslow Rebuttal, p. 5.
[237] Ex. 49, Lutz Direct, Schedule BDL-3, p. 38 of 89; Ex. 117, Lutz Direct, Schedule BDL-3, p. 38 of 89.
[238] Ex. 229, Sarah Lange Direct, p. 41.
[239] Ex. 83, Winslow Rebuttal, p. 6.
[240] Ex. 306 - EMW, Marke Direct, p. 16; Ex. 306 – EMM, Marke Direct, p. 10.
[241] Ex. 61, Miller Surrebuttal, p. 29.

200. Staff witness Sarah Lange recommends that Evergy's summer inclining block rare should be the default residential rate for customers who opt-out of Staff's proposed default TOU rates.[242]

201. Evergy recommends several changes to the residential class rate design to "clean-up" the residential tariff.[243] The rates to be eliminated were previously frozen.[244] These changes include the elimination of specific rates and transitioning those customers to existing rates.[245]

202. Staff agreed that duplicative rate codes should be eliminated, as most are the legacy of prior mergers and rate schedule consolidation that have become obsolete.[246]

203. To date, Evergy has completed more than 13 studies on TOU.[247]

204. Evergy has arguably had eight years to prep their customers for the value proposition of TOU rates since beginning installation of AMI meters.[248]

205. Given the customer education provisions of the 2018 stipulation,[249] EMM has spent $1,386,936 and EMW has spent $1,692,041 on TOU program costs, and EMM has spent $98,788 on customer education costs related to TOU and EMW has spent $24,000. Therefore, Evergy's customers at large should be well-educated on both the

[242] Ex. 229, Sarah Lange Direct, pp.51-52.
[243] Ex. 59, Miller Direct, p. 3; and Ex. 119, Miller Direct, p.3.
[244] Ex. 59, Miller Direct, pp. 12-17; and Ex. 119, Miller Direct, pp.12-17.
[245] Ex. 59, Miller Direct, p. 3; and Ex. 119, Miller Direct, p.3.
[246] Staff Initial Brief, p. 34.
[247] Ex. 306 - EMW, Marke Direct, p. 7; Ex. 306 – EMM, Marke Direct, p. 7.
[248] Ex. 307, Marke Rebuttal, p. 14.
[249] "Non-Unanimous Partial Stipulation and Agreement Concerning Rate Design Issues" issued on September 25, 2018 in cases ER-2018-0146 and ER-2018-0145.

general economic underpinning and the potential bill impacts of rates that vary with the time of day at which energy is consumed.[250]

206. One of the benefits of AMI meters is the ability to offer TOU rates.[251]

207. Residential customers currently have access to multiple non-TOU rates, such as Residential General Use, Residential General Use and Space Heater; and Residential Other Use.[252]

208. The price differential ratio is the single biggest factor affecting a customer's realized behavioral change.[253]

209. Staff proposed a residential customer charge for both EMM and EMW of $12.00. Staff calculated that amount by increasing the current EMM residential customer charge by the percentage adjustment of the EMM residential class revenue requirement, rounded to the nearest quarter.[254]

210. Evergy proposed a residential customer charge of $16.00 for both EMM and EMW.[255]

211. The residential classes will receive above-system-average rate increases.[256]

212. Raising the residential customer charge diminishes the customer incentive to be more energy efficient.[257]

[250] Ex. 229, Sarah Lange Direct pp. 15-16.
[251] Ex. 23, Caisley Surrebuttal, p. 17.
[252] Ex. 229, Sarah Lange Direct pp. 8-9.
[253] Tr. Vol. 11, pp. 719-720.
[254] Ex. 265, Sarah Lange Surrebuttal, pp. 30-31.
[255] Ex. 59, Miller Direct, p. 43; and Ex. 119, Miller Direct, p.34.
[256] Ex. 265, Sarah Lange Surrebuttal, p. 32.
[257] Tr. Vol. 10, p. 619.

213. Evergy proposed a $3.25 customer charge for customers with a second meter.[258]

214. Staff's calculation indicated the customer charge for a second meter is $4.11. Therefore, Staff proposed the customer charge for a second meter should be in the range of $4.25 to $5.00.[259]

215. Evergy's current and proposed residential TOU rates cannot be used by net metering customers due to statutory provisions that have not been updated to reflect dynamic rates.[260]

216. Staff's proposed low differential TOU rate, which is an adder to the existing residential general use rate, can be used by net metering customers with no need for legislative or tariff changes.[261]

217. Evergy, in the Stipulation and Agreement filed on August 30, 2022, (Revenue Requirement Stipulation) committed to developing a report that examines the technical, billing, and legal barriers to offering further TOU rate options to residential customer-generators with net-metering or interconnection agreements.[262]

218. The Revenue Requirement Stipulation was approved by the Commission on September 22, 2022.[263]

219. Evergy witness Kimberly Winslow estimated that for each customer enrolling in one of its opt-in TOU programs it would take approximately $150 per in marketing and education costs, $150 in customer acquisition cost.[264] The only basis to

[258] Ex. 243, Sarah Lange Rebuttal, p. 50.
[259] Ex. 243, Sarah Lange Rebuttal, p. 50.
[260] Ex. 49, Lutz Direct, Schedule BDL-3, p. 43 of 89; Ex. 117, Lutz Direct, Schedule BDL-3, p. 43 of 89.
[261] Tr. Vol. 11, pp. 689-690.
[262] Revenue Requirement Stipulation, para. 7(e).
[263] Order Approving Four Partial Stipulations and Agreements, issued September 22, 2022.
[264] Ex. 82, Winslow Direct, p. 54; and Ex. 128, Winslow Direct, p. 54.

support the $150 customer acquisition estimate is a statement that it is based on Evergy's experience. If Evergy's opt-in TOU rates are approved, it asks that it be authorized to recover prudently incurred program costs at a not-to-exceed acquisition cost of $150 per customer.[265]

220. Providing optional programs that lose $150 per participant, to be spread out to other ratepayers, is unreasonable.[266]

221. Evergy proposed changes for non-residential customers' rate schedules, design and structure – (1) a new time-related pricing rate; (2) seasonal alignment (changing EMM to match EMW); (3) consolidation of rates/codes; and (4) elimination of select end use rates.[267]

222. Evergy proposed the elimination of the Residential Other Use rate.[268]

223. Staff proposed a default TOU rate for non-residential customers using the same price differentials as proposed for the residential customers.[269]

224. Evergy witness Miller argues that Staff's non-residential TOU proposal does not consider the broad set of customers and the unique rate structures that exist across jurisdictions.[270]

225. Evergy has not had discussions with its commercial and industrial customers regarding the possibility of mandatory TOU rates.[271]

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[265] Ex. 82, Winslow Direct, p. 54; and Ex. 128, Winslow Direct, p. 54.
[266] Ex. 243, Sarah Lange Rebuttal, pp. 2-3.
[267] Ex. 59, Miller Direct, pp. 45-47; and Ex. 119, Miller Direct, pp.34-39.
[268] Ex. 58, Miller Direct, pp. 45-47; and Ex. 118, Miller Direct, pp.34-39.
[269] Ex. 229, Sarah Lange Direct, p. 60.
[270] Ex. 61, Miller Surrebuttal, p. 30.
[271] Tr. Vol. 11, p. 711.

226. MECG opposed Staff's proposed default TOU rates for the large power service (LPS) and large general service (LGS) rates.[272] MECG's opposition is due to the lack of a rate to evaluate and a lack of information regarding an impact analysis of the proposed changes to the LPS and LGS customer classes.[273]

227. Generally, for the commercial and industrial classes, Evergy proposed to apply 125% of each class increase to the fixed cost rate components (i.e. customer charges and demand charges) and 75% to the variable cost rate components (i.e. energy charges).[274]

228. The Revenue Requirement Stipulation states that EMW's Large Power Service voltage differential for pricing of energy blocks will be re-implemented.[275]

229. MECG supports Evergy's proposed rate design for commercial and industrial customers.[276]

230. Both OPC and MECG propose that Evergy should meet with stakeholders related to its rate modernization plan within 180 days after the effective date of rates in this case.[277]

231. Evergy meets with stakeholders on a periodic basis and is not opposed to discussing the rate modernization plan with interested parties.[278]

232. In the Revenue Requirement Stipulation, the signatories agreed to true-up revenues and billing determinants with the residential class's revenues by season

[272] Ex. 405, Maini Rebuttal, p. 4; Ex. 406, Maini Rebuttal, p.4.
[273] Ex. 405, Maini Rebuttal, p. 12; Ex. 406, Maini Rebuttal, pp. 13-14.
[274] Ex. 59, Miller Direct, pp. 43-44; and Ex. 119, Miller Direct, p. 35.
[275] Revenue Requirement Stipulation, p. 12.
[276] Ex. 403, Maini Direct, p. 34; Ex. 404, Maini Direct, p. 34.
[277] OPC Position Statement p. 30 and MECG Position Statement p. 16.
[278] Evergy Position Statement p. 36.

provided.[279] The Revenue Requirement Stipulation provides that Evergy's proposed Seasonal Alignment with no impact on revenues will be adopted, consistent with the true-up billing determinants.[280]

Conclusions of Law:

CC. In undertaking the balancing of interests required by the Constitution, the Commission is not bound to apply any particular formula or combination of formulas. Instead, the Supreme Court has said:

> Agencies to whom this legislative power has been delegated are free, within the ambit of their statutory authority, to make the pragmatic adjustments which may be called for by particular circumstances.[281]

Issues Presented by the Parties:

> B.[282] What are the appropriate rate schedules, rate structures, and rate designs for the non-residential customers of each company?
>
> D. What are the appropriate rate schedules, rate structures, and rate designs for the Residential customers of each utility?
>
> 1. What is the appropriate residential customer charge?
>
> E. What measures are appropriate to facilitate implementation of the appropriate default or mandatory rate structure, rate design, and tariff language for each rate schedule?
>
> F. Should the Company's proposed Time of Use rate schedules be implemented on an opt-in basis?
>
> G. Should the Staff's proposed Time of Use rate schedules be implemented on a mandatory basis?
>
> K. Should the Commission order Evergy to meet with stakeholders related to its rate modernization plan within 180 days after the effective date of rates in this case?

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[279] Revenue Requirement Stipulation, para. 3; see also Exhibit 2, billing determinants, attached to the Revenue Requirement Stipulation and marked confidential.
[280] Revenue Requirement Stipulation, para. 7(a).
[281] *Federal Power Comm'n v. Natural Gas Pipeline Co*., 315 U.S. 575, 586 (1942).
[282] The original lettering is retained here – the missing letters correspond to resolved issues.

L. Should Evergy work to improve the education of its customers regarding the billing options and rate plans it has currently?

Decision:

Residential Rates, Schedules and Structures; Opt-In Versus Opt-Out; High Price Differential Versus Low Price Differential; and Customer Education

Several of the parties to this case are supportive of TOU rates in general. The disagreements form around opt-in versus opt-out and a high price differential versus a lower price differential. The Commission sees a benefit in incorporating a mix of these approaches.

Evergy proposes four opt-in TOU rates for residential customers, which reflect higher differentials than Staff's lower TOU rate proposal. A high differential allows higher levels of savings for those customers who are able to change their energy usage times. Evergy's opt-in approach is based on the recommendation to provide its customers with the option of selecting the rates that work for them. Under this approach, Evergy's base default rates would be the standard flat rates. One of the primary benefits of AMI is the ability to provide customers with TOU rates. Given eight years of experience with AMI, millions of dollars invested in AMI across Evergy's footprint and many studies regarding TOU rates, the Commission is concerned with taking the status quo approach that currently reflects only minimal (1.1%) residential adoption of TOU rates.

Staff's recommendation included a low differential opt-out TOU rate in the form of an approximately two-cent swing between on- and off-peak pricing. Staff's proposal uses a low differential rate to offer more protection for the customers that cannot change usage times. The basis for Staff's low differential proposal is that it is the "training wheels" approach for introducing TOU rates to customers that currently are not and have never been enrolled in Evergy's TOU pilot. The Commission finds Staff's approach of implementing TOU rates as a default or opt-out rate is a better approach to introduce residential customer to TOU rates, since opt-out TOU rates result in higher enrollment. However, Staff's low differential rate, even though it would provide protections to some customers, does not provide sufficient incentive or opportunities for customers to see savings from TOU rates. Therefore, the Commission does not agree with Staff's low differential TOU rate being the introductory default TOU rate for residential customers.

Offering both high and low differential TOU rates will allow for more customer choice, will sufficiently introduce TOU rates to customers and will allow a higher differential rate to exhibit the benefits that derive from TOU rates. But the Commission also understands that allowing the option to opt-into a lower differential rate may better suit certain customers' lifestyles. As both Evergy's and Staff's proposals have multiple benefits, the Commission will authorize modified versions of both. The Commission finds Evergy's 2-period TOU rate, with a 4-times price differential between on-peak and super off-peak during summer and a 2-times differential between on-peak and off-peak during winter, to be the best introductory high differential TOU rate for residential customers as it has the lowest differential of Evergy's high differential TOU rates while still providing a benefit to those customers seeking substantial savings by altering the time of day of their energy consumption. Therefore, the Commission will order that Evergy's 2-period TOU rate be established as the default residential customer rate with Staff's low differential TOU rate as an opt-in TOU rate.

Given the high differential in the 2-period TOU rate and Evergy's customer surveys showing hesitancy regarding TOU rates, this 2-period high differential rate should take effect beginning on October 1, 2023, to correspond to the start of non-summer TOU season. This will allow more time for customer education prior to implementation and have the transition occur when the rate differential is lower. Additionally, the transition to TOU default rates shall be phased-in between October 1, 2023 and December 31, 2023. The phase-in shall occur by appropriate groupings of customers on the appropriate customer's billing cycle such that the TOU implementation for all Evergy customers shall be completed by December 31, 2023.

To assist Evergy with developing customer education and outreach regarding TOU rates, the Commission will convene a workshop to that effect under a separate File Number. As no expense amounts are included in the rates approved in this case for customer education and outreach costs associated with the implementation of mandatory and optional TOU rates, the Commission will also authorize the tracking of these costs for consideration and possible recovery in Evergy's next rate case. Evergy will be directed to submit quarterly reports detailing the types and amounts of any education and outreach expenses deferred.

Evergy's additional proposed TOU rates (3-period TOU rate; the High Differential EV TOU rate; and the Separately Metered Electric Vehicle TOU rate) will further advance customer choice. The Commission finds these additional proposed TOU rates reasonable and will also approve them as opt-in rates. Residential customers who are not currently on a TOU rate plan, will be assigned to the 2-period TOU rate automatically, and may opt-in to either Staff's low differential, Evergy's 3-period, High Differential EV rate or Separately Metered EV rate. Existing 3-period TOU customers shall stay on their existing 3-period TOU rate during and after the transition of non-TOU residential customers to the 2-period TOU rate unless those customers request to opt-in to the 2-period TOU rate or any other available residential TOU rate.

The Commission is not approving any traditional ratemaking structure for residential customers to be used after December 31, 2023, when the transition to TOU default rates is completed, with the exception of those residential customers without AMI meters. Since TOU rates are only available to customers with AMI meters, the Residential General Use rate (without space heating) will remain available for any customers without AMI meters.

The Commission recognizes that Evergy's TOU rates do not currently work for net metering customers due to the limitation of the current legislation. The parties agree that Staff's low differential rate can be used for net metering customers. As a result, Staff's low differential TOU rate shall be the default rate for net metering customers when Evergy's 2-period TOU rate is established as the default residential customer rate for the non-net metering customers.

Evergy has proposed the elimination of several residential rate codes, which were either previously frozen or are duplicative with other existing rate codes. Staff agrees with the removal of duplicative rate codes. Therefore, the Commission will order the elimination of the rate codes identified in this case. However, to avoid customer rate codes being switched multiple times in a short period, the elimination of the rate codes shall be delayed until the relevant customers are switched to a TOU rate. The rate code elimination, therefore, will begin October 1, 2023, and be phased-in in conjunction with those customers' transfer to the 2-period TOU rates; with rate code elimination ending no later than December 31, 2023.

On September 22, 2022, the Commission approved the Revenue Requirement Stipulation, which included revenue requirements, true-up revenues and billing determinants agreed to by the signatories. Therefore, the Commission finds that inter-season design of residential rates shall be based on the determinants and seasonal revenue agreed to by the signatories to that stipulation. The revenue requirement used shall not exceed the revenue requirement specified in the Revenue Requirement Stipulation.

To summarize, residential rates for Evergy are authorized to be Evergy's 2-period TOU proposed rate as the default rate beginning October 1, 2023. Staff's low differential rate is approved as an opt-in rate, without a lead-in time. Evergy's additional residential TOU proposals are also authorized on an opt-in basis, without a lead-in time. Customers are authorized to opt-out of the default high differential rate into one of the four additional TOU rates approved here. Existing 3-period TOU customers shall stay on their existing 3-period TOU rate during and after the transition of non-TOU residential customers to the 2-period TOU rate unless those customers request to switch to the 2-period TOU rate or an alternative opt-in TOU rate. Evergy shall implement a program to engage and educate customers in the approximate ten-month lead-in time until its 2-period TOU rate takes effect as the default rate for residential customers beginning October 1, 2023. Evergy shall work with Staff and OPC and permit them a chance to review materials related to the education program and to the implementation of TOU rates from October 1 through December 31, 2023, to ensure the program and implementation have a maximum potential for success. Further Evergy will eliminate the identified residential rate codes and transition customers to the identified existing codes on or after October 1, 2023, as they transition to the 2-period TOU rate.

Net Customer Acquisition Cost

Evergy proposed that the Commission authorize deferral for prudently incurred program costs, such as marketing, education, and administration, for its proposed residential TOU rates at a net customer acquisition cost of no more than $150 per customer. No other party was in favor of the net customer acquisition cost. There is no evidence in the record to suggest how the $150 was computed or to explain the need for a net customer acquisition cost. Furthermore, the Commission finds that if TOU rates are implemented on an opt-out basis instead of an opt-in basis as proposed by Evergy, there should be no acquisition process. The Commission is not persuaded that it is "more likely than not" that the proposed $150 net customer acquisition cost would be just and reasonable.

Residential Customer Charge

The Commission agrees with Staff's recommendation regarding the appropriate residential customer charge. As Evergy begins offering multiple TOU rates, it is important to foster customer interest, with one of the proven ways being to allow customers to impact their monthly electric bill. It is likely that significantly raising the residential customer charge will mute the TOU pricing signals such that interest or follow-through with TOU rates will wane as they cannot achieve their expected savings from TOU mitigation due to a higher customer charge. Ratemaking decisions are often interdependent, and the Commission's decision here is based on moving forward with TOU rates and authorizing a smaller increase than Evergy requested to the customer charge in order to foster the growth of the TOU rates. The Commission will re-evaluate the growth of the TOU programs and the monthly customer charge in Evergy's next rate case. In the present case, the Commission finds that $12.00 is the appropriate residential customer charge for all single-metered residential customers. Given that one of the opt-in TOU rates approved by the Commission requires a second meter, the Commission finds it appropriate to have a separate customer charge requirement for residential customers with a second meter. Therefore, all residential customers with a second meter shall be charged a customer charge of $3.25 for the second meter.

Non-residential Rates, Schedules and Structures

Given the unique make-up of non-residential customers, including small business, such as gas stations and restaurants, whose power consumption is customer driven, the Commission does not find Staff's proposed default TOU rate for non-residential customers appropriate without further study. The Commission agrees with Evergy's proposal for non-residential rates, schedules and structure, which MECG supported. Evergy proposed a new Time-Related Pricing rate, seasonal alignment matching EMM to EMW, code consolidation and elimination of select end use rates. The Commission is persuaded that the expansion of rate offerings while simplifying the codes and end use rates will improve customer satisfaction, efficiency and will result in just and reasonable rates to non-residential customers.

Meeting with Stakeholders

The parties also presented the question of Evergy being ordered to meet with stakeholders related to its rate modernization plan. Evergy stated it meets with stakeholders on a periodic basis and is not opposed to discussing the rate modernization plan with interested parties. Therefore, the Commission memorializes here that this meeting shall occur.

RATE BASE and RESOURCE PLANNING

The Commission is combining the two issues involving coal-fired generation.

Findings of Fact:

233. Generally, Sierra Club faulted Evergy for using the results of its Depreciation Study to set unit retirement dates for its coal fleet. Sierra Club suggested

instead an optimized capacity expansion model, which would allow the model to select retirement dates.[283]

234. Sierra Club stated that Evergy performed no optimized economic analyses on the projected performance of its coal fleet for its 2021 IRP.

235. Capacity expansion software is a tool that simply compares going-forward costs of the available alternatives and determine the lowest-cost option to meet capacity and energy requirements, subject to any modeling constraints (e.g., import limitations or annual build limits).[284]

236. As part of the joint resolution following the 2021 IRP, Evergy is utilizing capacity expansion modeling beginning with the 2022 Annual Update.[285]

237. Sierra Club asserted that Evergy has not demonstrated that continued investment in its coal fleet is the prudent and least-cost option to provide reliable power to ratepayers as part of these dockets or as part of its 2021 IRP.[286]

238. Sierra Club alleged that Evergy could retire one or even two of its existing coal units and would not need to replace the capacity for at least another decade.[287]

239. EMM has generation in excess of its customers' needs; while EMW does not have enough SPP accredited generation capacity to meet its peak. Combined, the two have enough SPP accredited generation to meet the combined loads.[288]

240. Having enough capacity is essential to having enough energy to meet customers' load requirements. However, having enough capacity does not necessarily ensure that energy will be available when it is needed. For instance, EMW does not have

[283] Ex. 450, Glick Direct, pp. 17-18.
[284] Ex. 56, Messamore Rebuttal, p. 13.
[285] Ex. 56, Messamore Rebuttal, p. 13.
[286] Ex. 450, Glick Direct, p. 4.
[287] Ex. 450, Glick Direct, p. 21.
[288] Ex. 302, Mantle Rebuttal p.4.

enough generation capacity through its owned resources and purchased power agreements to meet the SPP resource adequacy standards. It can only meet the SPP resource adequacy standards when combined with EMM. EMW's resource plan depends on EMM to provide capacity and on SPP to provide energy.[289]

241. EMM's generation produces revenue on the SPP energy market that offsets fuel costs and some of its load costs. The revenues produced by EMW's generation covers the fuel cost but does not offset much of its load costs. EMW relies on the market to provide the electricity needed by its customers.[290]

242. In the simplest terms, capacity is the maximum output an electricity generator can physically produce, measured in megawatts. Energy is the amount of electricity a generator produces over a defined period of time. For example, a generator with a capacity of 100 MW that runs at full capacity for 10 hours generates 1,000 MWh (100 MW * 10 hours = 1,000 MWh) of energy.[291]

243. During Winter Storm Uri, EMW incurred more than $315 million in fuel and purchased power expenses. In File No. EF-2022-0155, EMW requested to recover more than $300 million of those costs from its customer through securitization.[292]

244. The Commission's approach to IRPs involves the comparison of a variety of resource plans (including different combinations of retirements and demand-side/supply-side additions) to assess which is the lowest cost, and allows for the assessment of the value of incremental changes to the resource plan. The IRP process and the capacity expansion model have the same goal.[293]

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[289] Ex. 302, Mantle Rebuttal p. 10.
[290] Ex. 302, Mantle Rebuttal, p. 5.
[291] Ex. 302, Mantle Rebuttal, pp. 9-10.
[292] Ex. 302, Mantle, Rebuttal, p. 7, 17.
[293] Ex. 56, Messamore Rebuttal, p. 13.

245. When determining the acquisition, continuation, or retirement of any resource, the availability of fuel and the dispatchability of the resource, along with meeting environmental regulations needs to be considered. No one type of resource on its own can meet all of the requirements of a prudent resource plan; however, a diverse portfolio of resources will.[294]

246. Sierra Club's testimony did not mention generation types or discuss any base load alternatives in its discussion of the retirement of current base load units.[295] Sierra Club's analysis did not account for Evergy's need to have sufficient capacity and meet reserve margin requirements.[296]

247. Base load generating units/plants are electric power sources that operate continuously to meet minimum levels of power demand on a 24/7 basis. Base load plants are usually large scale and are key components of an efficient and reliable electric grid. Base load plants are not designed to respond to peak demands or emergencies. Examples of base load units include coal and nuclear power plants.[297]

248. Intermediate power plants/units are used during the transition between base load and peak load demand. These plants are not as difficult to ramp up as base load plants or as expensive to operate as peak load plants. Wind and solar and some natural gas power plants fall in the intermediate category. Because wind and solar resources are intermittent by nature, and the electricity they generate fluctuates with the weather and the time of day, they cannot be depended on to meet peak demand or to provide energy on a consistent basis for base load purposes.[298]

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[294] Ex. 302, Mantle Rebuttal, p. 14.
[295] Ex. 241, Hull Rebuttal, p. 6.
[296] Ex. 56, Messamore Rebuttal, pp. 11-12.
[297] Ex. 241, Hull Rebuttal, p. 4.
[298] Ex. 241, Hull Rebuttal, pp. 4-5.

249. A peaking power plant (commonly referred to as a “Peaker plant”) is one that can switch on when additional power is needed, which will come online without much delay, and will start generating power on a moments' notice. Once a peak has passed, they are returned to standby mode for future peaks. Peaker plants are often used much less frequently over the course of a year than base and intermediate plants.[299]

250. A dispatchable resource provides electricity when the electricity is needed. Fossil fuel units are units that can be relied on to generate electricity when needed, *i.e.* dispatched, when fuel is available. When it is not needed to generate electricity, the plant does not generate. Renewable generation is not completely dispatchable.[300]

251. A good resource portfolio is one that contains diverse types of generation resources, each with its own strengths and weaknesses that are chosen to meet the unique load demands of the utility’s customers in all hours of the year while also minimizing the risk of high utility bills and loss of service.[301]

252. OPC disagreed with Sierra Club’s recommendation to begin a process of retiring Evergy’s coal plants.[302]

253. Sierra Club recommended a disallowance for EMM pertaining to capital costs and O&M for La Cygne Units 1 and 2 and Iatan 1 on the basis that EMM has not demonstrated the prudence of continuing to operate the plant relative to retirement and replacement with alternatives.[303]

[299] Ex. 241, Hull Rebuttal, p. 5.
[300] Ex. 302, Mantle Rebuttal, p. 13.
[301] Ex. 302, Mantle Rebuttal, p. 14.
[302] Tr. Vol. 8, p. 272.
[303] Ex. 450, Glick Direct, p. 4; and Ex. 451, Glick Direct, p. 4 (Confidential version).

254. Sierra Club recommended a disallowance for EMW pertaining to capital costs and O&M for Jeffrey Units 1-3 and its share of Iatan Unit 1 on the basis that EMW has not demonstrated the prudence of continuing to operate the plant as compared to retirement and replacement with alternatives.[304]

255. La Cygne is a two-unit, coal-fired power plant near La Cygne, Kansas. Unit 1 is 873 megawatts (MW), and Unit 2 is 685 MW, for a combined nameplate capacity of 1,558 MW. Unit 1 came online in 1973, and Unit 2 came online in 1977. EMM owns 50% of both units, and Evergy Kansas owns the other 50%. In the preferred plan of EMM's 2021 IRP, Unit 1 is set to retire in 2032, and Unit 2 is set to retire in 2039.[305]

256. Iatan is a two-unit, coal-fired plant near Weston, MO. Unit 1 is 726 MW and Unit 2 is 999 MW, for a combined nameplate capacity of 1,725 MW. Unit 1 came online in 1980, Unit 2 came online in 2010. EMM owns 61% of the plant and EMW owns 18%. The remainder is owned by non-affiliated entities. In the preferred plan of Evergy MO's 2021 IRP, Iatan Unit 1 is slated to retire in 2039 and Iatan Unit 2 is slated to retire in 2070.[306]

257. Jeffrey is a three-unit, coal-fired plant located in Emmet Township in Pottawatomie County, Kansas. Each of the three units has a nameplate capacity of 740 MW, for a total capacity of 2,220 MW. EMW owns 8% (175 MW) of the Jeffrey plant, and Evergy Kansas owns the other 92%. Unit 1 came online in 1978, Unit 2 in 1980, and Unit 3 in 1983. Jeffrey Units 1 and 2 are set to retire in 2039, and Unit 3 is set to retire in 2030.[307]

[304] Ex. 450, Glick Direct, p. 5; and Ex. 451, Glick Direct, p. 5 (Confidential version).
[305] Ex. 450, Glick Direct, p. 8.
[306] Ex. 450, Glick Direct, p. 7.
[307] Ex. 450, Glick Direct, p. 7.

258. Generally, Sierra Club's concern was that continuing operations of coal plants could lead to large capital expenditures caused by future environmental regulations, and that such investment could then influence the continued use of the plant.[308]

259. Sierra Club asserted that the continued operation of all but two of Evergy's coal plants is potentially imprudent and thus all O&M and capital costs incurred at those facilities during the test year should be disallowed because of its dissatisfaction with Evergy's IRP process.[309]

260. EMW, as an 8% minority owner in the Jeffrey Energy Center, would not control a retirement decision.[310]

261. Sierra Club calculated that each of the plants incurred costs in excess of the value of its energy and capacity over the past five years, with the exception of 2021 (referring to Winter Storm Uri[311]).[312] However, Sierra Club's calculation did not reflect how expenses are passed on to ratepayers.[313]

262. Sierra Club concluded from its analyses that the historical net revenues for the period 2017 to 2020 were significantly higher when the full capital expense amount was allocated to the year it was incurred when compared to when the capital expenses were amortized.[314]

263. Utilities typically amortize capital expenditures (based on the utility's cost of capital) and spread the costs out over the remaining economic life of the plant.[315]

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[308] Ex. 450, Glick Direct, p. 13.
[309] Ex. 56, Messamore Rebuttal, p. 13.
[310] Ex. 56, Messamore Rebuttal, p. 8.
[311] Ex. 450, Glick Direct, pp. 23-24; and Ex. 451, Glick Direct, pp. 23-24 (Confidential version).
[312] Ex. 450, Glick Direct, pp. 21-22; and Ex. 451, Glick Direct, pp. 21-22 (Confidential version).
[313] Ex. 450, Glick Direct, pp. 32-33; and Ex. 451, Glick Direct, pp. 32-33 (Confidential version).
[314] Ex. 450, Glick Direct, p. 27 and 35; and Ex. 451, Glick Direct p. 27 and 35 (Confidential version).
[315] Ex. 450, Glick Direct, p. 33

264. Evergy argued that Sierra Club's analyses simply compare costs to market values of energy, ancillary services, and capacity, and assert that if costs are greater than total revenues, the continued operation of the plant must be imprudent. This type of analysis does not consider that Evergy needs to have sufficient economic capacity to serve customers and meet reserve margin requirements. [316]

265. Sierra Club's claim that almost 1,700 MW of capacity (over 4,300 MW if the capacity of those units which EMW and EMM do not own is included) should be retired on the basis of costs exceeding revenues and not including any assessment of costs for replacement capacity is not prudent.[317]

266. A prudent electric utility analysis of retiring a generating plant should include an assessment of the cost to replace its capacity.[318]

Conclusions of Law:

No additional Conclusions of Law are necessary.

Issues Presented by the Parties:

Resource Planning

A. Has EMW been imprudent in its resource planning process?

1. If yes, how should EMW's fuel and purchased power costs be determined?
2. If yes, how should EMW's FAC base factor be calculated?
3. If yes, how should EMW's accumulation period actual costs be adjusted for its FAC?

B. Should the Commission require Evergy to conduct a full retirement study of its coal fleet using optimized capacity expansion software, which identifies the optimal retirement date for each of its coal-fired units?

[316] Ex. 56, Messamore, pp. 11-12.
[317] Ex. 56, Messamore, pp. 11-12.
[318] Tr. Vol. 8, p. 272.

Rate Base

> Has Evergy met its burden of proof to permit recovery from ratepayers of capital and O&M costs proposed in the test year for Iatan Unit 1, Jeffrey Units 1-3, and La Cygne Units 1 and 2?

Decision:

Resource Planning

Sierra Club has suggested a finding of imprudence regarding the resource planning involved with coal-fired generating plant. Sierra Club proposes that coal plants should be retired more quickly than already planned. Staff, OPC and Evergy all disagree with Sierra Club's position for different reasons. Sierra Club's analysis over-simplifies the analysis required to make these decisions. Sierra Club's proposal does not account for the replacement of the capacity of the retired power plant; type of replacement capacity (baseload/dispatchable capacity) and its implications; and stranded costs of the retired plant. The standard to begin a prudency analysis is the raising of a serious doubt. The Commission finds that Sierra Club has not raised a serious doubt about Evergy's resource planning. The Commission does not find the reason for Sierra Club's request for a full retirement study of Evergy's coal units using optimized capacity expansion software persuasive, especially given that Evergy is already utilizing this tool.

Rate Base

Sierra Club's recommendation to disallow the costs of certain coal plants has overlooked two key factors in the retirement of utility generation. Sierra Club's analysis did not adequately address undepreciated investment and also fails to address the fact that these coal plants are not solely Evergy's to control and determine a retirement date. The standard to pursue a finding of imprudence is to raise a serious doubt about the practice at issue. The Commission does not find that Sierra Club has raised a serious doubt regarding the prudence of Evergy's resource planning and therefore its spending on capital and O&M costs for Iatan Unit 1, Jeffrey Units 1-3, and La Cygne Units 1 and 2. The Commission finds that Evergy has met its burden of proof to permit recovery of capital and O&M costs proposed in the test year for Iatan Unit 1, Jeffrey Unites 1-3, and La Cygne Units 1 and 2.

STREETLIGHTING (EMW ONLY)

Findings of Fact:

267. The City of St. Joseph (St. Joseph) recommends revisions to Tariff Sheet No. 150 to permit a municipality to build streetlights as part of a public works project, or to have them built by a contractor as part of a city-approved development, and deem ownership of the streetlights to be in Evergy.[319]

268. The proposal of transferring ownership of streetlighting was offered by St. Joseph Light and Power Company (SJLP) as part of its municipal street lighting tariff.[320]

269. Historically, St. Joseph was able to require a developer build the streetlights and then have the utility take ownership of the streetlights (Developer Installed Option). Evergy's current practice charges the streetlighting fees directly to St. Joseph.[321]

270. St. Joseph was the only EMW customer to have the Developer Installed Option to the municipal streetlighting tariff.[322]

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[319] Ex. 51, Lutz Rebuttal, p. 9.
[320] Ex. 51, Lutz Rebuttal, p. 10.
[323] Ex. 307, Marke Rebuttal, p. 23.
[322] Ex. 51, Lutz Rebuttal, p. 12.

271. To Evergy's best knowledge, the practice of allowing developer installed streetlighting in St. Joseph began through a memorandum of understanding that followed SJLP's purchase of the St. Joseph streetlighting system in the 1980s or early 1990s.[323]

272. Subsequently, SJLP and another electric utility, Missouri Public Service Company, merged under Aquila and then KCP&L Greater Missouri Operations Company, and in 2016 consolidated the various companies' streetlighting tariffs in File No. ER-2016-0156.[324]

273. The City of St. Joseph was a party to File No. ER-2016-0156.[325]

274. Provisions for the Developer Installed Option were not included in the 2016 consolidated streetlighting tariffs as the consolidation sought to end lighting options that were not suited for universal application across the service area.[326]

275. In a limited deployment, such as the city limits of St. Joseph with approximately 45 square miles, the Developer Installed Option was practical in that utility companies could travel to inspect a streetlight quickly and utility relationships with the small number of developers allowed some familiarity and interaction with the developers' streetlight installers to assist quality control.[327]

276. Beginning in 2017, Evergy began a systematic conversion of its municipal street lighting to light emitting diode (LED) technology.[328]

277. In spring of 2018, St. Joseph lifted a 12-year suspension on city-initiated streetlight expansion.[329]

[323] Ex. 51, Lutz Rebuttal, p. 10.
[324] Ex. 51, Lutz Rebuttal, p. 10.
[325] Order Granting Intervention, issued March 21, 2016, File No. ER-2016-0156.
[326] Ex. 51, Lutz Rebuttal, pp. 10-11.
[327] Ex. 52, Lutz Surrebuttal, p. 33.
[328] Ex. 117, Lutz Direct, p. 52.
[329] Ex. 51, Lutz Rebuttal, p. 11.

278. Also in spring of 2018, EMW completed a conversion of all non-decorative streetlighting fixtures to LED technology.[330]

279. St Joseph has approximately 6,500 LED lighting type streetlights, plus a few older light types such as high pressure sodium or mercury vapor.[331]

280. As a rule of thumb, and subject to change due to location and other conditions, it costs Evergy roughly $3,800 to purchase and install a metal street light pole.[332]

281. The LED conversion and the lifting of the 12-year suspension brought to attention the change in EMW's streetlighting tariff, which resulted in multiple meetings between Evergy and St. Joseph, resulting in a letter sent to St. Joseph in December of 2018.[333]

282. In 2019 St. Joseph attempted to invoke the terms of the Developer Installed Option contained in the pre-2016 streetlighting tariff, which had provided for transferring ownership of streetlighting to Evergy, which resulted in additional meetings and a letter sent to St. Joseph in April 2020.[334]

283. The letter sent in April 2020 presented two alternatives to St. Joseph: 1) let Evergy build all the new streetlights; or 2) St. Joseph build the new streetlights itself and also own and maintain them.[335]

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[330] Ex. 51, Lutz Rebuttal, p. 11.
[331] Tr. Vol. pp. 881-882.
[332] Tr. Vol. 12, p. 872; and pp. 880-881.
[333] Ex. 51, Lutz Rebuttal, p. 11.
[334] Ex. 51, Lutz Rebuttal, pp. 11-12.
[335] Ex. 850, Carter Direct, p. 3; Ex. 854 is a copy of the April 2020 letter.

284. A maintenance only rate in Tariff Sheet No. 151 attempts to remove the equipment ownership aspects and provide only maintenance and energy cost elements.[336]

285. Tariff Sheet No. 150.1 describes the additional optional charges applicable only to streetlights owned by EMW to recover the costs associated with the installation of the elements listed in 4.1 to 4.5 of the tariff sheet.[337]

286. City owned streetlights would not be subject to the charges in Tariff Sheet No. 150.[338]

287. St. Joseph can install and own streetlights, but that would require adding liability insurance and maintenance costs to the city budget.[339]

288. Breakaway bases are special bases for streetlight poles designed to fragment if hit by a vehicle. It is used as the base for a metal light pole.[340]

289. Undergrounding refers to how the electricity is extended to the light pole, by installing the electric distribution line underground rather than by overhead wire. Depending on soil conditions around the new streetlight, rock may need to be removed or other specialized trenching or boring be employed to extend electricity to the streetlight pole underground.[341]

290. The purpose of charges for underground conductors and breakaway bases is to cover the ongoing maintenance of these items; the costs are not accounted for elsewhere in the streetlighting tariff.[342]

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[336] Tr. Vol. 12, p. 884.
[337] Tr. Vol. 12, pp. 886-887.
[338] Tr. Vol. 12, pp. 886-887.
[339] Ex. 850, Carter Direct, pp. 3-4.
[340] Ex. 851, Carter Surrebuttal, pp. 6-7.
[341] Ex. 851, Carter Surrebuttal, p. 7.
[342] Ex. 51, Lutz Rebuttal, p. 12.

291. Where the streetlighting tariff refers to charges added for new, basic installations, it does not mean a new streetlight, rather it establishes the conditions of new installation versus a retrofit. The designation of new does not limit EMW's charges to installation only, it is an ongoing monthly charge for continued maintenance.[343]

292. In order to re-adopt the Developer Installed Option, EMW would need to be prepared to support all municipalities wishing to utilize the option.[344]

293. St. Joseph testified that the ability to require developers to install streetlighting at the developer's cost is a policy decision that should be left to local municipalities, but that it would be content with some other designated limitation to reduce the availability of the tariff to just itself or a small group.[345]

294. St. Joseph argues that the capital costs of streetlights should be borne by the developers who are causing the expansion, and not the city operating budget.[346]

295. St. Joseph distinguishes the capital costs of the city versus the operating costs.[347] It is this change in the city's budget – paying for the streetlights from its capital costs to its operating costs that is the cause of St. Joseph's concern.[348]

296. St. Joseph argues that the change to the streetlighting tariff removed the city's ability to allocate capital expense to developers, and instead burdened the city with significant infrastructure cost.[349]

[343] Tr. Vol. 12, pp. 871-872.
[344] Ex. 51, Lutz Rebuttal, p. 12.
[345] Ex. 851, Carter Surrebuttal, pp. 3-4.
[346] Ex. 850, Carter Direct, p. 4.
[347] Ex. 851, Carter Surrebuttal, p. 4.
[348] Ex. 851, Carter Surrebuttal, pp. 4-5.
[349] Ex. 851, Carter Surrebuttal, p. 2.

297. St. Joseph argued that it is unfair for it to have to pay ongoing monthly charges related to undergrounding, breakaway bases, rock removal, or other specialized trenching/boring.[350]

298. Sixty-one streetlights have been identified as being transferred from St. Joseph to EMW in 2017.[351]

299. Of the 61 identified streetlights, 31 have breakaway bases.[352]

300. All 61 identified streetlights require undergrounding.[353]

301. The 61 streetlights are in EMW's rate base valued at zero dollars.[354]

Conclusions of Law:

DD. Streetlighting Tariff Sheet No. 151 contains no restriction on third parties' ability to install streetlights.

EE. Section 393.130.3 prohibits an electrical corporation from granting undue or unreasonable preference to select ratepayers and locales.

Issues Presented by the Parties:

> A. Should language be added to EMW's Municipal Street Lighting Service Tariff providing that streetlights installed by a city contractor or a city-approved developer shall be deemed to be owned by Evergy, after inspection and approval by the Company, and shall not be subject to additional installation or structure charges?
>
> B. Should language be added to EMW's Municipal Street Lighting Service Tariff providing that no "Optional Equipment" charges in Section 4.0 or 5.0 of Municipal Street Lighting Service Tariff will be charged to streetlight facilities which are deemed to be owned by the Company and installed by a city or its contractor, or by a developer of a city-approved development?

[350] Ex. 850, Carter Direct, pp. 6-7.
[351] Ex. 850, Carter Direct, p. 7.
[352] Tr. Vol. 12, p. 867.
[353] Tr. Vol. 12, p. 867.
[354] Tr. Vol. 12, p. 873.

C. Should the Company be required to remove from its rate base streetlights that were installed by city contractors or city-approved developers?

D. Should the Company be required not to charge the City of St. Joseph for breakaway bases, undergrounding and other "Optional Equipment" charges under Sections 4.0 and 5.0 of the tariff for streetlights that were installed by city contractors or city-approved developers?

Decision:

The Commission is sympathetic to the position of St. Joseph. It had a program whereby the city accumulated street lights, but did not have to pay to purchase and install them as they were paid for by the developer. Under the previous tariff of transferring ownership of streetlighting, the city streetlights also received ongoing maintenance at no cost to the city.

Such a program, however, is not suited for universal application across the EMW service area. The Developer Installed Option provisions of the streetlighting tariff began with a memorandum of understanding between EMW's predecessor and St. Joseph when St. Joseph Light and Power was acquired by Aquila. It is from this arrangement that the original tariff provisions were created. No other city ever participated in the Developer Installed Option.

When the streetlighting tariffs were consolidated in File No. ER-2016-0156, the Developer Installed Option was removed as it was not suited for universal application across the service territory. In arguing for the revival of Developer Installed Option, St. Joseph argued that it would accept verbiage which limited the program's availability within the service territory. In essence, St. Joseph requested that the Commission order EMW to offer the Developer Installed Option to everyone, or just to St. Joseph.

By statute, tariffs are required to be non-discriminatory. St. Joseph first requests that the Developer Installed Option would be available to everyone. This argument fails due to the cost and involvement of offering such a streetlight ownership transfer program across the service territory. EMW's response in sum is that transferring ownership and maintenance of approximately 6,500 streetlights in a city of 45 square miles is achievable, but only due to the relatively small area. If the Developer Installed Option would be reinstated and available to all customers; the costs, personnel needed, and lack of current compliance standards makes enactment of the tariff provisions unreasonable.

St. Joseph argued that the Developer Installed Option could be limited to certain city or county classifications, or geographic identifiers. St. Joseph did not offer any evidence that there was a difference in the provision of street lighting service for St. Joseph's streetlights or in the provision of service of cities of a certain size or within a county of a certain designation as compared to other customers taking service under the streetlighting tariff such that the preference could be justified. The Developer Installed Option, as recommended by St. Joseph, is not appropriate due to the high cost associated with offering it across EMW's service area. Additionally, there is no evidence to support a finding that limiting the availability of the streetlight transfer of ownership provisions to only St. Joseph or other similarly situated cities would be justified.

St. Joseph also recommended that the streetlights it has already transferred ownership of be removed from EMW's rate base. EMW credibly testified that the transferred streetlights were in rate base for the purpose of tracking, but that all transferred streetlights were entered at a valuation of zero dollars. The Commission does not find St. Joseph's recommendation reasonable as the tracking is useful, and EMW is not earning a return on the transferred streetlights.

Lastly, St. Joseph recommended that it be exempted from having to pay for the continuing maintenance of the streetlights it transferred, specifically mentioning the undergrounding and breakaway bases. This recommendation fails for the reason that the charges it opposes are tied to the ongoing maintenance of the streetlights. Even though transferred by St. Joseph to EMW, St. Joseph must still pay the monthly charges for EMW-owned streetlights under the terms of the tariff. Those monthly charges include energy and, pertinent to this subissue, maintenance. If St. Joseph desires to pay EMW only for energy and not for maintenance, then Tariff Sheet No. 151 details the energy charges for streetlights not owned or maintained by EMW. However, streetlights not owned or maintained by Evergy will be the responsibility of the streetlight owners, which is the situation that St. Joseph finds objectionable. The Commission does not find reasonable the recommendation of St. Joseph to be exempt from certain streetlighting charges addressing ongoing maintenance due to a prior transfer of ownership of the streetlights.

CENTRAL NEBRASKA PUBLIC POWER AND IRRIGATION DISTRICT HYDRO PURCHASED POWER AGREEMENT

Findings of Fact:

302. EMM entered into a hydro purchased power agreement with Central Nebraska Public Power and Irrigation District ("the Hydro PPA") to meet the Kansas Renewable Energy Standard.[355]

303. The Company's response to a discovery request in File No. ER-2018-0145 provides a power point presentation that provides information related to its justification for entering into the Hydro PPA contract.[356]

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[355] Ex. 302, Mantle Rebuttal, p. 25; Tr. Vol 13, pp. 945-946.
[356] Ex. 336, Surrebuttal Testimony of Lena Mantle in ER-2018-0145, Schedule LMM-S-4C.

304. The Hydro PPA contract is effective from January 1, 2014, through December 31, 2023.[357]

305. The Hydro PPA contract has been serving customers in both Missouri and Kansas.[358]

306. Since the effective dates of rates from File No. ER-2018-0145, EMW alleges that the Hydro PPA has been included in base energy rates but has been excluded from the ongoing FAC Fuel Adjustment Rate ("FAR") filings.[359]

307. The Hydro PPA cannot be used to meet the Missouri Renewable Energy Standard because the three plants are accredited at 18 MW each and the Missouri statute requires plants to be rated at 10 MW or less to qualify for inclusion in meeting the Missouri Renewable Energy Standard.[360]

308. The Hydro PPA's capacity is not needed for EMM to meet resource adequacy requirements of SPP.[361]

309. The Hydro PPA's energy is not needed to meet customer load in Missouri.[362]

310. Staff argues that there is no benefit to Missouri customers just by being served; if the costs are exceeding the revenues, there is no benefit.[363]

311. OPC testified that there are no benefits to Missouri customers based on the Hydro PPA.[364]

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[357] Tr. Vol. 13, p. 951.
[358] Tr. Vol. 13, pp. 954-955.
[359] Ex. 66, Nunn Surrebuttal, p. 7.
[360] Ex. 303, Mantle Surrebuttal, p. 6; *see also* Tr. Vol. 13, p. 986, stating the generators are noncompliant with the Missouri limit.
[361] Ex. 303, Mantle Surrebuttal, p. 6.
[362] Tr. Vol. 13, p. 961, and pp. 986-987.
[363] Tr. Vol. 13, p. 960.
[364] Tr. Vol. 13, pp. 986-987.

312. Staff argues that there should be no recovery for the energy used to serve Missouri customers, and that Evergy can choose to serve Missouri customers without the Hydro PPA.[365]

313. Staff witness Shawn Lange, P.E., modeled EMM's generation and load requirements, and determined that, as modeled by Staff, EMM's generation exceeds its total load from Kansas and Missouri by approximately 6 million MWh annually.[366]

314. The Hydro PPA was modeled by Staff at providing 300,000 MWh annually.[367]

315. The modeled costs for the Hydro PPA were in excess of the revenues that were modeled.[368]

316. OPC testified to reviewing the test-year time period, and found that the costs of the Hydro PPA exceeded revenues for every month of the test-year period.[369]

317. There are instances where EMM would not be able to dispatch all 21 million MWh and would need to purchase power from SPP to meet its system load.[370]

318. EMM's generation is dispatched by the SPP.[371]

Conclusions of Law:

FF. The United States Supreme Court has stated:

> The filed rate doctrine also precludes a regulated utility from collecting any rates other than those properly filed with the appropriate regulatory agency. This aspect of the filed rate doctrine constitutes a rule against retroactive ratemaking or retroactive rate alteration. In its discussion of the doctrine, the [Court] explains that it explicitly prohibits an entity from "imposing a rate increase for gas already sold," and states, in a footnote, that an entity "may

[365] Tr. Vol. 13, p. 963.
[366] Tr. Vol. 13, pp. 974-976; Ex. 335C.
[367] Tr. Vol. 13, p. 977.
[368] Tr. Vol. 13, p. 983.
[369] Tr. Vol. 13, pp. 987-988, and 990.
[370] Tr. Vol. 13, p. 981.
[371] Tr. Vol. 13, p. 982.

> not impose a retroactive rate alteration and, in particular, may not order reparations.[372]

Issues Presented by the Parties:

> How should the net cost of the Central Nebraska Public Power and Irrigation District ("CNPPID") hydro purchased power agreement ("PPA") be treated?
>
> > 1. Should a normalized cost be included in the calculation of the fuel and purchased power costs of Evergy Metro's revenue requirement?
> >
> > 2. Should a normalized cost be included in the Evergy Metro fuel adjustment clause ("FAC") base factor calculation?
> >
> > 3. Should the actual CNPPID hydro PPA costs be included in Evergy Metro's actual accumulation period FAC costs?[373]

Decision:

Evergy argues that the Hydro PPA serves Missouri customers and as such is used and useful. Although used, evidence shows it is not needed to meet Missouri customer load, its costs have exceeded revenues in every month of the current rate case test year, and thus, it is not useful to Missouri customers or economic.

Evergy also argues that the Hydro PPA was included in the base energy rate in the previous rate case and that the practice should be extended in this rate case. Underlying this argument are the terms of a settlement agreement from EMM's same previous rate case, File No. ER-2018-0145. The parties have disagreed about the inclusion, or exclusion, of the Hydro PPA in the settlement, and whether the settlement only dictated exclusion of the Hydro PPA from recovery under the FAC, or excluded the Hydro PPA from recovery in the base energy rate as well. The Commission does not reach a decision on what was or was not involved in that settlement, nor is it permitted to

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[372] *State ex rel. Associated Natural Gas Co. v. Public Service Comm'n*, 954 S.W.2d 520, 531 (Mo. App. W.D. 1997) (internal citations omitted).
[373] Questions edited due to overlapping issues.

make adjustments even if the Hydro PPA was previously included in the base energy rate in error. The Commission's decision is based on the fact that the Hydro PPA's usefulness was not shown during the test-year. Moreover, the initial ten-year term of the Hydro PPA contract ends in December 31, 2023. The Hydro PPA does not provide benefits to Missouri customers and therefore will be excluded from recovery from Missouri customers.

Conclusion:

The Commission, having considered the competent and substantial evidence upon the whole record, makes the above findings of fact and conclusions of law. The positions and arguments of all of the parties have been considered by the Commission in making these findings. Any failure to specifically address a piece of evidence, position, or argument of any party does not indicate that the Commission did not consider relevant evidence, but indicates rather that omitted material is not dispositive of this decision.

Except as otherwise set out in the body of this order, the Commission finds that EMM and EMW have met their burden of proof to show that an increased rate for each is just and reasonable. Thus, the Commission concludes, based upon its review of the whole record that rates approved as a result of this order support the provision of safe and adequate service. The revenue requirement authorized by the Commission is no more than what is sufficient to keep EMM's and EMW's utility plant in proper repair for effective public service and provide to Evergy's investors an opportunity to earn a reasonable return upon funds invested.

By statute, orders of the Commission become effective in thirty days, unless the Commission establishes a different effective date.[374] To allow Evergy the earliest

[374] Section 386.490.2, RSMo.

opportunity to implement the approved rates, the Commission finds it reasonable to make this order effective in less than 30 days.

THE COMMISSION ORDERS THAT:

1. The tariff sheets submitted on January 7, 2022, by EMM, and assigned Tracking Nos. YE-2022-0200 and YE-2022-0201 are rejected.

2. EMM is authorized to file tariff sheets sufficient to recover revenues approved in compliance with this order and the *Order Approving Four Partial Stipulations and Agreements*, issued September 22, 2022.

3. The tariff sheets submitted on January 7, 2022, by EMW, and assigned Tracking No. YE-2022-0202 are rejected.

4. EMW is authorized to file tariff sheets sufficient to recover revenues approved in compliance with this order and the *Order Approving Four Partial Stipulations and Agreements*, issued September 22, 2022.

5. The retirement of Sibley was prudent.

6. All determinations regarding the Sibley AAO are as set forth in the body of this order.

7. AMI-SD meters installed for the three reasons of (1) exchange of AMI meter for AMI-SD meter; (2) exchange of AMI meter for an AMI-SD meter due to customer arrears; and (3) unknown reasons are disallowed from recovery.

8. Fifty percent of the cost of the consultant fees associated with Subscription Pricing are disallowed from recovery.

9. Residential rates for Evergy are authorized as follows:

   a. Evergy's 2-period TOU proposed rate will be the default rate beginning October 1, 2023. The 2-period TOU rate will be phased in by appropriate customer group from October 1, 2023, through December 31, 2023, and such phase-in shall be in coordination with the start of each customer group's billing cycle;

b. Staff's proposed low-differential rate is approved as an opt-in rate, without a lead-in time;

c. Evergy's additional TOU rate proposals are authorized on an opt-in basis, without a lead-in time.

d. Staff's low differential TOU will be the default rate for the net metering customers.

e. Evergy's Residential General Use rate will be the default rate for non-AMI metered residential customers.

f. The customer charge for all single-meter residential customers shall be $12.00. The customer charge for an additional residential meter shall be $3.25.

Evergy shall eliminate the identified residential rate codes and transition customers to the identified existing codes as discussed in the body of this order. Additionally, Evergy shall implement a program to engage and educate customers in the approximately ten-month lead-in time until its tariff provisions regarding the 2-period TOU rate as the default rate for residential customers becomes effective.

10. Evergy is authorized to track the education and outreach costs associated with TOU rate implementation for consideration and possible recovery in a future rate case.

11. Evergy shall submit in this file quarterly reports detailing the types and amounts of education and outreach expenses deferred with the first report due ninety days from the effective date of this order.

12. The Commission will open a new File Number to establish a forum allowing collaboration among stakeholders regarding the TOU education and implementation plans approved herein.

13. Non-residential rates for Evergy are authorized in the form of Evergy's proposed Time-Related Pricing rate on an opt-in bases, seasonal alignment matching EMM to EMW, and code consolidation and elimination of select end use rates.

14. Evergy shall host a meeting with interested stakeholders related to its rate modernization plan within 180 days of the effective date of Evergy's tariffs filed in compliance with this order.

15. Sierra Club's allegation of imprudence regarding resource planning involving coal plants is denied for lack of raising a serious doubt as to the prudence of existing resource planning.

16. Sierra Club's allegation of imprudence regarding Evergy's test-year spending on capital and O&M costs for Iatan Unit 1, Jeffrey Units 1-3, and La Cygne Units 1 and 2 is denied for lack of raising a serious doubt as to the prudence of its test-year spending for the above listed coal-fired generation plants.

17. St. Joseph's request to add language to EMW's streetlight tariff related to the Developer Installed Option is denied.

18. St. Joseph's request that the streetlights it has already transferred ownership of be removed from EMW's rate base is denied.

19. St. Joseph's request that it be exempted from having to pay for the continuing maintenance of the streetlights it already transferred to EMW is denied.

20. The Hydro PPA is disallowed from recovery as it is not used and useful to Missouri customers.

21. This *Amended Report and Order* will become effective on December 18, 2022.

BY THE COMMISSION

Morris L Woodruff

Morris L. Woodruff
Secretary

Silvey, Chm., Rupp, Coleman, and
Kolkmeyer CC., concur and certify compliance
with the provisions of Section 536.080, RSMo (2016).
Holsman, C., dissents.

Hatcher, Senior Regulatory Law Judge

STATE OF MISSOURI

OFFICE OF THE PUBLIC SERVICE COMMISSION

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

WITNESS my hand and seal of the Public Service Commission, at Jefferson City, Missouri, this 8th day of December, 2022.

Morris L. Woodruff

Morris L. Woodruff
Secretary

MISSOURI PUBLIC SERVICE COMMISSION

December 8, 2022

File/Case No. ER-2022-0129 and ER-2022-0130

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

Sincerely,

Morris L Woodruff

Morris L. Woodruff
Secretary

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