Exhibit No. 450

Sierra Club – Exhibit 450
Devi Click
Direct Testimony
File Nos. ER-2022-0129 & ER-2022-0130

Exhibit No.:	
Issues:	Revenue Requirement
Witness:	Devi Glick
Type of Exhibit:	Direct Testimony
Sponsoring Party:	Sierra Club
Case No.:	ER-2022-0129, ER-2022-0130
Date Testimony Prepared:	June 8, 2022

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

FILE NO. ER-2022-0129
FILE NO. ER-2022-0130

REVENUE REQUIREMENT
DIRECT TESTIMONY
OF
DEVI GLICK

ON BEHALF OF SIERRA CLUB

REDACTED VERSION

JUNE 8, 2022

BEFORE THE
MISSOURI PUBLIC SERVICE COMMISSION

In the Matter of Evergy Missouri Metro, Inc d/b/a Evergy Missouri Metro's Request for Authority to Implement a General Rate Increase for Electric Service	))))))	**CASE NO. ER-2022-0129**
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	))))))	**CASE NO. ER-2022-0130**

AFFIDAVIT

Pursuant to Missouri Public Service Commission requirements I, Devi Glick, hereby state:

1. My name is Devi Glick, and I am a Senior Principal at Synapse Energy Economics, Inc. My business address is 485 Massachusetts Avenue, Suite 3, Cambridge, Massachusetts 02139.
2. Attached hereto and made part hereof for all purposes is my Direct Testimony on behalf of Sierra Club, including an exhibit, which have been prepared in written form for introduction into evidence in the above-referenced dockets.
3. I hereby swear and affirm that based upon my personal knowledge, the facts stated in the Direct Testimony are true. In addition, my judgement is based on my professional experience, and the opinions and conclusions stated in the testimony are true, valid, and accurate.

Under penalty of perjury, I declare that the preceding to be true and correct to the best of my knowledge and belief.

Dated: June 8, 2022

Devi Glick

Devi Glick

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1. INTRODUCTION AND PURPOSE OF TESTIMONY

Q Please state your name and occupation.

A My name is Devi Glick. I am a Senior Principal at Synapse Energy Economics, Inc. ("Synapse"). My business address is 485 Massachusetts Avenue, Suite 3, Cambridge, Massachusetts 02139.

Q Please describe Synapse Energy Economics.

A Synapse is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Synapse's clients include state consumer advocates, public utilities commission staff, attorneys general, environmental organizations, federal government agencies, and utilities.

Q Please summarize your work experience and educational background.

A At Synapse, I conduct economic analysis and write testimony and publications that focus on a variety of issues related to electric utilities. These issues include power plant economics, electric system dispatch, integrated resource planning, environmental compliance technologies and strategies, and valuation of distributed energy resources. I have submitted expert testimony before state utility regulators in more than a dozen states.

In the course of my work, I develop in-house models and perform analysis using industry-standard electricity power system models. I am proficient in the use of spreadsheet analysis tools, as well as optimization and electric dispatch models. I

have directly run EnCompass and PLEXOS and have reviewed inputs and outputs for several other models.

Before joining Synapse, I worked at Rocky Mountain Institute, focusing on a wide range of energy and electricity issues. I have a master's degree in public policy and a master's degree in environmental science from the University of Michigan, as well as a bachelor's degree in environmental studies from Middlebury College. I have more than ten years of professional experience as a consultant, researcher, and analyst. A copy of my current resume is attached as Exhibit DG-1.

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of Sierra Club.

Q Have you testified previously before the Missouri Public Service Commission ("Commission")?

A No.

Q What is the purpose of your testimony in this proceeding?

A In this proceeding, I evaluate the historical and forward-looking economics of Evergy Metro's ("Metro") and Evergy West's ("West") (together "Evergy", "Evergy Missouri", or the "Company") coal units, namely Hawthorn Generating Station ("Hawthorn"), Iatan Generating Station ("Iatan"), Jeffrey Energy Center ("Jeffrey"), and La Cygne Generating Station ("La Cygne"). I quantify the ongoing cost to ratepayers of maintaining and running the Company's shares of the four plants relative to the market and to alternative resource options. I also assess the adequacy of the analysis the Company has performed to justify continued operation of its coal units, and the respective retirement years for the units that the Company is currently projecting and using for depreciation. I then

review and evaluate the projected forward-going economics of Hawthorn 5, Iatan Units 1 and 2, Jeffrey, and La Cygne Units 1 and 2.

Q How is your testimony structured?

A In Section 2, I summarize my findings and recommendations for the Commission.

In Section 3, I provide an overview of Evergy Metro's and Evergy West's coal fleet and outline the test-year expenses that the Company is requesting to recover in this current docket.

In Section 4, I review the analysis—or lack thereof—that Evergy Missouri has conducted to justify continuing to invest in and operate its coal-fired power plants, and to project that the units will operate through their respective retirement years.

In Section 5, I evaluate the respective historical economic performances of Hawthorn 5, Iatan Units 1 and 5, Jeffrey, and La Cygne Units 1 and 2, and I calculate the costs incurred and value provided to Evergy Missouri's ratepayers each during recent years.

In Section 6, I use the Company's own data to evaluate each unit's projected economic performance over the next decade under different assumptions and sensitivities. I discuss the market and regulatory risks that the Company faces over the next decade in continuing to operate its coal plants.

Q What information do you rely upon for your analysis, findings, and observations?

A My analysis relies primarily upon the workpapers, exhibits, and discovery responses of Evergy Missouri witnesses. I also rely on other publicly available documents and data.

2. FINDINGS AND RECOMMENDATIONS

Q Please summarize your findings.

A My primary findings are:

1. Evergy incurred [redacted] in negative net revenues at Hawthorn 5, Iatan Units 1 and 5, Jeffrey Units 1-3, and La Cygne Units 1 and 2 during four out of the last five years (with the exception being 2021 due to the high market prices during winter storm Uri).

2. Based on the Company's data, I find that Jeffrey Units 1, 2, and 3, and La Cygne Units 1 and 2 have been and are projected to continue to be most uneconomic when compared to market value and alternative resources. Evergy is likely to continue to incur negative net revenues by continuing to operate and invest in each of the plants over the next decade (2022–2031).

3. Evergy has not met its burden of proof to demonstrate 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, on which it relies in these dockets.

4. Evergy has likely underestimated the investments it will need to maintain its coal plants and comply with future environmental regulations, overestimated the future capacity factors and therefore future market revenue of its units, and modeled unrealistically long remaining lifetimes for many of its plants.

Q Please summarize your recommendations.

A Based on my findings, I offer the following recommendations:

1. The Commission should disallow from inclusion in rates;

    i. For Evergy Metro: $28.3 Million in capital costs and [redacted] in O&M for La Cygne Units 1 and 2 and $20.8 Million in capital costs and [redacted] in O&M for its share of Iatan 1 on the basis that the Company has not demonstrated the prudence of continuing to operate the plant relative to retirement and replacement with alternatives.

ii. For Evergy West: $6.6 Million in capital costs and [redacted] in O&M for Jeffrey Units 1-3 and $8.1 Million in capital cost and [redacted] in O&M for its share of Iatan 1 on the basis that the Company has not demonstrated the prudence of continuing to operate the plant relative to retirement and replacement with alternatives.

2. The Commission should require Evergy to conduct a full retirement study of its coal fleet using optimized capacity expansion software. This analysis should evaluate the economics of continuing to operate its coal plants relative to retirement, identify the optimal retirement date for each of its coal-fired power plants, and design an optimal future resource mix to meet the Company's projected load.

3. Given the poor to marginal economics of Jeffrey Units 1-3, Iatan Unit 1, or La Cygne Units 1 and 2, the Commission should signal that, in future dockets, it will not be inclined to approve cost recovery by Evergy of any capital investments of more than $1 million at these plants without prior Commission approval.

3. EVERGY MISSOURI'S COAL-FIRED POWER PLANTS

Q Describe Evergy's coal-fired fleet.

A Together, Evergy Missouri Metro and Evergy Missouri West own almost 2,700 MW of coal-fired generation capacity across four power stations, as shown in Table 1 below.[1] With the exception of Iatan, all of the coal units are owned 100 percent by Evergy Missouri and Kansas combined (the 92 percent of Jeffrey Units 1-3 and 50 percent La Cygne that are not owned by Evergy Missouri are owned by Evergy Kansas). This is important because joint-ownership relationships can introduce complications with retirement decisions. But where a plant is entirely owned by a single company, the ultimate decision-making authority rests with that single company.

[1] Testimony of Darrin R. Ives, page 6.

Table 1: Evergy Missouri coal-plant summary

Plant	Nameplate capacity of entire plant (MW)	Metro ownership share	West ownership share	Evergy KS ownership share	Year online	Planned retirement year
Hawthorn 5	594	100.0%	-	-	2001	2055
Iatan 1*	726	70.0%	18.0%	-	1980	2039
Iatan 2*	999	54.7%	18.0%	-	2010	2070
Jeffrey 1	740	-	8.0%	92%	1978	2039
Jeffrey 2	740	-	8.0%	92%	1980	2039
Jeffrey 3	740	-	8.0%	92%	1983	2030
La Cygne 1	873	50.0%	-	50%	1973	2032
La Cygne 2	685	50.0%	-	50%	1977	2039

Source: SEC 10-K; Direct Testimony of Evergy Metro Witness John Spanos, Schedule JJS-1, page 38; Direct Testimony of Evergy West Witness John Spanos, Schedule JJS-1, page 37; Evergy Metro CONF Response to SC 1-11 (b).
**Remainder of Iatan 1 and 2 is owned by Empire District Electric Company, Missouri Joint Municipal Electric Utility Commission, and Kansas Electric Power Cooperative.*

Hawthorn is a coal- and gas-fired power plant. Units 1-4 are fueled by gas and Unit 5 is fueled by coal. Unit 5 is 594 MW[2] and owned entirely by Evergy Metro. Unit 5 came online in 1969[3] and was significantly re-built in 2001 following a natural gas explosion.[4] The unit is slated to retire in 2055.[5]

[2] Evergy Metro CONF Response to SC 1-11 (b).

[3] Direct Testimony of Evergy Metro Witness John Spanos, Schedule JJS-1, page 38.

[4] *Hawthorn Unit 5 Rebuild,* Burns McDonnell. Available at burnsmcd.com/projects/hawthorn-unit-5-rebuild.

[5] *IRP Stakeholder Meeting, October 19, 2020.* IRP Appendix 8B, page 16; *see* EO-2021-0035, *In the Matter of Evergy Metro, Inc. d/b/a Evergy Missouri Metro's 2021 Triennial Compliance Filing Pursuant to 20 CSR 4240-22*; *see also* File No. EO-2021-0036, *In the Matter of Evergy Missouri West, Inc. d/b/a Evergy Missouri West's 2021 Triennial Compliance Filing Pursuant to 20 CSR 4240-22*.

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 1725 MW.[6] Unit 1 came online in 1980, Unit 2 came online in 2010.[7] Metro owns 61 percent of the plant and West owns 18 percent. The remainder is owned by non-affiliated entities.[8] In the preferred plan of Evergy MO's 2021 IRP, Iatan 1 is slated to retire in 2039 and Iatan 2 is slated to retire in 2070.[9]

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 2220 MW.[10] West owns 8 percent (175 MW)[11] of the Jeffrey plant, and Evergy Kansas owns the other 92 percent.[12] Unit 1 came online in 1978, Unit 2 in 1980, and Unit 3 in 1983.[13] Jeffrey Units 1 and 2 are set to retire in 2039, and Unit 3 is set to retire in 2030.[14]

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[6] Evergy Metro CONF Response to SC 1-11 (b).

[7] Direct Testimony of Evergy Metro Witness John Spanos, Schedule JJS-1, page 38.

[8] Iatan Generating Station Presentation, available at https://efis.psc.mo.gov/mpsc/commoncomponents/viewdocument.asp?DocId=936234192.

[9] *IRP Stakeholder Meeting, October 19, 2020.* IRP Appendix 8B, page 16; *see* EO-2021-0035, *In the Matter of Evergy Metro, Inc. d/b/a Evergy Missouri Metro's 2021 Triennial Compliance Filing Pursuant to 20 CSR 4240-22*; *see also* File No. EO-2021-0036, *In the Matter of Evergy Missouri West, Inc. d/b/a Evergy Missouri West's 2021 Triennial Compliance Filing Pursuant to 20 CSR 4240-22*.

[10] Evergy Metro CONF Response to SC 1-11 (b).

[11] *SEC* form 10k, fiscal year ending December 31, 2020.

[12] Andrejasich, Kelly, "Kansas denies Westar request to recover power plant purchase costs," S&P Global Market Intelligence, available at https://www.spglobal.com/marketintelligence/en/news-insights/trending/oraltwkesrdmc3kmexls3g2.

[13] Direct Testimony of Evergy West Witness John Spanos, Schedule JJS-1, page 37.

[14] *Evergy 2021 Integrated Resource Plan Overview*, page 8.

La Cygne is a two-unit, coal-fired power plant near La Cygne, Kansas. Unit 1 is 873 MW, and Unit 2 is 685 MW,[15] for a combined nameplate capacity of 1558 MW. Unit 1 came online in 1973, and Unit 2 came online in 1977.[16] Metro owns 50 percent of both units,[17] and Evergy Kansas owns the other 50 percent.[18] In the preferred plan of Evergy MO's 2021 IRP, Unit 1 is set to retire in 2032, and Unit 2 is set to retire in 2039.[19]

Q What portion of Evergy's current and future power fleet is reliant on coal?

A Coal is the single largest contributor to Metro's and West's capacity and energy, equivalent to 35 percent of the Company's current generation capacity (that it directly owns or contracts under PPA) and nearly 50 percent of its total generation, as shown in Table 2.

Table 2: Current capacity and generation by resource type for Evergy Missouri

	Metro and West capacity		Metro and West generation	
Resource	**MW**	**Share of total**	**GWh**	**Share of total**
Coal	2,712	35%	11,045	47%
Natural Gas	1,878	24%	508	2%
Oil	452	6%	6.5	0%
Renewables	2,178	28%	7,184	30%
Nuclear	553	7%	4,975	21%

Source: Executive Summaries to Evergy Missouri Metro and Evergy Missouri West's 2021 IRPs, page 10-13.

Evergy plans to retire much of its coal generation by 2040, but the Companies are planning to continue relying on their coal resources for both energy and capacity

[15] Evergy Metro CONF Response to SC 1-11 (b).

[16] Direct Testimony of Evergy Metro Witness John Spanos, Schedule JJS-1, page 38.

[17] SEC form 10k, fiscal year ending December 31, 2020.

[18] Carmen, "La Cygne Power Plant, US," Power Technology. December 3, 2021. Available at https://www.power-technology.com/author/carmenverdict/.

[19] *Evergy 2021 Integrated Resource Plan Overview*, page 8.

over the next two decades. And the Company's 2021 IRP shows coal will still represent 30 percent of its total generation capacity by 2030.

Table 3: Planned capacity for Evergy Missouri in 2030

	Metro and West capacity 2030	
Resource	**MW**	**Share of total**
Coal	2,654	30%
Natural Gas	1,878	22%
Oil	452	5%
Renewables	3,178	36%
Nuclear	553	6%

Source: Executive Summaries to Evergy Missouri Metro and Evergy Missouri West's 2021 IRPs, page 10-13.

Q Describe the major air pollution controls installed at each plant.

A Table 4 below summarizes the environmental controls installed at each of Evergy's coal-fired power plants.

Table 4: Environmental controls installed at Evergy's coal plans (whole plant)

($Million)	SCR	SNCR	Wet Scrubber	Baghouse	ACI	Other	Total
Hawthorn 5	$83.2	-	-	$17.5	$3.4	$33.6	$137.8
Iatan 1	$131.3	-	$213.2	$88.9	$3.1	-	$436.5
Iatan 2	$91.0	-	$280.5	$93.6	$3.8	-	$468.9
Jeffrey 1	$278.3	-	$190.7	-	$3.9	$57.3	$530.2
Jeffrey 2	-	$41.2	$169.2	-	$4.0	$50.9	$265.2
Jeffrey 3	-	$33.9	$193.0	-	$3.7	$58.3	$288.9
La Cygne 1	$104.9	-	$91.0	$91.9	$0.8	$1.0	$289.6
La Cygne 2	$109.3	-	$82.7	$78.3	$0.8	$1.0	$272.0

Source: EIA Form 860, Schedule 6A "Emissions Control Equipment," 2020.

When Evergy rebuilt Hawthorn 5 in 2001, the Company installed a fabric-filter baghouse to control particulate matter, a dry flue-gas desulfurization scrubber (FGD) to control sulfur dioxide (SO_2), and a selective catalytic reduction system (SCR) to control nitrogen oxides (NO_x). In 2016, the owners installed an activated

carbon injection system (ACI) to control mercury emissions. The total cost of these controls in 2022$ is $137.75 million.

At Iatan 1 and 2, the owners installed an ACI for mercury, a SCR for NOx, a spray-type wet scrubber for SO2, and a fabric filter baghouse. The combined cost of these controls in 2022$ is $905 million.

At Jeffrey, the owners installed a spray-type wet scrubber, an electrostatic precipitator for particulate, and ACIs for mercury. To control NOx, Unit 1 had an SCR installed for $278.3 million, while units 2 and 3 received selective non-catalytic reducers (SNCRs)—technologies that are less effective, but still adequate for compliance in some instances and which are much less expensive. The combined environmental control cost at Jeffrey in 2022$ is nearly $1.1 billion.[20] As discussed below, upgrading Jeffrey units 2 and 3 from SNCRs to SCRs is expected to comprise the lion's share of future environmental capital costs during the next decade.

At La Cygne 1, the owners installed an SCR in 2007 to control NOx. In 2015, they installed an ACI for mercury, a spray-type wet scrubber for SO2, a fabric filter baghouse for particulate, and additional environmental controls. That same year, the owners installed an SCR, an ACI, a spray-type wet scrubber, a fabric filter baghouse, and other environmental controls at La Cygne 2. The combined cost of these controls at La Cygne in 2022$ is $561 million.

Although the Company has already installed environmental controls at many of its units, this does not isolate them from the risk that future regulations will require them to install additional controls. The gaps in Table 4 show, for example, that Jeffrey Unit 2 and 3 do not have SCR's and likely will have to install this technology, or another similar NO_x control, to continue operating. Table 4 also

[20] 2020 EIA Form 860, Schedule 6A "Emissions Control Equipment."

shows the range and magnitude of compliance costs that the Company could be looking at in the future to keep its coal plants online.

Q What is the test year for this rate case?

A Evergy is using a historical test year of July 1, 2020–June 30, 2021.[21]

Q What power plant operations and maintenance ("O&M") expenses and capital expenditures did Evergy include in the test year?

A Evergy's test-year O&M expenses associated with its solid-fuel fleet [redacted], and its test-year sustaining capital expenditures (capex) totaled $87.8 million, as shown below in Table 5.[22]

[21] Direct Testimony of Albert R. Bass, Jr.

[22] Evergy Metro Response to SC 1-5, CONF Attachment SC 1-5(a-b); Evergy Metro Response to SC 1-5, Attachment SC 1-5(c-d); Evergy West Response to SC 1-5, CONF Attachment SC 1-5(a-b); Evergy West Response to SC 1-5, Attachment SC 1-5 (c-d).

Table 5: CONFIDENTIAL Test-year (July 1, 2020–June 30, 2021) O&M expenses and capital expenditures (capex) by plant

Plant	Total capex ($Million)	O&M ($Million)
Evergy Metro		
Hawthorn 5	$6.3	
Iatan 1	$20.8	
Iatan 2	$13.4	
La Cygne 1	$16.5	
La Cygne 2	$11.8	
Evergy West		
Iatan 1	$8.1	
Iatan 2	$4.4	
Jeffrey 1	$4.1	
Jeffrey 2	$1.1	
Jeffrey 3	$1.4	
Evergy Missouri Total	**$87.8**	

Source: Evergy Metro Response to SC 1-5, CONF Attachment SC 1-5(a-b); Evergy Metro Response to SC 1-5, Attachment SC 1-5(c-d); Evergy West Response to SC 1-5, CONF Attachment SC 1-5(a-b); Evergy West Response to SC 1-5, Attachment SC 1-5 (c-d).
Note: Common costs are allocated to each unit based on MW share of capacity. O&M for Jeffrey was not broken out by unit.

Q What is the remaining undepreciated balance for each plant?

A Evergy Metro has over $1.5 billion in undepreciated plant balances remaining in its aging coal fleet, while Evergy West has over $800 million in undepreciated plant balances as shown in Table 6 below.

Table 6: Remaining plant balance at Evergy Metro and Evergy West's coal plants (future book accruals)

Plant	Evergy Metro	Evergy West
Hawthorn 5	$150.8	
Iatan 1	$312.9	$192.5
Iatan 2	$564.1	$445.8
Jeffrey 1		$67.5
Jeffrey 2		$48.1
Jeffrey 3		$49.7
La Cygne 1	$258.1	
La Cygne 2	$229.9	
Evergy Missouri Total	**$1,515.8**	**$803.6**

Source: Direct Testimony of Evergy Metro Witness John Spanos, Schedule JJS-1, page 53-54; Direct Testimony of Evergy West Witness John Spanos, Schedule JJS-1, pages 53-54.
Note: Common costs are allocated to each unit based on MW share of capacity.

Q Is it concerning that Evergy has such a large undepreciated balance on its coal fleet?

A Yes. In the eyes of a utility, a large undepreciated balance is a barrier to retirement. Evergy has an incentive to keep the plants online because, if it retires any of the units early, it risks not recovering the remaining undepreciated balance, or at least not recovering its full rate of return on the remaining balance. But to keep the plants online, the Company will continue incurring costs for O&M and capital projects (in addition to fuel). And if future environmental regulations require large capital expenditures or increased O&M, those expenses will further inflate the undepreciated plant balance. Then, if the plants do retire prior to their scheduled retirement date, the Company could be left with a significant stranded asset that it seeks to pass on to ratepayers.

Q Is Evergy guaranteed recovery of the full undepreciated plant balance at its coal plants if any of them retire early?

A No, I don't believe so. I am not a lawyer, but my understanding is that if the Company does not demonstrate that continued investment and operation of a plant

is prudent relative to alternatives, and the resource is shown to be not used and useful, then Evergy is not guaranteed full recovery of any undepreciated plant balance when it retires the plant. The decision on whether and to what extent to allow recovery of undepreciated balance is left to the Commission. There is also the option of securitization, which I understand has been legally enacted in Missouri and Kansas, to facilitate at least some cost recovery of otherwise stranded assets.

Q What is securitization?

A Securitization is the process by which a generation asset with an undepreciated balance can be retired and the remaining plant balance refinanced using long-term, rate-payer backed, low-interest bonds. The Company immediately is paid by the bond holder and can reinvest that capital in new projects. The ratepayers still have to pay off the plant balance (now a regulatory asset) through their monthly bills, but they pay the lower bond rate instead of the rate of return to the utility. This will result in lower costs to ratepayers than if (1) the plant had stayed online and continued to operate uneconomically or (2) the plant had been retired and recovered as a regulatory asset at the utility's rate of return.

In this way, securitization is a good tool for facilitating retirement of aging and uneconomic coal plants. But it is not a substitute for careful oversight and consideration of whether additional capital and O&M costs should be poured into aging resources. It can bail out utilities who have made bad investment decisions and penalizes them only by removing their profit, not by forcing them take a loss on the investments they already made. And it provides only limited protection for ratepayers—they still have to pay for the balance, just at a lower interest rate. The best thing the Commission can do to limit costs added to the balance of an aging and uneconomic coal plant when it's clear that a plant is or will become uneconomic.

Q Is there precedent for disallowing or limiting the recovery of costs for a plant that is retired early?

A Yes. For one example, in Southwestern Electric Power Company's ("SWEPCO") most recent rate cases, Texas PUC Docket No. 51415, and Arkansas PSC Docket No. 21-070-U, the final orders in both cases allowed SWEPCO to place the undepreciated plant balance for the Dolet Hills Power Plant into a regulatory asset after the plant retires but rejected the Company's request to earn a rate of return on its investment once the plant retired.[23] Evergy knows that the utility has the burden of proof to demonstrate that continued investment in its resources is reasonable and in the best interest of ratepayers.

4. EVERGY FAILED TO IDENTIFY OPTIMIZED RETIREMENT DATES FOR ITS COAL FLEET AS PART OF EITHER THESE DOCKETS OR ITS MOST RECENT IRP

Q Has Evergy presented any evidence as part of its direct case in this proceeding to demonstrate the value of retaining its coal units?

A No. The Company referenced its most recent (2021) triennial IRP in response to nearly all of Sierra Club's requests for data on projected unit performance. But for its 2021 IRP, Evergy did not sufficiently analyze whether continued operation of and investment in its coal plants is the least-cost option for ratepayers or identify optimal retirement dates for its coal plants.

[23] Pub. Util. Comm'n of Tex., Docket No. 51415, *Application of Southwestern Electric Power Company for Authority to Change Rates*, Final Order (Jan. 14, 2022) at ¶¶ 44-65; Arkansas PSC Docket No, 21-070-U, *Application of Southwestern Electric Power Company for Approval of a General Change in Rate and Tariffs,* Order No. 14 (May 23, 2022) at page 50.

Q Please explain your concerns with the Company's 2021 IRP analysis.

A I have several specific concerns with Evergy's 2021 IRP.

First, Evergy performed no optimized economic analyses on the projected performance of its coal fleet for its 2021 IRP. The Company set its retirement dates based on a separate and highly limited Depreciation Study and then hard coded them into the model, along with hard-coded dates for new resource additions. Because of this, it is unlikely that Evergy's modeling results delivered a least-cost plan.

Second, the Company ignored the results of its own analysis that indicated that early retirement (prior to the current depreciation date) of at least some of its coal units, specifically La Cygne Unit 2 and Jeffrey Unit 2 and 3, would deliver a lower-cost portfolio than the Company's current preferred portfolio.

Third, Evergy did not appear to robustly and fairly consider solar photovoltaics (PV), battery storage, and solar-battery hybrids as resource alternatives.

Q Starting with your concerns about the company's IRP modeling, how does Evergy determine retirement dates if not using resource economics?

A Evergy identified the depreciable life span for each unit in its Depreciation Study. This study constitutes a narrow analysis that evaluates plants in isolation from the larger system in which they operate. The inputs are based largely on units' generic manufacturer useful lives and on staff's internal intuitions. Specifically, Evergy stated:

> The basis for the probable retirement years are life spans for each facility that are based on judgment and incorporate consideration of the age, use, size, nature of construction, management outlook and typical life spans experienced and used by other electric utilities for similar facilities. Most of the life span results in probable retirement years that are many years in

> the future. As a result, the retirements of these facilities are not yet subject to specific management plants. Such plans would be premature. At the appropriate time, detailed studies of the structure will be performed, and the results incorporated into the estimation of the facility's life span.[24]

This methodology is the same one that the Company has used for decades to project unit retirement dates. While this type of study might have been reasonable when replacement options were more limited, and coal-fired power's comparative economics were strong, it is not reasonable to do so today.

Q Please explain the limitations of a Depreciation Study.

A The Depreciation Study has a narrow purpose, and that purpose is to determine how long a power plant could remain active as a matter of engineering capability or book life. While this information is useful and even necessary in evaluating the economics of continuing to operate a plant, it is not sufficient for resource planning. Unit-level, forward-going economic analysis of the plant and potential resource alternatives in the market is required for that.

The Company has access to many alternative resource options in the market today (as I discuss below). And, announced retirements of coal-fired power plants have become ubiquitous in recent years. This reinforces the underlying comparative resource economics that support retirement and replacement of existing coal resources with less expensive resource combinations.

Q Explain your concerns with how Evergy used the results of its Depreciation Study to restrict the dates for unit retirement and additions.

A Evergy restricted the retirement dates it tested for its aging coal units to (1) the pre-determined date it found in its depreciation study and (2) several earlier dates

[24] Direct Testimony of John Spanos, p. 9-10.

for some of its aging units. The Company then paired plant retirement dates with resources additions and restricted the ability for new resources to come online outside of those predetermined dates. Although Evergy did test multiple retirement scenarios and dates for some of its coal plants, this entire framework limited the scenarios tested by the model to those that the Company had selected. And despite testing some earlier retirement dates for its coal plants, the Company largely ignored the results of any scenario that relied on a retirement date prior to its selected depreciation date when selecting its preferred portfolio (as discussed below). This makes it unlikely that the Company's modeling delivered a lowest-cost portfolio.

Q What type of economic analysis should the Company perform to develop projected retirement dates?

A The Company should conduct optimized capacity expansion modeling, which allows the model to endogenously select the dates to bring new resources online or retire existing resources.

This analysis should evaluate how much it will cost going forward to operate and maintain an existing unit relative to the costs of alternatives that might replace it. The analysis should also consider how the risks of continuing to operate the plant compare with the risks inherent to other resource options. And it should identify an optimal retirement date for existing aging units.

But critically, this analysis should also allow the model to optimally select new resources based on economics and need. Resources should not be modeled strictly as one-for-one replacement for retiring units. Instead, they should be made available for the model to select based on the system's need for energy, capacity, or other grid services and the relative economics of other resource and existing resources already on the grid.

Q On the issue of the retirement dates for the Jeffrey units and La Cygne 2 in the preferred portfolio, please explain your concerns.

A The Company did not follow the results of its own analysis in selecting unit retirement dates for many of its coal units. Five of the Company's ten lowest-cost alternative resource plans include a 2029 retirement for La Cygne 2, yet Evergy selected a scenario with a 2039 retirement for the unit without explaining the decision.[25] The Company's modeling results also included the early retirement (that is, retirement prior to the current depreciation date) of some of the Jeffrey units in nine of its ten lowest-cost plans, yet the preferred plan retained the depreciation retirement date for each of the Jeffrey units. The Company did later move the retirement date for Jeffrey Unit 3 up to 2030 based on the expectation that future environmental retrofits will be required to keep the unit online.[26]

What makes Evergy's decision to ignore the economic results in favor of early retirement dates concerning is that the Company currently has hundreds of MW of excess generation capacity.[27] This means that the Company could retire La Cygne 2 and at least one of the Jeffrey units without the Company having to acquire additional capacity for at least another decade (2032).

Q Please explain your concerns with the Company's modeling of renewable alternatives.

A The Company has access to many resource alternatives today, including solar PV, wind, battery storage, demand-side management, gas, and firm energy and

[25] Evergy Metro 2021 IRP, Volume 6, pages 21–27; *see* EO-2021-0035, *In the Matter of Evergy Metro, Inc. d/b/a Evergy Missouri Metro's 2021 Triennial Compliance Filing Pursuant to 20 CSR 4240-22*; *see also* File No. EO-2021-0036, *In the Matter of Evergy Missouri West, Inc. d/b/a Evergy Missouri West's 2021 Triennial Compliance Filing Pursuant to 20 CSR 4240-22*.

[26] *Id.*

[27] *Id.*, Executive Summary, page 9.

capacity purchases. These resources can, independently or in combination with other resources, provide the energy, capacity, and other grid services that Evergy needs to replace aging coal resources.

But the Company modeled storage as well as paired solar and storage in a limited number of its alternative resource plans. Evergy also did not model solar PV as a power purchase agreement (PPA) and instead assumed that only utility-owned solar PV was an option. This is concerning for two main reasons. First, PPA costs are incurred differently than self-build costs. Specifically, PPA costs are incurred on a levelized-cost basis while self-build costs are incurred as capital projects with a rate of return. This means that self-build options may have higher costs in the near term than PPAs, which would disadvantage the selection of solar PV on an NPV basis. Second, private developers may be able to utilize accelerated depreciation of the investment tax credit (ITC) to lower the project cost below what the utility could offer. This option is eliminated if PPAs are not considered as replacement resources.

Q Is the decision by Evergy to keep operating its coal plants without robustly assessing alternatives consistent with how other utilities across the country are treating resource planning around their coal assets?

A No. Since 2012, over 100 GW (100,000 MW) of coal capacity in the United States has retired. In 2022 alone, coal-fired power is expected to account for 85 percent of electric generation capacity retirements, and another 57 GW (57,000 MW) has announced retirement dates before 2030.[28]

[28] U.S. EIA. *Coal will account for 85% of U.S. electric generating capacity retirements in 2022*. January 11, 2022. Available at https://www.eia.gov/todayinenergy/detail.php?id=50838#.

Q Are you proposing that Evergy retire all its coal plants and replace the capacity and energy with alternative resources immediately, or even necessarily in the next few years?

A No, not necessarily. I recognize that Evergy cannot instantly replace the energy and capacity from 2,700 MW of coal-fired generation overnight; nor would it want to. It takes time to plan for a plant shut-down, to procure replacement resources, to construct replacements, and to get them grid-operational. But Evergy currently has a surplus of generation capacity, meaning that if it retired one or even two of its existing coal units it would not need to replace the capacity for at least another decade. And several of its coal units are already shown to be uneconomic based on the Company's own IRP analysis. Therefore, based on the Company's own IRP analysis, it makes no economic sense for the Company to continue to operate all its coal plants.

Given that the Company has already identified several of its coal units as the costliest, Evergy should complete the exercise and identify an optimal order and date to retire and (as necessary) replace each unit based on the availability of market alternatives.

5. EVERGY'S POOREST PERFORMING COAL PLANTS INCURRED [redacted] DOLLARS IN COSTS IN EXCESS OF THEIR VALUE FROM 2017–2020

Q Please summarize your analysis and findings on the historical performance of Evergy Missouri's coal fleet.

A I reviewed the economics of all of Evergy Missouri's coal plants. 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.

For all my calculations, I relied on historical unit costs provided by the Company, the cost of resource purchases provided by the Company, historical and projected market prices provided by the Company, and the cost of alternative resource options from the National Renewable Energy Laboratory ("NREL"), a widely recognized source of industry data. I evaluated plant performance both with and without the anomalous energy market revenues that the Company earned during winter storm Uri.

Q Describe how the Company has been operating its coal-fired power plants over the past five years.

A Over the last five years (2017–2021), Evergy operated the Hawthorn, Iatan, Jeffrey, and La Cygne plants at a collective average capacity factor of [redacted], as shown in Figure 1 below.[29] Looking forward, Evergy projects the combined average capacity factor for its coal plants will [redacted] over the next five years (2022–2026) [redacted] over the subsequent five years (2027–2031).[30] The Company's projection of [redacted] is surprising and likely incorrect, given the age of many of the Company's units and the decreased efficiency and increased operational costs expected from plants as they age. The [redacted] in the latter half of the 2020's is aligned with what we would expect, but also concerning given the capital and O&M required to maintain even [redacted] is most pronounced at La Cygne and Jeffrey, where projected capacity factors [redacted], but Hawthorn's capacity factor [redacted]

[29] Evergy Metro Response to SC 1-11, Attachment SC 1-11(f); Evergy West Response to SC 1-11, Attachment SC 1-11(f).

[30] Evergy Metro Response to SC 1-12, CONF Attachment 1-12S.

[redacted] Surprisingly, Evergy projects, without justification, that Iatan's utilization will actually [redacted] at both Units 1 and 2.

Figure 1: CONFIDENTIAL historical and projected capacity factors for Evergy's coal plants

Source: Evergy Metro Response to SC 1-11, Attachment SC 1-11(f); Evergy West Response to SC 1-11, Attachment SC 1-11(f); Evergy Metro Response to SC 1-12, CONF Attachment 1-12S.

Q Are there any market or regulatory factors to consider when evaluating the historical performance of Evergy's plants between 2017 and 2021?

A In February of 2021, winter storm Uri swept through the region. It knocked out power for days for many households and businesses and sent locational marginal prices ("LMPs") in the region to highly anomalous, record levels. Any plants that were able to remain online during this time earned enormous revenues. Hawthorn, Iatan, Jeffrey, and La Cygne earned combined energy market revenues in

February 2021 that were [redacted] than average for a February (based on the average of Evergy's revenues over the prior five Februarys).[31]

Q Is it reasonable for Evergy to plan around the assumption that another extraordinary market price spike, like the one associated with winter storm Uri, will deliver high revenue and offset standard unit spending?

A No. It would be imprudent for Evergy to plan its system around the assumption that another anomalous catastrophe will deliver record market revenues and offset the substantial costs and losses the Company is incurring based on standard operation. This is not to say that another extreme weather event isn't likely, because it is. But the associated energy market price spike we saw with Uri is not likely to be repeated for several reasons.

First, the alignment of environmental, infrastructural, and market conditions that caused the price spikes during winter storm Uri were unusual. And while there is still a lot of operational preparation to do in the region, efforts to winterize generation resources, adjust capacity accreditation, firm-up fuel supplies, and adjust market pricing rules have all been occurring or are in the works in the aftermath of that catastrophe.[32]

[31] Evergy Metro Response to SC 1-22S, CONF Attachment 1-22S; Evergy West Response to SC 1-22S, CONF Attachment 1-22S.

[32] *See* Direct Testimony of Bruce Akin, public Schedule BA-1, Final Report "Review of the Electric Transmission and Distribution 2020 – 2024 Grid Modernization Plan," pp. 31-32. *See also* Preparing for the Big Chill, OCC website (collecting presentations), available at https://oklahoma.gov/occ/divisions/public-utility/consumer-services/preparing-for-the-big-chill-2021.html; *see also, e.g.*, Runyon, Jennifer, "On Year after Uri: Texas energy experts weigh in on grid reforms," Power Grid International (Feb. 2, 2022), available at power-grid.com/td/one-year-after-uri-texas-energy-experts-weigh-in-on-grid-reforms/#gref.

Second, there is no guarantee that Evergy's plants will all be online if another event were to occur, and there is no reason to believe that alternative resources, such as solar PV, battery storage, and wind could not also be available during that time. As Evergy's 2022 grid modernization plan notes, the total number of major event days in Kansas and Missouri has increased about 25 percent in recent years, not only due to winter storm Uri, but also due to wildfires and the rapid succession of once-in-a-hundred-year storms. These types of events impose varied and severe strains on both transmission and distribution systems.[33] They are also indiscriminate in the infrastructures they damage, so there is no reason to believe that plants that benefited from winter storm Uri will necessarily be unimpacted by future extreme events with different impacts.

Third, it must be noted that while most of Evergy's coal plants did earn extraordinary energy market revenues during winter storm Uri, the overall financial benefit to Metro was modest, only $32 million, and West actually incurred $315.9 million in total energy costs, an increase of $297.3 million from its average February total (after adjustments for transmission costs, disallowances, and off-system sales revenue).[34] In other words, despite the Company earning high energy revenues at some of its own plants, it also incurred large costs to purchase additional energy from the market. This enormous burden prompted a petition to defer the cost and later to authorize financing the extraordinary cost to spare ratepayers "extreme customer rate impacts."[35] Planning on events such as

[33] Direct Testimony of Bruce Akin, Public Schedule BA-1, Final Report "Review of the Electric Transmission and Distribution 2020 – 2024 Grid Modernization Plan," page 31.

[34] *See* No. EU-2021-0283, Application of Evergy Metro and Evergy Missouri West for an Accounting Authority Order Allowing the companies to Record and Preserve Costs Related to the February 2021Cold Weather Event, page 9 and 10, available at https://efis.psc.mo.gov/mpsc/commoncomponents/view_itemno_details.asp?caseno=EU-2021-0283&attach_id=2021023780.

[35] *Id.*

this, that were costly, damaging, and disruptive to the system overall, as a way to justify continued coal plant operations would be nonsensical.

Q Taking into account these factors, describe the economic performance of Evergy's power plants over the past five years.

A Based on the Company's data, I find that all four coal plants incurred costs (variable and fixed) well in excess of their energy revenue and the value of their capacity in every year between 2017 and 2020, as shown in Table 7 below. In 2021, each coal plant earned positive revenues in excess of its value.

Table 7: CONFIDENTIAL Historical net costs/value of Evergy's coal fleet relative to the market value of each units' energy and capacity, 2017–2021 ($2022 million)

	2017	2018	2019	2020	2021
Hawthorn	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Iatan 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Iatan 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Jeffrey 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Jeffrey 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Jeffrey 3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
La Cygne 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
La Cygne 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Sources outlined in Q&A on next page.

In total, I find that Evergy's coal plants incurred over [redacted] in costs in excess of their value over the years 2017–2020, as shown in Table 8 below. When adding in 2021, the Company appears to have earned revenue significantly in excess of value because of the energy market price spikes that occurred during winter storm Uri. But, as I discuss above, it would be highly imprudent for Evergy to plan around an assumption that another anomalous event will deliver sufficient value to offset years of operational losses.

Table 8: CONFIDENTIAL Total historical net revenue ($2022 million), Evergy Missouri's Share

	2017–2020 (exclude 2021)		2017–2021	
	Total	Annual Average	Total	Annual Average
Hawthorn	[redacted]	[redacted]	[redacted]	[redacted]
Iatan 1	[redacted]	[redacted]	[redacted]	[redacted]
Iatan 2	[redacted]	[redacted]	[redacted]	[redacted]
Jeffrey 1	[redacted]	[redacted]	[redacted]	[redacted]
Jeffrey 2	[redacted]	[redacted]	[redacted]	[redacted]
Jeffrey 3	[redacted]	[redacted]	[redacted]	[redacted]
La Cygne 1	[redacted]	[redacted]	[redacted]	[redacted]
La Cygne 2	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]

Sources outlined below.

Q Explain how you calculated the values displayed in Table 7 and Table 8.

A I calculated the net revenues in Table 7 and Table 8, above, using the Company's own data on unit costs and revenues, supplemented by a small amount of public data.

For costs, Evergy provided historical fuel costs[36] and total O&M costs[37] by plant for each historical year between 2017 and 2021. The Company also provided historical sustaining capital expenditures and environmental capital expenditures for the period 2017–2021.[38] I added the capital expenditure costs to the fuel and

[36] Evergy Metro Response to SC 1-11 (l), CONF Attachments for 2017-2022; Evergy West Response to SC 1-11 (l), CONF Attachments for 2017-2022.

[37] Evergy Metro Response to SC 1-11(J-K), CONF Attachment 1-11(j-k) "Metro Fixed and Variable OM"; Evergy West Response to SC 1-11 (J-K), CONF Attachment 1-11(j-k) "West Fixed and Variable OM".

[38] Evergy Metro Response to SC 1-5 (c-d), CONF Attachment 1-5cd; Evergy West Response to SC 1-5 (c-d), CONF Attachment 1-5cd.

O&M costs to get total unit costs. I will explain the capital expenditures methodology in more detail later in this section.

For revenues, Evergy provided energy and ancillary market revenues[39] from selling the energy from each unit into the Southwest Power Pool (SPP) market. SPP does not have a capacity market, and therefore the Company earned no capacity market revenues over the years 2017–2021. I instead valued capacity based on the cost the Company could pay to purchase a new capacity resource during this time. Because Evergy actually did purchase firm capacity during this time period, I used the price Evergy paid the [redacted][40] for firm capacity multiplied by each unit's unforced capacity (UCAP). I summed this capacity value with the energy and ancillary revenues to get total unit revenues.

Finally, I calculated the difference in each year between unit costs and revenues to produce the net revenues at each plant, shown in Table 7.

Q Looking at each plant individually, how did Hawthorn 5 perform in recent years?

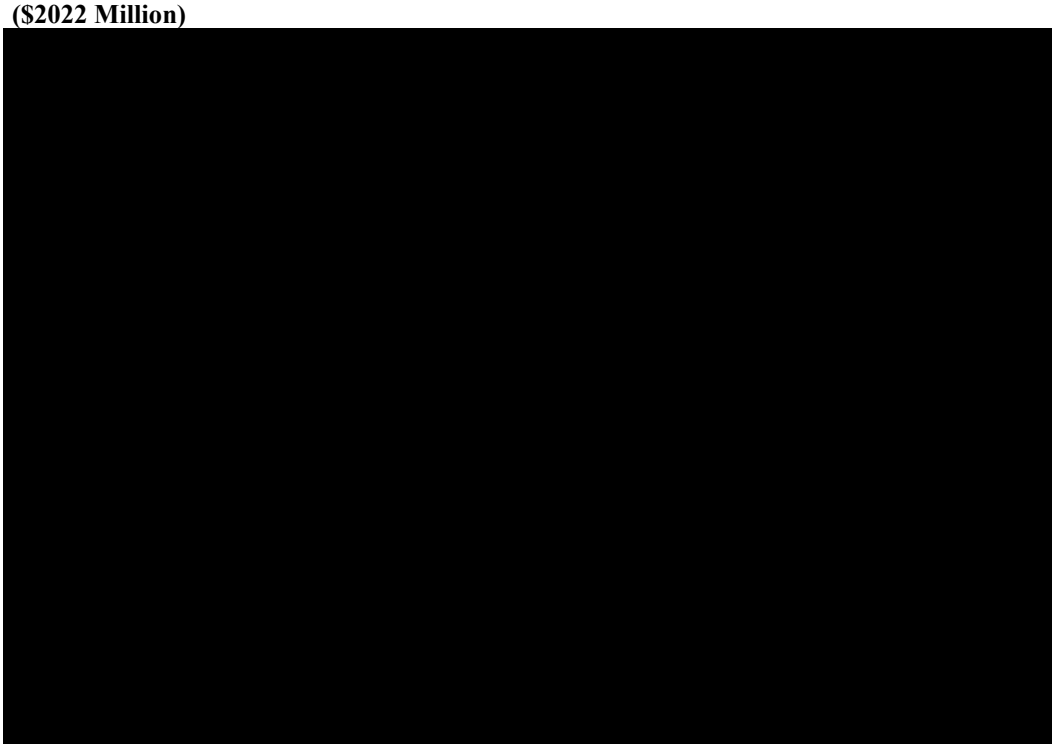
A Figure 2 below shows the historical cost breakdown at Hawthorn 5 (100 percent owned by West). Excluding 2021—the year of the anomalous Uri storm, from which lessons have been learned, and in response to which reforms have begun to be implemented (as discussed above)—Evergy West incurred costs in excess of market value at Hawthorn 5 on a forward-looking basis over the years 2017–2020

[39] Evergy Metro Response to SC 1-22S, CONF Attachment 1-22S; Evergy West Response to SC 1-22S, CONF Attachment 1-22S.

[40] Evergy Metro Response to SC 1-21, CONF Attachments; Evergy West Response to SC 1-21, CONF Attachments.

to a total of [redacted] This works out to an average of [redacted] in excess costs each year.

Figure 2: CONFIDENTIAL Annual costs and revenue for Hawthorn 5, 2017–2021 ($2022 Million)



See the Hawthorn Unit Analysis tab in the Evergy MO Economic Analysis_06072022 Workbook for sources and calculations.

This demonstrates how poorly the unit has performed relative to the market value of the unit's energy and capacity in recent years. And it shows that without the record market prices that resulted from winter storm Uri, and the highly anomalous revenue that the Company earned as a result, Hawthorn would have incurred substantial excess costs relative to the market over the past five years.

Q How did Iatan Units 1 and 2 perform in recent years?

A Figure 3 below shows the historical cost breakdown of Evergy Metro's share of Iatan 1, the older and poorer performing of the two units. Excluding 2021, Evergy as a whole, including both Metro and West's shares of Iatan 1, incurred costs in

excess of market value on a forward-looking basis totaling [redacted] [redacted] This works out to an average [redacted] each year.

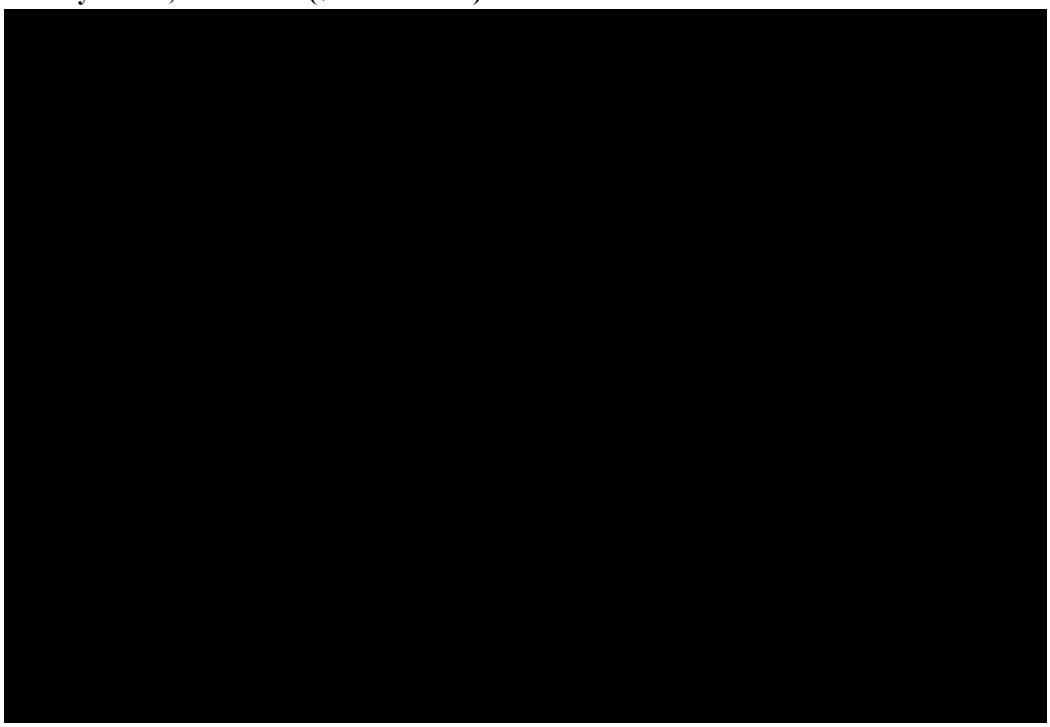
Figure 3: CONFIDENTIAL Annual costs and revenue for Evergy Metro's share of Iatan Unit 1, 2017–2021 ($2022 Million)

See the Iatan Unit Analysis tab in the Evergy MO Economic Analysis_06072022 Workbook for sources and calculations.

Q How did Jeffrey perform in recent years?

A Figure 4 below shows the historical cost breakdown at Jeffrey Unit 3. Excluding 2021, Evergy West incurred costs in excess of market value on a forward-looking basis totaling [redacted] at its share of the Jeffrey Energy Center. This works out to an average of [redacted] each year.

Figure 4: CONFIDENTIAL Annual costs and revenue for Evergy West's share of Jeffrey Unit 3, 2017–2021 ($2022 Million)



See the Jeffrey Unit Analysis tab in the Evergy MO Economic Analysis_06072022 Workbook for sources and calculations.

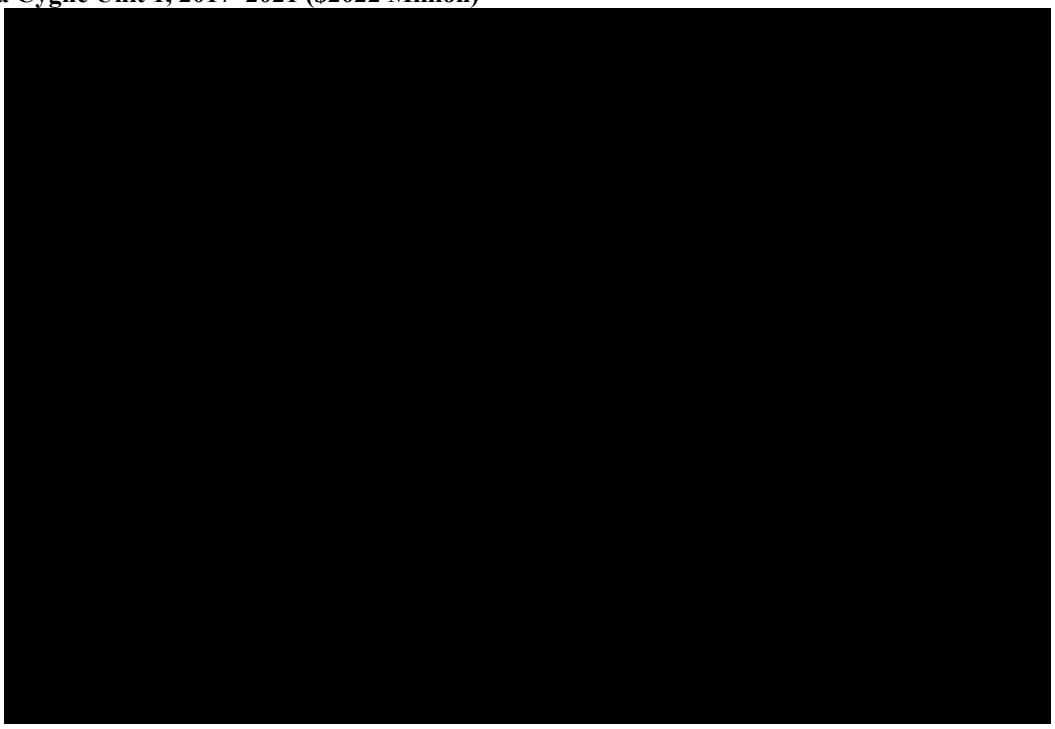
Q How did La Cygne Units 1 and 2 perform in recent years?

As shown in Table 7 and Table 8, at Evergy's share of La Cygne Units 1 and 2, the Company incurred costs in excess of value on a forward-looking[41] basis in four of the past five years (2017–2020), totaling [redacted] This works out to an average of [redacted] relative to the market every year.

[41] Forward-looking cost analysis looks at all costs incurred due to the continued operation of the plant, and therefore could be avoided by the retirement of the plant. All capital and fixed costs that had already been incurred, such as prior capital investments and fixed operating costs, are excluded from this analysis. This is because the decision to retire or operate the plant has no impact on whether or not they are incurred.

Figure 5 below shows the breakdown in costs and revenue for just Unit 1, which performed slightly worse than Unit 2. Evergy earned the majority of its energy market revenue in February 2021 during winter storm Uri.

Figure 5: CONFIDENTIAL Annual costs and revenue for Evergy's Metro's share La Cygne Unit 1, 2017–2021 ($2022 Million)



See the La Cygne Unit Analysis tab in the Evergy MO Economic Analysis_06072022 Workbook for sources and calculations.

Q Explain why you added the full cost of each expenditure in the year it was incurred instead of annualizing the costs over the remaining life of the plant.

A I expensed the full cost of each capital expenditure in the year to show the balance of costs incurred and revenues earned in each year. In years where large projects are undertaken, capital expenditures will likely exceed the resources' total revenues and value; but the reverse is also true. And over a multi-year timeframe, if the plant is operating economically, the total costs incurred and total energy revenues earned and capacity value should, at the very least, net out. If they do not—meaning that the plant's total fixed and variable costs consistently sum to

more than its total energy market revenues and capacity value—then continuing to invest in the plant is not in ratepayers' interest on a forward-going basis. This approach is more robust against early retirements and provides a clear picture of the actual costs being incurred at each plant, but, it does not reflect how expenses are passed on to ratepayers.

Q How does this approach differ from how utilities usually treat capital expenditures and pass the expenses on to ratepayers?

A Utilities typically amortize capital expenditures (based on the utility's cost of capital) and spreads the costs out over the remaining economic life of the plant. Table 9 below shows the capital costs that Evergy incurred at its share of its coal units during the past five years (2017–2021) and the annualized amounts passed on to ratepayers under two different depreciation timelines. Critically, this analysis begins with an assumption about how long the plant will continue to operate and shows the ratepayer impact of continuing to operate the plant, and recover all investments, over that assumed timeline. It is sensitive to retirement date assumptions but most closely represents how costs are passed on to ratepayers.

Table 9: Sustaining capital expenses incurred at Evergy's coal units and annualization amounts under different depreciation scenarios (Evergy Missouri's share) ($2022 Million)

Plant	Sustaining capital costs incurred (2017–2021)	Annualized expenses between 2017 and 2021 for capital costs incurred between 2017 and 2021	
		capex depreciated through planned retirement dates	capex depreciated through 2031
Hawthorn 5	$74.1	$18.4	$27.8
Iatan 1	$156.6	$49.2	$62.2
Iatan 2	$83.7	$20.9	$33.0
Jeffrey 1	$12.0	$3.2	$4.0
Jeffrey 2	$8.7	$2.3	$2.9
Jeffrey 3	$10.1	$2.8	$3.5
La Cygne 1	$87.6	$29.1	$30.4
La Cygne 2	$77.1	$23.4	$29.5

Calculations based on Evergy Metro Response to SC 1-15, Attachment SC 1-15; Evergy West Response to SC 1-15, Attachment SC 1-15.

If I had conducted my historical analysis annualizing the capital expenditures over the remining life of the plants, instead of expensing the costs in the year they are incurred, the historical losses would have looked lower because a large portion of the costs would be shifted to future years. I have replicated Table 8 below in Table 10 using the assumption that all capital expenses incurred between 2017 and 2022 would be annualized over the life of each unit. Using this approach, I find that the total costs passed on to ratepayers during this historical time period (2017–2020) exceed each unit's revenue by around [redacted]. Looking at just the Company's poorest performing plants, Jeffrey and La Cygne together incurred [redacted] costs in excess of their market value over the years 2017–2020.

Table 10: CONFIDENTIAL Total historical net revenues ($2022 million) assuming annualization of capital expenses, Evergy Missouri's Share

	2017–2020 (exclude 2021)		2017–2021	
	Total	Annual Average	Total	Annual Average
Hawthorn				
Iatan 1				
Iatan 2				
Jeffrey 1				
Jeffrey 2				
Jeffrey 3				
La Cygne 1				
La Cygne 2				
Total				

Source: See Table 8.

Q Do you have any concerns with the annualization approach?

A Yes. This approach might be reasonable with a project where there is a reasonable degree of certainty that the plant will operate through its planned retirement date. But it is dangerous with aging resources that we know are likely to retire early—in line with a strong, widespread, accelerating trend across the country.[42] A

[42] *See supra* footnote 28; *see also, e.g.*, Darren Sweeney, *et al.*, *More than 23 GW of coal capacity to retire in 2028 as plant closures accelerate*, S&P Global, available at https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/more-than-23-gw-of-coal-capacity-to-retire-in-2028-as-plant-closures-accelerate-68709205 ("Under price pressure from renewable power and a national move away from high-emission fuels, utilities plan to shutter 51 GW of coal power from 2022 through 2027, according to S&P Global Market Intelligence analysis. But in 2028 alone, retirements will jump by 23 GW, and that doesn't include the retirements of the 1,700-MW Conemaugh and 1,700-MW Keystone coal-fired power plants in Pennsylvania that were reported by media."); Rebecca J. Davis, *et al.*, *Coal-Fired Power Plant Retirements in the U.S.*, Working Paper 28949, June 2021, National Bureau of Economic Research, at 4, available at https://www.nber.org/papers/w28949 ("Figure 1 displays the location of the coal-fired generators that have retired between 2010-2019. They represent 473 generators with a nameplate capacity of nearly 80 thousand MWs.").

project might look economic when spread out over 20 years, with 20 years of energy market revenues and capacity value to balance it out. But if it has to be recovered over only five or ten years instead (with only five to ten years of revenue and value as well), it suddenly becomes clear how expensive and uneconomic it was to invest in the plant.

This is exactly what we are seeing now at other plants in the region. Examples include the Dolet Hills coal plant in Louisiana and the Pirkey power plant in Texas, both of which participate in SPP and happen to be at least partially owned by American Electric Power Company ("AEP") subsidiary, SWEPCO. Major capital investments at the two plants were justified based on the assumption that the costs were going to be recovered over the remaining decades of the plants' lives (despite clear indications that both plants were already uneconomic). Now that the plants are both retiring, SWEPCO ratepayers are exposed to hundreds of millions in incurred capital expenditures with no incoming revenue or value in exchange.[43] As I discuss in the next section, this is what I expect will happen at Evergy's coal plants if the Company continues to invest in these plants.

6. MANY OF EVERGY'S COAL PLANTS ARE LIKELY TO INCUR COSTS IN EXCESS OF THEIR MARKET VALUE OVER THE NEXT DECADE

Q How does the Company project it will operate its coal plants over the next decade?

A Based on the Company's own data from its most recent IRP, I found that Evergy's older coal units, Iatan 1, Jeffrey Units 1-3, and La Cygne Units 1 and 2, are projected to be either marginal or incur costs in excess of their projected value

[43] Pub. Util. Comm'n of Tex., Docket No. 51415, *Application of Southwestern Electric Power Company for Authority to Change Rates.*

over the next decade. Evergy's two newest units, Hawthorn 5, rebuilt in 2001, and Iatan 2, built in 2010,[44] are projected to perform economically, and based on the Company's own data, may earn net revenues over the next decade.

Overall, Evergy's modeling shows the capacity factors at some of its plants declining over time. These results indicate that there are lower-cost options that the Company can use to serve load, and that Evergy's coal plants are relatively more expensive and less competitive than market energy and other Company resources. The plants' economics will be further threatened if Evergy has to install costly equipment to comply with future environmental regulations.

Q Did you evaluate the forward-going economics of Evergy's coal-fired power plants, inclusive of both fixed and variable costs and the full value of each plant's energy and capacity?

A Yes, I evaluated the forward-looking value of each power plant in several ways. The goal of these pieces of analysis is to demonstrate the high level of uncertainty and also the high level of risk Evergy faces in continuing to operate its power plants without conducting robust economic retirement analyses.

First, I evaluated the total value of each plant using an average capacity value based on the price the Company pays for firm capacity.

Then, I evaluated the economics of each plant assuming that all capital costs will be depreciated over the remaining life of the plant instead of expensed in the year they are incurred. I also imposed an arbitrary but illustrative retirement date of 2031, to show the impact on unit economics if the Company continues to plan around retirement dates in 2039 and beyond for most of its units but ends up retiring a plant early.

[44] Unit 5 was destroyed by a natural gas accident in 1999 and was rebuilt in 2001.

Q Starting with the first analysis you discuss, what did you find regarding each plant's projected economic performance over the next decade based on the Company's data?

A As shown in Table 11 below, I find that, based on the Company's data, La Cygne Units 1 and 2 are projected to incur costs in excess of their market value over the next decade, and Jeffrey and Iatan 1 is expected to perform only marginally over the next decade. Iatan 2 and Hawthorn 5 are expected to earn positive net revenues.

Table 11: CONFIDENTIAL Projected performance of Evergy's coal plants (2021–2022) (Evergy Missouri's share of net cost or revenues)

Plant & unit	Annual average projected net revenues (2022–2031) 2022$	Forecasted NPV (2022–2031)
Hawthorn 5	[redacted]	[redacted]
Iatan 1		
Iatan 2		
Jeffrey 1		
Jeffrey 2		
Jeffrey 3		
La Cygne 1		
La Cygne 2		
Total		

Sources explained below.

Given that Iatan 1, Jeffrey Units 1, 2, and 3, and La Cygne Units 1 and 2 are projected to perform relatively poorly over the next decade compared to Evergy's other units, I will focus the remainder of my analysis on these less economic units.

Q How did you calculate the values shown in Table 11?

A I calculated the net revenues shown in the Table 11, above, using the Company's own projections on unit costs and revenues.

For costs, Evergy provided projected fuel costs[45] and projected plant O&M costs (variable and fixed combined)[46] by plant for each year between 2022–2031. The Company also provided projected sustaining capital expenditures and environmental capital expenditures for the period 2022–2031.[47] I added the capital expenditure costs to the fuel and O&M costs to get total unit costs.

For revenues, Evergy provided projected energy market revenues[48] from selling the energy from each unit into the SPP market (Evergy does not forecast ancillary revenues).[49] SPP does not have a capacity market, and therefore the Company will earn no capacity market revenues over the years 2022–2031. I instead valued capacity based on the cost the Company will pay to purchase firm capacity during this time period. I reviewed Evergy's firm capacity contracts, selected the mid-value contract, specifically Evergy's contract with [redacted] to represent the baseline cost of capacity which I applied to each unit's UCAP.[50] I summed this capacity value with the energy revenues to get total unit revenues.

Finally, I calculated the difference in each year between unit costs and revenues to produce the net revenues at each plant, shown in Table 7.

[45] Evergy Metro Response to SC 1-12S, CONF Attachment 1-12S; Evergy West Response to SC 1-12S, CONF Attachment 1-12S.

[46] *Id.*

[47] Evergy Metro Response to SC 1-18S; CONF Attachment 1-18S_CONF_Capital Expenditures.

[48] Evergy Metro Response to SC 1-23S2, Attachment 1-23S2_Market Revenue; Evergy West Response to SC 1-23S2, Attachment 1-23S2_Market Revenue.

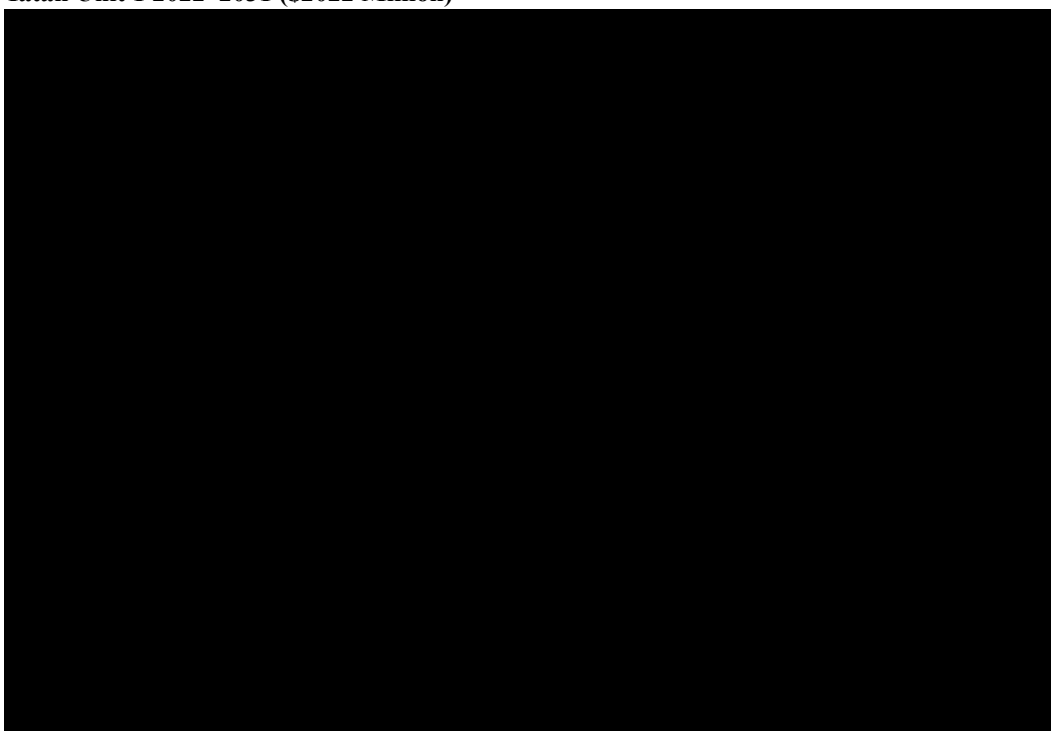
[49] *Id*.

[50] Evergy Metro Response to SC 1-21, CONF Attachments; Evergy West Response to SC 1-21, CONF Attachments.

Q Looking at each plant individually, how is Iatan Unit 1 projected to perform over the next decade?

A Figure 6 below shows the projected performance of Evergy Metro's share of Iatan 1, the older and poorer performing of the two units. Based on the Company's current projections, and using a mid-capacity price assumption, I find that Metro's and West's combined shares of the plant are projected to earn [redacted] in net revenues relative to the market on an NPV basis over the next decade. This works out to an average of [redacted] per year ($2022). Notably, the Company's own data shows that the unit is projected to incur net revenue losses over the next five years (2022–2026). During this time, the unit is projected to operate at a capacity factor between [redacted] It isn't until after 2027, when Evergy projects, without justification, that the unit's utilization and therefore associated energy market revenues will [redacted], that the unit starts to incur positive net revenues relative to the market.

Figure 6: CONFIDENTIAL Projected net revenues for Evergy Metro's share of Iatan Unit 1 2022–2031 ($2022 Million)



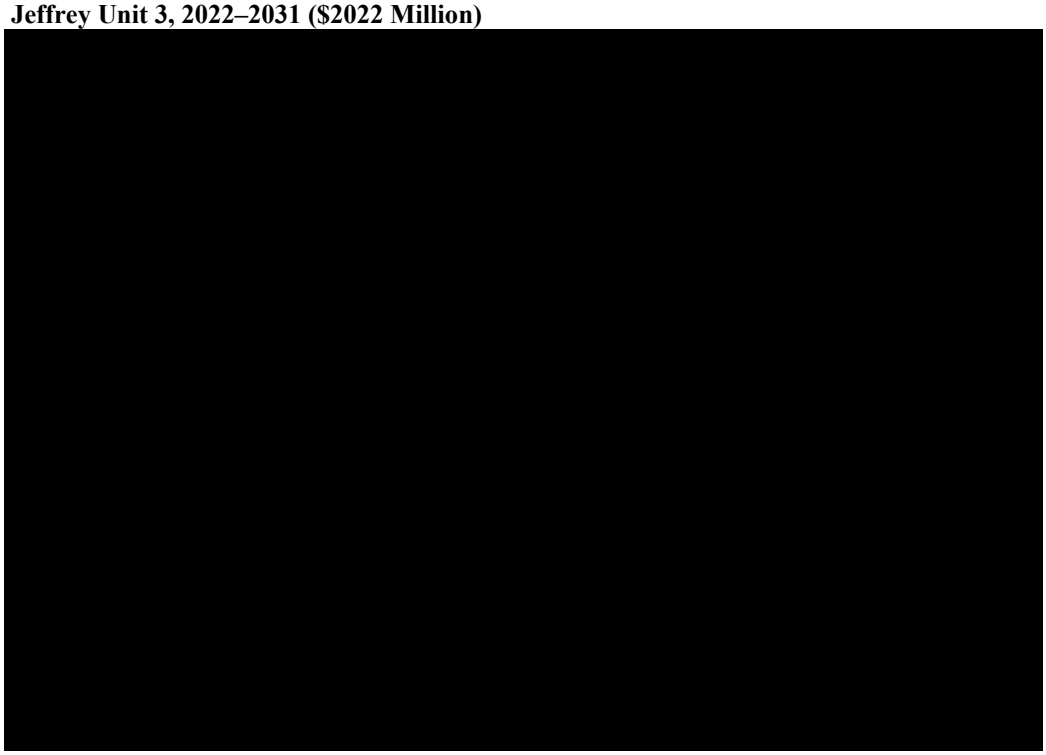
See the Iatan Unit Analysis tab in the Evergy MO Economic Analysis_06072022 Workbook for sources and calculations.

Q How is the Jeffrey plant projected to perform over the next decade?

A Based on the Company's data, I find that the Jeffrey Energy Center will earn net revenues of [redacted] relative to the market on an NPV basis at its share of the plant over the next decade. This works out to an average of [redacted] (2022$) in net revenues. Figure 7 below shows the projected net revenue for Jeffrey Unit 3 by year. This Unit is scheduled to retire in 2030 to avoid environmental compliance costs.[51] Jeffrey Units 2 and 3 both currently have SNCR's installed; only Unit 1 has an SCR.

[51] *Evergy 2021 Integrated Resource Plan Overview*, page 8.

Figure 7: CONFIDENTIAL Projected net revenues for Evergy's West's share of Jeffrey Unit 3, 2022–2031 ($2022 Million)



See the Jeffrey Unit Analysis tab in the Evergy MO Economic Analysis_06072022 Workbook for sources and calculations.

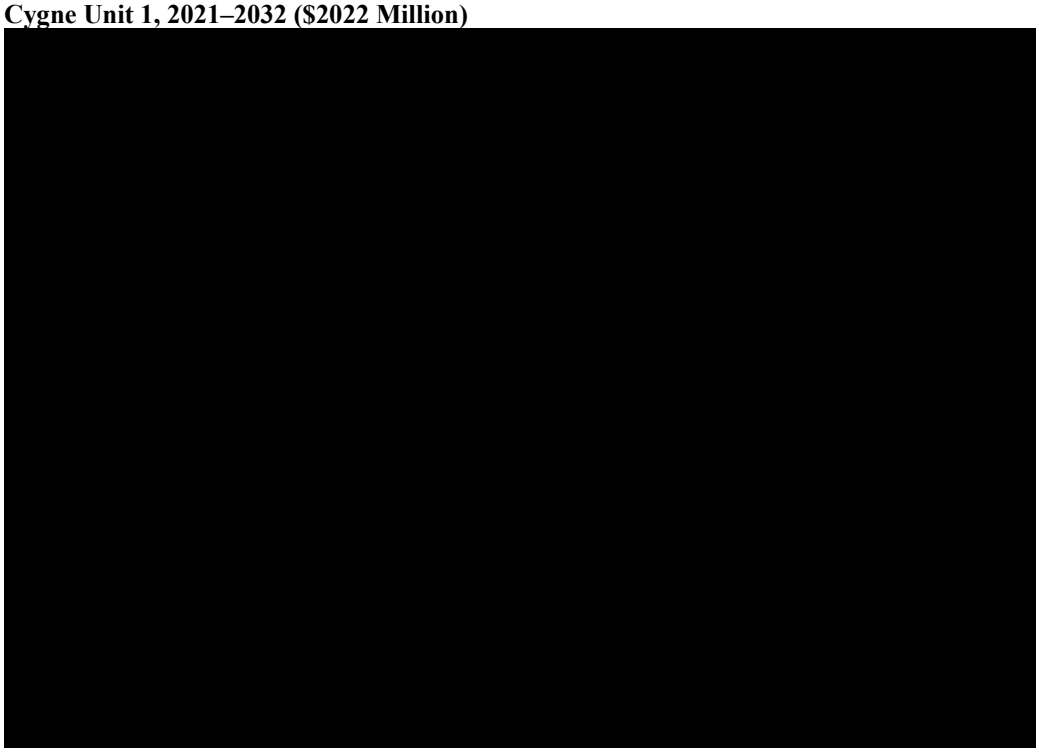
Q How are La Cygne Units 1 and 2 projected to perform over the next decade?

A As shown in Table 11, based on Evergy's own data, I find that the Company is expected to incur net revenue losses relative to the market at La Cygne Units 1 and 2 over the next decade. Specifically, I project Evergy will incur net revenue [redacted] on an NPV basis at its share of the plant over the next decade, for an average of [redacted] relative to the market. Evergy projects the capacity factors of the La Cygne [redacted] ** This results in decreased energy market revenue in later years.

[52] Evergy Metro Response to SC 1-12, CONF Attachment 1-12S.

Figure 8 below shows the breakdown in costs and revenue for just Unit 1, which is roughly representative of the expected performance of Unit 2 as well.

Figure 8: CONFIDENTIAL Projected net revenues for Evergy Metro's share of La Cygne Unit 1, 2021–2032 ($2022 Million)



See the La Cygne Unit Analysis tab in the Evergy MO Economic Analysis_06072022 Workbook for sources and calculations.

Q Given this finding, do you think it likely that Iatan 1, Jeffrey Units 1-3, and La Cygne Units 1 and 2 will continue to provide value to Evergy's ratepayers over the next few decades?

A No. My finding that, based on the Company's own data, La Cygne Units 1 and 2 will incur costs in excess of its value, and that Iatan 1 and Jeffrey may earn marginal net revenues over the next decade represents a best-case scenario—a scenario that assumes retirement dates well over a decade into the future. This very likely underestimates future capital costs required for base maintenance and environmental compliance projects.

It is implausible to assume that a fleet of aging coal plants will somehow become more economic in the long term—even as their equipment ages, renewables and battery storage penetration increase on the grid, and generation resources face increased environmental constraints. Given each plant's poor economic performance over the past five years, and the Company's current capacity surplus, it is unclear how Evergy can expect that the plants will transform into net revenue generators as their utilization drops.

Q Do you have any concerns with any of the input costs or revenues provided by Evergy?

A Yes, several. First, the Company relied on low-cost assumptions around base sustaining capital expenditures at Hawthorn 5, Iatan, and La Cygne. These assumptions are inconsistent with its historical spending, and with industry-leading estimates for sustaining capex.

Second, Evergy assumed that the capacity factor at most of its units (specifically at Hawthorn 5 and Iatan 1 and 2) would [redacted], and therefore energy revenues would stay high. The assumption that each plant's utilization would increase as it aged is both unsubstantiated and concerning, in that it inflates future energy revenue projections.

Finally, Evergy assumed that many of its plants will operate until 2039 and beyond. The only units it assumes will retire before 2035 are La Cygne 1 in 2032 and Jeffrey 3 in 2030. This means the Company assumes that any capital expenditures it incurs to keep the coal plants operating will be spread out over the remaining decades, with accompanying decades of revenue to cover the cost. It also means the Company is not considering how to ramp down spending in the event of an early retirement and it is not evaluating the cost and feasibility of alternatives.

Q Explain your concerns with Evergy's sustaining capex assumptions for its coal plants looking forward?

A Evergy's forward-looking sustaining and environmental capex assumptions for Hawthorn 5, Iatan Units 1 and 2, and La Cygne Units 1 and 2 are low, meaning Evergy is likely underestimating the cost to operate its coal plants on a forward-looking basis. We see an opposite and equally concerning assumption at Jeffrey, where the Company is projecting to make large capital investments in Jeffrey over the next decade to comply with numerous environmental regulations.

As shown below in Table 12, Evergy's projected capex spending at Hawthorn 5, Iatan Units 1 and 2, and La Cygne Units 1 and 2 over the next decade is between [redacted] than Evergy's historical average annual spending at each plant. This means that Evergy is projecting that it will cost around [redacted] less annually in capital expenditures to maintain these its share of Hawthorn 5, Iatan and La Cygne than it spent historically.

I also looked at industry-standard estimates for annual capex spending produced by the firm Sargent & Lundy for the EIA. I found Evergy's actual spending at Hawthorn 5, Iatan Unit 1, and La Cygne Units 1 and 2 over the past 5 years was substantially higher than what Sargent & Lundy projected. This means that, if historical spending at Hawthorn 5, Iatan 1, and La Cygne 1 is indicative of future costs trends, we can expect to see capex at these three units continue to exceed industry average estimates.

Table 12 below summarizes the cost comparisons discussed above.

Table 12: CONFIDENTIAL Historical capex spending vs. Evergy's projected future capex spending at Iatan 1&2, La Cygne 1&2, and Hawthorn 5 ($2021 Million) (Evergy Missouri's Share)

	Iatan 1 &2	La Cygne 1&2	Hawthorn 5	Total	Delta from projected
Historical average annual capex spending (millions)					
Average of 2017–2021 actual spending	$56.7	$29.9	$13.7	$100.3	[redacted]
Evergy's projected average forward-going annual capex spending					
Average of 2022–2031 projected spending	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
EIA / Sargent & Lundy estimates of annual sustaining capex for steam coal plant					
Sargent and Lundy report based on plant size, age, and FGD status	$33.1	$20.2	$16.6	$70.0	[redacted]

Calculations based on Evergy Metro Response to SC 1-15, Attachment SC 1-15; Evergy Metro Response to SC 1-18, Attachment 1-18(a)_ER-2022-0129_2017-2022 Capital Expenditures)Coal Plants by OU; Evergy Metro Response to SC 1-18S, CONF Attachment SC 18S; Evergy West Response to SC 1-15, Attachment SC 1-15; Evergy West Response to SC 1-18, CONF Attachment 1-18(a)_ER-2022-0129_2017-2022 Capital Expenditures)Coal Plants by OU; Sargent & Lundy Consulting, prepared for U.S. EIA, *Sargent & Lundy Consulting, prepared for U.S. EIA. Generating Unit Annual Capital and Life Extension Costs Analysis, December 2019. Available at https://www.eia.gov/analysis/studies/powerplants/generationcost/pdf/full_report.pdf.*

Q What impact do the Company's capex assumptions have on assumed cost to continue operating the plant over the planning horizon?

A Evergy has estimated the total forward-going capital costs to maintain its share of the Hawthorn, Iatan, and La Cygne plants to be [redacted] on an NPV basis over the years 2022–2031, as shown in Table 13 below. The Company's estimate is around [redacted] lower on an NPV basis over the years 2022–2031 than what I would project based on Evergy's recent historical spending at its coal plants.

Table 13: CONFIDENTIAL Total capex spending at Hawthorn 5, Iatan, and La Cygne over the time period (2022–2031) using original and updated assumptions (Million)

Capex data source	Total NPV	NPV Delta from Evergy projection
Evergy projected sustaining capex for its coal plants (2022–2031)	[redacted]	[redacted]
Estimate of sustaining capex for Evergy's coal plants based on EIA formulas	$487.2	[redacted]
Extrapolation of Evergy's historical capex spending at its coal plants	$773.3	[redacted]

Calculations based on Evergy Metro Response to SC 1-15, Attachment SC 1-15; Evergy Metro Response to SC 1-18, Attachment 1-18(a)_ER-2022-0129_2017-2022 Capital Expenditures)Coal Plants by OU; Evergy Metro Response to SC 1-18S, CONF Attachment SC 18S; Evergy West Response to SC 1-15, Attachment SC 1-15; Evergy West Response to SC 1-18, CONF Attachment 1-18(a)_ER-2022-0129_2017-2022 Capital Expenditures)Coal Plants by OU; Sargent & Lundy Consulting, prepared for U.S. EIA, *Sargent & Lundy Consulting, prepared for U.S. EIA. Generating Unit Annual Capital and Life Extension Costs Analysis, December 2019. Available at https://www.eia.gov/analysis/studies/powerplants/generationcost/pdf/full_report.pdf.*

Table 13 shows that Evergy is likely underestimating future capital costs needed to maintain the majority of its coal-fired power plants by hundreds of millions of dollars over the next decade. While it is reasonable that the Company will seek to minimize spending as each plant's utilization drops, there are baseline investments required to keep the plants functional and reliably available when needed. Underestimating those costs in planning doesn't result in reduced spending, but rather keeps uneconomic plants online at a high cost to ratepayers.

Q What are some of the future risks and factors that Evergy has not considered that could impact the cost to continue to operate its coal fleet?

A There are a number of reasonably foreseeable potential future regulations that would further weaken the comparative economics of coal-fired generation. One possibility is an effective constraint or cost on carbon emissions, with EPA

indicating that it is currently working on an electric sector carbon regulation.[53] Another is the risk of future water limitations that could impact the ability for Evergy to economically procure the water needed to operate its coal units.[54] Specifically, the North American Reliability Corporation's (NERC) cited water availability as a concern for plants that rely on water from the Missouri River Basin for cooling in the SPP in summer months. The Hawthorn, Iatan, Jeffrey, and La Cygne power plants are all located within the basin and require billions of gallons of water for cooling each year. Iatan 1, La Cygne 1 and 2, and Hawthorn 5 are particularly vulnerable to water constraints given that they use once-through cooling, but Iatan 2 and the Jeffrey Units 1-3 also require substantial water withdrawals (Table 14).[55]

[53] *See, e.g.*, U.S. EPA, "Climate Change Regulatory Actions and Initiatives," https://www.epa.gov/climate-change/climate-change-regulatory-actions-and-initiatives ("EPA is actively developing a strategy for achieving meaningful reductions in [carbon dioxide] emissions from existing power plants, building on the lessons of EPA's prior efforts and informed by engagement with a broad range of stakeholders.").

[54] NERC 2022 Summer Reliability Assessment, May 2020. Available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2022.pdf.

[55] EIA water cooling by generator and boiler 2020, available at https://www.eia.gov/electricity/data/water/.

Table 14: 2020 Water Withdrawals for Cooling (Total plant)

Unit	Water Withdrawals (Billion Gallons)	Cooling Type
Hawthorn 5	82	Once through
Iatan 1	106	once through
Iatan 2	3	recirculated
Jeffrey 1	13	recirculated
Jeffrey 2	13	recirculated
Jeffrey 3	13	recirculated
La Cygne 1	64	once through
La Cygne 2	75	once through
Total	**369**	

Source: EIA Thermoelectric cooling water data, 2020

Q Explain how Evergy's projected retirement dates impact plant economics.

A Evergy assumes that its coal plants will each operate through at least 2030, with the earliest retirement schedule in 2030 for Jeffrey Unit 3, and then 2032 for La Cygne 1. After that, the next retirements are not schedule until 2039, when La Cygne 2, Jeffrey Units 1 and 2, and Iatan 1 are schedule to retire. This means that the Company can assume that any investments it makes at La Cygne 2, Jeffrey Units 1 and 2, and Iatan 1 will have nearly a decade and a half worth of revenues to cover the costs (and multiple decades for Hawthorn 5 and Iatan 2 which are schedule to retire in 2055 and 2070 respectively). This has the impact of making large investments look relatively small, and thus more favorable, than if the Company instead assumed it had only, say, ten years to pay off an investment and ten years of market revenues to offset the costs.

Table 15 shows the implications for the NPV (ignoring all associated revenue implications) of spreading planned capital costs over ten years compared to spreading projected capital expenditures over the remaining life of each plant. Specifically, it shows how much lower capital expenditures look in the present when the Company assumes the majority of the cost will be paid a decade into the future.

Table 15: CONFIDENTIAL NPV of annualized capital expenditures at Evergy's share of its coal plants (whole plant)

	Annualized over ten years (2021–2031)	Annualized over years to planned retirement dates	Delta	Planned retirement year
Hawthorn 5	[redacted]	[redacted]	[redacted]	2055
Iatan 1	[redacted]	[redacted]	[redacted]	2039
Iatan 2	[redacted]	[redacted]	[redacted]	2070
Jeffrey 1	[redacted]	[redacted]	[redacted]	2039
Jeffrey 2	[redacted]	[redacted]	[redacted]	2039
Jeffrey 3	[redacted]	[redacted]	[redacted]	2030
La Cygne 1	[redacted]	[redacted]	[redacted]	2032
La Cygne 2	[redacted]	[redacted]	[redacted]	2039

Source: Evergy Metro Response to SC 1-18, Attachment 1-18(a)_ER-2022-0129_2017-2022 Capital Expenditures)Coal Plants by OU; Evergy Metro Response to SC 1-18S, CONF Attachment SC 18S; Evergy West Response to SC 1-18, CONF Attachment 1-18(a)_ER-2022-0129_2017-2022 Capital Expenditures)Coal Plants by OU. Evergy 2021 Integrated Resource Plan Overview.

Q Why is this important for understanding Evergy's projections and IRP analysis?

A As I discussed above, the Company did not use optimized capacity expansion modeling to select the planned retirement years for its coal units. Additionally, the Company's own IRP analysis did show that retirement of La Cygne 2 in 2029 and the retirement of some of the Jeffrey units between 2026 and 2034 could result in a lower cost portfolio than continuing to operate them through their planned retirement dates of 2039. And just because the Company selected a preferred portfolio with the original retirement dates doesn't mean that those retirement dates will ultimately materialize. What is more likely is that the Company will continue to make investment decisions based on far-off retirement dates, but then ultimately retire the plant earlier based on economics. And given the large difference I show in Table 15, above, between the NPV of capex annualized over 10 years versus the plant's lifetime, it is likely at many plants that a capital

investment decision that would be justified by the current retirement date would not be economic if the plant retires earlier.

It is reasonable for the Company to have some level of uncertainty about when it will retire a plant. What is not reasonable is for Evergy to know that early retirement is likely more economic for some of its plants, ignore those results, and continue to make investment decisions without understanding the cost implications and ratepayer impacts of those decisions if the unit does retire early.

Q Your analysis in the beginning of this section evaluated capital expenses the year they are incurred without including depreciation expenses. Why is this analysis an important complement to depreciation analysis?

A As I discussed in section 4 above, both depreciation analysis and the original analysis presented above are important in understanding the economics of the Company's coal fleet. Regardless of how costs are spread out, on net, a plant's value must exceed costs for it to be economic. The main difference is that the original analysis shows the overnight cost of project, as if the project had been paid off all at once, whereas the depreciation analysis shows financed costs spread out over multiple years.

Q Have you conducted any analysis where you evaluate the costs with financing and spread out over a longer time to more closely approximate the costs ratepayers are likely to see?

A Yes. As shown in Table 16 below, the projected excess value for the plants over the next decade decreased [redacted] when the capital costs were annualized and spread out, compared to [redacted] when the capital costs were expenses in the year incurred. But the impact of annualizing was not uniform across all plants because when you annualize costs, you also add financing. At Evergy's most uneconomic plants, particularly Jeffrey

Units 1-3, and La Cygne 1, annualization actually increased the net revenue losses that Evergy is projected to incur over the next decade. And these projections are even before considering the likely underestimation of sustaining capital expenditures that I discussed above.

Table 16: CONFIDENTIAL NPV of projected performance of Evergy's coal plants (2022–2031) with capital costs annualized and expensed (Evergy's share of each plant)

	Forecasted NPV (2022–2031)	
Unit	expenses annualized through plant's planned retirement date	expenses added in year incurred
Hawthorn 5	[redacted]	[redacted]
Iatan 1		
Iatan 2		
Jeffrey 1		
Jeffrey 2		
Jeffrey 3		
La Cygne 1		
La Cygne 2		
Total		

See Table 11.

Q What do you conclude regarding the economic status of the Evergy coal plants, particularly Iatan 1, Jeffrey, and La Cygne Units 1 and 2?

A I find that, despite Evergy's data initially showing that only La Cygne is projected to incur net revenue losses relative to the market, it likely that all of its marginal plants, specifically Iatan 1 and Jeffrey, will also incur losses relative to the market under more reasonable cost assumptions.

Specifically, Evergy has potentially underestimated base capital costs at many of its plants and overestimated future energy market revenue by assuming relatively high future capacity factors. There is a large range of costs implied here, and also some level of uncertainty, but Evergy has the data and the wherewithal necessary

to narrow this range of costs and assess the likelihood of each of the costs being incurred.

My findings with my various screening analysis discussed here support the need for full capacity expansion and production cost modeling by Evergy. Such analysis should rely on optimization logic, detailed system cost and revenue data, and full consideration of alternatives to deliver detailed and specific retirement dates and resource plans.

Q Does this conclude your testimony?

A Yes.