PUBLIC

Review of Evergy Metro and Evergy Missouri West 2024 Integrated Resource Plan

By: Chelsea Hotaling, Energy Futures Group
Anna Sommer, Energy Futures Group
Ivan Urlaub, The Council for the New Energy Economics

On behalf of The Council for the New Energy Economics ("NEE")

August 29, 2024

TABLE OF CONTENTS

1. INTRODUCTION

Energy Futures Group ("EFG") was engaged by the Council for the New Energy Economics ("NEE") to review and provide comments on Evergy's 2024 IRP Annual Update. EFG is a clean energy consulting company that performs IRP modeling and critically reviews IRPs in over a dozen states, provinces, and territories. Our work in these jurisdictions involves conducting our own simulations and/or reviewing modeling conducted using a wide variety of electric system modeling platforms including the PLEXOS software used by Evergy. Ivan Urlaub, Director of Energy and Infrastructure Policy at NEE, also contributed to the review and comments of Evergy's 2024 IRP Annual Update.

The following sections discuss EFG's review of Evergy's 2024 IRP filing and how Evergy's IRP complies with Missouri's Chapter 22 requirements. Table 1 below provides a summary of our areas of concern and deficiency and the proposed remedy. Our recommendations throughout this report are intended to provide feedback on improvements Evergy could make in preparation for future IRP filings.

Table 1. Chapter 22 Deficiencies and Concerns for Evergy's IRP

Title	Deficiency or Concern	Chapter 22 Citation	Proposed Remedy
Supply Side Resource Analysis (Evaluation of all resources)	Concern	20 CSR 4240-22.040 (1) and 20 CSR 4240-22.040 (4)	1. Evergy should continue to evaluate build limits that are binding in modeling runs for each service territory. 2. Evergy should relax the build limits applied to wind resources to allow the model to consider the replacement of existing wind PPAs..
Supply Side Resource Analysis (Costs)	Deficiency	20 CSR 4240-22.040 (1)	The capital cost for Combined Cycle resources should be increased.
Supply Side Resource Analysis (Evaluation of all resources)	Deficiency	20 CSR 4240-22.040 (1) and 20 CSR 4240-22.040 (4)	Accreditation for new thermal resources should be in line with the SPP proposed accreditation to ensure fair treatment

			amongst technology types. The forced outage rate used to adjust the unit's accredited value should also be modeled as the forced outage rate in PLEXOS.
Supply Side Resource Analysis (Evaluation of all resources)	Concern	20 CSR 4240-22.040 (1) and 20 CSR 4240-22.040 (4)	Similar to the evaluation performed for the 2023 IRP Update, Evergy should continue to evaluate coal to natural gas conversion options in future IRP filings.
Production Cost Modeling	Concern	20 CSR 4240-22.010 (2)(B)	If Evergy is not performing production cost modeling on an 8,760 basis then they should do so for future IRP filings.
Supply Side Resource Analysis (Evaluation of all resources)	Concern	20 CSR 4240-22.040 (1) and 20 CSR 4240-22.040 (4)	In future IRP stakeholder workshops, Evergy should discuss how the retirement costs were modeled and incorporated into the Present Value of Revenue Requirement ("PVRR") results.
Natural Gas Price Forecast	Concern	20 CSR 4240-22.040(5) and 20 CSR 4240-22.040(5)(A)	Evergy should work with stakeholders to incorporate fuel price volatility into the development of the natural gas price forecasts.
SERVM Modeling	Concern	20 CSR 4240-22.080 (5) and 20 CSR 4240-22.080 (5)(A)	Evergy should include a discussion of the SERVM modeling process in the IRP stakeholder workshops to allow stakeholders the opportunity to ask questions and provide feedback.
Stakeholder Workshops	Concern	20 CSR 4240-22.080 (5) and 20 CSR 4240-22.080 (5)(A)	Evergy should adopt the technical stakeholder process suggested by NEE.

In addition to the deficiencies and concerns identified above, we also have a set of recommendations for future IRP filings, which include:

1. Evergy should include the extension of the ITC/PTC for new renewable and battery storage resources. If Evergy is not amenable to including this as a base case assumption, then it should be run as a separate scenario.

2. Evergy should evaluate the settings applied in PLEXOS for capacity expansion modeling to ensure the value of battery storage resources are being accurately captured.

3. Evergy should evaluate whether assuming transmission upgrades would have a significant impact on the market prices developed. If there is a significant impact, then Evergy should include those market prices as a sensitivity.

2. EVERGY'S 2024 IRP

Evergy's 2024 IRP includes a few changes from the 2023 IRP Annual Update for Evergy Metro and Evergy Missouri West. Table 2 and Table 3 below show the comparison of the retirements and new resource additions for the Evergy Metro and Evergy Missouri West Preferred Plans as identified in the 2024 IRP and the 2023 IRP Annual Update.

Table 2. Evergy Metro[1] Preferred Plan Comparison

	2023 IRP Annual Update	**2024 Triennial IRP**
Retirements	LaCygne 1 in 2032 Iatan 1 in 2039 LaCygne 2 in 2039	LaCygne 1 in 2032 Iatan 1 in 2039 LaCygne 2 in 2039
Total Wind Additions Through 2030[2]	0 MW	300 MW
Total Solar Additions Through 2030	300 MW	450 MW
Thermal Additions	-	415 MW CT 2032
DSM	RAP+MO/ Low KS	RAP+ MO, Extend KS DSM

[1] Evergy Metro 2024 IRP, Volume 1: Executive Summary, Table 3, page 6.
[2] Builds through 2030 are only shown in this table to compare near term resource build differences between the 2024 Triennial IRP and the 2023 IRP Annual Update.

Table 3. Evergy Missouri West[3] Preferred Plan Comparison

	2023 IRP Annual Update	**2024 Triennial IRP**
Retirements	Lake Road 4/6 in 2030 Jeffrey 2 in 2030 Jeffrey 3 in 2030 Iatan 1 in 2039 Jeffrey 1 in 2039	Lake Road 4/6 in 2030 Jeffrey 2 in 2030 Jeffrey 3 in 2030 Iatan 1 in 2039 Jeffrey 1 in 2039
Total Wind Additions Through 2030[4]	150 MW	0 MW
Total Solar Additions Through 2030	300 MW	150 MW
Thermal Additions	143 MW Dogwood in 2024 260 MW CC in 2028	143 MW Dogwood in 2024 325 MW CC in 2029 415 MW CT in 2030
DSM	RAP+	RAP+

For the 2024 IRP, Evergy is not including any changes to the coal retirement dates from what was modeled in the 2023 IRP Update, but there are changes in the level of new thermal, solar, and wind resource additions. In the IRP Evergy indicated that the change in resource additions and need for more capacity has resulted from load growth and reserve margin requirement changes from what was modeled in the 2023 IRP Update. For Evergy Metro, the 2024 IRP has an increase in both solar and wind added through 2030, while the level of solar and wind additions for Evergy Missouri West has decreased through 2030. For new thermal resources, the Evergy Metro plan has 415 MW of combustion turbine ("CT") resources added in 2032 and Evergy Missouri West has 325 MW shared combined cycle ("CC") added in 2029 and 415 MW of CTs added in 2030. The level of demand side management ("DSM") continues to be at the RAP+ level.

[3] Evergy Missouri West 2024 IRP, Volume 1: Executive Summary, Table 3, page 6.
[4] Builds through 2030 are only shown in this table to compare near term resource build differences between the 2024 Triennial IRP and the 2023 IRP Annual Update.

3. SUPPLY SIDE RESOURCES

3.1 NEW RESOURCE CONSTRAINTS

In capacity expansion modeling, it is not atypical to see either annual or cumulative build constraints applied to the new resources available for selection in the model in order to help the model achieve manageable run times. However, these types of build constraints are concerning when they become binding. A constraint is binding when the model adds new resources only up to the level specified by the constraint. Typically, if the constraint is relaxed, i.e. more wind could be selected, then the model would add more of those resources. For Evergy Metro and Evergy Missouri West, Evergy applied specific annual build limits to the new resource technologies available for selection within PLEXOS. Table 4 shows the annual build constraints Evergy applied in PLEXOS for each utility.

Table 4. Evergy Resource Build Constraints (MW)[5]

Resource	Capacity (MW)	Units/Year
Wind	150	1
Solar	150	2
Battery Standalone	150	2
Battery with Wind	150	2
Combined Cycle	325	1
Combustion Turbine	415	1

In the narrative of the IRP, Evergy described the build limits by saying that:

> *The amount of resource additions was limited in each year of the planning period to respect expected capital budget spending considerations. All alternate resource plans developed using these limits are expected to maintain Evergy Metro's balance sheet stability and financial metrics. Variations in spending from year to year, within these limitations, are not expected to change Evergy Metro's financial ratios, as other components of the company capital budget can be adjusted to accommodate higher resource spends in some years (with lower spend years making room for other priorities*).[6]

It is our understanding that the build limits modeled are tied to annual capital spend limits[7] rather than apportioning limits to different technology types. This does not seem to align with the build limits used since the limit of 150 MW of wind per year would not have the

[5] Evergy response to NEE 3-6.
[6] Evergy Metro 2024 IRP, Volume 6: Integrated Resource Plan and Risk Analysis, page 12.
[7] Evergy Missouri West 2023 IRP Annual Update, page 8.

same cost as the CC or CT gas capacity allowed in a single year. We are concerned that these limits are too restrictive and will likely make the feasible outcomes narrow in scope.

An additional concern about the build limits is that there is no flexibility built in for consideration of how the model can treat the wind PPAs that will expire throughout the planning period. As Evergy indicated in the IRP, "most of Evergy's wind supply is Power Purchase Agreements (PPAs) which will roll off in the 20-year time horizon."[8] Table 5 shows the wind PPAs that are expiring for Evergy Metro and Evergy Missouri West.

Confidential Table 5. Evergy Wind PPA (MW) Expiring[9]

***

[redacted]

***

When Evergy presented the build limits in the stakeholder workshops, NEE provided comments to Evergy asking that Evergy increase the build limits, or if, in the case of Evergy not being willing to make that change, to model at least one run that allows for relaxed build constraints to see if the model would take more of any constrained resource. In the IRP, Evergy stated that it had conducted one Evergy Missouri West run in which it doubled the amount of solar or battery storage resources that could be built. Evergy reported that the same amount of solar and battery storage were built in this run.[10] We could not find a comparable plan for Evergy Metro so it is not clear if Evergy also tested changing the build limits for Evergy Metro. This would be helpful to know since the wind builds are binding in several years of the planning period for Evergy Metro. In addition, it would be helpful to know if allowing more resources to be built would change the result of the expansion plans when other inputs are also changed, such as the construction cost (see our discussion of the

[8] Evergy Metro 2024 IRP, Volume 4: Supply-Side Resource Analysis, page 22.
[9] Evergy workpaper named "IRP2023 PBAEvergy Winter CapacityCONFIDENTIAL".
[10] Evergy Missouri West 2024 IRP, Volume 6: Integrated Resource Plan and Risk Analysis, page 61.

combined cycle capital costs in the next section). We appreciate that Evergy evaluated relaxed build constraints for Evergy Missouri West. We ask that if Evergy continues to implement build limits based on the capital budget, then additional testing should be done on any constraints that are binding.

3.2 COMBINED CYCLE CAPITAL COST ASSUMPTIONS

For this IRP, Evergy used a CC and CT capital cost assumption that was higher than the costs modeled in the 2023 IRP Update. While we appreciate that Evergy increased the capital costs, it is likely that these costs are still understating the costs that Evergy will incur for these resources. EFG works in jurisdictions across the country and we have seen cases where utilities have needed to pay reservation fees for turbines even for projects with online dates in the latter half of this decade. This is an unprecedented situation, but is due to the demand for new turbines. Confidential Table 6 shows a comparison of the costs Evergy modeled for new CCs and CTs, against those of three other utilities including Duke Energy Indiana, Dominion Energy South Carolina ("DESC") and Santee Cooper. Duke Energy Indiana is currently in the process of developing its upcoming IRP, DESC filed its IRP at the end of March 2024, and Santee Cooper is also in the process of developing its upcoming IRP. While Evergy modeled a combined cycle at 650MW or 325MW when half a CC is modeled for each service territory, we are also including the costs that these three utilities modeled for 2x1 CCs. There are typically economies of scale associated with larger units, such as a 2x1 CC, and so it would be highly unusual for a smaller CC to cost materially less than a much larger facility. The 1x1 CCs modeled by DESC and Santee Cooper are about 27% higher than the 2x1 CC. If you applied that same cost difference to the 2x1 CC for Duke Energy Indiana, that would make an estimated 1x1 CC cost at $1,547/kW. All of these costs are significantly higher than the cost modeled by Evergy. The cost modeled by Evergy is more in line with the costs we have seen for 2x1 CCs, which is unusual given the size difference of the CCs.

Confidential Table 6. Comparison of CC Costs (2028 dollars)

	Evergy Base[11]	Duke Energy Indiana[12]	DESC[13]	Santee Cooper[14]
1x1 CC	***[redacted]***	-	$1,724[15]	$1,796
2x1 CC	-	$1,214	$1,353[16]	$1,411[17]

For this IRP, Evergy also evaluated the build and interconnection costs as a critical uncertain factor. The base costs were modeled with a 50% probability and the high/low costs were each assigned a 25% probability. Evergy indicated that the probabilities assigned to the high and low build costs were developed from the statistical variation between the high/low and mid scenarios (e.g., the interconnection costs utilized represent the 25th and 75th percentile of the historical dataset)."[18] For the CC resources, Evergy modeled a low cost of ***[redacted]*** and a high cost of ***[redacted]***.[19] The low cost modeled by Evergy is significantly lower than the capital costs we have seen modeled and the results of modeling runs conducted with that cost assumption will not provide an accurate representation of the costs for new CCs. While the +/-25% adjustment might be an accurate adjustment for interconnection costs associated with CCs, the same assumption should not be made to adjust the CC costs downward by 25% given that the costs modeled in the base case are lower than what we have seen modeled in other jurisdictions.

Evergy's cost estimate assumed for the CCs modeled in the 2024 IRP are still too low and are lower than the costs we have seen modeled in other jurisdictions. We recommend that Evergy increase the costs modeled for CCs and not apply a 25% cost reduction in the low construction cost scenarios.

---

[11] Evergy workpaper named "CONFIDENTIAL New Build CC and CT 2024". Evergy costs include capital and interconnection costs.

[12] 2024 Duke Energy Indiana Integrated Resource Plan Stakeholder Meeting 2, slide 95, https://www.duke-energy.com/-/media/pdfs/for-your-home/dei-irp/20240429-dei-irp-public-meeting-2-slides.pdf?rev=1591debf2adb469b82489e56db3d4ecd

[13] Dominion Energy 2024 Integrated Resource Plan Update, Table 12 at 64. Docket No. 2024-9-E.

[14] Slide 48 from https://www.santeecooper.com/About/Integrated-Resource-Plan/2026-IRP-Stakeholder-Process/_pdfs/Santee-Cooper-IRP-Working-Group-Meeting-2-FINAL_Updated.pdf

[15] DESC size is 650 MW.

[16] The DESC 2x1 CC is modeled as DESC's 50% ownership share of a 1,325 MW CC.

[17] The Santee Cooper 2x1 CC is modeled as Santee Cooper's 50% ownership share of a 1,325 MW CC.

[18] Evergy Metro 2024 IRP, Volume 6: Integrated Resource Plan and Risk Analysis, page 10-11.

[19] Evergy workpaper named "CONFIDENTIAL New Build CC and CT 2024". Evergy costs include capital and interconnection costs.

3.3 CAPACITY VALUE OF NEW THERMAL RESOURCES

In this IRP Evergy discusses the expected changes to the Resource Adequacy Requirements in the future. One of those changes is to accreditation of resources. The accreditation for thermal resources will be determined based on the resource's summer or winter seven-year forced outage rate and in the case of new resources that do not have historical information available, SPP will use class average outage rates.[20, 21]

Under this change—commonly known as "unforced capacity" or "UCAP"—resources will lose accreditation, which will also impact the reserve margin since outage risk will now be accounted for in accreditation instead of in the reserve margin. Evergy has indicated that this expected change in accreditation was incorporated into their modeling beginning in summer 2026.[22] Upon evaluation of the modeling input and output files, it appears that the new CC and CT resources were accredited at their nameplate rather than at UCAP.[23] A UCAP value appears to have been used for existing thermal resources, but not for the new thermal resources.[24] In contrast, Evergy used expected ELCC values for renewable and battery resources in its IRP simulations.[25] Modeling performance adjustments to accreditation for solar, wind, and battery storage without also modeling those changes for new thermal resources would bias the expansion plans towards thermal resources.

Evergy also stated that "Evergy expects SPP [further change thermal accreditation by] coupl[ing] ELCC with performance-based accreditation for thermal resources in a future filing." Those anticipated changes should also be modeled in future IRPs.

In addition, absent extenuating circumstances such as major maintenance to improve reliability or a reasonable basis for differences between class average forced outage rates and the performance of new units, e.g. the use of firm gas transport, the forced outage rate modeled for each thermal resource should align with the rate used to develop the unit's

---

[20] Evergy Metro 2024 IRP, Volume 4: Supply-Side Resource Analysis, page 27-28.

[21] This method of accreditation is commonly known as unforced capacity or UCAP and is calculated as Nameplate x (1-Forced Outage Rate) = Unforced Capacity.

[22] Evergy Metro 2024 IRP, Volume 4: Supply-Side Resource Analysis, page 27-28.

[23] Evergy response to Sierra Club 2-2. PLEXOS input files named "Firm Capacity HalfCC", "Half CC Winter Capacity", and "Max Capacity HalfCC", "Firm Capacity newCTCC", "CC_CT Winter Capacity", and "Max Capacity newCTCC".

[24] Evergy workpapers named "MET CAAB Plan" and "MOW CAAA Plan". In response to NEE 3-2, Evergy stated "The Equivalent Gain or Loss of Capacity from PBA is referenced as "MOW PBA" and "MET PBA" in the preferred plan workbooks, MOW CAAA Plan.xlsx and MET CAAB Plan.xlsx. The calculations used to develop the Net effect of Performance Based Accreditation (PBA) are provided for both Evergy Missouri West and Evergy Metro in the workpaper titled, IRP2023 PBAEvergy Summer CapacityCONFIDENTIAL.xlsx for the summer season. For the winter season, please refer to IRP2023PBAEvergy Winter CapacityCONFIDENTIAL.xlsx." Upon review of the workbooks referenced in this discovery response, we could not find where the PBA was applied to new resources.

[25] Evergy Metro 2024 IRP, Volume 4: Supply-Side Resource Analysis, page 28.

UCAP value. Evergy stated in a discovery response that "New combined cycle units were modeled with a forced outage rate (FOR) of 8%. The FOR for new combustion turbines was not modeled."[26] While it is not clear why a forced outage rate was not modeled for new CTs in PLEXOS, the forced outage rate assumed for the new CC units appears to be lower than what SPP provided as summer and winter weighted average forced outage values in the 2023 Loss of Load Expectation ("LOLE") Study, which are shown in Table 8.

Table 7. Natural Gas Weighted Average Forced Outage Value[27]

	Summer Weighted Average	Winter Weighted Average
0-50 MW	17%	23%
51-100 MW	23%	28%
101 – 200 MW	13%	20%
201 – 400 MW	12%	16%
401 – 600 MW	22%	27%
601+ MW	-	-

No thermal unit experiences zero outage regardless of whether it is new or not, and therefore we recommend that Evergy model new thermal resources adjusting their accreditation by the SPP class average forced outage rate and also model that rate as the forced outage rate for the unit.

3.4 MODELING THE INVESTMENT TAX CREDIT ("ITC") AND THE PRODUCTION TAX CREDIT ("PTC")

Evergy modeled the ITC and PTC for solar, wind, and battery storage resources as being phased out starting in 2034 (2034 resources eligible for 75% PTC/ITC and 2035 resources eligible for 50% PTC/ITC) and ceasing for new resources after 2035. [28] Under the IRA, tax credit phase outs will not occur until nationwide power sector emission reduction targets have been met. While we understand that this assumption for the duration of the tax credits is attempting to reflect emission reduction targets under the Inflation Reduction Act ("IRA")[29], it does not take into consideration the likelihood that nationwide emission reduction targets will not be met by 2035 nor the likelihood of the tax credits being extended in the future. Given the uncertainty around when the emission reductions will be reached and the history

[26] Evergy response to CURB-5, issued in connection with KCC Docket No. 24-EKCE-387-CPL.
[27] 2023 SPP Loss of Load Expectation Report, page 18. Retrieved from https://www.spp.org/documents/71904/2023%20spp%20lole%20study%20report.pdf
[28] Evergy Metro 2024 IRP, Volume 4: Supply-Side Resource Analysis, pages 53-54.
[29] Evergy Metro 2024 IRP, Volume 4: Supply-Side Resource Analysis, page 53.

of tax credits being renewed for renewable projects, there is reason to believe that the tax credits would be extended. If Evergy is not amenable to making this a base case assumption for the alternative resource plan modeling, we recommend that Evergy at least run a sensitivity with the ITC and PTC extended for solar, wind, and battery storage resources.

In previous comments submitted on Evergy's IRP, we have requested that Evergy consider the additional 10% bonus applied if projects are cited in an energy community.[30] For this IRP Evergy has increased the ITC for battery storage resources to 40% beginning in 2029. We appreciate that Evergy incorporated the energy bonus community adder for battery storage resources in the modeling for this IRP.

3.5 COAL TO NATURAL GAS CONVERSION OPTIONS

For the 2023 IRP Annual Update, Evergy evaluated the possibility of natural gas conversions at the Jeffrey Energy Center and Hawthorn 5. In the 2023 IRP narrative, Evergy stated:

> *At this stage, retiring Jeffrey Units 2 and 3 is more economic than converting them to natural gas and retaining Hawthorn Unit 5 as a coal plant is more economic than converting to gas given the high cost of natural gas firm service required for capacity accreditation and the very low expected capacity factor of converted coal units. However, Evergy will continue to evaluate these options in the future as an alternative to retirement given the potential conversion offers to retain accredited capacity, reduce the need for environmental retrofits, and reduce operating costs.*[31]

Table 9 below shows the PVRR results for some of the Evergy Metro portfolios modeled in the 2023 Annual Update. As the results show, the natural gas conversion for Hawthorn 5 was within 1% of the Preferred Plan, which indicates that the results are not significant and can be deemed as comparable from a cost perspective.

[30] Energy communities as defined by the IRA are: (1) a "brownfield site", (2) A "metropolitan statistical area" or "non-metropolitan statistical area" that has: .17% or greater direct employment or 25% or greater local tax revenues related to the extraction, processing, transport, or storage of coal, oil, or natural gas; and has an unemployment rate at or above the national average unemployment rate for the previous year, or (3) a census tract or directly adjoining census tract in which a coal mine has closed after 1999 or in which a coal-fired electric generating unit has been retired after 2009. Please see https://energycommunities.gov/energy-community-tax-credit-bonus/

[31] Evergy Metro 2023 Annual Update, page 106.

Table 8. Evergy Metro PVRR Difference[32]

Plan	PVRR ($M)	$ Difference	% Difference	Retirements
BAAA	$20,408	-	-	2021/2022 Preferred Plan
BDAA	$20,424	16	0.08%	Iatan 1 Retires 2030
BACA	$20,506	98	0.48%	Hawthorn 5 to NG 2027
BDCA	$20,574	166	0.81%	Iatan 1 Retires 2030 Hawthorn 5 to NG 2027
BEAA	$20,578	170	0.83%	Hawthorn 5 Retires 2027

While co-firing options at Evergy's coal plants were considered for the GHG Rules scenario modeled in this IRP, it is not clear why the coal to natural gas conversions were not evaluated in the 2024 IRP like they were for the 2023 IRP Update. We recommend that Evergy continue to evaluate the potential for coal to natural gas conversions in future IRP filings.

4. PLEXOS MODELING

4.1 PLEXOS CAPACITY EXPANSION

For capacity expansion models, it is typical for simplifications to be made in order to achieve a reasonable problem size and find a feasible solution subject to the constraints imposed on the model, e.g., the reserve margin constraint. In order to manage model run times, we usually see a subset of the hours in the planning period modeled in the capacity expansion step. One of the settings in PLEXOS is to use "Partial Chronology" which means that load is ordered from the highest value to lowest value instead of chronologically. For its capacity expansion modeling, Evergy is using the Partial Chronology, a month duration curve, and 12 blocks.[33] This means that load duration curves are developed for each month and within each load duration curve, there will be 12 blocks. For a month consisting of 30 days there will be 30 days x 24 hours = 720 hours that must be allocated to those 12 blocks. If those hours are allocated evenly across all 12 blocks, then each block will consist of 60 hours of load ordered from highest to lowest load with the exception that the global slicing block setting will keep the chronology of two hours together in this load duration curve. So, for example, hours 10 and 11 in one day could be contiguous but could be followed by hours 10 and 11 from a completely different day.

The load duration curve methodology also assumes that unit characteristics in one hour have no bearing on the performance of those units in any other hour. For example, the ability of a battery storage resource to serve load is influenced by its state of charge in the prior hour

[32] Evergy Metro IRP 2023 Annual Update, Table 35, page 83 (Confidential information removed).
[33] Evergy response to NEE 3-11.

and the value of battery storage can be best reflected when chronology is modeled in the capacity expansion model.

We have raised this concern in prior comments on Evergy IRPs, and we raise it again because we experienced an instance in PLEXOS where the utility was allowing PLEXOS to determine whether an existing demand response resource should be retired. Under the utility's approach of Partial Chronology, it was selected for retirement. When we performed our own modeling and tested whether the same resource would be retired under the Fitted Chronology setting, where chronology is preserved, and set the curve fitting period to "day" instead of "month", PLEXOS did not select the resource for retirement.[34] It is possible that battery storage resources may encounter the same issue, but additional testing of the Partial and Fitted Chronology settings in PLEXOS would be needed to understand what combination of chronology (whether hours are ordered by load or sequentially), the curve fitting period (whether the sampled period per month is a day, week, or month in length), and the number of blocks (how many units of time are in each curve fitting period, e.g., eight blocks per day would imply periods that are more than an hour in length) might influence whether storage is added or not.

The other reason why we have raised this question again in our comments is that in the 2023 Annual Update, Evergy evaluated a scenario for Evergy Missouri West where the Dogwood resource was removed as a candidate supply side resource option in the model. The result of this change was that the model selected the 150 MW battery-wind resource. The important consideration for this change is that the resulting Present Value of Revenue Requirements ("PVRR") for the plan with Dogwood was $10,858 and the PVRR of the plan without Dogwood was $10,867, (a 0.08% difference) which made the plans extremely close in PVRR terms and comparable on a cost basis.

Given the importance that chronology has for battery storage resources, we ask that if Evergy has not explored these settings in PLEXOS before, that they evaluate the potential impact the setting choice may have on the selection of battery storage resources.

4.2 PRODUCTION COST MODELING

Our understanding of Evergy's modeling process is that Evergy starts with capacity expansion modeling for plans under the "Mid-Mid-Mid"[35] endpoint and then the resulting new resource builds from those modeling runs are used to develop the modeling runs conducted across the 27 endpoints. Typical practice would be to develop the costs of each plan across the endpoints based on production cost runs. This is because simulating resource

[34] Direct Testimony of Anna Sommer, pages 6-7. Case No. 2022-00402.

[35] Mid natural gas forecast, mid construction cost, and mid level of carbon restrictions.

dispatch using hourly, chronological modeling will eliminate any inaccuracies in generation and therefore cost that can arise from sampling time in the capacity expansion modeling. We assumed that Evergy was following this typical practice. Based on information we have seen for this IRP, we are now uncertain about Evergy's modeling process and whether the plans are modeled in a production cost step. Evergy said that "For the second test, all five representative plans were re-run through the production cost model with each uncertain factor sensitivity. Capacity expansion was not used, as the build plans were fixed."[36] However, in response to a Sierra Club discovery question that asked for modeling output files, Evergy provided files that included a reference only to "LT Plan" – the capacity expansion module of PLEXOS.[37] Evergy has also stated that endpoints are modeled with a Fitted Chronology, a day duration curve, and six blocks, which would also suggest that their basis was capacity expansion and not production cost modeling.[38] If indeed, Evergy is *not* conducting production cost modeling, we would strongly recommend that Evergy do so since this is consistent with best IRP practice and provides a better estimate of dispatch costs. We also ask that Evergy provide those results with modeling output files provided to intervening parties along with any capacity expansion\ modeling output.

5. COAL PLANT RETIREMENT COSTS

Evergy has modeled a "Retirement Cost" for each of the coal plants with that cost differing depending on the retirement date modeled in the resource plan. Upon first review of these retirement costs, we thought that these might be related to transmission upgrades that would be needed if the coal unit was retired, however, the transmission upgrade costs that Evergy provided in discovery did not align with the retirement costs modeled in PLEXOS. As a result, we are uncertain about the categories of cost that are included in the retirement costs modeled in PLEXOS. Confidential Table 10 and Confidential Table 11 show the comparison of the transmission upgrade costs provided in discovery and the retirement costs modeled in PLEXOS for Evergy Metro and Evergy Missouri West.

[36] Evergy Metro 2024 IRP Volume 6: Integrated Resource Plan and Risk Analysis, page 79.
[37] Evergy response to Sierra Club 2-2. Modeling output files indicate "LT Plan" as the "Phase_name" in the files.
[38] Evergy response to NEE 3-11.

Confidential Table 9. Metro Level Retirement Costs ($Millions)

***

[redacted]

***

Confidential Table 10. Missouri West Retirement Costs ($ Millions)

***

[redacted]

***

If these retirement costs include unrecovered plant balances, that should be made clear and Evergy should explore the financial impact of securitizing those balances. If they include any capitalized costs, rather than modeling them as if the full cost is incurred the year following the retirement date, that cost should be levelized according to the amortization schedule for

[39] Response to NEE 3-3.
[40] Evergy response to Sierra Club 2-2. PLEXOS input file named "Retirement Costs MET".
[41] Response to NEE 3-3.
[42] Evergy response to Sierra Club 2-2. PLEXOS input file named "Retirement Costs MOW".

the investment.[43] We ask that Evergy clarify what these costs represent and why the full cost is included in the PVRR in the year following the retirement date modeled.

6. MARKET PRICE FORECASTS

For the market prices that are modeled within PLEXOS, Evergy uses a market price forecast that incorporates transmission congestion by using prices at different nodes/zones within the Southwest Power Pool ("SPP") system. Instead of having one market price for load and all resources, Evergy uses market price forecasts based on nodal pricing. The IRP market price forecasts incorporate pricing at load zones for each utility, coal sites, wind location used for all new and existing wind resources, and generation zones used for the remaining existing generators.[44]

The modeling used to develop the nodal price forecasts reflect current transmission topology and does not make assumptions around future transmission upgrades. As Evergy said in the IRP:

> *Because these models are used to identify future transmission needs, congestion tends to increase in future model years as new resources are assumed without corresponding transmission upgrades that might improve their economic deliverability to load. The base models are likely to overestimate future congestion, however future transmission upgrades are uncertain. The long-term transmission planning processes attempt to identify and select beneficial transmission projects that can reduce the total costs to serve load. Development of new resources may exacerbate congestion, but it can take time for potential savings to reach a tipping point where transmission becomes cost effective. Lags in planning and uncertainty around the timing and viability of new resource additions can also delay new transmission investment. Given the significant expected build-out of renewable resources between 2032 and 2042, which is not accompanied by forecasted enabling transmission investment and thus results in a significant increase in congestion in the "base" SPP model, Evergy assumes congestion is held constant over this second decade of the planning horizon.*[45]

Figure 1 and Figure 2 show the market prices modeled for Evergy Metro and Evergy Missouri West, respectively, under the SPP Future 3 scenario. Given the decline in pricing throughout the planning period, it would be helpful to understand if congestion is the main cause of the negative prices, or if the negative pricing is caused entirely from the level of renewable

---

[43] Evergy workpaper named "GHG NPVRR Results_2024 IRP".
[44] Evergy Metro 2024 IRP, Volume 4: Supply-Side Resource Analysis, page 12.
[45] Evergy Metro 2024 IRP, Volume 4: Supply-Side Resource Analysis, page 12.

buildout under SPP Future 3 and the PTC impact from those resources. We ask that Evergy consider evaluating a market price forecast where transmission upgrades are assumed to be included, in order to see what the impact to the market price forecast is. If the impact is significant, then we ask that Evergy consider including this as a sensitivity in future modeling.

Figure 1. Metro Market Prices[46]

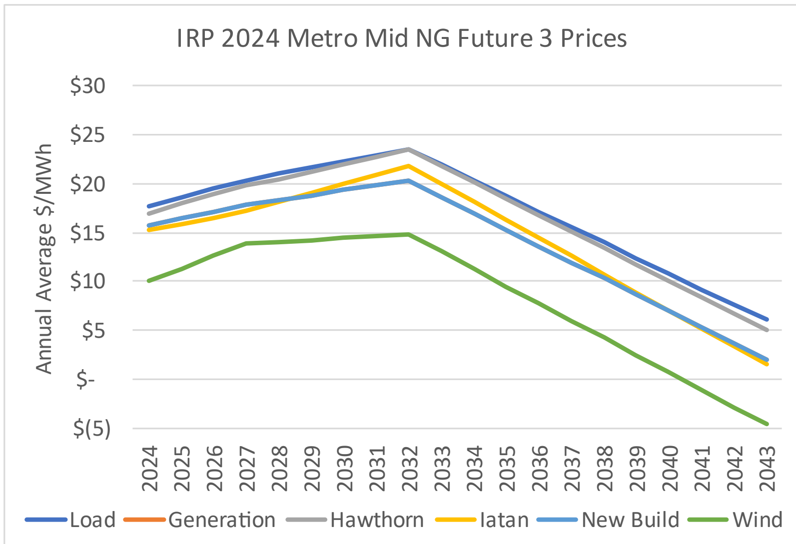
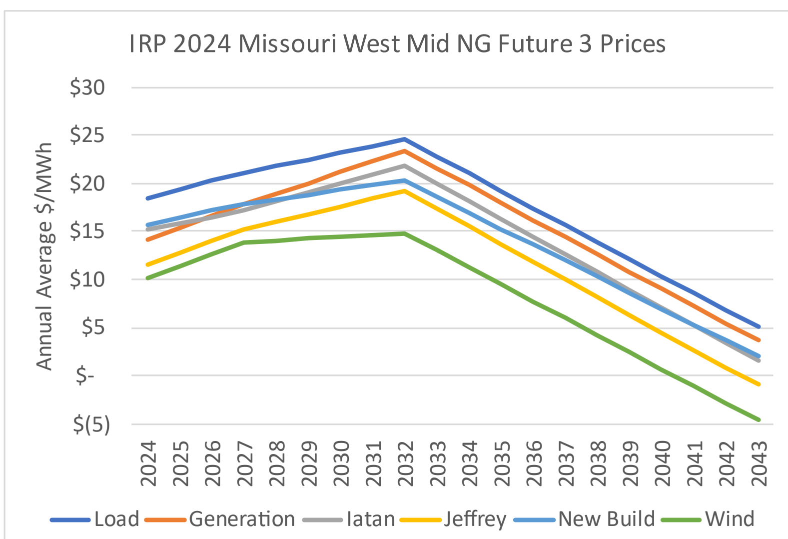


Figure 2. Missouri West Market Prices[47]



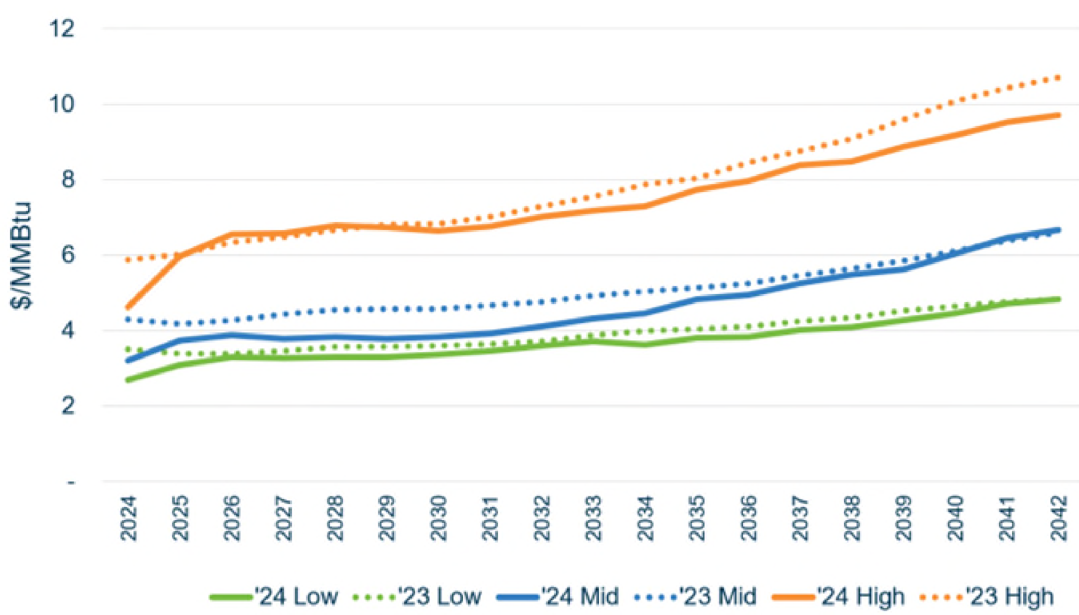
[46] Evergy Metro 2024 IRP, Volume 4: Supply-Side Resource Analysis, Figure 11, page 14.
[47] Evergy Missouri West 2024 IRP, Volume 4: Supply-Side Resource Analysis, Figure 11, page 14.

7. NATURAL GAS PRICE FORECAST

Figure 3 below shows the comparison of the natural gas price forecasts modeled for the 2023 IRP Update and the 2024 IRP. This figure shows that the entire gas price forecast horizon shifts up or down by multiple dollars per MMBtu each year in reaction to the most recent 12 months. This shift between 2021, 2023, and 2024 indicates that inevitable future fuel price volatility and prolonged periods of higher price are not incorporated into the gas price forecast methodology.

NEE would like to discuss in more detail during the stakeholder process with Evergy what risks Evergy is incorporating, which they may be understating, and potential methodologies to more accurately anticipate the inevitable occurrence and effects of acute and prolonged periods of elevated gas prices and more volatile gas prices into the Company's natural gas fuel price forecast. Our objective is to arrive at a forecast method that will facilitate more accurate modeling of gas fuel prices over the entire planning horizon and improved resource selection and accuracy of anticipated costs.

Figure 3. Evergy Natural Gas Price Forecast[48]



[48] Evergy Metro 2024 IRP, Volume 4: Supply-Side Resource Analysis, Figure 1, page 2.

8. SERVM MODELING

For this IRP, Evergy incorporated a probabilistic reliability analysis of two alternative resource plans using the Strategic Energy and Risk Valuation Model ("SERVM"). SERVM evaluates several areas of risk – weather, economic forecast error, load uncertainty, and unit performance – to evaluate reliability events for an electric system. For weather and load related risk, SERVM uses historical weather patterns to develop load profiles for each weather year to predict how loads would respond if the weather experienced in that particular year were to repeat. SERVM then applies load forecast error multipliers with their associated probabilities to capture the potential for uncertainty in economic forecasts. Since economic variables are typically one of the key variable inputs into the development of a load forecast, the load forecast error multipliers simulate the expected probability that the peak demand would be higher or lower because of an error in the economic indicator forecast. The weather years included in the model also reflect the uncertainty around renewable resources, as the profiles for each resource will reflect the expected availability for that resource based on the historical weather profiles. SERVM models the uncertainty around generator unit availability through the simulation of random unit outage draws.

Evergy used SERVM in the 2024 IRP to evaluate how the Preferred Plan and the "High Renewables Plan" compared to the industry standard Loss of Load Expectation ("LOLE") metric, which is one day in 10 years or .1 days per year. Based on the information contained in Volume 8 of the IRP, it appears that the SERVM studies were conducted in response to a special contemporary issue related to resource adequacy.[49]

The following subsections are related to open questions we had after our review of the information provided in Volume 8 of the IRP and the SERVM database. We were able to request and receive access to the SERVM database in discovery[50] and we appreciate Evergy providing that database. It appears that Evergy will continue to utilize SERVM in future IRPs[51] and we have aimed our questions and recommendations under the lens of importance of incorporating this modeling into IRP stakeholder workshop discussions.

8.1 SERVM MODELING RESULTS

Evergy performed the SERVM modeling for the Preferred Plan and the High Renewables Plan for the future study year of 2033. This means that the study will evaluate the projected resource mix and load under the 2033 conditions. Table 12 below shows the major differences

[49] Evergy Metro 2024 IRP, Volume 8: Stakeholder Engagement, page 9.
[50] Evergy response to NEE 3-7(g).
[51] Evergy Metro 2024 IRP Volume 8: Stakeholder Engagement, page 10.

between the two plans, as the High Renewables Plan was developed under the assumption that no new thermal resources could be selected in the PLEXOS capacity expansion model.

Table 11. Evergy Capacity (MW) in SERVM Studies[52]

Resource	Preferred Plan	High Renewables Plan
CCGT	2,219	594
CT	4,265	3,435
Future Solar	1,800	750
Future Wind	1,250	8,550
Storage	0	5,550

Based on the LOLE results presented by Evergy, the High Renewables Plan did not meet the LOLE metric of .1 days/year. In these instances, we would typically see more iteration between the portfolio and SERVM to evaluate what might be driving this result. Evergy did present the unserved energy ("EUE") occurrence for the High Renewables Plan across the hours and months of the study as shown in Figure 4 below.

[52] Evergy Workpaper named "SERVM Studies".

Figure 4. Evergy High Renewable Plan EUE Percent Occurrence[53]

	Month of Year											
Hour of Day	1	2	3	4	5	6	7	8	9	10	11	12
1	0.0000%	0.0065%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
2	0.0000%	0.0026%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
3	0.0000%	0.0065%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0163%
4	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0098%
5	0.0000%	0.0290%	0.0000%	0.0000%	0.0000%	0.0094%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
6	0.0000%	0.0104%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0681%
7	0.0381%	0.1410%	0.0000%	0.0000%	0.0000%	0.0000%	0.0002%	0.0169%	0.0000%	0.0000%	0.0000%	0.0345%
8	0.1156%	0.3311%	0.0000%	0.0000%	0.0000%	0.0000%	0.0031%	0.0074%	0.0000%	0.0000%	0.0000%	0.2107%
9	0.0738%	0.2967%	0.0000%	0.0000%	0.0000%	0.0000%	0.0026%	0.0000%	0.0000%	0.0000%	0.0000%	0.1985%
10	0.0909%	0.0922%	0.0000%	0.0000%	0.0000%	0.0151%	0.0112%	0.0000%	0.0000%	0.0000%	0.0000%	0.0358%
11	0.1068%	0.1539%	0.0000%	0.0000%	0.0000%	0.0173%	0.0282%	0.0079%	0.0000%	0.0000%	0.0000%	0.1197%
12	0.0609%	0.0531%	0.0000%	0.0000%	0.0000%	0.0154%	0.1803%	0.1233%	0.0000%	0.0000%	0.0000%	0.0855%
13	0.0000%	0.1109%	0.0000%	0.0000%	0.0000%	0.0152%	0.1681%	1.4871%	0.0000%	0.0000%	0.0000%	0.0000%
14	0.0000%	0.0707%	0.0000%	0.0000%	0.0000%	0.0082%	0.3171%	6.1019%	0.0000%	0.0000%	0.0000%	0.0000%
15	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0531%	1.3957%	10.4503%	0.0000%	0.0000%	0.0000%	0.0000%
16	0.0000%	0.0293%	0.0000%	0.0000%	0.0000%	0.0391%	2.5824%	15.0612%	0.0000%	0.0000%	0.0000%	0.0000%
17	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	2.4264%	20.7364%	0.0118%	0.0000%	0.0000%	0.0000%
18	0.0000%	0.1184%	0.0000%	0.0000%	0.0000%	0.0145%	1.6796%	16.9049%	0.0000%	0.0000%	0.0000%	0.0034%
19	0.0000%	0.1879%	0.0000%	0.0000%	0.0000%	0.0000%	1.7887%	9.2203%	0.0000%	0.0000%	0.0000%	0.0000%
20	0.0000%	0.2073%	0.0000%	0.0000%	0.0000%	0.0110%	1.9206%	3.3130%	0.0000%	0.0000%	0.0000%	0.0000%
21	0.0000%	0.2099%	0.0000%	0.0000%	0.0000%	0.0138%	0.1270%	0.2858%	0.0000%	0.0000%	0.0000%	0.0000%
22	0.0000%	0.0580%	0.0000%	0.0000%	0.0000%	0.0000%	0.0058%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
23	0.0000%	0.0301%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
24	0.0000%	0.0088%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%

These results show that approximately 97% of the EUE is occurring in the summer months of June to August. We recommend that Evergy close the loop between its SERVM and PLEXOS modeling and explore making portfolio changes to address outcomes such as these. For example, could a different mix of renewable and storage resources improve the LOLE of the plan? I.e., a larger amount of solar (and potentially storage) given the identified summer risk in this portfolio. Additionally, would the results change if some of the four-hour battery storage resources were modeled as longer duration, such as six- or eight-hour batteries? Only four-hour battery storage resources were modeled in PLEXOS and it would be important to understand whether or not SERVM sees additional value for longer duration resources that is not visible to PLEXOS. This information would help inform what battery duration should be included in the PLEXOS capacity expansion modeling.

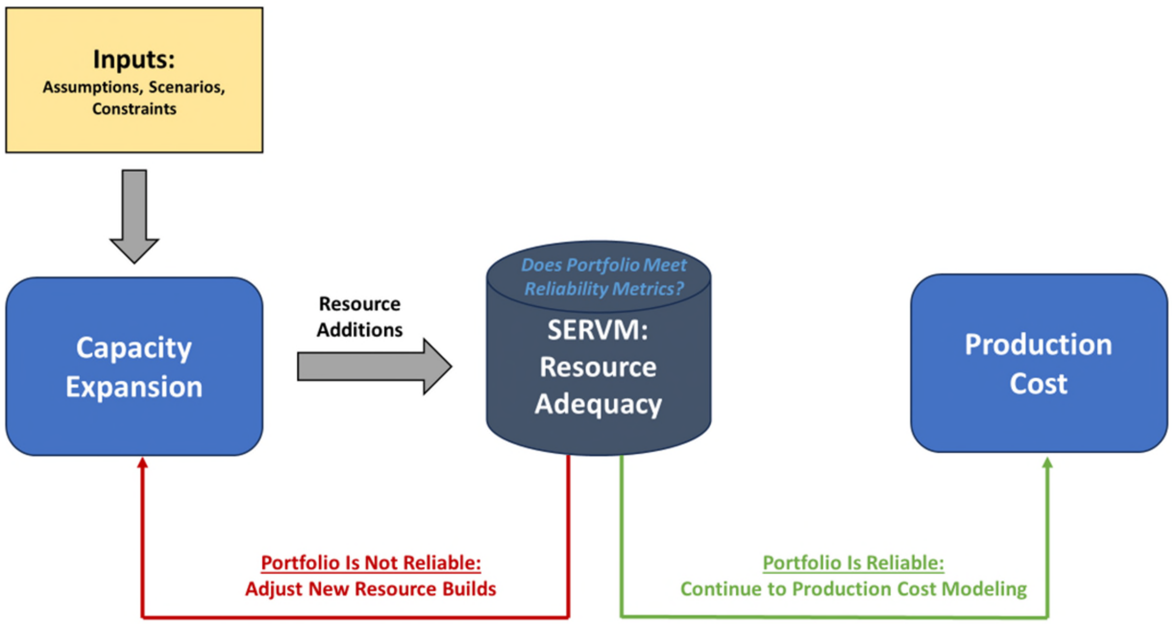
Figure 5 below illustrates an example of a Round-Trip modeling process[54] where capacity expansion portfolios are then passed to a resource adequacy model, such as SERVM. If the portfolio is reliable then it is then passed to the production modeling step. However, if the portfolio is not reliable, changes are made in the capacity expansion step (i.e. including

[53] Evergy Metro 2024 IRP, Volume 8: Stakeholder Engagement, Table 4, page 13.

[54] See Derek Stenclik, Redefining Resource Adequacy, slide 25. Retrieved from https://www.esig.energy/event/webinar-redefining-resource-adequacy/

additional resources, switching resources in the mix, moving to longer duration storage) are implemented to address the shortfall events and then the portfolio will be rerun through the resource adequacy modeling. This process continues until the portfolio is reliable.

Figure 5. Round Trip Modeling Process[55]



8.2 SERVM COLD WEATHER OUTAGE ADDER

In addition to capturing forced or partial outages, incremental cold weather outages can be modeled in SERVM. These outages are intended to capture the relationship between temperature and forced outages and is one of the modeling changes the Southwest Power Pool ("SPP") incorporated for its 2023 LOLE study. The process for developing the cold weather outage adders is outlined in the SPP LOLE study:

> *Astrapé Consulting analyzed historical forced outages and created the temperature-correlated outage data for the 2023 LOLE study by analyzing NERC GADS data (2012-2021) in the SPP footprint (see Figure 10). Forced outages and forced de-rates were compared to historical temperatures to derive an outage curve for each LOLE zone based on extreme cold temperatures. As expected, extreme cold temperatures increase outages due to prolonged cold time periods, regardless of fuel type. In*

---

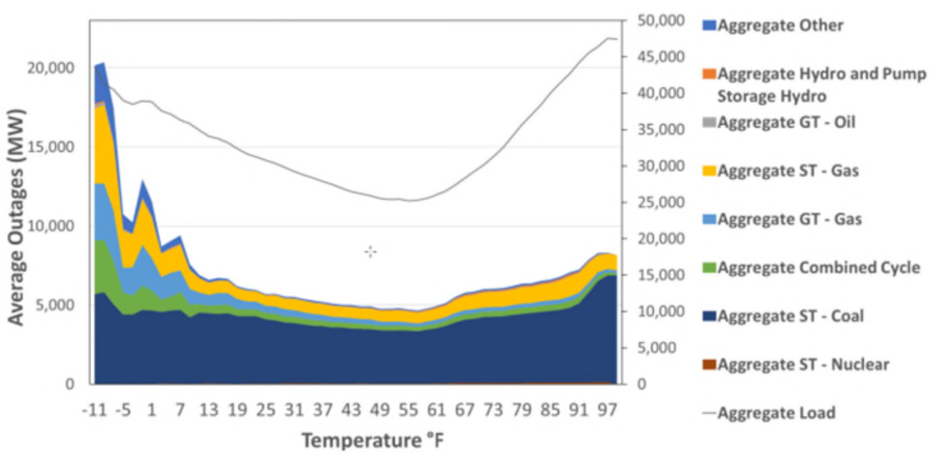
[55] Direct Testimony of Chelsea Hotaling, page 15. Docket No. 2023-154-E before the South Carolina Public Service Commission.

addition, more northern located resources showed a strong correlation with temperature at lower degrees than resources located more south within SPP.

In SERVM, cold weather outage data, which was implemented on a zonal basis, was modeled as additional outages on top of the baseline simulated forced outages. The random draws of forced outages are mainly driven by net load of the system, which does not always correspond to temperature patterns. The incremental cold weather outages give an additional, or cumulative outage effect on LOLE from temperature that was not considered in the 2021 LOLE Study. Historical zonal temperatures of each weather year were aligned with the expected outages for the observed extreme cold temperatures in addition to the outages that were already being simulated as forced outages through the probabilistic forced outage rates (EFOR) modeling of thermal resources.[56]

Figure 6 shows the resulting forced outages from the Astrapé analysis for SPP and the relationship between outages and temperatures across the different generator classes.

Figure 6. SPP Weather Related Outages[57]



While Astrape generally identified a higher risk of outages at higher temperatures especially for gas units, Evergy's SERVM modeling appears to only include incremental cold weather outages for ***[redacted]*** resources as shown in Confidential Figure 7 below.

---

[56] 2023 SPP Loss of Load Expectation Report, page 20. Retrieved from https://www.spp.org/documents/71904/2023%20spp%20lole%20study%20report.pdf

[57] 2023 SPP Loss of Load Expectation Report, Figure 10, page 20. Retrieved from https://www.spp.org/documents/71904/2023%20spp%20lole%20study%20report.pdf

Confidential Figure 7. Cold Weather Outage Adder Modeled in SERVM[58]

***

[redacted]

***

[redacted] In a report that Astrapé developed on the correlated outages in SPP, the results indicate that there are outages for SPP for ***[redacted]*** resources.[59] This implies including cold weather outages for ***[redacted]*** resources would result in additional outages for those resources during periods of lower temperatures. Since the Preferred Plan ***[redacted]*** resources, it is possible that including cold weather outages for ***[redacted]*** resources would result in a higher LOLE result for the Preferred Plan. We ask that Evergy clarify why the cold weather outages were not modeled for ***[redacted]*** resources or include these outages for all applicable technology types in future SERVM modeling.

8.3 MODELING BATTERY STORAGE RESOURCES IN SERVM

After review of the SERVM modeling results and the database, we also have questions about how the battery storage resources were modeled in SERVM. Based on the settings in the database, it appeared that the battery storage resources were modeled under the assumption of ***[redacted]*** Typically when we have reviewed other utility databases, the battery storage resources are modeled with ***[redacted][60] [redacted]

[58] Evergy response to NEE 3-7(g).

[59] SPP Correlated Outages Analysis. Retrieved from https://spp.org/spp-documents-filings/?id=159642

[60] *** [redacted] ***

[redacted][61][redacted]*** [62] Without executing runs in SERVM and reviewing more detailed output results ourselves, it is hard to know if this ***[redacted]*** for the battery storage resources has an impact on the LOLE result, but it would be important information to know, given the significant difference in the battery storage resource build between the two plans.

If Evergy plans to include SERVM modeling in future IRP filings, we ask that Evergy include the modeling as a discussion item in one of the IRP stakeholder meetings to allow stakeholders the opportunity to ask questions and be able to react to results of any SERVM modeling conducted.

9. EVERGY'S STAKEHOLDER IRP PROCESS

As Evergy prepares for future IRP filings, we would also like to make some recommendations about how the Company can improve stakeholder engagement. NEE appreciates Evergy's interest in transparency and the solicitation of feedback from stakeholders, but the process is not currently structured to allow best practice transparency and to solicit input from stakeholders. We would offer several recommendations in that regard to improve the process. NEE acknowledges that Evergy did provide modeling inputs and outputs with the 2024 IRP filing and through discovery, but that information came at a point in the process where it was too late for Evergy to incorporate any feedback from stakeholders.

We view the purpose of the stakeholder process as being to narrow the set of contested issues and reach as much consensus as possible. It's difficult to do that if stakeholders can't react to most of the utility's assumptions and data until the IRP has been filed. For example, the deficiency identified above regarding the accreditation of new thermal resources was identified after the IRP was filed and the modeling was complete. Had Evergy shared its

[61] Calculated from the SERVM EUE Report for the High Renewables study.

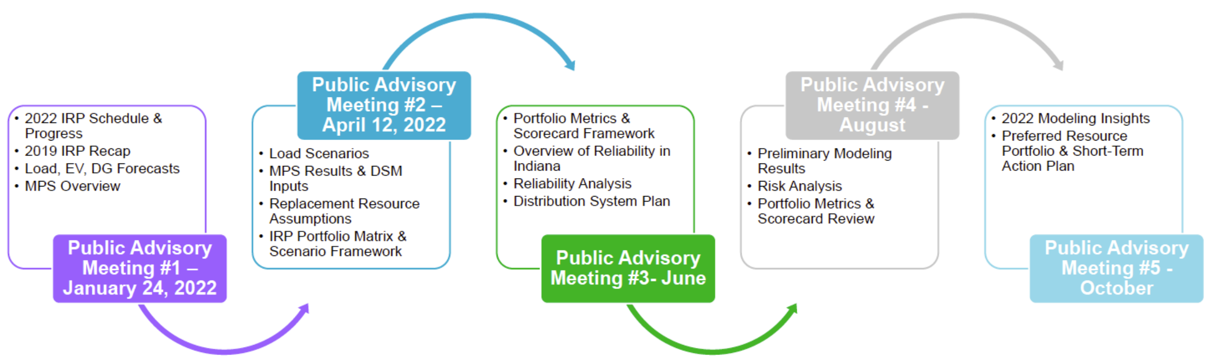
[62] Evergy Workpaper named "SERVM Studies".

assumptions earlier, the deficiency could have been addressed before the filing and the Commission and stakeholder would be able to view the impact of the adjustment.

In order to ensure that the process is collaborative, and that stakeholder feedback is taken into consideration with enough time for Evergy to be able to incorporate that feedback into the modeling well in advance of the filing, NEE asks that Evergy implement these additional steps as part of the stakeholder process:

- Use an online data sharing platform (e.g., Drop Box, Sharefile, etc.) to provide IRP data files to stakeholders who have executed NDAs.
- Provide direct and clear responses to stakeholder input, such as through additional calls or as part of the technical conferences, so that stakeholders can understand how their feedback was considered.
- Commit to providing its data inputs and modeling files to stakeholders on a schedule that permits stakeholders to provide feedback and gives Evergy sufficient time to be able to incorporate that feedback into the modeling inputs.

EFG has been a part of stakeholder processes in other jurisdictions that follow a model like the one suggested above and it has led to more collaborative and robust IRP processes. One such IRP was the 2022 AES Indiana IRP.[63] AES Indiana provided the following timeline to stakeholders to set expectations about its stakeholder process.



Several days before the start of the meetings, AES Indiana would share the data that was relevant to the topic(s) addressed at the forthcoming meeting. This would allow stakeholders the opportunity to review and come prepared to ask questions. After the conclusion of each

[63] The public documents from the AES IN IRP stakeholder process are available at: https://www.aesindiana.com/integrated-resource-plan

meeting, AES IN invited stakeholders to submit comments on the discussion and on the data and supplemented any missing data. And at the start of the subsequent meeting, AES Indiana shared how it planned to change its analysis or inputs to address stakeholder feedback. The result of this was relatively very few unresolved stakeholder issues by the time the IRP was filed.

We strongly recommend that in order to enable stakeholders to make a good faith effort to provide feedback on the IRP, Evergy make its input data and modeling files available along the way for intervenors to review and comment on as described above. Ideally, this will help narrow the issues of dispute once the IRP is filed, and also has the benefit of facilitating dialogue about the major factors that influence the utility's IRP modeling by providing greater insight into the rationale and reasoning for the utility's assumptions.