SIERRA CLUB

BEFORE THE ARIZONA CORPORATION COMMISSION

In the Matter of Resource Planning and Procurement in 2021, 2022, and 2023.	Docket No. E-99999A-22-0046

Sierra Club Comments on Tucson Electric Power Company's 2023 Integrated Resource Plan

1. Introduction

Sierra Club appreciates the opportunity to comment on Tucson Electric Power Company's ("TEP" or "the Company") 2023 Integrated Resource Plan ("IRP"). These comments were prepared with the assistance of Synapse Energy Economics, Inc. ("Synapse") and are based on our examination of TEP's input assumptions and resource options, its resource portfolios, and our participation in TEP's Resource Planning Advisory Council ("RPAC") and public stakeholder process. Our comments focus on the Company's retirement plans for Springerville Generating Station ("Springerville") and Four Corners Power Plant ("Four Corners") and the replacement resources that TEP plans to bring online over the next fifteen years, including gas and clean energy resources. Our comments advocate for transparent resource planning that provides customers a reliable electricity system at a reasonable cost while minimizing risk and environmental impact.

We recommend that TEP revise its IRP in accordance with our recommendations outlined below, including conducting updated capacity expansion modeling runs using the Aurora model and clearly presenting the results of staggered retirement scenarios for Springerville. If the Company does not voluntarily revise its IRP, we recommend that the Commission not acknowledge TEP's IRP, require that the Company revise its modeling to address the concerns we have highlighted, and require Commission approval for any new resource acquisitions in the interim.

2. Summary and Recommendations

Summary of findings:

1. TEP did not follow the Commission's directive[1] to utilize capacity expansion modeling software to select its resource mix, and instead opted to "hand-craft" its resource portfolios outside of the software. TEP relied on the Aurora model only to dispatch portfolios it had already selected, not to develop or test optimized portfolios.

2. TEP did not follow the Commission's directives[2] to test alternative retirement dates for both Four Corners and Springerville in all years between 2024 and 2031. TEP did not test 2028 or 2029 retirement dates for Springerville in its November 1, 2023 IRP (although it later provided analysis of those years in a supplement filed on January 24, 2024). TEP did not test any alternative retirement dates for Four Corners, and instead simply assumed 2031 retirement.

3. TEP found that staggered retirement of the Springerville units would save between $300 million and $500 million over the study period, yet TEP did not test any staggered unit retirements in its "Balanced Portfolio" besides the baseline assumption of Unit 1 retirement in 2027 and Unit 2 retirement in 2032.

4. The economics of the Springerville units have been declining. TEP is currently operating Springerville Unit 1 on a seasonal basis and plans to transition Unit 2 to seasonal operations in 2024.

5. The economics of Four Corners have been declining, and APS's own 2023 IRP analysis found that retiring the plant early in 2028, 2029, or 2030 would generate millions in cost savings for ratepayers relative to APS's reference case. TEP performed no independent analysis of the economics of continuing to rely on the Four Corners plant, or of the decision not to operate the plant seasonally.

6. TEP indicated in its prior 2020 IRP that the Company planned build only clean energy resources moving forward. TEP is going back on that commitment by proposing substantial new gas resources in the current IRP.

7. As part of TEP's "Balanced Portfolio," the Company proposes to build 400 MW of new gas capacity in 2028 to replace Springerville Unit 1 when it retires.

[1] Decision No. 78499 at 17:10-17, Docket No. E-00000V-19-0034 (Mar. 2, 2022), *available at* https://edocket.azcc.gov/search/document-search/item-detail/295256 [hereinafter "Decision No. 78499"].
[2] *See* Decision No. 78499 at 12:19-23.

8. TEP's reliance on gas resources exposes its ratepayers to risks from high gas price volatility, and the risks of higher costs associated with new and proposed environmental rules that regulate fossil-fueled generating resources. It is not clear whether TEP has properly captured these risks in its modeling.
9. TEP's "Balanced Portfolio" contains a large quantity of economically selected clean energy resources, including 1,330 MW of new battery energy storage systems ("BESS"), 1,740 MW of solar photovoltaics ("PV"), and 500 MW of wind over the next fifteen years (2024-2038). Of those resources, just over 350 MW of solar, 40 MW of wind, and 280 MW of BESS are planned to come online between now and 2030.
10. TEP's IRP omits or limits the model's access to several critical energy resources, including long duration energy storage ("LDES"), which it does not model at all, and high-quality New Mexico wind, which it caps based on transmission availability.
11. TEP did not assume any western market integration when designing its resource portfolio in the IRP.
12. TEP made efforts to engage stakeholders in the IRP process, but the Company's engagement and data sharing with RPAC members ultimately fell short, and has significant room for improvement in the future, as explained below.
13. TEP did not provide capacity expansion modeling files to RPAC members until the middle of November 2023, after the Company's IRP was filed, and provided supplemental updates in December 2023 and January 2024. That delayed timeline did not allow for stakeholders to complete a thorough review of TEP's assumptions or any of its updated modeling.

Recommendations:

On the basis of these findings, we offer the following recommendations**:**

1. TEP should update its modeling and provide the results of Aurora capacity expansion modeling runs that test (1) optimized retirement dates for the coal units at Springerville and Four Corners; (2) staggered retirement dates for the Springerville units, and (3) early retirement of Four Corners.
2. TEP should continue to pursue seasonal operations at the Springerville units, and look for ways to further reduce operations and use of the units leading up to their retirement.
3. TEP should engage with the co-owners of Four Corners to (1) regularly evaluate the feasibility and economics of retiring Four Corners early and procuring replacement resources, and (2) re-evaluate switching the Four Corners units to seasonal operations.

4. TEP should adhere to its commitment from its 2020 IRP to build only clean energy resources going forward.

5. TEP should focus on issuing all source request for proposals ("ASRFPs") and procuring as many clean energy resources as possible between now and when Springerville Units 1 and 2 retire. Given the risks associated with gas price volatility and future regulations, the Company should only consider gas resources once it has exhausted its ability to economically procure clean energy resources while maintaining system reliability.

6. TEP should update its modeling to reflect a complete picture of the risks and costs associated with reliance on gas resources, including the risks of gas price volatility and increased environmental regulations. The Company should first evaluate the impact of these risks on its "Balanced Portfolio." TEP should then update its capacity expansion modeling runs to develop a new resource portfolio that better mitigates or avoids these risks.

7. TEP should clearly describe all tangible actions it is currently taking to pursue transmission expansion required to access high quality New Mexico wind resources, what actions are required of TEP and other parties to make this expansion happen, and the timeline, feasibility, and cost of gaining access to these resources.

8. TEP should have allowed its IRP model to select LDES as part of its resource portfolio at least starting in the mid 2030s.

9. TEP should carefully monitor cost trends for renewables and clean energy resources and update its modeling regularly to evaluate the impact of updated cost trends.

10. TEP should model the energy community tax credit adders available under the federal Inflation Reduction Act ("IRA"), and further analyze potential financing from the federal Energy Infrastructure Reinvestment ("EIR") program.

11. TEP should conduct additional analysis through IRP modeling as well as supplemental studies to understand how market integration will impact its reserve margin and reliability needs, and how market reliance can reduce its capacity needs, and its dispatch costs.

12. TEP should continue to use the RPAC process to engage stakeholders, share information, and solicit feedback. The Commission should again direct that in the next IRP process, TEP should again provide RPAC members with no-cost licenses in order to use the same modeling software used by the Company,

and direct that TEP provide RPAC members with modeling inputs and data, as the Commission ordered for this IRP process in Decision No. 78499.[3]

13. TEP should improve its RPAC process in future IRP proceedings by providing access to all modeling inputs and data to RPAC members at least 3 months before the final IRP is filed with the Commission, in order to allow time for meaningful stakeholder input before the IRP is filed. TEP should also provide training on proper use of the modeling software at least 4-6 months before the IRP is filed.

3. TEP did not follow the Commission's mandates regarding the modeling of its coal plants in developing its resource portfolios.

a) None of TEP's portfolios were developed using long-term capacity expansion modeling.

i. TEP developed its portfolios outside of the long term capacity expansion model.

Commission Decision 78499, issued on March 2, 2022, required TEP to use capacity expansion modeling to develop its IRP.[4] TEP did not follow the Commission's directive, and instead opted to "hand-craft" its resource portfolios and then used the Aurora production cost model to dispatch its selected resource mix and "iterat[e]" on the hand-crafted resource portfolio it had already selected.[5] The dispatch functions of Aurora are distinct from the model's long-term capacity expansion ("LTCE") resource selection capabilities. TEP stated the following about its modeling methodology:

> "The iterative process typically begins with an estimate of the amount of solar and storage needed in addition to the wind power assumptions to meet firm demand reliably and cost-effectively in all hours of the 15-year planning period. The resulting reserve margin is compared to a minimum planning reserve margin (PRM) of 16.5% of peak demand. In most cases, solar and storage deployments are adjusted and remodeled until both the CO_2 goal and PRM target is met each year."[6]

This approach is concerning for several reasons. First, TEP did not comply with the Commission's mandate to use capacity expansion modeling, and instead employed a distinct approach. Second, given that all of TEP's foundational resource planning was done outside the Aurora software, the software that RPAC members have access to, this left RPAC members with

[3] Decision No. 78499, 14:9-14.

[4] Decision 78499 at 17:10-17 (adopting Ascend Analytics recommendation that TEP "use capacity expansion model[ing] in future Integrated Resource Plans" and ordering that TEP "shall use and provide to the Commission the capacity expansion model used in their next Integrated Resource Plans, *in addition to* any hand-selected portfolio" (emphasis added)).

[5] Tucson Elec. Power, 2023 Integrated Resource Plan at 30, Docket No. E-99999A-22-0046 (Nov. 1, 2023), *available at* https://edocket.azcc.gov/search/document-search/item-detail/323077 [hereinafter "TEP 2023 IRP"].

[6] *Id.* at 31.

no ability scrutinize TEP's selection of its resource mix. Third, the purpose of a capacity expansion model is to develop a resource portfolio that meets the company's load, pursuant to specific reliability metrics, such as the PRM, and regulatory goals, including CO_2 emission rates. Estimating resource needs *outside* the model and then iterating via modeling runs is an inferior approach that can only tell the Company how the cost and performance of the specific scenarios modeled compare to one another, not whether those scenarios are optimal. By contrast, long term capacity expansion modeling can tell the Company what the optimal resource mix looks like from among all resource options available. The Company can still iterate with the LTCE software, and omit resource options that are infeasible, and the results delivered are more robust and comprehensive. Finally, TEP's flawed approach did not allow the model to make endogenous retirement decisions, or otherwise optimize resource retirement or replacement decisions.

ii. While TEP eventually used the LTCE modeling, it was too late in the process and its use of the model was flawed.

After substantial feedback by RPAC members (dating back to June 2023, when RPAC members first received the Company's modeling files), TEP did eventually agree to conduct limited capacity expansion modeling using the Aurora software. But TEP was skeptical of the LTCE software from the start, stating that:

> "[the] results can guide and verify results derived from the modeling approach described above. However, because this semi-independent methodology evaluates a large number of potential resource combinations, it must make simplifying assumptions about the electric generation and transmission systems and therefore cannot be relied upon as the sole basis for evaluating portfolio costs and reliability."[7]

While we appreciate that TEP eventually agreed to use the Aurora model, it is not clear from the IRP narrative exactly how the Company used the model and what value it provided to the process. TEP did not present the results from the capacity expansion modeling runs in its IRP and didn't conduct any additional modeling runs that leverage the optimization capabilities of the model to both identify economically optimal resource additions and identify economically optimal retirement dates.

Additionally, TEP didn't provide its capacity expansion model inputs until November 13, 2023, nearly two weeks *after* it filed its IRP with the Commission on November 1, 2023 and five months after it provided its initial modeling files. This precluded RPAC members from adequately scrutinizing and validating TEP's resource selection before the filing of the final IRP.

[7] TEP 2023 IRP at 31.

Overall, TEP's retirement analysis was flawed and incomplete because of its failure to utilize LTCE software from the start. Had TEP utilized LTCE software and allowed the model to make endogenous retirement decisions for its coal plants, the Company would have had more information regarding which retirement dates, or series of dates, were most economic for each unit and plant across a range of scenarios.

Recommendation: TEP should update its modeling and provide the results of Aurora capacity expansion modeling runs that test: (1) optimized retirement dates for the coal units at Springerville and Four Corners; (2) early retirement of Four Corners; and (3) staggered retirement dates for the Springerville coal units.

b) TEP did not model the retirement of Springerville and Four Corners as ordered by the Commission.

Commission Decision 78499 ordered that TEP's IRP must evaluate the economics of alternative retirement dates, including retiring Springerville and TEP's share of Four Corners in *every year* from 2024 through 2031.[8] (Springerville Unit 1 is currently scheduled to retire in 2027, while Springerville Unit 2 is scheduled to retire in 2032[9] and Four Corners is scheduled to retire in 2031.)[10] TEP failed to comply with this requirement. Instead, TEP modeled only three alternative retirement scenarios: (1) retirement of both Springerville Unit 1 and Unit 2 in 2027; (2) retirement of both Springerville units in 2030; (3) retirement of both Springerville units in 2034.[11] TEP did not evaluate any alternative retirement years for Four Corners.

TEP's failure to comply with multiple requirements of the Commission's order is concerning for a number of reasons.

First, TEP's IRP did not test each of the early retirement years for the Springerville units as required by Decision 78499. While TEP tested retirement of both Springerville units in 2027, 2030, and 2034, TEP did not model Springerville retirement in 2028 or 2029 as part of its November 1, 2023 IRP.[12] On January 24, 2024, only one week before stakeholder comments on the IRP were due, TEP belatedly filed an IRP supplement with additional modeling runs

[8] Decision No. 78499 at12:19-23 ("in its next resource planning process, Tucson Electric Power Company shall file a comprehensive early retirement analysis for Springerville Generating Station Units 1 and 2 and of its stake in Four Corners Power Plant . . . retirement dates in 2024, 2025, 2026, 2027, 2028, 2029, 2030, and 2031 shall be considered").
[9] TEP 2023 IRP at 6.
[10] *Id.*
[11] *Id.* at 46.
[12] TEP also did not test early retirement in 2024–2026.

containing a 2028 and 2029 retirement analysis for Springerville.[13] This did not allow sufficient time for stakeholders to evaluate these additional modeling runs.

Second, TEP only modeled concurrent retirement of the two Springerville units at the same time, and did not model staggered retirement dates for the Springerville units in different years, except for the baseline assumption that Unit 1 will retire in 2027 and Unit 2 in 2032.[14] This is concerning because TEP failed to evaluate whether staggered retirement of the two units in alternative years (e.g. Unit 1 in 2027 and Unit 2 in 2028, 2029, or 2030) might be optimal. TEP even acknowledged the benefits to staggering retirement dates, stating that it found that retiring both units at the same time will raise costs by $300 million to $500 million over TEP's planning period.[15] Therefore, is not entirely surprising that none of TEP's alternative early retirement portfolios were lower cost than the "Balanced Portfolio," as none of the alternative portfolios benefited from staggered retirement of the Springerville units. TEP's January 2024 supplemental analysis acknowledged that staggered retirement of the Springerville units is lower cost than concurrent retirement, but still did not evaluate alternative staggered retirement dates.[16]

Third, TEP did not allow the IRP model to endogenously retire the Springerville and Four Corners units to evaluate the optimal retirement dates for each unit. This is critical because there are technically dozens of combinations of early retirement scenarios between the two units at Springerville and the two units at Four Corners.

Finally, all portfolios in TEP's IRP assumed that Four Corners would operate year-round until the plant retires in 2031.[17] The Company never evaluated any other retirement options for the plant. This is especially concerning because APS's 2023 IRP found that retiring Four Corners in 2028, 2029, or 2030 would all be lower cost than the reference retirement date of 2031, with the largest cost savings coming from a 2028 retirement.[18] TEP should have followed the Commission's mandate to model other retirement years for Four Corners, including in 2027, 2028, 2029, and 2030,[19] as APS did in its IRP. TEP also should have modeled seasonal

---

[13] TEP 2023 IRP Supplemental Information, Docket No. E-99999A-22-0046 (Jan. 24, 2024), *available at* https://edocket.azcc.gov/search/document-search/item-detail/325675 [hereinafter "Jan. 24, 2024 supplemental filing to TEP 2023 IRP"].
[14] TEP 2023 IRP at 46.
[15] Jan. 24, 2024 supplemental filing to TEP 2023 IRP.
[16] *Id.*
[17] TEP 2023 IRP at 52.
[18] Ariz. Pub. Serv., 2023 Integrated Resource Plan at 75, Table 5-3, Docket No. E-99999A-22-0046 (Nov. 1, 2023), *available at* https://edocket.azcc.gov/search/document-search/item-detail/323087 [hereinafter "APS 2023 IRP"]; see also *id.* at 80 (noting "early exit scenarios indicating a potential for cost savings").
[19] Retirement of Four Corners in 2024-2026 is likely not feasible at this point, but TEP should have explicitly acknowledged its decision to omit these Commission-mandated scenarios.

operations at Four Corners. APS previously planned to switch the plant to seasonal operations in 2023, before reversing course.[20]

Recommendation: TEP should update its modeling to evaluate each of the Commission-mandated early retirement scenarios for Springerville and Four Corners as required by Decision 78499. This includes early retirement of Four Corners. TEP should also test early retirement of the Springerville units on a staggered timeline in alternative years.

c) TEP should evaluate accelerated retirement of Springerville and Four Corners, and take action to minimize usage of the plants until their respective retirement dates.

i. Springerville

TEP currently plans to retire Springerville Unit 1 in 2027 and Unit 2 in 2032.[21] As discussed above, TEP's retirement analysis has multiple flaws, including TEP's failure to use LTCE modeling to develop its portfolios and its failure to model alternative retirement years for the plant as ordered by the Commission. Although TEP tested concurrent retirement of both Springerville units in 2027, 2030, and 2034, and later added supplemental analyses of 2028 and 2029 retirements, TEP did not analyze any staggered retirement years aside from the baseline.

The economic and operational performance of Springerville Units 1 and 2 has been declining, and the units are likely to become riskier and more costly going forward.[22] Outage rates at the unit are above average, which subjects ratepayers to potentially high and volatile market prices for energy and gas when replacement energy is needed.[23] The cost to operate and maintain Springerville Units 1 and 2 substantially exceeds the cost of alternatives, including clean energy resources.[24] TEP can likely avoid substantial unnecessary capital expenditures and operations and maintenance costs by retiring Springerville earlier than the currently scheduled retirement dates.[25]

Additionally, in January 2024 the U.S. Environmental Protection Agency ("EPA") announced a proposed update to the Good Neighbor Rule which would limit nitrogen oxide ("NO_x") emissions during ozone season (May – September) in the states of Arizona and New Mexico

[20] APS 2023 IRP at 28–29.
[21] TEP 2023 IRP at 6.
[22] Direct Testimony of Devi Glick On Behalf of Sierra Club at 10–19, Docket No. E-09133A-22-0107 (Jan. 11, 2023), *available at* https://edocket.azcc.gov/search/document-search/item-detail/306679 [hereinafter "Glick Direct"].
[23] *Id*. at 11.
[24] *Id.* at 19–21.
[25] *Id.* at 23–24.

(and several other states) starting as soon as 2025.[26] Preliminary allocation data[27] released by the EPA indicates that Springerville's allocation of NO_x emissions will be reduced, meaning that during ozone season, Springerville would have to either reduce operation or purchase potentially costly NO_x emissions credits to keep operating at current levels. This is just one example of the risk of increased federal regulation of fossil fuel generations, and the costs that it could impose on ratepayers.

TEP currently operates Springerville Unit 1 on a seasonal basis, and plans to transition Unit 2 to seasonal operations in 2024.[28] This involves an extended planned outage of three months at each unit, with the two units alternating idling between the spring and fall (and the adjacent winter months). The Company plans to ramp down operations at each Springerville unit leading up to its scheduled retirement date.[29] TEP will transition Unit 1 to summer-only operations prior to full retirement at the end of 2027.[30] After Unit 1 retires, TEP will transition Unit 2 to a 9-month operating year and will ramp the unit down to summer-only operations starting in 2030 through its retirement at the end of the 2032 summer season.[31]

ii. Four Corners

As discussed above, TEP assumed that Four Corners would operate through 2031 in all its resource portfolios,[32] and thus failed to comply with the Commission's mandate to evaluate alternative retirement years. This is especially concerning because of the substantial cost savings TEP identified from early retirement of the plant. Specifically, APS found that 2028 retirement of Four Corners would save \$139 million, 2029 retirement would save \$91 million, and 2030 retirement would save \$57 million relative to continued operations through 2031.[33] TEP should also should have modeled seasonal operations at Four Corners. APS previously planned to switch the plant to seasonal operations in 2023, before reversing course.[34]

---

[26] U.S. EPA, Supplemental Air Plan Actions: Interstate Transportation of Air Pollution for the 20158-hour Ozone National Ambient Air Quality Standards and Supplemental Federal "Good Neighbor Plan" Requirements for the 2015 8-hour Ozone National Ambient Air Quality Standards (Jan. 16, 2024) (to be codified at 40 C.F.R. pt. 52, 97) [hereinafter "Good Neighbor Plan for 2015 Ozone NAAQS"], *available at* https://www.epa.gov/system/files/documents/2024-01/11159_gn-plan-supplemental-proposed-preamble-and-rule_20231220_admin.pdf.

[27] Good Neighbor Plan for 2015 Ozone NAAQS, Unit-level Allocations and Underlying Data for the Proposed Supplemental Rule (xlsx), *available at* https://www.epa.gov/system/files/documents/2024-01/unit-level-allocations-and-underlying-data-for-the-proposed-supplemental-rule.xlsx.

[28] TEP 2023 IRP at 3.

[29] *Id.* at 56.

[30] *Id.*

[31] *Id.*

[32] *Id.* at 52.

[33] APS 2023 IRP at 75, Table 5-3.

[34] *Id.* at 28–29.

As a co-owner of Four Corners, TEP cannot take unilateral action to retire the plant or change it to seasonal operations, but it does still have an obligation to advocate that APS operate and maintain the plant in a manner that serves the best interest of TEP ratepayers. Because TEP simply assumes that the 2031 retirement date APS has selected is the only option for Four Corners, TEP's IRP fails to determine whether ratepayers would be better served by pushing for an earlier retirement date. Given APS's findings that early retirement of Four Corners would create cost savings, TEP should critically review Four Corners retirement timeline and use its power as a co-owner to advocate for a more robust evaluation of what is required to retire the plant early.

Recommendation: TEP should continue to pursue seasonal operations at the Springerville units and look for ways to further reduce operations and use of the units leading up to their retirement.

At Four Corners, TEP should engage with the co-owners to regularly evaluate the feasibility and economics of retiring Four Corners early and procuring replacement resources and to re-evaluate switching the plant to seasonal operations.

4. TEP should minimize its deployment of gas resources to replace retiring coal assets and meet load growth needs.

a) TEP is planning to build 400 MW of new gas CT resources in 2028 as part of its "Balanced Portfolio."

i. TEP is planning to build new gas in its Balanced Resource Portfolio despite its modeling results showing similar sensitivity to changes in costs and prices in its Solar + Storage Portfolio.

As part of TEP's preferred portfolio in the 2023 IRP, which TEP calls the "Balanced Resource Portfolio" (P02), TEP is planning to build 400 MW of new peaking gas resources by 2028 to replace Springerville Unit 1 when it retires in 2027.[35] TEP plans to obtain this new gas capacity from eight fast-ramping aeroderivative combustion turbines ("CTs").[36]

As part of the 2023 IRP, TEP also evaluated an equivalent portfolio, called the Solar + Storage Portfolio (P01), which would rely on an additional 850 MW of 4-hour storage and 200 MW solar to replace Springerville in place of the 400 MW of CTs that TEP added in the "Balanced Portfolio."[37] The BESS and solar in this portfolio provided a similar level of reliability as the

[35] TEP 2023 IRP at 46.
[36] *Id.*
[37] *Id.* at 47.

CTs in the Balanced Portfolio.[38] The Solar + Storage Portfolio (P01) did have a higher net present value revenue requirement ("NPVRR") than the Balanced Resource Portfolio, although the cost difference was less than 2 percent of the total portfolio NPVRR.[39] Additionally, the sensitivity of each portfolio to changes in electricity prices, gas prices, and capital costs was similar across portfolios. Despite the relatively non-definitive results when comparing the Solar + Storage Portfolio to the portfolio including the CTs, TEP has selected the CTs as part of its preferred future resource plan.

ii. TEP committed to building no additional new gas as part of its 2020 IRP.

TEP's plan to bring online new gas in the next five years is concerning because as part of its prior 2020 IRP, the Company had stated that the gas resources it was planning for the early 2020s were the last such resources the Company would bring online. At the time TEP filed its 2020 IRP, the Company had just brought online 182 MW of gas peaking resources (reciprocating internal combustion engine or RICE units)[40] at the Sundt Generating Station and 550 MW of combined cycle resources at Gila River Power Station.[41] Specifically, in its 2020 IRP TEP said the following:

> "As we retire older fossil-fuel generation resources, ***all of the new replacement resources will be a combination of renewable resources, energy storage and energy efficiency.*** TEP's Preferred Portfolio calls for 70 percent of our energy coming from renewable resources, 1,400 MW of new energy storage, and 2.5 times more energy efficiency than originally planned by 2035. In addition to the carbon emission reductions, the plan will result in the elimination of surface water use for power generation and a 70 percent decrease in groundwater consumption."[42] (emphasis added).

> "The foundation for this transition was laid over the past two years through TEP's strategic acquisition of Gila River Units 2, a highly efficient 550 MW NGCC plant, and the construction of ten efficient and flexible RICE generators at the Sundt Generating station. These two resource additions set the stage within this 2020 IRP to allow for the eventual elimination of coal while replacing all future capacity with clean resources. Even with the future planned retirement of 1,073 MW of coal capacity and 225 MW of natural gas capacity, ***TEP's Preferred Portfolio does not include the addition of any new fossil-fuel resources***."[43] (emphasis added).

---

[38] *Id.* at 46.
[39] *See id.* at 49, 52.
[40] Tucson Elec. Power, 2020 Integrated Resource Plan at 24, Docket No. E-00000V-19-0034 (June 26, 2020), *available at* https://edocket.azcc.gov/search/document-search/item-detail/272637.
[41] *Id.* at 59, 91.
[42] *Id.* at 18.
[43] *Id*. at 171.

TEPs decision to reverse course and build new gas capacity erodes trust. The statements that TEP made as part of its last IRP indicated a commitment by the Company to building only clean energy resources once the RICE units and Gila River acquisition was approved. This leads us to question the sincerity of TEP's statements when it is seeking support from the Commission and stakeholders for new resource acquisitions.

Recommendation: TEP should adhere to its prior commitment to only build clean energy resources moving forward.

b) There are many risks to relying on gas resources that TEP has not fully considered and that are not reflected in the IRP analysis.

i. TEP failed to adequately evaluate the impacts of gas price volatility and the potential impacts on ratepayers.

High reliance on gas resources, especially at baseload generating resources such as Gila River gas plant, can expose ratepayers to fuel price volatility for which ratepayers cannot plan. Gas is a global commodity, which means that both domestic and global market forces can impact the price and demand for the resource. After roughly doubling from 2019 to 2022, North American liquid natural gas export capacity is projected to double again by 2027, from current levels to more than 24 billion cubic feet per day.[44] To put this in perspective, the United States' total gas consumption in 2022 averaged roughly 88 billion cubic feet per day.[45] The global market consumption effect on prices in the United States will continue to increase significantly over even just the next few years.

When the market is constrained and gas prices spike, those costs are passed on directly to ratepayers. For example, DTE Electric Company in Michigan noted in a 2023 fuel reconciliation docket filing that 2022 gas spending was 74 percent higher than planned.[46] These higher-than-expected prices resulted in large part from the war in Ukraine. As a result, DTE requested to recover an additional $154 million for 2022 fuel costs alone.[47] Absent action from the Michigan Commission, DTE and its shareholders would not be impacted by these gas price spikes—these

[44] Victoria Zaretskaya and Max Ober, U.S. Energy Info. Admin. (EIA), *LNG export capacity from North America is likely to more than double through 2027* (Nov. 13, 2023), *available at* https://www.eia.gov/todayinenergy/detail.php?id=60944.
[45] U.S. EIA, *Natural Gas Consumption by End Use* (Oct. 2023), *available at* https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm.
[46] Exhibit A-7, Docket No. E-21051 (Mich. Pub. Serv. Comm'n Mar. 31, 2023), *available at* https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000007N4mzAAC.
[47] *Id.*

costs are entirely passed on to ratepayers. The same phenomenon could happen just as easily in Arizona or elsewhere in the southwest.

While TEP modeled high capital costs and high gas and market price sensitivities,[48] TEP did not explicitly consider the cost of gas price volatility in its November 1, 2023 IRP modeling. However, the Company did conduct supplemental fuel, market and demand risks analysis as part of an IRP supplement filed on December 19, 2023.[49] It is also not clear if TEP has a firm source of gas for the CTs, and if that assumption was modeled as part of the IRP.

ii. Hydrogen-capable CTs are just gas CTs without an economic supply of green hydrogen.

TEP's IRP asserts that gas-burning technologies at fossil-fueled generating plants are capable of using hydrogen as a carbon-free fuel source in the future.[50] While renewable hydrogen combustion could theoretically offer a lower-emissions alternative to burning gas, the reality is that operation of CTs on 100 percent hydrogen is not currently commercially viable. Production and delivery of renewable hydrogen at economic prices is also not currently commercially viable. So while hydrogen-capable CTs could theoretically burn hydrogen at some point in the future, they have no realistic prospect of doing so in the short term. Without commercially viable hydrogen, a hydrogen-capable CT is just a fossil gas CT.

It is reasonable for TEP to make long-term plans around potential carbon-free technologies. In the near term, however, CTs do, and will continue to, rely on fossil gas for operation. Gas is subject to volatility in price and firm availability, as well as regulation under a variety of provisions, including proposed federal regulation of greenhouse gas emissions under Clean Air Act Section 111, as discussed below. For near term firm, carbon-free resources, TEP should focus on zero carbon technologies that are commercially available today, including stand-alone BESS, paired BESS and solar, and peak-focused demand-side management solutions. Relying on the hope that hydrogen-compatible CT units will eventually burn hydrogen risks making those CTs stranded assets if the technology does not develop in time.

---

[48] TEP 2023 IRP at 44.

[49] TEP 2023 IRP Supplemental Information, Docket No. E-99999V-22-0046 (Dec. 19, 2023), *available at* https://edocket.azcc.gov/search/document-search/item-detail/324649 [hereinafter "Dec. 19, 2023 supplemental filing to TEP 2023 IRP"].

[50] TEP 2023 IRP at 57, 63.

iii. Existing, proposed, and new environmental regulations could make reliance on existing fossil resources more expensive or otherwise limited.

Congress and federal regulators are considering a variety of environmental rules and regulations which could increase the cost to operate TEP's new and existing fossil-fueled power plants. These include EPA's review of Arizona's proposed State Implementation Plan under the Clean Air Act to implement Round II of the Regional Haze Rule, EPA's proposed decision for the reconsideration of the national ambient air quality standards for particulate matter ("PM") issued on January, 2023,[51] and the proposed supplemental update to the Good Neighbor Rule that the EPA announced on January 16, 2024, which would expand the rule to cover Arizona and New Mexico.[52] The Good Neighbor Rule could limit NO_x emissions from new gas plants, and therefore require installation of more costly emissions controls technologies in new plants that are built. Additionally, on May 23, 2023, the EPA announced a proposed set of rules to limit greenhouse gas emissions from new and existing power plants under Section 111 of the Clean Air Act.[53]

In the IRP, however, TEP does little to capture the potential impacts of future carbon regulation and instead only models its carbon reduction commitments as a constraint in the model.[54] TEP has committed to an 80 percent reduction in carbon emissions by 2035 and has committed to net zero carbon emissions by 2050.[55] However, TEP does not model a carbon price, and therefore makes no efforts to understand how a carbon price would impact its resource decisions.[56] EPA's current estimate of the social cost of carbon is $51 per ton.[57] However, in December 2023 EPA finalized regulations which included a new social cost of carbon estimate of $190 per ton.[58]

---

[51] Reconsideration of the National Ambient Air Quality Standards for Particulate Matter, 88 Fed. Reg. 5,558 (Jan. 27, 2023) (to be codified at 40 C.F.R. pt. 50, 53, 58).
[52] Good Neighbor Plan for 2015 Ozone NAAQS.
[53] New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule, 88 Fed. Reg. 33,240 (May 23, 2023) (to be codified at 40 C.F.R. 60).
[54] TEP 2023 IRP at 31.
[55] *Id.* at 15.
[56] *Id.* at 17; *id*. at Appendix H.
[57] *See* EPA, *EPA Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances* at 101 (Nov. 2023), *available at* https://www.epa.gov/system/files/documents/2023-12/epa_scghg_2023_report_final.pdf; *see also* EPA, EPA's 'Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances' (Dec. 2, 2023), *available at* https://www.epa.gov/environmental-economics/scghg; Coral Davenport, Biden Administration Unleashes Powerful Regulatory Tool Aimed at Climate, *The New York Times* (Dec. 2, 2023), *available at* https://www.nytimes.com/2023/12/02/climate/biden-social-cost-carbon-climate-change.html.
[58] *Id.*

Given these higher costs, greenhouse gas regulation could be significantly more impactful than anticipated in TEP's IRP.

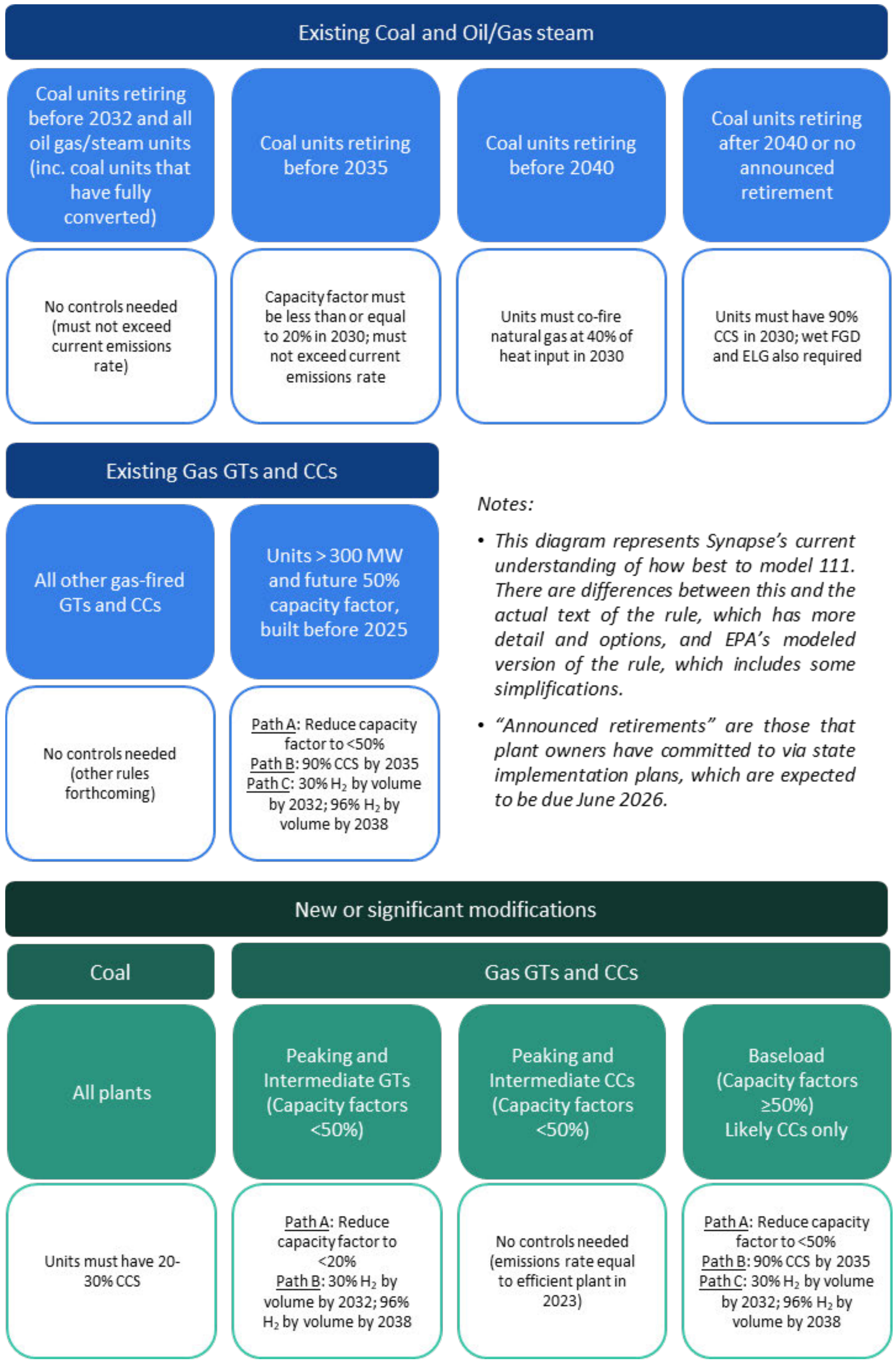
Unfortunately, modeling TEP's carbon reduction commitment does not serve as an accurate proxy for increased carbon regulations, such as those proposed under Section 111 of the Clean Air Act. If enacted as proposed, the Section 111 regulations would limit TEP's operations at its existing and new gas plants in the following ways:[59]

- Both new and existing CC plants would have to cap operations at a 50 percent capacity factor, or else choose to (1) co-fire on 30 percent hydrogen by 2032 and 96 percent hydrogen by 2038 or (2) install carbon capture and sequestration ("CCS") technology with a 90 percent capture rate by 2035.[60]

- New CTs would be limited to a 20 percent capacity factor, or else they would have to co-fire 30 percent on hydrogen by 2032. Existing CTs would be exempt from regulation.[61]

[59] Figure 1 below provides a more comprehensive summary of the proposed rule.
[60] 88 Fed. Reg. 33,240.
[61] *Id.*

Figure 1: Synapse's understanding of EPA's Proposed Rule under Section 111 of the Clean Air Act



Recommendation: TEP should update its modeling to reflect a complete picture of the risks and costs associated with reliance on a large quantity of gas resources, including the risks of gas price volatility and increased environmental regulations. The Company should first evaluate the impact of these risks on its "Balanced Portfolio." Then, TEP should update its capacity expansion modeling runs to develop a new resource portfolio that is more robust against these risks.

This will give TEP and stakeholders an idea of both (1) the cost to ratepayers of not planning for price volatility, and then incurring costs when volatility and increased regulatory pressures occur; (2) the optimal current and future resource mix, assuming the Company plans around the risks of price volatility and future regulations impacting gas generation.

5. TEP should focus on continued and increased deployment of clean energy resources.

a) TEP is investing in renewables and should ramp up its near term investment.

TEP has invested in 490 MW of new wind and solar plus storage projects over the last few years (2021–2022).[62] TEP's current IRP indicates that the Company plans to invest in a substantial quantity of renewables and clean energy resources over the next decade. However, in its IRP modeling, TEP limited clean replacement resources to 400 to 600 MW per year.[63]

In TEP's "Balanced Portfolio," the Company plans to add 1,330 MW of new BESS, 1,740 MW of solar PV, and 500 MW of wind over the next fifteen years (2024–2038).[64] Of those resources, just over 350 MW of solar, 40 MW of wind, and 280 MW of BESS are planned to come online between now and 2030.[65] In the Solar + Storage portfolio, TEP would add an additional 200 MW of solar PV and 750 MW of BESS in place of the additional gas.[66]

i. TEP should invest in solar paired with BESS as a replacement for Springerville Unit 1.

As discussed above, TEP modeled several different replacement portfolio options for Springerville, including replacement of the plant's capacity with solar and BESS (P01) and replacement with gas (P02). It is concerning that TEP is planning to build 400 MW of new peaking gas resources by 2028 to replace Springerville Unit 1 when it retires in 2027.[67] While it is reasonable that TEP will need to replace Springerville with firm capacity resources, battery storage can provide firm capacity, whether as a stand-alone storage project or paired with solar

[62] TEP 2023 IRP at 5.
[63] *Id.* at 32.
[64] *Id*. at 52.
[65] *Id.* at 53.
[66] *Id.* at 52.
[67] *See id.* at 46.

PV. We recognize that TEP did test a portfolio that relied on Solar PV and BESS which provided the same level of reliability as the "Balanced Portfolio."[68] But because it was slightly more expensive, TEP did not put forward that portfolio as its preferred plan. Rather than focusing on procuring new gas, in the near term TEP should focus on testing the market for replacement resources for Springerville through ASRFPs. The Company should only procure new gas if it cannot economically procure sufficient solar PV and BESS.

ii. TEP should increase wind procurement and model access to high quality New Mexico wind.

TEP modeled two different wind resources: Four Corners wind and East New Mexico wind.[69] TEP limited wind additions to 500 MW total in all but one portfolio, assuming that any wind beyond that will require transmission investment that will increase the price substantially.[70] In the one wind-heavy portfolio that the Company did model, TEP allowed the model to add 750 MW of wind, and assumed a lower capital cost and a transmission wheeling cost to access high-value wind in eastern New Mexico.[71]

While TEP's portfolio does include New Mexico wind, the quantity of wind proposed is relatively modest. We commend TEP for including some wind in its replacement portfolio. However, TEP should be more aggressive in its procurement of wind over the long term.

Both TEP's and APS's IRPs state that there is a need to expand the transmission network in order to access the high quality, high-capacity-factor wind resources available in neighboring states, particularly New Mexico.[72] APS also discussed how access to high-capacity-factor wind resources, particularly those that provide overnight generation, can greatly improve portfolio economics.[73] To access economic wind resources, TEP and other regional entities will need to plan a build out of the transmission system. TEP's IRP does not explain what specific transmission options the Company is considering.

---

[68] TEP 2023 IRP at 46.
[69] *Id.* at 16.
[70] *Id.* at 49.
[71] *Id. at* 46.
[72] *Id. at* 46; APS 2023 IRP at 7.
[73] APS 2023 IRP at 7.

iii. TEP should have evaluated Long-duration Energy Storage.

TEP's IRP discusses LDES technology, specifically iron air batteries such as those made by Form Energy, which are currently being piloted in multiple states.[74] LDES includes battery storage with durations of 50-100 hours.

However, TEP does not model LDES in the IRP. This is concerning because further out in the planning period, at least beyond 2030, it is likely that long-duration storage will become widely commercially available. There are currently a number of 100-hour BESS pilot projects being pursued around the country. Specifically, Form Energy has 100-hour BESS projects either proposed or already underway (many with regulated utilities) in the states of Georgia,[75] Virginia,[76] New York,[77] Colorado,[78] Minnesota (where there are actually two pilot projects),[79] Washington,[80] and California.[81] Some of these pilots are already demonstrating several critical advancements that were identified as necessary by a U.S. Department of Energy report in order for LDES to become commercially available as soon as the early 2030s.[82] Half a dozen utilities and resource authorities have found the technology to be advanced and commercially developed enough to deploy pilots as part of their grid.

---

[74] TEP 2023 IRP, Appendix K: Future Resource Technologies, at 15–16.

[75] Jason Plautz, Form Energy announces partnership with Georgia Power to test 100-hour iron-air battery, *Utility Dive* (Feb. 10, 2022), *available at* https://www.utilitydive.com/news/form-energy-announces-partnership-with-georgia-power-to-test-100-hour-iron-/618626/.

[76] Charlie Paullin, Dominion proposes pilot to test longer-lasting battery storage, *Virginia Mercury*, (Sept. 26, 2023), *available at* https://www.virginiamercury.com/2023/09/26/dominion-proposes-pilot-to-test-longer-lasting-battery-storage/.

[77] New York State Energy Research and Development Authority (NYSERDA), Nearly $15 Million Awarded to Four Demonstration Projects to Advance Long Energy Duration Energy Storage Technology Solutions (Aug. 17, 2023), *available at* https://www.nyserda.ny.gov/About/Newsroom/2023-Announcements/2023-08-17-Governor-Hochul-Announces-Nearly-15-Million-in-Long-Duration-Energy-Storage.

[78] Andy Colthrope, US utility Xcel to put Form Energy's 100-hour iron-air battery at retiring coal power plant sites, *Energy Storage News* (Jan. 27, 2023), *available at* https://www.energy-storage.news/us-utility-xcel-to-put-form-energys-100-hour-iron-air-battery-at-retiring-coal-power-plant-sites/.

[79] *Id.*; Kristi Marohn, Xcel Energy to add iron-air battery system to store electricity in Becker, *MPR News* (Jan. 26, 2023), *available at* https://www.mprnews.org/story/2023/01/26/xcel-energy-to-add-iron-battery-to-store-electricity-in-becker; Frank Jossi, Minnesota utility co-op sees big battery as piece of grid reliability puzzle, *Energy News Network* (Sept. 10, 2021), *available at* https://energynews.us/2021/09/10/minnesota-utility-co-op-sees-big-battery-as-piece-of-grid-reliability-puzzle/.

[80] Kavya Balaraman, Puget Sound Energy, Form Energy explore 10-MW, 100-hour iron-air battery pilot, *Utility Dive* (Jan. 9, 2024), *available at* https://www.utilitydive.com/news/puget-sound-energy-form-energy-long-duration-iron-battery/704026/.

[81] Kavya Balaraman, Form Energy snags $30M grant for California's largest long-duration energy storage project, *Utility Dive* (Dec. 18, 2023), *available at* https://www.utilitydive.com/news/form-energy-30m-grant-california-largest-long-duration-energy-storage/702765/.

[82] U.S. Department of Energy, *Pathways to Commercial Liftoff: Long Duration Energy Storage*. (Mar. 2023), *available at* https://liftoff.energy.gov/long-duration-energy-storage/.

Considering that TEP did model another emerging technology, Small Modular Nuclear Reactors ("SMR"), in its model as a resource option, it is unclear why TEP did not also consider LDES as a long-term resource option. SMRs are arguably less likely to be commercially available than LDES. To be consistent, TEP should have modeled LDES as well.

iv. TEP should consider trends in renewable energy costs.

Renewable capital and power purchase agreement ("PPA") costs spiked in 2020–2021 due to supply chain challenges but have since stabilized and fallen. A July 2023 report published by LevelTen Energy found that solar power purchase agreement prices fell by around 1 percent in aggregate across the US in the second quarter of 2023, following three years of large price increases.[83] The report goes on to state that the aggregate 1 percent decline is actually composed of much larger declines in most parts of the country and was skewed upward by a 14 percent price jump in Texas due to the unstable legislative climate.[84] Thus, for non-Texas regions, in the aggregate, the price decline is substantially larger than 1 percent. Although prices did once again rise in some parts of the country in the second half of 2023, supply chain challenges have eased and it is mainly inflationary pressures that were responsible for this trend.[85] As inflation is tamped down, prices should stabilize and decline again.

TEP should take these trends seriously. As has been seen with the cost trajectories of other clean energy technologies, underlying fundamental drivers are lowering real costs for solar, wind, and battery energy storage. These drivers arise from economies of scale, scope, and improvements in technologies. The trends of lower costs for these resources are re-establishing prominence over the shorter-term disturbance in the cost trends that arose from the aftermath of the pandemic and related supply chain pressures and inflationary increases.

Overall, these trends together indicate that renewable costs have stabilized and are likely to once again begin a trajectory of cost decline. TEP evaluated a series of capital cost sensitivities as part of its modeling. Under a low capital cost assumption, the gap between P01 (Solar and Storage) and P02 (the "Balanced Portfolio") narrowed.[86] Given that that cost difference is relatively small under a reasonable range of assumptions, TEP should not commit to gas. Instead, it should focus on testing the market through ASRPFs to see what resource options are available at the lowest cost: BESS + solar, gas, or a combination of the two.

---

[83] Emma Penrod, Solar PPA prices drop for first time since onset of COVID-19: LevelTen, *Utility Dive* (July 18, 2023), *available at* https://tinyurl.com/bdcy4u98.

[84] *Id.*

[85] LevelTen Energy, Q4 2023 PPA Price Index Executive Summary: North America, *available at* https://go.leveltenenergy.com/l/816793/2024-01-29/38hfl3/816793/1706556743ShckjIIC/2023Q4_NA_ES.pdf.

[86] TEP 2023 IRP at 49.

Additionally, there is reason to believe that recent interconnection reforms are working to ease the backlog in the interconnection queue for renewable projects. In July 2023, the Federal Energy Regulatory Commission ("FERC") issued an order on improvements to generator interconnection procedures and agreements.[87] This order adopts reforms to (1) implement a first-ready, first-served cluster study process; (2) speed up interconnection queue processing; (3) incorporate technological advances into the interconnection process; and (4) establish an effective date and transition process.[88] These reforms are expected to alleviate interconnection backlogs and speed up renewable project approval timelines in the future.

v. TEP did not adequately consider federal tax incentives and financing opportunities.

In addition to market trends discussed above, overall clean energy resources benefit from tax credits available under the IRA. With the passage of the IRA, the Investment Tax Credit ("ITC") and Production Tax Credit ("PTC") are now extended for solar and wind projects, and BESS projects are newly eligible for the ITC.[89] The IRA also increases the ITC and PTC for projects placed into service in the next few years, and entitles any solar, wind, or storage projects to an additional 10 percent tax credit adder if they meet domestic content criteria and another 10 percent adder if they are located in an energy community.[90] Large swaths of Arizona will qualify as energy communities.[91]

While TEP's IRP models the IRA's extended tax credits for solar PV, wind, and BESS projects,[92] TEP did not include the bonus tax credit adders available for energy communities. The Company's failure to consider the energy communities adder is a substantial oversight, given that large areas of Arizona will qualify for this additional tax credit.

Additionally, it's not clear how TEP incorporated the potential to leverage the U.S. Department of Energy's Energy Infrastructure Reinvestment ("EIR") program. Created by the IRA, the EIR program provides up to $250 billion in low-cost financing for upgrading existing energy infrastructure, replacing retired energy infrastructure with clean energy infrastructure, and

[87] FERC, Fact Sheet: Improvements to Generator Interconnection Procedures and Agreements (July 27, 2023), *available at* https://tinyurl.com/nhjhhjpc.
[88] *Id*.
[89] 26 U.S.C. §§ 45, 45Y, 48, 48E.
[90] 26 U.S.C. § 45(b)(9); *id*. § 45(b)(11)(A).
[91] *See* 26 U.S.C. § 45(b)(11)(B) (defining an energy community as any census tract, or adjacent tract, where a coal mine has closed since 1999 or coal-fired power plant has closed since 2009, as brownfield sites, and as areas where fossil fuels account for at least 0.17% of employment or 25% of local tax revenues and where the unemployment rate is above average).
[92] TEP 2023 IRP at 39.

building new facilities that utilize legacy energy infrastructure.[93] TEP discusses the EIR program in relation to Springerville, but it is not clear whether the Company incorporated EIR investment into its IRP.[94]

Given TEP's plans to retire Springerville, TEP will have significant fossil infrastructure retirements that could leverage the EIR for reinvestment and upgrades to clean energy resources. However, the EIR program sunsets by 2026, so TEP should evaluate the potential to use the program for Springerville now, before the plant retires.[95]

vi. Distributed energy resources

Customer-sided resources play a small role in TEP's IRP. TEP currently has 550 MW of customer-sited distributed generation ("DG") and projects that this will grow to just over 700 MW by 2038.[96] Despite the modest quantity of distributed resources reflected in the IRP, TEP asserts that the Company favors both distributed and large-scale resources and talks about co-optimizing DG and large-scale resources. It is not clear how TEP co-optimized these resources or intends to do that as part of future IRP exercises, but this is a critical step.[97]

Recommendations:

TEP should focus on issuing ASRFPs and deploying as much solar PV and BESS as it can in the near term. Only after the Company has exhausted its deployment of economic clean resources should it consider new gas. The benefit of this approach is that TEP may find that it doesn't need gas, or at least needs less than 400 MW of gas, to replace Springerville, and can rely on other, less costly and less risky replacement resources.

TEP should clearly describe all tangible actions it is currently taking to pursue transmission expansion required to access high quality New Mexico wind, what actions are required of TEP and other parties to make this expansion happen, and the timeline, feasibility, and cost of gaining access to this resource.

TEP should have allowed its IRP model to select long-duration BESS as part of its resource portfolio at least starting in the mid 2030s.

---

[93] U.S. Department of Energy, Energy Infrastructure Reinvestment, *available at* https://www.energy.gov/lpo/energy-infrastructure-reinvestment; *see also* U.S. Department of Energy, Energy Infrastructure Reinvestment Financing, *available at* https://www.energy.gov/lpo/energy-infrastructure-reinvestment-financing.
[94] TEP 2023 IRP at 22.
[95] *Id.*
[96] *Id.* at 38.
[97] *Id* at 55.

TEP should carefully monitor trends in costs for renewables and clean energy resources and update its modeling regularly to evaluate the impact of updated cost trends.

TEP should model the energy community tax credit adders available under the IRA, and further analyze potential funding from the EIR.

b) TEP did not adequately consider market participation and integration.

TEP's IRP includes minimal analysis of regional integration, and the Company states it plans to take a phased approach toward participation in the regional western market initiatives.[98] Specifically, TEP does not rely on market energy as a firm resource in its long-term planning, but does allow economic market purchases and sales after each resource-adequate portfolio is determined.[99] This means that while TEP does not allow market resources to impact its resource build plan, it does allow the model to ramp up or down its use of existing resources based on the relative economics of market energy.

TEP models one portfolio (P10) where it assumes market and transmission reform.[100] The Company has also participated in the Western Markets Exploratory Group, a utility group formed to evaluate the two markets available in the west.[101] In the near term, it is good that TEP modeled integration with the market to meet energy needs. In its next IRP, TEP should better evaluate the potential of the market to reduce its capacity needs.

Recommendations: TEP should conduct additional analysis through IRP modeling as well as supplemental studies to understand how market integration will impact its reserve margin and reliability needs, and how market reliance can reduce its capacity needs, and its dispatch costs.

6. TEP's IRP process should be improved to enable earlier and more meaningful stakeholder engagement.

Sierra Club appreciated the opportunity to participate in the Company's IRP process as part of the RPAC. While TEP's sharing of the model and data increased our insights into, and understanding of, the Company's modeling, there are still areas for improvement. Our main recommendations concern the timing of data sharing and the frequency of IRP updates. Specifically:

1. TEP should share data and modeling inputs with stakeholders much earlier in the IRP process. TEP did not provide key data to stakeholders until far too late in the IRP process. TEP did not share the full modeling data and inputs with RPAC members until November 13, 2023, two weeks after the final IRP was filed with

[98] TEP 2023 IRP at 61.
[99] *Id.* at 41.
[100] *Id.* at 52.
[101] *Id.* at 23.

the Commission on November 1, 2023. TEP provided updates in December 2023, and provided supplemental modeling runs on January 24, 2024, only one week before stakeholder comments on the IRP were due. That delayed timeline did not allow for stakeholders to complete a thorough review of TEP's assumptions or its updated modeling. If the Company had provided the full data and inputs earlier, before the final IRP was filed in November, RPAC members would have been able to provide meaningful feedback. Moreover, the Company did not share a full draft of its IRP with RPAC members in advance of the document's filing on November 1, 2023.

2. In the next IRP process, the Commission should direct TEP to provide the Company's modeling inputs and data to RPAC members at least 3 months before the final IRP is filed with the Commission, in order to allow time for meaningful stakeholder input before the IRP is finalized.

3. In the next IRP, TEP should use the LTCE model (that RPAC members have access to) from the beginning of the IRP process, instead of waiting to use the model until the end of the process. In TEP's 2023 IRP, the Company's decision to delay using the LTCE model until the very end of the process impeded meaningful stakeholder participation. Stakeholders were not able to verify the accuracy of the inputs and validate the model results before the final IRP was filed on November 1, 2023.

4. Sierra Club appreciates that TEP provided RPAC members with no-cost licenses to use the Aurora model and access to training. In the next IRP process, the Commission should again direct that TEP again provide RPAC members with no-cost licenses in order to use the same modeling software used by the Company, and that TEP provide RPAC members with modeling inputs and data, as the Commission did for this IRP process in Decision No. 78499.[102]

5. The Commission should order that, in the next IRP process, TEP should again provide RPAC members with training in how to use the modeling software.

6. The Commission should direct TEP to provide access to the modeling software and training on that software 4-6 months before the filing deadline for the next IRP, and well before it provides RPAC members with modeling input data.

[102] Decision No. 78499 at 14:9-14.

Respectfully submitted this 31st day of January, 2024.

Sandy Bahr
Director
Sierra Club Grand Canyon Chapter