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BEFORE THE ARIZONA CORPORATION COMMISSION

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SANDRA KENNEDY
JUSTIN OLSON
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IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	DOCKET NO. E-01933A-19-0028 **NOTICE OF FILING REDACTED SURREBUTTAL TESTIMONY OF SIERRA CLUB**

Pursuant to the Procedural Orders issued by the Arizona Corporation Commission on May 20, 2019 and September 19, 2019, Sierra Club hereby files the Redacted Surrebuttal Testimony of Avi Allison, to be presented at the January 16, 2020 Hearing in this matter. A competitively-sensitive confidential version of this testimony is being provided under seal to the assigned Administrative Law Judge. Confidential and competitively-sensitive confidential versions will be provided to Tucson Electric Power and subsequently made available on the Confidential Section of TEP's Data Room for those who have signed the protective agreement.

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RESPECTFULLY SUBMITTED this 16th day of December, 2019.

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BEFORE THE
ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	**DOCKET NO. E-01933A-19-0028**

Surrebuttal Testimony of Avi Allison

PUBLIC VERSION

On Behalf of Sierra Club

December 16, 2019

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LIST OF EXHIBITS

Exhibit No. AA-S-1	Public Discovery Responses
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1. INTRODUCTION AND SUMMARY

Q Please state your name and occupation.

A My name is Avi Allison and I am a Senior Associate with Synapse Energy Economics, Incorporated (Synapse).

Q Are you the same Avi Allison who filed direct testimony in this case?

A Yes.

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of Sierra Club.

Q What is the purpose of your surrebuttal testimony?

A The purpose of my surrebuttal testimony is to respond to the rebuttal testimony of Tucson Electric Power Company (TEP or the Company) witness Michael Sheehan. Specifically, I respond to Mr. Sheehan's claims regarding the prudence of TEP's decisions to (1) invest in the Gila River Unit 2 natural gas combined cycle (NGCC) facility and (2) construct 10 new reciprocating internal combustion engine (RICE) units at the H. Wilson Sundt Generating Station (Sundt).[1]

[1] The rebuttal testimony of TEP witness David Hutchens also addresses the prudence of the Gila River Unit 2 and RICE investments. However, the testimony of Mr. Hutchens appears to summarize Mr. Sheehan's arguments rather than presenting separate claims. My surrebuttal testimony therefore focuses on Mr. Sheehan's testimony.

Q Please summarize the findings of your surrebuttal testimony.

A Generally, I find that TEP's rebuttal testimony does not adequately address the concerns with TEP's resource planning processes and decisions that I raised in my direct testimony. My specific findings include the following:

1. **TEP has still failed to establish that investing in Gila River Unit 2 was a prudent choice relative to non-fossil fuel alternatives.** TEP has not presented any rigorous resource planning analyses justifying the decisions to enter a tolling agreement for and purchase Gila River Unit 2.

2. **TEP's claim that it needed the capacity of Gila River Unit 2 to meet its load requirements misrepresents the Company's capacity position.** When the Company's existing and planned resources are accounted for, it is clear that Gila River Unit 2 was a larger and earlier investment than justified by any of TEP's analyses.

3. **TEP's 2017 Integrated Resource Plan (IRP) does not adequately support the Company's decision to invest in Gila River Unit 2.** The 2017 IRP made no mention of Gila River Unit 2, did not identify a need for an NGCC unit as large as Gila River Unit 2, did not identify a least-cost resource plan, and was rejected by the Commission in part for focusing too narrowly on natural gas resources.

4. **TEP's claim that state-wide carbon-dioxide reduction requirements justified investing in Gila River Unit 2 is unsupported and illogical**. Investing in renewables and other non-fossil fuel resources would have reduced emissions more than Gila River Unit 2.

5. **Identifying a general role for peaking gas capacity in a future regional grid does not justify the decision to invest in Gila River Unit 2**. In any case, Gila River Unit 2 does not match the Company's stated vision of having natural gas resources serve a peaking capacity role in the future.

6. **Both the Gila River Unit 2 tolling agreement and acquisition decisions were made after the Commission expressed concerns that TEP's resource planning process was overly focused on gas resources**. Yet TEP proceeded with these decisions without rigorously evaluating non-fossil fuel alternatives to investing in Gila River Unit 2.

7. **TEP's decision to acquire Gila River Unit 2 in 2019 was unnecessarily rushed and will likely result in increased costs for ratepayers**. Even if purchasing Gila River Unit 2 were ultimately the right choice, TEP would likely have saved money by waiting to exercise its purchase option until 2021.

8. **TEP has still not established that the RICE units are needed to meet near-term ramping requirements**. TEP's rebuttal testimony does not contain any new analysis to support the alleged need for the RICE units.

9. **TEP has still not established that the RICE project was a reasonable investment relative to non-fossil fuel alternatives.** TEP failed to evaluate whether delaying new investment to take advantage of battery storage cost declines could have reduced system costs.

Q Please summarize your recommendations.

A My recommendations are similar to those from my direct testimony. They include the following:

1. The Commission should not permit TEP to place Gila River Unit 2 into rate base.

2. The Commission should not permit TEP to place its RICE units into rate base.

3. The Commission should not allow recovery of test year capital costs at the Springerville and Four Corners plants until TEP has presented rigorous analyses justifying the continued operation of those plants.[2]

4. The Commission should require TEP to present economic retirement assessments for each of the Springerville and Four Corners units in its 2020 IRP.

2. GILA RIVER UNIT 2 INVESTMENT

Q Please summarize this section.

A In this section, I respond to TEP witness Michael Sheehan's claims regarding the reasonableness of TEP's decisions to first enter a tolling agreement for and then acquire Gila River Unit 2. I show that:

1. TEP has still not established that investing in Gila River Unit 2 was a prudent choice relative to non-fossil fuel alternatives.

2. TEP's claim that it needed the capacity of Gila River Unit 2 to meet its load requirements misrepresents the Company's capacity position.

3. TEP's 2017 IRP does not adequately support TEP's decision to invest in Gila River Unit 2.

4. TEP's claim that Clean Power Plan emission reduction requirements justified investing in Gila River Unit 2 is unsupported.

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[2] I note that TEP's rebuttal testimony did not respond to my testimony indicating that the Springerville and Four Corners units may be uneconomic.

5. An anticipated general role for peaking gas capacity in a future regional grid does not justify the decision to invest in Gila River Unit 2.

6. Both the Gila River Unit 2 tolling agreement and acquisition decisions were made after the Commission expressed concerns that TEP's resource planning process was overly focused on gas resources.

7. TEP's decision to acquire Gila River Unit 2 in 2019 was unnecessarily rushed and will likely result in increased costs for ratepayers.

Based on these findings, I recommend that the Commission not allow TEP to place Gila River Unit 2 into rate base.

i. TEP has still not established that investing in Gila River Unit 2 was a prudent choice relative to non-fossil fuel alternatives

Q What did your direct testimony show regarding the basis for TEP's decisions to invest in Gila River Unit 2?

A My direct testimony showed that the basis for TEP's decision to invest in Gila River Unit 2 was insufficient and far too narrow.[3] I showed that, despite the fact that TEP had access to low-cost alternative resources, the Company never conducted rigorous assessments evaluating the potential for an alternative set of resources to meet its system requirements more cost-effectively than Gila River Unit 2.

[3] Direct Testimony of Avi Allison, pp. 6-11.

Q How did TEP respond to your claim that the Company has not established that its investment in Gila River Unit 2 was prudent?

A Mr. Sheehan's rebuttal testimony argues that I failed to provide sufficiently in-depth analysis to support the "theory" that the acquisition of Gila River Unit 2 was imprudent.[4] Mr. Sheehan specifically argues that my comparisons of the levelized cost of energy (LCOE) of Gila River Unit 2 to non-fossil fuel alternatives do not sufficiently account for overall cost and reliability considerations.[5]

Q How do you respond to Mr. Sheehan's criticism of your use of an LCOE comparison?

A Mr. Sheehan's criticism of my use of LCOE comparisons as insufficiently rigorous is odd in light of his own reliance on much cruder, less comprehensive metrics. For example, on the same page of his testimony in which he critiques my use of LCOE, Mr. Sheehan emphasizes the difference in capital costs between Gila River Unit 2 and a theoretical solar-plus-storage project.[6] This misleading comparison ignores the fact that any solar-plus-storage project would have zero fuel costs, whereas TEP projects that Gila River Unit 2 will incur [redacted] in net present value (NPV) fuel costs from 2020 through 2038.[7] The value of an LCOE comparison is that it allows for a more balanced comparison of relatively high-capital, low-fuel-cost resources with low-capital, high-fuel-cost comparisons. Mr. Sheehan's narrow focus on capital costs misses this tradeoff. My LCOE comparisons show that when both capital and operating costs are taken into account, it is clear that TEP has access to non-fossil fuel energy resources that are more cost-effective than Gila River Unit 2.

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[4] Rebuttal Testimony of Michael E. Sheehan, p. 4.
[5] *Id.*, pp. 9-10.
[6] *Id.*, p. 10.
[7] CONFIDENTIAL Exhibit MES-6.

Q More broadly, what is your response to Mr. Sheehan's attempts to use TEP's comparisons of Gila River to a theoretical solar-plus-storage project to justify the Company's investment in Gila River?

A TEP's superficial comparisons of one type of generic alternative resource to Gila River Unit 2 are not sufficient to establish the prudence of investing in Gila River Unit 2. My direct testimony contains a detailed discussion of the limited analyses described by Mr. Sheehan and explains why those analyses are inadequate to justify investing in Gila River Unit 2.[8] In summary, the analyses that Mr. Sheehan describes (1) inappropriately require that an alternative resource replace the exact services provided by Gila River Unit 2 rather than requiring that such resources meet TEP's system needs, (2) incorrectly assume that all services provided by Gila River Unit 2 would need to be replaced by a single resource type, and (3) do not account for the potential for any non-fossil fuel resources other than solar-plus-storage to provide any of the services offered by Gila River Unit 2.

Q Are there reasons to be cautious when using an LCOE comparison?

A Yes. It is true that an LCOE comparison does not capture all relevant resource characteristics and is not sufficient to determine an optimal resource portfolio. For example, an LCOE comparison may understate the value of resources like solar that provide a large fraction of their energy during high-load, high-priced hours.[9] However, LCOE is a useful, relatively comprehensive screening metric. As my direct testimony makes clear, the purpose of my

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[8] Direct Testimony of Avi Allison, pp. 8-11.

[9] Accounting for the timing of generation may make a solar-plus-storage resource appear even more cost-effective relative to Gila River Unit 2 than a simple LCOE comparison would suggest. TEP's analysis indicates that solar-plus-storage resources provide a greater fraction of their energy during peak hours than Gila River. Attachment "SC 6.2 Energy and Capacity Comparison.xlsx" to TEP Response to Data Request No. SC 6.2, tab "Energy and Capacity." All public discovery responses referenced in this testimony are compiled and attached as Exhibit AA-S-1 ["Ex. AA-S-1"]. This tab shows that the peak capacity provision of a solar-plus-storage resource is 1.7 times greater than its average production ((319 *8.76)/1,638 = 1.7) whereas the peak capacity production of Gila River Unit 2 is 1.3 times greater than its average production ((550 *8.76)/3,373) = 1.3).

LCOE comparison was *not* to attempt to identify a specific resource plan that TEP should have pursued instead of Gila River Unit 2. Instead, I used an LCOE comparison to establish that TEP's failure to rigorously evaluate its decision to invest in Gila River Unit 2 relative to low-cost alternative resources was imprudent.

ii. TEP's claim that it needed the capacity of Gila River Unit 2 to meet its load requirements misrepresents the Company's capacity position

Q What did your direct testimony show regarding TEP's need for Gila River Unit 2 at the time the Company decided to contract for the unit?

A My direct testimony showed that, at the time of TEP's decision to contract for Gila River Unit 2, TEP's own IRP indicated Gila River Unit 2 was not needed in the near term and was oversized relative to a speculative capacity need projected for five years in the future.[10]

Q What does TEP now claim regarding the Company's need for Gila River Unit 2?

A Mr. Sheehan's rebuttal testimony claims that TEP's 2017 IRP indicated that Gila River Unit 2 was needed for capacity purposes.

Q What evidence does TEP provide to support this claim?

A Mr. Sheehan presents two figures comparing TEP's forecasted loads to its forecasted resources.[11] The first figure presents the going-in load and resource balance associated with TEP's 2017 IRP. The second figure is identified as containing a load and resource forecast associated with the Company's 2019 Preliminary IRP. Mr. Sheehan states that these figures

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[10] Direct Testimony of Avi Allison, pp. 14-17.
[11] Rebuttal Testimony of Michael E. Sheehan, p. 7.

show that TEP had a 2022 capacity need of 800 megawatts (MW) and that Gila River Unit 2 was needed to meet this shortfall.[12]

Q Does Mr. Sheehan claim that Gila River was needed prior to 2022?

A No. Mr. Sheehan only focuses on a claimed capacity need starting in 2022, five years after TEP contracted for Gila River Unit 2. Thus, Mr. Sheehan does not appear to contest the point that there was not a near-term need for Gila River Unit 2 at the time TEP entered the tolling agreement.

Q Does the going-in capacity position figure from TEP's 2017 IRP represent TEP's forecasted resource position at the time of its decision to invest in Gila River Unit 2?

A No. That figure represents TEP's forecasted capacity position as of the start of the 2017 IRP process. TEP's decision to invest in Gila River Unit 2 came after TEP had filed its 2017 IRP. As part of its 2017 IRP, TEP developed plans to invest in additional renewable, RICE, and demand-side resources by 2022.[13] As a result, TEP's 2017 IRP concluded that the Company would only need 412 MW of new NGCC capacity over the entire period from 2017 to 2032.[14] It is therefore misleading for TEP to suggest that TEP was forecasting an 800 MW shortfall at the time of its decision to invest in Gila River Unit 2.

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[12] *Id.*, p. 6.
[13] Tucson Electric Power, *2017 Integrated Resource Plan*, p. 52 (Apr. 3 2017), *available at* https://www.tep.com/wp-content/uploads/2016/04/TEP-2017-Integrated-Resource-FINAL-Low-Resolution.pdf ["TEP 2017 IRP"].
[14] *Id.*, pp. 52, 260.

Q Does the load and resource balance figure associated with TEP's 2019 Preliminary IRP accurately portray TEP's current expected resource position?

A No. Surprisingly, that figure also does not appear to account for resources to which TEP has already committed.[15] For example, the figure does not account for the 182 MW of RICE units that TEP is expecting to begin operating by January 2020.[16] The figure also does not appear to fully account for TEP's 2017 IRP renewable resource commitments, which Mr. Sheehan elsewhere claims that TEP is exceeding.[17] For these reasons, this figure also overstates TEP's need for a resource as large as Gila River Unit 2 and understates the degree to which investing in Gila River Unit 2 is causing TEP to have excess capacity on its system. The degree of that excess capacity is demonstrated in part by the 475 MW tolling agreement that TEP entered to sell off the excess capacity provided by Gila River Unit 2.[18]

iii. TEP's 2017 IRP did not support the decision to invest in Gila River Unit 2

Q Did the Company's 2017 IRP evaluate the Gila River Unit 2 project?

A No. TEP's 2017 IRP makes no mention of any plan or decision to invest in Gila River Unit 2.

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[15] Ex. AA-S-1, Attachment "SC 6.1 - Sheehan Rebuttal - Figure 2 - L&R Charts.xlsx" to TEP Response to Data Request No. SC 6.1.
[16] Rebuttal Testimony of Michael E. Sheehan, p. 3.
[17] *Id.*, p. 28.
[18] Tucson Electric Power, *2018 Action Plan Update*, p. 26 (Apr. 30, 2018), *available at* https://www.tep.com/wp-content/uploads/2018/06/TEP-Action-Plan.pdf ["TEP 2018 Action Plan Update"].

Q What does TEP claim regarding the relationship between the Company's 2017 IRP and its decision to invest in Gila River Unit 2?

A Mr. Sheehan's rebuttal testimony claims that TEP's 2017 IRP analysis supported the Company's decision to invest in Gila River Unit 2.[19] Mr. Sheehan points out that the Company's 2017 IRP Reference Case resource plan, which he describes as a "least-cost resource plan," included an NGCC resource built in 2022. He further claims that TEP's 2017 Reference Case plan was found to be lower-cost than other resource portfolios that assumed greater investments in renewables and other alternatives.[20]

Q Are you concerned with TEP's claim that its 2017 IRP supported the decision to invest in Gila River Unit 2?

A Yes. There are at least four problems with Mr. Sheehan's reliance on TEP's 2017 IRP to support the decision to invest in Gila River Unit 2:

1. As discussed previously, and as noted by Mr. Sheehan himself, the 2017 IRP Reference Case did not call for any new NGCC capacity until 2022 and only included 412 MW of new NGCC capacity between 2017 and 2032.[21] Yet TEP decided to contract for 550 MW of Gila River Unit 2 capacity in 2017.

2. Contrary to Mr. Sheehan's statements, TEP did not compare its Reference Case plan to an alternative portfolio that included expanded renewable development. The misleadingly named "expanded renewables portfolio" to which Mr. Sheehan refers was structured to meet the same 30 percent renewable penetration target as the Reference Case. The only difference between the "expanded renewables" case and

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[19] Rebuttal Testimony of Michael E. Sheehan, p. 8.
[20] *Ibid.*
[21] TEP 2017 IRP, p. 52.

the Reference Case was that the two cases used different mixes of solar and wind resources to meet that same overall renewable penetration target.[22]

3. Contrary to Mr. Sheehan's claims, TEP has no basis for describing its 2017 Reference Case as a "least-cost resource plan." This is because TEP's 2017 IRP compared a small number of manually constructed portfolios rather than using optimization modeling to identify a least-cost portfolio. In fact, comments submitted by TEP as part of its 2017 IRP process explicitly state that the Company's Reference Case plan was not designed to be "lowest cost" but rather to achieve a "reasonable cost."[23]

4. The Commission declined to acknowledge TEP's 2017 IRP, in part due to concerns regarding the over-projection of future energy demand and over-reliance on natural gas resources.[24] Both of these flaws may have contributed to an exaggerated assessment of need for new NGCC capacity in TEP's 2017 IRP.

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[22] *Id.*, pp. 279-281.
[23] TEP's Response to Sierra Club Comments, *In the Matter of Resource Planning and Procurement in 2015 and 2016*,Docket No. E-00000V-15-0094, pp. 5-6 (Ariz. Corp. Comm'n) (October 10, 2017). Attached as Exhibit. AA-S-2 ["Ex. AA-S-2"].
[24] Decision No. 76632, *In the Matter of Resource Planning and Procurement in 2015 and 2016*, Docket No. E-00000V-15-0094, (Ariz. Corp. Comm'n) (Mar.29, 2018) [Decision No. 76632].

iv. TEP's claim that the need to reduce carbon-dioxide emissions to comply with the Clean Power Plan justified investing in Gila River Unit 2 is unsupported

Q What does TEP argue regarding the historical context of the decision to invest in Gila River Unit 2?

A TEP argues that the "historical context" of the federal Clean Power Plan (CPP) justified TEP's decision to invest in Gila River Unit 2.[25] Mr. Sheehan claims that Gila River Unit 2 was determined to be part of "the least-cost plan to comply with the CPP."[26]

Q Has TEP provided any evidence or analysis to support the contention that Gila River Unit 2 was part of a "least-cost" CPP compliance plan?

A No.

Q Is it reasonable to use the CPP to justify investing in Gila River Unit 2 without performing robust alternatives analysis?

A No. While the CPP might have favored Gila River Unit 2 relative to existing coal units, it would not have favored Gila River Unit 2 relative to non-fossil fuel alternatives. As shown in Mr. Sheehan's testimony, replacing coal generation with natural gas generation was only one of several potential mechanisms for complying with the CPP.[27] And increased use of renewable generation and demand-side resources would have provided greater emission reductions than investing in Gila River Unit 2. Thus, the existence of the CPP does not justify a failure to evaluate Gila River Unit 2 relative to non-fossil fuel alternatives.

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[25] Rebuttal Testimony of Michael E. Sheehan, p. 4.
[26] *Id.*, p. 5.
[27] *Ibid.*

v. A general role for peaking gas capacity in a future regional grid does not justify the decision to invest in Gila River Unit 2

Q What does TEP argue regarding the role of natural gas resources in the future regional electric grid?

A Mr. Sheehan's rebuttal testimony states that TEP believes that regional dependence on natural gas resources for energy will decline over the long run, but also believes that gas will still be needed for capacity purposes.[28]

Q Is it reasonable to justify specific investments in Gila River Unit 2 based on the Company's general belief around the future role of gas resources?

A No. Even if TEP's assumptions about the ongoing role for gas are accurate, a general role for gas capacity in the future regional grid cannot justify an immediate investment in a particular project under TEP's specific system conditions. Rigorous analysis is required to justify a major investment in a specific resource such as Gila River Unit 2.

Q Are the characteristics of Gila River Unit 2 consistent with the type of future gas capacity role identified by TEP?

A No. The future regional natural gas role described in Mr. Sheehan's rebuttal testimony corresponds to a peaking capacity resource with a low capacity factor. But TEP's economic case for investing in Gila River Unit 2 assumes that the Company will operate Gila River Unit 2 as an energy resource with a capacity factor of approximately 70 percent.[29] If operated at a lower capacity factor, the economics of Gila River Unit 2 would deteriorate, because the same fixed costs would be spread over fewer megawatt-hours of generation.

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[28] *Id.*, p. 22.
[29] Direct Testimony of Michael E. Sheehan, p. 24 n.46.

vi. TEP made both the Gila River tolling agreement and acquisition decisions despite Commission concerns that TEP's resource planning process was overly focused on gas resources

Q What concerns did your direct testimony raise regarding the nature of the analytical process underlying TEP's decision to invest in Gila River Unit 2?

A My direct testimony observed that TEP's analyses and decisions regarding Gila River Unit 2 appeared to not sufficiently account for the Commission's previously expressed concerns that TEP's resource planning process was overly focused on natural gas resources.[30]

Q How did TEP respond to this observation?

A TEP argued that my observation was "misleading" because the Company's decision to acquire Gila River Unit 2 was made prior to the Commission imposing a temporary moratorium on the development of new gas resources.[31]

Q Was the imposition of the natural gas moratorium the first time that the Commission expressed its concern with an excessive focus on natural gas resources in TEP's resource planning processes?

A No. As I show in my direct testimony, Commissioner Tobin filed a comment in 2016 expressing concern that the preliminary IRPs submitted by TEP and other Arizona utilities were heavily weighted toward the selection of gas resources.[32] Commissioner Tobin filed

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[30] Direct Testimony of Avi Allison, pp. 17-18.
[31] Rebuttal Testimony of Michael E. Sheehan, p. 16.
[32] Direct Testimony of Avi Allison, p. 17.

this comment six months before TEP began its due diligence work to acquire Gila River Unit 2.[33]

Q Was the temporary natural gas moratorium imposed prior to TEP filing its application in this docket?

A Yes. The Commission issued its order declining to acknowledge TEP's 2017 IRP and imposing a temporary moratorium in March 2018.[34] The Commission subsequently reinstated and extended the moratorium in February 2019.[35] TEP did not file its application in this docket until April 2019. Yet TEP's application and supporting testimony, which included its only project-specific justifications for its decision to acquire Gila River Unit 2, did not contain any analyses comparing investing in Gila River Unit 2 to developing non-fossil fuel alternatives. TEP developed its limited analysis of non-fossil fuel resources only after receiving a specific request from Commissioner Kennedy, more than two years after beginning its due diligence work on the Gila River Unit 2 acquisition.

Q What is the implication of this chronology?

A The implication is that TEP's repeated failure to rigorously assess Gila River Unit 2 relative to non-fossil fuel alternatives ran counter to previous Commission guidance counseling utilities against overly focusing on natural gas resources.

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[33] Rebuttal Testimony of Michael E. Sheehan, p. 16. Commissioner Tobin filed his comment in December 2016. Mr. Sheehan states that TEP began its due diligence work in May 2017.
[34] Decision No. 76632, pp. 51-52.
[35] Decision No. 77086, *In the Matter of Resource Planning and Procurement in 2015 and 2016*, pp. 2-3, Docket. No. E-00000V-15-0094, (Ariz. Corp. Comm'n) (Feb. 20, 2019).

vii. TEP's decision to acquire Gila River Unit 2 in 2019 was unnecessarily rushed and will likely result in increased costs for ratepayers

Q Did TEP's rebuttal testimony provide an update regarding the status of the Company's plans to acquire Gila River Unit 2?

A Yes. Mr. Sheehan's rebuttal testimony states that TEP executed its option to purchase Gila River Unit 2 on October 14, 2019.[36]

Q Was TEP's decision to purchase Gila River Unit 2 in 2019 driven by a deadline in the Gila River Unit 2 tolling agreement?

A No. As Mr. Sheehan stated in his direct testimony, TEP had until May 1, 2021 to exercise its option to purchase Gila River Unit 2.[37]

Q Are you aware of any direct testimony that questioned the value in TEP exercising its purchase option in 2019?

A Yes. I am aware that the direct testimony of Residential Utility Consumer Office witness Ralph Smith stated that TEP could take additional time to more fully evaluate whether ownership of Gila River Unit 2 is in the best interest of ratepayers. Mr. Smith further argued that "[t]he Commission should not be rushed into a decision on whether to approve TEP's purchase of Gila River Unit 2 by TEP's statements to the effect that TEP wants to purchase that unit by the end of 2019."[38]

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[36] Rebuttal Testimony of Michael E. Sheehan, p. 3.
[37] Direct Testimony of Michael E. Sheehan, p. 25.
[38] Direct Testimony of Ralph C. Smith, p. 24.

Q Do you share Mr. Smith's concerns with TEP's decision to exercise its purchase option in 2019?

A Yes, I do. Even if one were to assume that it will ultimately be in the interest of ratepayers for TEP to purchase Gila River Unit 2, there were two strong reasons for TEP to wait to purchase the unit until 2021. First, delay would have allowed time for a more thorough analysis of the Company's options with respect to Gila River Unit 2. Such analysis could have incorporated updated assumptions (*e.g.,* the cost of capital determined through this rate case) and evaluated additional options, such as exiting Gila River Unit 2 entirely prior to 2038. Second, delaying the purchase option would likely have saved ratepayers money, as I discuss further below.

Q Has the Company presented any analyses justifying its decision to exercise its purchase option in 2019 rather than exercising that option in 2021?

A No. I am not aware of any such analysis, either in the Company's initial case or in its rebuttal testimony. The only analysis that the Company presented in support of its decision to exercise its purchase option compared exercising that option in 2019 to remaining in the Gila River Unit 2 tolling agreement through 2038.

Q What were the results of TEP's evaluation of exercising its purchase option in 2019 relative to remaining in the tolling agreement through 2038?

A TEP claims that its analysis showed an $83 million benefit from exercising its Gila River Unit 2 purchase option.[39] However, this is a misleading estimate, as it was calculated by summing nominal dollars across 19 years. This unconventional approach of presenting aggregate nominal dollars does not account for the effects of inflation and the time value of

[39] Rebuttal Testimony of Michael E. Sheehan, p. 19.

money on the value of a given resource choice. On a more conventional NPV basis, TEP's analysis indicated a [redacted] benefit of exercising the purchase option in 2019 relative to remaining in the tolling agreement through 2038.[40]

Q Have you identified any errors in TEP's calculation of the benefits of exercising its purchase option?

A Yes. TEP's analysis mistakenly assumed that under the continued tolling agreement scenario the Company would face a constant monthly capacity charge of [redacted] in every month from January 2020 through May 2038.[41] In fact, the tolling agreement set the capacity charge at only [redacted] through April 2021.[42]

Q Have you evaluated the effect of correcting this error?

A Yes. Correcting this error reduces the NPV cost of the tolling agreement scenario by [redacted] This reduces the calculated NPV benefit of entering the purchase agreement in 2019 rather than remaining in the tolling agreement through 2038 to [redacted].

Q What is the primary factor behind TEP's analytical finding that purchasing Gila River Unit 2 will save money relative to remaining in the tolling agreement?

A As Mr. Sheehan identifies in his direct testimony, the primary contributor to the savings of the purchase scenario is the increase in the monthly capacity charge that TEP would have to pay starting in May 2021 if it were to remain in the tolling agreement. Mr. Sheehan states that this capacity charge increase explains $78 million of the $83 million in aggregate

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[40] CONFIDENTIAL Exhibit MES-6.
[41] *Ibid.* [redacted]
[42] COMPETITIVELY SENSITIVE CONFIDENTIAL Attachment "RUCO 2.05 - Competitively-Sensitive Confidential" to TEP Response to Data Request No. 2.05, Schedule 1. Attached as Exhibit AA-S-3 [Ex. AA-S-3].

nominal savings of the purchase scenario.[43] However, this understates the impact of the capacity charge increase on TEP's case for exercising its purchase option.[44] In fact, the effect of the capacity charge increase on the cost of the tolling agreement scenario is greater than TEP's estimate of the net benefit of the purchase decision. Modifying TEP's analysis to reflect the counterfactual assumption that the lower capacity charge remains in place through 2038 flips TEP's estimated [redacted] NPV benefit into a [redacted] of entering the purchase agreement in 2019 relative to remaining in the tolling agreement through 2038. Table 1 compares the result of TEP's analysis as it was filed to the results of that same analysis with (1) a correction to TEP's analytical error and (2) the revised, counterfactual assumption that the lower tolling agreement capacity charge would remain constant through 2038.

Table 1. Benefit of 2019 Gila River purchase vs. remaining in tolling agreement

	Net Benefit (NPV $Million)
As Filed	[redacted]
Corrected	
Constant Low Capacity Charge	

Sources: CONFIDENTIAL Exhibit MES-6; Ex. AA-S-3, COMPETITIVELY SENSITIVE CONFIDENTIAL Attachment "RUCO 2.05 - Competitively-Sensitive Confidential" to TEP Response to Data Request No. 2.05.

Q What is the implication of this analytical result?

A This result shows that the 2021 increase in the tolling agreement's capacity charge is *entirely responsible* for TEP's finding that exercising its purchase option will save money relative to remaining in the tolling agreement. This suggests that the tolling agreement would have

[43] Direct Testimony of Michael E. Sheehan, p. 26. Again, note that the use of nominal dollars is unconventional and better expressed in terms of NPV.

[44] The underestimate appears to result from a combination of analytical errors and Mr. Sheehan's use of nominal rather than NPV estimates.

remained a less costly alternative than unit ownership as long as the lower capacity charge remained in place. Thus, purchasing Gila River Unit 2 likely only made sense, at the earliest, in May 2021, when the tolling agreement capacity charge was designed to increase by [redacted][45]

Q Are there additional reasons to believe that delaying a Gila River Unit 2 purchase decision would have resulted in lower costs?

A Yes. TEP's initial analysis—which, due to the erroneous capacity charge assumption, over-stated the near-term costs associated with a tolling agreement scenario—still showed that remaining in the tolling agreement rather than exercising the purchase option would have resulted in [redacted] in 2020 and 2021.[46] Remaining in the tolling agreement through May 2021 would have enabled TEP to take advantage of those [redacted] and delay the large up-front investment associated with unit purchase while still preserving the Company's ability to exercise its purchase option.

Q What are your conclusions with respect to the prudence of TEP's decisions to first enter a tolling agreement for and then purchase Gila River Unit 2?

A I conclude that TEP has failed to demonstrate the prudence of its initial decision to contract for the oversized Gila River Unit 2 rather than pursuing alternative options to meet a speculative future capacity need. I further conclude that TEP's decision to exercise its option to purchase Gila River Unit 2 in 2019 was imprudent and will likely result in increased costs to customers, even if owning Gila River were ultimately a reasonable decision. I therefore recommend that the Commission not allow TEP to place Gila River Unit 2 into rate base.

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[45] Ex. AA-S-3, COMPETITIVELY SENSITIVE CONFIDENTIAL Attachment "RUCO 2.05 - Competitively-Sensitive Confidential" to TEP Response to Data Request No. 2.05, Schedule 1. [redacted]

[46] CONFIDENTIAL Exhibit MES-6.

3. SUNDT RICE PROJECT

Q Please summarize this section.

A In this section, I respond to TEP witness Michael Sheehan's claims regarding the reasonableness of TEP's decisions to invest in 182 MW of RICE units. I show that TEP has not established a ramping capacity need for the RICE project and did not sufficiently evaluate non-fossil fuel alternatives to the RICE units. I therefore recommend that the Commission not allow TEP to place the RICE units into rate base.

i. TEP has still not established that the RICE units are needed to meet near-term ramping requirements

Q What did your direct testimony demonstrate regarding TEP's alleged need for 182 MW of RICE units?

A My direct testimony showed that TEP had not demonstrated any near-term ramping capacity need and had certainly not shown a need for 182 MW of RICE units to provide incremental ramping capacity.[47]

Q What does TEP's rebuttal testimony claim regarding the Company's evolving ramping capacity requirements?

A Mr. Sheehan's rebuttal testimony asserts that TEP's planned accelerated buildout of renewable resources will result in greater near-term ramping capacity needs than were identified in its previous analyses of its RICE project.[48]

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[47] Direct Testimony of Avi Allison, pp. 34-37.
[48] Rebuttal Testimony of Michael E. Sheehan, p. 28.

Q Did TEP provide any analysis or evidence to support the claim that the RICE units are needed to serve near-term ramping capacity needs?

A No. In discovery, TEP stated that it is currently working on a resource adequacy analysis as part of its 2020 IRP process. But the Company was unable to identify any analyses it has conducted that demonstrate a near-term need for ramping capacity.[49] The one ramping need analysis that TEP has presented in support of its RICE unit investment decision remains an analysis that indicates that even without any of the RICE units TEP may still have sufficient ramping capacity available to meet its needs through 2024.[50]

Q Mr. Sheehan argues that any ramping requirement analysis should account for the fact that ramping requirements are often highest during times of year when multiple TEP generation units are out of service for planned maintenance.[51] How do you respond?

A I believe this argument relies on an overly simplistic view of utility resource management. Historically, power plant owners have scheduled maintenance outages for the spring because that is when the value of having those plants online is lowest. But TEP should never reach the point where it observes ramping capacity shortages resulting from overlapping planned outages, because it can plan outages to avoid any such overlap (and avoiding capacity shortfalls is a clear value indicator in favor of keeping more units available during those times). It is not reasonable for TEP to base an alleged need for new capacity on a ramping shortage resulting from the Company's decision to schedule overlapping planned outages during times of high ramping need.

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[49] Ex. AA-S-1, TEP Response to Data Request No. SC 6.9(b).
[50] Appendix A to TEP 2018 Action Plan Update, H. Wilson Sundt Generating Station Reciprocating Engine Use Case: Final Report, p. 14 (Dec. 2017) ["RICE Use Case Final Report"].
[51] Rebuttal Testimony of Michael E. Sheehan, p. 26.

Q TEP suggests that such inconveniently overlapping planned outages may be outside of its control because most of the Company's units are jointly owned.[52] How do you respond?

A This argument is not persuasive. Most of TEP's jointly owned thermal units are either slated for retirement within the next two years, do not provide substantial ramping capacity, or both.[53] TEP is a minority owner of only one unit that it relies on for substantial ramping capacity, the Luna plant.[54] And even where TEP does not have direct control over the timing of maintenance outages, it is possible that the other joint owners may experience the same seasonal capacity limitations as TEP. Regardless, TEP should be able to offer input and coordinate to avoid creating unnecessary constraints.

ii. TEP has still not established that the RICE project was a reasonable investment relative to non-fossil fuel alternatives

Q What does TEP's rebuttal testimony claim regarding the Company's evaluation of non-fossil fuel alternatives to the RICE units?

A Mr. Sheehan's rebuttal testimony repeats TEP's claim that the Company's 2017 analyses indicated that battery storage resources would not become cost-competitive with RICE units for five to seven years.[55]

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[52] Ex. AA-S-1,TEP Response to Data Request No. SC 6.8.
[53] Direct Testimony of Michael E. Sheehan, pp. 3, 7.
[54] Direct Testimony of Michael E. Sheehan, p. 3; RICE Use Case Final Report, p. 14.
[55] Rebuttal Testimony of Michael E. Sheehan, p. 29.

Q Has TEP established a need for ramping capacity within five to seven years of the 2017 analysis?

A No. As discussed above, the ramping requirement analysis conducted by TEP indicated that there was minimal need for new ramping capacity through 2024. This suggests that any ramping capacity need would arise after TEP was projecting that battery storage resources would reach cost parity with RICE units. In addition, TEP's analysis indicated that the Company would likely save money by delaying a decision to invest in the RICE units.[56] Yet TEP chose not to evaluate the possibility of postponing an investment in new capacity and subsequently investing in storage rather than rushing to build the RICE units to meet potential future ramping capacity needs.

Q What are your conclusions with respect to the prudence of TEP's decision to construct and operate 182 MW of RICE units?

A I conclude that TEP has failed to demonstrate a need for the RICE project and has not sufficiently evaluated non-fossil fuel alternatives to the RICE units. I therefore recommend that the Commission not allow TEP to place the RICE units into rate base.

Q Does this conclude your surrebuttal testimony?

A Yes, it does.

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[56] RICE Use Case Final Report, p. 30.

Exhibit AA-S-1

Exhibit AA-S-1

TEP Public Responses to Sierra Club Data Requests

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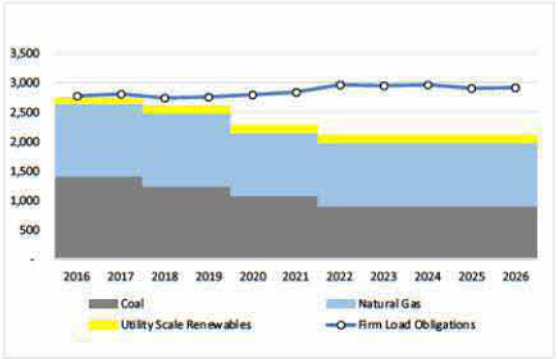
1. Attachment "SC 6.1 - Sheehan Rebuttal - Figure 2 - L&R Charts." to TEP Response to Data SC 6.12

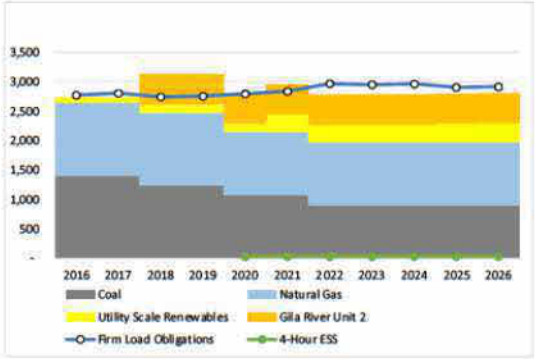
2. Attachment "SC 6.2 Energy and Capacity Comparison" to TEP Response to Data Request No. SC 6.2 ("Energy and Capacity" tab only)

3. TEP Response to Data Request No. SC 6.8

4. TEP Response to Data Request No. SC 6.9(b)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	
Coal	1 411	1 411	1241	1 241	1 073	1073	903	903	903	903	903	903	903	903	903	793	793	
Natural Gas	1 237	1 237	1237	1 237	1 075	1075	1 075	1 075	1075	1 075	1 075	1075	1 075	952	952	848	848	
Utility Scale Renewables	97	97	139	139	139	139	139	139	139	139	139	139	139	139	139	139	139	(Coincident Peak)
Total Firm Load Obligations with Reserves	2 776	2 809	2746	2 761	2 799	2843	2 970	2 954	2968	2 908	2 920	2932	2 930	2 943	2962	2 982	3 002	
Shortfall	31	64	129	144	512	556	853	837	851	791	803	815	813	949	968	1 202	1 222	
Incremental Adds																		
Natural Gas			515	515	515	515	515	515	515	515	515							(Coincident Peak)
Utility Scale Renewables	97	97	139	139	139	295	294	293	292	308	317							
4-Hour ESS					30	30	30	30	30	30	30							





Firm Load Obligations	2,661	2,642	2,735	2,753	2,712	2,720	2,668	2,684	2,692	2,628	2,643
	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!
	2,745	2,745	2,617	2,617	2,287	2,287	2,117	2,117	2,117	2,117	2,117
			20	187	237	233	233	234	234	238	238
	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!
Firm Load Obligations	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!
	#REF!	#REF!	#REF!	#REF!	(586)	(640)	(839)	(926)	(954)	(903)	(886)
					2,498	2,545	2,570	2,646	2,671	2,626	2,611
	#REF!	#REF!	#REF!	#REF!	2,873	2,927	2,956	3,043	3,071	3,020	3,003
	84				#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!

	550 MW Solar SAT + 165 MW ESS
Solar SAT Resource Capacity, MW	550
ESS Resource Capacity, MW	165
Summer Peak Coincident Capacity, MW	319

Annual Capacity Factor, %	34%
Annual Energy, GWh	1638

	Gila River Unit 2
Resource Capacity, MW	550
Summer Peak Coincident Capacity, MW	515

Annual Capacity Factor, %	70%
Annual Energy, GWh	3373

Gila River Unit 2 Capacity Value vs. Solar + ESS	161%
Gila River Unit 2 Energy Value vs. Solar + ESS	206%

SC 6.8

Please refer to Rebuttal Testimony of Michael Sheehan, page 26, lines 12-15. Does TEP expect to continue scheduling overlapping maintenance outages for spring and fall hours even if those scheduling practices result in an identified need for additional capacity? If so, explain why.

RESPONSE:

Yes. Due to lower load levels and lower wholesale power prices for replacement power, both the Spring and Fall seasons are heavily concentrated with multiple planned unit outages. While the Company has the ability to better manage scheduled outages at the plants it directly operates, a majority of TEP's generation assets are either jointly owned facilities or managed by other plant operators. Under these jointly owned and operated facilities, planned outages are not directly controlled by TEP. In addition, given the Company's high-level of renewable generation that is planned to be in-service by the end of 2020, the Company will need to evaluate its future need to seasonally cycle its baseload resources to avoid significant amounts of overgeneration on its system.

RESPONDENT:

Michael E. Sheehan

WITNESS:

Michael E. Sheehan

SC 6.9

Please refer to Rebuttal Testimony of Michael Sheehan, page 28, lines 11-20.

a. Is it the Company's contention that it is necessary to have the RICE units online in order to bring the 250 MW New Mexico project online? If so, produce any analyses, reports or documentation in the Company's possession supporting that contention.
b. Has the Company conducted any analysis of the ramping capacity needs associated with its currently planned 2021 renewable penetration level? If so, provide that analysis, including all supporting workpapers, in native format with all formulas intact.

RESPONSE:

a. Yes. As noted in TEP's 2017 IRP Reference Case,[6] the Company's goal of adding approximately 800 MW of new renewable resource capacity by 2030 put TEP on a path to serve 30% of its retail load by 2030. The RICE Use Case[7] details how the Company's RICE project was a cost-effective resource to support this long-term goal. However, in the interim between the 2017 IRP filing and the update to the Company's 2018 Action Plan,[8] the Company accelerated its plans to bring in nearly 450 MW of new low-cost wind and solar resources. This change to the Company's resource plans is enabling TEP to reach its longer-term renewable energy goal nearly nine years ahead of its original 2017 plan.
b. As part of TEP's 2020 IRP, the Company is working with Siemens[9] to perform an assessment on the future resource adequacy on TEP's system. This analysis will be a central part of the Company's 2020 IRP that is to be filed in April 2020.

RESPONDENT:

Michael E. Sheehan

WITNESS:

Michael E. Sheehan

[6] https://www.tep.com/wp-content/uploads/2017/04/TEP-2017-Integrated-Resource.pdf Page 262.
[7] https://www.tep.com/wp-content/uploads/2018/06/TEP-Action-Plan.pdf. Appendix A.
[8] https://www.tep.com/wp-content/uploads/2018/06/TEP-Action-Plan.pdf Page 27.
[9] https://new.siemens.com/us/en/products/energy html

Exhibit AA-S-2

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BEFORE THE ARIZONA CORPORATION COMMISSION

Arizona Corporation Commission
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COMMISSIONERS
TOM FORESE, CHAIRMAN
BOB BURNS
DOUG LITTLE
ANDY TOBIN
BOYD W. DUNN

IN THE MATTER OF RESOURCE PLANNING AND PROCUREMENT IN 2015 AND 2016.

DOCKET NO. E-00000V-15-0094

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO SIERRA CLUB COMMENTS

Tucson Electric Power Company ("TEP" or "Company"), through undersigned counsel, hereby submits the following response to the September 25, 2017 comments filed by Sierra Club ("Sierra Club comments") related to its evaluation of the TEP 2017 Integrated Resource Plan ("TEP 2017 IRP").

Overview

Integrated Resource Planning is a continuous process of long-term planning organized into two to three-year cycles. These cycles provide for interaction between the Company and interested stakeholders through preliminary deliverables and workshops culminating in the development and submittal of a final report to be acknowledged by the Arizona Corporation Commission ("ACC" or "Commission"). Stakeholder comments on the final report can be addressed in final comments prepared by the Company, but more importantly will guide the process followed in subsequent planning cycles.

As a long-term plan, the results of the IRP are highly sensitive to the assumptions upon which the plan relies. While all assumptions are subject to a degree of uncertainty, that uncertainty increases exponentially the further into the future that the assumption is realized. The

Company employs various strategies to place boundaries on key uncertainties and to understand the risks they present; however, uncertainty remains.

Many of Sierra Club's comments on the TEP 2017 IRP stem from Sierra Club's failure to recognize both the continuous nature of the planning process and the relatively higher uncertainty in the latter part of the 15-year plan. Sierra Club advocates for commitments to certain technologies long before the information necessary to make those decisions can be reliably known. In addition, Sierra Club's comments imply a high degree of certainty with regard to the nature and rate of future changes.

TEP affords a much higher degree of respect to the uncertainty inherent in long-term planning. One only needs to look at the last ten years to see how drastically circumstances can change due to forces largely beyond our control. Therefore, the Reference Case Plan presented in the IRP targets a diverse portfolio of resources with optionality to respond to unforeseen changes. TEP does not believe putting all its eggs in one basket is a prudent plan.

Structure and Analysis of Portfolios is Robust and Transparent

Sierra Club wrongly states that "There is no explanation in the IRP as to how the portfolios were developed." The challenges and opportunities that are driving resource additions are changing. One of the key challenges we highlight in the IRP is the need to maintain compliance with reliability standards in light of increasing renewable energy generation on the system.[1] This and other opportunities and challenges are described in Chapter 3 – Operational Requirements and Reliability. With these important system needs in mind, the rationale for future additions is described in detail in Chapter 10 – Future Resource Requirements. For example, in Chapter 10, TEP explains that the rationale behind the addition of battery energy storage systems in 2019 and 2021 is to "facilitate the integration of more renewable energy into TEP's resource mix."[2] The

[1] TEP 2017 IRP, Pages 59-60.

[2] TEP 2017 IRP, Page 237.

same is true for the addition of Reciprocating Internal Combustion Engines (RICEs)[3] but these also provide important reliability and peak capacity services needed to compensate for the retirement of older steam generators.[4]

In addition to planning for operational needs and regulatory requirements, the IRP should also be a vehicle for communicating the Company's long-term strategy and goals, and Sierra Club acknowledged as much.[5] One of TEP's key long-term objectives is to diversify its resource portfolio by increasing the capacity of renewable energy and natural gas-fired resources on the system, while simultaneously reducing its reliance on coal-fired generation (see Coal Resource Economics below). TEP reflects these key objectives through our target of serving 30% of retail load using renewable energy resources by 2030, and through commitments to retire 35% of its coal fleet over the next five years while maintaining energy security through a balanced fuel diversity goal.[6] TEP's final key objective was to develop a near-term resource portfolio that met compliance under the Clean Power Plan. These strategic initiatives fundamentally shape TEP's resource portfolio leaving only small incremental opportunities for near-term resource choices, some of which directly flow from these key objectives.[7]

Sierra Club incorrectly asserts that the TEP 2017 IRP "fails to meet the criteria of AAC R14-2-703(F),"[8] and then offers the "three key stages in any electric system resource planning

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[3] TEP 2017 IRP, Page 238.

[4] See Supplemental Report - H. Wilson Sundt Generating Station Reciprocating Engine Use Case regarding the support of future reliability requirements in light of the planned expansion of renewable energy resources. The Company can provide this report to IRP stakeholders that have been granted intervention and executed a protective agreement in this docket.

[5] Sierra Club comments, Page 1

[6] See Commissioner Andy Tobin's September 28, 2017, correspondence opening a generic docket related to questions on how do Arizona's energy policies promote reliability, security, and affordability and address shifts in energy markets and identify considerations that should be made to maintain a reliable baseload energy portfolio into the future. A copy is attached as **Attachment 1**.

[7] TEP 2017 IRP, Page 261. High renewable energy penetration is the key driver for the need for additional grid balancing resources. Moreover, the need for the near-term addition of NGCC generation is due to the loss of baseload capacity associated with coal plant retirements.

[8] Sierra Club comments, Page 2.

process."[9] However, the Sierra Club's "three key stages" do not align with the Commission's Integrated Resource Planning rules at R14-2-703.F. For example, Sierra Club's "Stage 2" to "find the least cost portfolio of resources" is nowhere to be found in the Commission's rules. Rather R14-2-703.F.8. requires that the reference case portfolio "will achieve a reasonable long-term total cost."

The TEP 2017 IRP does in fact meet the letter and spirit of R14-2-703.F. The following paragraphs present information detailing the TEP 2017 IRP's compliance with three specific provisions of the IRP rules for which Sierra Club states the TEP 2017 IRP is deficient.

R14-2-703.F.1 requires a reference case portfolio "based upon comprehensive consideration of a wide range of supply- and demand-side options." The TEP 2017 IRP includes 77 pages of supply- and demand-side options.[10] TEP weighed the relative strengths and weaknesses of each of these resource options through a high-level screening process that ultimately determined the resources to be included in the reference case plan. There is no requirement in the rule to consider "hundreds of thousands" of these options through capacity expansion modeling as suggested by Sierra Club,[11] and it is unlikely that such an effort would result in significantly different results.

R14-2-703.F.7 requires a Reference Case Portfolio that will effectively manage uncertainty and risk. The TEP 2017 IRP accounts for risk using both scenario analysis[12] and stochastic modeling. The scenario analysis tests the portfolio against a wide range of possible futures, thus ensuring that the portfolio's performance is not too heavily dependent on the input assumptions to the model.

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[9] Sierra Club comments, Page 3.

[10] The TEP IRP segregates resources based on the type of "service" they provide to the system. Chapter 5 covers "Load Modifying Resources"; Chapter 6 covers "Load Serving Resources" (both fossil and renewable); and Chapter 7 covers "Grid Balancing Resources".

[11] Sierra Club comments, Page 3.

[12] Scenarios were developed by PACE Global, (see TEP 2017 IRP, Appendix A – PACE Global Future States of the World).

The goal in TEP's stochastic risk modeling is to value each portfolio in different market and demand scenarios in order to identify and quantify value changes that arise from inherently volatile factors. TEP's risk analysis goes beyond basic stochastic modeling. Using stochastics in conjunction with the simulation capabilities of our production cost model allows us to quantify risk in the context of total production cost. Ranking portfolios based on risk and the potential system cost allows us to select an optimal low cost and low risk scenario.

R14-2-703.F.8 requires that the Reference Case Portfolio will achieve a reasonable long-term total cost. Sierra Club incorrectly states that the reference case portfolio does not meet this standard because it is "not based on an optimization mechanism."[13] Again Sierra Club confuses "lowest cost" with "reasonable cost," and overlooks the complexity involved in resource choices and how this is recognized in the IRP rules. Rather than rely on a "black box" model with limited transparency for stakeholders,[14] the Company used a logical set of steps, and a rigorously documented sequence of assumptions using high-level screening tools followed by the use of an hourly production cost model to develop its 2017 IRP Reference Case Portfolio. In Step 1 of this process, TEP used the data assumptions from the report developed by the Electric Power Research Institute (EPRI)[15] which developed estimates for cost-effective energy efficiency through 2035 (see Energy Efficiency Value and Opportunity section below) to offset TEP's baseline retail load forecast. In Step 2, TEP developed the expansion of its renewable portfolio which targeted a diversified mix of both the lowest cost solar and wind resources available in the Arizona and New Mexico region.[16] In Step 3, TEP modeled its future coal plant retirements based on economics

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[13] Sierra Club comments, Page 5

[14] Even Sierra Club's outside consultant Synapse Energy Economics in a February 2016 report published a study that listed the challenges associated with using utility-scale capacity expansion models. These criticisms are listed on page 14 of this report. http://www.synapse-energy.com/sites/default/files/Guide-to-Clean-Power-Plan-Modeling-Tools.pdf

[15] *U.S. Energy Efficiency Potential Through 2035*, Electric Power Research Institute, dated April 2014. http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001025477

[16] TEP 2017 IRP, Page 236. TEP provide an in-depth discussion on both the renewable technology consideration as well as the need to diversify its renewable resource portfolio.

tied to known contractual end dates in its current coal supply and joint-ownership participation agreements (see Coal Resource Economics section below). In Step 4, TEP layered in these outcomes from Steps 1 - 3 and evaluated the thermal resource requirements that were capable of replacing several hundred megawatts (MW) of baseload capacity and grid-balancing resources to address the variability of intermittent renewable energy. In Step 5, TEP utilized an hourly dispatch production cost model to simulate a number of different portfolios using a wide range of scenarios and sensitivities. In the end, the 2017 IRP Reference Case Portfolio is a long-term plan based on "reasonable costs" focused on near-term changes while providing TEP the optionality to modify future resource plans as conditions change. Finally, Sierra Club makes an overarching allegation that "much of the Company's data was stale before it was published." In response to this inaccurate statement, the Company can only assume that Sierra Club failed to read Appendix A to TEP's 2017 IRP. Appendix A contains a report developed by Pace Global titled Future States of the World that was used to develop TEP's 2017 IRP scenarios and was finalized in December 2016 (3 months prior to the April 2017 IRP filing date). This reports details most of the major cost inputs related to fuel costs, capital costs, load growth assumptions and CO_2 emission prices.

Coal Resource Economics

TEP's Coal Resource Planning Decisions

Sierra Club makes an unsubstantiated claim that TEP has "played a surprisingly backseat role in the robust discussions" around its coal plants.[17] This statement lacks merit based on the number of decisions the Company has made in the last few years to significantly reduce its reliance on coal in a measured manner that maintains system reliability and fuel diversity while improving environmental performance and lowering costs for its customers. One only needs to

[17] Sierra Club comments, Page 2.

read the Executive Summary in the Company's 2017 IRP to understand that TEP fully acknowledges the changing role of coal-fired generation within its resource portfolio.[18] Furthermore, TEP's 2017 IRP reflects a commitment to retire 35% of its existing coal fleet (508 MW) over the next five years and by the end of the IRP planning period, the Springerville Generating Station ("SGS") is the only coal asset in TEP's generation portfolio. The following overview summarizes TEP's proactive management decisions related to its coal fired generation resources.

Sundt and San Juan Unit 2 Coal Retirement Commitments

TEP took its first steps in the 2014 IRP with its commitment to eliminate coal as a fuel source at the Sundt Generating Station ("Sundt"). In August 2015, TEP discontinued burning coal at Sundt.[19] In addition, as part of the 2014 IRP, TEP along with the other plant participants at the San Juan Generating Station ("San Juan"), committed to retire San Juan Units 2 and 3 by the end of 2017.[20]

San Juan Unit 1 Coal Retirement Commitment

After the 2014 IRP, TEP continued to take further steps to reduce its reliance on its higher cost coal generation resources in favor of cleaner, lower cost resources. As part of TEP's August 2016 Rate Case Settlement Agreement (in which Sierra Club was a signatory), the Company proposed to fully depreciate its San Juan Unit 1 assets by 2022.[21] This proposal to accelerate

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[18] TEP 2017 IRP, Section: Market Fundamentals, Page 25. "The ultimate effect of high penetrations of renewables and low cost natural gas will likely accelerate the retirement of higher cost coal and nuclear resources".

[19] http://www.power-eng.com/articles/2015/08/tucson-power-plant-to-stop-using-coal-switch-to-natural-gas.html

[20] TEP 2017 IRP, Page 20. As part of the 2014 IRP analysis, TEP avoided approximately $165 million in pollution controls with its commitment to retire San Juan Unit 2 at the end of 2017.

[21] Decision No. 75975 (February 24, 2017), Exhibit A (Settlement Agreement Regarding Revenue Requirement), Section 4.1.

depreciation, which was supported by the Sierra Club, Western Resource Advocates and TEP, provided the Company with another opportunity to rebalance its generation fleet in the near term without large rate impacts on TEP's customers.[22] Moreover, in early 2017, TEP notified PNM's management team that it had no intention to extend the coal supply agreement or the ownership participation agreement beyond 2022.[23] TEP's notification to PNM was made several weeks ahead of PNM's March 16, 2017 preliminary announcement that San Juan could "provide long-term benefits for its customers" if retired in 2022.[24] TEP's commitment in its 2017 IRP to exit San Juan was made several months ahead of PNM's 2017 IRP that was filed on July 3, 2017.[25]

Navajo Generating Station Coal Retirement Commitment

In 2016, as the lease negotiations related to the Navajo Generating Station ("NGS") stalled and the wholesale power market impacts of high solar penetration along with low priced natural gas fundamentally changed the economic outlook on coal, the Company began developing an exit strategy to prepare for the possible shutdown of NGS in 2019. Furthermore, in early 2017, Salt River Project, the majority owner-operator of the plant, determined that renewing the lease on the mine and extending the life of NGS was not cost effective and announced that it would withdraw from the plant in 2019. Finally, in compliance with TEP's rate case order (Decision No. 75975), the Company submitted to the Commission an in-depth analysis on the long-term economics of

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[22] Decision No. 75975, Page 11, Lines 5-12.

[23] TEP 2017 IRP, Page 20. In the 2017 IRP analysis, TEP's customers will realize an additional net present value savings of approximately $179 million related to the retirement of TEP's ownership interest in Navajo at the end of 2019 and the retirement of TEP's ownership interest in San Juan Unit 1 at the end of June 2022. (Of the $179 million net present value savings, $97 million is related to retirement of San Juan Unit 1 in 2022.)

[24] California Energy Markets, Energy News Data. March 24, 2017. "Preliminary PNM Study Casts Shadow Over Future of San Juan Power Plant". Page 1, 11 & 12. A copy is attached as **Attachment 2**.

[25] https://www.pnm.com/documents/396023/396193/PNM+2017+IRP+Final.pdf/eae4efd7-3de5-47b4-b686-1ab37641b4ed

NGS.[26] This analysis concluded that the retirement of TEP's share of NGS provided TEP with a "cost effective opportunity to rebalance its resource portfolio over the long-term".

The Acquisition of Springerville Unit 1 Capacity

The Sierra Club also makes the statement that "TEP had an obligation to assess, in detail, the ratepayer costs and benefits of acquiring the remainder of Springerville 1".[27] While such an assessment was not filed as part of the 2017 IRP, the Company did conduct a detailed assessment of Springerville Unit 1 ("SGS Unit 1") prior to acquiring a 49.5% ownership share upon expiration of the SGS Unit 1 leases, and also prior to acquiring the remaining 50.5% share of SGS Unit 1 in 2016. As part of TEP's 2015 rate case, Company witness Kentton C. Grant testified[28] to the decision making process employed by TEP, as well as the circumstances regarding the litigation outcome between TEP and the majority share co-owners[29] at Springerville Unit 1. In addition, Company witness Michael E. Sheehan also testified[30] that prior to entering into a settlement agreement with the co-owners, the Company hired PACE Global[31] to conduct a long-

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[26] See April 3, 2017 Notice of Compliance in Docket Nos. E-01933A-15-00239 and E-01933A-15-0322. As part of the Company's on-going resource planning evaluations, TEP performed an in-depth analysis on the long-term economics of NGS that showed that customers would realize a $82 million net present value savings related to the 2019 retirement of TEP's share of NGS capacity. The Company can provide this confidential report to IRP stakeholders that have been granted intervention and executed a protective agreement in this docket.

[27] Sierra Club comments, Page 8.

[28] Direct Testimony of Kentton C. Grant, Page 29, Line 15 through Page 31, Line 20 (Docket Nos. E-01933A-15-00239 and E-01933A-15-0322); Rebuttal Testimony of Kentton C. Grant, Page 16, Line 1 through Page 17, Line 2 (Docket Nos. E-01933A-15-00239 and E-01933A-15-0322).

[29] The majority share co-owners were Alterna Capital Partners and Fortress Investment Group.

[30] Rebuttal Testimony of Michael E. Sheehan, Page 4, Line 17 through Page 8, Line 9 (Docket Nos. E-01933A-15-00239 and E-01933A-15-0322).

[31] Pace Global, A Siemens Business, is a leading provider of strategic energy consulting services. Pace Global has provided consulting services to support the execution of business strategies, complex energy transactions, asset development, and operations focusing on select markets in the Americas. More information can be found at http://www.paceglobal.com.

term assessment[32] of TEP's generation portfolio to evaluate whether the acquisition of the remaining 50.5% of the co-ownership share of SGS Unit 1 would be in the best interest of TEP's retail customers. The PACE analysis focused on three key objectives: least cost, rate stability, and environmental compliance. In terms of least cost, the PACE analysis determined that the resource portfolios that included the 50.5% co-ownership share of SGS Unit 1 reflected net present value revenue requirement outcomes that were lower by $326 million to $385 million relative to the scenarios that retired SGS Unit 1 and replaced the capacity with a combination of natural gas and renewable resources. Moreover, the PACE analysis also concluded that generation portfolios that retained SGS Unit 1 maintained higher rate stability for TEP's retail customers due to the reduced exposure to natural gas commodity risk and reduced commitments to large capital investments in the near term. Finally, the acquisition of the 50.5% co-ownership share of SGS Unit 1 still allowed TEP to meet compliance under the Final Rule of EPA's Clean Power Plan.

TEP's Coal Resource Strategy in the 2017 IRP

Sierra Club apparently would like stakeholders to believe that TEP does not take its resource planning decisions related to its coal generation fleet seriously. However, TEP's decisions made over the last few years related to coal tell a much different story. TEP has systematically taken proactive steps in the outcomes cited above and TEP's 2017 IRP Reference Case plan provides the roadmap forward that will enable TEP to transform its generation fleet in a balanced manner while maintaining energy security, planning optionality, system reliability and rate payer affordability.

[32] See Supplemental Report - Analysis of Tucson Electric Power's Long-Term Resource Portfolio Options. The Company can provide this report to IRP stakeholders that have been granted intervention and executed a protective agreement in this docket.

Renewable Energy Value

Sierra Club branded TEP's planned expansion of renewable energy to serve 30% of retail load by 2030 as "relatively modest"[33] and states that "TEP's 2017 IRP shows a reticence towards substantial renewable buildout." This assessment is not supported by the facts. A recent analysis by the Database of State Incentives for Renewables & Efficiency (DSIRE)[34] shows that TEP's goal of 30% by 2030 meets or exceeds the standards of most states, while doubling its obligation under the Arizona Renewable Portfolio standard.[35]

In addition, Sierra Club postulates that TEP's method for assigning peak capacity value to solar resources is one of the key factors limiting TEP's renewable energy buildout. To the contrary, TEP assigns a relatively high net coincident peak value to solar resources (34% for fixed-tilt and 65% for single axis tracking).[36] Sierra Club fails to recognize that Chart 12 of the TEP 2017 IRP[37] makes clear that the net load pattern changes as solar generation is added to the system. Calculating the Effective Load Carrying Capability (ELCC) for solar resources, as suggested by Sierra Club,[38] would not change the fact that system net peak, under high solar penetration, shifts to later in the day when the sun is no longer shining.

Sierra Club's Belief that Coal and Renewable Generation Resources are Interchangeable

Sierra Club's characterization of renewable energy resources as a replacement for coal demonstrates a lack of understanding of the basic function of dispatchable resources within a

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[33] Sierra Club comments, Page 8.

[34] DSIRE is the most comprehensive source of information on incentives and policies that support renewables and energy efficiency in the United States. Established in 1995, DSIRE is operated by the N.C. Clean Energy Technology Center at N.C. State University and is funded by the U.S. Department of Energy.

[35] http://ncsolarcen-prod.s3.amazonaws.com/wp-content/uploads/2017/03/Renewable-Portfolio-Standards.pdf

[36] TEP 2017 IRP, Page 96. Table **Error! Main Document Only.** – Renewable Load Serving Resources – Cost Assumptions, See "Net Coincident Peak".

[37] TEP 2017 IRP, Page 70.

[38] Sierra Club comments, Page 9.

portfolio. Intermittent renewable resources, due to their unpredictability, are not a replacement for baseload resources, which are characterized by steady output over long periods of time, and under the control of the system operator.

Chapter 4 of TEP's 2017 IRP presents an overview of the services provided by various categories of resources, and explains how renewables and coal have different functionality. Intermittent renewable energy does present operational challenges (which Sierra Club does not address in its comments), and requires a coordinated deployment with grid balancing resources.[39]

Overlooking the importance of implementing grid balancing resources along with intermittent renewable energy resources would risk, among other things, the stability of the power grid.

Energy Efficiency Value and Opportunity

Sierra Club asserts two "substantial flaws" in TEP's treatment of energy efficiency (EE) in the 2017 IRP; first that the TEP 2017 IRP treats EE "inconsistently with other resources" in its assessment of costs and benefits, and second, that the Company "assumed that cost-effective energy efficiency will cease being available by 2020." Both of these alleged "flaws" are flatly wrong, and in the case of the former allegation, Sierra Club proposes a cure that includes the same "flaw" that they allege exists in the TEP 2017 IRP.

The TEP 2017 IRP accurately reflects the timing of the costs involved in EE relative to the resulting benefit. TEP's intent is to treat EE as a demand-side resource which entails modeling EE consistently with supply-side resources. The TEP 2017 IRP does just that by recognizing the cost to achieve the incremental energy savings targeted in each year's set of programs and incentives in that year, then allowing those energy savings to persist annually thereafter at no additional cost. In fact, TEP's 2017 IRP treatment of EE is quite generous as it allows energy savings to persist

[39] TEP 2017 IRP, Pages 59-61, 69 and 84.

indefinitely, even though most if not all programs have a finite lifetime.[40] In short, the money is accrued in the year it is spent, and the energy savings are accrued in the year that they occur. This is exactly how supply-side resources are modeled.

Oddly, while alleging inconsistent treatment of EE, Sierra Club proposes to use a "lifetime cost" in which they pretend that the costs to achieve the energy savings accrue in the same year that the energy savings occurs, by spreading the costs evenly over the lifetime of the measure. That treatment would be completely inconsistent with how all other supply-side resources are modeled.

Sierra Club's second allegation that TEP's 2017 IRP assumes that no cost effective EE is available after 2020 is simply wrong. In fact, TEP relied on a report developed by EPRI[41] which developed estimates for cost-effective energy efficiency through 2035. EPRI estimated that it would be cost effective to achieve a 51% reduction in the annual growth rate of energy use relative to the Annual Energy Outlook of the 2012 Reference Case. TEP's 2017 IRP applies that 51% reduction in annual growth to our load forecast to arrive at the energy savings that can be achieved through cost-effective EE programs through the planning period. TEP's assumptions for EE beyond 2020 represent strong support for EE relative to other state standards.[42]

Battery Storage

Battery energy storage (BES) in electric utility applications is maturing, and the pace of that maturation has increased significantly over the past couple years. The buildout of BES in the TEP 2017 IRP shows optimism in the technology and leadership in the industry, particularly given its size and the lack of hard, long-term data on how these systems operate within a balancing

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[40] TEP intends to revise its methodology relating to EE program persistence in future planning cycles.

[41] *U.S. Energy Efficiency Potential Through 2035*, Electric Power Research Institute, dated April 2014. http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001025477.

[42] American Council for an Energy-Efficient Economy, Energy efficiency resource standards by state, http://aceee.org/topics/energy-efficiency-resource-standard-eers

authority and the bulk energy system. California investor-owned utilities, for example, are required to purchase 1,325 MW of energy storage by 2020, equivalent to 2.2% of California's peak retail load. By comparison, the three batteries that TEP will have in place by 2020 will also be equivalent to 2.2% of its peak retail load.

Sierra Club seems to have misinterpreted Table 4[43] of the TEP 2017 IRP in stating, "the Reference case assumes that TEP will only have 30 MW of BES total by 2020 (on top of its existing 5 MW) and will only add another 20 MW in addition (for a total of 55 MW) through 2030." As stated directly above the table, these values represent each "resources' contribution to system peak". The full BES buildout is presented on Figure 42[44] which shows that by 2032, the IRP assumes a total of 220 MW BES in the Reference Case Plan. As of the date of these comments, TEP has approximately 21 MW of BES providing ancillary grid support services – this represents approximately 4% of total installed utility scale BES in the United States.[45]

Sierra Club also states that "TEP's valuation of storage is also clearly inconstant with the actual projects it is procuring." This mischaracterization is presumably due to Sierra Club conflating the TEP IRP with TEP's May 2017 announcement of a solar purchase power agreement (PPA) that includes an on-site battery with thirty (30) MW of power and four hours of storage. It is worth noting that the request for proposal for that PPA was issued on November 4, 2016 and did not require a storage system to be included. TEP, however, had to finalize its IRP battery assumptions in early 2017 in order to complete the IRP by April 1, 2017. The winning bidder for the PPA was not determined until May 2017, thus, the IRP could not include the information ultimately provided by that project.

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[43] TEP 2017 IRP, Page 52.

[44] TEP 2017 IRP, Page 275.

[45] Based on World Energy Resources E-Storage Report, 2016, page 57. See https://www.worldenergy.org/wp-content/uploads/2017/03/WEResources_E-storage_2016.pdf

Sierra Club is also critical of TEP's assumption on the amount of capacity value to assign to the BES system ("TEP's IRP assumes that storage … provides a 50% capacity value (meaning it is unavailable half the time during peak requirement hours).") while at the same time alleging that "TEP fails to include any other value propositions for grid-scale storage." Sierra Club's conflicted position underscores the fundamental challenge in incorporating BES; although BES systems can provide multiple services, they cannot provide all of the them simultaneously. For example, if a battery is being used during the day to regulate frequency, provide reactive power, and reduce load on a particular distribution feeder, it cannot be reliably expected to provide 100% power and energy coincident with peak system demand. TEP believes that a 50% capacity value is a reasonable assumption for IRP purposes. However, there is much work to be done to understand how BES systems can function most effectively and economically within our system.

Finally, the TEP 2017 IRP does account for the expected reductions in the future cost of storage. Specifically, data publicly available from Lazard and DNV GL were used as the basis for assuming a 30% decline in storage costs ($/kWh) between 2016 and 2019, and a 38% decline between 2016 and 2021.[46] In its cost assumptions, TEP also considered the batteries' state-of-charge limits, roundtrip efficiency, energy storage degradation, storage medium replacement requirements, and annual fixed O&M costs.

Clean Power Plan Assessment

In its critique of the TEP 2017 IRP's assessment of compliance with the Clean Power Plan (CPP), Sierra Club states that "TEP effectively applies no constraint to carbon dioxide emissions, and yet continues to imagine that the CPP remains in effect."[47] This sentence contradicts itself

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[46] Lazard, *Lazard's Levelized Cost of Storage – Version 2.0*, December 2016 (https://www.lazard.com/perspective/levelized-cost-of-storage-analysis-20/) and DNV GL, *Battery Energy Storage Study for the 2017 IRP: PacifiCorp*, August 2016 (http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/10018304_R-01-D_PacifiCorp_Battery_Energy_Storage_Study.pdf)

[47] Sierra Club comments, Page 13.

and is illogical. The CPP is a final rule,[48] promulgated by the Environmental Protection Agency, which places limits on emissions of carbon dioxide ("CO_2") from Electric Generating Units (EGUs), including those owned by TEP. Under the CPP, emissions of CO_2 from EGUs in Arizona must decrease by 25% between 2012 and 2030. By evaluating TEP's compliance with the CPP, TEP applies the rule's emission limitations to the EGUs owned by the Company.

TEP is able to meet the strict emission limits in the CPP because its forward strategy is well aligned with the "Building Blocks"[49] that form the rule's emission reductions, specifically:

- Reducing coal-fired generation in favor of cleaner burning natural gas,
- Increasing generation from renewable energy resources,
- Increasing energy efficiency.

Sierra Club is a strong supporter of the CPP,[50] yet they seem to lament the fact that TEP is reducing emissions by employing the precise strategies called for in the rule. Sierra Club's critique of TEP on this issue is perplexing.

The CPP was (and still is) a final rule with a clear CO_2 emission mitigation methodology that could be applied to the EGUs within TEP's system, and is therefore, an appropriate surrogate for gauging TEP's position relative to future CO_2 mitigation requirements. Measuring compliance with any other target would be highly speculative.

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[48] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 80 FR 64662; Supreme Court Stayed the final rule on February 9, 2016, pending litigation in the D.C. Circuit Court of Appeals

[49] In the final CPP, EPA determined that the "Best System of Emission Reductions" (BSER) is comprised of three "Building Blocks" summarized as 1) existing coal plant operational efficiency, 2) re-dispatch from coal-fired generation to natural gas-fired generation, and 3) increasing renewable energy generation. The proposed Building Block 4 – Consumer Energy Efficiency was omitted from BSER in the final rule, but identified by EPA as a strategy available to States.

[50] https://content.sierraclub.org/creative-archive/sites/content.sierraclub.org.creative-archive/files/pdfs/1131CleanPowerPlan_FactSheet_06_web.pdf

Conclusions and Recommendations

TEP's IRP is robust, complies with all applicable Commission rules governing resource planning, and articulates a clear strategy for diversifying its resource portfolio that will result in a portfolio balanced between coal, natural gas, renewable energy, and energy efficiency. TEP's diversification strategy demonstrates leadership with respect to many of the changes that will be required to meet the challenges and opportunities brought about by the rapid pace of technological advancement in the utility industry. Specifically, TEP has set a target to serve 30% of its retail load from renewable energy resources by 2030. TEP has already deployed 20 MW of battery energy storage on its system and has a long-term plan to develop hundreds more MWs. TEP has been proactive in identifying and acting on opportunities to reduce our coal-fired generation capacity, while protecting ratepayers.

TEP rejects Sierra Club's recommendations for modified and/or additional analysis. As described in detail above, Sierra Club's arguments for changes to the TEP 2017 IRP are either wrong, misinformed, or ignore relevant sections of the TEP 2017 IRP. Integrated resource planning is a continuous process and adjustments to reflect changing market conditions, technology development, and other factors will be evaluated and captured in subsequent planning cycles.

RESPECTFULLY SUBMITTED this 16th day of October, 2017.

TUCSON ELECTRIC POWER COMPANY

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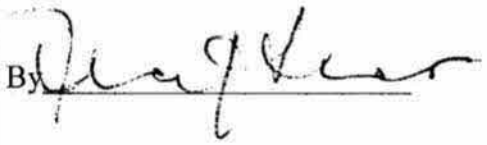
By 

Attachment 1

ORIGINAL

NEW APPLICATION

0000183075

Memorandum

From the office of
Commissioner Andy Tobin
Arizona Corporation Commission
1200 W. WASHINGTON
PHOENIX, ARIZONA
(602) 542-3625

Arizona Corporation Commission
DOCKETED

SEP 28 2017

DOCKETED BY

TO: Docket Control

DATE: September 28, 2017

E-00000Q-17-0293

FROM: Commissioner Andy Tobin's Office

SUBJECT: Opening a New Docket (Doc. No. _-_____-__-____)

Please open a new docket related to Arizona's baseload in general and our state's energy security. The title of this docket will be: "Evaluating Arizona's current & future baseload security"

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Direct Line: (602) 542-3625
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ARIZONA CORPORATION COMMISSION

September 28, 2017

Dear Commissioners and other interested parties,

Over the past decade, there have been significant changes to our state's energy mix and infrastructure. Most notably, a rapidly expanding solar rooftop market has lead the Commission, utilities, and solar companies to come together in creating a proactive response through the Value of Solar docket[1]. In addition to the growth of residential solar, Arizona is now a national leader in utility scale solar generation.[2] While we have seen these increases in renewables, we have also seen shifts in our traditional baseload electricity portfolio. For instance, in 1990 coal made up over 50 percent of electricity generation in our state while natural gas equated to less than four percent. In 2015, coal was only 32 percent of generation and natural gas had risen to nearly 30 percent.[3] With the looming decommissioning and closure of the Navajo Generating Station, that trend will continue and accelerate into the future.

Understanding the impact of these changes and the characteristics associated with various types of electricity generation are essential to being effective at the Commission. This is why I am opening a docket to investigate and answer the questions: "What are Arizona's electricity needs both today, and in the future, and how do we ensure that Arizona's energy policies promote reliability, security, and affordability as we power the state and fuel our economy?" This docket will allow us to gather information and engage with stakeholders to determine how Arizona should address shifts in energy markets and identify considerations that should be made to maintain a reliable baseload energy portfolio into the future.

Sincerely,

Andy Tobin
Commissioner

[1] "Value of Solar Docket" Arizona Corporation Commission; azcc.gov; Docket No. E-00000J-14-0023
[2] U.S. Energy Information Administration; "Utility-scale solar has grown rapidly over the last five years" https://www.eia.gov/todayinenergy/detail.php?id=31072
[3] U.S. Energy Information Administration; "Net generation by state by type of producer by energy source" https://www.eia.gov/electricity/data/state/

CERTIFICATION OF SERVICE

On this 28th day of September, 2017, the foregoing document was filed with Docket Control as a correspondence from Commissioner Andy Tobin, and copies of the foregoing were mailed on behalf of Commissioner Andy Tobin to the following who have not consented to email service. On this date or as soon as possible thereafter, the Commission's eDocket program will automatically email a link to the foregoing to the following who have consented to email service.

Doc. No. _-_____-__-____

By: _____

Nick Loper

Deputy Policy Advisor to Commissioner Andy Tobin

Attachment 2

CALIFORNIA ENERGY MARKETS

Energy NewsData, Seattle & San Francisco: March 24, 2017 • No. 1429

BILLBOARD

PG&E, Customers in Discussions Over Wires Planning Complaint... ***Jump to [5].***

Potomac: Gorsuch Defends Chevron Deference Stance..... ***Jump to [6].***

MCE Finds Developer to Build Solar Project at Refinery..... ***Jump to [7].***

Early-Morning Fire at PG&E Vault Knocks Out Power .....***Jump to [7.1].***

PG&E Close to Settlement in Ex Parte Investigation at CPUC ....***Jump to [7.2].***

Bottom Lines: Getting to the Root Cause at Aliso Canyon..... ***Jump to [8].***

CPUC Making Progress on Staffing Issues .....***Jump to [11.1].***

CPUC Authorizes Additional Financing for Efficiency Pilots .....***Jump to [11.2].***

Court Affirms EPA's Navajo Generating Station Plan.....***Jump to [14.1].***

NM Utility Says Wind Power Cheaper, Less Risky Than Gas.....***Jump to [14.2].***

ACC Mulls Regulation to Reveal Election Donors .....***Jump to [14.3].***

PRICE REPORT

CAISO Renewables Hit New Record

Details on Page 4.

ENERGY JOBS PORTAL

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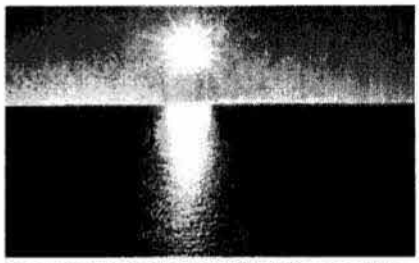
THE WEEK IN SUMMARY

[1] CARB Approves Methane Emissions Regulation for Oil and Gas Facilities

The California Air Resources Board has approved a new regulation aimed at tackling fugitive and vented methane emissions from oil and natural gas facilities in the state. The regulation, described as the strictest in the nation, establishes standards designed to facilitate early detection of gas leaks, with an eye toward preventing the type of catastrophic leak that occurred at Aliso Canyon. ***Tackling short-lived climate pollutants at [10].***

[2] Task Force Charts Course for Offshore Wind Development

An intergovernmental task force is looking at accelerating siting of offshore wind projects along the California coast, but the group is hampered by a dearth of data. The effort comes as the U.S. Bureau of Ocean Energy Management may issue a lease as early as the end of 2018. ***Boosting offshore wind at [11].***



Deepwater Wind's Block Island wind farm at sunrise. *Photo: Deepwater Wind*

[3] IOUs Fail to Find Community Renewables Projects to Offer Customers

Investor-owned utility customers eager to invest in local renewables will have to wait, as the IOUs have yet to secure projects for their community renewables programs. The utilities had hoped to have executed power-purchase agreements by now, but responses to a solicitation issued last year were sparse and ultimately did not result in any contracts. While some have blamed the lack of interest by developers on the program's newness, others are questioning whether there's enough benefit from the cost. ***Doing the math at [12].***

[4] PNM Study Casts Shadow Over Future of San Juan Coal Plant

Tucson Electric Power's apparent lack of commitment to the coal-fired San Juan Generating Station may have led PNM to preliminarily recommend a 2022 retirement date for the plant. The San Juan retirement, coupled with the expected closure of the Navajo Generating Station, means there could be an almost 4 GW reduction in coal-fired power in the Southwest within five years. ***Potential coal plant retirements at [14].***

to dismiss the complaint. PG&E said the parties are raising arguments that FERC already addressed in its 2006 Order 890 notice of proposed rulemaking (NOPR) and in CAISO's subsequent compliance filing.

PG&E said the projects at issue in the complaint "are regularly occurring replacement, repair, and maintenance type projects that do not trigger the kind of access to transmission capacity and preference issues that were the focus of Order No. 890." They also include projects necessary to stay current with North American Electric Reliability Corporation and Western Electricity Coordinating Council reliability standards, according to the utility.

PG&E said excerpts from Order No. 890 cited by complainants to suggest such projects were meant to be included in separate, utility-specific Order No. 890 processes "are taken out of context and ignore the fact [that] the very same arguments" were rejected by FERC in the development of the order.

PG&E believes the filing of the complaint was not necessary, highlighting to FERC that it was filed a day after it met with parties and committed "to begin a series of meetings . . . to negotiate a consensual process" for transmission projects that do not go through CAISO's TPP.

FERC's 'concerns about . . . the current transmission planning process are largely absent in California and the West.'

PG&E maintains there is nothing in the order that stipulates individual participating transmission owners that have turned control of their facilities over to an RTO or ISO must have separate Order No. 890 transmission planning processes. The utility quoted a number of the complainants' own comments in the Order 890 development proceedings, including one in which the CPUC said that FERC's "concerns about a lack of coordination, openness and transparency in the current transmission planning process are largely absent in California and the West."

The complainants "are resurrecting the same arguments that NCPA made repeatedly, and unsuccessfully, throughout the Order No. 890 proceedings," PG&E emphasized. "This commission had the opportunity to consider those arguments and concluded that the CAISO TPP satisfies the requirements of Order No. 890. That conclusion remains valid today."

Other parties that filed to intervene in the docket include Southern California Edison; Modesto Irrigation District; Six Cities; Western Power Trading Forum; Alliance for Retail Energy Markets; Santa Clara and M-S-R Public Power Agency, which filed jointly; LSP Transmission Holdings LLC; California Municipal Utilities Association; CAISO; San Diego Gas & Electric; FirstEnergy Service Co.; Trans Bay Cable LLC; Imperial Irrigation District; and NextEra Energy Transmission West LLC. ***–Ben Tansey***

SOUTHWEST

[14] Preliminary PNM Study Casts Shadow Over Future of San Juan Power Plant

(from [4])

Prospects for the 1,683 MW, coal-fired San Juan Generating Station look as black as its fuel, and while a potential closure of the plant could benefit the environment, Navajo Nation leaders are unhappy that Native Americans will lose jobs at the plant.

PNM, operator of the aging plant in northern New Mexico, announced on March 16 that, under a preliminary analysis completed for the utility's integrated resource plan process, shutting down the San Juan units in 2022 could be beneficial to customers and could open up opportunities for renewables. San Juan's coal-supply contract and the ownership agreement with other utilities both end in June 2022, potentially providing PNM with a convenient time to retire the plant. PNM disclosed few other details on how it would replace power from San Juan.

PNM Resources President and CEO Pat Vincent-Collawn, however, emphasized that the 2022 retirement date represents "only a preliminary finding" and could be changed.

"We understand and recognize the fact that retiring the station would impact not only the local economies of Farmington, San Juan County, and the Four Corners [area, where New Mexico, Arizona, Utah, and Colorado abut], but the state of New Mexico as well," Vincent-Collawn said.

San Juan employs 286 workers, most of whom are Native Americans.

"The Four Corners region will be severely impacted by the closure," said Navajo Nation President Russell Begaye.

The Navajo Nation wants the energy industry to help employees find other jobs if San Juan is closed, Begaye said. He called on President Donald Trump to minimize regulations so that part of San Juan could continue operations.

PNM announced the preliminary findings as it began work on an integrated resource plan that will analyze a 20-year planning horizon and a detailed, four-year action plan.

Also, as part of the San Juan ownership restructuring agreement approved by the NMPRC in 2015, PNM agreed to report in 2018 on the outlook for continued operation of the coal plant.

The San Juan ownership restructuring plan grew out of PNM's 2013 agreement with the U.S. Environmental Protection Agency to reduce San Juan nitrogen-oxide emissions, which contribute to regional haze over the Grand Canyon and other national parks.

The EPA accepted PNM's proposal for reducing nitrogen-oxide emissions at San Juan. The EPA agreement provides for PNM to retire San Juan Units 2 and 3 by the end of 2017. Also, the agreement required PNM in 2016 to retrofit Units 1 and 4 with selective non-catalytic reduction equipment to lower NOx emissions.

San Juan Generating Station. *Photo: PNM*

Under the restructuring plan, PNM will own 562 MW of San Juan capacity by the end of this year, followed by Tucson Electric Power with 170 MW.

Tucson Electric, however, has signaled that it may exit San Juan in 2022.

In a February general rate-case decision, Tucson Electric agreed to almost fully depreciate its San Juan assets by 2022. As a result, TEP could divest its San Juan ownership stake and avoid the need for a large rate increase to compensate for the write-off of undepreciated plant.

The potential loss of TEP would make it even harder for PNM to continue operating San Juan beyond 2022, said Steve Michel, chief of policy development at Western Resource Advocates.

'We need to help that region to transition to another economic future.'

WRA in 2015 signed the ownership restructuring agreement that allowed San Juan to continue operations until 2022. The agreement required PNM in 2018 to re-evaluate the costs and benefits of extending San Juan operations beyond 2022. (The New Mexico Public Regulation Commission approved the ownership restructuring agreement in 2015.)

"That settlement agreement is playing out the way we hoped and thought that it would," Michel said.

"From an environmental and health perspective, it's a great moment," he added.

WRA will focus on securing closure of the plant, replacing the maximum amount of San Juan capacity with renewables, and helping northwestern New Mexico rebuild its economy without coal, Michel said.

"There's a very heavy reliance on coal-fired generation, and we need to help that region to transition to another economic future," Michel said.

Northwest New Mexico "is one of the most solar-rich parts of the country," Michel said.

Preliminary analysis shows that retiring San Juan would open opportunities for increased renewable-energy production, PNM said.

The Navajo Nation is developing renewables to generate electricity for itself and other customers, Begaye said.

Through an agreement with the Salt River Project, the Navajo Tribal Utility Authority started developing the Kayenta Solar Facility, a 28 MW photovoltaic installation south of Monument Valley, Ariz., in January 2016, according to the U.S. Department of Energy.

The Four Corners region could accommodate a natural gas-fired plant for backing up intermittent renewables. PNM could also ensure reliability and backup through its demand-side management programs or by joining the Western energy imbalance market, Michel said.

Meanwhile, PNM is preparing for the final steps under an ownership-restructuring agreement.

Under this agreement, PNM will acquire 197 MW of additional Unit 4 capacity from M-S-R Public Power Agency, the City of Anaheim, and Tri-State Generation and Transmission Association, ending those entities' ownership interest in San Juan as of December of this year. The Southern California Public Power Authority owns 207 MW of San Juan Unit 3 and will exit San Juan with the closing of that unit, also in December.

Remaining San Juan owners will include the City of Farmington, N.M., with 43 MW; Los Alamos County, N.M., with 37 MW; and Utah Associated Municipal Power Systems, with 36 MW.

–John Edwards

[14.1] Court Affirms EPA's Coal Plant Plan After Owners Schedule Plant Closure

In two anticlimactic decisions, the U.S. Court of Appeals for the 9th Circuit upheld U.S. Environmental Protection Agency action to shut down the 2,250 MW, coal-fired Navajo Generating Station in Arizona by 2044.

The EPA in 2014 approved a stakeholder proposal to retire one of three 750 MW NGS units in 2019 and retrofit the two remaining units with selective catalytic reduction equipment by 2030. The plan would reduce nitrogen-oxide emissions, which contribute to regional haze over the nearby Grand Canyon and other national parks.

The 9th Circuit decisions may be moot, however, because NGS owners in February voted to exit the coal plant by December 2019, when the current lease with the Navajo Nation expires. NGS owners have suggested the Nation could take over the plant.

The owners decided to close the plant early because electricity from NGS costs more than energy purchased on the wholesale spot market.

A three-judge panel of the 9th Circuit on March 20 denied the appeal of environmental groups that wanted to retire NGS before 2044. Those groups included the Sierra Club, the National Parks Conservation Association, and lead plaintiff Vincent Yazzie.

The U.S. Bureau of Reclamation owns a 25 percent interest in NGS, and conservation groups argued that the EPA agreed to the proposal to minimize negative effects on the federal government's ownership interest in the plant. The 9th Circuit disagreed.

The same three-judge panel on March 20 also rejected a separate appeal from the Hopi Tribe, which opposed shutting down NGS.

The tribe said that stakeholders negotiated the plan without consulting the Hopi, but the court rejected that claim as well.

Exhibit AA-S-3

This file is marked competitively-sensitive confidential and will be made available on the Confidential Section of TEP's Data Room for those who have signed the protective agreement.