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TEP

Tucson Electric Power

&

UNS Electric, Inc.

88 East Broadway Blvd., P.O. Box 711
Tucson, Arizona 85702

Arizona Corporation Commission
DOCKETED

APR 23 2018

DOCKETED BY

April 23, 2018

Elijah Abinah, Utilities Director
Arizona Corporation Commission
1200 West Washington Street
Phoenix, AZ 85007

Re: Response to the Notice of Inquiry – Review, Modernization and Expansion of the Arizona Renewable Energy Standard and Tariff Rules and Associated Rules
Docket No. E-00000Q-16-0289

Attached is the response of Tucson Electric Power and UNS Electric, Inc. to the Notice of Inquiry dated February 22, 2018.

If you have questions regarding this report, please feel free to contact me.

Sincerely,

Bradley S. Carroll

cc: Docket Control
Service List for Docket for No. E-00000Q-16-0289

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RESPONSES TO ACC NOTICE OF INQUIRY

DOCKET NO. E-00000Q-16-0289

INTRODUCTION

The ambitious scope of the proposed Energy Modernization Plan reveals the strength of this Commission's commitment to address the complexities and costs of providing safe, reliable and increasingly sustainable electric service. Tucson Electric Power ("TEP") and UNS Electric ("UNSE") (together "Companies") share that commitment and appreciate this opportunity to provide an overview of those issues.

Our companies support the principles and objectives outlined in the Energy Modernization Plan. Arizona needs a coordinated, integrated energy policy established and overseen by this Commission, and we embrace the development of a more comprehensive resource planning process that incorporates resiliency, affordability, reliability, innovation, economic development and resource diversity.

Instead of pursuing a one-size-fits-all approach, the Commission should draft rules that accommodate the unique situation of each regulated utility. Every electric provider has a unique service area base and resource portfolio built around specific power plants, supply contracts, and systems designed for different communities and customers. The imposition of universal, statewide standards under such circumstances could create disparate and potentially damaging impacts for customers. It would be better to create rules that recognize these differences and allow accommodations that preserve affordability, reliability and resiliency for the customers of each affected utility.

Uncertainty about this and other aspects of this emerging policy make it extremely difficult to calculate the cost of compliance at this time. Without knowing more about how the policy will take shape, we cannot assess whether it would create significant stranded costs or require steep increases in our customers' rates. We will continue to provide the Commission with the best available information about cost of compliance as we work through the process of creating this far-reaching policy.

We can predict that costs will be higher if the plan includes rigid mandates for specific energy-related systems. The Company supports the use of technologies proposed in the plan, including forest bioenergy in Arizona, electric vehicles and energy storage. But in developing policies to deploy such technologies, the Commission should not put itself in a position of picking winners and losers by requiring the use of specific types or models of systems, some of which may be available from only a single provider. Customers benefit from policies that give utilities the flexibility to select the most appropriate, affordable resources to satisfy a policy objective, such as expanding energy storage or reducing overall emissions.

Cost recovery will be essential to the success of this policy. Rather than leaving such considerations for later proceedings, the Commission should develop specific recovery mechanisms and incorporate them into the policy itself. Attending to such details now will provide guidance to future Commissions while removing a potential barrier to the investments that will be needed to pursue these policy directives.

It's also important that we maintain our commitment to reliability and resiliency as we integrate cleaner energy resources. Although wind and solar resources can be paired with storage to reliably serve some energy needs, it remains unknown whether it will be possible to deploy this combination affordably at a scale that would allow us to abandon fossil fueled resources by 2050. And while natural gas-fired power plants are very reliable, they currently depend on fuel that is delivered in real time through lengthy interstate pipelines that have limited redundancy and were not designed for the rapid diurnal shifts in flow that are anticipated to occur. For that reason, the Energy Modernization Plan's 20% "non-clean" resource target should be carefully analyzed and designed to preserve the flexibility necessary to protect and preserve our state's energy security through 2050 and beyond.

The Companies hope you will consider our preliminary responses to the many questions posed in this notice of inquiry as prelude to an extensive, thoughtful review of this proposed policy. This review should be conducted through a broad, independent stakeholder process and incorporated in the existing integrated resource planning process of each affected utility. This ambitious proposal represents the Commission's first-ever attempt to develop a comprehensive, integrated energy policy for our entire state. Because of its broad impact, it deserves considerable research, careful review and diligent attention to due process to ensure an optimal outcome.

As this process proceeds, TEP and UNSE will continue our own efforts to diversify our energy portfolios which are in alignment with many of the tenets of the Energy Modernization Plan. UNSE is on track to provide 20 percent of its power from renewable resources by 2020, while TEP is aiming toward 30 percent renewables by 2030. Both goals exceed the state's current requirement, and we look forward to working with the Commission to create more ambitious goals that reflect our shared commitment to build a more sustainable energy future.

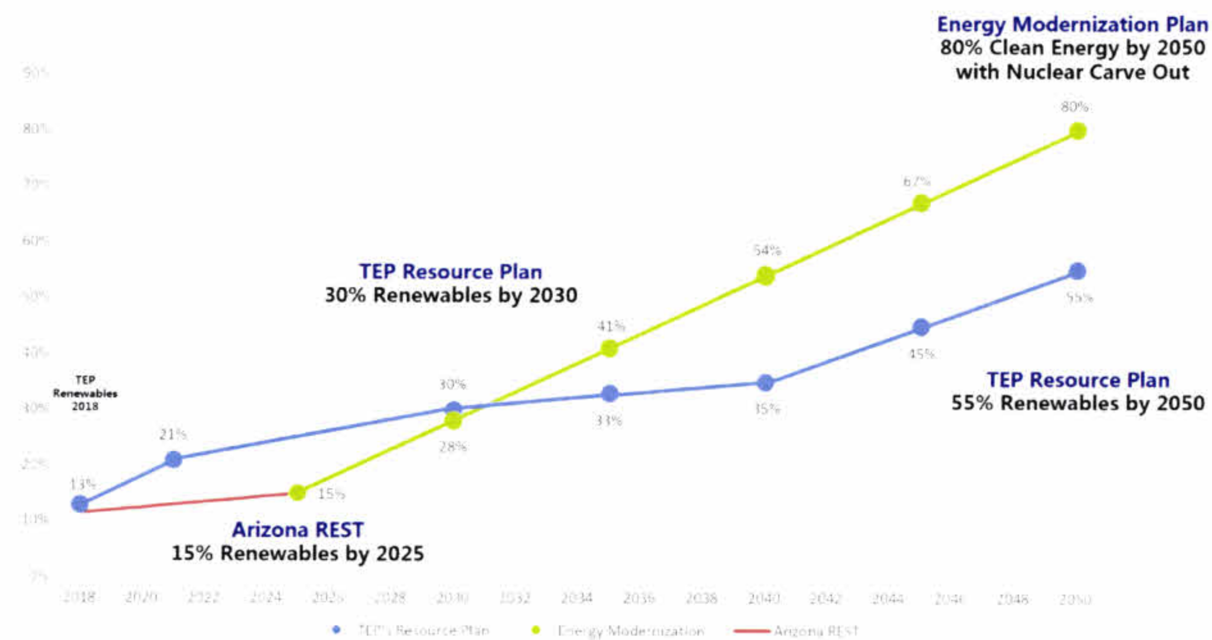
PRELIMINARY FINANCIAL ANALYSIS
THE ENERGY MODERNIZATION PLAN'S IMPACT ON TEP

Energy Modernization Plan versus TEP's Resource Plan

In response to the Commission's Notice of Iquiry related to the Energy Modernization Plan ("EMP"), TEP modeled a proposed build out of its resource portfolio through 2050 ("Resource Plan")[1] and compared the cost differential to compliance under the EMP.[2] Under this updated Resource Plan, TEP would target serving 55% of its retail load with renewable energy by 2050.

In 2017, 13% of TEP's retail load was served from renewable energy resources. As shown in Chart 1 below, under the proposed Resource Plan shown below, TEP takes an aggressive approach in serving 30% of its retail load from 'clean energy' renewable resources by 2030. Beyond 2030, it was assumed TEP would plan to target 35% renewables by 2040, 45% renewables by 2045 and 55% renewables by 2050.

Chart 1 - TEP's Updated Resource Plan (55% Renewables by 2050)



TEP's proposed Resource Plan has lower 'clean energy' targets than what is proposed under the EMP due to the Company's lack of baseload nuclear generation. TEP's lack of nuclear resources puts the Company at a disadvantage under the EMP by reducing its "clean energy" options to

[1] The Resource Plan discussed below reflects a plan based on a proposed 'clean energy' target of 55% by 2050. For purposes of modeling the EMP, the Company assumed that it would have to comply as a stand-alone entity and some of the compliance goal required the Company to meet a pro-rata share of the state wide targets.

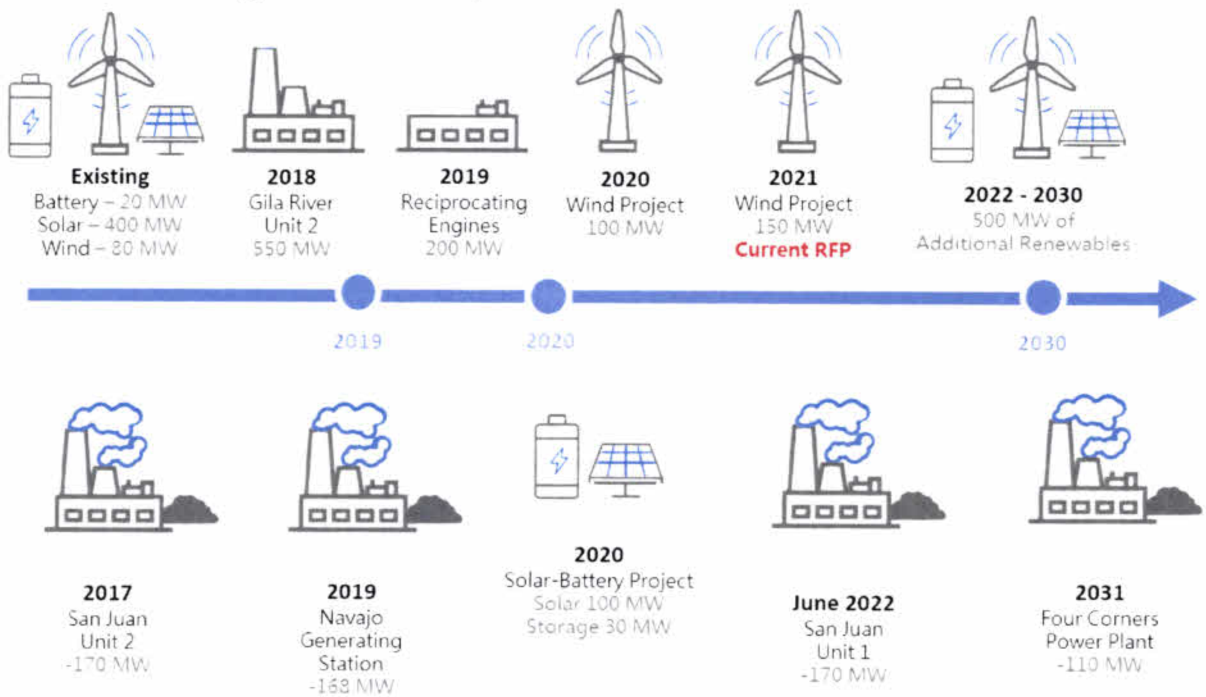
[2] While the Resource Plan targets 55% by 2050, the financial analysis only runs through 2040 since the Company's resource planning models are currently only configured to run through 2040. The Company plans to extend the models in future updates.

only low capacity factor intermittent renewables.[3] In addition, without flexibility for existing coal resources, under the EMP, TEP's baseload coal generation would face retirement by 2035 in order to accommodate the high penetration of renewable resources.[4] This early retirement of TEP's coal generation fleet would reduce the Company's portfolio diversity and resiliency over the long-term.[5] TEP highlights these major differences in the EMP versus TEP's updated Resource Plan including the long-term costs requirements under each plan.

TEP's Resource Planning Requirements from 2018 - 2030

Based on the Company's updated Resource Plan, TEP would continue to target serving 30% of its retail load from renewable resources.[6] This plan would also meet the compliance under the EMP through 2030. The Resource Plan shown in the timeline in Figure 1 below reflects TEP's updated resource plans that will be submitted as part of its April 30, 2018 short-term action plan update filing.

Figure 1 - TEP's Updated Resource Plan from 2018 - 2030



[3] Under the EMP, the 'clean energy' carve out for nuclear generation will provide utilities with nuclear resources a significant compliance advantage since a substantial portion their 'clean energy' requirements will be fulfilled by these high capacity factor baseload resources. In addition, these same utilities will have less reliance on renewable resources in the near term and will avoid the associated cost of integrating renewables into their system.

[4] The Company's current end of useful life for Springerville Unit 1 is 2045 and Unit 2 is 2050 (60-year life).

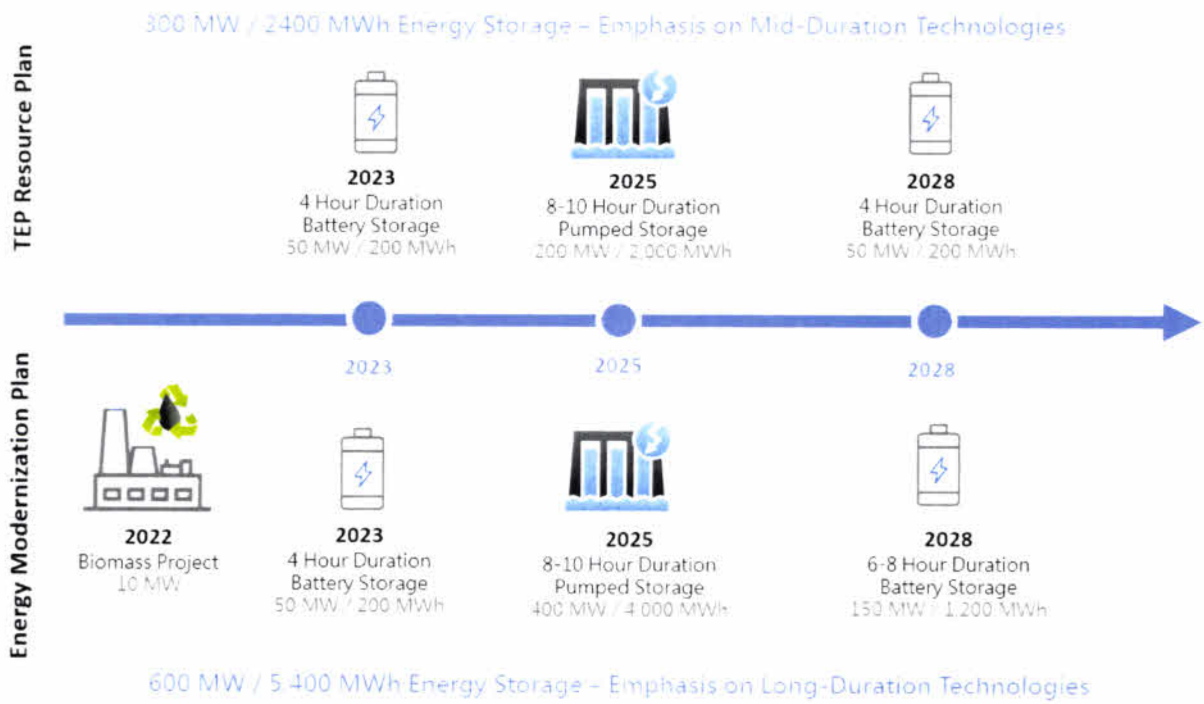
[5] Under high renewable penetration scenarios, TEP would have to retire large increments of coal capacity at the Springerville Generation Station (Unit 1 - 387 MW & Unit 2 - 406 MW) and replace this capacity with a mix of natural gas generation and energy storage resources in order to maintain its system diversity and resiliency.

[6] Using a straight line approach in setting the 'clean energy' targets under the EMP, TEP would need to have approximately 28% of its retail load served by renewable resources by 2030. This amount rises to 41% by 2035 and 54% by 2040.

Differences in the TEP Resource Plan and the EMP through 2030

From 2018 through 2030, the TEP Resource Plan varies from the EMP in two specific areas. The first difference is the proposed requirement for all state regulated electric utilities to procure a proportional share of biomass energy from a 60 MW biomass facility starting in 2022. Under this requirement, TEP estimates it would need to procure approximately 10 MW (70,080 MWh of biomass energy each year).[7] The second requirement where the EMP varies from TEP's Resource Plan is the requirement for the state to pursue a target of 3,000 MW of deployed energy storage by 2030. Assuming that each electric utility would be responsible for the procurement of a prorata share of this requirement, by 2030, TEP would need to increase its future energy storage requirements from 300 MW (medium-duration storage technologies) to 600 MW (long-duration storage technologies). This differences are shown on the timeline in Figure 2 below.

Figure 2 - Differences between the EMP & TEP's Resource Plan from 2018 - 2030



The EMP Results in Significant Cost Increases through 2030

While these capacity differences in the Resource Plan from 2018 through 2030 may seem insignificant, the cost associated with these increased investments in biomass and energy storage are significant. Between 2018 and 2030, TEP 's total revenue requirements would be approximately $804 million higher under the EMP. The primary drivers behind this revenue requirement increase is a result of spending approximately $53 million more on biomass energy

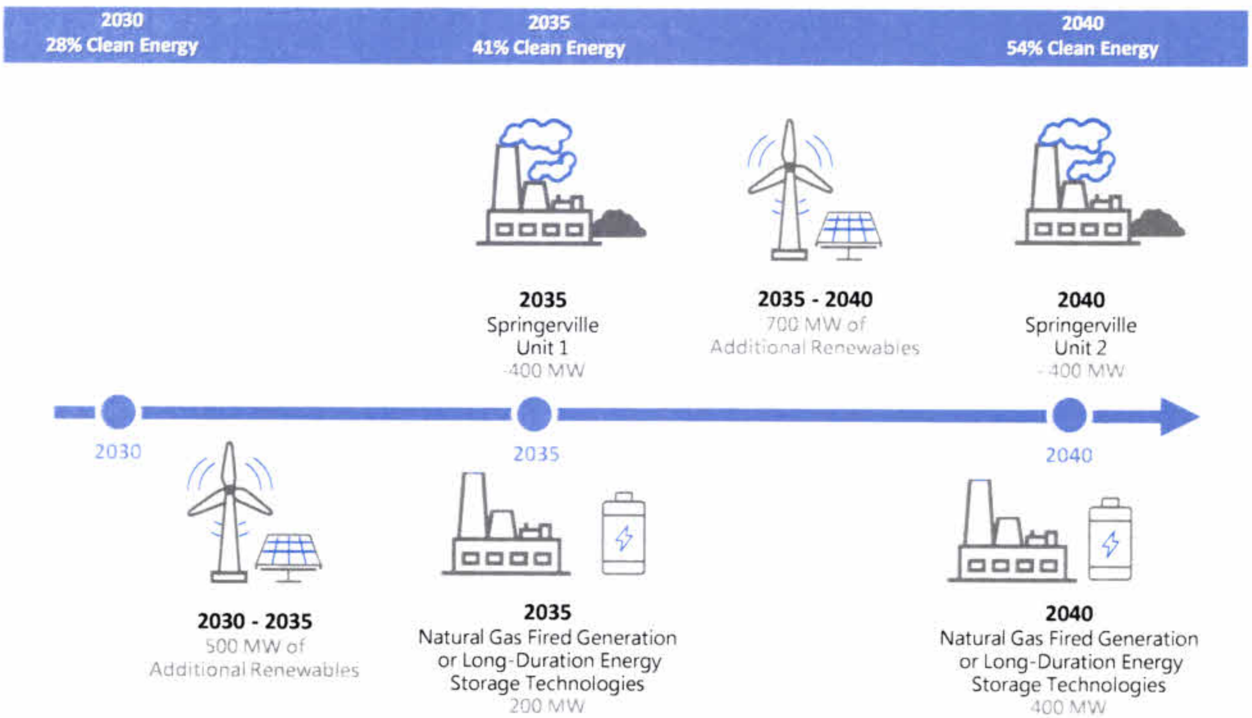
[7] This estimate assumes TEP would be responsible for 10 MW (17%) of the capacity from the 60 MW biomass project. (10 MW x 8,760 hours x 80% capacity factor = 70,080 MWh).

versus lower cost solar or wind energy[8] and $673 million more in energy storage investments.

TEP's Planning Requirements from 2031 - 2040

Figure 3 below shows the planning requirements beyond 2030 when the 'clean energy' targets under the EMP grow to 41% by 2035 and 54% by 2040. These compliance targets will result in significant changes to TEP's long-term resource portfolio. By 2040, under the EMP, the Company would have to retire approximately 800 MW of coal fired generation (assuming there aren't any carve-outs for existing coal-fired resources) and in its place install approximately 600 MW of natural gas fired generation or long duration energy storage to maintain reliability during the hours when renewable resources are unavailable. Finally, TEP would need to install approximately 1,200 MW of additional renewable capacity bringing its total renewable capacity to 2,600 MW by 2040.

Figure 3 - TEP's Updated Resource Plan from 2031 - 2040



As shown in Table 1 below, by 2040, TEP would need to grow its resource capacity to 5,176 MW in order to serve its firm load obligations of 2,932 MW and meet compliance under the EMP.

[8] The excess is a result of paying $95/MWh more for bio-energy versus 'clean energy' from a solar resource. [$53 million = 70,080 MWh (See footnote 3) x ($125/MWh for bio-energy less $30/MWh solar energy) x 8 years]. This excess would cost TEP retail customers approximately $133 million more in 'clean energy' over the life of a 20-year contract.

Table 1 – TEP's Firm Load Obligations versus Resource Capacity under the EMP

Peak Demand, MW	2018	2020	2025	2030	2035	2040
Firm Load Obligations	2,784	2,825	2,812	2,837	2,916	2,932
Resource Capacity, MW	**2018**	**2020**	**2025**	**2030**	**2035**	**2040**
Coal Resources	1,241	1,073	903	793	406	-
Natural Gas Resources	1,753	1,783	1,783	1,660	1,556	1,556
Direct Load Control & Energy Storage	52	62	502	612	824	1,026
Renewable Resource (Utility Scale & DG)	485	524	1,004	1,468	2,229	2,593
Total Resource Capacity	3,531	3,441	4,192	4,533	5,015	5,176

Early Retirements at the Springerville Generating Station ("SGS")

Without any coal-related carveouts under the EMP, TEP would need to retire SGS Unit 1 by 2035 and SGS Unit 2 by 2040 in order to accommodate the high level of renewable capacity to meet the EMP compliance targets. By 2030, TEP's system would have approximately 1,450 MW of renewable capacity and during the non-summer months[9] the Company would need to employ new operating strategies that utilizes both charging of energy storage and baseload coal curtailments in order to avoid periods of over generation. By 2035, when TEP's renewable capacity grows to approximately 2,225 MW, this will result in significant coal unit curtailments throughout the year that will lower the capacity factors at SGS below 50%. This reduction in coal operations will have a negative economic impact on both the viability of SGS as well as the mine operations at El Segundo. Under these future EMP compliance targets, the Company will be forced to eliminate any baseload coal generation from its fleet in favor of new natural gas or energy storage technologies.

SGS Retirements and Potential Stranded Investments

By 2035, the total net book value of SGS Units 1 & 2 will be approximately $350 million. If the EMP does not allow for carveouts related to coal-fired resources, the Company would work with the Commission through future rate cases to adjust the useful lives of its coal fired assets to accelerate the depreciation of those assets to align with potential early retirement dates in order to minimize the level of stranded costs for TEP's customers.

Regional Economic Impacts due to the Closure of Springerville Units 1 and 2

An economic study conducted by Dr. Anthony Evans and Professor Tim James at the L. William Seidman Research Institute, at Arizona State University ("ASU Study") examined the direct, indirect, and induced economic impacts related to the closure of SGS at the county and state level. For purposes of this analysis, TEP assumes that if Units 1 and 2 at SGS close that approximately 40% of the total economic impacts assessed in the ASU study will be realized. As shown in Table 2 below the closure of SGS will result in the loss of approximately 765 jobs and

[9] During the months of November through April TEP's average daily peak demands are approximately 1,200 MW.

a loss of approximately $151 million in Gross State Product in Apache County alone (2013 Dollars).

Table 2 – Overview of Economic Impacts Associated with the Closure of SGS Units 1 &2 (CY2013)

Economic Indicators	State of Arizona	Apache County
Loss of Total Private Employment (Job Years)[10]	1119	765
Loss of Gross State Product (Millions) [11]	$182	$151
Loss of Real Disposable Personal Income (Millions)[12]	$61	$44

The EMP Results in Significant Capital Expenditure Increases through 2040

Under the EMP, TEP's capital expenditures between 2018 and 2040 would be approximately $2.5 billion higher than TEP's updated Resource Plan that targets serving 35% of its retail load with renewable resources by 2040. Table 3 below shows the capital expenditure differences between the plans by investment type.

Table 3 - Summary of Capital Expenditures by Investment Type (2018-2040)

Capital Expenditures, $000	TEP Resource Plan	EMP	EMP vs. TEP Resource Plan
Existing Generating Resources	$772,702	$711,632	-$61,070
New Generation Resources	$334,634	$334,634	$0
New Renewables Resources	$1,413,827	$2,303,847	$890,020
New Transmission Resources	$150,053	$150,053	$0
New Energy Storage Resources	$1,169,895	$2,841,807	$1,671,912
Total Capital Expenditures	$3,841,111	$6,341,973	$2,500,862

The main differences in capital expenditures between the EMP and TEP's Resource Plan are primarily related to higher investments in renewables and storage technologies. By 2040, under the EMP, the Company would invest approximately $1.6 billion more energy storage technologies[13] and $890 million more in renewable resources. In addition, TEP would reduce its investments in its existing resources by $61 million as a result of the early retirement of SGS Units 1 and 2.

TEP Rate Payer Impacts under the EMP

In comparing the rate impacts between the two resource plans as shown in Table 4 below, by 2030 rates increases under the EMP would be approximately twice that of TEP's Resource Plan and two and half times higher by 2040. These rate increases only assume cost impacts

[10] A job year is equivalent to one person having a full-time job for exactly one year.

[11] This is the market value of goods and services produced by labor and property in a specific geography.

[12] This is the household income that is available to be spent after taxes have been paid.

[13] Of this $1.6 billion increase in storage investments, approximately $673 million would be incurred by 2030 with the remaining $1 billion being incurred from 2030 to 2040.

associated with the changes to the resource portfolio and exclude other investments related to the high voltage transmission and distribution systems.

Table 4 - Summary of Average Rate Increases by Time Periods (2030 & 2040)

Timeframe	TEP Resource Plan	EMP	EMP vs TEP Resource Plan
2018-2030	5.5%	11.9%	218%
2031-2040	7.1%	17.5%	248%

The Factors Leading to the Closure of the Navajo Generation Station

The TEP Resource Plan assumes that the Navajo Generating Station ("NGS") will shut down in December 2019. While it was contemplated by the plant participants to possibly extend the operation of NGS out to 2030, the decision to exit the project in 2019 was driven primarily by the long-term outlook of low natural gas prices and the increased penetration of renewable resources across California and the Desert Southwest.

Reduction in Overall Natural Gas Demand and Commodity Prices

The build out of renewable resources is dramatically reducing the power sector's overall demand for natural gas.[14] Low load growth coupled with a higher penetration of renewable energy has resulted in historically low natural gas and wholesale power prices during the last three years. This trend is forecasted to continue for some time due to the increased efficiencies in shale production and the declining cost of renewable energy resources which are below the cost of traditional fossil fuel resources.

[14] NREL Study: A Retrospective Analysis of the Benefits and Impacts of U.S. Renewable Portfolio Standards. https://emp.lbl.gov/sites/all/files/lbnl-1003961.pdf

Chart 2 – 2018 – 2027 Forward Permian Natural Gas Prices ($/mmBtu)[15]

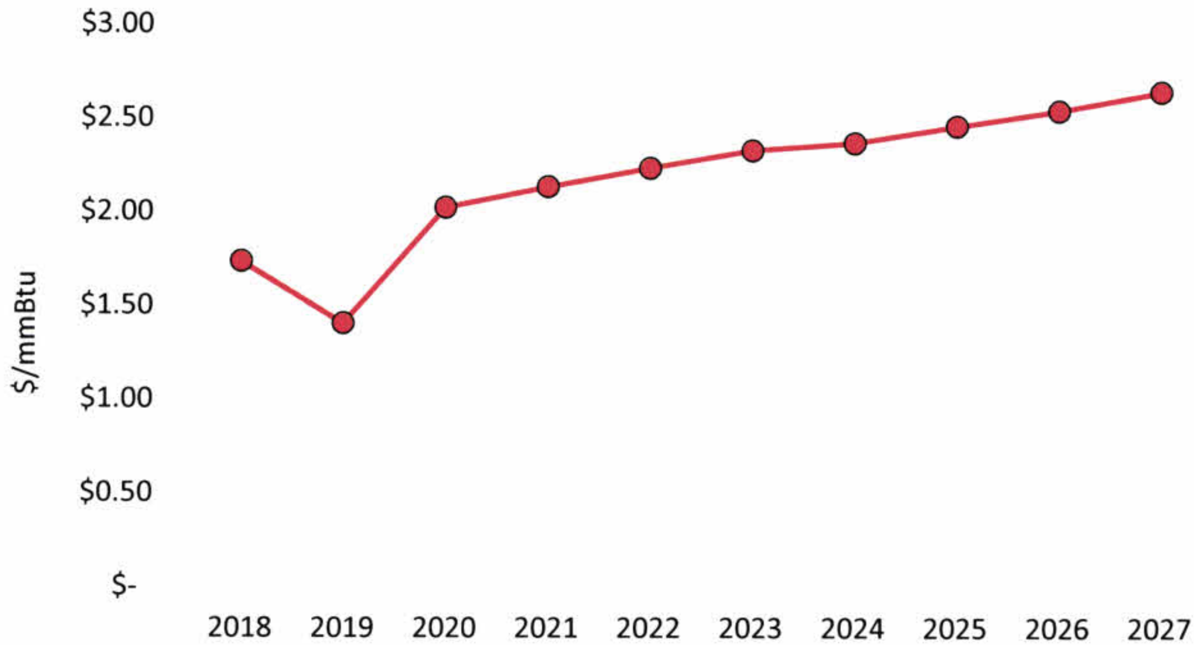
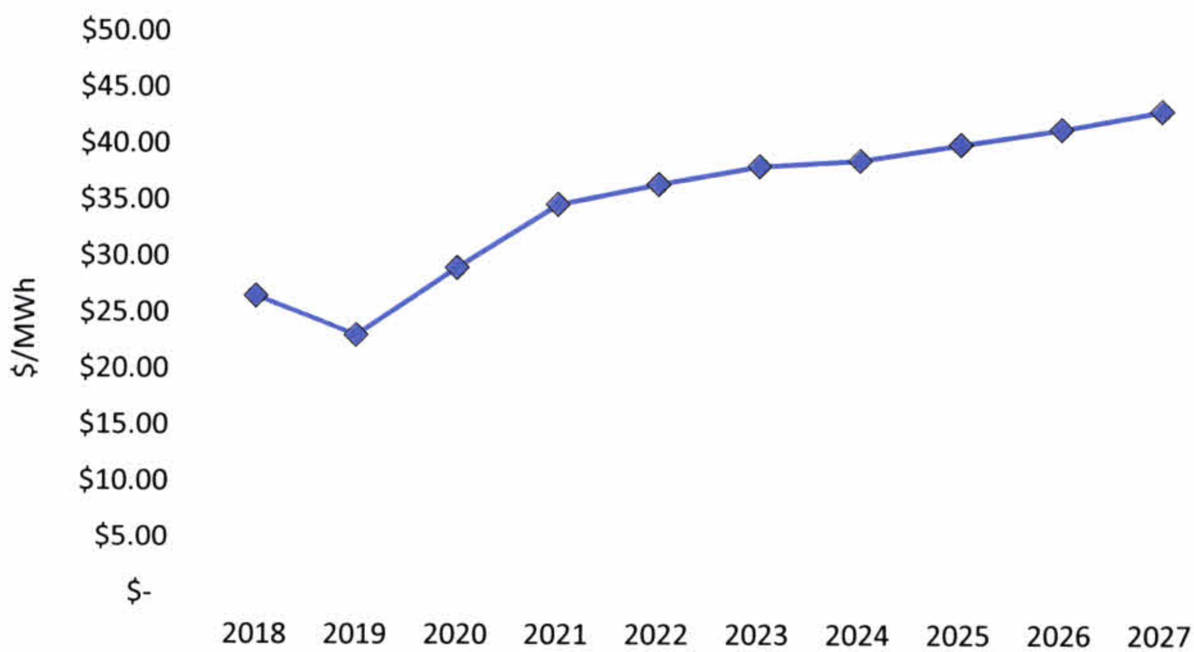


Chart 3 – 2018 – 2027 Forward Palo Verde Power Prices (7x24 $/MWh)[16]

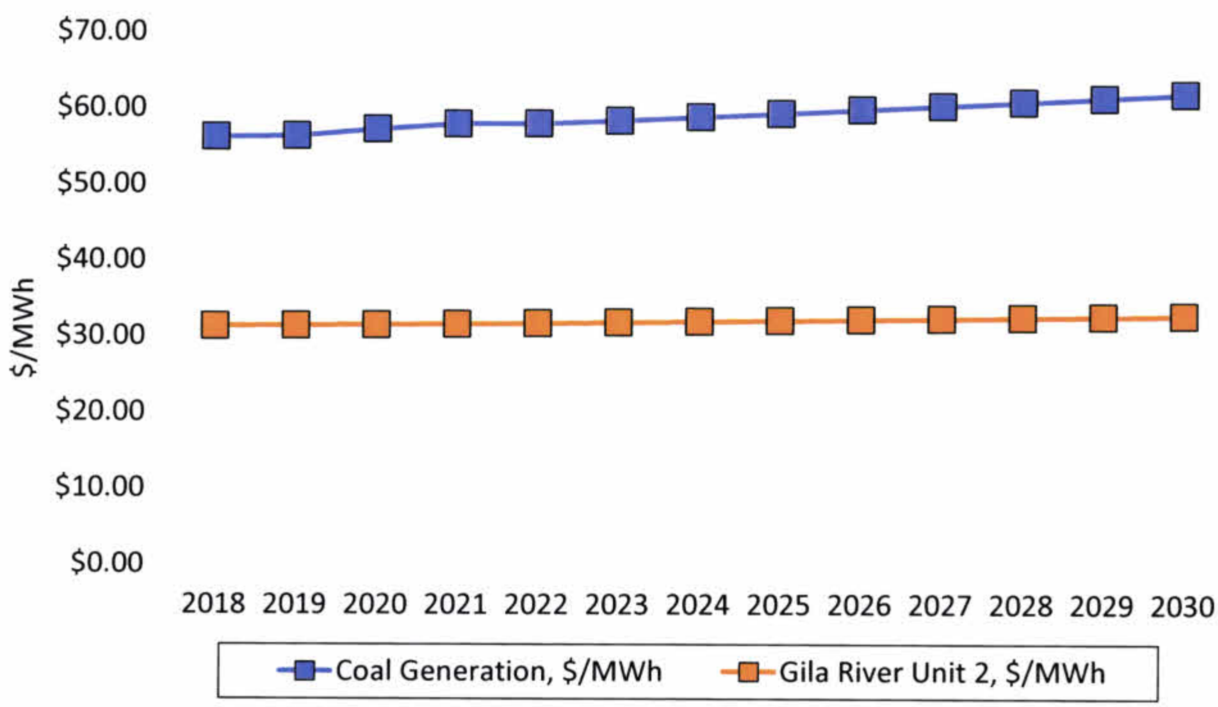


[15] Forward natural gas price projections based on April 2018 NYMEX and Chicago Mercantile Exchange data.
[16] Forward Palo Verde market price projections based on April 2018 NYMEX and Chicago Mercantile Exchange data.

Economics of Baseload Generation Resources

In this low power price environment, plants like coal and nuclear, which have large fixed costs, cannot fully recover their cost of operations. Thus, the ultimate effect of high penetrations of renewables and low cost natural gas will accelerate the retirement of baseload resources like coal and nuclear. Alternatively, resources like natural gas combined cycle ("NGCC") units that have much lower capital and fixed costs are more competitive than coal and nuclear in today's wholesale power markets. This competitive advantage has set the stage for NGCC units to displace coal and nuclear as baseload resources since they are better positioned to maintain profitability in a market driven by low natural gas prices. As noted in a 2017 Wood MacKenizie report, "despite speculation on US energy policy changes, recent analysis suggests low natural gas prices are one of the biggest disruptors of the power sector. This long-term low price trajectory will cause natural gas to increasingly displace coal in the foreseeable future. Because of this trend and steady growth in renewables, baseload resources like coal and nuclear will likely have trouble recovering their costs over the long term."[17] Chart 4 below compares the total cost of coal generation in comparison to the total cost of Gila River Unit 2.

Chart 4 - Comparison of Coal versus Natural Gas Combined Cycle Resources ($/MWh)

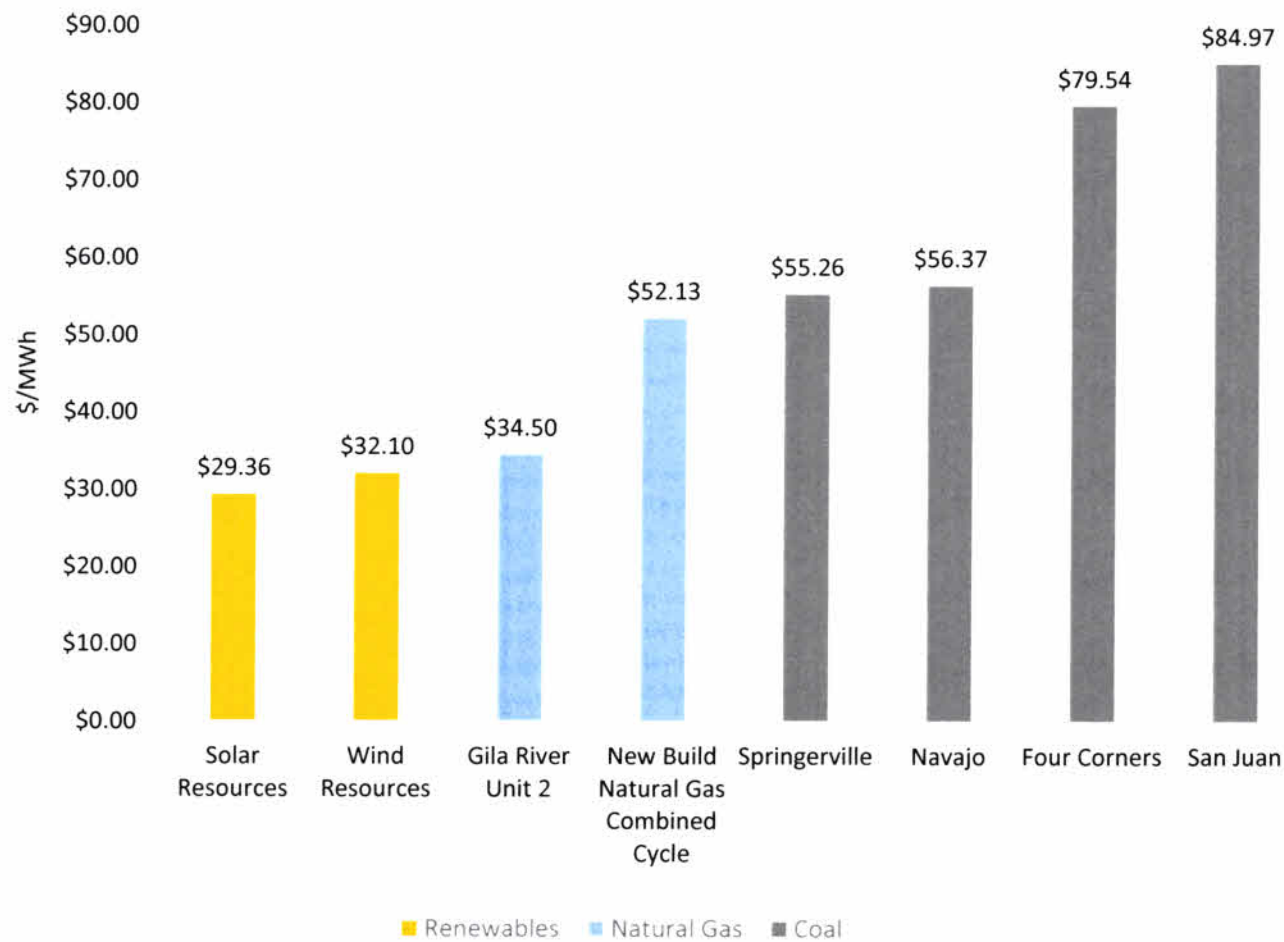


[17] Long-term forecast projections based on Wood-Mackenzie, North America Gas, Power and Coal Markets–No Carbon Case. February 2017.

Cost of Energy by Resource Type

Chart 5 below compares the cost of energy by resource type. These cost comparisons are based on the Company's price projections for its coal facilities assuming operations between 2020 and 2030. The renewable resource cost estimates are based on data gathered through our competitive bidding processes and recent requests for proposal (RFP) solicitations.

Chart 5 – Cost of Energy by Resource Type 2020 - 2030 ($/MWh)



Renewable Resource Notes:

The solar resources are based on an average of bid submittals from TEP's 2017 Solar RFP. These solar projects assumed the benefit of a 30% investment tax credit. The wind resources are based on an average of bid submittals from TEP's 2017 Wind RFP. These wind projects assumed the benefit of a $24/MWh production tax credit.

Natural Gas Resource Notes:

Gila River Unit 2 is based on an acquisition cost of $300/kW. The new build natural gas combined cycle construction costs are assumed to be $1,100/kW. Forward natural gas price projections based on April 2018 NYMEX and Chicago Mercantile Exchange data and are reflected in Chart 2 above. Natural gas transportation is also captured as fixed fuel cost for all natural gas resources.

Coal Resource Notes:
The coal generating stations are based on TEP's current coal supply agreements or offers that were put forth as potential fuel supply extensions. The Navajo Generating Station fuel cost assumptions incorporates the coal supply discount offer put forth by Peabody Energy in its letter dated February 8, 2017 to the NGS participants. All on-going O&M and capital costs are based on projected budgets through 2030.

RESPONSES TO SPECIFIC REQUESTS FOR INFORMATION

The Companies hereby provide their responses to the specific requests set forth in the NOI. The Companies have responded to many, but not all, of the requests because they may not have developed a position or possess sufficient information to provide a meaningful response to certain requests at this time.

1. Public Interest/Cost Benefit

The Companies have address many of the questions below in the preceding Introduction and the Preliminary Financial Analysis.

a. Please provide a thorough analysis of the prospective cost to ratepayers of the Energy Modernization Plan.
b. What is the potential impact/consequences to ratepayers?
c. What is the possibility of stranded investment?
d. What is the magnitude of stranded investment?
e. What is the potential for cross-subsidization between regulated public service corporations' functions and non-regulated functions?
f. What is the positive and/or negative impacts to reliability and resiliency?
g. What is the amount of additional investment that may be required to comply with or implement the Energy Modernization Plan?
h. What is the possibility of negative pricing to Arizona ratepayers as a result of the Energy Modernization Plan?
i. What is the magnitude of negative pricing to Arizona ratepayers as a result of the Energy Modernization Plan?
j. How much of the utilities current energy portfolios would be classified as "clean?"
k. Can utilities project how their energy portfolios will appear by 2050 without the Energy Modernization Plan?
l. How would future energy planning change for utilities if the Energy Modernization Plan is adopted?
m. If the Energy Modernization Plan is adopted, would utilities change their plans regarding the useful life of current coal plants?
n. How does the cost of continued use of coal plants compare to the cost of new natural gas plants or solar projects?
o. Under the Energy Modernization Plan, do utilities expect they would prematurely close coal plants?.
p. How do utilities expect consumer prices to change with coal plant retirements?
q. What is the cost per kWh of electricity currently produced at the Navajo Generating Station ("NGS")?
r. How does that compare to cost per kWh at other coal facilities in Arizona?
s. What factors are leading to the closing of NGS?

t. How much does it currently cost to build a utility scale solar project?

The current installed cost for a utility-scale solar project is approximately \$1.00 per watt to \$1.75 per watt, depending on the size of the system.

u. How does that compare to the current cost to build a natural gas plant for the same electricity output?

v. What percentage of each utility's customers currently have residential solar panels?

TEP has about 385,000 residential customers overall, and it currently has roughly 18,600 residential customers with solar systems at their premises. This equates to about 4.85% with systems. UNSE has about 85,000 residential customers overall, and it currently has approximately 3,000 residential customers with solar systems at their premises. This equates to about 3.53% with systems.

w. Please provide the trend over the last five years?

x. Please project how many new residential solar projects will be completed in the next ten and twenty years?

We assume that customers will still continue to install solar systems. Many factors will influence adoption, such as the cost of solar panels, solar panel and metal tariffs, changes to investment tax credits, and changes in utility rate structures. It is not possible to predict how any systems will be installed ten or twenty years from now.

y. How much storage is currently being used by the utilities?

TEP currently has three utility-scale battery storage systems deployed; (1) 1 MW, and (2) 10 MW batteries.

z. How long have those storage projects been in effect?

All three battery projects have been interconnected since the 1st quarter of 2017.

aa. What are the capabilities of current batteries in terms of kWh storage?

The 1 MW battery is capable of delivering 1 MWh of energy. Both of the 10 MW batteries are each capable of delivering 2.5 MWh of energy.

bb. How much of the peak demand can be expected that storage will be able to mitigate in the next five to ten years?

TEP does not expect to use energy storage in the next 5-10 years to reduce peak demand. TEP does expect to use energy storage for the integration of renewable energy resources. See 1.z.tt-ww

cc. How do the utilities expect to invest in storage without the Energy Modernization Plan?

As more intermittent resources are connected to the grid, we will work to identify locations on the distribution network where a battery system can provide benefits. Battery storage on the distribution grid is potentially able to help alleviate issues such as voltage spikes, solar over-generation above minimum daytime load, and substation backflow. At a grid-scale level, the we will look for solutions such as pumped-storage hydro facilities and fast-responding gas resources to help mitigate issues caused by the non-coincident peak of solar plants. These types of resources can help react to the steep afternoon load ramps that are expected in the future. In addition, they can firm up fluctuating power output caused by the weather.

dd. What energy storage projects are currently being contemplated?

In addition to the 21MW of battery energy storage currently operating, TEP is contracted for 30MW of 4-hour (120 MWh) battery energy storage as part of the 100MWac Solar PV PPA scheduled for commercial operation in late 2020. TEP is currently contemplating purchasing or contracting for up to 200 MW of the proposed Big Chino Valley pumped-storage hydro project, which is expected to be online in 2025. In addition, TEP's resource plan contemplates 100 MW of battery energy storage in 2031.

ee. Is a target of 3,000 MW of energy storage by 2030 an attainable goal?

Yes, 3,000 MW of energy storage may be an attainable goal, as long as all storage resources in the state are considered (regardless of technology, ownership or the state/jurisdication served by the storage project) and the Big Chino pumped hydro project reaches commercial operation.

ff. Is a mandate related to Arizona's forests a proper function of the Commission's mission to regulate utility rates?

The Companies support some level of utility participation in forest bioenergy proportionate to the size of their respective resource portfolios and customer bases. The PPA or ownership/operating costs should be recoverable in rates.

gg. Is there a constitutional or statutory provision granting authority to the Commission to issue policy regarding Arizona's forests?

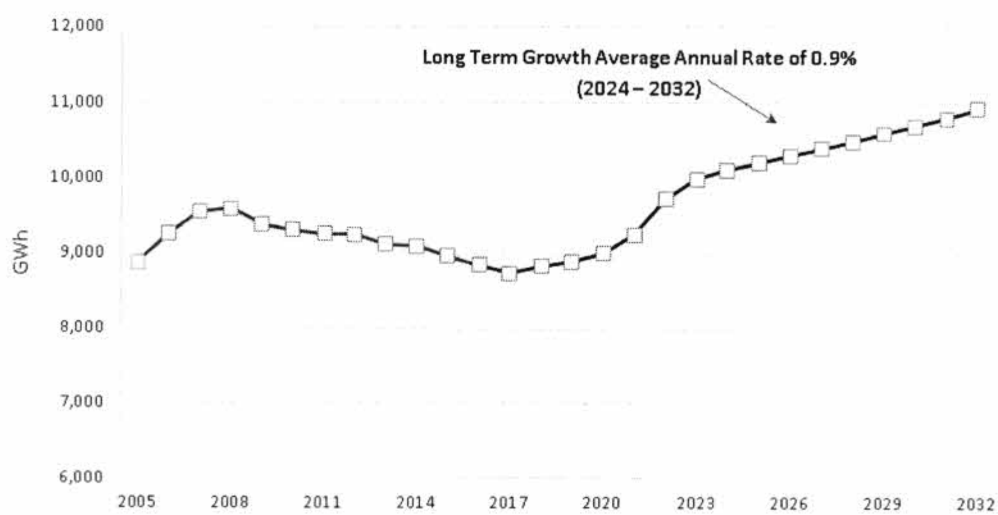
hh. If the health of Arizona forests is a statewide issue, should that issue be debated and discussed at the Arizona Legislature?

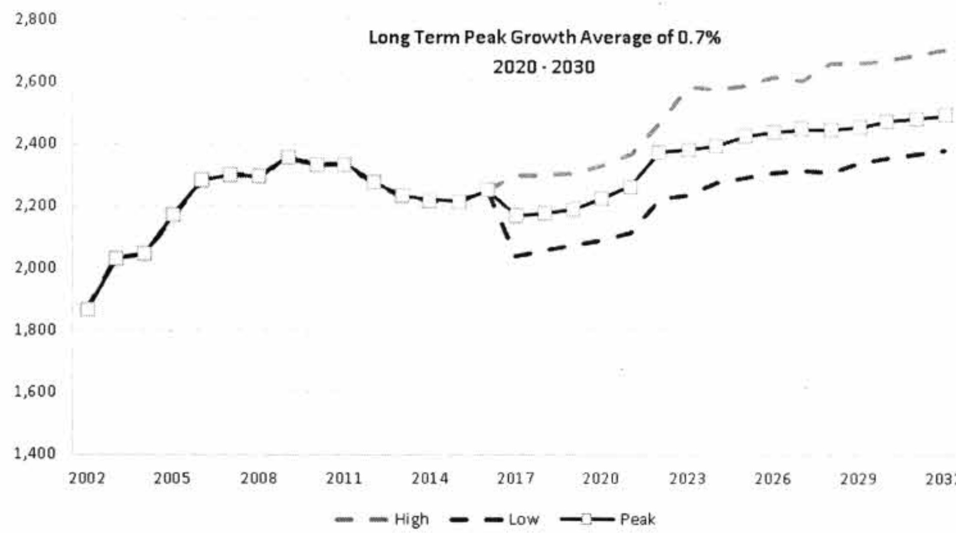
See part 5 below.

ii. What percentage of Arizona electric customers does the Commission regulate?
jj. Which utilities provide the balance of the electricity?
kk. How much biomass energy is currently procured by Arizona utilities?
ll. Why did utilities decide to enter contracts for biomass energy?
mm. What is the price per kWh of the current biomass contracts?
nn. How does that price compare with energy produced from conventional sources?
oo. Is biomass energy currently procured by any other plant besides Novo BioPower in Snowflake, Arizona?
pp. Are there any other options for procuring power from biomass in Arizona?
qq. When do the current power purchase contracts expire?
rr. Do the utilities expect to renew those contracts? Why or why not?
ss. Without any action from the Commission, would Arizona utilities continue to procure biomass energy?
tt. Please explain how utilities currently meet peak demand?

The following comments apply to 1.z.tt-ww.

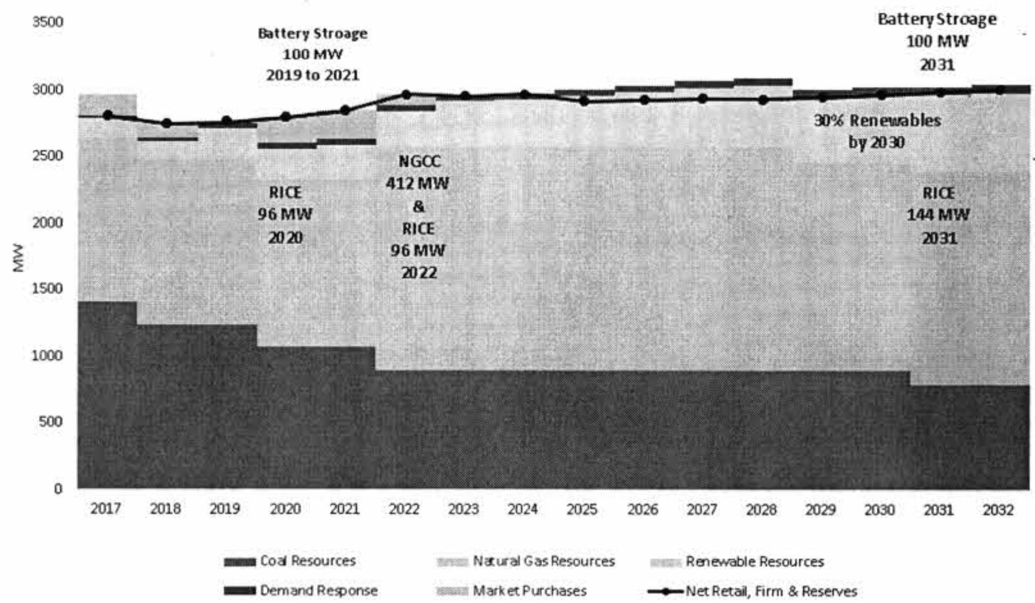
The charts below show TEP's anticipated load growth and peak load growth at less than 1% annually.





With these relatively low load growth projections, along with TEP's current plan to meet 30% of retail load using renewable resources by 2030, and more so under the EMP, the primary planning objectives are (1) to cost effectively add grid balancing resoruces to the portfolio to address the variability in load caused by higher penetration of intermittent renewable resources, and (2) to manage mid-day over generation duing spring and fall months while having sufficient resorurces on line to meet a steep ramping requirement as solar output fades. The combination of TEP's planned expansion of renewable resources as well as the grid balancing resources needed to satisfy these key objectives, therefore TEP does not plan to add any new resources over the planning period to meet current or projecte peak deamd.

A summary of TEP's loads and resources is presented in the chart below.



TEP's solar resouces alone have coincident peak factors of greater than 30% for fixed-tilt and greater than 60% for single-axis tracking. TEP is also investing in approximately 200 MW of Reciprocating Internal Combustion Engine (RICE) technology and 30 MW of 4-hour battery energy storage to address renewable energy intermittancy.

TEP's limited peak load growth projections combined with the current and planned resource acquisitions leaves the Company very little flexibility to target investments focused on generating clean energy during the peak unless additional existing baseload resources are retired.

uu. What is the cost of meeting peak demand for each generating source?

vv. What is the current feasibility of using dispatchable clean energy during peak demand?

ww. Are there clean energy projects already contemplated for use during peak demand?

TEP's existing battery energy storage systems are not currently used for peak demand. Our general view of future energy storage systems is that battery energy storage projects will be used primarily for distribution-level optimization, and system level ancillary services relating to renewable energy integration, though they may also provide energy during peak demand as conditions permit. The Big Chino pumped hydro project also has many use cases, however, would be used primarily for system level benefits including meeting late afternoon ramp requirements, generating power during on peak hours, and even energy arbitrage. A planned 100 MW solar PV facility, with

attached 30 MW (120 MWh) battery will not necessarily be designed to meet peak demand, but it is a potential use case.

xx. Is it a proper function of the Commission to require ratepayers to pay for electric vehicle infrastructure?

The Companies believe that EV infrastructure should be a component of an integrated resource plan in order to incentive mid-day charging as a way of alleviating over generation from renewables.

yy. What is the relationship between electric vehicle infrastructure and a utility's costs of providing electricity?

EV infrastructure could be treated similar to other assets and included in the utility's rate base.

zz. If electric vehicle infrastructure would benefit all Arizonans, should the issue be debated and discussed at the Arizona legislature?

aaa. What percentage of Arizonans currently use fully electric cars?

bbb. How do Arizonans currently charge their electric car?

To the Companies' knowledge, residential customers are able to charge their vehicles via Level 1 or Level 2 charging station. Public charging stations are also available in some cases at Level 2 or Level 3.

ccc. If Arizonans with electric cars desire charging stations around Phoenix, would the market provide that service?

ddd. Do Arizona utilities have any plans to be involved with electric car stations?

At the request of Commissioner Tobin and Chairman Forese[1], TEP filed an EV plan on December 22, 2017 in Docket No. E-01933A-17-0250.

eee. If Arizona utilities built electric vehicle infrastructure, would the investments be included in rate base?

Rate base treatment is consistent with TEP's proposed EV plan.

fff. Is it just, fair and reasonable to charge ratepayers for infrastructure that is only used by a certain population of Arizonans?

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[1] Letters filed in multiple dockets on Nov. 27-28, 2017.

Yes. TEP and UNSE have proposed EV plans that include rate base treatment of EV infrastructure.

ggg. Should a utility customer have exclusive rights to an electric charging station built by that utility?

This is a policy decision to be made by the Commission.

hhh. How will the customer be charged, at what rates, and who sets those rates?

The Commission would ultimately approve such rates.

2. Policy Framework

The Energy Modernization Plan proposes to use the Renewable Energy Standard and Tariff ("REST") policy framework for modernizing the state's energy policy to be renamed the Clean Resource Energy Standard and Tariff ("CREST").

a. Please describe the entities which would be required to participate in the state's energy policy.

Broad stakeholder participation is an important step in the development and implementation of the EMP. All interested parties should be provided a forum to provide input.

b. Should the Energy Modernization Plan encompass entities not regulated by the Commission such as municipal corporations or quasi-federal entities?

It is unclear how the Commission would facilitate the participation of non-ACC regulated entities.

c. Would legislation be necessary to include such entities as participants in the Energy Modernization Plan?

d. Should the Energy Modernization Plan apply to all utilities regardless of size or characteristics, or should certain utilities, for example small companies and/or cooperatives, be treated differently?

The EMP should be structured to cover the affected utilities pro rata share of the overall state policy objectives. In addition, the Commission should consider, among other things, the unique circumstances of each affected utility during the development and implementation of the Plan. The Companies oppose a one size fits all plan.

e. Please comment on any energy policy in Arizona you deem to be outdated, explain why, and identify proposed improvements to these policies.

Renewable energy and EE targets should be focued on providing cost-effective benefits to the grid rather than simply achieving broad annual kWh targets.

f. Please explain the role of traditional regulated energy providers changing in the future as a result of market and technological changes.

g. Please comment regarding the Energy Modernization Plan's flexibility of allowing 20% of the energy mix to come from resources other than the clean resources described in the Energy Modernization Plan.

The following comments related to 2.g-l,n; 3.d; 6.a-e

TEP's resouce plan calls for achieving a portfolio roughly evenly balanced between coal, natural gas (included purchased power), and renewable resoruces by 2032.

TEP's portfolio was identified through the IRP based on the need to (1) maintain affordable rates, (2) improve environmental performance by reducing emissions and water consumption, and (3) limit the risk associated with unforeseen future conditions.

TEP believes that planning processes focused on these types of customer-focused objectives, which often compete with each other, is in the best interest of our customers. While it may be reasonable to expand the list of objectives, potentially to include jobs, economic development, or other metrics important to the community, TEP believes that plans designed to meet rigid, state-wide standards are often counter productive in that they do not take into account each utility's unique circumstances.

For example, TEP plans to reduce generation from coal by 20% over the next five years. Such a goal is not applicable to UNS Electric, as there is no coal in its portfolio. In fact, it may not even be appropriate for UNSE to target a reduction in direct emissions[2] as UNSE has acquired resources to reduce its reliance on market power.

The installation of renewable energy resources, and for that matter the implementation of energy efficiency measures, should not be goals in and of themselves, rather, they are the tools that utitlies deploy to meet broader resource planning objectives. The rate of deployment and the specific technologes and measures that are used should vary by utility.

Implementing one-size-fits-all standards (whether they be for renewable energy, baseload energy, energy efficiency, etc) almost ensures sub-otimal

[2] "Direct emissions" referes to emissions from generating facilities owned by the utility. Emissions from purchased power would not be considered "direct emissions".

ecomonics by requiring resources either earlier or later than they are actually needed. In addition, procuring a resource to meet a specific standard can make that resource unavailable to perform potentially higher value services.

For example, if TEP were to employ battery energy storage in order to meet a Clean Peak Standard, that resource would need to be reserved for the hours that qualify as peak hours even if it would have been more cost effective to deploy that battery ealier in the day for different grid-related services.

h. Please address anticipated costs of implementation of the CREST standard, including implications for stranded costs, and ratepayer impacts.

i. What level of existing non-clean resources would have to be retired or sold to merchant companies? How rapidly should retirement occur?

See 1(c) and 1(m) above.

j. Please discuss the role of merchant generation (clean and non-clean) with respect to the Energy Modernization Plan.

These generating resources should be accounted for in the EMP to the extent they are serving affected utilities under purchased power agreements.

k. Please comment regarding the appropriateness of the 20% limit on "non-clean" resources.

The Companies believe this limit should be determined by the IRP process rather than prescribed in a rule.

l. Is this enough to ensure reliability of the bulk electric transmission system and local distribution systems?

See (k) above.

m. Who would benefit, and in what manner, from the Energy Modernization Plan? Please include a consideration of costs associated with the benefits of the Energy Modernization Plan. Should the costs be borne by the beneficiaries?

n. What role should natural gas, both a fuel for power generation and for the provision of service to end users, play in the Energy Modernization Plan?

The following answer responds to parts n-p.

Current and future expected renewable penetration into regional energy production requires an increase in resources with fast ramping ability. The market, depending upon import/export constraints, market depth, and market prices may also be used to balance renewable intermittency and the ramping requirements of the "duck" or "camelback" curves. Batteries, natural gas storage, and pumped storage will each have increased value in an environment with increased renewable generation. Natural gas storage, and its associated generation, is both lower in cost and has longer duration than batteries and pumped storage. Despite the lower cost and longer generation of natural gas storage and associated generation, diversification of storage technologies is valuable. Diverse storage technologies may provide improved resiliency through geographic diversity and unique performance profiles.

The existing natural gas infrastructure, assuming growing gas demand in the Southwest, may not support increased variability in power demand. El Paso's South Mainline is rapidly reaching capacity and may soon be fully subscribed due to increasing international demand. Local natural gas storage is an efficient solution in comparison to a large project from the Permian or San Juan basins. Building local natural gas storage will expand delivery options available and avoid the cost of a mainline project. This will benefit natural gas LDCs as well as electric utilities. Black-start capability is an added benefit to electric utilities of local natural gas storage. Freeze-off events, or other force majeure events can also be avoided by the presence of local natural gas storage. Each mile of natural gas haul reduced also reduces the risk of disruption of supply. Improved resiliency, reliability, and deliverability are all exceptional benefits of natural gas storage.

o. Will the flexibility of natural gas-fired generation continue to play an important role in Arizona's energy future?

p. Given Arizona's expected reliance on natural gas generation in the coming decades, discuss the importance of continued efforts to develop market area natural gas storage and other tools to provide more flexible and reliable natural gas delivery in Arizona.

q. Should Arizona natural gas and/or propane local distribution companies be included in the Energy Modernization Plan? If so, in what area(s)?

r. Does the Energy Modernization Plan raise any concerns regarding the "management interference doctrine"? Can these concerns, if any, be addressed through flexibility in the plan implementation?

3. Clean Energy

The Energy Modernization Plan proposes a target of 80% clean resources by 2050 including solar, hydro, wind, nuclear, energy efficiency, and other measures such as energy storage, with the ultimate goal of being 100% from clean resources.

a. Should the existing REST rule targets change and if so how should they change?

The Commission could grant REST waivers to affected utilities and address growth of renewable energy, on a utility-specific basis, in the CREST.

b. What other measures should be incorporated to achieve the target of 80% clean energy resources?

c. Should the Energy Efficiency ("EE") rules, both gas and electric, be revised, repealed, suspended, or integrated into the Energy Modernization Plan?

Since the EE Rules expire in 2020, the Commission could grant waivers and introduce new EE objectives within the CREST that are focused on providing cost effective benefits to the grid rather than meeting generic kWh savings targets.

d. Please provide suggestions regarding maximum allowable contributions from clean resources (i.e. targets for specific resources). For example, should there be a maximum percentage of nuclear or solar that contributes to the 80% target, or should the contributions be flexible?

No, the Companies support flexibility across all resources to ensure safe, reliable, affordable and clean energy for customers.

e. Should distributed energy resources ("DER") be factored into the 80% target?

Yes, based on interconnection to the utility regardless of REC ownership.

f. How should plans for customer-owned DER be factored into the 80% target?

Total output from the DG system should apply to the 80% target.

g. Please comment on the efficacy of current REST policies and provide suggestions for any specific improvements.

Carve-outs for specific resources should be eliminated. Cost-effectiveness, environmental performance, and reliability should be the over-arching goal.

h. How can the REST and CREST policies be integrated?

i. How will CREST address the rapidly changing energy landscape (i.e. changing/future technologies)?

Market conditions should drive the adoption of changing/future technologies.

j. Please comment whether, the renewable requirement in the REST rules could or should be increased, to help achieve the 80% clean resource target by 2050.

Each utility is uniquely situated and should not be bound to targets for specific resources; results from the IRP processes, which consider feasibility and costs, should determine appropriate resource portfolios.

k. With regard to CREST, should there be specific targets by clean energy type (i.e. renewable, biomass, nuclear, etc.)? No.

l. Are there any qualitative benefits to CREST that should be considered?
m. How would CREST affect job growth in Arizona?
n. What is the total residential/commercial customer cost with and without CREST?
o. As a part of CREST, should nuclear power be expanded in Arizona? If so, is it advisable to do so while there is no current long-term solution for storage of high level radioactive waste?

Expansion of nuclear resources could be an option depending on the technology and cost advances with small modular reactors.

p. Please comment on why or why not nuclear energy should be considered a renewable energy source.
q. Please comment regarding what would happen over the next 30 years if Arizona does not adopt CREST in terms of:

    i. Ratepayer costs?
    ii. Electric Grid Stability and Security?
    iii. Peak Energy Usage?
    iv. Arizona Economy?
    v. Arizona Air Quality?
    vi. Other?

r. Please comment on the "Renewable Electricity Futures Study" ("Study") completed by the National Renewable Energy Laboratory ("NREL") and others. Specifically, please comment regarding the underlying technology cost assumptions, performance assumptions, the energy model used, the timeliness of assumptions, other data inputs, and the overall methodology.
s. Please comment regarding the rigor and robustness of the Study.

t. Should there be ongoing review of the conclusions expressed in the Study? If so, how should they be conducted, and by whom? Is such a review planned by NREL?

u. Please comment regarding any other analyses, journal articles or reports which support, critique or rebut the conclusions of the Study.

v. Please comment regarding whether there are any readily available studies, reports, or calculations on reduced water usage associated with a large clean resource goal (50% or greater). If so, please identify them.

w. Please comment on the likelihood of technological advances impacting the renewal of Palo Verde's licenses beyond 2045.

x. Please comment on any costs associated with keeping Palo Verde operational beyond 2045.

y. Please comment on the impact to the 80% clean resource target if Palo Verde generation is included or excluded.

z. Please comment on any opportunities and the associated costs to further deploy nuclear resources in the State to help achieve the 80% clean resource goal.

aa. Please comment on the Energy Modernization Plan's suggestion of ultimately achieving a goal of 100% from clean energy sources.

4. Energy Storage

The Energy Modernization Plan proposes a target of 3,000 MW of storage by 2030.

a. Please provide comments regarding the proposed amount of storage by 2030. For example, is a storage target of 3,000 MW too high or too low?

The IRPs of affected utilities should be analyzed to determine a feasible storage goal for each utility.

b. Please discuss the costs associated with different forms of storage and the extent to which those costs are expected to decline in the future.

Refer to Lazard's Leveled Cost of Storage Study.[3]

c. Please describe what would be the most accurate method for estimating costs and net cost benefits for the development of this amount of energy storage, or the amount of energy storage you deem appropriate.

The following three items need to be considered when estimating costs and defining benefits: overall power capacity; capability to provide ancillary grid services; and energy duration. Each storage system must be considered independently, since a unit of energy from one system might not be equivalent to a unit of energy from another system.

[3] https://www.lazard.com/media/450338/lazard-levelized-cost-of-storage-version-30.pdf

d. Please describe how the obligation for meeting the storage target would be best allocated among utilities.

See 4.a.

e. Please describe the most realistic timeline for achieving such a storage target and whether interim targets should be established. For example, what timeframe is the most reasonable for the majority of the 3,000 MW to come online?

Currently the energy storage cost curve is expected to stay relatively high until around 2025. At that time, it is anticipated, that in addition to the proposed pumped-storage hydro, larger-scale (>50 MW) battery storage systems may become economically competitive with other resources. Until then, utilities should deploy smaller scale systems to better understand the effects on the utility system.

f. Is there a forecast of declining costs which signal a "tipping point" which would make 3,000 MW achievable before 2030?
The success of the Big Chino Hydro project in the mid-2020s would help make the storage target attainable.

g. Please discuss the technical and operational issues, if any, impacting the efficiency of energy storage?

h. What are typical energy conversion efficiencies for energy storage technologies? (i.e. Lithium ion batteries, pumped hydro, flywheel, etc.)

Based on TEP's operational experience and estimations, batteries have an energy conversion efficiency of between 85 to 90%, and pumped-storage hydro will be at approximately 82%.

i. Should there be any consideration and/or prioritization of different storage functions (e.g. peak shaving, grid support, etc.) within the 3,000 MW target?

No. The use case for energy storage may differ based on system needs.

j. Please comment on and describe any resource configurations, which include storage (i.e. solar PV plus storage), that would be cost competitive with resources currently used to address peak demand (i.e. combustion turbines).

5. Forest Health/Biomass-Related Energy

The Companies anticipate filing Biomass proposals in their respective 2019 REST I Implementation Plans on July 1, 2018. We will work to achieve the most cost-effective outcome for customers.

The Energy Modernization Plan proposes a target of procuring 60 MWs of biomass derived energy for state-regulated electric utilities that deliver more than 100,000 MWh annually.

a. Please provide comments regarding the respective roles and fiscal responsibilities of the Federal and State Land management agencies to address concerns regarding overgrown forests.
b. How will procurement of 60 MWs of biomass benefit individual ratepayers of regulated utilities (investor owned and/or nonprofits)? Will this require ratepayers to pay more for electric service?
c. Please provide comments regarding the length of time and expense of environmental processes required by state, local, and federal agencies for the siting and permitting of biomass facilities and any necessary transmission lines and roadways.
d. What is the environmental/habitat impact of removing biomass from Arizona forests?
e. What is the environmental/habitat impact of generating electricity by biomass?
f. Please provide comments and data regarding the estimated cost to ratepayers if the 60 MW goal is mandated for regulated utilities.
g. Please provide comments regarding whether entities not regulated by the Commission should be subject to a biomass goal as it aims to resolve a statewide problem. If so, what is the best method to ensure these entities contribute to a biomass goal?
h. Please comment on the Energy Modernization Plan goal to generate a total of 60 MWs of electricity from biomass.
i. How could this goal be implemented and apportioned among utilities? Please describe the cost of permitting and construction of adequate generation sources and attendant infrastructure to produce 60 MWs of electricity.
j. Please comment on transmission costs to deliver biomass produced energy via non- owned transmission lines.
k. Please comment regarding typical permitting and construction timelines for the construction of biomass facilities and attendant infrastructure such as substations, switchyards, transformers, transmission lines and roadways?
l. Please comment regarding the current data and research regarding the costs of bioenergy and the conclusion that "the average residential customer's bill will increase by $1.54 for 57 MW of bioenergy statewide, and $2.57 for 87 MW of bioenergy."
m. Please comment regarding the benefits of forest thinning and how these benefits would factor into utility ratemaking.

6. Dispatchable Clean Energy

The Energy Modernization Plan would require regulated utilities to set a Clean Peak Target ("CPT") that incorporates existing and new clean energy sources to be deployed during peak hours and increases baseline by 1.5% per year on average until 2030.

The Companies' answers in part 2 above (g-l and n) are applicable to this section of questions.

a. Please comment regarding how to ensure dispatchability of clean energy resources, and include a discussion of technologies and costs.
b. Please comment regarding the costs and impacts of energy storage to reduce demand during peak hours.
c. Please comment regarding the measurement of improvement of air quality by reducing the need for rapid cycling from gas turbines.
d. Please comment regarding how the addition of dispatchable clean energy could provide room for baseload power to operate efficiently.
e. Please comment on the CPT proposed in the Energy Modernization Plan.

7. Energy Efficiency

The current Energy Efficiency ("EE") rules are scheduled to sunset in 2020 and the Energy Modernization Plan proposes to initiate a process to implement a new EE policy to complement the new 80% clean energy resource target.

a. Please provide detailed comments regarding appropriate EE initiatives, including percentages of EE and/or demand-side management ("DSM") reduction costs together with a proposed timeline (which includes milestones), and any recommended EE rule changes.

   The current EE rules should be allowed to expire in 2020. The Companies do not support a predetermined EE target, rather the appropriate resource mix should be determined through a comprehensive IRP process where all resources are evaluated on a level playing field.

b. Please comment regarding how EE should be addressed in any resource planning process.

   See (a) above.

8. Electric Vehicle

The Companies filed EV proposals in their respective EE Implementation Plans which are pending before the Commission.[4]

The Energy Modernization Plan includes a provision that regulated utilities propose plans to include electric vehicle ("EV") infrastructure.

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[4] TEP, Docket No. E-01933A-17-0250 (Dec. 22, 2017) and UNS Electric, Docket No. E-04204A-17-0251 (Jan. 17, 2018).

a. Should the Commission consider these infrastructure plans as part of its Integrated Resource process?

Yes.

b. What impacts, if any, would Commission approval of utility-owned EV infrastructure plans have on future "prudency" determinations in rate cases?

The Commission still retains the right to evaluate the prudency of such investments in a rate case; however, appropriate consideration must be given to these investments if they are being made in compliance with a Commission order.

c. Please provide comments regarding estimates of future deployment of EVs nationally and in Arizona.

Per EEI June 2017 report, annual sales of EVs will exceed 1.2 million in 2025, which would account for over 7% of annual vehicle sales. The number of EVs on the road is predicted to total 7 million by 2025, equaling 3% of total cars and light trucks registered in the United States. We do not have specific Arizona projections.

d. Please provide information on the EV programs in other states.

Many of the EV programs practiced around the country include a variety of incentives and benefits to the customer considering EV adoption. These include, but are not limited to: tax credits, sales tax exemptions, emissions test exemptions, reduced car registration fees, HOV lane access, car insurance discounts, rebates for charging station installs, and reserved parking spaces.

e. Please provide comments regarding the costs of implementing EV infrastructure, and a proposed means to recover those costs, including potential tax incentives, or utility incentives for customers using EV infrastructure.

TEP filed an EV plan on December 22, 2017 in Docket No. E-01933A-17-0250. The plan has not been considered by the Commission. TEP's plan consists of:

Smart City EV Buildout Plan. This pilot program proposes investment by TEP of up to $8 million in EV infrastructure projects to establish and highlight the benefits of EV charging at workplaces, at multi-family dwellings, in neighborhoods and, on university campuses. The EV Buildout Plan will also support electrification of commercial vehicle fleets, and the proposed Smart Schools EV Bus Pilot Program. The Company believes that utility funding and ownership of charging facilities will help to kick start

broader adoption of EVs and attract other EV funding sources. This program also includes $450,000 of DSM budget to cover program administration, management, implementation, marketing, and customer education expenses.

New and Existing Home Program. Offer rebates of $100 for new home EV pre-wiring and incentives for existing home EV charging installations. The total budget for this program is $650,000.

School Bus EV Pilot. This program would help offset the cost of new EV busses and charging facilities for schools. The total budget is approximately $660,000.

Regional Electric Vehicle Plan ("REV West Plan"). TEP will actively engage in Arizona's participation in the REV West Plan to support the development of EV interstate and highway infrastructure. TEP is proposing a research and development budget of up to $95,000 for the REV West Plan in 2018.

f. Please provide comments regarding metrics and a methodology to measure potential impacts to air quality (including reductions of criteria pollutants) from the potential widespread adoption of electric vehicles.

g. Please provide comments regarding how to plan EV infrastructure on major highways and interstates, and what collaboration with other agencies would be necessary or advisable. See part e above.

h. Please identify any highway funds or other federal monies and grants which may be available to plan and construct such facilities.

i. Please provide information regarding other utilities in the country who may have undertaken similar efforts to develop EV infrastructure.

Other utilities have begun testing pilot programs for charging stations, which would be company owned and managed. These would include residential, workplace, public, and fast-charging stations. Some utilities are offering incentives for customers to install their own charging stations.

j. When considering development of EV infrastructure, which cost-effectiveness test, or tests, should be utilized to determine the appropriateness of such infrastructure investments?

k. In keeping with the intent of the Electric Vehicles section of the Energy Modernization Plan, should the use of natural gas fueled vehicles be encouraged?

l. Should the use of vehicles fueled with Renewable Natural Gas ("RNG") be encouraged? If so, should an incentive program like California's Low Carbon Fuel Standard be encouraged by the Commission?

m. Please comment on the Arizona Department of Environmental Quality ("ADEQ") estimate that the cost to Arizona for developing and implementing a more stringent air quality plan to reduce emissions would range from $76 million to $380 million. How would these costs be paid, and by whom?

n. What economic impacts would the adoption of an EV infrastructure plan have on Arizona's economy?

9. Resource and Transmission Planning

The Energy Modernization Plan proposes to amend the Integrated Resource Plans ("IRP") process to support and promote its policies.

a. Should the IRP process be modified? If so, please explain how it should be modified.

The Companies support a more comprehensive IRP process rather than separate implementation plans for certain resources that may or may not be aligned. As discussed above[5] the Companies support a long-term planning process whereby each utility works to balance the objectives most important to their customers. This process would require robust stakeholder dialogue including workshops and some level of interim reporting.

b. The Commission conducts a Biennial Transmission Assessment ("BTA") as required by ARS 40-360.02 (G). The purpose of the BTA is to examine the adequacy of existing and planned transmission facilities to meet Arizona's energy needs in a reliable manner.

i. How does the Energy Modernization Plan impact the BTA?

The BTA identifies specific studies to evaluate the reliability of the Arizona transmission system. These studes will be based upon the resource mix of each affected utility. Regardless of the Companies' resource portfolios, we plan our system to meet the requirements of NERC TPL-001-4 and any future reliability requirements.

ii. Should the IRP process and BTA be evaluated jointly?

Not necessarily; however, the Commission could request that the IRPs contain additional discussion and analysis regarding transmission investments that facilitate the resources contemplated by the IRP.

c. The current IRP process applies only to specific regulated utilities. How does that fact impact the Energy Modernization Plan?

d. Please comment regarding the current IRP process, and how it should be modified to effectuate the Energy Modernization Plan.

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[5] See Company's response to 2.g-l.

e. Please comment regarding the 5-year action plans of the utilities and whether the plans should include greater Commission involvement? (For example, explicit approval and or denial of the plans, direction on procuring specific resources to achieve the goals of the Energy Modernization Plan, etc.).

f. Please comment regarding the 5-year action plans of the utilities and whether it would be beneficial to have more stakeholder engagement in the development of the plans.

TEP and UNSE conduct stakeholder outreach meetings during the development of their IRPs. The Companies also believe that the current IRP process provides stakeholders with several engagement opportunities including writing letters to the docket or by participating in workshops and open meetings.

10. Process-Related Issues

a. Please comment on whether consolidating open dockets would aid in efficiently analyzing proposed rule changes.

The Companies do not believe it is necessary to consolidate pending dockets that may touch upon the myriad of issues that may be addressed in considering the Energy Modernization Plan. Consolidation could lead to confusion as to scope of issues, service lists, supporting record or other matters. The Commission could take administrative notice of information collected in other dockets. However, some of the information could be outdated and the Commission should be cautious with respect to importing information from other dockets.

The Companies believe that a new docket ("Notice of Inquiry into the Development of an Arizona Energy Modernization Plan") should be opened to provide an initial investigation of the development of the Energy Modernization Plan or that Docket No. E-00000Q-16-0289 could be converted to the initial docket for considering all the issues raised by the Plan. Commissioner Tobin's proposed Plan, together with the Notice of Inquiry, provide a sound foundation for the process. This docket would then identify and codify overarching Commission policies, goals and guidelines for the development of an appropriate Energy Modernization Plan. Based on those policies and goals, the Commission would then direct one or more rulemakings to proceed.

b. Should the dockets listed below be part of such consolidation? See response to 10.a.

i. REST Rule Revisions (Docket No. E-00000R-16-0084)
ii. EE Rule Revisions (Docket No. E-00000Q-16-0289)
iii. Role of Forest Bioenergy in Arizona (Docket No. E-00000Q-17-0138)
iv. Future of Navajo Generating Station (Docket No. E-00000C-17-0039)
v. Evaluating Arizona's Current and Future Baseload Security (Docket No. E-00000Q-17-0293)
vi. Innovations and Technological Developments in Generation and Delivery of Energy (Docket No. E-00000J-13-0375)

c. Are there other dockets that should be included in this list?

There may be other dockets or Commission workshops that contain pertinent information. Commissioner Tobin has identified other dockets and workshops in his January 30, 2018 letter in the docket.

d. Should the implementation of the Energy Modernization Plan be accomplished in a single or multiple rulemaking docket(s)?

The initial process conducted through the NOI and subsequent proceedings in this docket would identify the necessary rulemaking(s). The Companies would support a single rulemaking regarding resource planning that would incorporate elements regarding clean and renewable resources, energy efficiency, transmission, reliability, etc. However, there may be other, more specific rulemakings that may be necessary.

e. What Parties (regulated and non-regulated entities) should participate in the docket?

Any interested party should be allowed to participate and provide input into the docket and the issues raised by the NOI.

f. What other process issues are raised and how can those issues best be addressed?

The process is already potentially confusing due to the various other issue-related dockets that may or may not be affected by the consideration of the Plan. The Companies believe that a new docket should be opened and include Commissioner Tobin's Energy Management Plan, the NOI and any submissions in response to the NOI.

The Hearing Division should adopt the service list from Docket No. E-00000Q-16-0289 for the new docket (including email service). The Hearing Division could also issue notices to the service lists in other appropriate issue-related dockets about the need to request to be added to the service list in the new docket.

11. Security and Reliability/Resiliency

a. Discuss any operational and reliability issues associated with implementation of the Energy Modernization Plan.

Operational and reliability issues will be minimized if the Plan contains sufficient flexibility in the IRP process.

b. Are there measures that should be taken to increase overall grid reliability and resiliency in Arizona?

The Plan must take into account the operational benefits provided by traditional thermal resources as well as the limitations of intermittent renewable resources.

c. Discuss any security issues that may arise as a result of the Energy Modernization Plan. What can be done to address these issues?