SIERRA CLUB

BEFORE THE
ARIZONA CORPORATION COMMISSION

IN THE MATTER OF RESOURCE PLANNING AND PROCUREMENT IN 2019, 2020, AND 2021	Docket No. E-00000V-19-0034

Sierra Club Comments on Arizona Public Service's 2020 Integrated Resource Plan

1. Introduction

Sierra Club appreciates the opportunity to comment on Arizona Public Service's (APS or the Company) 2020 Integrated Resource Plan (IRP). These comments were prepared with the assistance of Synapse Energy Economics, Inc. (Synapse) and are based on our examination of APS's input assumptions and portfolio construction, and our evaluation of the Company's resource options. Although not invited to participate in APS's Advisory Council process, Sierra Club was an active participant in the stakeholder process leading up to the development of APS's 2020 IRP and provided detailed comments earlier this year as part of the Preliminary-IRP process. The final comments we submit here focus on APS's IRP process and modeling assumptions, with the goal of pushing for transparent resource planning that provides customers a reliable electricity system at the lowest possible cost and with the least negative environmental impact.

APS does not currently have an acknowledged IRP; therefore, we stress the importance of the Company producing a robust and comprehensive IRP this time. We recommend that APS revise its IRP in accordance with our recommendations outlined below, including modeling the retirement of Four Corners prior to 2031, updating its load forecast to reflect more reasonable load growth assumptions, and testing a more comprehensive set of sensitivities, particularly regarding gas prices. If the Company does not voluntarily do so, we recommend that the Commission once again not acknowledge APS's IRP, require that the Company re-do its modeling to address the concerns we have highlighted, and require Commission approval for any new fossil resource acquisitions in the interim.

2. Summary and recommendations

In our review of APS's IRP, we find some positive aspects. Specifically, the Company evaluated critical but limited sensitivities around key inputs such as load and natural gas prices and included a significant quantity of renewable generation resources and battery storage in each of its final three final portfolios.

However, we are also concerned that APS presents the result from a very limited number of portfolios (four), does not test a wide range of sensitivities, and does not evaluate or consider the retirement of Four Corners prior to 2031 in any of its portfolios. Further, the Company continues to rely heavily on fossil resources in all portfolios (both gas and coal), justified by unsupported assumptions around high load growth. In combination, these flaws produce a planning process that systematically favors fossil resources and disadvantages renewables, as we will discuss throughout these comments. The Company's continued reliance on unrealistically high load growth projections is especially concerning given the Commission's decision to not acknowledge APS's last IRP, which was driven in large part by the Company's over-projected load forecast.

Our concerns are oriented around seven key topics as follows:

1. **Mistakes from 2017 are repeated with an unrealistically high load forecast, and a bias towards gas resources.** The Arizona Corporation Commission refused to acknowledge APS's 2017 IRP based on, most notably, the Company's reliance on an unrealistically high load forecast and on a high level of natural gas replacement resources. APS has repeated these mistakes in its current IRP.

2. **APS modeled limited scenarios and sensitivities, the Company does not select a preferred portfolio, and the presentation of results makes the renewable-focused portfolio appear deceptively expensive.** APS presents only three final portfolios—all of which have nearly identical short-term action plans. While the Company does not explicitly select a preferred scenario, there is a clear bias towards the "Bridge" scenario that sustains and expands reliance on natural gas. Scenario results, and subsequent sensitivity analyses, show the Net Present Value Revenue Requirement (NPVRR) results are very close across scenarios, despite APS's misleading presentation of the scenario and sensitivity analysis results to make the high renewables "Accelerate" scenario appear more expensive.

3. **Incomplete accounting of the costs to operate Four Corners.** The Company does not appear to properly consider the costs associated with water limitations required to maintain and operate the plant. Further, APS has not considered the avoided cost of compliance with Effluent Limitation Guidelines (ELG) if the plant retires by the end of 2028 or earlier.

4. **No consideration of closing Four Corners prior to 2031**. APS does not seriously evaluate closing the Four Corners coal plant before 2031 as part of any of its final portfolios. Specifically, the Company does not evaluate the

cost of its coal contract and include that in its alternatives analysis. It also does not evaluate the value of its water, the step down in sustaining capital costs, the impact on market prices of locking in Four Corners, and the importance of a known retirement schedule for the impacted communities to plan a just and equitable transition.

5. **Continued reliance on an unrealistically high load forecast**. As with its unacknowledged 2017 IRP, and the 2014 IRP before it, APS continues to rely on an unrealistically high load forecast. This forecast drives the alleged need for additional resource capacity.

6. **Significant decline in investment in energy efficiency measures after 2020. APS.** The Company's forecasted energy efficiency (EE) investments decline significantly from levels achieved under the Commission's 2010 EE mandate. For the IRP period, the Company forecasts EE investments of between only 0.2 and 0.6 percent of retail sales. National average levels of EE investment as a percent of retails sales are around 1.3 percent (from 2018).

7. **Renewable cost inputs are high, especially given APS's high penetration of renewables.** APS's renewable costs assumptions continue to be on the conservative end of industry estimates. APS includes a renewable integration cost that is totally unreasonable and unnecessarily penalizes renewables, and it is unclear whether APS's model can build wind + transmission to access high quality wind resources in eastern New Mexico.

8. **Assumed natural gas prices and technology costs are too low.** All of APS's three scenarios rely on natural gas resources, and two out of the three allow new natural gas resources (both new generation resources and power purchase agreements (PPA)). But the Company's natural gas price assumptions are low relative to industry standard estimates, and therefore make long-term reliance on natural gas appear more favorable than it likely will be. Further, APS has adopted a misleading framing around Natural Gas Combustion Turbines (CT), asserting that they can eventually be converted to run on hydrogen—a technology that has not been proven.

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

- **The Commission should decline to acknowledge this IRP. Instead, APS should be required to submit a revised IRP that:**
    - Includes a more reasonable load forecast that incorporates the impacts of COVID-19 and does not continue to rely on rapid load growth that has historically failed to materialize.

- Incorporates the cost of compliance with future environmental regulations, including the ELG.
- Incorporates any costs or risks associated with continued reliance on surface water to operate Four Corners.
- Includes one or more scenarios that test and allow for the endogenous retirement (within the model construct) of the Company's coal plants prior to each plant's scheduled retirement date.
- Tests and provides transparent results for a larger range of scenarios and sensitivities around resource costs, fuel prices, load forecast, plant retirement dates, plant operational parameters, and environmental regulations.
- Includes forecasted energy efficiency program investment of at least 1.3 percent of retail sales annually.
- Excludes the renewable integration cost for, at a minimum, all paired renewable resources.

- **APS should conduct, as part of its IRP, a detailed study of the economics of continuing to operate Four Corners that includes:**
    - The full cost of terminating the Company's existing coal contract;
    - The cost and risk of obtaining water;
    - A schedule of sustaining capital costs matched with retirement dates to ramp down capital spending in advance of retirement;
    - Community economic, employment, and tax base impacts;
    - An alternative market price forecast developed without the assumption that Four Corners is locked in until 2031; and
    - The option to build wind in the northeast corner or Arizona or the northwest corner of New Mexico to utilize the transmission infrastructure that will be freed up with the retirement of Four Corners.
- **The Commission should not allow APS to procure any new fossil resources based on the results of its current IRP.**
    - In the near term, APS should not be allowed to procure any new fossil resources until it has updated its load forecast to reflect the impacts of COVID-19.

- For the larger study period, the Company should not be allowed to procure natural gas (among other) resources until the Company has re-run its IRP based on a lower and more realistic load forecast. This forecast should be aligned with historical trends and updated and other sensitivities around resource and fuel costs. The prior Commission gas moratorium sent a clear and necessary message that utilities should not rely too heavily on natural gas resources in their IRPs.

- **The Commission should require APS to better explain and justify the results of its renewable integration study, and to update the study to address shortcomings.**
  - APS should clearly outline the specific system needs that are purported required and met by the renewable integration costs.
  - APS should clearly explain how it calculated each component of its integration cost.
  - APS should update its study to address the shortcomings associated with its decisions to only model solar and wind together, to remove the impact of forced outages and other load deviations, and to not factor the ability for the Energy Imbalance Market (EIM) to provide renewable integration services.

3. APS repeats mistakes from 2017 with an unrealistically high load forecast, and a bias towards gas resources.

In its proposed IRP, APS has repeated many of the mistakes it made in its 2017 IRP, most notably a continued reliance on an unrealistically high load forecast and a bias towards continued reliance on natural gas resources and PPAs. This is particularly concerning given that these mistakes led to the Commission's refusal to acknowledge APS's last IRP.[1] Specifically, APS's over-reliance on natural gas resources in its 2017 IRP led to the Commission temporarily imposing a natural gas moratorium to slow the build-out of gas resources in light of technological advances that may render gas infrastructure obsolete, as this could result in abandoned assets and harm ratepayers.[2] The Commission should reject APS's attempt to once again put forward an IRP that contains very similar flaws biasing its results in favor of heavy reliance on gas resources.

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[1] Decision No. 76632 at 47:25-48:2, 53:4-6, No. E-00000V-15-0094 (Ariz. Corp. Comm'n Mar. 29. 2018), *available at* https://docket.images.azcc.gov/0000186964.pdf.
[2] Ariz. Corp. Comm'n, March 13, 2018 Open Meeting, Agenda Item 22 at 5:11:13–5:13:00 (Comm'r Tobin).

4. **APS modeled limited scenarios and sensitivities, it does not select a preferred portfolio, and the presentation of results makes the renewable-focused portfolio appear deceptively expensive.**

APS's 2020 IRP focuses on three portfolios: Bridge, Shift, and Accelerate. APS does not select a preferred portfolio from among these three. Notably, all scenarios call for nearly identical resources and resource additions in the near-term action plan window (2020–2024).[3] All are designed to meet the goal of 100 percent carbon free electricity by 2050,[4] meet an interim target of 65 percent clean energy mix / 45 percent generation from renewables by 2030,[5] and retire all 1,400 MW of coal by 2031.[6] APS developed a fourth portfolio that it labeled the Technology-Agnostic portfolio which was intended to serve as a bookend or point of reference scenario.[7] None of the scenarios allow the model to fully optimize APS's resource mix or coal plant retirement dates, however.

All four portfolios are described below:

- **Bridge Portfolio:** This portfolio sustains and expands APS's reliance on natural gas generation through both existing and new Company-built resources and natural gas PPAs. Renewables (9,830 MW) and energy storage (4,852 MW) are also built out by 2035. Four Corners retirement date is hard-coded at 2031 and the Company's emissions goals are met.[8]

- **Shift Portfolio:** This portfolio relies on additional renewables and storage incremental to Bridge. No new natural gas builds are allowed, but APS does purchase gas generation from merchant PPAs. 11,330 MW of renewables and 6,502 MW of energy storage are built out by 2035. Four Corners retirement date is hard-coded at 2031 and the Company's emissions goals are met.[9]

- **Accelerate Portfolio**: This portfolio shifts further towards renewables and storage. No new gas capacity or PPAs for gas resources are allowed, but APS continues its reliance on existing gas resources and PPAs. 15,755 MW of renewables and 10,552 MW of energy storage are built out by 2035. Four Corners retirement date is hard-coded at 2031 and the Company's emissions goals are met.[10]

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[3] Ariz. Pub. Serv., 2020 Integrated Resource Plan at 135 (June 26, 2020), *available at* https://docket.images.azcc.gov/E000007312.pdf [hereinafter "APS 2020 IRP"].
[4] *Id.* at 137.
[5] *Id.* at 129.
[6] *Id.* at 133.
[7] *Id.* at 129.
[8] *Id.* at 134.
[9] *Id.*
[10] *Id.*

- **Technology-Agnostic Portfolio**: This portfolio is developed with resource optimization software that does not impose limits on new gas resources. The resulting portfolio does not meet emissions goals and requirements and was intended as a bookend portfolio.[11]

No optimization modeling for a baseline portfolio

APS has not utilized optimized capacity expansion modeling to create and evaluate its long-term resource plan. Instead, the Company has hard-coded specific retirement dates for its coal plants (as discussed below) into all its portfolio model runs and constrained the resource types that the model could select. APS's so-called Technology-Agnostic portfolio removes the limit on natural gas build but keeps hard-coded coal retirement dates and removes the Company's emissions cap. The Company claims this portfolio was intended to serve only as a bookend scenario,[12] but it is unclear what value this comparison provides without enforcing an emissions cap while locking in coal operation.

Instead, APS should have modeled an optimized scenario that is truly technology-agnostic; where resource selection was constrained only by the emission cap and not by hard-coding retirements and constraining resource selection. This type of scenario provides a valuable starting point for the Company in understanding the fossil and renewable build-out selected by the model given only the emission cap as a constraint. This type of baseline run is critical for helping the Company to accurately isolate the incremental cost of imposing additional constraints and requirements on the model.

No recognition of the importance of early efforts to cut emissions to minimize cumulative carbon emissions

APS has designed its portfolios to meet several mid- and long-term emission reduction goals. But the Company's IRP does not discuss or acknowledge the importance of taking early actions to reduce CO_2 emission with the goal of minimizing total cumulative carbon emissions. Nor does it design any of its portfolios with a focus on the cumulative emission levels of each. Even assuming coal operations through 2031, there will be a large difference in cumulative emissions between (1) a coal plant that a Company operates at a high capacity factor through its retirement date in 2031, and (2) the same coal plant that ramps down to seasonal and then to summer-only operations in the years leading up to its retirement also in 2031. By focusing on total annual emissions, both options meet APS's future emission reduction goals, but the second option would reduce emissions earlier, and therefore would emit significantly less cumulatively than the first. *The Commission should require APS to model the cumulative emissions impact of is*

[11] *Id.*
[12] *Id.*

portfolios, and incorporate actions in the near term that begin reducing emissions from existing units.

Expanded reliance on natural gas in two portfolios

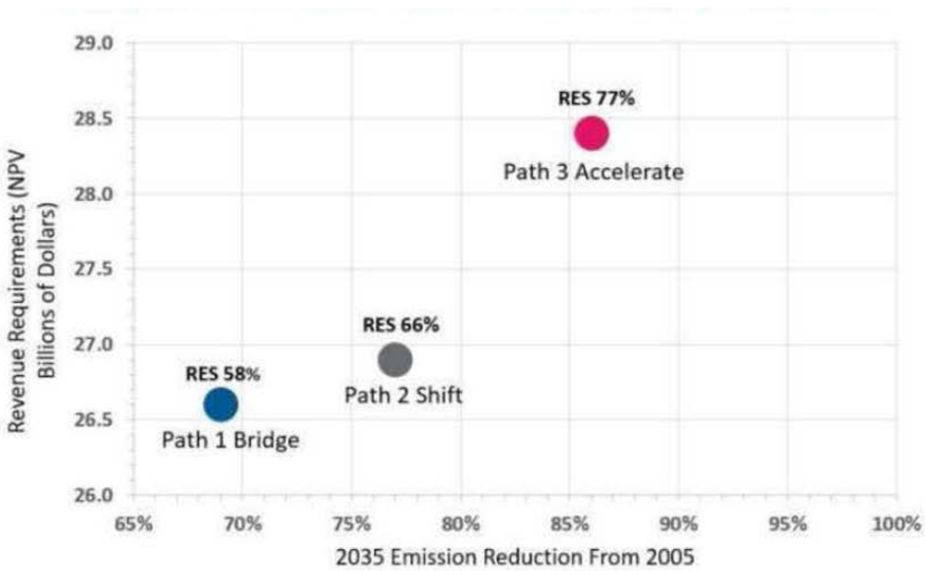
Even APS's renewable-focused Accelerate portfolio sustains APS's reliance on natural gas generation. Further, both the Bridge and the Shift portfolios expand APS's reliance on natural gas generation—the Bridge portfolio through both company-build resources and natural gas PPAs (1,859 MW of Combined Cycle and Combustion Turbine generation capacity)[13] and the Shift portfolio through just natural gas PPAs (1,135 MW).[14] This continued reliance on natural gas, especially in the Bridge and Shift portfolios, locks APS's ratepayers into additional new fossil resources for the next few decades and exposes them to stranded asset and gas price volatility risk. These risks do not exist with renewable resources and are mitigated in the Accelerate portfolio that does not rely on any new natural gas resources or PPAs. However, APS fails to evaluate reduced reliance on existing gas in any of its scenarios.

Misleading presentation of NPVRR results

APS claims that is has not selected a preferred scenario from among the Bridge, Shift, and Accelerate scenarios; but its misleading presentation of the NPVRR results is concerning and skews in favor of the natural-gas heavy Bridge scenario.[15] Specifically, as shown in Figure 1, APS presents the total cost and emissions of each scenario in a manner that makes the Bridge scenario appear significantly cheaper (less than half the cost) of the Accelerate scenario, when in reality the 2020 – 2035 NPVRRs between all scenarios differ by less than seven percent. Figure 2 below shows a corrected version of APS's NPVRR graph. *APS should correct its misleading chart in its IRP and be clear about the actual magnitude of differences among the portfolios.*

[13] *Id.* at 387, Attachment F.1(A)(1) Bridge Portfolio L&R And Energy Mix.
[14] *Id.* at 389, Attachment F.1(A)(2) Shift Portfolio L&R And Energy Mix.
[15] *Id.* at 140.

Figure 1: APS Portfolio Cost and CO_2 Emission Reduction Chart (APS Figure ES-4)



Insufficient consideration of sensitivities analysis

Additionally, when APS tested sensitivities around load and natural gas forecasts, it found that the difference between scenarios decreased in both cases (as shown in Figure 2). This critical finding shows how sensitive APS's results are to its input assumptions, in particular its two assumptions around load forecast and natural gas prices that we find APS has over-projected (as we will discuss later).

Figure 2: APS NPVRR and emission Reduction with Sensitivities

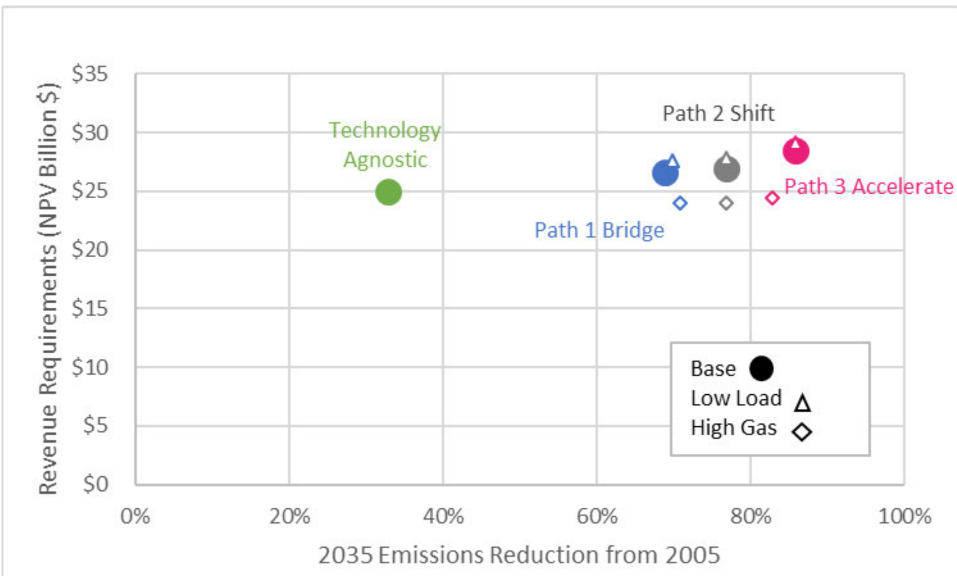


Table 1 shows the difference in emissions and net revenue between the three final scenarios under the base assumptions, the low load sensitivities, and the high gas price sensitivity.[16] *The Commission should require APS to test these, and other sensitivities, in combination to fully understand the interplay between assumptions, and to develop proper bookends to its analysis.*

Table 1: NPVRR for Scenarios and Sensitivities

	Emission Redux	NPV RR (Billions $)	Delta from Bridge
Technology Agnostic	33%	$24.9	
Path 1 Bridge	69%	$26.6	
Path 2 Shift	77%	$26.9	$0.3
Path 3 Accelerate	86%	$28.4	$1.8
Path 1 Bridge (Low Load)	71%	$23.9	
Path 2 Shift (Low Load)	77%	$24.0	$0.1
Path 3 Accelerate (Low Load)	83%	$24.4	$0.5
Path 1 Bridge (High Gas)	70%	$27.6	
Path 2 Shift (High Gas)	77%	$27.8	$0.2
Path 3 Accelerate (High Gas)	86%	$29.1	$1.5

5. Incomplete accounting of the costs to operate Four Corners

In its IRP modeling, APS has failed to accurately capture the full cost of operating Four Corners through its current retirement date in 2031. Specifically, it is not clear that APS properly considers the risk and cost of future water limitations or shortages at Four Corners and the cost of complying with the effluent limitation guidelines in modeling any of its current portfolios. While these costs will be close, if not identical, across scenarios, it is still critical for APS and ratepayers to understand the magnitude of costs associated with continuing to operate Four Corners and where in particular those costs are likely to be incurred. *The Commission should require APS to model the full costs associated with operating Four Corners through its closure date as part of its IRP.*

Incomplete accounting of water limitations

Water access and limitations are increasingly becoming a central part of resource planning decisions in the western United States. Southwest Public Service Company (SPS) announced last year that it cannot continue to economically operate the Tolk Generating Station through its

[16] *Id.* at 152.

depreciation retirement date of 2042 based on the depletion of the Ogallala Aquifer on which it relies for its cooling water.[17] In its analysis, SPS evaluated the cost of drilling wells and installing other necessary infrastructure to maintain access to an adequate water supply. This analysis provided a baseline understanding of the incremental cost of procuring water sufficient to operate the plant, and therefore the point at which drilling wells would become too expensive to justify continued operations of the plant. In light of these extreme water limitations, SPS is required to, per the terms of the uncontested comprehensive stipulation in New Mexico Docket No. 19-00170-UT, conduct a full-scale retirement analysis for the Tolk Generating Station.[18]

APS discusses water limitations throughout its IRP and evaluates the water use of each resource and each of its three final portfolios. But given the importance of impending water limitations, it is unclear how future water infrastructure needs and water limitations at Four Corners are factored into APS's modeling—if at all. Four Corners relies on surface water from the San Juan River and is party to a shortage sharing agreement between the Bureau of Reclamation and the rest of the parties utilizing the surface water as their water supply. This agreement is set to expire at the end of 2020. APS stated in its IRP that plans are in place to continue this agreement, but the Company has provided no confirmation or details on the future agreement.[19] *The costs and risks associated with both securing the agreement and being exposed to a future water shortages should be quantified and included in APS's analysis.*

No consideration of the cost of compliance with Effluent Limitation Guidelines

In August 2020 the U.S. Environmental Protection Agency (EPA) finalized a rule revising Steam Electric Power Generating Effluent Guidelines for Steam Electric Power Generating units.[20] In the latest revisions, steam electric generators are exempt from complying with the ELG rules if they retire by the end of 2028. This means that any coal plant that does not currently comply with ELG rules has to invest in pollution control upgrades by 2023 to continue operating beyond the end of 2028. This also means that Four Corners can avoid the capital and operations and maintenance (O&M) costs associated with the ELG upgrades if it moves its retirement date up by three years to 2028. APS estimates that its share of ELG compliance costs will be $6–$20 million in capital costs and $0–$2.7 million per year for O&M.[21] *APS should be required to incorporate these costs associated with ELG compliance into its IRP analysis.*

[17] Southwestern Pub. Serv. Co., Application at 3, Case No. 19-00170-UT (N.M. Pub. Regulation Comm'n July 1, 2019), *available at* https://edocket.nmprc.state.nm.us/AspSoft/HandlerDocument.ashx?document_id=1179758.
[18] Final Order Adopting Certification of Stipulation, Case No. 19-00170-UT (N.M. Pub. Regulation Comm'n May 20, 2020), *available at* https://edocket.nmprc.state.nm.us/AspSoft/HandlerDocument.ashx?document_id=1188786 (login credentials to the NMPRC docket site required for access).
[19] APS 2020 IRP at 31.
[20] U.S. EPA, *2020 Steam Electric Reconsideration Rule: Effluent Guidelines*, https://www.epa.gov/eg/2020-steam-electric-reconsideration-rule (last viewed Oct. 9, 2020).
[21] APS 2020 IRP at 215.

6. No consideration of closing Four Corners prior to 2031

In its IRP modeling, APS has also failed to accurately capture the cost that the Company will avoid if it retires Four Corners in advance of its 2031 retirement date. APS assumes that Four Corners Power Plant will operate through the end of its coal contract in 2031, and in fact locks the plant in and does not allow it to retire, in any of its final portfolios. APS does not evaluate the economics of retiring Four Corners—inclusive of the cost of its coal contract, the cost of obtaining water, and avoided sustaining capital costs—compared to alternatives resource options, including renewables and battery storage. The Company also does not evaluate the impact on market prices of locking in Four Corners. This failure to model and understand the economics of retiring the plant also unfairly impedes realistic transition planning for the communities that will be impacted by the plant's retirement.

Failure to include the value of the coal contract as a retirement cost

APS's decision to model the Four Corners plant as operating through 2031 is driven by its current long-term coal contract.[22] APS has acknowledged that it could avoid some of the costs of this coal contract and terminate the agreement with 24-months' notice. Given the increasingly poor economic performance of coal plants relative to gas and renewable resources in this country, APS should calculate the remaining contract cost and model this as a cost of an alternative portfolio. Even with substantial termination costs, it is possible, and even likely, that a portfolio with an early retirement for Four Corners and a renewable replacement portfolio will be more economic for ratepayers. *APS should model its coal contract as a cost, not as a physical system constraint, and allow the model to evaluate the economics of retiring the plant early and paying out or terminating the contract relative to alternative resource portfolios.*

Omission of the cost of obtaining water

In evaluating the retirement of Four Corners, another critical consideration is the value of water rights or the cost of obtaining access to water for the plant. If APS retires the plant, it will no longer need the associated water access. Water rights are valuable. Therefore, the value of selling the water rights, or costs avoided by not requiring water access, should be incorporated into APS retirement analysis for the plant. In New Mexico, the commission ordered SPS to quantify and incorporate the value of water rights in its retirement analysis for the Tolk Generating Station.[23] *APS should evaluate water-related costs in retirement analysis scenarios as part of its IRP.*

[22] *Id.* at 133.
[23] Final Order Adopting Certification of Stipulation, Case No. 19-00170-UT (N.M. Pub. Regulation Comm'n May 20, 2020), *available at* https://edocket.nmprc.state.nm.us/AspSoft/HandlerDocument.ashx?document_id=1188786 (login credentials to the NMPRC docket site required for access).

Imprecise accounting of sustaining capital costs

All generation resources require periodic maintenance to sustain plant operations. Standard O&M costs are generally accounted for as part of the Company's variable and fixed O&M costs, but some large capital investments go beyond traditional O&M and may be accounted for separately. Sustaining capital costs represent the costs of capital investment needed to perform the maintenance overhauls required to keep a plant online. These costs can be significant at large aging steam plants in particular. Because sustaining capital costs are not only large but also lumpy (unlike fixed O&M, which tend to be smoother from year to year), the decision to incur these costs should be factored into the timing of retirement decisions. Sustaining capital costs should ramp down in the years prior to retirement (i.e., you should not replace a steam boiler or a roof two years prior to a planned retirement); therefore, retiring a plant early will avoid or minimize sustaining capital costs not just after retirement, but also in the years leading up to a retirement.

APS has not evaluated the earlier retirement of Four Corners as part of the IRP, and therefore has not evaluated the incremental savings from retiring the plant early. *Any retirement analysis modeling should incorporate a schedule of sustaining capital costs that is matched with each retirement date to allow for a ramp-down in sustaining capital costs in the years prior to retirement.* This will allow the Company to factor into its analysis the important trade-off between required capital investment in new generation resources, and the decrease in sustaining capital costs at the existing coal plant.

The presence of Four Corners through 2031 contributes to negative market pricing that disadvantages new renewables

Negative market pricing occurs when there is more energy available in the system than is demanded, such as when inflexible thermal plants are not able to reduce output below a minimal operating level.

To estimate the costs of importing or exporting electricity to or from its system, APS uses an hourly wholesale market price forecast for the Palo Verde Market hub developed by E3.[24] This forecast is developed based on regional electricity market fundamentals and natural gas price forecasts, reflects California's renewable mandate of 60 percent renewables by 2020, and factors in the existence and operating levels of inflexible thermal plant that has not yet been retired. The model used to develop the market price forecast allows APS to purchase electricity from the

[24] APS 2020 IRP at 130.

wholesale market to offset its own fossil generation, and also to curtail APS-owned solar when it benefits customers.[25]

But, as discussed above, APS assumes Four Corners coal is locked in through 2031. This assumption, when included in the market pricing model that E3 created for APS, contributes to the need to curtail solar, and it critically impacts market hub prices to systematically disadvantage renewables. Coal plants cannot be efficiently turned on and off regularly, and therefore they generally operate at a minimum level consistently. In the shoulder months when load is low, energy from baseload coal plants plus renewables can surpass load. When this happens—if the coal plant is locked in as APS assumes Four Corners is locked in—the renewables have to be curtailed. This drives negative market pricing.[26] Because APS's market price forecast is prepared with the assumption that Four Corners is locked in through 2031, the resulting market price forecasts are skewed, resulting in unnecessary negative pricing. Absent the artificially-forced operation of Four Corners, the model could economically retire the coal unit, increasing the "flexibility" of the system, lessening the need for solar curtailment (which occurs when the coal plant is online and operating at a minimum level), and resulting in less negative or positive market prices.

These skewed price forecasts represent a significant disadvantage for renewable resources. Negative pricing limits the revenue potential for new renewable resources and makes them look less economic relative to alternatives. Allowing the model to retire Four Corners (or even just switch the plant to seasonal operations) would remove large segments of marginally uneconomic energy and instead meet load with resources that might otherwise be curtailed. Minimizing the amount of curtailed solar will allow market prices to increase and would allow renewables to accrue higher revenues (or at the very least accrue less negative market revenue) and therefore be more competitive.

<u>*APS should be required to model its system without Four Corners locked in and to evaluate the impact on market prices, and on the competitiveness of renewable resources. APS should also be required to utilize an alternative wholesale market price forecast developed without the assumption of regional coal plants locked in through their current retirement dates.*</u>

Importance of just and equitable transition planning for impacted communities

APS's failure to evaluate the economics of retiring Four Corners prior to 2031 does a disservice to the communities that will be impacted by the plant's closure (and the closure of the mine serving the plant). The communities need years to develop transition plans to mitigate impacts from employment and tax-based loss, to determine what to do with the site and the infrastructure,

[25] *Id.*
[26] *Id.*

to coordinate site cleanup, and to address any other local activities.[27] APS's modeling of Four Corners as operating through 2031, and its refusal to evaluate the economics of retiring the plant sooner, does not guarantee that the plant will actually operate through 2031. The market is continuing to shift towards renewables and natural gas, and the economics of operating the plant will continue to get worse. The Company will likely have its hand forced and have to retire the plant early. But the longer APS keeps its head in the sand, the less notice and time impacted communities will have to plan a transition (relative to the planning time they would have if the retirement analysis were conducted today). <u>*APS should be required to conduct a retirement analysis for Four Corners as part of every IRP to give impacted communities as much notice as possible in developing community transition plans.*</u>

7. Continued reliance on an unrealistically high load forecast

Continued over-projection of load growth that is unsupported by historical growth trends

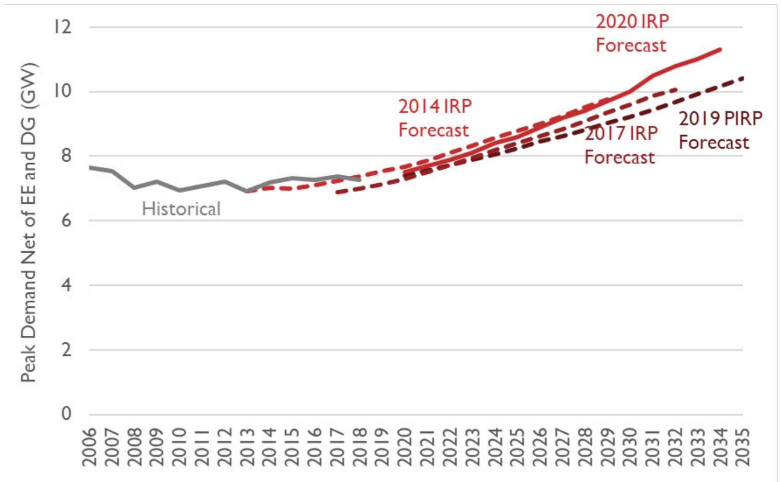
APS's base load forecast once again assumes a high level of energy and peak load growth throughout the study period that is unsupported by historical growth trends.[28] This continues the pattern seen in APS's 2014 and 2017 IRPs (and which led to the Commission's refusal to acknowledge APS's 2017 IRP) of the Company planning its IRP around an assumption that economic and population growth will drive an increase in demand (see Figure 3). There is strong evidence of the decoupling of population and load growth in the region as increasing energy efficiency measures have largely offset new demand from residential population growth. In fact, demand has been flat and little, if any, load growth has materialized over the past decade.[29] Load growth accounts for a significant portion of the new resources that APS claims it needs by 2035 and is a critical driver of APS's future resource plan.[30] Therefore, it is critical that APS has an accurate base load forecast around which to plan its near- and longer-term resource procurement.

APS's base load forecast assumes that annual peak demand and energy needs increase at a compound annual growth rate (CAGR) of 2.1 percent and 2.7 percent over the IRP planning period of 2020–2035.[31] That is attributed in large part to APS's assumption around population growth, economic growth, data center growth, and changing customer trends related to electric vehicles (EVs) and distributed generation.[32] Historically, load growth has been relatively flat in the region at 0.32 percent from 2008–2018.

[27] *Id.* at 52.
[28] *Id.* at 109-110.
[29] U.S. Energy Info Admin, *Annual Electric Power Industry Report, Form EIA-861, Annual Sales* (Oct. 18, 2019), *available at* https://www.eia.gov/electricity/annual/.
[30] APS 2020 IRP at 43.
[31] *Id.* at 19, 109.
[32] *Id.* at 111-112.

APS should be required to update its IRP based on a load forecast that reflects a more reasonable growth projection that aligns with historical observed trends.

Figure 3: APS Historical and Forecasted Peak Load Growth



High near-term load growth assumed and no incorporation of impacts of COVID-19

APS projects 550 MW of peak load growth between now and 2024.[33] This level of near-term load growth is partly attributed to data center load,[34] and partly also to residential load growth.[35] While near-term data center load growth assumptions are tied to specific, known facilities, residential load growth projections are based on economic and population trends and are less certain. Additionally, the Company acknowledges the impact that COVID-19 has, and likely will continue to have, on load, but it has not updated its modeling to incorporate any near-term load modifications.[36]

APS should not be allowed to procure any fossil resources to meet near-term load growth until it has refined its residential load forecast and updated its load forecast to reflect the impacts of COVID-19.

APS conducted low load sensitivities but did not rely on them for any base portfolios

APS also models two lower load growth sensitivities as shown in Figure 4[37] (at the requirement of the Commission under ACC Decision No. 76632); however, it relies on the highest forecast as its base forecast.[38]

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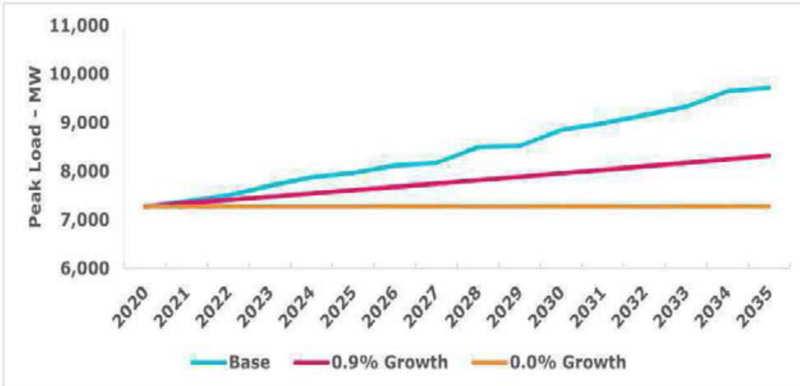
[33] *Id.* at 108.
[34] *Id.* at 112.
[35] *Id.* at 111.
[36] *Id.*at 111.
[37] *Id.* at 110.
[38] *Id.* at 110.

Figure 4: Load Sensitivities



With lower load sensitivities assuming (a) just under 1 percent annual average load growth and (b) no load growth, the NPVRR delta between the three scenarios decrease significantly. Specifically, with a load growth forecast that matches historical trends (no load growth assumed), the NPVRR difference between the fossil-heavy Bridge portfolio and the renewable-heavy Accelerate portfolio dropped to less than a third the level we see under the high load baseline scenario. [39] In other words, APS's reliance on unrealistic and high load growth assumption makes its fossil-heavy portfolio appear more economic than a renewable-focused portfolio.

The Commission should require APS to base its final IRP scenarios on a lower and more realistic load forecast that is aligned with historical trends. The Company should not be allowed to procure natural gas resources based on the results of its current IRP modeling.

8. Significant decline in investment in energy efficiency measures after 2020

APS states in its IRP that it expects to achieve cumulative energy savings of 22 percent of retail sales by 2020.[40] In doing so, APS claims it will fulfill the Commission's 2010 order requiring that by 2020, each investor-owned utility achieve cumulative annual electricity savings of at least 22 percent of its retail electric sales in Calendar Year 2019 through cost-effective energy efficiency programs.[41] It is unclear if APS has actually met this goal, as its average annual EE savings as a percent of retail sales has fallen from a high of 1.8 percent in 2012 to only 0.5

[39] *Id.* at 154.
[40] *Id.* at 60.
[41] Am. Council of Energy-Efficient Economy, *State and Local Policy Database – Arizona Utilities*, https://database.aceee.org/state/arizona#:~:text=In%202010%2C%20the%20Arizona%20Corporation%20Commission%20(ACC)%20ordered%20in,cost%2Deffective%20energy%20efficiency%20programs (last visited Oct. 13, 2020).

percent in 2019.[42] Further, with the expiration of this Commission order, APS is no longer obligated to increase annual investment in energy efficiency (EE) and demand-side management (DSM) programs. On October 14, 2020, the Commission did give preliminary approval to a new EE standard, but that rule has not yet received final approval. The Company's IRP shows a significant decline in the Company's annual average EE investments moving forward, with forecasted levels ranging from 0.2 percent to 0.6 percent.[43] These levels of EE investment are very low relative to the national average levels of 1.3 percent EE investment as a percent of retail sales.[44] *The Commission should require that APS commit to achieve at least the industry average levels of EE investment (1.3 percent) for the IRP period. Further, APS should be required to demonstrate specifically how it will meet its annual EE obligations.*

9. Renewable cost inputs are high, especially given APS's high penetration of renewables

The renewable cost assumptions that APS uses in its IRP continue to fall on the high end among leading industry forecasts.[45] This is concerning given that APS currently ranks fifth among all U.S. investor-owned utilities for overall solar capacity,[46] and therefore should have access to some of the lowest cost solar and renewables in the United States today. APS states in its IRP that its capital costs assumptions are based on information "obtained from vendors, industry publications, and evaluation of bids in APS's [request for proposal] (RFP) processes."[47] But there is no transparency into how the Company aggregated the information from these various sources to develop the Company's final cost projections.

The Commission should require APS to provide additional information on its resource cost projections.

Specifically, APS's Solar PV costs are slightly higher than even the most the conservative case in the National Renewable Energy Laboratory's (NREL) 2019 Annual Technology Baseline (ATB) report.[48] Further, for paired Solar PV and storage resources, APS simply adds together the projected capital cost of solar and battery storage to find the cost for the paired resource.[49]

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[42] U.S. Energy Info. Admin., *Annual Electric Power Industry Report, Form EIA-861, Annual Sales, & Energy Efficiency* (Oct. 18, 2019), *available at* https://www.eia.gov/electricity/data/eia861/.
[43] APS IRP at 243-50, Attachment C.1(B): Energy Consumption by Month and Customer Class.
[44] Grace Relf, et al., *2020 Utility Energy Efficiency Scorecard*, (Am. Council of Energy-Efficient Economy Feb. 20, 2020), *available at* https://www.aceee.org/research-report/u2004.
[45] APS 2020 IRP at 375, Attachment D.3: Generation Technologies.
[46] *Id.* at 11.
[47] *Id.* at 131.
[48] Nat. Renewable Energy Laboratory, U.S. DOE, *2019 ATB*, https://atb.nrel.gov/electricity/2019/ (last visited Sept. 10, 2020).
[49] APS 2020 IRP at 375, Attachment D.3: Generation Technologies.

This is an unnecessarily conservative assumption and gives the resource zero credit for value created through shared infrastructure such as inverters and interconnection costs.[50]

IRP modeling results are typically more sensitive to assumptions around capital costs for renewable resources than to assumptions around capital costs for traditional fossil resources. With traditional fossil resources, a resource's lifetime cost is attributed in large part to both fuel costs and capital costs (among other cost categories). But with renewables, fuel costs are zero. This means that when gas and renewable resources are being compared head to head, the key input for renewable resources is capital costs, while fuel costs play a substantial role for fossil resources.

Even with high renewable cost assumptions, the NPVRR of the higher renewable Accelerate portfolio is still within 7 percent of the NPVRR for the fossil-heavy Bridge portfolio.[51] APS did not run any capital cost sensitivities, so we do not know precisely where the break-even point on renewable resource cost will be at which the Accelerate portfolio will be cheaper than the Bridge portfolio. But we know that with lower renewable costs, the delta between the portfolios will be much smaller, and the Accelerate portfolio may even be less expensive than the Bridge portfolio.

The Commission should require APS to conduct low renewable capital cost sensitivities model runs as part of this IRP.

There is no evidentiary support for the Company's renewable integration costs

APS models all renewables in its IRP with renewable integration cost adders (a separate one for solar PV and one for wind) that were developed by Energy Exemplar.[52] These cost adders are intended to represent "namely increased operating and maintenance costs" imposed on the system by renewables that are not otherwise captured by the IRP model.[53] We don't challenge the concept that renewables can require the integration of additional resources and technologies to address intermittency and supply other essential grid services (namely incremental requirements for operating reserve and regulation resources). But based on our review of the limited information available on the study, we do not believe that APS has adequately explained what specific costs renewables are imposing, and how it calculated those incremental costs. Better forecasting of wind and solar—coupled with presence of battery storage and EIM exchanges at sub-hourly intervals lessens—considerably if not completely, the impact that otherwise gives rise to considering an integration cost effect.

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[50] Lazard, *Levelized Cost of Storage Analysis-Version 5.0* (Nov. 2019), *available at* https://www.lazard.com/media/451087/lazards-levelized-cost-of-storage-version-50-vf.pdf.
[51] *Id.* at 140.
[52] *Id.* at 458, Appendix C: Energy Exemplar Renewable Integration Study.
[53] *Id.* at 47.

The area that most concerns us is paired resources, specifically solar paired with battery energy storage systems (BESS). APS modeled a renewable integration cost on all solar; but for solar paired with BESS, it is not reasonable to add an integration cost. The presence of the BESS lends a degree of control as to the forecasting of net export from a paired system. This makes the solar a more predictable, not less predictable, resource; thus, the resource doesn't cause an increase in system integration costs. APS even acknowledged during a call with Sierra Club that this issue is one it is continuing to investigate,[54] but it is unclear if and how it plans to modify its IRP based on its current investigation. While BESS dedicated to solar PV may not be available to provide other critical grid services as readily as utility-scale BESS, that does not directly imply that an integration cost should therefore be added. Moreover, it appears APS may have *double-counted against* solar PV paired with BESS by essentially reducing the capacity of the solar resource due to efficiency losses from using batteries while also adding solar integration costs that could be substantially mitigated by the use of paired BESS. Doing so irrationally penalizes the paired resource as compared with standalone solar, despite the substantial grid benefits provided by BESS.

Additionally, we find several other flaws with the study. First, Energy Exemplar appears to have modeled a portfolio of resources that includes both solar and wind, without also modeling a portfolio with only one renewable resource at a time. This makes it challenging for APS to fully isolate the individual system impacts of solar PV and wind. Second, APS excluded the "impact of forced outage, dispatchable deviation, and load deviations."[55] It is not reasonable to calculate an integration cost for a different system than the one APS is actually operating. Without including the effect of load deviation, a normal part of operations, when assessing sub-hourly impacts, the modeling is insufficient. Third, to the extent APS already has storage on the system, even if it was not necessarily procured to address solar and wind variability, the co-benefits of storage include reducing costs associated with regulating reserves anyway. Stated another way, if stand-alone battery storage is already providing some of the critical grid services that are required to support the integration of renewables, there is no reason to include an additional renewable integration charge associated with procuring still more of the same service. Fourth, APS states that it will resolve things within its service territory; but APS is part of EIM, which (in 2030 and 2035 certainly, and likely much sooner) allows for imbalance market transfers at 15-minute intervals.[56] This market exists in part to improve overall efficiency of dispatch considering variable output resources patterns all over the Western Electric Coordinating Council (WECC).

[54] Ariz. Pub. Serv. Telephone Call with Sierra Club (Sept. 25, 2020).
[55] APS 2020 IRP at 485, Appendix C: Energy Exemplar Renewable Integration Study.
[56] *Id.* at 458, Appendix C: Energy Exemplar Renewable Integration Study.

The Commission should not allow APS to use a non-zero renewable integration cost in its IRP without updating its modeling to address the concerns outlined above, outlining what the purported costs are attributed to, and explaining how they were calculated.

Access to high wind potential in New Mexico may not have been properly modeled

The best wind resources available to APS are in the northern part of the state or in the neighboring state of New Mexico.[57] But, APS stated in its IRP that, "Gaining access to these wind facilities can power significant additional costs due to required transmission buildout or upgrades."[58] This means that to tap into much of this high quality wind could require the construction of significant new transmission infrastructure. It is reasonable and even desirable to consider the limitations and constraints of existing transmission infrastructure, and the cost of building out new infrastructure; however, it appears that in its modeling, the Company assumed that the high quality wind resources further away are simply not available until more transmission is built. Further, it is unclear if and how APS considered the transmission line capacity located in the northeast part of the state that will be freed up with the closure of Four Corners.

APS should clearly outline its assumptions around the cost to access high quality wind, including the cost to build new transmission infrastructure. It should then conduct modeling runs that evaluate the break-even cost for new transmission infrastructure. The Company should also ensure that when conducting its Four Corners retirement analysis, it makes wind resources available to the model to come online in the northwest corner of New Mexico and northeast corner of Arizona, to test the economics of retiring Four Corners relative to utilizing the transmission infrastructure to move high quality wind resources across the state.

10. Gas prices and gas technology costs are too low

Natural gas technology costs are too low

APS relies on capital cost estimates for new natural gas resources (specifically, a large frame combustion turbine)[59] that are lower than industry-standard estimates as reported by the U.S. Energy Information Administration (EIA) in its Annual Energy Outlook (AEO) 2020 report.[60] This is concerning given that, as discussed above, APS also relied on capital costs for renewable technologies that are on the high end of industry estimates. The combined impact of APS relying on high capital costs for renewable resources and low capital costs for natural gas resources biases the results in favor of gas generation resources and away from renewable resources. *APS*

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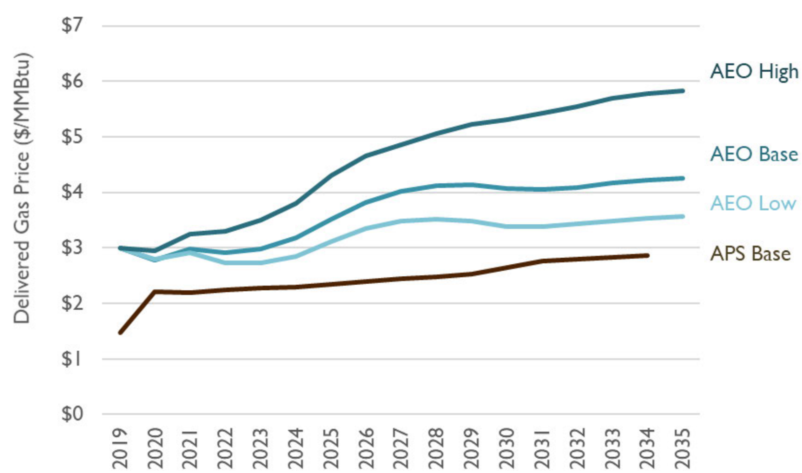
[57] *Id.* at 99.
[58] *Id.*
[59] *Id.* at 375, Attachment D.3: Generation Technology.
[60] U.S. Energy Info. Admin., *Assumptions to the Annual Energy Outlook 2020: Electricity Market Module* (Jan. 2020), *available at* https://www.eia.gov/outlooks/aeo/assumptions/pdf/electricity.pdf.

should be required to justify its capital cost assumption for new gas resources, or else use a cost most in line with industry sources, such as the EIA AEO.

Natural gas price forecasts are too low

In addition to the capital cost, natural gas prices also have a significant impact on the resource economics seen by the model. APS's natural gas price forecasts[61] are once again significantly lower than the industry-standard forecasts published by EIA AEO[62] as shown in Figure 5. This repeats a pattern we have seen in the last two IRPs of APS projecting lower natural gas prices than other leading sources. Fuel costs comprise a significant portion of the NPVRR for fossil resources. Therefore, APS's reliance on artificially low gas price forecasts makes it fossil-heavy portfolio look cheaper relative to a renewable portfolio that relies more heavily on zero-fuel cost resources.

Figure 5: APS Natural Gas Price Forecast



APS does test several natural gas price forecast sensitivities with lower and higher price assumptions. As we would expect, APS's analysis shows that with increased gas prices the NPVRR delta between the Bridge and Accelerate portfolios decreased.[63] But the Company relies on its very low base gas price forecast for all its final portfolio results.[64]

Given the interplay among renewable capital costs, natural gas capital costs, and natural gas fuel prices, the Commission should require that APS conduct sensitivities that reflect costs closer

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[61] APS 2020 IRP at 147.
[62] U.S. Energy Info. Admin., *Annual Energy Outlook for 2020, Table 63. Natural Gas Delivered Prices by End-Use Sector and Census Division, Reference case, Mountain Electric Sector Delivered Price* (Jan. 2020), *available at* https://www.eia.gov/outlooks/aeo/data/browser/#/?id=78-AEO2020&cases=ref2020&sourcekey=0.
[63] APS 2020 IRP at 152.
[64] *Id.* at 147.

<u>to the industry standard. Specifically, lower renewable resource capital costs, higher natural gas capital resource cost, and higher natural gas fuel prices.</u>

These sensitivities are critical to understanding what could happen if fuel prices go up in the future. Capital costs tend to change in a manner that is generally stable and predictable. For solar PV, for example, resource capital costs have been steadily declining, and all evidence points to this trend continuing for the foreseeable future. Fuel prices, on the other hand, tend to be subject to market volatility and spikes on a more granular basis and even could display unpredictable long-term changes based on global economic trends.

When a utility builds a fossil resource, it locks its ratepayers into reliance on the fossil resource for the long term. If fuel prices increase, the utility is stuck either (a) buying high cost fuel and operating the unit at a loss; (b) temporarily shutting the unit down (i.e., putting it into cold storage); (c) converting the unit to run on another fuel, if possible; or (d) replacing the generation with a lower-cost resource and shutting down the original unit (while attempting to continue to collect the capital cost of building and maintaining the unit from ratepayers despite not actually running the unit). When a utility builds a renewable resource or signs a renewable PPA, once the unit is built or the contract is signed, the majority of the lifetime project cost is set and certain.

In discussing fuel price volatility, we are not asserting that we think gas prices will rise in the near future. Rather we are arguing that APS's current gas price assumptions do not provide an adequate representation of likely future gas prices; nor do they capture the risk of future fuel price volatility. APS also does not appear to reflect the value that renewables provide in fundamentally avoiding the risks and costs associated with natural gas price volatility. *<u>The costs and avoided costs associated with fuel price volatility are real and significant, and APS should quantify and integrate them into its IRP modeling.</u>*

Misleading framing of CTs as hydrogen-ready natural gas generation

APS repeatedly refers to natural gas CT units as "hydrogen-ready" and "hydrogen capable" natural gas generation.[65] This framing is concerning and misleading. The technology to convert CTs to run on hydrogen instead of natural gas is being explored but has not been fully developed or proven to be viable to scale to market. Even if it does come to market in the next decade, any gas plant built between now and then will continue producing carbon emissions in the interim. Further, APS does not justify its decision to rely on an unproven fossil-fuel technology that has the *potential* to produce zero emissions peaking generation in the future over proven fossil-free technologies available today that can provide the same services. *<u>Natural gas CTs are fossil resources and classifying them as anything else is false and misleading, and therefore should be removed from the IRP.</u>*

[65] *See, e.g., id.* at 129, 180.

11. Conclusions and Recommendations

APS's 2020 IRP relies on a very limited number of portfolio and sensitivities and critically does not evaluate or consider the retirement of Four Corners prior to 2031 in any of its portfolios. Further, the Company continues to rely heavily on fossil resources in all portfolios (both gas and coal), justified by unsupported assumptions around high load growth. The result is once again a planning process that systematically favors fossil resources and disadvantages renewables. We recommend that the Commission once again not acknowledge APS's IRP until the Company addresses the flaws we have outlined.

Specifically, we recommend the following:

- **The Commission should decline to acknowledge this IRP. Instead, APS should be required to submit a revised IRP that:**
    - Includes a more reasonable load forecast that incorporates the impacts of COVID-19 and does not continue to rely on rapid load growth that has historically failed to materialize;
    - Incorporates the cost of compliance with future environmental regulations, including the ELG;
    - Incorporates any costs or risks associated with continued reliance on surface water to operate Four Corners;
    - Includes one or more scenarios that test and allow for the endogenous retirement (within the model construct) of the Company's coal plants prior to each plant's scheduled retirement date;
    - Tests and provides transparent results for a larger range of scenarios and sensitivities around resource costs, fuel prices, load forecast, plant retirement dates, plant operational parameters, and environmental regulations; and
    - Includes forecasted energy efficiency program investment of at least 1.3 percent of retail sales annually.
    - Excludes the renewable integration cost for, at a minimum, all paired renewable resources.
- **APS should conduct, as part of its IRP, a detailed study of the economics of continuing to operate Four Corners that includes:**
    - The full cost of terminating the Company's existing coal contract;
    - The cost and risk of obtaining water;

- A schedule of sustaining capital costs matched with retirement dates to ramp down capital spending in advance of retirement;
- Community economic, employment, and tax base impacts;
- An alternative market price forecast that developed without the assumption that Four Corners is locked in until 2031; and
- The option to build wind in the northeast corner or Arizona or the northwest corner of New Mexico to utilize the transmission infrastructure that will be freed up with the retirement of Four Corners.

- **The Commission should not allow APS to procure any new fossil resources based on the results of its current IRP.**
  - In the near term, APS should not be allowed to procure any new fossil resources until it has updated its load forecast to reflect the impacts of COVID-19.
  - For the larger study period, the Company should not be allowed to procure natural gas (among other) resources until the Company has re-run its IRP based on a lower and more realistic load forecast that is aligned with historical trends and updated and other sensitivities around resource and fuel costs. The prior Commission gas moratorium sent a clear and necessary message that utilities should not rely too heavily on natural gas resources in their IRPs.
- **The Commission should require APS to better explain and justify the results of its renewable integration study, and to update the study to address shortcomings.**
  - APS should clearly outline the specific system needs that are purported required and met by the renewable integration costs.
  - APS should clearly explain how it calculated each component of its integration cost.
  - APS should update its study to address the shortcomings associated with its decisions to only model solar and wind together, to remove the impact of forced outages and other load deviations, and to not factor the ability for the EIM to provide renewable integration services.