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2017 SEP 27 P 12: 13

Before the Arizona Corporation Commission

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DOCKETED
SEP 27 2017
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IN THE MATTER OF RESOURCE PLANNING AND PROCUREMENT 2015 AND 2016

Docket No. E-00000V-15-0094

Sierra Club Comments on Arizona Public Service's 2017 Integrated Resource Plan

1. Introduction

Sierra Club appreciates the opportunity to comment on Arizona Public Service's (APS) 2017 Integrated Resource Plan (IRP). These comments were prepared with the assistance of Synapse Energy Economics, and are based on our examination of APS's input assumptions, portfolio construction, and evaluation of its resource options. Sierra Club was an active participant in planning dockets in the development of APS's 2017 IRP, and actively contributes to planning proceedings in jurisdictions across the United States, as stakeholders, intervenors, and commenters. In these comments, we focus on the overarching goal of achieving transparent, evidence-based resource planning that strikes a balance between low costs and risk mitigation.

2. Summary and Recommendations

An IRP should identify a path toward reliably satisfying future energy service demands in an economic manner, subject to various legal and policy constraints. A useful IRP contains a reasonable array of input assumptions, and fairly evaluates the costs and benefits of competing demand- and supply-side resources.

We find that there are elements of APS's IRP that are laudable. Specifically, the overall structure of APS's IRP is methodologically sound in that it relies on optimization models, evaluates sensitivities around key assumptions, and attempts to assess risks.

However, we find that APS's IRP rests on a combination of implausible assumptions, analytical errors, and flawed conclusions. In general, APS's IRP is systematically biased in favor of the construction of new natural gas resources. This bias is reflected in an array of assumptions that exaggerate the need for new resources, under-state likely future natural gas prices, and under-value alternatives such as renewable energy, battery storage, and demand-side resources. In addition, we find that APS does not provide sufficient justification for ignoring its own modeling results indicating that it would be more cost effective to retire coal capacity more rapidly than currently planned.

The most serious flaws in the APS IRP include:

- **An unrealistically high load forecast:** APS uses an implausibly high load forecast that is inconsistent with the last decade of flat load. Moreover, this forecast is nearly identical to the forecast used, and rejected, in the 2014 IRP. This forecast results in a false impression that APS needs to rapidly procure thousands of megawatts of capacity to serve new load.

- **Systematic bias against demand-side management alternatives.** APS incorrectly includes customer energy efficiency costs in its calculation of net present value revenue requirements. This causes an expanded demand-side management portfolio to appear far more costly than the selected portfolio, when it is in fact the *most* cost-effective portfolio over the next 15 years. In addition, APS likely over-states the long-term costs of efficiency programs.

- **Inadequate justification for portfolio selection**: The IRP indicates that a Carbon Reduction portfolio, which involves the retirement of all APS coal units by 2032, provides a benefit of more than $200 million relative to the selected portfolio over the long term, while also resulting in lower emissions and water usage. APS's reasons for selecting its Flexible Resource Portfolio over the Carbon Reduction portfolio are unconvincing, and APS does not provide a transparent description of how APS weighted its various key metrics in coming to a decision.

- **Inflated renewable cost assumptions:** APS over-states the future costs of available solar and wind resources, ignoring both the current low cost of Arizona renewables and ongoing cost declines. These assumptions bias the IRP results against the inclusion of more renewables.

- **Under-valuation of battery storage:** APS assumes inflated battery storage costs and under-states the potential for batteries to provide near-term, cost-effective peak capacity and ancillary services. APS claims that battery storage may not even be feasible within the next 10 years, despite recent procurement of cost-effective storage by APS and other Arizona utilities. APS's treatment of storage biases it against one clear alternative to APS's planned pursuit of extensive new natural gas capacity.

- **Deflated natural gas price assumptions:** APS assumes long-term gas prices that are lower than even the lowest sensitivities evaluated by other, standard long-term forecasters. Furthermore, APS's gas price sensitivities are not sufficiently spread out to reasonably assess exposure to gas price risk. These assumptions further bias the IRP in favor of the construction of natural gas capacity.

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

- **APS should submit a revised IRP that:**
  - Includes a credible load forecast and does not depend on rapid load growth that is unlikely to materialize;
  - Corrects for the erroneous inclusion of participant demand-side management costs in its assessment of the revenue requirements of alternative scenarios;
  - Accounts for the current low costs, and likely future declines in the costs of, renewable and battery storage resources;
  - Incorporates gas price and load forecast sensitivities that cover a more reasonable range of likely futures; and
  - Provides greater transparency around its portfolio selection process.
- **APS should withdraw its recently released RFP for up to 700 MW of new capacity.** It should hold off on procuring additional capacity to serve new load until it has produced a more reasonable load forecast.
- **APS should pursue all cost-effective energy efficiency**, and it should not dismantle its current efficiency programs simply because it believes they will not be required by law after 2020.
- **APS should investigate near-term opportunities to invest in cost-effective renewable and battery storage resources.**
- **APS should conduct a detailed analysis of the economic viability of each of its remaining coal units.**

3. APS Relies on Implausibly High Forecasts of Load Growth

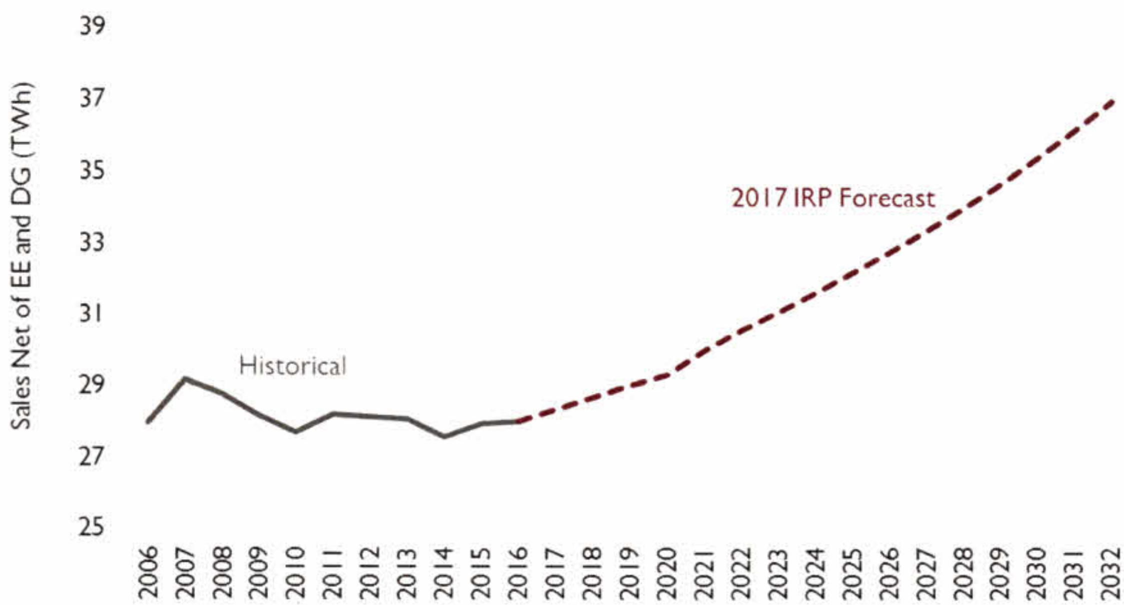
The load forecast is a critical component of any IRP. Since future load growth largely determines the need for future energy and capacity, IRP load forecasts can have a substantial impact on future system reliability and costs faced by ratepayers. If a load forecast is too low, it can result in under-procurement of new resources and a possible need to invest in last-minute, expensive capacity. If a load forecast is too high, it can lead to the procurement of unnecessary, costly new resources.

In this IRP, APS proposes to base its planning on sales and load forecasts so high as to border on the absurd. Ignoring past Commission guidance to avoid over-forecasting load, APS instead positions itself to procure thousands of megawatts of unnecessary new capacity in the next decade.

APS Sales Forecast Is Inconsistent with Recent Trends

APS's 2017 IRP assumes that sales will increase at an average annual rate of about 1.8 percent between 2017 and 2032, after accounting for energy efficiency and distributed generation.[1] This is inconsistent with APS's recent sales trajectory. APS's sales have been essentially flat over the past decade, and in fact they decreased slightly between 2007 and 2016.[2] Ignoring this trend, APS forecasts that sales will start growing at an annual rate greater than 1.2 percent this very year and will continue to grow steadily throughout the IRP study period, as shown in Figure 1. This forecast growth adds up to an 18 percent sales increase over the coming decade, and a 30 percent increase over the 15-year IRP study period.[3]

Figure 1. APS Historical and Forecast Retail Sales



Sources: Form EIA-861, APS 2017 IRP

APS Peak Demand Forecast is Inconsistent with Recent Trends

APS's forecast of future peak demand is even more bearish than its sales forecast. Like its sales, APS annual peak demand has been remarkably consistent in the recent past, with only a slight

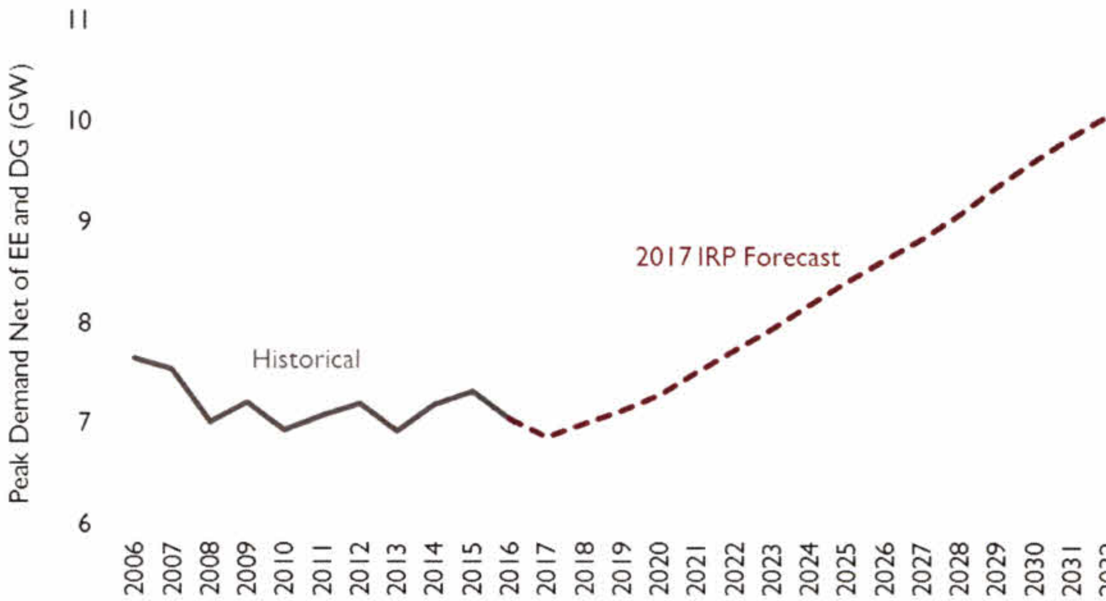
[1] APS 2017 IRP, Attachment C.1(B).

[2] Form EIA-861.

[3] APS 2017 IRP, Attachment C.1(B).

decline over the past decade.[4] However, APS is now projecting peak demand (after accounting for energy efficiency and distributed generation) to grow at a rate of 2.6 percent per year over the next 15 years.[5] This results in a projected peak load increase of 900 MW over the next 5 years, and 3.2 GW over the next 15 years.[6]

Figure 2. APS Historical and Forecast Peak Demand



Sources: Form EIA-861, APS 2017 IRP

APS Explanations for Projected Growth Are Not Credible

APS states that its load forecast is largely driven by expectations of future population and economic growth.[7] APS dismisses the past decade of flat and declining load as merely a "pause []" in "the state's rapid growth in electricity demand," caused by "the recent economic downturn," and argues that "future growth will once again be driven by" the growing Arizona population and economy.[8] This explanation would lead one to believe that Arizona's population

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[4] Form EIA-861.

[5] APS 2017 IRP, Attachment C.1(A).

[6] APS reports that on June 21, 2017, the utility hit "an all-time record peak demand of 7,350 MW of energy consumed between 5 and 6 p.m." (http://www.pinnaclewest.com/newsroom/news-releases/news-release-details/2017/Aps-Customers-Set-All-time-Record-For-Electricity-Use/default.aspx). This peak exceeded the last record high (set in 2006) of 7,236 MW by 114 MW, a 1.5% increase over a ten year span, or a cumulative average growth rate of 0.14% per year.

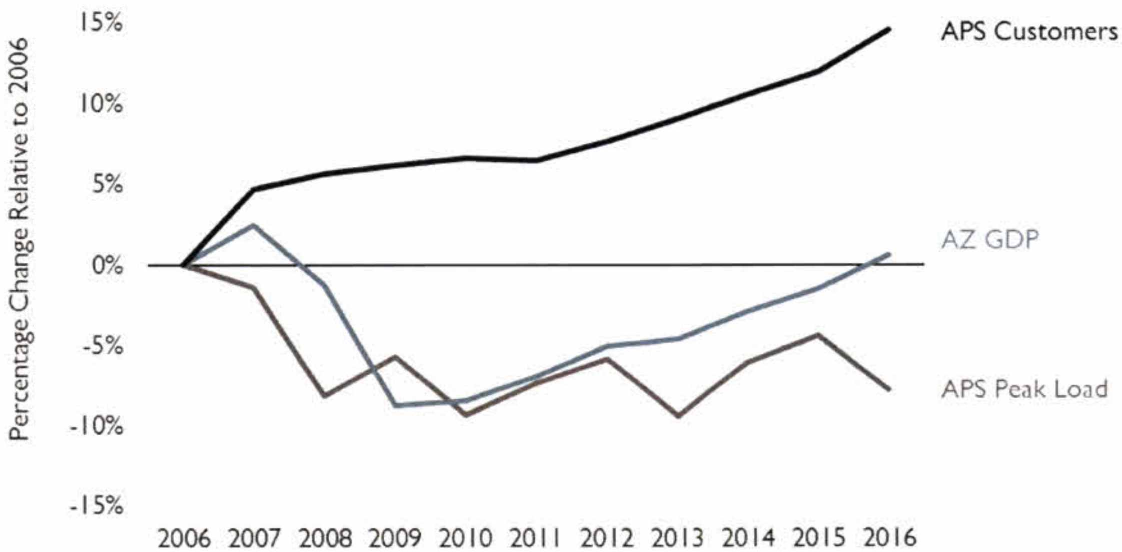
[7] APS 2017 IRP, pp. 33-34.

[8] APS 2017 IRP, p. 33.

and economy have been stagnant or declining throughout the past decade. This is simply not the case.

Although Arizona's Gross Domestic Product (GDP) declined sharply during the Great Recession of 2008 and 2009, it has been increasing steadily since 2010, and in 2016 reached its highest level since 2007. Between 2011 and 2016, Arizona's GDP grew 8 percent, for an annual average growth rate of 1.6 percent.[9] Over this same period, APS's annual peak load remained roughly flat. In fact, as Figure 3 shows, APS peak load has remained within a tight range ever since 2008, even as the Arizona economy first crashed and then rebounded. This indicates that APS's insistence that future economic growth will necessarily lead to rapidly increasing peak demand is not well supported.

Figure 3. APS Peak Demand, Arizona Real GDP and APS Customer Number, Relative to 2006



Sources: Form EIA-861, U.S. Bureau of Economic Analysis, Arizona Office of Economic Opportunity

Figure 3 also undercuts APS's claim that future population growth will cause electric demand to suddenly start growing as it did decades ago, rather than as it has over the past decade. This claim ignores the fact that APS's customer base has continued to grow steadily even as demand has stagnated. The number of APS customers has increased at an average annual rate of 1.0 percent since 2008, and 1.5 percent since 2011.[10] Throughout this time, APS peak demand has hovered between 5 and 10 percent below 2006 levels.

[9] U.S. Bureau of Economic Analysis. Regional Data: Real GDP by State. Available at https://bea.gov/itable/iTable.cfm?ReqID=70&step=1#reqid=70&step=10&isuri=1&7003=900&7035=-1&7004=naics&7005=-1&7006=04000&7036=-1&7001=1900&7002=1&7090=70&7007=-1&7093=levels.

[10] Form EIA-861.

The recent increase in APS customers is consistent with recent and projected population growth rates for both the state of Arizona and APS's service territory. Over the past decade, Arizona's population has grown at an annual average rate of 1.1 percent, and Maricopa County's population growth rate has been 1.2 percent per year.[11] The Arizona Office of Economic Opportunity projects that long-term annual population growth rates will average 1.3 percent for Arizona and 1.4 percent for Maricopa County.[12] These slight upticks in the population growth rate are hardly sufficient to justify APS's assumption that peak load will suddenly transition from its stagnant trajectory toward one of rapid growth at rates in excess of population growth.

APS Load Forecast Runs Counter to Commission Guidance

This is not the first time that APS has presented an unreasonably high load forecast in an IRP. In its 2014 IRP, APS projected that its peak load, net of energy efficiency and distributed generation, would increase at an annual average rate of 2.2 percent between 2014 and 2029.[13] Commission Staff's report on the 2014 Arizona IRPs found that APS's load forecast was "optimistic," and recommended that "APS re-examine [its] load forecasting techniques prior to the filing of the 2016 IRPs to ensure APS [is] not forecasting high load growth that is unlikely to occur."[14] The Commission endorsed this recommendation and ordered APS to file a report on the results of its re-examination of its load forecasting techniques by October 2015.[15]

APS complied with the literal requirements of the Commission's order by filing a report describing its load forecasting techniques.[16] However, APS appears to have violated the spirit of the Commission's order. After going through the motions of re-examining its load forecasting techniques, APS has presented a 2017 IRP load forecast that is remarkably similar to its 2014 IRP forecast, despite APS having three more years of historical data to indicate that its load is not, in fact, rapidly increasing. Figure 4 shows that the 2014 and 2017 IRPs both forecasted load growth of between 12 and 13 percent from 2017 to 2022, and between 28 and 29 percent from 2017 to 2027. The only notable differences between these forecasts are that the vintage 2017 forecast has a lower near-term starting point, due to the past three years of continued stagnant load, and that the 2017 forecast extends the projected growth out another three years. For all intents and purposes, APS simply replicated the 2014 load forecast in the 2017 IRP.

[11] Arizona Office of Economic Opportunity. Population Estimates. https://population.az.gov/population-estimates.

[12] Arizona Office of Economic Opportunity. Arizona Medium Population Projections. Available at https://population.az.gov/population-projections.

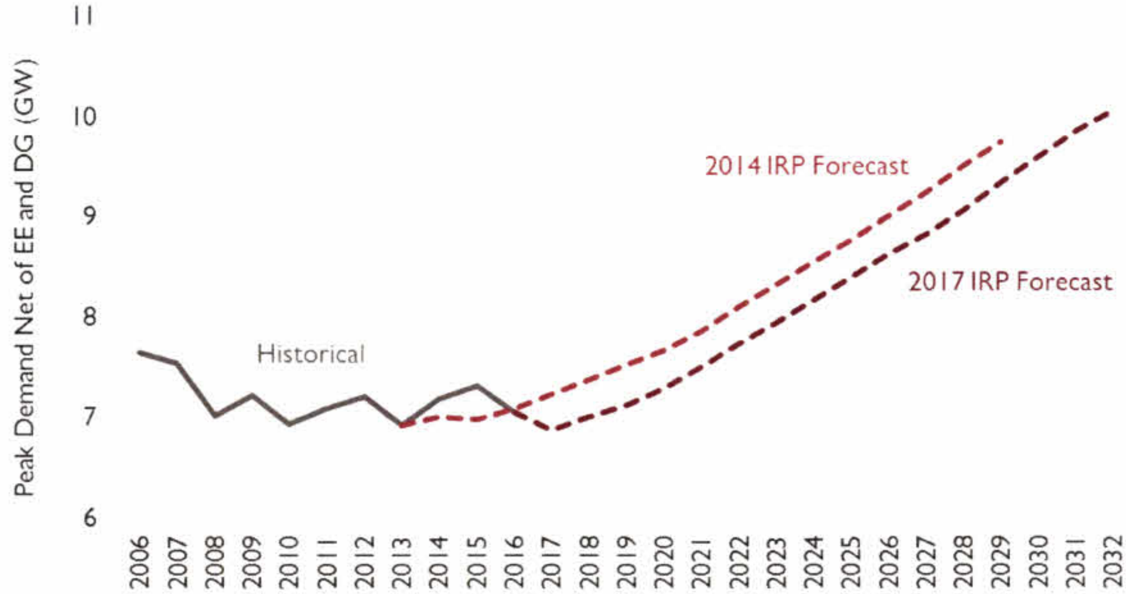
[13] APS 2014 IRP, p. 225.

[14] Global Energy and Water Consulting LLC and Evans Power Consulting, Inc. on Behalf of Arizona Corporation Commission Staff. December 2014. Assessment of the 2014 Integrated Resource Plans of the Arizona Electric Utilities. P. 8.

[15] Arizona Corporation Commission. May 8, 2015. Decision No. 75068. Pp. 14-15.

[16] APS. October 30, 2015. Re-examination of APS Load Forecasting Techniques. Docket No. E-00000V-15-0094.

Figure 4. APS Peak Demand, Historical and Forecasted in 2014 and 2017 IRPs



Sources: Form EIA-861, APS 2014 IRP, APS 2017 IRP

APS's response to the Commission's 2014 IRP order indicates that requiring APS to re-examine its load forecasting techniques has not been sufficient to convince APS to produce a reasonable forecast. We therefore recommend that the Commission refuse to acknowledge the 2017 IRP until APS revises it to incorporate a reasonable base load forecast.

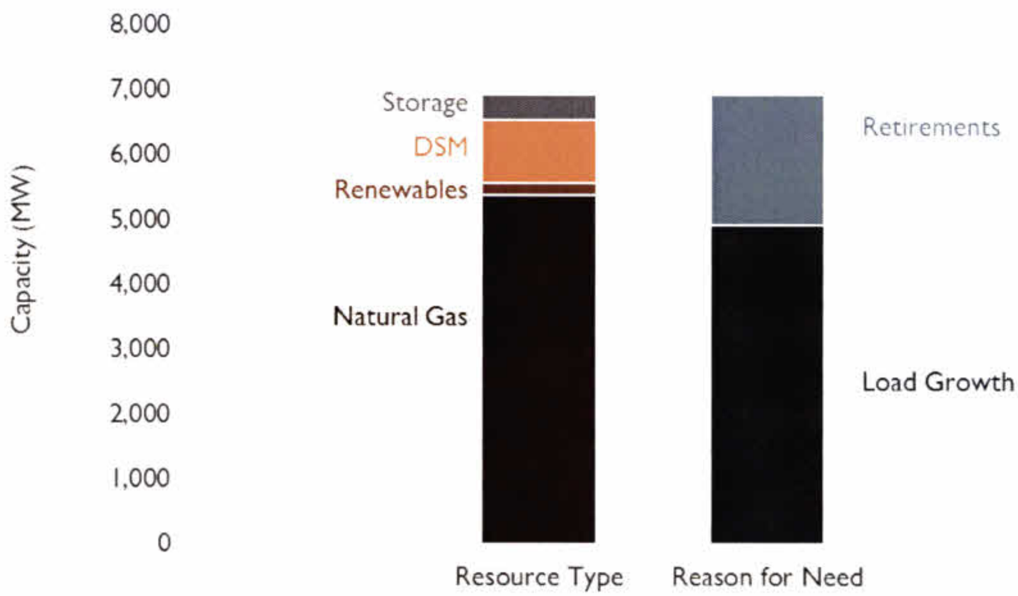
APS Load Projections Would Result in Substantial Capacity Overbuild

APS's overly optimistic load forecast has weighty implications for its resource plan, and therefore for the costs likely to be borne by APS ratepayers. APS's selected Flexible Resource Portfolio calls for the addition of 6,946 MW of new capacity, including 5,387 MW of new natural gas capacity, between 2017 and 2032.[17] While 2,025 MW of this new capacity is driven by power purchase agreement (PPA) expirations and unit retirements, the remaining 4,921 MW evidently result from an alleged need for capacity to serve increasing load (see Figure 5).[18] These 4,921 MW represent 71 percent of planned new capacity and 61 percent of current peak capacity. The capital costs of developing this much capacity would register in the billions of dollars.

[17] APS 2017 IRP, p. 12.

[18] Id.

Figure 5. APS Projected Capacity Additions by Resource Type and Reason for Addition, 2017-2032



Source: APS 2017 IRP

Of more immediate concern, APS's near-term action plan is headlined by the issuance of a request for proposals (RFP) "to meet future summer season peak capacity needs for 2021 and beyond."[19] Media reports indicate that APS has in fact already issued this RFP, and is seeking 400 MW to 700 MW of new capacity to come online no later than June 2021.[20] This RFP is likely driven by APS's improbable load forecast. The 315 MW of planned coal retirements between now and 2021 are more than covered by APS's recently announced procurement of 565 MW of natural gas peak capacity.[21] But APS is not just planning to maintain sufficient capacity to serve current levels of peak demand. It is proposing to add 1,197 MW of incremental peak capacity between now and 2021, to serve load growth that is highly unlikely to materialize.[22]

We recommend that APS withdraw its 2017 RFP until it has produced a more reasonable load forecast from which to determine whether additional near-term capacity is needed. If APS moves forward with this current capacity plans, the Commission should reject future rate recovery of the cost of any new capacity that is built to meet speculative, unsupported projected increases in peak demand.

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[19] APS 2017 IRP, p. 24.

[20] Power Engineering. April 1, 2017. APS Issues RFP for up to 700 MW of Peaking Capacity. http://www.power-eng.com/articles/2017/04/aps-issues-rfp-for-up-to-700-mw-of-peaking-capacity.html

[21] APS 2017 IRP, p. 24.

[22] APS 2017 IRP, p. 24.

APS's Load Forecast Sensitivities Are Unhelpful

APS does follow standard practice in including IRP sensitivities that vary its load growth assumptions. However, APS has structured its load sensitivity analysis in such a way as to render it useless. Even APS's "low" load growth sensitivity assumes 2.3 percent annual peak load growth, prior to energy efficiency and distributed generation. [23] As discussed previously, recent history provides little reason to expect any substantial near-term growth in APS peak demand, let alone growth of greater than 2 percent per year. In addition, APS has evidently not optimized or otherwise evaluated any portfolios that adjust to lower load expectations by building out less new capacity. This lack of evaluation makes it difficult to assess how APS's plan would change were it to adopt a lower, more realistic load forecast.

4. APS IRP Is Biased Against Demand-Side Management

Throughout its IRP, APS consistently under-states the value of, and over-states the costs of, demand-side management (DSM) programs.

APS Unjustifiably Forecasts a Dramatic Decline in Energy Efficiency Savings

Under APS's selected portfolio, its annual incremental energy efficiency savings continue at their current, relatively strong levels of approximately 1.6 percent of sales through 2020. However, starting in 2021 forecasted savings drop to less than 0.3 percent of sales, and they remain at that level through the end of the study period in 2032.[24] This represents an 85 percent decline in annual savings levels.

Even under the "Expanded DSM" portfolio, future APS savings are lower than current levels. Under this portfolio, incremental savings drop steadily from 2021 onward, reaching levels of 1.2 percent of sales by 2032.[25] Figure 6 compares recent APS savings levels to those forecasted in the 2017 IRP.

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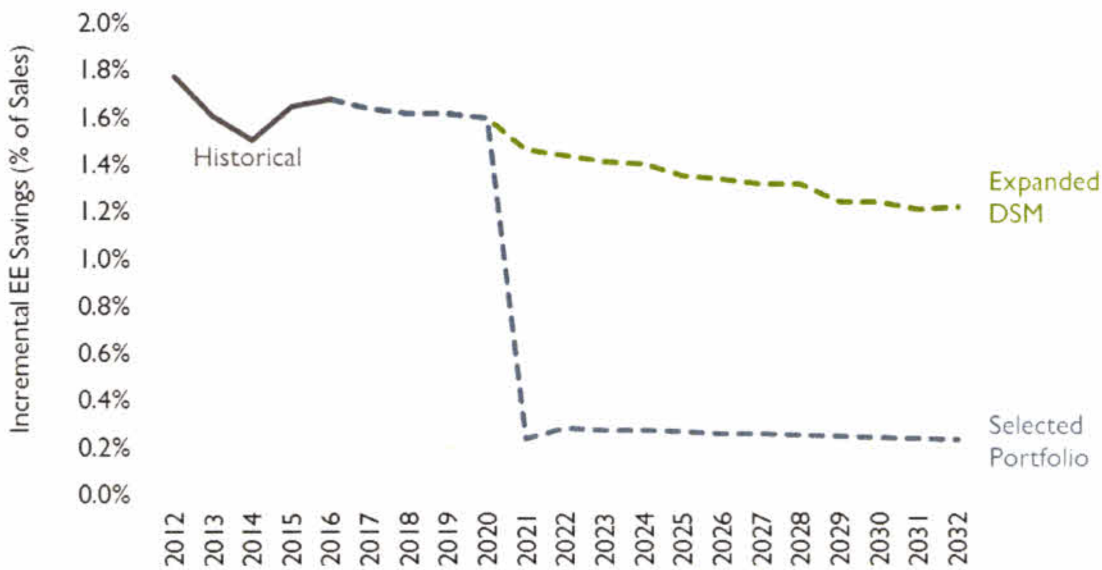
[23] APS 2017 IRP, p. 123.

[24] APS 2017 IRP, Attachment C.1(B).

[25] APS 2017 IRP, p. 170; APS 2017 IRP, Attachment C.1(B).

Figure 6. Historical and Forecast Efficiency Savings as Percent of Sales



Sources: Form EIA-861, APS 2017 IRP

The timing of the forecast decline in savings corresponds to the assumed expiration of Arizona's Energy Efficiency Standard (EES). The EES currently requires that APS meet a cumulative savings goal of 22 percent of sales by 2020, but does not specify any savings goals beyond that year.[26] Still, the absence of an explicit post-2020 savings target does not mean that APS should cease to pursue cost-effective efficiency savings. On the contrary, in reaching the 2020 standard APS will have already done much of the hard work of setting up the administrative structure to implement efficiency measures at scale. To suddenly cease energy efficiency implementation after 2020 would be to waste much of that effort, and to throw away ratepayer money in the process.

APS's Current Efficiency Portfolio Is, and Will Likely Continue to Be, Cost-Effective

APS's IRP makes clear that the current APS energy efficiency portfolio is cost-effective. The utility's residential and non-residential portfolios each had a 2016 benefit-cost ratio of approximately 1.5, well above the 1.0 break-even point.[27] Of all APS energy efficiency programs, only the relatively small "Prepaid Energy Conservation" program had a benefit-cost ratio less than 1.

Nonetheless, APS proposes to nearly completely phase out its current energy efficiency portfolio by 2021, in favor of peak demand management programs that "align better with system resource

[26] Arizona Administrative Code. R. 14-2-2401 et seq. http://apps.azsos.gov/public_services/Title_14/14-02.pdf.

[27] APS 2017 IRP, p. 176.

needs."[28] We commend APS for its efforts to develop peak-focused demand management programs. However, APS does not have to choose between implementing one set of cost-effective demand management programs or another. It should pursue both.

APS offers two main arguments for why its current energy efficiency portfolio will not continue to be cost-effective. First, APS argues that it may not be able to "continue the high levels of energy reductions for such an extended period of time."[29] Second, APS suggests that in the future, current programs will not provide sufficient "savings during high cost, high demand late afternoon and evening hours."[30] Neither view is supported by evidence. The expressed concern of utilities that opportunities for energy efficiency will simply disappear has not borne out. Over the last decade, major utilities have continued to successfully increase demand-side management programs year-on-year. While utilities do anticipate that the federal lighting standards[31] will take away some elements of low-cost efficiency, opportunities abound in commercial lighting, heating and air cooling, and specialized programs for industrial customers. APS's view that its current programs will fail to provide reductions during peak hours is also unsupported. There is reason to believe that some of APS's largest existing programs, including HVAC and consumer lighting programs, would provide high value during peak summer hours, when air-conditioning units are in operation and households start to turn their lights on.

APS Wrongly Includes Participant Energy Efficiency Costs in its Revenue Requirements Comparison

Given the cost-effectiveness of APS's energy efficiency portfolio, it comes as a surprise that APS concludes that its Expanded DSM portfolio, which does little more than continue current energy efficiency programs, has a net present value (NPV) revenue requirement that is more than $640 million higher than the selected portfolio.[32] The simple explanation is that this conclusion is inaccurate. APS misleadingly and incorrectly included incremental participant costs in its calculation of revenue requirements.[33] There is no logical basis for including participant costs, which by definition are not incurred by the utility and will therefore never be recovered by a utility through its revenue mechanisms, in a calculation of revenue requirements.

The attachments to the APS IRP show that, calculated properly, the Expanded DSM has NPV revenue requirements of $25,712 million over the 2017–2032 period, and $39,297 million over the 2017–2046 period.[34] Using these results, the Expanded DSM portfolios is the single most

[28] APS 2017 IRP, p. 66.

[29] APS 2017 IRP, p. 121.

[30] APS 2017 IRP, p. 66.

[31] See, for example Energy Efficiency Standards for the Design and Construction of New Federal Low-Rise Residential Buildings' Baseline Standards Update. 82 FR 2857.

[32] APS 2017 IRP, p. 14.

[33] APS 2017 IRP, attachment F.1(B).

[34] APS 2017 IRP, p. 341.

cost-effective portfolio over the 2017–2032 period, and exceeds the selected portfolio's costs by a mere $66 million over the full 2017–2046 period (this greater cost over a longer timeframe is likely driven by inflated energy efficiency assumptions, as discussed below).[35] Table 1 shows the NPV revenue requirements of each alternative scenario relative to the selected portfolio both as filed by APS and as corrected to exclude customer DSM costs.

Table 1. NPV Revenue Requirement Increase/(Decrease) of APS Portfolios Relative to Selected Portfolio

	2017–2032 Period		2017–2046 Period	
Portfolio	As Filed	No Participant Costs	As Filed	No Participant Costs
Flexible Resource	$0	$0	$0	$0
Carbon Reduction	$119	$119	($210)	($210)
Expanded DSM	$16	($239)	$643	$66
Expanded Renewables	$200	$200	$567	$567
Energy Storage	$303	$303	$513	$513
Resource Mandates	$556	$301	$1,722	$1,146

Source: APS 2017 IRP

Given the significance of this methodological error, we recommend that APS submit a revised IRP that corrects for it. We would expect that this revision would lead APS to select a portfolio with greater DSM levels than its current selected portfolio.

APS Likely Artificially Inflated the Long-Term Cost of Energy Efficiency

In another surprising artifact of APS's modeling results, the Expanded DSM case goes from being more than $230 million cheaper (in terms of NPV revenue requirements) than the selected portfolio over the 2017–2032 period to about $70 million more expensive over the extended 2017–2046 period.[36] In this case, the likely explanation is that APS inflated long-term efficiency costs.

Figure 7 shows that, based on the incremental costs and savings of the Expanded DSM portfolio relative to the selected portfolio, we estimate that APS assumes levelized efficiency costs that are unjustifiably high in 2021 but then quickly drop to a reasonable range of between $20/MWh and $40/MWh.[37] However, in 2032—the last year for which the IRP reports data—incremental efficiency costs suddenly double to $59/MWh. If APS assumed that this unexplained increase in

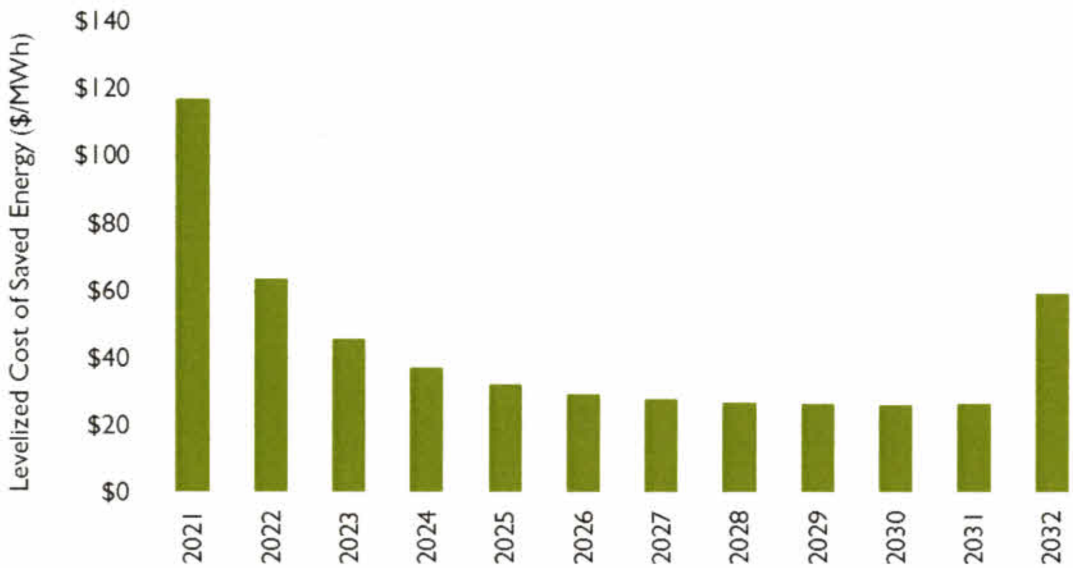
[35] APS 2017 IRP, pp. 14, 124.

[36] APS 2017 IRP, attachment F.1(B).

[37] APS 2017 IRP, pp. 170, 338.

the cost of saved energy holds throughout the 2032–2046 period, that would likely be sufficient to account for the Expanded DSM portfolio appearing less cost-effective over the longer term.

Figure 7. APS Projected Incremental Energy Efficiency Costs, Expanded DSM Portfolio



Sources: APS 2017 IRP

APS Conflates the Cost-Effectiveness and Cost-Shifting Attributes of Efficiency

In its 2017 IRP, APS undermines its energy efficiency programs by alleging that those programs cause a cost shift, and conflating that alleged cost shift with cost-effectiveness. The IRP strongly advocates for the inclusion of the Ratepayer Impact Measure (RIM) test as a means of evaluating "the shifting of revenues from participating customers' bill savings to non-participating customers."[38]

The RIM test does not evaluate cost-effectiveness at all, despite APS's labeling it as such. The RIM test does not weigh a program's costs against it benefits, but rather assesses the extent to which avoided energy and avoided costs affect per-MWh rates. The use of the RIM test has been widely discredited as inconsistent with economic theory and counter to the goal of reducing system costs and customer bills.[39]

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[38] APS 2017 IRP, p. 67.

[39] See, e.g., National Efficiency Screening Project. 2017. National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources. Appendix C. Available at https://nationalefficiencyscreening.org/national-standard-practice-manual/

After asserting its belief in the importance of the RIM test, APS goes on to include "System Average Cost," in units of $/MWh, as one of its core metrics for evaluating alternative resource portfolios. This metric's name provides the misleading impression that it is a useful measure of system costs. It is not. Even if energy efficiency programs were to cut system costs in half while preserving the same level of energy service, the System Average Cost measure would look worse so long as those programs reduced sales by less than half. In other words, this is a measure of potential cost shift, not of total costs or cost-effectiveness.

Both the RIM test and the System Average Cost measure are only meaningful to the extent that there are substantial numbers of electricity consumers who do not have access to efficiency programs, and who stand to face higher rates as a result of other customers' participation in energy efficiency programs. However, there need not be a sizable pool of such non-participants. In its IRP, APS chooses to use the possibility of a cost shift as a strike against portfolios with higher levels of energy efficiency. Instead, APS should focus on maximizing the benefits of efficiency and reaching as many customers as possible through its efficiency programs, so that all customers who wish to be are energy efficiency participants. APS should continue to target the acquisition of all cost-effective energy efficiency, and focus on enrolling as many customers as feasible in those programs. Energy efficiency continues to provide the opportunity to reduce customer bills, defer costly system investments, and meet customer needs cost effectively.

5. APS Inadequately Justifies its Dismissal of Additional Coal Retirements

APS followed past Commission guidance in evaluating a portfolio in which it retires its entire coal fleet by the end of the study period. However, APS fails to adequately justify its decision to reject that portfolio.

Carbon Reduction Scenario Is Least-Cost and Offers Additional Benefits

Under the Carbon Reduction portfolio, APS retires all of its coal capacity by 2032. Since APS already plans to retire most of its coal units during the next 15 years, the key components of the Coal Reduction portfolio involve moving up the Cholla units' retirement date to 2022, and the Four Corners Units 4 and 5 retirement date to 2031.[40] *The APS IRP indicates that the Carbon Reduction portfolio has the lowest NPV cost of all evaluated portfolios over the long term, providing a benefit of more than $200 million relative to the selected portfolio.*[41] Notably, APS found the Carbon Reduction portfolio to have the lowest 30-year cost even under sensitivities with no carbon price and a high gas price.[42] This scenario also results in substantially fewer carbon emissions and lower water usage than the selected portfolio.[43] In addition, earlier coal

[40] APS 2017 IRP, p. 120.

[41] APS 2017 IRP, p. 14.

[42] APS 2017 IRP, p. 133.

[43] APS 2017 IRP, p. 128.

plant retirements would reduce local pollution, an important consideration given that much of the APS service territory has been designated as in non-attainment with National Ambient Air Quality Standards for ozone.[44]

APS's stated reasons for selecting its preferred Flexible Resource portfolio over the Carbon Reduction portfolio are unconvincing. APS touts the "higher mix of flexible resources" of its selected portfolio.[45] But the Carbon Reduction Portfolio clearly has more flexible resources than the selected portfolio, as it primarily replaces inflexible coal resources with relatively more flexible natural gas capacity. APS points to the lower cost of the selected portfolio over the next 15 years, but that difference of about $120 million, possible driven by short-term replacement and decommissioning costs, is more than overcome over the full 30-year time horizon.[46] Finally, APS identifies the Carbon Reduction portfolio drawbacks of involving greater capital expenditures and gas burns than other scenarios.[47] These are legitimate concerns. But they are best addressed through sensitivity analyses, and all of APS's sensitivities point to the Carbon Reduction portfolio as more favorable than the selected portfolio. In addition, APS could mitigate these issues by replacing some coal units with cost-effective demand-side management and renewables rather than with gas.

More broadly, APS does a poor job of explaining exactly how it weighed its various evaluation metrics in selecting its preferred resource plan. We recommend that APS provide greater transparency around this decision-making process in future IRPs.

APS Should Rigorously Evaluate the Viability of the Four Corners Units

The fact that the Carbon Reduction portfolio comes out as the least-cost portfolio indicates that the remaining Four Corners units may not be cost-effective long-term investments. There are other strong lines of evidence to support this interpretation. In its most recent rate case, Public Service Company of New Mexico published the results of modeling runs indicating that continuing to operate the Four Corners units until 2031 will cost more than $440 million more than it would have cost to retire the units in 2017.[48] Furthermore, recent declines in the capacity factors of the Four Corners units suggest that those units are struggling to operate economically in the current energy market (see Figure 8).

[44] APS 2017 IRP, p. 182.

[45] APS 2017 IRP, p. 128.

[46] APS 2017 IRP, pp. 339-340.

[47] APS 2017 IRP, p. 128.

[48] Public Service Company of New Mexico's Second Supplemental Objections and Responses to New Energy Economy's Sixth Set of Interrogatories and Requests for Production of Documents. July 26, 2017. Case 16-00276-UT Before the New Mexico Public Regulatory Commission.

Figure 8. Four Corners Units 4 and 5 Historical Capacity Factors

Sources: Form EIA-923; Form EIA-860

We therefore recommend that APS analyze the economics of each of the coal units that it proposes to continue operating, to determine whether and when further retirements are warranted. In this analysis, APS should consider a range of potential low-cost replacement options, including renewables, energy efficiency, and battery storage.

6. APS Over-States the Costs of Renewable Technologies

APS's IRP assumes inflated costs for renewable energy resources. These assumptions bias the IRP's results against renewables.

APS Solar Cost Assumptions Fail to Account for Cost Decline Trajectory

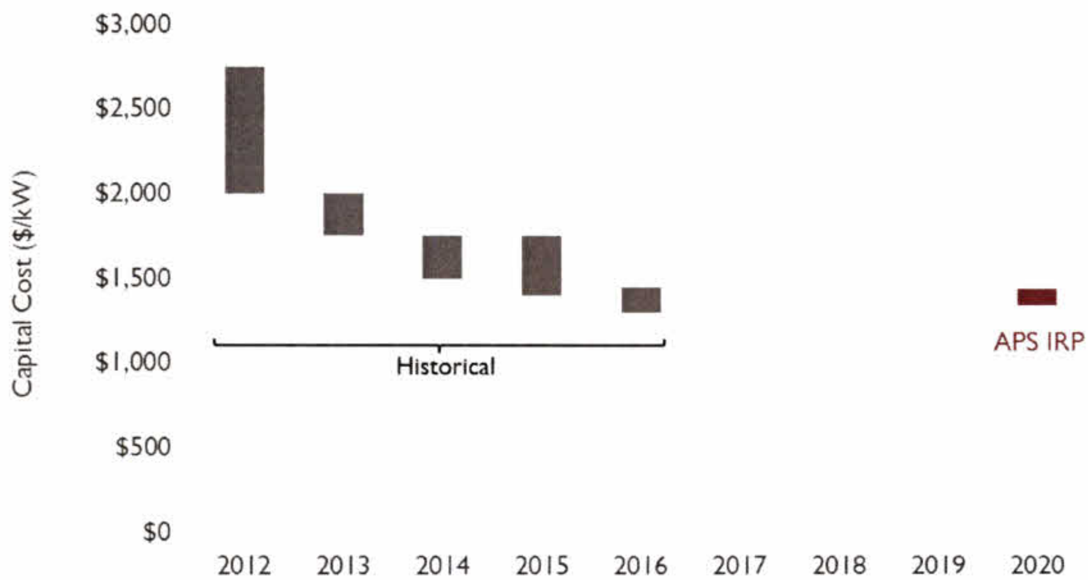
APS presents its cost assumptions in terms of the cost incurred to develop a resource in 2020.[49] These costs should therefore account for expected changes in costs in the coming years. APS's solar cost assumptions fail to do this. APS assumes 2020 capital costs of $1,344/kW for fixed-axis solar resources and $1,439/kW for single-axis resources.[50] These cost estimates are within the range of current capital costs, as reflected by Lazard's 2016 Levelized Cost of Energy Study.

[49] APS 2017 IRP, p. 49.

[50] APS 2017 IRP, p. 49.

[51] However, recent Lazard reports demonstrate that utility solar capital costs have steadily declined over the past five years, dropping by about 35 percent between 2012 and 2016 (see Figure 9).[52] Given this recent history, it is reasonable to expect at least some degree of continued decline in the coming years. By failing to account for this, APS likely over-states the cost of solar in its analysis.

Figure 9. Utility Solar Capital Costs, Historical and APS Forecast



Sources: Lazard LCOE Analysis, APS 2017 IRP

APS's capital cost forecast contributes to inflated levelized solar cost assumptions. The unsubsidized levelized costs of utility-scale solar have declined even more dramatically than capital costs in recent years, decreasing by more than 50 percent between 2012 and 2016.[53] Figure 10 shows that APS ignored this trend and instead forecasted 2020 levelized solar costs that are at the higher end of current unsubsidized levels. It is notable that TEP did assess a

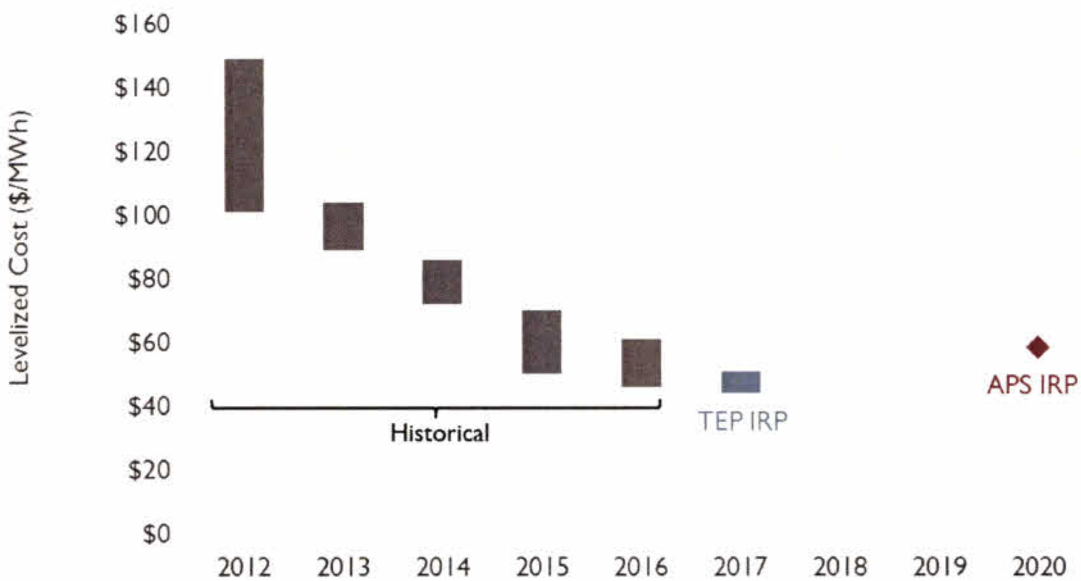
[51] Lazard. December 2016. Lazard's Levelized Cost of Energy Analysis – Version 10.0.

[52] Lazard. December 2016. Lazard's Levelized Cost of Energy Analysis – Version 10.0; Lazard. November 2015. Lazard's Levelized Cost of Energy Analysis – Version 9.0; Lazard. September 2014. Lazard's Levelized Cost of Energy Analysis – Version 8.0; Lazard. August 2013. Lazard's Levelized Cost of Energy Analysis – Version 7.0; Lazard. June 2012. Lazard's Levelized Cost of Energy Analysis – Version 6.0.

[53] Lazard. December 2016. Lazard's Levelized Cost of Energy Analysis – Version 10.0; Lazard. November 2015. Lazard's Levelized Cost of Energy Analysis – Version 9.0; Lazard. September 2014. Lazard's Levelized Cost of Energy Analysis – Version 8.0; Lazard. August 2013. Lazard's Levelized Cost of Energy Analysis – Version 7.0; Lazard. June 2012. Lazard's Levelized Cost of Energy Analysis – Version 6.0.

declining cost for utility-scale solar, and projects that fixed-tilt PV will decline by about 7% (to $1,220) by 2023.[54]

Figure 10. Utility Solar Levelized Costs: Unsubsidized Historical, APS Forecast, and TEP Forecast



Sources: Lazard LCOE Analysis, APS 2017 IRP, TEP 2017 IRP

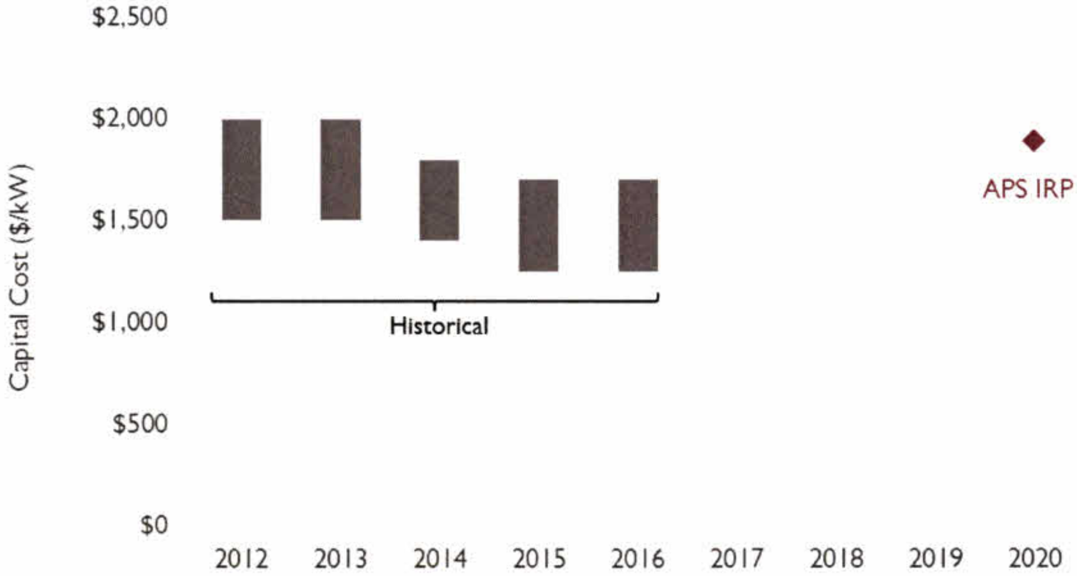
APS Ignores the Possibility of Access to Low-Cost Wind Resources

APS's IRP assumes wind capital costs that are well above current levels. Whereas wind capital costs have steadily declined to between $1,250/kW and $1,700/kW, APS assumes 2020 wind resources will cost nearly $1,900/kW, as shown in Figure 11.[55]

[54] Tucson Electric Power. April 3, 2017. 2017 Integrated Resource Plan. P. 104.

[55] APS 2017 IRP, p. 49; Lazard. December 2016. Lazard's Levelized Cost of Energy Analysis – Version 10.0.

Figure 11. Wind Capital Costs, Historical and APS Forecast

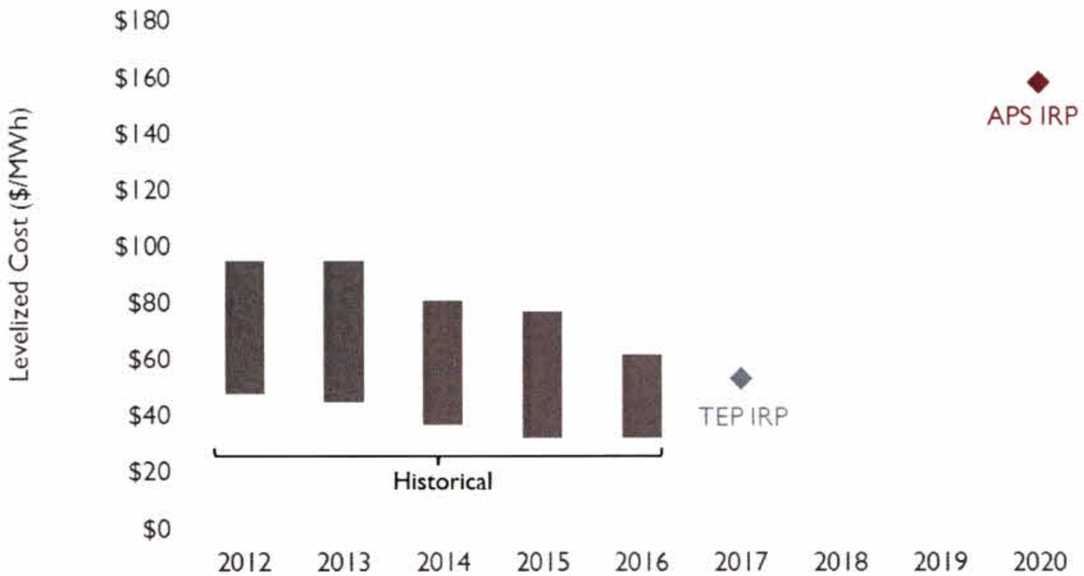


Sources: Lazard LCOE Analysis, APS 2017 IRP

In addition, APS appears to assume that it can only procure Arizona wind resources with relatively low capacity factors. This leads APS to assume 2020 levelized wind costs that are about three times higher than the unsubsidized cost of current productive resources (see Figure 12).[56] This is an inappropriate assumption. TEP, APS's neighboring utility, assumed in its IRP that it has access to New Mexico wind, and found the levelized cost of New Mexico wind to be $53/MWh, more than 65 percent lower than APS's assumed wind cost.

[56] APS 2017 IRP, p. 49; Lazard. December 2016. Lazard's Levelized Cost of Energy Analysis – Version 10.0.

Figure 12. Wind Levelized Costs: Unsubsidized Historical, APS Forecast and TEP Forecast



Sources: Lazard LCOE Analysis, APS 2017 IRP, TEP 2017 IRP

APS Neglects Current Opportunities to Invest in Cost-Effective Renewables

The historical cost values presented above are unsubsidized values. As APS discusses in its IRP, federal law currently offers a 30 percent solar investment tax credit (ITC), and a wind production tax credit (PTC) of 2.3 cents/kWh.[57] These incentives have driven the levelized cost of renewables to record-low levels below $40/MWh in high-resource regions such as the American Southwest.[58] Recent reports indicate that TEP has taken advantage of the current low-cost environment to sign a PPA for a paired solar-and-battery system with a *combined* cost of $45/MWh, with the solar portion representing about $30/MWh of that total.[59]

Nevertheless, APS's IRP appears to contain no concrete plans to take advantage of the low current cost of renewables. Instead, APS bases its renewable cost assumptions on a future year by which both the PTC and the ITC will have expired, and assumes that future renewables will cost more than even current unsubsidized renewables. We recommend that APS investigate near-term opportunities to develop low-cost renewables that take advantage of federal tax credits and strong Southwest resource potential.

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[57] APS 2017 IRP, pp. 55, 60.

[58] Lazard. December 2016. Lazard's Levelized Cost of Energy Analysis – Version 10.0.

[59] Utility Dive. May 23, 2017. Updated: Tucson Electric signs solar + storage PPA for 'less than 4.5 c/kWh.' http://www.utilitydive.com/news/updated-tucson-electric-signs-solar-storage-ppa-for-less-than-45kwh/443293/

7. APS UNDER-VALUES BATTERY STORAGE

APS's IRP assumes an inflated price for battery storage, and it fails to account for the near-term availability and value of cost-effective storage options.

As Commissioner Tobin's amendment recently mandated that "when acquiring any new resource, APS shall demonstrate that its analysis of resource options include[s] a storage alternative."[60] The APS analysis "must demonstrate that it has reasonably considered all of the costs and benefits of each resource option, allowing for comparisons to be made on similar terms and planning assumptions."[61] In addition, "APS shall account for the forecasted decline in energy storage costs and ensure that storage resources are modeled in such a way that the Integrated Resource Planning model captures their impact. Costs shall be transparent by providing the cost of each technology with and without state and federal tax incentives and/or credits." [62]

Despite this clear directive from the Commission, while the APS IRP does include some analysis of battery storage technologies, it both assumes inflated prices for storage and does not account for current availability and value for storage technologies. As such, we recommend that APS revise this section of the IRP to fix these flaws and to meet the Commission's new mandate.

APS Over-States the Cost of Future Battery Storage

APS's modeling assumes inflated battery storage costs. APS projects 2020 battery storage levelized costs of $315.29/MWh.[63] These values are in line with current costs for battery-based peak capacity and transmission support, but are higher than Lazard's estimate of the current cost of lithium-ion technology for frequency regulation,[64] and well over the costs assumed by TEP ($257/MWh).[65] Furthermore, lithium-ion battery costs have been declining rapidly, and are very likely to continue to do so. Lazard estimates that battery capital costs will decline by 20 to 40 percent over the next five years.[66] APS's battery cost assumptions evidently fail to account for these cost declines, and therefore over-state the cost of batteries relative to natural gas resources that provide similar peak capacity and fast-ramping services. Storage is accessible cost-effectively today; TEP's addition of a 30 MW storage project in a recent PPA demonstrates that utility-scale storage is readily available.[67]

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[60] Tobin Amendment, August 14, 2017, APS, Docket Nos. E-01345A-16-0036, E-01345A-0123.

[61] Tobin Amendment, *Id.*

[62] Tobin Amendment, *Id.*

[63] APS 2017 IRP, p. 312.

[64] Lazard. December 2016. Lazard's Levelized Cost of Storage – Version 2.0.

[65] TEP 2017 IRP, page 100. Table 13.

[66] Lazard. December 2016. Lazard's Levelized Cost of Storage – Version 2.0. P. 20

[67] http://www.utilitydive.com/news/updated-tucson-electric-signs-solar-storage-ppa-for-less-than-45kwh/443293/

APS Under-States the Near-Term Value of Battery Storage

The APS IRP's outlook on the near-term value proposition of battery storage is remarkably conservative and inconsistent with APS's own experience. The IRP states that, with continued cost declines, battery storage "may be feasible within the next 10 years."[68] On the contrary, battery storage is already both feasible and cost-effective in many contexts today, and it will only become more cost-effective as capital costs continue to decline. This fact is proven by the experience of APS and its neighbors. APS recently announced that it will install two battery storage systems in Punkin Center because it found that the storage system will provide necessary reliability upgrades at a cost similar to that of traditional transmission and infrastructure investments.[69] Meanwhile, the recent, low-cost combined solar-and-battery PPA signed by TEP demonstrates that battery storage is already a worthy investment as a flexible ramping and capacity resource in Arizona.

APS's under-valuation of battery storage may be a result of APS neglecting to evaluate some of the more cost-effective applications of storage. For example, the storage example provided in the IRP envisions batteries as both consuming and offsetting natural gas generation.[70] This suggests that APS is not focused on the more valuable proposition of charging from low-cost renewables, and thereby using batteries to help address the ramping and peak-shifting issues raised by APS throughout its IRP.

APS also appears to unjustifiably discount the capacity value of battery storage resources. One of the most important characteristics of battery storage is its ability to discharge on demand. However, APS assumes that the first 500 MW of storage it could procure would have an 80 percent capacity value, and the next 600 MW would achieve a capacity value of only 60 percent.[71] It is unclear what the basis is for APS's claim that "increasing the amount of storage capacity results in reduced capacity value."[72] On the contrary, battery storage's dispatchability and granularity makes it hard to imagine why its capacity value would decline noticeably at any foreseeable level of penetration.

APS's assumptions about the costs and benefits of storage cause it to dismiss its Energy Storage Systems Portfolio as expensive and impractical.[73] However, a better-supported set of assumptions and use cases may well reveal batteries to be an important of APS's optimal near-term procurement plan.

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[68] APS 2017 IRP, p. 229.

[69] APS. August 19, 2017. "APS Brings Battery Storage to Rural Arizona." https://www.aps.com/en/ourcompany/news/latestnews/Pages/aps-brings-battery-storage-to-rural-arizona.aspx

[70] APS 2017 IRP, p. 229.

[71] APS 2017 IRP, p. 128.

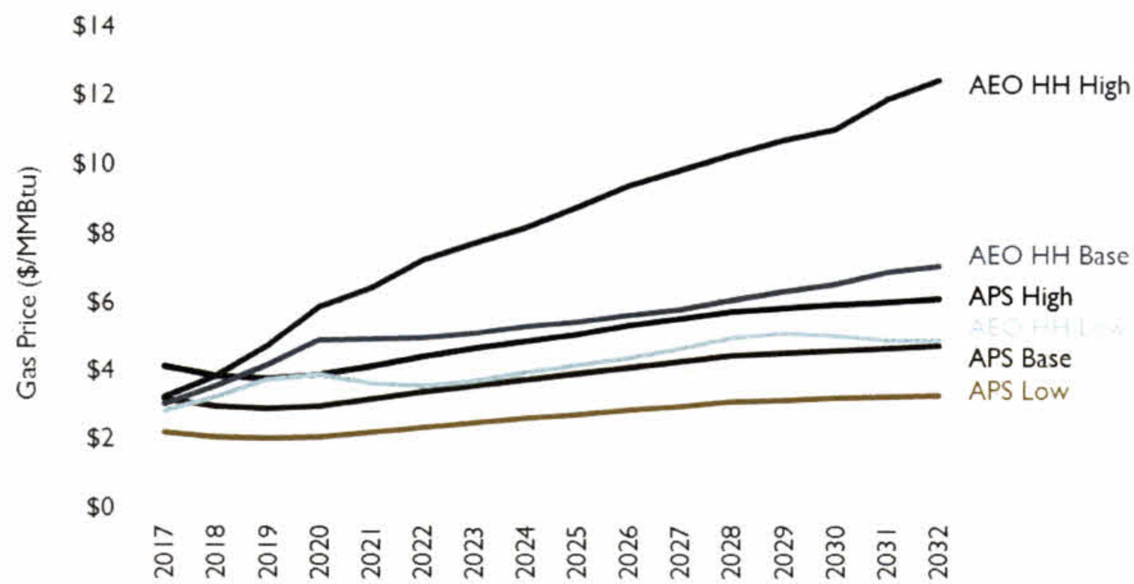
[72] APS 2017 IRP, p. 128.

[73] APS 2017 IRP, p. 128.

8. APS Long-Term Gas Price Assumptions Are Deflated

While APS's near-term gas price forecast is consistent with current levels and futures markets, its long-term price forecasts are significantly lower than most comparable forecasts. One common benchmark for natural gas price forecasts is the Annual Energy Outlook (AEO) published by the U.S. Energy Information Administration (EIA). AEO 2017 includes a range of forecasts for the Henry Hub gas price, accounting for a variety of possible futures. The lowest price trajectory projected in AEO 2017 occurs under the High Oil and Gas scenario, in which abundant natural gas supply continues to depress gas prices.[74] Figure 13 shows that APS's Base Case gas price forecast is even lower than this lowest forecast put out by EIA.[75] The same figure shows that even APS's high gas price sensitivity is lower than the AEO base case. This indicates that the APS price sensitivities do not cover a sufficiently wide range of likely futures.

Figure 13. APS Delivered Gas Price Forecasts Compared to AEO 2017 Henry Hub Price Forecasts



Sources: AEO 2017, APS 2017 IRP

It is worth noting that other utilities in Arizona have done a more effective job of accounting for a likely range of potential future gas prices. For example, TEP's 2017 IRP evaluated gas prices that are very similar to APS's low and high price forecasts, but also examined a more genuine

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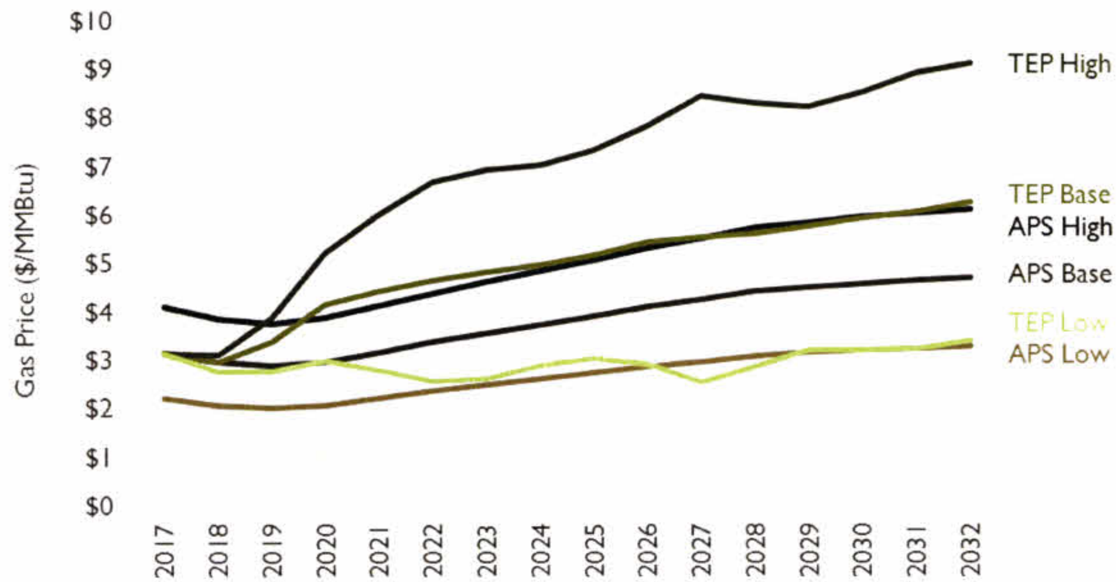
[74] U.S. EIA. AEO 2017 Natural Gas Henry Hub Spot Price. Available at https://www.eia.gov/outlooks/aeo/data/browser/#/?id=13-AEO2017&region=0-0&cases=ref_no_cpp~highprice~lowprice~highrt~lowrt&start=2015&end=2050&f=A&linechart=~~~~~ref_no_cpp-d120816a.59-13-AEO2017~highprice-d120816a.59-13-AEO2017~lowprice-d120816a.59-13-AEO2017~highrt-d120816a.59-13-AEO2017~lowrt-d120816a.59-13-AEO2017&sourcekey=0

[75] APS 2017 IRP, p. 123.

upper-bound forecast that is substantially higher than any price trajectory evaluated by APS (see Figure 14.)[76] In addition, TEP's sensitivity forecasts all start from the same, known current gas price, rather than maintaining a fixed percentage difference from the base forecast even in near-term years, as is the case with the APS sensitivities.

Figure 14. APS Delivered Gas Price Forecasts Compared to TEP Gas Price Forecasts



Sources: APS 2017 IRP, TEP 2017 IRP

APS's decision to use an unusually low base gas price forecast, and to not evaluate a true high gas price sensitivity, systematically biases its resource optimization process in favor of natural gas, and against alternatives such as renewables and energy storage. We therefore recommend that APS use a more plausible set of base and sensitivity gas price forecasts in the future. These forecasts should be tethered to current prices, and should also reflect a reasonable range of possible future prices.

[76] Tucson Electric Power. April 3, 2017. 2017 Integrated Resource Plan. P. 245.

RESPECTFULLY SUBMITTED this 25th day of September, 2017.

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ORIGINAL and 13 copies filed
this 25th day of September, 2017 with:
Docket Control
Arizona Corporation Commission
1200 W Washington Street
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Before the Arizona Corporation Commission

IN THE MATTER OF RESOURCE PLANNING AND PROCUREMENT 2015 AND 2016	Docket No. E-00000V-15-0094

Certificate of Service

I hereby certify that I have this day served the foregoing Sierra Club Comments on Arizona Public Service's 2017 Integrated Resource Plan via email or U.S. Mail to all parties of record in the proceeding listed below.

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