SWEEP Comments on the APS 2017 Integrated Resource Plan

I. INTRODUCTION

The Southwest Energy Efficiency Project (SWEEP) has conducted a technical review of the Arizona Public Service Company (APS) 2017 Integrated Resource Plan (Plan or IRP) dated April 10, 2017. While we reviewed many aspects of the Plan, our focus was primarily on APS’ treatment of Demand-Side Management resources (DSM), energy efficiency resources (EE) (which some parts of the APS IRP focused on specifically, as a subset of DSM resources), and demand response resources (DR). Our main observations are summarized immediately below, followed by a summary of SWEEP’s recommendations. An explanation of SWEEP’s analysis and reasoning behind these observations and recommendations is provided in more detailed comments in Section IV further below.

II. SUMMARY OF SWEEP’S OBSERVATIONS

1. The resource portfolio selected by APS is bad for customers and is not in the public interest because it increases both cost and risk significantly, and more than is necessary to deliver reliable energy resources to meet customer needs.
   - APS’ selection of the Flexible Resource Portfolio as its Selected Portfolio leads to a revenue requirement that is at least $239 M (NPV) higher than another portfolio assessed in the IRP (the APS Expanded DSM Portfolio). A portfolio with even more DSM resources than the APS Expanded DSM Portfolio would likely result in a revenue requirement that is even lower still, meaning that it would likely be more than $239 M lower than the Selected Portfolio.
   - Under the APS Selected Portfolio, the annual revenue requirement increases by $992 M (44% above 2017 levels) over the next decade. New supply-side natural gas resource additions are by far the biggest driver of future rate increases. Information provided publicly by APS in its Plan indicates that at least $626 M (63%) of the $992 revenue requirement increase is due to fixed generation costs attributable to new natural gas additions.\(^1\) The exact amount of revenue

\(^1\) Public information provided by APS in the IRP is not an adequate indicator of the total costs of new gas generation additions since the revenue requirements provided in the Plan do not differentiate between new and existing resources.
requirement increase attributable to new natural gas additions could not be determined without confidential information provided by APS in response to a SWEEP data request.²

• Under the APS Selected Portfolio, fuel price risk to customers increases significantly,³ with annual fuel costs rising by $474 M over the 15-year planning horizon (a 97% increase). This is at least $111 M more than another portfolio assessed in the IRP (the Expanded DSM Portfolio) and likely more than other portfolio options that could be deployed. A portfolio with even more DSM resources than the Expanded DSM Portfolio would likely lead to fuel costs more than $111 M lower than the Selected Portfolio.

2. APS' Selected Portfolio is weighted too heavily towards costly supply-side resources. The analysis presented in the IRP is biased in favor of these resources, and is biased against demand-side resources that would lower overall costs to customers.

• Natural gas plants comprise the clear majority of APS' planned capacity additions over the next 15 years. Combined cycle units dominate these additions in the near term (2017-2022).
• Natural gas resources are more expensive than alternatives – especially DSM resources such as EE and DR.
• Combined cycle additions can be counter-productive to increasing system flexibility.
• APS' IRP is biased in favor of natural gas combined cycle additions by leaving them virtually unchanged across all portfolios, despite varying levels of DSM, renewables, storage, small modular reactors (nuclear, SMR), and other resource contributions.
• APS' IRP is biased in favor of supply-side natural gas by adding more generation capacity than is necessary in upcoming years.
• Under APS' Selected Portfolio, APS significantly reduces DSM investments after the current Energy Efficiency Standard sunsets in 2020. These reductions would eliminate over $600 M in net benefits to customers over the 15-year planning horizon.
• APS' Plan biases against DSM resources by screening measures based on load factor. This APS-developed screening step is arbitrary, harmful to customers, and counterproductive to APS' stated objective of reducing peak demand.
• APS' Plan biases against DSM resources by rationalizing several changes to existing DSM programs as necessary to address “duck curve” issues. Significantly reducing or shifting investment from existing DSM programs based on APS assertions about the effects of the duck curve, which occur in a small part of the year, is premature and will lead to increased costs for customers.
• APS' portfolio analysis is biased against DSM resources by inappropriately and incorrectly including out-of-pocket customer costs – the portion of incremental project costs that individual participating customers pay out of their own pockets, as their share of the project costs after receiving a DSM program rebate or financial incentive, and which are not paid by ratepayers – in the Expanded DSM Portfolio when comparing revenue requirements. This incorrect approach results in APS presenting inaccurate and inflated costs for DSM resources. The IRP analysis

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² According to APS' response to SWEEP's data request (SWEEP 1.19), new natural gas additions account for $879 M (89%) of the revenue requirement increase over the next 10 years.

³ Since fuel costs are a direct pass through to customers, customers bear most of the associated price risk.
should be based on revenue requirements, and should not include the out-of-pocket costs of individual participating customers.

- APS’ portfolio analysis is biased against DSM by including costs in its Expanded DSM Portfolio that are unreasonable and are not justified in the APS Plan for the year 2032 and beyond.
- Biasing against DSM resources in its IRP is one approach APS uses to assert, in error, that it needs to add more natural gas resources.

3. A resource portfolio with more demand-side resources would outperform the APS Selected Portfolio on virtually every relevant metric, including costs to customers.
   - The Expanded DSM Portfolio, which contains more DSM resources than the APS Selected Portfolio, is the least cost option among the portfolios examined in the APS IRP in terms of both revenue requirement and total resource costs over the 15-year planning horizon.
   - Over the 15-year planning horizon, the Expanded DSM Portfolio performs better than the Selected Portfolio for all the following key metrics:
     - Revenue requirement
     - Total resource costs
     - Average customer bill impacts
     - Capital expenditures
     - Wholesale market purchases
     - Gas burn
     - CO₂ emissions
     - Water use
     - Cost shift to APS customers that benefits APS investors and the federal government (due to the natural gas plant buildout in the APS Selected Portfolio)
   - Even though APS biases against DSM, the APS-developed Expanded DSM Portfolio still outperforms the APS Selected Portfolio. APS’ own analysis and numbers demonstrate this, despite their biases.
   - Identifying and securing additional DSM resources beyond those identified in the Expanded DSM Portfolio would likely result in even lower costs for customers and other benefits.

4. APS’ natural gas plant buildout under the APS Selected Portfolio creates a significant new “cost shift” that would transfer $2.9-4.1 billion (NPV) from its customers to APS’ investors and the federal government.
   - The APS Selected Portfolio would result in a cost shift and increase of $2.9-4.1 billion in costs for all customers, not just for some customers. The $2.9-4.1 billion (NPV) of increased costs paid by customers would result in increased earnings for APS investors and increased tax revenues for the federal government.
   - This cost shift and wealth transfer can be reduced by at least $228-422 M under the Expanded DSM Portfolio included in the Plan.
   - The remaining cost shift/wealth transfer under the Expanded DSM Portfolio is due to the significant natural gas expansion that APS has included in all portfolios in its Plan, including the Expanded DSM Plan. A portfolio with even more DSM resources than the Expanded DSM Portfolio would lead to a cost shift/wealth transfer more than $228-422 M lower than the APS Selected Portfolio.
III. SUMMARY OF SWEEP RECOMMENDATIONS

Based on the observations summarized above and detailed below, APS’ Plan is not reasonable and is not in the public interest, and therefore it should be rejected by the Commission. SWEEP recommends the Commission take the following actions in this proceeding regarding the APS 2017 IRP, the Selected Portfolio, and the near-term action plan.

1. The Commission should reject and should not acknowledge the APS 2017 Integrated Resource Plan. The APS Plan is heavily biased in favor of supply-side natural gas additions and against demand-side resources. APS has failed to demonstrate that its IRP and the APS Selected Resource Portfolio is in the best interest of its customers. As such, both the APS Plan and the APS Selected Portfolio should be rejected by the Commission.

2. The Commission should explicitly reject APS’ proposed approach to reduce deployment of demand-side resources after 2020. A significant shortcoming in APS’ IRP is its approach to reduce or eliminate demand-side resource programs that provide significant value to customers after 2020. APS’ Plan to reduce investment in these resource is misguided, would increase customer costs, and should be rejected.

3. The Commission should require APS to select and implement a resource portfolio, as an improved Selected Portfolio, with fewer MW of supply-side, natural gas resources and more MW of demand-side resources. The fact that the Expanded DSM Portfolio outperforms the APS Selected Portfolio in almost every way is a clear indication that APS should be required to implement more demand-side resources.

4. The Commission should require APS to use the Expanded DSM Portfolio as a floor for the level of DSM resources in the improved Selected Portfolio, and should require APS to identify and secure additional DSM resources beyond those identified in the Expanded DSM Portfolio as long as the additional DSM resources would result in lower costs for customers based on the revenue requirement.

5. The Commission should order APS to address these issues in its next IRP. In its order rejecting the APS-proposed IRP, the Commission should specify the improvements to be made in APS’ next IRP. This should include steps to reduce the bias in favor of natural gas resources and the bias against DSM resources as identified by SWEEP.

6. The Commission should prioritize its actions to ensure prudent resource decisions are made in the near term. This includes consideration of APS’ 2018 DSM Plan as well as any near-term decisions to approve the acquisition, construction, or cost-recovery of supply-side natural gas resources.

7. The Commission should order APS to modify its Near-term Action Plan to include additional DSM investment after 2020. At a minimum, the Commission should order APS to maintain its current resource share and level of investment in DSM resources beyond 2020. Additionally, the Commission should order APS to consider an expanded level of DSM investment.

IV. ADDITIONAL DETAILS SUPPORTING SWEEP’S OBSERVATIONS

1. APS’ Selected Portfolio is bad for customers because it increases both cost and risk significantly and more than is necessary.
1.1. APS’ Selected Portfolio leads to a revenue requirement that is at least $239 M more than necessary. The revenue requirement likely could be reduced even further if additional DSM were pursued.

Under APS’ Selected Portfolio, the total annual revenue requirement increases from $2.3 billion in 2017 to $2.7 billion by 2022 (a 17% increase over the 2017 value) and $4.0 billion by 2032 (a 77% increase over the 2017 value).\(^4\) For a typical residential customer, this equates to an annual bill increase of $83 per year five years from now and $329 per year fifteen years from now, which would affect all of the customers served by APS.\(^5\)

While some increase in costs may be unavoidable, choosing the Flexible Resource Portfolio as the APS Selected Portfolio subjects APS customers to an increase in costs that is greater than necessary. For example, the annual revenue requirement reported by APS for the Expanded DSM Portfolio is $239 M lower than the Selected Portfolio over the 15-year planning period (net present value).\(^6\) Thus, if APS had selected a different portfolio (e.g. Expanded DSM) its customers would experience a lower overall cost on their bills over the 15-year planning horizon.

1.2. Costs associated with new natural gas generation are the biggest driver of future rate increases for the next decade

\(^4\) APS 2017 IRP, ATTACHMENT F.1(B) – REVENUE REQUIREMENTS FOR SEVEN PORTFOLIOS.
\(^5\) Based on APS’ projections in which system costs increase from $74.6/MWh in 2017 to $101.4/MWh in 2032 and an average annual consumption per customer of 12,259 kWh.
\(^6\) APS 2017 IRP, ATTACHMENT F.1(B) – REVENUE REQUIREMENTS FOR SEVEN PORTFOLIOS. This reflects the difference in revenue requirement excluding any out-of-pocket incremental customer costs which are technically not part of the revenue requirement. Out-of-pocket incremental customer costs are not collected by APS nor are they reflected in rates set by the ACC. For reasons explained further below, SWEEP also believes the revenue requirement reported by APS for the Expanded DSM Portfolio may be inflated. If this is correct, the comparison would be even more favorable for DSM in terms of costs. Additionally, supply-side gas additions could be displaced by other resources, further lowering the total revenue requirement versus the selected option.
Under APS’ Selected Portfolio, revenue requirements will increase by $992 M over the next decade, a 44% increase over 2017 values. Fixed costs related to new natural gas generation additions (including capital, fixed operations and maintenance (O&M), new transmission, and gas transport) account for a significant share of this projected increase, accounting for more than 60% of the projected increase in each of these years. This is reflective of APS’ bias towards the addition of new supply-side natural gas generation at a significant cost to customers. By contrast, customer resource costs (such as Distributed Energy (“DE”) and EE program costs) contribute a relatively small amount (1% or less) of the cost increase in each year over the same 10-year period.

Over the 15-year planning period, APS’ Selected Portfolio increases its natural gas resources from 4,341 MW in 2017 to 8,606 MW in 2032, while fixed generation costs increase from $1,200 M annually to $2,114 M annually. This equates to ~4.3 GW of capacity value added in exchange for a $914 M increase in annual revenue requirement. This excludes any fuel costs necessary to operate the supply-side resources which would also add to the revenue requirement. By comparison, DSM resources (including

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7 Since almost no other generation resources are added besides natural gas, virtually all of the fixed generation costs can be attributed to natural gas resource additions.

8 Based on APS 2017 IRP, Attachment F.1(A)(1) – Flexible Resource (Selected Portfolio L&R and Energy Mix, p 324 and APS 2017 IRP, ATTACHMENT F.1(B) – REVENUE REQUIREMENTS FOR SEVEN PORTFOLIOS, p 339. SWEEP includes the following categories in fixed generation costs: Capital, Fixed Fuel + O&M, New Transmission, and Gas Trans.
both EE and DR) increase from 116 MW in 2017 to 1,095 MW in 2032 while DSM resource costs only increase from $47.2 M to $91.6 M. This equates to ~1.0 GW capacity value added in exchange for a $44 M increase in revenue requirement.

<table>
<thead>
<tr>
<th></th>
<th>Natural Gas Resource Additions (est. from Fixed Gen Costs)</th>
<th>DSM Resource Additions (EE and DR Costs)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ann. Rev. Req. Increase ($M) by 2032</td>
<td>$914</td>
<td>$44</td>
</tr>
<tr>
<td>Net GW Added by 2032</td>
<td>4.3</td>
<td>1.0</td>
</tr>
<tr>
<td>$M increase/GW</td>
<td>$213</td>
<td>$44&lt;sup&gt;10&lt;/sup&gt;</td>
</tr>
</tbody>
</table>

Based on this analysis using APS’ numbers it is readily apparent, that DSM customer resources provide significantly more value than supply-side resources in terms of MW of capacity added per dollar of revenue requirement increase. Nevertheless, APS has selected a portfolio that prioritizes supply-side resources at significant additional cost to its customers.

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<sup>9</sup> This estimate is based on public information provided in APS’ IRP. It does not account for generation assets that have depreciated during this time and are likely to be subtracted from the 2017 revenue requirement. As such, the fixed generation revenue requirement attributable to new gas additions is much higher than the estimate shown here, but can be documented only with the use of information that APS labeled as confidential.

<sup>10</sup> SWEEP believes the cost estimates for future EE and DR included in APS’ IRP are too high and do not reflect actual program experience. Thus, this valuation reflects a conservative, high-end estimate.
1.3. **Fuel price risk to customers increases significantly in the APS Selected Portfolio, with annual costs increasing $111 M more than other portfolio options.**

Expenditures on fuel carry greater risk than other categories of expenditures due to the historic and potential future volatility of fuel prices. Importantly, customers are exposed to much of the risk associated with fuel price fluctuations since fuel costs are primarily a direct pass-through, so it is particularly important to ensure these risks are minimized. Due to its significant expansion of natural gas, APS’ Selected Portfolio leads to significant increases in the amount of fuel costs (and associated risks) that are directly passed on to customers. The figure below illustrates that total fuel costs increase from approximately $486 million annually today, to approximately $960 million in 2032 under the APS Selected Portfolio (a 98% increase). The increased expenditure on fuel under the Selected Portfolio represents a greater number of customer dollars at risk if fuel prices were to rise unexpectedly. The amount of dollars at risk is far greater under the Selected Portfolio than it is under other potential portfolios. For example, under the Expanded DSM portfolio, fuel costs are over $111 million lower in the final year (2032). As noted in Table 7-2 of APS’ IRP, the Expanded DSM portfolio reduces overall gas burn
by more than 16% relative to the Selected Portfolio. Thus customers are exposed to substantially less fuel price risk under the Expanded DSM Portfolio than under APS’ Selected Portfolio.

In addition to commodity price risk, natural gas is also subject to risks associated with pipeline constraints. While this has not been a significant issue for Arizona in the recent past, there are indications that it could be an issue going forward. For example, a recent presentation by Navigant Consulting before the Commission made several key observations that are summarized in the figure below.

Figure 3. Comparison of Fuel Costs (Annual Revenue Requirements). Source: ATTACHMENT F.1(B) – REVENUE REQUIREMENTS FOR SEVEN PORTFOLIOS, p 339 and 341
2. **APS’ Selected Portfolio is weighted too heavily towards costly supply-side resources. The analysis presented in the IRP is biased in favor of these resources, and is biased against demand-side resources that would lower overall costs to customers.**

2.1. **Natural gas plants comprise the clear majority of APS’ planned capacity additions over the next 15 years. Combined cycle units dominate these additions in the near term.**
In its 2017 Integrated Resource Plan (IRP), APS has selected a resource portfolio (“Flexible Resource Portfolio”) that includes the addition of over 5,000 MW of new natural gas resources by 2032. This includes major combined cycle resource additions in 2017, 2020, 2021, and 2026 and major combustion turbine additions in 2019, 2022, 2024 and every year thereafter. Combined cycle units make up the bulk of capacity additions in the early years, with 1,500 MW being added by 2021.

<table>
<thead>
<tr>
<th>Year</th>
<th>NG-CC</th>
<th>NG-CT</th>
<th>RE</th>
<th>DE</th>
<th>DR</th>
<th>DSM(^\text{11})</th>
</tr>
</thead>
<tbody>
<tr>
<td>2017</td>
<td>+250 MW</td>
<td></td>
<td></td>
<td>+15 MW</td>
<td>+18 MW</td>
<td>+98 MW</td>
</tr>
<tr>
<td>2018</td>
<td></td>
<td>+510 MW</td>
<td></td>
<td>+17 MW</td>
<td>+1 MW</td>
<td>+100 MW</td>
</tr>
<tr>
<td>2019</td>
<td></td>
<td></td>
<td></td>
<td>+11 MW</td>
<td>+3 MW</td>
<td>+100 MW</td>
</tr>
<tr>
<td>2020</td>
<td>+500 MW</td>
<td></td>
<td></td>
<td>+11 MW</td>
<td>+1 MW</td>
<td>+99 MW</td>
</tr>
<tr>
<td>2021</td>
<td>+750 MW</td>
<td></td>
<td></td>
<td>+10 MW</td>
<td>+16 MW</td>
<td>+51 MW</td>
</tr>
<tr>
<td>2022</td>
<td></td>
<td>+431 MW</td>
<td></td>
<td>+13 MW</td>
<td>+12 MW</td>
<td>+43 MW</td>
</tr>
<tr>
<td><strong>2017-2022</strong></td>
<td><strong>+1,500 MW</strong></td>
<td><strong>+941 MW</strong></td>
<td><strong>+0 MW</strong></td>
<td><strong>+77 MW</strong></td>
<td><strong>+51 MW</strong></td>
<td><strong>+491 MW</strong></td>
</tr>
</tbody>
</table>

Customer resources, including demand-side management (DSM), demand response (DR), and distributed generation (DG) each provide a meaningful contribution to peak capacity, but are much smaller components of APS’ Selected Portfolio, both in the near term and in the long term. Notably, DSM additions decline substantially after 2020, which corresponds with the sunset of the current Energy

\(^{11}\) In the load and resource tables of the APS IRP, DSM resources are listed separately from DR resources. SWEEP considers DR to be a component of DSM along with energy efficiency (EE).
Efficiency Standard (EES). The APS Plan adds no new renewable energy (RE) and virtually no energy storage within the next 5 years.

2.2. The natural gas resources that comprise the majority of APS’ resource additions are more expensive than many other resource options.

APS has selected a portfolio that is heavily reliant on natural gas additions even though less costly options exist. Other resources -- particularly DSM resources -- are significantly less costly than Combustion Turbine and Combined Cycle plants both in terms of providing peak capacity ($/kW) and in terms of providing energy ($/MWh). The table below compares the incremental costs of several supply side resources as reported in APS’ IRP and the actual incremental cost of EE programs as reported in APS’ annual DSM reports. Even though natural gas resources are more expensive, APS has selected a portfolio that adds a significant amount of natural gas generation. A portfolio that focused on expanding DSM resources instead of natural gas would be less costly overall to customers.

<table>
<thead>
<tr>
<th>Resource</th>
<th>$/kW, peak (installed costs)</th>
<th>$/MWh (fuel cost)</th>
<th>$/MWh (levelized total cost)</th>
</tr>
</thead>
<tbody>
<tr>
<td>APS Incremental EE (2015)</td>
<td>$631</td>
<td>$0</td>
<td>$12</td>
</tr>
<tr>
<td>APS Incremental EE (2016)</td>
<td>$676</td>
<td>$0</td>
<td>$12</td>
</tr>
<tr>
<td>Large Frame Combustion Turbine</td>
<td>$759</td>
<td>$68</td>
<td>$230</td>
</tr>
<tr>
<td>Natural Gas Combined Cycle</td>
<td>$1,236</td>
<td>$39</td>
<td>$92</td>
</tr>
<tr>
<td>Aeroderivative Gas Turbine</td>
<td>$1,475</td>
<td>$63</td>
<td>$326</td>
</tr>
</tbody>
</table>

Figure 7. Sources: APS 2016 and 2015 DSM Reports, APS 2017 IRP Table 2-3 (p 49). APS 2017 IRP Attachment D.3 – Generation Technologies (p 312). EE costs and savings exclude demand response, behavioral efficiency, and prepay programs. EE costs are all portfolio costs, e.g. rebates and incentives; training and technical assistance; consumer education; program implementation; program marketing; planning and administration; measurement, evaluation, and research; and performance incentives.

2.3. Combined cycle additions are counter-productive to increasing system flexibility

APS states that it has a need for additional flexibility on its system to meet ramping challenges and that natural gas is a good solution for this. For example, the company states the following: “natural gas generation is a cost-effective, proven technology that provides much-needed summer peaking capacity,
ramping capability and the dispatch flexibility needed to integrate renewable energy resources throughout the year.”

However, the focus on adding combined cycle in the near term does not appear particularly helpful for increasing system flexibility and may in fact be counter-productive. While simple cycle combustion turbine units can ramp up quickly (within minutes) to serve ramping needs, combined cycle units generally require several hours to reach their full capacity. According to APS, the time needed to ramp up a 2x1 combined cycle unit to its minimum operating level can be up to 330 minutes (5.5 hours). This is consistent with data recently shared by the Western Electricity Coordinating Council (WECC) regarding operating statistics of power plants in the western U.S., which show start times (warm) for gas-fired combined cycle plants ranging from 5 to 40 hours. Additionally, emissions constraints can keep some combined cycle units from being utilized for flexible load following, limiting their ability to be ramped down quickly in the event of overgeneration. Thus, while combined cycle plants may be more maneuverable than certain baseload steam turbines (e.g. coal, nuclear), they are not as ideal for increasing flexibility as alternatives such as simple cycle combustion turbines, battery storage, or demand response and advanced load controls, all of which can respond within minutes or seconds.

Despite these limitations, APS adds significant amounts of combined cycle facilities in its Selected “Flexible Resource” Portfolio.

2.4. APS’ IRP is biased in favor of natural gas combined cycle additions by leaving them virtually unchanged across all portfolios, despite varying levels of DSM & other resource contributions.
The figure above illustrates the fact that nearly all of the portfolios evaluated by APS in its IRP contain identical expansions of natural gas combined cycle (NGCC) resources. The only discrepancy is the Carbon Reduction portfolio which includes 710 MW of additional NGCC in 2032.

APS has essentially left this portion of its Plan fixed and “baked in” regardless of which portfolio is selected. In this sense, the IRP does not appear to be sensitive in any way to identifying alternatives that could displace NGCC additions. SWEEP believes APS’ IRP is inadequate in this regard since it does not explore such alternatives and the impact they would have on key performance metrics, including costs to customers, water use, emissions, etc. SWEEP believes a more thorough IRP analysis would have included at least one portfolio where NGCC additions were reduced due to displacement by other resources.

This is especially true because other resources – particularly DSM resources – are significantly less costly than NGCC both in terms of providing peak capacity ($/kW) and in terms of providing energy ($/MWh).

One of the primary benefits of DSM resources is the deferral or avoidance of future capacity additions. However, if such deferrals are not fairly represented in the IRP (as appears to be the case for APS’ analysis of NGCC), it is much more difficult, if not impossible, to discern the full magnitude of benefits.
that an Expanded DSM portfolio can provide. By leaving the amount of NGCC “baked in” across portfolios, APS is not only biased in favor of the NGCC additions, but also limits any comparative analysis that might favor alternatives. This inappropriate approach employed by APS essentially pre-selects the natural gas portion of the resource mix rather than allowing the IRP analysis to inform the best resource mix.

2.5. APS’ IRP biases in favor of supply-side natural gas by adding more generation capacity than is necessary in upcoming years. Reducing over-procurement of supply-side resources can significantly reduce the revenue requirements for each portfolio.

In several of the portfolios assessed in APS’ IRP, there are years in which the MWs of total resources held by APS significantly exceed the total load requirements (including the planning reserve margin). The figure above illustrates this excess capacity for both the Selected Portfolio and the Expanded DSM Portfolio in a few upcoming years (2019, 2020, and 2021). For the Expanded DSM Portfolio, the excess capacity is partly attributable to the fixed MW amount of NGCC added (as described above), despite a lower overall MW need due to demand-side resource additions. Simply put, APS is planning to procure natural gas additions that customers do not need, and then charge customers for the unneeded plants.

Reducing or deferring supply-side capacity additions to more closely align them with the true need can yield significant savings to customers. Based on the example above (Figure 9), SWEEP estimates that a 72 MW over-procurement of new NGCC capacity in 2021 equates to approximately a ~$121 M (NPV) in

![Excess Capacity (Total Resources net of Load Requirements)](image-url)

*Figure 9. Excess capacity in MW (total resources, net of load requirements) for two portfolios evaluated in APS’ 2017 IRP. Source: APS 2017 IRP, Attachment F.1(A)(1) and F.1(A)(3)*
total fixed cost revenue requirements over the life of the asset.\textsuperscript{16,17} For context, this is greater than the 
\textit{total} difference in cost between some of the portfolios that APS calculates. By not adjusting the addition of supply-side generation downwards under the Expanded DSM portfolio (and other portfolios), and keeping these investments fixed, APS’ IRP distorts the overall costs of the other portfolios and masks the benefits of portfolios that deploy more demand-side resources.

SWEEP recognizes that over-procurement is partly due to the “lumpiness” of traditional supply-side resources, which typically come in large MW quantities that cannot easily be tailored to system needs. However, instead of consistently over-procuring large supply-side resources, a portfolio could be constructed that includes a greater number of other resource types that can be more readily tailored to fit system needs.

These other resource types could include demand-side resources such as EE and DR, and storage. It could also include renewable energy or market purchases. Importantly, several of APS’ excess capacity additions occur within the next 5-years. This falls within the window that the Commission specified as appropriate to include market purchases in a utilities’ resource plan as outlined in Decision 73884. Thus it would be possible for APS to meet its load growth requirements through market purchases, incremental renewables, storage, and DSM in the near term and defer costly generation additions to later years.

\textbf{2.6. APS’ selected portfolio significantly reduces DSM investment after 2020, despite significant customer benefits. This approach may eliminate over $600 M in net benefits to customers over the next 15 years.}

The discussion above illustrates the benefits that DSM can provide to customers both in terms of reduced fixed generation costs and reduced fuel costs. DSM programs that are found to be cost effective provide a significant benefit to customers and should be expanded or at least maintained in APS’ Selected Portfolio. In contrast, APS’ Selected Portfolio significantly decreases the level of investment in DSM as illustrated below for EE program savings, beginning in 2021. According to APS’ IRP projections, this will lead to an 85% annual reduction in energy savings and a 61% reduction in annual peak demand savings achieved by EE programs starting in 2021 (see Figure 10 and Figure 11). By reducing its investment in EE resources, APS increases the amount of energy (MWh) and capacity (MW) that it must procure from other resources, primarily from natural gas, at higher costs to customers.

\textsuperscript{16} NPV @7.5\%. Assumptions used in this calculation were based on the following included in APS’s plan: $1,236/kW capital cost, Table 2-3 (p 49); After-tax WACC: 7.5\%, Composite income tax rate: 38.9\%, Table D-8 (p 163); 32 year book life, 20 year tax life, Table D-9 (p 163); Fixed O&M: $6.53/kW-yr Attachment D.3 − Generation Technologies (p 309).
\textsuperscript{17} Notably, APS over-procures by more than 72 MW in 2021 and the 7 following years.
Figure 10. EE Program Energy Savings (MWh) as projected in APS’ IRP. Source: APS 2017 IRP, ATTACHMENT C.1(B) – ENERGY CONSUMPTION BY MONTH AND CUSTOMER CLASS, p 245-252.

Figure 11. EE Program Capacity Savings (MW) as projected in APS’ IRP. Source: APS 2017 IRP, ATTACHMENT C.1(A) – COINCIDENT PEAK DEMAND BY MONTH AND CUSTOMER CLASS, p 237-244.
As reported in Table D-23, APS’ 2016 EE Programs achieved over $62 million in net benefits with a current benefit to cost ratio of approximately 1.5:1. By reducing investment in these programs, as APS proposes to do in its Selected Portfolio, less of these benefits will be realized by APS customers. The chart below illustrates SWEEP’s rough estimate of the potential benefits at risk under APS’Selected Portfolio (versus a portfolio that maintains EE investment at current levels). This rough estimate represents the cumulative reduction in net benefits for each program year commensurate with the reduction in annual EE program savings that APS has proposed beginning in 2021. The results illustrate that customers may lose over $600 M in benefits by 2032 due to the APS-proposed reductions in EE program investments.18

2.7. APS’ Plan biases against DSM resources by screening measures based on load factor. This screening proposed by APS, which is not practiced in the industry, is arbitrary, harmful to customers, and counterproductive to APS’ stated objectives.

APS’ IRP describes a significant growing need for resources to meet peak demand. In discussing the role of DSM to meet this need, APS states the following: “APS is already transitioning the current portfolio of EE measures toward peak demand management programs that will provide high value to customers and align better with system resource needs.”19

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18 Note that these benefits are calculated using the ACC’s Staff’s prevailing methodology. Improvements to this methodology would likely demonstrate additional benefits beyond what is currently estimated.

19 APS 2017 IRP, p 66.
SWEEP supports the policy objective of reducing peak demand, however the steps taken by APS to “transition” its DSM portfolio as described in the IRP are actually counterproductive to achieving this goal. In developing its future DSM portfolios beyond 2020, APS develops two cases: a High Case that continues the current DSM portfolio trajectory and a Base Case that arbitrarily screens out cost-effective measures based on an arbitrary load factor number determined by APS. APS describes this screening as follows: “Energy efficiency (EE) technologies similar to those included in the APS 2016 and 2017 DSM Implementation Plans were screened by using the SC [societal cost] test, and only those with load factors in the 0%-30% range, typically summer peak programs, were selected for inclusion in the Base DSM Case.”  

This screening process appears particularly detrimental to APS’ goal of achieving peak demand savings. As shown below, while the screening may be intended to focus the DSM portfolio on EE measures with higher peak demand savings, it actually reduces overall peak demand savings as a result. While APS proposes to add new “load shifting” measures in the Base DSM Portfolio, these measures do not appear to provide any meaningful peak demand reduction since they do not appear to be included or expressly identified in the load and resource tables of any portfolio. Moreover, according to APS, all of the future MW saved from Demand Response in its Base DSM Plan are from “unspecified programs.” Additionally, all of the load shifting is attributable to “future rate structures.” Thus, unlike the energy and capacity savings APS has achieved through existing EE programs, neither of these new components (i.e. “load shifting” and “unspecified DR”) have a proven track record and may not be able to deliver savings as anticipated. In SWEEP’s view this approach is very likely to lead to an overall decrease in both energy and capacity savings and an overall increase in costs for customers.

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20 Section D, P 169  
21 See APS response to SWEEP 1.8.
The additional screening based on load factor provides no additional value and only serves to arbitrarily remove programs and measures that contribute to reducing peak demand and are otherwise cost-effective.

Additionally, the SC test currently implemented already provides a robust screening process to determine which measures are economically beneficial and already takes into account each measure’s contribution to reducing peak demand. The SC test is largely self-correcting over the long-run and will already screen out measures for which benefits do not justify the costs, including any future changes to both peak demand contribution or energy value.

SWEEP welcomes improvements to the cost-effectiveness methodology and has worked with the Commission and other stakeholders to implement such improvements. However, an arbitrary 30% load factor screen as applied by APS is detrimental to this effort and is not based on any rational policy objective.

Figure 13. Comparison of peak demand savings between APS’ Base DSM Plan (blue) included in its Selected Portfolio and its High DSM Plan which continues the current trajectory. The load factor screening applied by APS to reach the Base DSM Plan results in a significant reduction in peak demand savings. Source: APS 2017 IRP Table D-15 and D-16, p 170.
Additionally, it’s worth noting that the incremental annual DSM savings proposed for elimination by APS in its Base DSM Plan (>400,000 MWh annually)\(^{22}\) for a single future program year exceeds the total amount of renewable energy curtailed in all of California Independent System Operator (CAISO) in 2016 (308,000 MWh)\(^{23}\) and in 2017 (343,000 MWh, YTD).\(^{24}\) Notably these savings achieved in each year of APS’ DSM programs would extend for approximately 10 years based on a typical EE measure life. Thus, each year of reduction in DSM savings contemplated in APS’ Plan equates to more than 10 years renewable energy curtailment in CAISO.

2.8. APS biases against DSM programs by suggesting changes are needed to address “duck curve” issues. Significantly reducing or shifting investment from existing DSM programs based on the effects of the duck curve, which occur in a small part of the year, appears to be premature and may be harmful to customers.

In its IRP, APS states the following: “To stay cost effective and focus program spending on the highest value savings, the DSM portfolio needs to evolve to better align with these changing resource needs by focusing programs on reducing the late afternoon and early evening peak demand with less focus on midday kWh savings.”\(^{25}\)

SWEEP agrees that DSM portfolios should evolve over time to align with system needs and maximize benefits to customers. However, SWEEP cautions that significant changes to the DSM portfolio should be considered carefully to ensure that: 1) existing programs that are still cost effective and provide system value are not diminished arbitrarily or inappropriately, and 2) new programs provide enough value to justify the cost and do not cannibalize existing programs that continue to provide net benefits. SWEEP does not believe that APS’ IRP has proved either of these important considerations when proposing significant changes to its DSM portfolio.

SWEEP also agrees that solar PV has lowered the avoided energy costs during some midday hours, which may suggest reevaluating certain programs or measures. However, this does not necessarily mean that measures with midday savings provide no value. It also does not mean that a radically new approach to DSM is necessary or justified. For example, some measures with midday savings may still provide significant value in terms of total energy savings over the course of a year, or measure life. Additionally, even if energy value is diminished or savings overlap with instances of low or negative pricing, measures may still be cost-effective based on capacity value or energy savings in other time periods. This determination should already be occurring through the existing DSM program framework and cost-

\(^{22}\) APS’ proposed Base DSM Plan includes approximately 90,000 MWh of annual incremental savings from EE programs beginning in 2021 while APS’ current DSM Portfolio (as documented in APS 2016 DSM Annual Progress Report) is achieving over 500,000 MWh in annual incremental savings.


\(^{24}\) P 64 of APS’ 2017 IRP
effectiveness screening process that is currently in place. No additional screening is required, especially no arbitrary screening of the type proposed by APS.

SWEEP is concerned that APS is using the “duck curve” as a justification in its IRP for reducing investment in cost-effective EE (and thereby trying to justify pursuing more natural gas additions), without a careful examination of the facts. For example, while it is true that there have been instances of negative pricing, real-time wholesale market prices vary considerably based on market conditions. Even some spring days have no negative pricing or “duck curve” behavior. The figure below illustrates the real-time market price for APS on two separate days in April of this year, one of which exhibited no negative pricing.

![Interval Locational Marginal Prices for ELAP-AZPS Node (hourly average) on 4/1/17 and 4/17/17](image)

*Figure 14. Comparison of two spring day real time prices. Note one day exhibits all positive pricing while the other exhibits some negative pricing. Source: CAISO OASIS, retrieved September 2017.*

Furthermore, the recent impact of negative price events on costs to customers is relatively small. According to data provided by APS, energy purchased on the wholesale market in 2017 (YTD) for a negative price has amounted to ~50 GWh or <0.2% of APS total energy load forecast for the entire
Any benefit that customers may derive from increasing load during these hours (e.g., via reduction in efficiency measures) must be weighed against the cost of increasing load during other hours. For example, if the 50 GWh purchased by APS in 2017 came at a price of -$20/MWh, this equates to approximately $1M in customer savings. In contrast, APS EE programs delivered $62M in net benefits in 2016.

An appropriate evaluation of the energy value from an EE measure must consider the savings generated (and costs incurred) throughout the life of a measure – not just for a specific interval. Thus, if a time-based approach is used, it should be based on either 8760 hour values or an average annual value for a specific time period of savings.

The chart below illustrates the average day-ahead and real-time market prices for the APS load zone for the last 12-months during which APS has participated in the CAISO Energy Imbalance Market (EIM). In both cases average prices are positive throughout the day, meaning there is a positive value for achieving energy savings even during midday. Additionally, all day-ahead average prices and nearly all real-time average prices exceed the DSM portfolio costs. This illustrates that even under today’s market conditions, increasing DSM investment is likely to yield net benefits based on energy savings alone. Efficiency measures that produce savings only during hours 9-12 are worth examining for cost-effectiveness. However, these measures may provide other benefits such as energy savings during other hours, and capacity savings, both of which could offset any reduction in daytime energy value.

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Based on APS response to SWEEP 1.12 and 2017 load forecast data provided in APS’ 2017 IRP.

The lowest hourly average real time price for APS for any month to date in 2017 was -$16/MWh in June for the 7-8am hour.
Figure 15. Average Real-time and Day-ahead locational marginal pricing data for the AZPS load aggregation point as reported by the CAISO OASIS system. This reflects the marginal cost of production for both the real-time (5-minute) market intervals and day-ahead (hourly) schedules. Source: CAISO OASIS, retrieved October 2017. EE portfolio cost data based on APS 2016 DSM Reports; NGCC Cost Data based APS 2017 IRP Attachment D.3 – Generation Technologies (p 312).

2.9. Time-specific analysis of EE measure savings confirms that significant energy value is being provided both now and in the future, despite negative pricing.

To better understand the effects of the duck curve on the potential value of EE measures, SWEEP has conducted a time-specific analysis of EE measure savings and compared this to the real-time market prices for the APS load zone. In its 2018 DSM Plan, APS has provided information on when EE measure savings occur within three distinct time periods: On Peak (3-8pm weekdays), Super Off-Peak (10-2pm, weekdays, Oct-Apr), and Off-Peak (all other hours). SWEEP has calculated the average wholesale price during these periods for the most recent 12-month period from October 2016 to September 2017 using CAISO Energy Imbalance Market (EIM) market data for the APS load zone. These prices are shown below and reflect the avoided real-time energy cost due to energy savings occurring during these periods.
<table>
<thead>
<tr>
<th>Time Period</th>
<th>CAISO EIM RTM Average Price for AZPS load zone ($/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>3-8pm (weekdays)</td>
<td>50.72</td>
</tr>
<tr>
<td>10-2pm (weekdays, Oct-Apr)</td>
<td>10.12</td>
</tr>
<tr>
<td>Other Hours</td>
<td>21.01</td>
</tr>
</tbody>
</table>

These prices were then applied to the time-weighted energy savings for each EE measure to produce a time-specific avoided energy cost for each measure. This was done for all 207 measures for which time-specific savings was provided in APS’ 2018 Plan and in response to SWEEP’s data request in this proceeding. SWEEP found that all measures produced positive energy savings on average ranging from $22-49 per MWh. This does not include additional benefits from each measure such as capacity savings. For 100% of measures, the average avoided energy costs (the benefits) also exceeded the average DSM portfolio implementation costs (Figure 16).

Figure 16. Real-time energy cost savings (time-weighted average) for each EE measure in APS’ 2018 DSM portfolio based on the time of day in which savings occur. Energy savings were calculated using CAISO EIM price data for APS load zone from October 2016 through August 2017. Average prices were computed for each of the three periods specified in APS’ 2018 DSM plan. These were then applied to the portion of savings generated by each measure in each of the time periods. For comparison, the Average

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28 See APS response to SWEEP 1.7.
29 This includes many measures proposed for elimination by APS.
Portfolio Cost in $/MWh of APS’ DSM portfolio is included. Note that all measures yield positive savings on average and that savings from all measures exceed the portfolio cost.

We also examined the impact of savings from these measures going into the future. Figure 7-3 of APS’ IRP shows the forecast of 2025 hourly market prices for the Palo Verde hub. While there are some negatively priced hours in the spring, there are many positively priced hours during the rest of the year. We used this data to examine the value of savings from the same 207 EE measures using the 2025 hourly prices (Figure 17). The results show positive savings for all measures, ranging from $30-49/MWh. These savings exceed implementation costs for all measures, even after accounting for a 5% annual escalation in EE portfolio costs.

![Time-Weighted EE Measure Energy Savings Value, 2025](image)

Figure 17. Future energy cost savings (time-weighted average) for each EE measure in APS’ portfolio based on the time of day in which savings occur. Energy savings for each of the three time periods was calculated using data from Figure 7-3 of APS’ IRP and provided in SWEEP 1.12. Note that the public information provided by APS only contained month-hour values so weekend/weekday adjustments were not possible.

2.10. APS’ portfolio analysis is biased against DSM resources by inappropriately and incorrectly including additional costs – specifically, the out-of-pocket costs paid by individual participating customers as their share of the incremental project costs, which are not paid by ratepayers and are not part of the revenue requirement – in the Expanded DSM Portfolio when comparing revenue requirements.

In numerous places in the IRP, APS compares the NPV revenue requirements of each portfolio. In several of these cases, this comparison contains an error. Specifically, APS includes additional costs that are not technically part of the revenue requirement and APS does not always indicate that these additional
costs were included. This incorrect approach results in APS representing inaccurate and inflated costs for DSM resources. Moreover, APS only includes these additional costs for the Expanded DSM and Resource Mandates Portfolios, creating an “apples to oranges” comparison when comparing portfolios.

Out-of-pocket customer costs are the portion of project costs that individual participating customers pay out of their own pockets, as their share of the incremental project costs after receiving a DSM program rebate or financial incentive. These individual participating customer costs are not paid by ratepayers. Incremental out-of-pocket customer costs are not considered when setting rates and are not collected by the utility so it is inaccurate to include these costs when comparing revenue requirements.

For example, in Figure ES-3 of the APS IRP, the Expanded DSM Portfolio revenue requirement is reported as $39,873 M (NPV, 2017-2046). However, as indicated in the footnote in Attachment F.1(B) on p 338, this number technically includes incremental out-of-pocket customer costs for DSM projects. Including incremental out-of-pocket customer costs in this comparison is misleading and incorrectly inflates the APS-represented cost of the Expanded DSM Portfolio. For example, calculating the revenue requirement for the Expanded DSM Portfolio without the out-of-pocket customer costs would result in a cost reduction of $255 M (NPV, 2017-2032) and $576 (NPV, 2017-2046) for the Expanded DSM. A true comparison of the revenue requirements, without out-of-pocket individual customer costs included, would yield a lower NPV value for the Expanded DSM Portfolio when compared to the Selected Portfolio over the 15-year planning horizon. In Figure 18 below SWEEP provides the corrected values for the 15-year planning horizon.

The IRP analysis should be based on revenue requirements, and should not include the incremental out-of-pocket costs of individual participating customers.

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30 Instances where customer costs were inappropriately included as part of the NPV revenue requirement:
- Figure ES-3, p 14;
- Table 7-2, p 124;
- Figures 7-16, 7-17, and 7-18, p 125;
- Figure 7-26, p 129;
- Figure 7-27, p 130;
- Table 7-3, p 133;
- Table 7-4, p 134;
- Table 7-5, p 135;
- Table 7-6, p 136.

31 SWEEP notes that over the 30-year planning horizon, the APS-calculated revenue requirements for the Expanded DSM Portfolio are 0.2% higher than the Selected Portfolio once out-of-pocket customer costs are removed. However as explained below in Section 2.11, SWEEP believes that APS has inappropriately and significantly inflated other parts of the revenue requirement (specifically EE portfolio costs) in the Expanded DSM portfolio in the 2033-2046 time period and thus the 30-year time horizon should not be used in this case. Adjusting the EE portfolio costs to more reflect more reasonable estimates of future costs produces a 30-year revenue requirement that is lower than the Selected Portfolio as explained in Section 2.11 below.
Figure 18. SWEEP’s reproduction of APS’ Figure ES-3 with corrected values for the Expanded DSM and Resource Mandates portfolios, for the 15-year planning horizon. The original figure misrepresented the revenue requirements for these portfolios by mistakenly including out-of-pocket customer costs. The 15-year horizon is shown (rather than the 30-year horizon) to avoid inflated costs in the 2033-2046 time period described in Section 2.11. Note that the Expanded DSM portfolio is $239M less than the selected portfolio.

2.11. APS’ portfolio analysis is biased against DSM by including costs in its Expanded DSM Portfolio that appear unreasonable for the year 2032 and beyond.

As described above, APS included incremental out-of-pocket DSM customer costs in the revenue requirement comparison between portfolios. Not only is this incorrect, but the incremental out-of-pocket customer costs themselves do not appear to be reasonable for all years included in the IRP analysis. The figure below shows the customer costs for each year as reported in Attachment F.1(B) – Revenue Requirements for Seven Portfolios, on p 342. After gradually increasing each year, the costs rapidly spike in the final year to more than double the previous year. While future customers costs are
unknown and contain some uncertainty, this sudden increase appears arbitrary and has not been adequately explained by APS. SWEEP does not agree with APS that this increase would arise due to “replacement programs from earlier years that have reached end of life.” Ratepayers are not going to have to pay again to “replace” the end-use efficiencies already captured and imbedded in the electric system and market at the end of the life of a DSM measure. SWEEP is concerned that this variable has been inappropriately altered by APS, resulting in a bias against the Expanded DSM portfolio when comparing its NPV cost to other portfolios.

Figure 19. Source: APS 2017 IRP, ATTACHMENT F.1(B) – REVENUE REQUIREMENTS FOR SEVEN PORTFOLIOS, p 342.

Furthermore, the EE and DR program costs as reported in the revenue requirements table show a similar pattern.

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32 APS response to SWEEP 1.2; assuming continuous implementation of DSM measures, these costs can be expected to increase gradually over time. The costs would not dramatically increase in a singly time step.
Thus, both the program and customer costs associated with DSM programs are inflated in the final year of the 15-year horizon, which affects the comparison of both the NPV revenue requirements and the total resource costs.

Beyond 2032, the DSM program costs as estimated by APS rise even more dramatically in the Expanded DSM Portfolio, ultimately increasing to nearly $2 billion annually in the final years (or 4000% higher than 2017 levels). Costs in the final 15 years grow by a staggering 946%, representing an 18% annual average growth rate. SWEEP finds this acceleration in costs to be unreasonable, and the APS approach distorts the overall cost of the Expanded DSM portfolio. For example, reducing the EE/DR costs in the final 15-year period to a 14% annual growth rate (which SWEEP contends is still extraordinarily high) yields a 30-year NPV revenue requirement that is over $470 M lower than the Selected Portfolio. This is important because APS uses the 30-year comparison (rather than the 15-year comparison) in several key places, such as the Executive Summary of the IRP (e.g. Figure ES-3).
Figure 21. Illustration of EE/DR program cost increases over the 30-year planning horizon in APS’ plan. Note the significant increases in costs in the later years, which influence the NPV revenue requirements for each portfolio. Source: APS15957, response to SWEEP 1.1.

3. **A resource portfolio with more demand-side resources outperforms the selected portfolio on virtually every relevant metric, including costs to customers.**

   3.1. *The Expanded DSM Portfolio is the least cost option examined in APS’ IRP in terms of revenue requirement over the 15-year planning horizon.*

As explained above (see Figure 18), APS has included additional costs beyond the revenue requirement when comparing the Expanded DSM Portfolio to other options. SWEEP has calculated the corrected version of the revenue requirements comparison for the 15-year IRP planning horizon (2017-2032). It is readily apparent that the Expanded DSM portfolio has the lowest overall revenue requirement of any portfolio.

SWEEP is aware that APS’ original comparison (e.g. in Figure ES-3 of the APS 2017 IRP, etc.) also includes an extended 30-year planning horizon (2017-2046), however, SWEEP believes the 15-year horizon is more appropriate timeline in this case due to the lack of information APS has provided about its 30-year resource plan, including load, resource, and cost assumptions. As specified under A.C.C. rule R14-2-703 (D)(1), the IRP process is primarily intended to focus on the 15-year planning period. In fact, the 30-year time period is specified nowhere in the A.C.C. rules relating to resource planning. Without additional information from APS regarding the load, resources, and cost assumptions for years 2033 through 2046, it is not possible to evaluate the reasonableness of the revenue requirements.
3.2. The Expanded DSM Portfolio is the least cost option examined in APS’ IRP in terms of total resource costs over the 15-year planning horizon.

As described above, both the DE-EE program costs and DSM customer costs that APS assumes exhibit a large spike in year 2032. SWEEP does not think it is reasonable to assume that such a large increase would happen in a single year. As such, SWEEP recommends recalculating the revenue requirement and total resource costs of the Expanded DSM portfolio with appropriate adjustments made for the year 2032.

SWEEP has performed this recalculation assuming an incremental out-of-pocket customer cost of $50M in year 2032 and a EE revenue requirement of $206M. This is consistent with the annual growth rates APS assumes in prior years (see Figure 19 and Figure 20). This adjustment results in a total resource cost (including customers costs) for the Expanded DSM Portfolio of $25,905M (NPV, 2017-2032 @7.5%). Notably this is lower than the revenue requirement of APS’ Selected Portfolio and all other portfolios examined in the IRP. Thus, even if customer costs are included (i.e. a total resource cost comparison applied solely to DSM), which SWEEP notes is an incorrect comparison, the Expanded DSM Portfolio is still the least cost option over the 15-year planning horizon.

3.3. The Expanded DSM Portfolio performs better than the APS Selected Portfolio in terms of average customer bill impacts.

While average system cost in $/MWh is included in the IRP as a key metric, SWEEP believes that for most customers the average monthly bill (in total $) is a more meaningful measure of each portfolio’s cost. In Figure 6 below SWEEP has computed the monthly bill for an average residential customer under
the Selected Portfolio using information from APS’ IRP. Additionally, SWEEP has computed the average bill for residential customers under the Expanded DSM Portfolio. Note that this only represents the portion of the bill that covers the resource-related costs examined in the IRP and may not include certain distribution-related costs.

<table>
<thead>
<tr>
<th>Item</th>
<th>Value in 2032</th>
<th>Unit</th>
<th>Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 Residential Sales Forecast</td>
<td>24,050,019</td>
<td>MWh</td>
<td>APS IRP, ATTACHMENT C.1(B), p 252</td>
</tr>
<tr>
<td>2 Total Sales Prior to EE/DE</td>
<td>45,739,085</td>
<td>MWh</td>
<td>APS IRP, ATTACHMENT C.1(B), p 252</td>
</tr>
<tr>
<td>3 EE</td>
<td>-2,880,706</td>
<td>MWh</td>
<td>APS IRP, ATTACHMENT C.1(B), p 252</td>
</tr>
<tr>
<td>4 DE</td>
<td>-5,904,328</td>
<td>MWh</td>
<td>APS IRP, ATTACHMENT C.1(B), p 252</td>
</tr>
<tr>
<td>5 Total Sales (after EE/DE)</td>
<td>36,954,051</td>
<td>MWh</td>
<td>APS IRP, ATTACHMENT C.1(B), p 252</td>
</tr>
<tr>
<td>6 Total Sales (after EE/DE), Residential</td>
<td>19,430,770</td>
<td>MWh</td>
<td>Based on 53% of total sales, [1]/[2]</td>
</tr>
<tr>
<td>7 Average # Residential Customers</td>
<td>1,585,013</td>
<td>No.</td>
<td>APS15959 (response to SWEEP 1.4)</td>
</tr>
<tr>
<td>8 Average Monthly Consumption, Residential Customer</td>
<td>1,022</td>
<td>kWh</td>
<td>Calculation from lines above</td>
</tr>
<tr>
<td>9 System Cost, Selected Portfolio</td>
<td>$101.4</td>
<td>$/MWh</td>
<td>APS IRP, Table 7-2</td>
</tr>
<tr>
<td>10 Average Residential Bill, Selected Portfolio</td>
<td>$103.59</td>
<td>$</td>
<td>[8]x[9]</td>
</tr>
<tr>
<td>11 Additional EE Achieved under Expanded DSM Portfolio</td>
<td>4,121,371</td>
<td>MWh</td>
<td>APS IRP, Tables 15 and 16.</td>
</tr>
<tr>
<td>12 Customer Savings (adjusted for losses)</td>
<td>3,837,821</td>
<td>MWh</td>
<td>Loss factor calculated from APS IRP ATTACHMENT C.1(B)</td>
</tr>
<tr>
<td>13 Total Sales (after EE/DE), Expanded DSM</td>
<td>33,116,230</td>
<td>MWh</td>
<td>Calculation from lines above</td>
</tr>
<tr>
<td>14 Total Sales, Residential, Expanded DSM</td>
<td>17,412,809</td>
<td>MWh</td>
<td>Based on 53% of total sales, [1]/[2]</td>
</tr>
<tr>
<td>15 Average Monthly Consumption, Residential Customer</td>
<td>915</td>
<td>kWh</td>
<td>[14]x[7]/12</td>
</tr>
<tr>
<td>16 System Cost, Expanded DSM</td>
<td>$112.5</td>
<td>$/MWh</td>
<td>APS IRP, Table 7-2</td>
</tr>
</tbody>
</table>

Figure 23. Calculation of average residential customer bill in both the Selected Portfolio and the Expanded DSM Portfolio. The final results of each are shown in green. Note that the Expanded DSM Portfolio results in a lower average bill.

As shown, the average bill impact of the Expanded DSM Portfolio is lower than the Selected portfolio. Additionally, as indicated in Figure 20, SWEEP believes that the EE program costs for the Expanded DSM portfolio were inappropriately inflated by APS in 2032. SWEEP estimates that this reduction in revenue requirement would reduce the average system cost for the Expanded DSM Portfolio to $108.9/MWh.
(from $112.5/MWh). This adjustment would further reduce the average customer bill of the Expanded DSM Portfolio to $99.65, or 4% lower than the Selected Portfolio. SWEEP believes this bill impact could be lowered even further if additional DSM measures were pursued instead of the significant supply side additions included in the Expanded DSM portfolio.

4. **APS’ characterization of the “cost shift” for the Expanded DSM portfolio is misleading and ignores significant cost shifts occurring in its Selected Portfolio.**

   4.1. **APS’ characterization of the “cost shift” for the Expanded DSM portfolio is misleading since the majority of customers are participants, all customer segments have an opportunity to participate, and all customers benefit either directly or indirectly from DSM programs.**

In its IRP, APS describes the two portfolios with higher levels of EE as leading to a significantly higher cost shift. SWEEP is continuing to analyze this and just received several new responses to data requests. However, at this point, SWEEP disagrees with APS’ characterization that EE programs lead to a cost shift for two reasons.

1) The majority of APS customers participate in these programs. As APS moves closer to full participation levels for its DSM programs in the future (and as programs are implemented that benefit all customers and customer segments, such as conservation voltage reduction), there will be fewer and fewer customers who are “non-participants.” Ultimately, all customers will be beneficiaries of EE programs in the form of direct bill savings, or will have had the opportunity to participate. Moreover, all customers will be beneficiaries due to lower overall system costs.

2) In SWEEP’s view the most important key metric from a customer’s standpoint is their overall bill in total dollars per month. As long as EE programs cause average customer bills to be lower than the alternative (which is what APS’ IRP demonstrates), the APS assertion of a cost-shift is no longer an important or relevant metric.

4.2. **APS’ natural gas plant buildout under the selected portfolio creates a significant new “cost shift” that transfers $4.1 billion from its customers to its investors and the federal government. This cost shift and wealth transfer can be reduced significantly under the Expanded DSM Portfolio.**

Moreover, APS’ focus on the cross-subsidies associated with customer resources overlooks an even larger and more important “cost shift” or wealth transfer that is occurring due to the planned buildout of supply-side natural gas resources. A significant portion of the costs that will ultimately be collected from customers to pay for these resources goes to benefit APS’ investors both in the form of return on equity to shareholders and interest on debt to lenders. Additionally, a significant portion goes to pay for taxes on shareholder income that go to the federal government. These can equally be characterized as wealth transfers, cross-subsidies, or “cost shifts” and should also be examined.

The chart below illustrates the annual increase in revenue collected for these components associated with APS’ planned buildout of natural gas combustion turbine resources. Notably, the shareholder return, interest on debt, and federal income taxes for the NG-CTs amounts to $1.3-2.5 billion (NPV)
under APS’ Selected Portfolio – much more than any cost shift APS claims for demand-side resources. Additionally, under the Expanded DSM portfolio, this wealth transfer can be reduced by over $228-422 M due to displacement of some future NG-CTs with DSM resources. The remaining cost shift is due to the significant supply-side gas expansion that APS still includes in its Expanded DSM portfolio. SWEEP believes this could be further reduced if additional DSM resources were procured instead of supply-side gas resources.

Since all portfolios evaluated by APS have identical NGCC additions, a comparison is not possible. However, it is worth noting that the NGCC additions increase the total wealth transfer by an additional $1.6 billion (NPV), to a total of $2.9-4.1 billion for the Selected Portfolio.

$$\text{NPV (Annual):}$$

$$\begin{align*}
\text{Selected Portfolio} &= \$2.5 \text{ bn} \\
\text{Expanded DSM} &= \$2.1 \text{ bn} \\
\text{Difference} &= \$422 \text{ M}
\end{align*}$$

Figure 24. Illustration of the annual incremental cost to customers necessary to pay for the shareholder return on equity, interest on debt, and taxes to the federal government associated with APS’ proposed buildout of Natural Gas Combustion Turbine resources (assuming aeroderivative model is selected). This does not include any combined cycle resources. Notably the Expanded DSM portfolio leads to less wealth transfer due to a smaller buildout of NG-CT units. SWEEP calculated these values using a pro forma tool developed by WECC with assumptions included in APS’ IRP. NPV is calculated over the life of the asset.

5. The Expanded DSM Portfolio performs better than the Selected Portfolio on virtually every metric.

As illustrated in the table below, the Expanded DSM Portfolio performs better than the APS’ Selected Portfolio on virtually every metric with only two exceptions.

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33 In its IRP, APS does not specify the specific type of combustion turbine added in each year. This range represents the range of costs for frame CT versus aero-derivative CT additions.
As stated above, SWEEP is choosing to emphasize the 15-year period (rather than the 30-year period) for three reasons: 1) this is the time horizon where the Plan is mostly likely to have an effect on resource decisions. 2) APS did not provide critical information on the load, resources, and cost assumptions for years 2033 through 2046, making evaluation more challenging. 3) As specified under A.C.C. rule R14-2-703 (D)(1), the IRP process is primarily intended to focus on the 15-year planning period.

Regarding the two exceptions, SWEEP disagrees with APS’ characterization of the cost shift, as explained in Section 4.1 and is continuing to analyze this issue. Additionally, SWEEP believes the Average System Cost ($/MWh) metric is not particularly relevant if overall customer bills have decreased, which is the case for standard DSM participants during which the $/MWh cost has increased.

<table>
<thead>
<tr>
<th></th>
<th>Selected Portfolio</th>
<th>Expanded DSM Portfolio</th>
<th>Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>Revenue Requirement, $M, (2017-2032 CPW@7.5%)</td>
<td>$25,951</td>
<td>$25,712</td>
<td>APS 2017 IRP, ATTACHMENT F.1(B)</td>
</tr>
<tr>
<td>Total Resource Cost, $M, (2017-2032 CPW@7.5%)</td>
<td>$25,951</td>
<td>$25,905</td>
<td>APS 2017 IRP, ATTACHMENT F.1(B); Adjusted as described in section 3.2 above.</td>
</tr>
<tr>
<td>Capital Expenditure, $Bn (2017-2032 CPW@7.5%)</td>
<td>$8.2</td>
<td>$8.1</td>
<td>APS 2017 IRP, Table 7-2</td>
</tr>
<tr>
<td>Wholesale Market Purchases, GWh</td>
<td>4,223</td>
<td>3,582</td>
<td>APS 2017 IRP, Figure ES-4</td>
</tr>
<tr>
<td>Gas Burn, 2032 BCF</td>
<td>140.9</td>
<td>117.9</td>
<td>APS 2017 IRP, Table 7-2</td>
</tr>
<tr>
<td>CO₂ Emission, MMT</td>
<td>13.5</td>
<td>12.1</td>
<td>APS 2017 IRP, Table 7-2</td>
</tr>
<tr>
<td>Water Use, Th acre-ft</td>
<td>52.7</td>
<td>49.9</td>
<td>APS 2017 IRP, Table 7-2</td>
</tr>
<tr>
<td>Average System Cost in 2032 ($/MWh)</td>
<td>$101.4</td>
<td>$108.9</td>
<td>APS 2017 IRP, Table 7-2, SWEEP estimate (see section 3.3 above).</td>
</tr>
<tr>
<td>Average Customer Bill in 2032 ($/month, res.)</td>
<td>$103.59</td>
<td>$99.65</td>
<td>SWEEP Calculation based on APS data (see section 3.3 above)</td>
</tr>
<tr>
<td>APS-calculated Cost Shift, $Bn (2017-2032 CPW@7.5%)</td>
<td>$0.1 34</td>
<td>$0.8 18</td>
<td>APS 2017 IRP, Table 7-2</td>
</tr>
<tr>
<td>NG-related Cost Shift/Wealth Transfer, $ billions (CPW@7.5%) – low estimate</td>
<td>$2.9-</td>
<td>$2.7</td>
<td>SWEEP calculation based on APS data (see section 4.2 above)</td>
</tr>
<tr>
<td>NG-related Cost Shift/Wealth Transfer, $ billions (CPW@7.5%) – high estimate</td>
<td>$4.1</td>
<td>$3.7</td>
<td>SWEEP calculation based on APS data (see section 4.2 above)</td>
</tr>
</tbody>
</table>

Figure 25. Comparison of Key Metrics for the Selected Portfolio and Expanded DSM Portfolio

V. Conclusion

Based on the observations detailed above, APS’ Plan is not reasonable and is not in the public interest, and therefore it should be rejected by the Commission. The analysis in the Plan is biased in favor of costly expansion of supply-side natural gas resources, which impose significant additional risk to customers.

34 SWEEP is still analyzing APS’ cost shift calculations and has recently received answers to data requests.
APS also selected a resource portfolio that performs worse than the Expanded DSM Portfolio on nearly every relevant metric. If Arizona is limited to choosing one of the Portfolios that APS developed (which it is not), then the Expanded DSM Portfolio is clearly the best portfolio for customers with adequate and reliable energy resources, at lowest customer costs. Despite the biases against DSM in the APS Plan, the APS-developed Expanded DSM Portfolio still out-performs the APS Selected Portfolio. APS’ own analysis and numbers demonstrate this.

Even though the Expanded DSM Portfolio performs better than other APS-developed portfolios, it still includes significant expansion of supply-side natural gas and can be improved upon to increase customer benefits. APS should be ordered to pursue at least the amount of DSM included in the Expanded DSM Portfolio as a floor and should also be ordered to consider additional expansion of its DSM portfolio beyond that. More specifically, SWEEP recommends the Commission take the actions outlined in Section III regarding the APS 2017 IRP, the Selected Portfolio, and the near-term action plan.

Those recommendations include the following:

1. **The Commission should reject and should not acknowledge the APS 2017 Integrated Resource Plan.** The APS Plan is heavily biased in favor of supply-side natural gas additions and against demand-side resources. APS has failed to demonstrate that its IRP and the APS Selected Resource Portfolio is in the best interest of its customers. As such, both the APS Plan and the APS Selected Portfolio should be rejected by the Commission.

2. **The Commission should explicitly reject APS’ proposed approach to reduce deployment of demand-side resources after 2020.** A significant shortcoming in APS’ IRP is its approach to reduce or eliminate demand-side resource programs that provide significant value to customers after 2020. APS’ Plan to reduce investment in these resource is misguided, would increase customer costs, and should be rejected.

3. **The Commission should require APS to select and implement a resource portfolio, as an improved Selected Portfolio, with fewer MW of supply-side, natural gas resources and more MW of demand-side resources.** The fact that the Expanded DSM Portfolio outperforms the APS Selected Portfolio in almost every way is a clear indication that APS should be required to implement more demand-side resources.

4. **The Commission should require APS to use the Expanded DSM Portfolio as a floor for the level of DSM resources in the improved Selected Portfolio, and should require APS to identify and secure additional DSM resources beyond those identified in the Expanded DSM Portfolio as long as the additional DSM resources would result in lower costs for customers based on the revenue requirement.**

5. **The Commission should order APS to address these issues in its next IRP.** In its order rejecting the APS-proposed IRP, the Commission should specify the improvements to be made in APS’ next IRP. This should include steps to reduce the bias for natural gas resources and the bias against DSM resources as identified by SWEEP.
6. The Commission should prioritize its actions to ensure prudent resource decisions are made in the near term. This includes consideration of APS’ 2018 DSM Plan as well as any near-term decisions to approve the acquisition, construction, or cost-recovery of supply-side natural gas resources.

7. The Commission should order APS to modify its Near-term Action Plan to include additional DSM investment after 2020. At a minimum, the Commission should order APS to maintain its current resource share and level of investment in DSM resources beyond 2020. Additionally, the Commission should order APS to consider an expanded level of DSM investment.