aps®

2023 INTEGRATED RESOURCE PLAN

PUBLIC

NOVEMBER 2023 | FILED IN COMPLIANCE WITH A.A.C. R14-2-703

November 1, 2023

On behalf of APS, I am pleased to present the Company's 2023 Integrated Resource Plan (IRP).

The results of APS's 2023 IRP, represented by the Company's Preferred Plan, identify the resources necessary to reliably and affordably serve the future energy needs of all APS customers over the next 15 years. The Preferred Portfolio includes a balanced mix of diverse resources that ensure system reliability and affordability. The 2023 IRP demonstrates that APS is prepared to meet the forecasted increase in customer energy needs and maintain the quality of electric service that Arizona families and businesses have come to rely on.

The Company would like to recognize the feedback received through stakeholder engagement and collaboration throughout the development of the IRP. The Company's efforts to develop a thoughtful IRP benefited from over 20 meetings of the Resource Planning Advisory Council and support from external consultants, such as Energy & Environmental Economics, Astrapé Consulting, and 1898 & Company.

We look forward to a robust and productive IRP review process.

Sincerely,

Todd P. Komaromy

Director, APS Resource Planning

FORWARD-LOOKING STATEMENTS

This report contains forward-looking statements based on current expectations. These forward-looking statements are often identified by words such as "forecast," "estimate," "projection," "may," "believe," "expect," "plan," "require," "intend," "assume," "anticipate," and other similar words. Because actual results may differ materially from expectations, APS cautions against placing undue reliance on these statements. A number of factors could cause future results to differ materially from historical results, or from outcomes currently expected or sought by APS. A discussion of some of these risks and uncertainties is contained in APS's Annual Report on Form 10-K and in its Quarterly Report on Form 10-Q for the quarter ended June 30, 2023 both of which are filed with the Securities and Exchange Commission. The reports are available on APS's corporate parent's website at www.pinnaclewest.com, and should be carefully reviewed before placing any reliance on APS's forward-looking statements, financial statements or disclosures. APS assumes no obligation to update any forward-looking statements, even if internal estimates change, except as may be required by applicable law.

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POWERING AHEAD

EXECUTIVE SUMMARY

Arizona is in the midst of a transformation. Our state's population continues to grow, especially in Maricopa County, which has been the county with the highest annual population gains in the United States since 2016. Phoenix is booming as a vibrant commercial hub in the Southwest region, attracting an influx of new residents and businesses, with large industrial customers and data centers continuing to express interest in the Valley. These changes are driving a significant increase in electric loads. At the same time, our customers' needs and preferences are evolving: adoption of electric vehicles is accelerating and many customers continue to express enthusiasm for innovative demand-side programs and options to purchase clean energy directly.

It is in this context that we present this updated Integrated Resource Plan (IRP or Plan) for the next fifteen years. The story we tell here is about how APS will meet and stay ahead of energy demands, but it is really about our customers. We know they count on us to power their lives and businesses. Our job is to continue the excellent service Arizonans have come to expect by making responsible, necessary investments to:

- Ensure reliability
- Maintain affordability
- Secure a clean, balanced energy supply for Arizona

The massive growth within Arizona comes as our resource mix is poised to undergo significant changes. Our two remaining coal plants are quickly approaching the end of their operating lives: we continue to plan for the retirement of the Cholla Power Plant (Cholla) by April 2025 and APS's exit from Four Corners Power Plant (Four Corners) in 2031. Over this same period, we are investing heavily in affordable renewable and clean technologies, with more than 2,500 megawatts (MW) of utility-scale batteries coming online by the end of the Action Plan period.

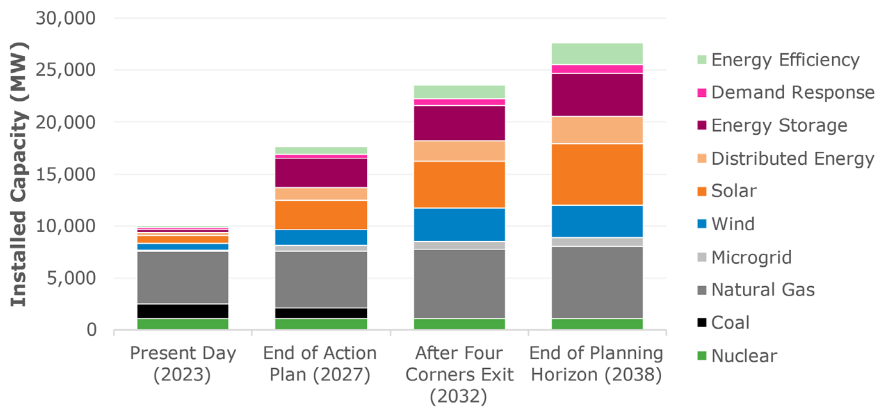
The planning landscape of the electric utility industry has also shifted in dramatic ways since the publication of our 2020 Integrated Resource Plan. During and after the COVID-19 pandemic, disruptions to global supply chains triggered delays and cancellations in the development of new resources throughout the country, and the costs of wind, solar, and storage resources began to increase after declining for more than a decade. The federal government passed the Inflation Reduction Act (IRA) in 2022, dedicating billions of dollars in funding through tax credits and loan guarantees for the development of new clean energy resources. Geopolitical instability in eastern Europe created shocks that rippled through global markets for fuels, resulting in a return to volatility in natural gas pricing after roughly a decade of low and stable prices. As extreme weather has become the norm — in 2023, Phoenix experienced 55 days over 110° F — our ability to maintain reliability is critical to the health and welfare of Arizona. These types of changes directly impact the development of our Plan, but also serve as powerful reminders of how suddenly and unexpectedly change can occur — and how we, as the largest electric utility in Arizona, need to be agile and ready to respond to these challenges to meet the needs of our customers.

What hasn't changed is APS's commitment to providing safe, reliable, and affordable energy to our customers. We've met this commitment for 137 years and our success in doing so is part of what has made the region attractive to families, business, and investment.

Navigating this period of change and uncertainty while delivering on our commitment to provide safe, reliable, and affordable power to Arizona requires a strategy that is robust but adaptive, opportunistic but measured in approach. It will also require us to add new resources to our portfolio at a pace that is unprecedented for our system: our Preferred Plan (which is the term we use for the selected path forward resulting from the IRP analysis) includes nearly 8,000 MW of new resources in the Action Plan window and more than twice that over the 15-year planning horizon.

Our Preferred Plan reflects our current strategy to meet APS customers' increasing needs over the Planning Period based on the information available today, but we recognize that continuously changing conditions will require adaptation and evolution over time. Through annual updates to our demand forecast and frequent All-Source Request for Proposals (ASRFP), we will continue to seek out the most cost effective opportunities to meet those needs. While the information contained in our Plan will influence future resource acquisition decisions, our competitive ASRFP process ultimately determines which resources are procured.

FIGURE ES-1. TOTAL INSTALLED CAPACITY ACROSS THE PLANNING HORIZON IN THE PREFERRED PLAN



Throughout the process of developing this Plan, we sought input from key stakeholders, such as customer advocacy groups, developers, economic development organizations, and environmental advocates, through the Resource Planning Advisory Council (RPAC) and public stakeholder meetings. We held collaborative meetings where we shared progress updates on the IRP and related topics, sought feedback on our approaches to planning, and invited stakeholders and external consultants to provide viewpoints that helped us understand how our Plan fit into the context of changes across the broader electric utility industry. Also, for the first time, we shared modeling information with a subset of these stakeholders, giving them access to our data and software tools so they could run their own scenarios. This new level of engagement with stakeholders has led to meaningful improvements in our planning process, and we are deeply appreciative of the time they dedicated to this effort.

We have also continued to evolve our participation in wholesale energy markets. As a natural next step in market participation, we have been actively engaged in the development of two western day-ahead market constructs, which are intended to more efficiently forecast and align market needs and resources. By participating in both day-ahead market developments, we are able to compare and identify which will save our customers the most money while at the same time enhancing our access to reliable resources across the Western U.S. region. In concept, by centralizing participants' anticipated supply and demand information, the day-ahead market allows available resources to balance more effectively, resulting in improved economics, reliability, and carbon-intensity. For several years we have been involved in multiple efforts to shape and analyze the benefits of different market rules and structures. The creation of a day-ahead market provides additional benefits for our customers, especially when paired with additional transmission development, which drives reliability and affordability through increased access to regional diversity. Importantly, the potential development of a future day-ahead market does not displace the need for prudent planning or procurement of resources — which is essential to secure resource adequacy regardless of market developments.

PLANNING PRINCIPLES TO MEET THE CHALLENGES OF A CHANGING ARIZONA

ENSURE RELIABILITY

Providing reliable service, no matter the season or weather condition, is essential to our customers' health and welfare, as well as the Arizona economy. Businesses and families rely on APS every hour of every day, especially during the summer when energy is a matter of public safety and customers must be able to rely on energy to meet their cooling needs.

Historically, our system was designed to ensure sufficient resources were in place to meet peak customer demand — typically occurring on the hottest summer afternoons. But as resource types and customer energy usage evolves, so must our approach to planning. As the generation portfolio continues to evolve toward energy storage and additional renewables, the net peak will continue to shift later into the evening, indicating that resource planning will need to account for both the traditional load peak and the net load peak. APS must evaluate load needs "net" of renewable resources to identify remaining generation needs that must be met with dispatchable resources. These changes are shifting peak demand to other times of the day, most notably the evening hours when demand remains high while solar generation has dropped to zero. This phenomenon — that reliability risks will coincide with the "net peak" — has been widely recognized throughout the industry. It is the reason behind calls for reliability planning methods that can identify risks that may be present in all hours throughout the year. Our own methods, described in further detail below, use industry-leading software to ensure our portfolio has sufficient resources to always meet customer demand.

The challenges we face in planning a reliable portfolio are not unique to our system. According to the North American Electric Reliability Corporation's (NERC) most recent summer assessment, the combination of increasing frequency of extreme weather, growing loads, and retirements of aging resources has resulted in conditions of elevated reliability risk across many parts of the country. The presence of these conditions across the entire Western Interconnection makes our own reliability planning efforts even more important, as the lack of surplus resources has contributed to tight capacity and energy market conditions and extreme prices during recent summer heatwaves. In this environment, it is essential to ensure we have a resource portfolio capable of meeting our customers' energy needs with limited assistance from our neighbors.

MAINTAIN AFFORDABILITY

Affordability is a priority for us and our customers; therefore, minimizing unnecessary costs while ensuring reliability is a fundamental consideration in the decisions we make across the Company. In Resource Management, this includes joining the Western Energy Imbalance Market, which has provided over $375 million in benefits through Q2 2023, and has allowed us to purchase energy at negative prices from California; it is why we continue to actively explore opportunities to join a day-ahead market through the Western Markets Exploratory Group (WMEG); and it is why we use ASRFPs when we procure new resources — to ensure our customers have access to the most competitive pricing in the market. Affordability is also a fundamental guiding principle in our IRP process, which provides the long-term blueprint for a best-fit, least-cost portfolio.

The passage of the IRA one year ago provides a new opportunity to leverage federal tax credits for the benefit of our customers here in Arizona. Those tax credits are expected to materially impact the future costs of a wide range of clean energy resources. However, the impacts of these tax credits have not been fully realized in the industry so far: high demand, insufficient manufacturing facilities, and global supply chain issues have limited the impact on resource pricing that has been observed in competitive solicitations. Nonetheless, we explicitly incorporate these tax credits into our planning and will seek to take advantage of them where possible to mitigate the costs of new resource additions for our customers.

Prioritizing affordability also leads us to invest in a diverse, evolving energy portfolio. Resource diversity makes our system more resilient to the risks associated with any single technology or fuel source. Flexibility to respond to changing market conditions by absorbing negative priced energy when available and being able to reduce peak capacity needs through demand-side management (DSM) and demand response (DR) programs are vital components of a resilient resource mix. In general, we observe that access to high-capacity factor wind resources, especially those that provide overnight energy, greatly improves portfolio economics. Arizona has few of these regions and the development of large-scale transmission facilities will be necessary to access these high-capacity wind resources going forward. Resource Planning and Transmission Planning are actively engaged with these transmission possibilities and see this as a critical aspect of our resource plan.

SECURE A CLEAN, BALANCED ENERGY MIX

In 2022 we served customers' energy needs with 51% clean energy, which includes energy from nuclear, renewables, and DSM resources. We arrived at this energy mix through robust procurement processes, including our ASRFP, intended to deliver the most affordable and reliable resources available in the market. As our resource mix becomes cleaner into the future, we will follow the same approach.

Palo Verde Generating Station (Palo Verde) and its carbon-free generation are critical to meeting our clean energy goals affordably. The plant has been the nation's largest power producer of any kind for 31 years. As the heart of our generation fleet, Palo Verde provides the foundation for the reliable and affordable service counted on by customers in four Southwestern states. The plant's continued operation is vital to a clean, reliable, and affordable energy future for Arizona, as well as its ongoing contributions to the local economy. Nuclear power continuously produces a predictable, steady amount of carbon-free energy.

APS is rapidly increasing the amount of cost effective clean energy on our system. In addition to providing environmental benefits, utility-scale clean resources support system reliability and are the most affordable options available today, and over the long term provide the greatest value for customers. This has been demonstrated throughout the results of our frequent ASRFPs. Our Plan includes utility-scale solar and maintains continued uptake of rooftop solar as an important option for customers. In addition to depending on solar energy, we will further diversify our energy mix by investing in wind, energy storage, DR and DSM resources, including energy efficiency (EE) — all of which contribute to a cleaner energy future.

When contemplating APS's Clean Energy Commitment, which has a goal of 65% clean energy by 2030, there is an opportunity to pull forward additional renewable resources through the Green Power Partners Program. This program allows large customers to achieve their individual carbon reduction goals through the purchase of energy credits from these resources, while accelerating the APS transition to clean energy without cost shifts to other customers. By serving these large customer energy needs cost effectively, this program also drives further job-creating investments within APS's service territory.

PORTFOLIO DEVELOPMENT

New complexities have been introduced into our planning process as our industry transitions away from conventional baseload generators and towards a portfolio that is increasingly dependent on variable renewables and energy storage resources. Operational dynamics are changing, including:

- Periods of surplus renewable resources — largely during the middle of the day when solar output is the highest — that must be stored, sold, or curtailed
- Shifting reliability risks from the afternoon "gross peak" to the evening "net peak" after sundown, and the corresponding need for flexible natural gas and energy storage resources to meet that need
- Longer overnight stretches where firm capacity resources will be needed to ensure that we can serve customers reliably throughout all hours of the year

To allow our planning efforts to account for these evolving complexities and continue to align with industry best practices, we have integrated new models into our planning toolkit for this IRP. The models we use are directly linked to our planning objectives:

- To ensure that our portfolio can reliably meet our customers' needs across all hours of the year, we use the Strategic Energy and Risk Valuation Model (SERVM), a Resource Adequacy model developed and licensed by Astrapé Consulting. The need for detailed, chronological simulations of system operations across a wide range of conditions has been called for by experts throughout the industry, including Western Electricity Coordinating Council (WECC) and highlighted in the Energy System Integration Group's (ESIG's) Redefining Resource Adequacy whitepaper. Astrapé's SERVM tool is widely regarded as being one of the best in the industry, and the results obtained from this study account for the weather variations seen over the last decade, the lack of resource adequacy in the west, and the optimal dispatch of energy-limited resources to support system capacity needs.

- To create portfolios that maximize affordability, we have adopted Aurora, which includes both long-term capacity expansion (LTCE) and production cost modeling (PCM) capabilities. Aurora's LTCE functionality, which uses optimization to identify least-cost investments in new resources to meet reliability needs, is particularly important to ensure that the combination of resources we identify achieves these objectives at the lowest cost to our customers.

We use these tools to develop and analyze future resource portfolios under a range of different scenarios and assumptions that help us understand the implications of key decisions and the impacts of significant uncertainties. The scenarios we study in this IRP include:

- **Reference Case:** We begin our IRP analysis with a Reference Case that reflects our current commitments and incorporates the best available forecasts of load, technology costs, and commodity prices for the future. This Reference Case serves as a starting point for our IRP analysis; we study its outcomes and compare them against a range of alternative scenarios and sensitivities to discern what types of decisions will best serve our customers' needs and preferences (notably, the Reference Case is not the Preferred Plan).
- **Commission Required Portfolios:** This collection of portfolios demonstrates resource selections associated with minimal load growth, as well as rapid adoption of DSM and DR programs. A technology agnostic portfolio is provided as well, which is the least-cost method of serving customer load absent any voluntary commitments.
- **Four Corners Exit Scenarios (2027-2030):** These cases are also required by the Commission and are provided as a hypothetical look at the resource mix and costs associated with the earlier exit from Four Corners. APS does not support the earlier exit from Four Corners due to reliability concerns associated with the transition to newer, nascent technologies, as well as the lack of sufficient excess capacity resources in the west. These cases leverage additional renewables and natural gas facilities and are heavily dependent on both transmission and natural gas availability, as well as project execution. In each case, the development timeframes needed for new generation resources, along with the necessary fuel delivery and electricity transmission infrastructure associated with those resources, very likely would not allow for an earlier exit from Four Corners prior to 2031.
- **Additional Strategic Portfolios:** These portfolios show the impact of different input assumptions, with changing gas prices and renewable technology costs. These portfolios demonstrate the durability of resource decisions under a broad subset of future scenarios.
- **Preferred Plan:** This portfolio continues to leverage renewable energy, additional hydrogen-capable natural gas units, and maintains our exit from Four Corners in 2031, which is necessary for reliable service. The resource mix is durable to changing market conditions and provides diversity and flexibility to respond to future events. This portfolio also defines the Action Plan resources and is our strategy for 2023-2027. This portfolio is our preferred plan because it optimizes ensuring reliability, maintaining affordability, and securing a clean and balanced energy mix for our customers.

OUR PREFERRED PLAN: STAYING AHEAD OF ENERGY DEMANDS

Our analysis culminates in the creation of a Preferred Plan, a portfolio that spans the 15 years of our planning horizon. In this process, we arrive at a Preferred Plan after analyzing a range of different scenarios and sensitivities, synthesizing learnings and findings across those analyses to understand how we can best meet our customers' needs. Based on those analyses, we have constructed a Preferred Plan that incorporates actions that our analyses demonstrate produce least-cost, reliable outcomes.

INVEST IN NEW HYDROGEN-CAPABLE NATURAL GAS GENERATION TO ENSURE RELIABILITY

Our analysis demonstrates that hydrogen-capable natural gas combustion turbines (CTs) are complementary to renewables and storage in a least-cost portfolio. Even as we add renewables and storage, we will continue to need resources that are capable of reliably meeting demand throughout the overnight period — especially with the retirement of Cholla and our exit from Four Corners. Because of their relatively low capital costs, natural gas facilities provide a low-cost option to meet a share of our future capacity needs.

Prioritizing customer affordability is a core principle of the IRP process. Our impending retirement or exit of baseload coal facilities, such as Cholla and Four Corners, leaves significant gaps in both total energy produced and reliable summertime capacity. Quick-start, hydrogen-capable, natural gas resources provide flexibility and could potentially be sited where existing coal generation is located, providing benefits to the local economy and cost savings to customers by reusing existing infrastructure.

Along with its affordability, natural gas is a source of reliable system capacity that will allow us to transition to cost effective renewable resources while maintaining a reliable safety net for our customers should any new resource projects be delayed. Natural gas will help us to negotiate the best possible prices for new resources by providing flexibility in renewable and clean peaking capacity timing.

INVEST IN RENEWABLES AND STORAGE TO SERVE NEAR-TERM GROWTH

Our Plan demonstrates that investment in additional renewable energy is a cost effective means to meeting customer needs. Capitalizing on opportunities for new renewable resources will require complementary investments in transmission infrastructure. Our Preferred Plan includes significant quantities of New Mexico wind, delivered to APS loads via a combination of new transmission and the repurposing of existing transmission after the exit from Four Corners.

Utility-scale energy storage is an essential piece of our future resource mix and an area that we have invested heavily in, with over 2 gigawatts (GW) of planned battery additions during the Action Plan period. Storage technologies will help us use regional excess solar generation that is frequently available at low, zero, and even negative prices. We remain dedicated to a responsible adoption and integration of this nascent technology, and have committed to a maximum of 3 GW of battery energy storage through 2027. We will continually evaluate this cap as more industry experience with the technology is gained.

PREPARE FOR EXIT FROM FOUR CORNERS IN 2031

We remain committed to exiting from Four Corners in 2031. Analysis in this IRP shows that APS's Preferred Plan produces much greater cost savings than any of the resource portfolios studied in the scenarios evaluating an earlier exit from Four Corners (i.e., in years 2027 through 2030). Additionally, as noted above, we cannot responsibly support the early exit from Four Corners due to reliability concerns associated with the transition to newer, nascent technologies, as well as the lack of sufficient excess capacity resources in the Western United States and sufficient electricity transmission infrastructure needed to deliver replacement resource capacity to APS's service territory. Due to the large amount of both capacity and energy provided by the Four Corners facility, it is prudent to invest in replacement resources early to guarantee their reliability prior to exiting from the plant.

We are, nonetheless, committed to continuing to study the economics of continued operation of Four Corners in the years prior to 2031. There are many factors that impact unit economics, such as coal contract pricing and damages, pricing of alternative fuels, future environmental regulations, availability of replacement resources, and sufficient transmission infrastructure to deliver remote generation to load. We will continue to evaluate opportunities to create cost savings in our resource mix, while at the same time ensure resource adequacy for a reliable grid. We look to optimize our resource mix to bring the most benefit to customers while ensuring reliability and a responsible transition to other resource types.

LEVERAGE PALO VERDE TO MANAGE COSTS

Palo Verde and its carbon-free generation are critical to ensuring reliable service for the long term at an affordable value. The plant's continued operation is vital to a clean, reliable, and affordable energy future for Arizona, in addition to being a significant contributor to the local economy. Nuclear power provides certain climate and grid resiliency advantages over other energy sources, and continuously produces a predictable, steady amount of carbon-free energy.

OUR ACTION PLAN: POWERING HOMES AND BUSINESSES

Our Action Plan focuses on near-term developments, has more certainty over the next four- to five-year window, and is intended to offer a view into potential resource needs and decisions through 2027 that continue to support reliable electricity service to a growing customer base. We will update this Action Plan as needed with additional details, including the results of outstanding and proposed ASRFPs.

The immediate path ahead is clear: **continued investment in affordable renewable technologies, utility-scale battery energy storage, and additional hydrogen-capable natural gas facilities to provide necessary peaking and overnight load support**. Going forward, a key part of our plan will be to partner with customers on EE measures, DR programs, and microgrid projects. Combining all of these resources will support the rapid load growth we are experiencing in Arizona and will continue to provide a diverse resource portfolio.

At the same time, the looming changes to our portfolio just beyond the Action Plan window — and the long lead times associated with some of those changes — requires advanced planning. That's why our Action Plan also includes activities that will help us prepare for the next phase of the transition of our portfolio.

FREQUENT ALL-SOURCE RFPS TO PROCURE LEAST-COST RESOURCES

As discussed above, our Preferred Plan identifies the need and commitment to add significant amounts of new renewable and energy storage resources to our generation mix, with some incremental hydrogen capable natural gas generation included, to provide dispatchable, fast ramping flexibility to the grid. Currently, we plan to frequently release ASRFPs to solicit the market for both capacity and energy resources. This approach to resource procurement allows us to understand industry pricing and trends at a deeper level, and establish long-term partnerships with developers who have proven their ability to deliver on projects within budget and on schedule. However, given the uncertainty inherent in future resource and commodity prices, we will keep stakeholders informed about updates to our plans or future forecasts through stakeholder meetings and Action Plan updates.

The 2023 ASRFP seeks at least 1,000 MW of resources, with 700 MW expected to be coming from renewable resources. Projects signed from this ASRFP will support our Action Plan in this IRP. We will keep stakeholders informed about the results of this ASRFP, as well as the project types and sizes that are signed from this solicitation.

COORDINATION WITH TRANSMISSION PLANNING EFFORTS

With approximately 1.4 million customers across the state depending on us for reliable and affordable energy, we rely on our network of transmission and distribution lines to safely deliver power. In planning the future development of our transmission infrastructure, we consider a broad range of technologies, including generation, transmission and distribution resources, and non-transmission alternatives to address the challenges of an increasing array of resource types and geographies.

The 2023-2032 Ten-Year Transmission System Plan includes approximately 29 miles of 500 kilovolt (kV) transmission lines, one mile of new 345kV transmission line, 54 miles of new 230kV transmission lines, 11.5 miles of underground 230kV upgrades, 40 miles of 230kV transmission line rebuilds, and three miles of 115kV transmission line upgrades. We project that significant additional transmission will be required to provide access to renewable energy, especially high-capacity factor wind projects that are not located within Arizona.

In addition to the transmission planning efforts being performed internally, we have opened our ASRFP solicitation to include transmission projects, which better inform existing transmission development in the west and pricing associated with external projects. These projects also bring the opportunity to partner with other utilities to share resource cost and reduce risk.

MOVING FORWARD

Understanding the changes that are impacting our state and our industry, and looking ahead to those changes yet to come, our Plan will reliably serve our existing customers and robust forecasted growth within Arizona.

We have leveraged industry-leading consultants and tools in the development of this IRP and are confident the resources identified in the Action Plan will support reliability and affordability for our customers. We recognize the value of collaboration, and have met with the RPAC, our external stakeholder group, extensively in the years since our 2020 IRP, including sharing modeling information with them. It is our goal to provide a transparent, rigorous, and detailed strategy to navigate the challenges ahead.

There are many challenges in front of us, including coal plant retirements, expiring power purchase agreements, and robust customer growth. We continue to focus on procuring sufficient resources to provide reliable capacity and energy to our customers during the Action Plan window from 2023-2027. We are continually evaluating the replacement resources necessary to backfill our exit from coal generation; and we will leverage the marketplace, industry partnerships, and feedback from our community stakeholders as we transition to cleaner, cost effective resources, meeting the demands of our customers in a changing world — and a state that is transforming dramatically. Arizona's energy future is bright, and we value the opportunity to "power ahead" with all of you — our regulators, our stakeholders, our communities, and, above all, our customers.

CHAPTER 1

PLANNING FOR THE FUTURE

IRP PLANNING PROCESS

In alignment with the APS Promise, this Integrated Resource Plan (IRP) focuses on identifying a resource mix that is resilient to many potential futures and ensures the delivery of reliable, affordable, and increasingly clean energy to our customers.

This IRP includes a variety of portfolios to better understand the rapidly changing circumstances at the local state, federal and global levels. To provide technical guidance and insight throughout this process, APS leveraged external consultants Energy and Environmental Economics (E3) and Astrapé Consulting. APS also engaged with and incorporated feedback from a diversified group of external stakeholders including members of the Resource Planning Advisory Council (RPAC). Unique to this IRP process, APS provided interested stakeholders training on and access to the IRP modeling software and data, which allowed stakeholders to run their own scenarios for the first time. In short, this IRP is the culmination of a robust and transparent stakeholder engagement process that delivered meaningful benefits to all participants and provided a shared value solution.

COLLABORATION IS FUNDAMENTAL TO SUCCESS

Collaboration with stakeholders is integral to the development of the IRP, and APS engaged with several stakeholder groups throughout the development of the IRP. Examples of these partnering opportunities include monthly RPAC meetings, topic-specific workshops, meetings with individual RPAC members, and public stakeholder meetings in April and September 2023. The RPAC consists of members who represent a wide range of stakeholder groups, such as residential and large commercial and industrial customers, environmental organizations, customer advocates, and resource project developers. Since 2021, the Company has hosted more than 20 engagements with RPAC members. Presentations and summaries from the monthly RPAC meetings are publicly available on the APS website at aps.com/resources. APS also involved stakeholders in resource procurement decisions (through the Request for Proposals (RFP) processes) and the development of load forecasts, resource technology costs, and commercial availability timelines. To maximize the value of this stakeholder collaboration, APS enlisted leading utility industry consultants, such as E3 and 1898 & Co., to provide regional perspectives, enhanced stakeholder education, and meeting logistics and moderation.

Resource Planning Approach

The IRP begins by evaluating forecasted customer demand and energy usage over the 15-year planning horizon. Demand is measured in megawatts (MW) and is the amount of power being consumed at any given instant, while energy is measured in megawatt-hours (MWh) and represents an amount of power consumed over time. Both are important considerations in the IRP. The IRP is a planning tool used to demonstrate that sufficient resources will be in place to reliably serve future system demand and energy. These resources include capacity and energy market purchases, customer-sited resources, and utility-scale generation. When evaluating sufficiency from a demand standpoint, APS is not only required to maintain resources that meet the expected seasonal peak demand, but also enough reserve capacity to ensure sufficient reliability is maintained under various unplanned system conditions. These conditions include combinations of load, weather, intermittent resource output, and planned or unplanned generation facility outages. Generation reserves are captured in the system Planning Reserve Margin (PRM), which at a minimum is established every three years during the development of the IRP. While APS IRPs have historically focused on meeting peak summer demand, as the resources across the Western U.S. region become increasingly constrained and the resource mix increasingly shifts toward intermittent (or variable) renewable generation, it is necessary to ensure sufficient capacity is available to meet demand in all hours of the year.

One of the first steps in developing an economic and reliable resource mix is determining the anticipated level of capacity required. Once a base level of capacity is determined, alternative portfolios can be developed. Portfolios are the least cost combination of different resource types that maintain reliability. Once portfolios are identified for all scenarios being studied, they are then comparatively evaluated against a common set of near-term metrics, to identify the most resilient resources for inclusion in our 2023-2027 five-year Action Plan. The Aurora Long-Term Capacity Expansion (LTCE) and Production Cost Model (PCM) modules were leveraged heavily throughout this process to compare scenario outcomes.

RELIABILITY

Foundational to each resource plan is maintaining reliable electric service for all customers. APS adopted the Loss of Load Expectation (LOLE) reliability target of one day in ten years as the minimum threshold of resource adequacy across all scenarios studied. LOLE is widely used across the electric utility industry as a core reliability metric. APS leveraged Astrapé Consulting and their industry leading SERVM software platform to conduct a rigorous resource adequacy study to establish the required Planning Reserve Margin (PRM) needed to meet this targeted reliability metric. The study used modes of analysis based on randomly determined data sets to capture the intermittent nature of variable energy resources and inherent variability of demand, as well as the operational performance uncertainty of conventional resources. The suite of factors considered include asymmetry, variability, and correlation of conventional resource outages; interaction between various renewable and energy-limited resources; energy market liquidity; and weather-impacted stochastically treated load patterns. The resource adequacy study resulted in a recommended Installed Capacity (ICAP) PRM of 20.2 %, which is an increase of about 5% from APS's current ICAP PRM of 15%.

Additionally, the Astrapé study helped inform and establish a PRM using the superior Perfect Capacity (PCAP) accounting methodology, which is more efficient, equitable in its treatment of different resources, and unaffected by changes in the portfolio resource mix for a given load pattern. In comparison, the traditional ICAP and Unforced Capacity (UCAP) methodologies only use proxies for conventional resource perfect capacity. For these reasons, beginning in 2026, APS is adopting a PCAP PRM of 6.9%, which is equivalent to the ICAP PRM of 20.2%.

REGIONAL MARKETS

APS currently participates in the Western Energy Imbalance Market (WEIM) operated by the California Independent System Operator (CAISO). Since joining the WEIM in 2016, APS customers have realized $375M in savings due to increased efficiency of the regional market dispatch. APS supports the expansion of wholesale energy markets in the Western U.S. region as a way to increase reliability and mitigate customer costs through improved regional integration of resources. APS has been actively engaged for several years in the development of two western day ahead market constructs and is involved in multiple efforts to shape and analyze the benefits of different market rules and structures. The creation of a day-ahead market can enable additional benefits for customers, and it is critical that these markets have independent governance and that all participating entities operate on an equal footing. APS is committed to exploring additional market participation steps up to and including participation in a Regional Transmission Organization (RTO), provided it meets our three goals: 1) reliability, 2) customer cost savings, and 3) clean energy integration. APS is participating in several efforts to advance reliability and market activity in the Western U.S. region. In fact, APS is a recognized leader and has a significant presence in all of these efforts.

WESTERN MARKETS EXPLORATORY GROUP

APS was one of seven founding participants in the Western Markets Exploratory Group (WMEG), which was created specifically to study the benefits of taking additional steps forward in market participation. The WMEG grew to 25 entities across the Western U.S. region, comprising approximately 95GW of peak load. To inform future market participation decisions, the group studied the benefits of different steps that could be taken in the market and did a cost benefit study that looked at future market opportunities, footprints, and timing.

The WMEG completed study work that quantifies the production cost benefits of several different potential market footprints in the Western U.S. region operated by differing market operators. Broadly, this study shows benefits for APS to participate in a future day ahead market and that, even in a western multi-market scenario, APS and its customers can benefit. Additional details can be found in the public report and supplemental information provided in Appendix A and B.

WESTERN RESOURCE ADEQUACY PROGRAM

The Western Resource Adequacy Program (WRAP) is an effort across much of the western interconnection to establish consistent and measurable resource adequacy through a reliability planning and compliance program that holds entities who participate to equal standards of reliability. This program is foundational to supporting a regional electricity marketplace that maintains resource adequacy while reducing the total amount of generation resources necessary to support electricity needs across a broader footprint. The WRAP tariff was approved by the Federal Energy Regulatory Commission (FERC) in the spring of 2023. As of April 2023, APS and 21 other utilities, from across the Northwest, Desert Southwest, Canada, and Northern California have committed to the program. APS is currently a fully participating member of the non-binding program and has opted to join the binding program in the Summer 2026.

DAY-AHEAD MARKET PARTICIPATION

APS is currently evaluating two day-ahead market options. APS is participating in the creation of and supporting the efforts of both the CAISO extended day-ahead market (EDAM) and the Southwest Power Pool (SPP) Markets+ day-ahead market options. The selection of one of these day-ahead options would also require participation in that same market's real-time market. It is important for APS and others in the Western U.S. region to have multiple options when it comes to markets as many factors impact the long-term outcomes for customers. Governance, resource adequacy, transmission utilization, congestion revenues, as well as the load and resource diversity of participating entities (market footprints), all come into play in determining the best way to meet the needs of our customers in the future.

TREATMENT OF WESTERN MARKETS IN THE 2023 IRP

Due to the uncertainties and unknowns associated with Western Market programs and options, the timing of participation in these markets, and the possibility of broad changes to market design, APS does not include day-ahead market participation or WRAP requirements within the quantitative portion of our analysis in this IRP. As potential day-ahead market structures become more certain, APS will be able to estimate the cost impacts in future IRPs from different programs and options. In the interim, APS does model access to regional resources and the ability to purchase energy in both its reliability and production cost modeling. Both of these models are limited in the amount of resources they can purchase from the marketplace, which accurately reflects the current lack of surplus firm resources in the Western U.S. region.

TECHNOLOGY

Generation technologies are rapidly developing to support increased energy demand and the transition from traditional thermal generation resources that have been in operation since the 1960s or 1970s and are approaching the end of their useful lives. APS has included technologies that are available today, such as battery energy storage, wind, solar, combustion turbines, and demand side programs in the modeling to develop future resource portfolios. Nascent technologies such as advanced nuclear and Small Modular Reactors (SMRs) that are not yet available at scale but continue to attract significant investment are likely to become available within the IRP planning period. Technologies that are heavily dependent on geological formations, such as pumped storage hydropower and compressed air energy storage are also included, though APS recognizes the inherent challenges of developing some of these resources and that cost estimates may vary widely due to project specific factors. Finally, resources that rely on partnerships with large commercial or industrial customers, such as microgrids, biomass, and biogas are included, but with costs that reflect the full amount of the resource to account for execution uncertainty.

FUTURE & UNCERTAINTIES

The goal of the IRP is to establish a resource portfolio that is resilient to a number of future uncertainties. Cases have been developed to recognize the impact of input price volatility in key areas, such as renewable resource costs and natural gas prices, which help demonstrate the resilience of resource decisions. Further, it is important to note that there are numerous factors that are not well quantified in our stochastic modeling, such as the benefit of standardization across a particular resource type, or the diversification of risk associated with a particular technology, that require the Company to exercise judgement on each specific project. As such, resource selections from this analysis should not be viewed as binding. APS will continue to evaluate individual resource selections with the latest available information and economic outlook.

Sustainability

APS's vision is to create a sustainable energy future for Arizona. APS creates value for its customers and for Arizona when it provides reliable electricity to its customers, at an affordable price, and while adding cost-effective, increasingly clean resources. APS engages with a host of internal and external stakeholders as it continues to pursue the most cost-effective balance of reliable, affordable, and clean resources, including consumer advocates, environmental groups, community members, regulators, legislators, academics, and others.

ACHIEVING SHARED VALUE

Reliability: Reliability is a cornerstone of APS service. As the largest utility in Arizona, the company is proud that Arizona is among the best performing states in regard to frequency and duration of power outages and electrical downtime. Achieving this outcome is the product of hard work, as it requires APS to manage multiple and often interdependent factors, including:

1. Substantial load growth
2. Extreme weather events
3. Resource adequacy
4. Dynamic resource changes, including facility retirements and integration of intermittent renewables
5. A shifting and more dramatic net peak
6. Regional resource constraints
7. Transmission constraints

While the Arizona grid is robust, the stakes for failure are high. Conditions that create extended outages, especially during the extreme heat in the southwestern desert, could result in catastrophic public health consequences. Reliability is a shared value between society and APS.

APS's overarching strategy to achieve long term reliability is to maintain a balanced and diverse portfolio of generation resources; simultaneously procure new resources, including clean-energy generation and storage technologies; and continue to explore opportunities to partner with others through western regional market integration to meet critical resource needs.

Affordability: Affordability also is a shared value between society and APS. If APS customers are unable to afford the cost of their electricity, they will experience unreliable electricity service. APS regularly seeks the lowest cost solutions for customers, including market-driven solutions, flexibility, and attracting new business to grow our state's economy to maximize resources and help keep costs down for APS customers.

Supporting customers' increasing energy needs requires new resources. In 2022 and 2023, APS engaged in All-Source RFP processes to identify the most cost competitive resources to meet customers' needs. Renewable and energy storage resources have already proven to be cost effective, and federal incentives like the 2022 Inflation Reduction Act are expected to maintain or improve the cost-competitiveness of these resources. As a result, APS expects to continue further investments in renewable energy and clean energy technologies, while also maintaining affordability of electricity.

Clean Energy: Investing in clean energy provides a balanced and diverse energy portfolio as we make a deliberate and responsible transition to a clean, secure energy future to meet Arizona's growing energy demand. Through competitive procurement, clean resources are among the most affordable options available today, and over the long term, they provide the greatest value as part of a diverse energy mix backed by dispatchable resources. These resources can help reduce price volatility and variable costs experienced with other generation fuel sources and leverage tax benefits to reduce overall investment costs.

Consistent with these overall trends in the energy market, APS has committed to being 100% clean and carbon free by 2050. This commitment is supported by interim goals of achieving a resource mix that is 65% clean energy, with 45% of our generation portfolio coming from renewable energy, by 2030, and a plan to exit from coal-fired generation in 2031. It takes time to plan, procure, and integrate new resources to make progress on these goals, while not sacrificing on reliable and affordable energy to meet our customers' needs. As of 2022, 51% of APS's resource mix is clean, and total carbon dioxide emissions have been reduced by 24% since 2005.

Going forward, a deliberate and responsible transition to a clean energy future requires balanced investments in multiple resource types that account for both reliability and affordability. Doing so will both contribute to a cleaner energy future for Arizona and ensure reliable and affordable service to customers.

CHAPTER 2

ASSESSING NEEDS AND RESOURCES

LOAD FORECAST

Arizona has experienced rapid growth in the three years since the Company's 2020 Integrated Resource Plan (IRP) was filed. There has been investment in many sectors within Arizona, especially in manufacturing, data centers, and health care. Arizona's population continues to grow, especially in Maricopa County, which has been the county with the highest annual population gains in the United States since 2016. These macroeconomic forces are the fundamental drivers of the Company's projections for load growth into the future. APS will continue to communicate updates to its load forecast, as well as changes in the economic environment, to the Arizona Corporation Commission (ACC or Commission) and the Resource Planning Advisory Council (RPAC).

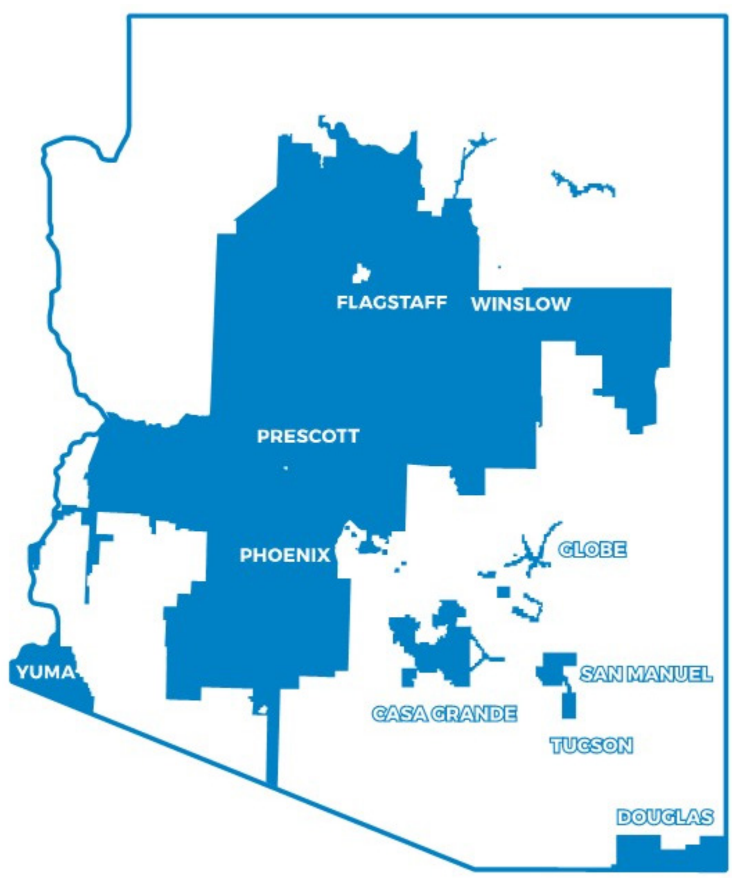
APS is the largest and longest-serving electric public service company in Arizona, with operations dating back 137 years. Today, APS provides electricity to approximately 1.4 million customers in 11 of Arizona's 15 counties, with a diverse energy portfolio totaling more than 10,000 MW, including purchased power agreements and customer-based resources, and more than 38,000 miles of transmission and distribution lines.

The APS load forecast provides a basis for both supply and demand-side resource additions into the future. The forecast is long-term in nature, however the most important period to consider is the near-term view as it will guide decisions that must be made over the Action Plan window, 2023-2027. The longer-term forecast is important to develop a long-term strategy and directional resource targets, but those items have the benefit of being updated over time and in subsequent IRPs when outer years become near-term and actionable.

During the IRP Planning Period of 2023-2038, APS projects that annual peak demand and energy needs will increase at compounded annual growth rates of 2.4% and 3.7%, respectively, which is inclusive of distributed generation and Demand-Side Management (DSM)/energy efficiency (EE). The growth over the Planning Period equates to approximately 3,400 MW of capacity needs or nearly 230 MW annually, on average. Energy needs are also expected to grow approximately 23,700 GWh, but the transformation of customers' usage and resource mix will change significantly over the same period. For the Action Plan window, APS expects total load requirements to grow by over 1,300 MW after the impacts of EE and Distributed Energy (DE), which will require new resource additions that are evaluated in subsequent chapters of the IRP.

Projected growth in the APS service territory is driven by three major factors: data center growth, large industrial customer growth, and electric vehicle adoption. Those variables are a result of favorable attributes such as the climate, statewide amenities, a positive business environment, technological focused development, and a relatively low cost of living.

FIGURE 2-1. APS SERVICE TERRITORY MAP

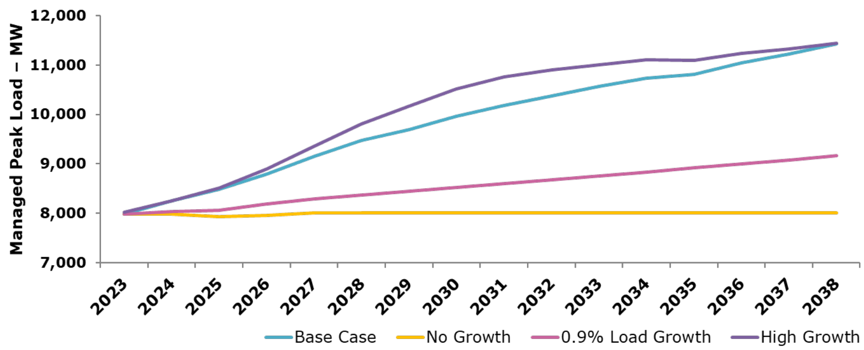


Load Forecast Update and Evaluation

Forecasting load is a foundational component of an IRP, fundamental to analyzing not only how many resources the Company needs and when, but to an increasing degree, the type of resources needed. Weather, population growth, economic activity, and energy consumption patterns all play a role in determining future energy demand, and each is subject to variability, producing actual results that may vary from original projections. Also important is evaluating how those variables interact over the course of both the near-term view (Action Plan window) and a 15-year period (Planning Period). Although future unknowns cannot be removed from the forecasting process, APS's robust forecasting methodologies are structured to address uncertainty over the Planning Period.

LOAD GROWTH FORECAST

FIGURE 2-2. LOAD SENSITIVITIES



Future resource requirements are calculated based on a peak consumption hour growth rate under four scenarios — a base assumption, a high load forecast scenario, a forecast growth rate of 0.9%, and no growth or 0%,[1] and are shown in Figure 2-2. The base assumption is that peak load growth, after customer resources including DSM/EE and distributed energy resources (DER), is expected to average approximately 2.4% annually over the next 15 years and result in a peak load increase of about 3,400 MW or 230 MW annually. Under the high load forecast scenario, peak demand growth is similar to the base assumption over the Planning Period; however, much of the growth in the high load scenario occurs earlier than under the base forecast. Under a forecast growth rate of 0.9%, peak demand growth averages approximately 80 MW annually or approximately a 1,200 MW increase over the Planning Period. Finally, zero growth does not require any additional resources related to peak load growth.

FORECAST ENERGY DRIVERS

ENERGY GROWTH SUMMARY

The main driver of energy growth for the Planning Period is the growth of new data centers and large industrial and manufacturing customers. Electric vehicle charging is also expected to be a key growth driver. Additionally, traditional drivers such as population and economic growth, and the resulting increase in residential customers and commercial and industrial (C&I) employment levels, will continue to support energy growth in the future. Average residential usage is expected to decrease slightly, which is driven by home product efficiencies and the impacts of DER and DSM/EE programs. Overall, total residential energy is expected to grow because the positive impact of customer growth in APS's service territory outweighs the expected decline in average residential usage. Similarly, C&I is expected to see a reduction in intensity for existing customers, but new customer additions are expected to drive energy requirements. A further discussion of the main components driving energy growth is developed below.

TABLE 2-1. SOURCES OF ENERGY GROWTH 2023-2038

COMPONENT	GWH
New Data Centers	12,997
Large Industrial & Manufacturing	5,843
Electric Vehicles	3,406
C&I	785
Residential	657
TOTAL GROWTH	**23,689**

**Numbers in table have been rounded for ease of presentation.*

1 Required under Decision No. 76632 (March 29, 2018).

DATA CENTERS AND LARGE INDUSTRIAL CUSTOMERS

Data centers and large industrial customers are attracted to the APS service territory because of the dry climate and limited risk of natural disasters, as well as the Company's competitive rates, customer service, reliability, and commitment to an increasingly cleaner energy mix. In addition to high levels of expected growth from data center customers, there has also been a surge in expected energy growth due to large industrial companies, particularly in the semiconductor chip manufacturing industry, including its supply chain, as well as the hydrogen production industry. While the dramatic influx of data center and large industrial customers can provide economic benefits to Arizona, the volume and total energy demand of these requests pose challenges during periods of time when generation resources are already limited. These large new customers can also cause planning challenges due to the possibility that a customer may be delayed in their start date or may ramp more quickly or more slowly than expected. APS is committed to serving these customers while maintaining reliability and affordability for everyone within the Company's service territory.

Several companies are planning data center and large industrial locations in APS's service territory, and many sites have already started taking power or are currently under construction. While there is some uncertainty regarding the rate of growth, APS projects annual peak demand and energy needs will grow 1,550 MW and 13,000 GWh, respectively, due to data center load, and will grow 690 MW and 5,800 GWh, respectively, due to large industrial load during the IRP Planning Period of 2023-2038.

ELECTRIC VEHICLES

As electric vehicle (EV) adoption rates continue to increase, APS expects the EV market share of new vehicles sold to steadily increase. The transition to electric mobility serves an important role in reducing emissions from the transportation sector and improving air quality in Arizona. To better understand this transition, and based on stakeholder feedback in our IRP process, APS retained Guidehouse to study anticipated EV adoption and energy impacts in APS's service territory. The Company has adopted a forecast that projects the addition of over 1 million EVs during the Planning Period, which equates to approximately 490 MW of capacity needs and 3,400 GWh of energy requirements. Compared to the 2020 IRP Planning Period, this forecast update represents increases of 780,000 EVs, 310 MW of capacity needs, and 2,100 GWh of energy requirements, which reflect the impacts of increasing customer demand for EVs, new EV model availability, improving incentives, and policy changes since the prior IRP. With the rapid development of EV adoption and ever-changing EV legislation, APS recognizes the importance of continuously updating its assumptions. The Company will continue to work with industry experts to improve its EV forecast as it monitors the pace and scale of EV adoption amongst its customers and within the state.

POPULATION AND ECONOMIC ACTIVITY

Although growth in residential customers and traditional C&I customer growth no longer account for as large a share of total expected energy needs as in prior IRPs, they remain important drivers of peak and energy needs through the Planning Period.

Population growth is an important variable in developing the APS load forecast, providing the basis for several other forecast components, such as growth in households and residential customers. Population growth is also a key driver of increased economic activity in the state and the APS service territory. For Arizona, APS projects an average annual population growth rate of 1.3% for the Planning Period, largely driven by strong migration rates.

As a result of the population growth and higher levels of economic activity, the Company expects to add about 20,000-23,000 residential customers annually in the near-term. For the 2023-2038 Planning Period, APS anticipates adding 320,000 residential customers (1.6% annual growth, on average).

DEMAND-SIDE MANAGEMENT

Customers are increasingly interested in managing their own energy consumption, whether passively or actively. APS's current portfolio of DSM programs provides opportunities for customers to save energy, reduce peak demand, and shift their energy use to off-peak hours within a wide range of customer segments and energy end uses.

The 2023 DSM Plan filing reflects the Company's and its customers' ongoing commitment to cost-effective DSM measures, and increases investment into measures such as traditional EE, load shifting, demand response (DR), and education. The focus is simple: help customers save money while contributing to a cleaner system and reducing peak demand. By focusing efforts to shift customer energy usage from high demand hours to parts of the day where resources are more plentiful, the Company can save customers money and further support the efficient operation of the grid.

Moving forward, APS is expanding flexible DSM capacity with customers. This is happening while ongoing changes in the market for DSM technologies are beginning to limit the future EE opportunities that are available to pursue cost effectively. These changes include increases to baseline efficiency levels as a result of higher building codes and appliance standards (most notably, Energy Independence and Security Act of 2007 (EISA) lighting standards that increase the baseline to an LED bulb for most residential general service lighting applications); increased saturation of cost effective DSM measures such as smart thermostats over time; the need to pay incentives that cover a higher percentage of customer incremental technology costs in order to attract additional participation; and the need for higher education and outreach costs to engage harder-to-reach customer segments. In addition, there is increased risk of not being able to achieve annual savings targets as numbers push closer to the maximum achievable potential (particularly as efficient electric loads such as EVs and data centers are added to the APS system), which does not offer significant EE savings potential.

DISTRIBUTED GENERATION/ROOFTOP SOLAR

Installation of private DER, such as rooftop photovoltaic (PV) solar, is expected to continue at a strong pace in APS's service territory. Nationally, Arizona ranks fifth for most cumulative residential solar capacity installed. APS is one of the few utilities that has added more than 100 MW of residential solar energy for each of the past three years.[2] APS expects the pace of customer-sited solar installations to average more than 100 MW of capacity added annually. As the amount of DER installed in APS's service territory continues to increase, APS will be required to purchase increasing amounts of solar production that is not self-consumed by customers. However, peak savings from additional rooftop solar are relatively small and declining, as rooftop solar capacity contributions during peak evening hours are low and the APS system peak continues to shift to hours later in the evening.

LOAD FORECAST RISKS

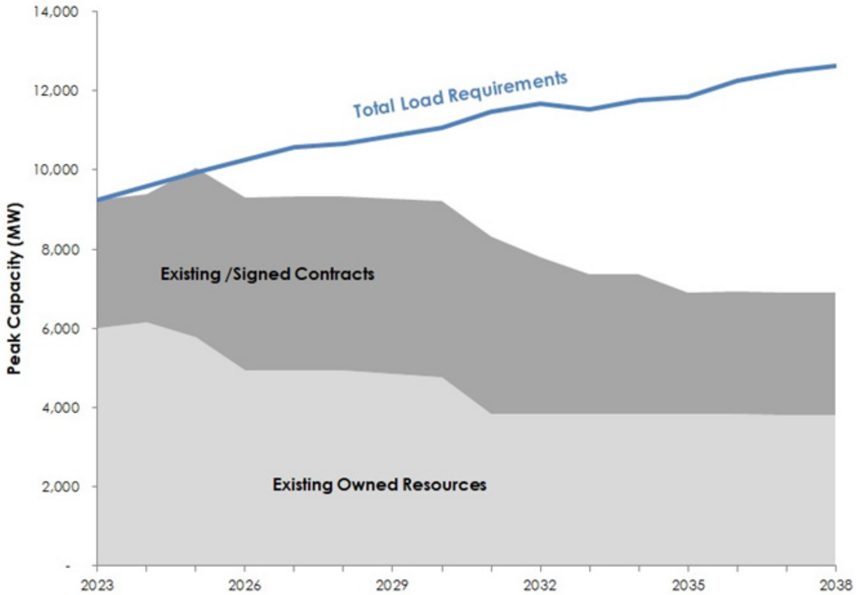
Growth of data centers and large industrial and manufacturing customers are the primary drivers of the forecasted energy growth, and therefore pose the greatest uncertainty to the forecast. Risks to data center and large customer growth include potential delays in customer start dates and the pace at which customers ramp-up energy usage to their expected level of demand. To mitigate some of this risk, APS benchmarked with other utilities that have significant data center load growth on forecasting assumptions and applied a discount to load ramps on a probabilistic basis. EV adoption is also a key driver of forecasted energy growth, and the rate of actual adoption may differ from the forecast. Population and economic growth are also forecast drivers that are subject to uncertainty; however, the fundamentals of the Arizona economy are resilient and the long–term outlook remains strong. Finally, additional risks to the forecast include changes in residential usage and C&I intensity, which could be driven by several factors: the pace of new DER installations, higher or lower levels of DSM programs, or new legislation on building codes or appliance standards.

2 Solar Energy Industries Association (SEIA). *Arizona Solar*. https://www.seia.org/state-solar-policy/arizona-solar

MEETING FUTURE NEEDS

APS will meet future energy demand by using current and new resource technologies that balance reliability and affordability while becoming increasingly clean. Even with current forecasts that show additional customer on-peak resources of more than 750 MW of distributed solar generation and 1,300 MW of EE by 2038, APS still expects a reliability need of nearly 8,000 MW to meet peak load requirements over this period. Approximately half of that need is driven by load growth, and the other half by plant retirements and expiring purchase power contracts.

FIGURE 2-3. SUPPLY-DEMAND GAP (2023–2038)



Meeting future needs will require APS to:

- Ensure reliability
- Maintain affordability
- Secure a clean, balanced energy supply for Arizona

The Company continues to invest heavily in renewable technologies, and has acquired more than 2,000 MW of resources from the 2020 and 2022 All-Source Request for Proposals (ASRFPs) combined. This chapter describes technologies that are commercially available at scale today or can reasonably be expected to become so in the near future, though it is not possible to predict emerging technologies that may be available in the longer term. APS will collaborate with stakeholders including universities, policymakers, and potential suppliers to drive development of technologies that will enable the Company to meet its long-term goals. APS is technology neutral and ultimately will choose technologies that best meet customers' energy and reliability needs while maintaining affordability.

EXISTING APS RESOURCES

Palo Verde Generating Station (Palo Verde) is the cornerstone of the APS fleet, providing reliable, carbon-free power to millions of customers across the Southwest. Solar and wind resources, DSM, and distributed generation account for a significant amount of APS's resource portfolio and are the fastest growing categories by far. Natural gas resources, needed for reliability and to integrate variable solar resources, provide low-cost, low-emitting, and flexible capabilities. The baseload power provided by the Company's coal-fired generating units will be phased out by 2031. This chapter provides additional details on APS's current set of resources.

FUTURE RESOURCE OPTIONS

New capacity and energy resources needed to close the supply-demand gap during the Planning Period will come primarily from renewables, energy storage, natural gas combustion turbines, customer DSM programs, DR, and microgrids. APS has engaged stakeholders and has an open public process as part of the IRP to better understand how to meet the needs of its customers. The Company is working with stakeholders and consultants to balance industrywide knowledge with the unique energy usage patterns witnessed in the Desert Southwest. Further, APS will continue to work with industry groups and is in regular contact with developers in the utility industry. This allows the Company to continuously evaluate new resources, technology, and ideas that will be required to meet customers' energy needs.

PLANNING STUDIES

With the magnitude of change in projected system operations going forward, it was appropriate to re evaluate some key planning inputs affecting the composition of future resource plans.

DSM Opportunity and Market Potential Studies: APS conducted a DSM Opportunity Study in 2019 that was closely coordinated with DSM stakeholders, in order to provide updated information on the technical, economic, and achievable potential from a number of traditional and emerging EE technologies and program opportunities. APS updated this study and worked with Guidehouse to develop a new EE/DR Potential Study in 2023 to determine the achievable potential based on updated technologies, DSM planning, baseline efficiency levels, pricing and market saturation data, and APS load growth. APS is using the data collected from these studies in conjunction with information from current and historic DSM program activities to develop more granular DSM planning tools that will support future load forecasting and integrated resource planning needs. The 2023 EE/DR Potential Study is summarized below and included in Appendix C of the IRP.

In the 2023 EE/DR Potential Study, APS forecasted energy savings and costs for EE and DR opportunities between 2023-2038 to support IRP and DSM planning efforts. The study also included consideration of the potential impacts that IRA tax credits may have to increase the amount of achievable potential available by reducing customer incremental costs for adopting certain DSM technologies.

The study included a Business As Usual (BAU) base case, a High Adoption Scenario that allows APS to achieve 1.3% EE savings through a longer duration of the study period, and a 1.5% EE savings case that allows APS to model 1.5% EE savings through the study window in compliance with Decision No. 78499. In order to achieve the High and 1.5% EE Savings Scenarios required for modeling, it was necessary to increase incentives to cover 75% of all incremental measure costs for the High Scenario and 100% of all incremental measure costs for the 1.5% EE Savings Scenario. In addition, the 1.5% EE Savings Scenario lowers the cost effectiveness (CE) threshold to 0.45 in 2027 (significantly below the 1.0 CE threshold typically required for EE programs in Arizona to be included in the DSM portfolio) in order to achieve the necessary EE savings levels. While these scenarios provide a foundation for modeling, they are not necessarily feasible to implement as they fall outside of the Commission's current DSM policy guidelines. For APS, it is necessary to develop resource plans that maintain the reliability of the system while balancing the necessary gradualism that is a result of the regulatory process.

During the IRP period, APS can achieve between 175 GWh and 200 GWh in cost-effective energy savings at an estimated cost of $37 million to $49 million annually.

- **Residential Sector EE potential primarily consists of:** Smart thermostats, HVAC Quality Installation, and Energy Star Homes
- **Non-Residential Sector EE potential primarily consists of:** Data Center Computer Room AC, Advanced Rooftop Controls, Custom Projects, and Commercial Energy Management Systems
- **Other technologies contributing to achievable EE potential include:** Commercial Smart Thermostats and Networked Thermostats, Linear LEDs, Packaged AC, Home Energy Reports, Limited Income Weatherization, Attic Insulation, and Multifamily New Construction

Approximately 60% of technical potential savings pass the economic screen of the ACC Cost Test.

The results of the EE/DR Potential Study represent a current snapshot of forecasted future potential. It was beyond the scope and timeframe of this study to consider all new emerging technology applications in the analysis of future EE potential, particularly in growing subsegments like XHLF loads and advanced manufacturing which may offer significant additional savings opportunities in the future. APS intends to continue to work with customers and trade allies to pursue cost effective EE projects in these segments, research emerging EE opportunities, and provide updated EE/DR potential forecasts in subsequent IRPs.

Electric Vehicle Adoption Forecast and Charging Station Siting Analysis: In 2019, APS retained Guidehouse to develop a forecast of plug-in electric vehicles (PEVs) in Arizona and in APS's service territory over the next 20 years, and to determine the electric charging infrastructure required to support that level of EV adoption. APS retained Guidehouse to update this forecast in 2023. Guidehouse used the VAST™ Adoption and VAST™ Charging Forecasting modules to perform the studies. The VAST™ Adoption module is a systems dynamics model that forecasts the penetration of vehicles, by powertrain (battery electric vehicle (BEV), plug-in hybrid electric vehicle (PHEV)), vehicle class, and ownership type (individual/fleet) for plug-in electric vehicles (PEV). It was used to generate geographic outputs for estimated vehicles in operation in the state. The VAST™ Charging Forecasting module estimates the number of chargers needed to meet future demand. The result can be used to estimate load growth, grid impacts, costs, and more.

Key inputs to the study included:

- Baseline vehicle registrations and charging infrastructure – from APS
- Historic vehicle sales and vehicle availability
- Gasoline, battery, and component price forecasts – including electricity rates from APS
- State, national, and utility incentives
- Demographic data: Income, educational attainment, units in structure

Key outputs of the study were:

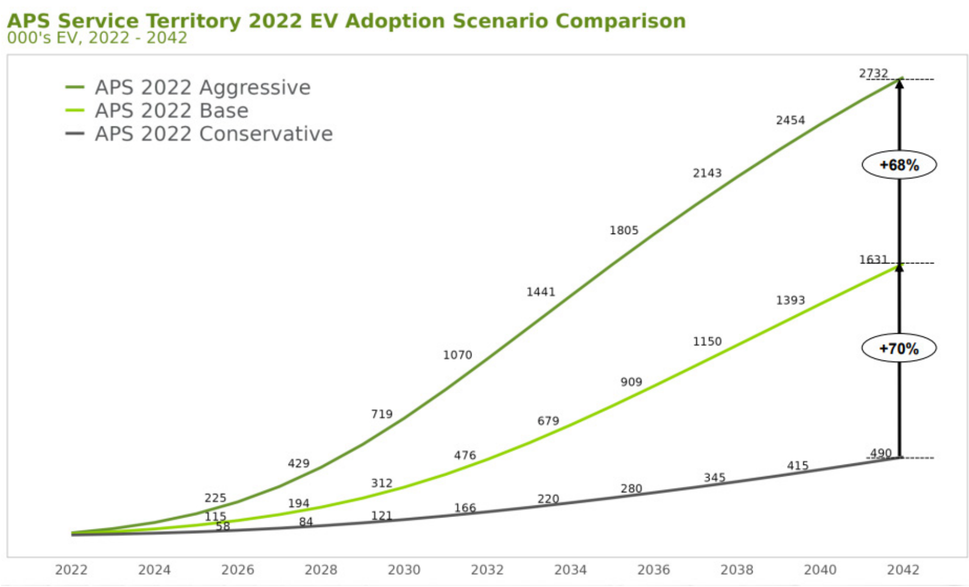
- PEVs anticipated in APS's service territory from 2022 through 2042
- Forecasted number of charging ports in APS's service territory from 2022 through 2042
- Impacts to load forecasting

The results included Aggressive, Base, and Conservative scenarios, and are shown in Figure 2-4. Guidehouse estimated that the number of PEVs in APS's territory will increase to 476,000 vehicles in 2032 under the Base scenario. These results were factored into APS's load forecast.

Integration Cost Study: APS is committed to providing cost-effective and reliable clean energy to its customers, and that means planning for the addition of increased variable or intermittent renewable resources, such as solar or wind generation. For the purposes of this analysis, such resources are identified as Variable Energy Resources (VERs). VERs come with their own unique benefits and challenges — although their fuel is free, their forecasts are not perfect. The potential for weather variation, whether it is unexpected cloud cover that reduces solar generation or a forecasted windy day that does not materialize, does not alleviate APS of its obligation to provide reliable power to its customers at all times. Because of the forecast error associated with VERs, APS asked Energy & Environmental Economics (E3) to conduct an integration study to assess the additional costs for integrating both solar and wind resources into APS's generation portfolio.

E3 looked at the historical variability of solar and wind resources to develop a view of APS's system in the future. Renewable forecast errors place the system in a position of either generation deficiency or generation surplus on a sub-hourly basis. In order to account for this and maintain resource adequacy (RA), APS must carry operating reserves to either "fill the gap" left by renewables underperforming with respect to its forecast (Regulation Up) or to absorb the additional unexpected energy from the renewable resources (Regulation Down). E3 found that there are additional costs associated with both scenarios that are captured in the integration costs, namely increased operating and maintenance costs. Additionally, APS plans to utilize storage resources to aid in the integration of VERs,

FIGURE 2-4. PEVS FORECAST IN APS SERVICE TERRITORY



facilitating cleaner integration while maintaining system flexibility.

The results of the VER integration cost study show that there are additional costs associated with incorporating renewable resources into the APS system. The costs are resource dependent and are outlined in Table 2-2. APS considers these costs when evaluating renewable resources to ensure affordability and reliability for its customers.

TABLE 2-2. RENEWABLE INTEGRATION COSTS

	2025	2032
Solar Integration Cost ($/MWH)	$1.04	$0.78
Wind Integration Cost ($/MWH)	$1.75	$1.16

Reserve Margin Planning: Historically, resource adequacy primarily centered around annual peak demand, typically occurring during summer afternoons when maximum generation capacity is required to serve customer demand and the threat of a shortage is most significant. Due to uncertainty in the availability of resources coupled with ever varying load, power system operators need to maintain reserves to ensure a reliable energy supply is available in the face of the various uncertainties that affect the system. The reserves typically take two forms: the planning reserve and the operating reserves.

Planning reserve or reserve margin (PRM) represents the additional capacity beyond what is necessary to serve peak demand to overcome the supply and load uncertainties. PRM is a powerful tool in resource planning, offering an intuitive and easily integrated measure for capacity expansion modeling. APS utilizes the industry standard widely used in North America of "one-day-in-ten-years" Loss of Load Expectation (LOLE) RA metric.

The landscape of RA has evolved significantly in recent years. The deep penetration of variable energy resources, both within APS territory and its immediate neighbors (particularly California) has shifted reliability risks to different times of the day. With the widespread adoption of rooftop and utility-scale solar resources, the net peak has moved to later in the evening after the sun sets, diverting reliability risks away from the traditional peak hours. Additionally, the anticipated adoption of energy-limited resources (e.g., battery energy storage) is extending the reliability risk across longer time periods, due to flattening of the net load shape.

This shift has introduced new complexities and interactions among the diverse portfolio of resources integrated into the APS system. To capture and account for these effects, APS has employed industry-leading software, Strategic Energy & Risk Valuation Model (SERVM), and leveraged Astrapé Consulting to establish APS's PRM and accredit its resources in meeting the demand and PRM requirements. Furthermore, in line with leading industry recommendations, APS has proactively transitioned to a perfect capacity PRM methodology starting in 2026. This approach evaluates all resources based on their perfect capacity equivalent, ensuring each resource is assessed on a level playing field, taking into account its respective strengths and limitations.

These dynamic changes made by APS reflect the ongoing efforts to adapt to a more diverse and complex energy ecosystem, where reliable capacity and demand considerations are continually evolving to meet the challenges of achieving affordability over time. A summary of the planning reserve margin study can be found in Appendix D.

Natural Gas Supplies: Natural gas generation has been, and will continue to be, a critical part of delivering reliable and affordable energy to customers. Natural gas generation is a "bridge" resource that will allow APS to balance the incorporation of additional clean and affordable resources while maintaining reliability. Due to the changing supply and demand picture of natural gas and the fully subscribed nature of certain interstate pipelines running through Arizona, APS is working with natural gas providers and other Arizona gas shippers and utilities to assess long-term gas supply options aimed at ensuring reliable gas transportation into the future. Some of the key data driving the supply and demand balance includes the following.

Natural Gas Supply/Demand Drivers

- Natural gas demand and trends within the Desert Southwest and California;
- Natural gas supply and pricing;
- Natural gas reliability, including contracts on existing pipes, storage landscape, rate impacts of new capacity, and pipeline flexibility; and
- Impact of market changes on APS natural gas portfolio, including pipeline capacity and intraday pipeline flexibility.

Natural Gas Reliability

- **Weather:** Freeze-offs are an event to consider for reliability for gas markets in the Southwestern U.S. region;
- **Pipeline Rupture:** APS's risk related to reliance on natural gas is not seen as materially different than other regions of the United States that are more reliant on gas-fired generation;
- **Reliability Events:** There is a need to weigh the probability of reliability events against the timing and cost of mitigation
- **Variability of Renewable Resources:** There is a need for consideration of the impacts of wind and solar resources and long-term gas needs to support reliability.

Impacts of Market Changes

- The service quality, reliability, flexibility, and rates of APS's existing pipeline contracts would not be affected if existing pipelines require expansion;
- APS is only subject to cost increases associated with a pipeline expansion if it contracts for additional capacity that requires an expansion; and
- Any additional future flexibility would require contracting for additional capacity that may or may not require a pipeline expansion.

Natural Gas Storage: Natural gas storage in Arizona has been a matter of discussion for several years. The benefits offered by natural gas storage include local redundancy of fuel supplies if a pipeline disruption occurs. Kinder Morgan (KM) has proposed building a natural gas storage facility near Eloy, Arizona to help meet those needs. The Arizona Gas Storage (AGS) project has been offered by El Paso Natural Gas (EPNG) on behalf of KM. Gas storage requires multiple anchor shippers to commit to long-term investments that will require coordination among Arizona utilities.

The AGS project offers Arizona a sizeable gas storage solution. AGS, as proposed, would involve a salt dome storage facility with a minimum of four caverns, offering at least 4 billion cubic feet (Bcf) of working gas. Salt dome gas storage facilities offer the highest deliverability and cycling of any geological gas storage facility. Due to the high cost, expected water usage, and need for long haul gas pipeline infrastructure, the project has not gained enough regional support to move forward. At this time no other natural gas storage projects are currently being offered in proximity to APS's service territory. APS will continue to monitor developments in this area and consider if or how natural gas storage fits into the Company's resource strategies.

Existing APS Resources

The map in Figure 2-5 "APS Resource Map" details the location of APS's existing resource mix, with the exception of small-scale solar projects, customer-sited resources such as EE, rooftop solar, and DR, and conventional purchased power contracts. These resources were forecasted to be in service by summer, 2023.

TABLE 2-3. APS EXISTING RESOURCES[3]

BY RESOURCE	
TOTAL RESOURCES	**13,397 MW**
Nuclear	1,146 MW
Coal	1,357 MW
Natural Gas	5,216 MW
Owned Resources	3,573 MW
PPAs	1,643 MW
Microgrid	42 MW
Energy Storage	300 MW
Renewables	1,448 MW
Solar	784 MW
Owned Resources	399 MW
PPAs	385 MW
Wind (PPAs)	637 MW
Other (PPAs)	27 MW
Customer-Based	3,888 MW
Energy Efficiency	2,104 MW
Distributed Energy	1,556 MW
Demand Response	228 MW

3 Table 2-3 includes smaller scale and distributed energy resources not included in Table 2-4 or Figure 2-5.

FIGURE 2-5. APS RESOURCE MAP

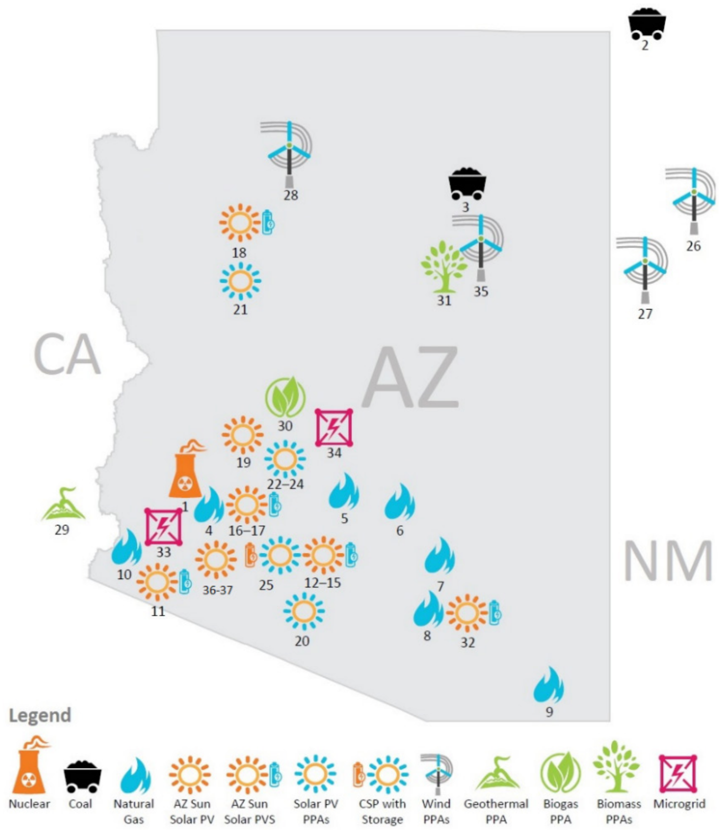


TABLE 2-4. APS RESOURCE MAP DETAILS

MAP #	PLANT	APS MW	IN SERVICE	MAP #	PLANT	APS MW	IN SERVICE
1	Palo Verde	1,146	1986-1988	21	Prescott Project	10	2011
2	Four Corners	970	1969-1970	22	Saddle Mountain	15	2012
3	Cholla	387	1962-1980	23	Badger 1 Solar	15	2013
4	Redhawk	1,088	2002	24	Gillespie	15	2013
5	West Phoenix	997	1972-2003	25	Solana	250	2013
6	Ocotillo	620	1960-1970	26	Aragonne	200	2022
7	Sundance	420	2002	27	High Lonesome	100	2009
8	Saguaro	189	1972-2002	28	Perrin Ranch	99	2012
9	Douglas	16	1972	29	Salton Sea	10	2006
10	Yucca	243	1971-2008	30	NW Regional	3	2012
11	Foothills*	35	2013	31	Snowflake	14	2008
12	Paloma*	17	2011	32	Red Rock*	40	2016
13	Cotton Center*	17	2011	33	MCAS Yuma	22	2016
14	Gila Bend*	32	2014	34	Aligned Microgrid	11	2017
15	Desert Star*	10	2015	35	Chevelon Butte	238	2023
16	Hyder*	16	2011	36	Agave Solar	150	2023
17	Hyder II*	14	2013	37	Mesquite Solar*	60	2023
18	Chino Valley*	19	2012	N/A	Tolling Agreement #1	570	2020†
19	Luke AFB	10	2015	N/A	Tolling Agreement #2	463	2021†
20	Ajo Project	5	2011	N/A	Tolling Agreement #3	565	2010†

** Paired with battery storage | † First year of contract with APS | ‡ Table 2-4 shows actual resource performance data and may not match contract amounts.*

Existing Nuclear

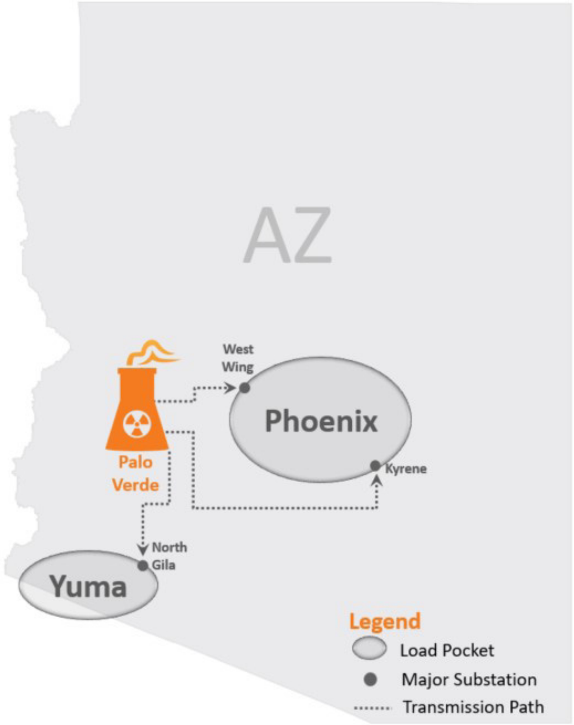
POWER PLANT (APS MW ENTITLEMENT) TOTAL: 1,146 MW

PALO VERDE GENERATING STATION (1,146 MW)

Palo Verde is a three-unit nuclear power plant located 50 miles west of Phoenix. APS operates the plant and owns 29.1% of Palo Verde Units 1 and 3 and has a combined ownership/leasehold interest of 29.1% in Unit 2. The U.S. Nuclear Regulatory Commission (NRC) issued renewed operating licenses for each of the three units in April 2011, which extended the licenses for Units 1, 2, and 3 to June 2045, April 2046, and November 2047, respectively.

In 1986, APS entered into agreements with three separate lessor trust entities in order to sell and lease back approximately 42% of its share of Palo Verde Unit 2 and related common facilities. APS will retain the assets through 2033 under all three lease agreements. At the end of the lease renewal period, APS will have the option to purchase the leased assets at their fair market value, extend the leases for up to two years, or return the assets to the lessors.

FIGURE 2-6. HOW PALO VERDE MEETS CUSTOMER DEMAND



Other Plant Highlights:

- Total plant operating capacity: over 4,000 MW (APS's share: 1,146 MW)
- Commercial operation of Units 1 and 2 began in 1986 and Unit 3 in 1988
- Provides electricity to 4 million people in Arizona, California, New Mexico, and Texas
- Only nuclear plant in the world not located near a large body of water
- Only nuclear power plant in the world that uses reclaimed municipal wastewater as its cooling water (on average, Palo Verde recycles 20 billion gallons of wastewater per year)
- Has a $2.1 billion annual economic impact and is the largest single commercial taxpayer in Arizona
- Major trading hub in the West

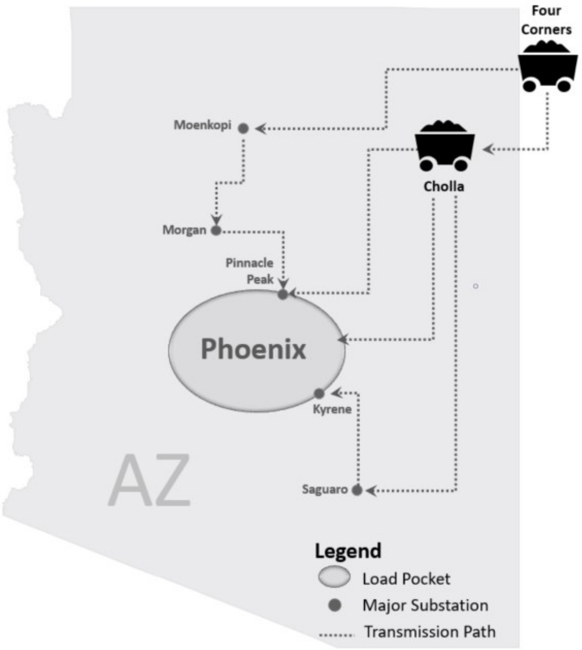
Existing Coal

POWER PLANTS (APS MW ENTITLEMENT AT BEGINNING OF PLANNING PERIOD) TOTAL: 1,357 MW

FOUR CORNERS POWER PLANT (970 MW)

Four Corners Power Plant (Four Corners) is composed of two 770 MW units located near Farmington in the northwest corner of New Mexico. APS operates and owns 63% of the plant. In June 2021, APS and the owners of Four Corners entered into an agreement that would allow Four Corners to operate seasonally at the election of the owners beginning in fall 2023, subject to the necessary governmental approvals

FIGURE 2-7. HOW EXISTING COAL RESOURCES MEET CUSTOMER DEMAND



and conditions associated with changes in plant ownership. Under seasonal operation, one generating unit would be shut down during seasons where electricity demand is reduced, such as the winter and spring. The other unit would remain online year-round, subject to market conditions as well as planned maintenance outages and unplanned outages. APS elected not to begin seasonal operation in 2023 as it was not economical to implement seasonal operations in the fall of 2023. APS will continue to evaluate this option and exercise seasonal operations in the future as economic opportunities become available. APS will exit from the facility in 2031 after six decades of operation.

CHOLLA POWER PLANT (387 MW)

Cholla Power Plant (Cholla), originally a four-unit coal-fired power plant, is located in northeastern Arizona. APS operates the plant and owns 100% of Cholla Units 1 and 3. PacifiCorp owns the 380 MW Unit 4, the plant's largest unit, which retired at the end of 2020. Unit 2 was closed on October 1, 2015, in accordance with U.S. Environmental Protection Agency (EPA) regulations. Units 1 and 3 are projected to stop burning coal no later than April 2025 as part of the same regulations.

Existing Natural Gas

APS-OWNED POWER PLANTS (APS MW ENTITLEMENT AT BEGINNING OF PLANNING PERIOD) TOTAL: 3,573 MW

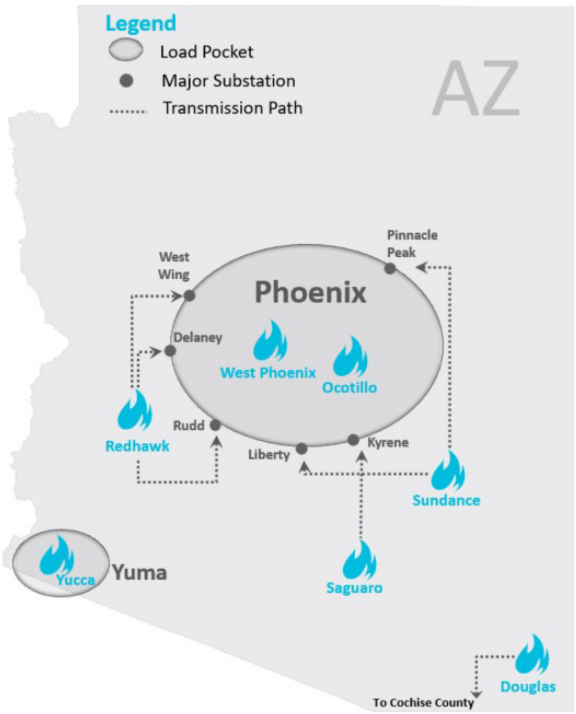
REDHAWK POWER STATION (1,088 MW)

Redhawk Power Station (Redhawk), which began operating in mid-2002, consists of two identical approximately 500 MW natural gas-fueled combined-cycle units. Located west of Phoenix, Redhawk utilizes treated effluent purchased from Palo Verde to meet its cooling needs. Redhawk also is a zero liquid discharge site, meaning that the cooling water is continually reclaimed and reused. Chillers are being installed at the plant prior to the summer of 2024 to improve plant output at higher ambient temperatures. The plant is owned and operated by APS.

WEST PHOENIX POWER PLANT (997 MW)

West Phoenix Power Plant (West Phoenix), located in southwest Phoenix, has seven natural gas-fueled generating units — two combustion turbine units and five units that employ combined-cycle technology. In 2024, a performance upgrade will be implemented on one of the combined cycle units, which will increase the summertime output of the plant by 55 MW. The plant is owned and operated by APS.

FIGURE 2-8. HOW EXISTING NATURAL COAL RESOURCES MEET CUSTOMER DEMAND



OCOTILLO POWER PLANT (620 MW)

Ocotillo Power Plant (Ocotillo) in Tempe is a seven-unit gas plant. In 2019, APS modernized the plant, which involved retiring two older 110 MW steam units, adding five 102 MW combustion turbines and maintaining two existing 55 MW combustion turbines. The plant is owned and operated by APS.

SUNDANCE GENERATING STATION (420 MW)

Sundance Generating Station (Sundance) in Coolidge is a natural gas-fueled combustion turbine plant that consists of ten quick-start units. Chillers are being installed at the plant prior to the summer of 2024 to improve plant output at higher ambient temperatures. The plant is owned and operated by APS.

SAGUARO POWER PLANT (189 MW)

Saguaro Power Plant (Saguaro), a natural gas-fueled facility located north of Tucson, includes three combustion turbine units. The plant is owned and operated by APS.

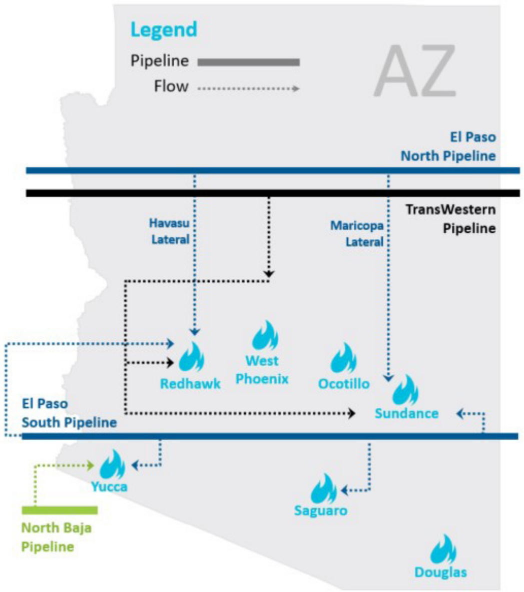
DOUGLAS POWER PLANT (16 MW)[4]

Douglas Power Plant (Douglas), located in Douglas in southeastern Arizona, has one 16 MW combustion turbine peaking unit and is put into service only when demand for electricity is high in the Douglas area. The plant is owned and operated by APS.

YUCCA POWER PLANT (243 MW)[5]

Yucca Power Plant (Yucca), a natural gas-fueled plant near Yuma, Arizona, has six combustion turbine units that produce 243 MW owned and operated by APS, and one 75 MW steam turbine and one 22 MW combustion turbine that are owned by Imperial Irrigation District and operated by APS.

FIGURE 2-9. NATURAL GAS PIPELINE MAP



NATURAL GAS PURCHASED POWER AGREEMENTS (APS MW ENTITLEMENT AT BEGINNING OF PLANNING PERIOD) TOTAL: 1,643 MW

APS currently has 1,598 MW of natural gas-based Purchased Power Agreements (PPAs) in place. Current PPAs include three tolling agreements — one ending in 2031 (565 MW, increasing to 600 MW in 2026), another ending in 2032 (463 MW, increasing to 525 MW in 2025), and one ending in 2034 (570 MW). The Company also includes a 45 MW contract for capacity in this calculation.

Existing Grid-Scale Renewable Energy

GRID-SCALE RENEWABLE ENERGY (APS MW ENTITLEMENT AT BEGINNING OF PLANNING PERIOD) TOTAL: 1,448 MW

SOLAR - TOTAL: 784 MW

PALOMA SOLAR POWER PLANT (17 MW)

Paloma Solar Power Plant is a photovoltaic (PV) facility located in Gila Bend. The plant began serving customers in the third quarter of 2011, and is comprised of 280,000 thin-film fixed tilt modules. The plant is owned and operated by APS.

COTTON CENTER SOLAR PLANT (17 MW)

Cotton Center Solar Plant is a PV facility also located in Gila Bend. The plant began serving customers in the third quarter of 2011 with about 93,000 polycrystalline modules on a single-axis tracking system. The plant is owned and operated by APS.

4 Douglas is fueled by diesel oil, but is listed within the natural gas category for ease of reporting.

5 Yucca CT4 is fueled by diesel oil.

HYDER SOLAR POWER PLANT (16 MW)

Hyder Solar Power Plant is a PV facility located in Hyder. The plant began serving customers in the fourth quarter of 2011 with about 70,000 multicrystalline modules on a single-axis tracking system. The plant is owned and operated by APS.

HYDER II SOLAR POWER PLANT (14 MW)

Hyder II Solar Power Plant is a PV facility located in Hyder. The plant began serving customers in the fourth quarter of 2013 with more than 71,000 multicrystalline modules on a single-axis tracking system. The plant is owned and operated by APS.

CHINO VALLEY SOLAR PLANT (19 MW)

Chino Valley Solar Plant is a PV facility located in Chino Valley near Prescott. The plant began serving customers in the fourth quarter of 2012 with about 77,000 multicrystalline modules on a single-axis tracking system. The plant is owned and operated by APS.

FOOTHILLS SOLAR PLANT (35 MW)

Foothills Solar Plant is a PV facility located near Yuma. Construction of the plant was completed in the fourth quarter of 2013. The plant is composed of more than 182,000 polycrystalline modules on a single-axis tracking system. The plant is owned and operated by APS.

GILA BEND SOLAR PLANT (32 MW)

Gila Bend Solar Plant, a PV facility located near Gila Bend, became fully operational in October 2014. Built on 400 acres, the plant includes about 172,000 polycrystalline modules on a single-axis tracking system. The plant is owned and operated by APS.

LUKE AIR FORCE BASE (AFB) SOLAR PLANT (10 MW)

Luke AFB Solar Plant is a 11 MW PV facility located on Luke AFB in Glendale, about 18 miles northwest of downtown Phoenix. Owned and operated by APS, the facility has 50,800 multicrystalline modules and became operational in the summer of 2015.

DESERT STAR SOLAR PLANT (10 MW)

Desert Star Solar Plant is located on 100 acres in Buckeye, and became fully operational in June 2015. The plant, owned and operated by APS, has 50,800 multicrystalline modules on a single-axis tracking system.

AJO PROJECT (5 MW)

Ajo Project, a crystalline PV single-axis tracking system, is located near Ajo and began commercial operation in September 2011. APS has a 25-year PPA for the entire project output.

PRESCOTT PROJECT (10 MW)

Prescott Project, located two miles north of Prescott Regional Airport, is a crystalline PV single-axis tracking system. APS purchases the generation output under a 30-year agreement, which began in November 2011.

SADDLE MOUNTAIN PROJECT (15 MW)

Saddle Mountain Project is a crystalline PV single-axis tracking system located near Tonopah. APS purchases the generation under a 30-year agreement, which began in December 2012.

BADGER 1 SOLAR FACILITY (15 MW)

Badger 1 Solar Facility, a crystalline PV single-axis tracking system located near Tonopah, reached commercial operation in November 2013. APS has a 30-year purchased power agreement for the entire output.

GILLESPIE (15 MW)

Gillespie, located near Arlington, is a crystalline PV single-axis tracking system. APS purchases the generation output from Recurrent Energy under a 30-year agreement, which began in December 2013.

SOLANA GENERATING STATION (250 MW)

Solana, located near Gila Bend, uses concentrated solar power (CSP) technology with a thermal energy storage system. APS purchases the generation output from Arizona Solar One (Abengoa) under a 30-year agreement, which began in October 2013.

RED ROCK (40 MW)

Red Rock is a 40 MW PV facility located in southern Pinal County. It includes 182,880 multi-crystalline modules. The facility is an APS collaboration with PayPal and Arizona State University — two commercial customers that purchase the equivalent of 100% of the facility's energy output from APS. The plant is owned and operated by APS.

AGAVE SOLAR* (150 MW)

Agave Solar is a 150 MW PV single-axis tracking system facility located west of Phoenix. This facility was energized in 2023, is owned and operated by APS, and consists of over 400,000 panels.

MESQUITE SOLAR* (60 MW)

Mesquite Solar is a 60 MW PV single-axis tracking system paired with battery storage west of Phoenix. This facility was energized in 2023. APS purchases the generation output from RWE Renewables under a 20-year agreement, which began June 2023.

SCHOOLS & GOVERNMENT† (13 MW)

The solar installations for Schools & Government are fixed solar PV systems installed throughout Arizona. The program consists of 59 school installations that APS owns and operates.

LEGACY† (4 MW)

Legacy solar PV systems installed throughout Arizona are a mix of fixed and single-axis tracking systems. The fleet is comprised of 36 systems, representing the oldest of the APS owned and operated solar facilities.

APS SOLAR PARTNER PROGRAM / FLAGSTAFF COMMUNITY PROJECT / SOLAR COMMUNITIES PROGRAM† (22 MW)

These projects include more than 2,400 rooftop, covered parking, and shade structure solar systems installed within APS's service territory. The solar PV systems are owned and operated by APS.

BAGDAD† (15 MW)

Bagdad is a 15 MW crystalline PV single-axis tracking facility located in Yavapai County. A third-party contract with APS to buy back the entire output under a 25-year agreement began in December 2011.

** These projects achieved commercial operations post June 1, 2023, but were included in modeling as a 2023 resource due to forecasted completion.*

† These diverse small-scale solar projects and grid-scale distributed resources are not shown on the APS Resource Map.

WIND - TOTAL: 637 MW

ARAGONNE MESA WIND PROJECT (200 MW)

Aragonne Mesa Wind Project, located in New Mexico, delivers its capacity to APS at the Four Corners switchyard. APS has a 20-year PPA to purchase the entire project output. The project began making energy deliveries to APS in January 2022.

HIGH LONESOME WIND PROJECT (100 MW)

High Lonesome Wind Project, located in New Mexico, delivers its capacity to APS at the Four Corners switchyard. APS has a 30-year PPA to purchase the entire project output. The project began making energy deliveries to APS in 2009.

PERRIN RANCH WIND PROJECT (99 MW)

Perrin Ranch Wind Project, located near Williams, reached commercial operation in June 2012. APS has a 25-year PPA to purchase the entire project output.

CHEVELON BUTTE WIND PROJECT (238 MW)

Chevelon Butte Wind Project, located near Winslow, reached commercial operation in May 2023. APS has a 20 year PPA to purchase the entire project output.

OTHER RENEWABLE ENERGY - TOTAL: 27 MW

SALTON SEA GEOTHERMAL PROJECT (10 MW)

Salton Sea Geothermal Project, located in the Salton Sea area of southeastern California, delivers capacity to the APS system in Yuma. APS has a 23-year PPA to purchase its output. The project began delivering energy to APS in January 2006.

NORTHWEST REGIONAL BIOGAS PROJECT (3 MW)

Northwest Regional Biogas Project, located in Surprise, Arizona, commenced operations in August 2012 and sells all its energy to APS under a 20-year PPA.

SNOWFLAKE BIOMASS PROJECT (14 MW)

Snowflake Biomass Project, located in Snowflake, Arizona, commenced commercial operations in June 2008 and sells part of its output to APS under a 15-year PPA. In 2022, APS extended its contract with Novo BioPower until 2033.

Existing Energy Storage Resources

GRID SCALE ENERGY STORAGE - TOTAL: 300 MW

AZ SUN PHASE I RETROFIT (140 MW)

Batteries were installed at Desert Star, Cotton Center, Paloma, Hyder I & II, Gila Bend, and Foothills as part of the Arizona Sun retrofit program.

AZ SUN PHASE II RETROFIT (60 MW)

Batteries were installed at Chino Valley and Red Rock as part of the Arizona Sun retrofit program.

MESQUITE SOLAR (60 MW)

Mesquite Solar is a 60 MW PV single-axis tracking system paired with battery storage west of Phoenix. This facility was energized in 2023. APS purchases the generation output from RWE Renewables under a 20-year agreement, which began June 2023.

AES WESTWING* (40 MW)

AES Westwing is a 40 MW battery storage facility located northwest of Phoenix. This facility is anticipated to be energized in 2023. APS purchases the generation output from AES Energy Storage under a 20-year agreement.

**This project was included in modeling as a 2023 resource due to forecasted completion.*

Existing Microgrid Resources

MICROGRIDS (APS MW ENTITLEMENT) – TOTAL: 42 MW

MARINE CORPS AIR STATION (MCAS) YUMA MICROGRID (22 MW)

The MCAS Yuma project provides the base with 100% backup power in the event of a grid disruption utilizing fast-starting, cleaner-burning diesel generation set (genset) power. The microgrid islanding features have operated nine times since commissioning to support MCAS Yuma operations. In addition, the microgrid can be dispatched to provide capacity and ancillary services to the grid, increasing reliability for all APS customers. The benefits of the project also extend to adding needed flexible capacity to the system while delivering a customized solution to a critical military installation. Since being placed in service, this system responded to 237 frequency events and was dispatched 30 times to assist with capacity events.

ALIGNED MICROGRID (11 MW)

The Aligned Microgrid is a ground-up, purpose-built system designed specifically for the load profile associated with the Aligned Data Center (ADC) and the surrounding community. The microgrid integrates underground 69 kV power supply with leading-edge reliability designed into all systems and subsystems. Since being placed in service, this system responded to 145 frequency events and was dispatched 20 times to assist with capacity events.

TABLE 2-5. TOTAL NUMBER OF OPERATING EVENTS

	MCAS	ADC
EVENT TYPE	# EVENTS	# EVENTS
Frequency Response	237	145
Capacity	30	20
Island	9	1
TOTAL	276	166

SMALL MICROGRID INSTALLATIONS (10 MW)

APS operates several microgrids for local reliability and system support. These microgrids are located in Phoenix, Punkin Center, and Young and contribute a nominal amount of resource adequacy to the broader system.

Existing Customer-Based Resources

CUSTOMER-BASED RESOURCES – TOTAL: 3,888 MW

ENERGY EFFICIENCY (2,104 MW)

APS complies with the current annual EE savings goal by targeting energy savings in excess of 1.3% of its retail sales in 2023. APS's EE portfolio includes a balanced mix of programs that address APS's diverse customer base in both residential and non-residential categories. These programs include, but are not limited to, the following:

- Residential Existing Homes program promotes EE in existing homes with Heating, Ventilation and Air Conditioning (HVAC) and Home Performance program elements that support energy-efficient residential air conditioning and heating, including smart thermostats, HVAC system quality installation, home air sealing, insulation, and duct repair;
- Residential New Construction program promotes high-efficiency construction practices for new homes;
- Large Existing Facilities program provides incentives to non-residential facilities for EE improvements in HVAC, motors, controls, and custom energy saving projects;
- Non-Residential New Construction and Major Renovations program promotes an integrated and comprehensive approach to improve the efficiency of new non-residential construction facilities through improvements in building design, construction, and energy efficient systems; and
- Schools program provides assistance in reducing energy used in schools, including public, private and charter schools (K-12), through upgrades to lighting, refrigeration, HVAC, and other end uses.

DEMAND RESPONSE (228 MW)*

APS's DR programs include:

- APS Peak Solutions is a 55 MW commercial and industrial DR program for APS's Yuma and Phoenix metropolitan customers;
- Peak Event Pricing (or Critical Peak Pricing) for residential and business customers is a rate rider that provides a high price signal over a small number of core summer peak days and hours;
- The APS Cool Rewards program is an award-winning virtual power plant (VPP) that provides flexible distributed capacity through an aggregation platform that connects to customer smart thermostats. Cool Rewards has over 78,000 connected smart thermostats that can deliver more than 135 MW of first-hour peak savings during events;
- The Residential Battery Pilot includes more than 1,000 total batteries, with 263 of these batteries participating in the capacity share element of the program. These batteries provide close to 1 MW of dispatchable capacity for a duration of up to 3 hours; and
- The Residential Behavioral Demand Response program sends emails to over 300,000 customers to encourage them to reduce peak demand on up to five afternoons each summer. This program provides up to 7 MW of peak demand reduction.

**Total differs from programs listed due to how APS accounts for DR as a resource.*

ROOFTOP SOLAR (1,556 MW)

APS customers have been adopting rooftop solar systems in increasing amounts for decades. At the end of 2022, APS had more than 154,000 customer-owned/leased distributed PV systems, 119 APS-owned distributed PV systems on residential and commercial customer premises as part of the Flagstaff Community Power Project, 1,389 APS-owned distributed PV systems on residential customer premises as part of the APS Solar Partner program, 776 APS-owned distributed PV systems on residential and commercial premises as part of the APS Solar Communities program, and 59 APS-owned distributed PV systems on commercial and industrial premises as part of the APS Schools & Government program.

PURPA Resources

Under the Public Utility Regulatory Policies Act (PURPA), APS evaluates qualifying facilities (QFs) that engage APS and provides avoided costs to QF developers that wish to sell their projects' output to APS. APS does not currently have any PURPA resources under contract.

Future Resource Options

APS ASSESSMENT OF FUTURE RESOURCE OPTIONS

Due to the rapid growth within Arizona, the Company is exploring all options that provide its customers with reliable, affordable, and increasingly clean energy. Factors considered in the assessment of future resource options include the following.

RESOURCE RESILIENCE

The evaluation of future resource options, some in early phases of development, includes assessing the potential contribution of those resources to enterprise agility — meaning the ability to adapt to changing operating conditions over time. Resources will need to be integrated in a way that maintains the reliability and affordability that customers have come to expect. Natural gas resources will be necessary to enable the integration of variable resources and supporting advanced grid capabilities that require quicker response times. As newer technologies develop, that ability to supplant the flexibility of natural gas with other resources that enable reliable generation dispatch is likely.

TECHNOLOGICAL DUE DILIGENCE

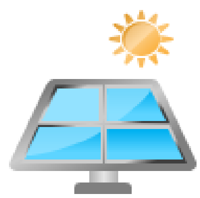
The technological due diligence process considers several factors, including:

- **Resource reliability:** The ability to reliably produce energy for APS customers when they most need it
- **Technological maturity:** Sufficient confidence that the addition of a new resource type will not subject APS customers to costs from timing uncertainty, difficulties in graduating from test-scale to grid-scale, shortfalls in operational capabilities under a full range of conditions, and limited integration capability with resources already in place
- **Capability of new technologies:** Measured through small scale evolutions as technology is maturing
- **Environmental impact:** The commitment to limit the impact of a resource on carbon emissions, Arizona's water levels, noise levels, land use, soil quality, and local habitat.

COST

At a time when investments in infrastructure upgrades and new technologies are key objectives, maintaining affordable cost of service to customers through the Company's planning and other processes is paramount. A key consideration in the assessment of new technologies is not only their cost outlooks, but also the reliability of those cost outlooks given the lack of track record in large-scale, operational settings. To ensure APS continues to deliver reasonably priced power as it expands its resource mix over the Planning Period and beyond, the Company's commitment to a comprehensive and proactive stance on cost issues remains.

Solar: Rooftop



OVERVIEW AND RISK CONSIDERATIONS

Residential and commercial solar continue to show robust additions in Arizona.

At the end of 2022, APS had approximately 154,000 customers with rooftop solar that produced 2,366 GWhs in 2022. However, the integration of rooftop solar has provided some challenges because APS currently has no control over the output, which has led directly to operational issues on the distribution system and contributed to over-generation issues on the bulk power system. APS continues to innovate and run pilots to understand how other DER technologies such as electric vehicles, battery storage, smart thermostats, and advanced solar inverters can allow APS to better integrate the large amount of rooftop solar interconnected on the APS grid.

DSM Programs and Initiatives

APS continuously strives to align DSM programs and EE resources with its resource needs. During the planning process for each DSM Implementation Plan, APS reviews the CE of all EE programs using updated avoided costs and is increasingly pursuing peak-focused solutions that provide high value savings.

CURRENT DSM PROGRAMS	NEW DSM PROGRAMS	DSM PROGRAMS IN DEVELOPMENT
DSM programs that are currently being implemented	**New and recently proposed DSM programs and pilots**	**DSM technologies and trends currently being assessed**
• Existing Homes Program (includes HVAC, Home Performance, and Consumer Products) • Residential New Construction • Multi-Family EE • Limited Income Weatherization • Home Energy Reports • Non-Residential Existing Facilities (includes Small Business) • Non-Residential New Construction • Schools • EV Managed Charging Pilot • APS Rewards Program, including Cool Rewards Residential Smart Thermostat Program • Energy Information Service • Codes and Standards • APS System Savings • Demand Response • Energy and Demand Education	• Residential Battery Pilot • Shade Tree Program • Advanced Rooftop Controls • Connected Hot Water Heating Pilot • Managed EV Charging Load Management	• Connected Devices • Load Monitoring and Management • Load Shifting • Automated Demand Response • Reverse Demand Response • Vehicle to Grid (V2X)

New DSM Programs

While traditional EE programs provide customers a greater role in managing their energy use, the focus of DSM efforts needs to align with APS resource needs to provide value as a reliable energy resource. This can be achieved by emphasizing savings during high cost, high demand late afternoon, and evening hours rather than midday hours when solar generation is abundant and wholesale energy market prices are low or negative. Shifting energy use through smart load management, energy storage, and increasing midday load with beneficial electrification initiatives is emerging as an essential tool to reach future clean energy goals.

APS continues to closely examine opportunities for peak demand reduction technologies and programs. Reviewing a broad range of DSM programs and measures, each one is assessed for its peak coincidence factor potential (likelihood that the measure provides energy savings at the time of the system peak) and for its impact on 8,760 hourly annual load shapes, particularly its ability to improve late afternoon ramping needs. APS has been evolving the current DSM portfolio toward peak demand management programs that provide high value to customers and align better with system resource needs. These types of innovations are seen in the Company's new Residential Battery Pilot, Connected Water Heating Controls, and the Cool Rewards smart thermostat demand response program.

DSM Programs in Development

Increasingly, the future of DSM involves an integrated approach to DER for managing energy demand and shifting load not only on the grid as a whole, but also in specific locations to help defer the cost of distribution-related upgrades. As connected devices become more economic and integrated with each other, these resources will offer more instantaneous demand response capabilities — optimizing the operation of key appliances to save customers money while offering benefits for utility operations. APS is further exploring integrated DER solutions. In such a changing environment, it is important to frequently evaluate how DSM tools are valued, and how they can be expanded to meet resource needs for all customers.

Generation Resources

In assessing generation resource options available, APS considered several technologies in nuclear, natural gas, grid-scale solar, rooftop solar, energy storage, and other renewable energy technologies.

TABLE 2-6. LIST OF FUTURE GENERATION RESOURCE OPTIONS AND ASSOCIATED COSTS*

FUTURE GENERATION RESOURCE OPTIONS	CAPITAL COSTS ($/KW)
NUCLEAR	
Advanced Nuclear	$6,790
Small Modular Reactor (SMR)	$7,463
NATURAL GAS	
Large Frame Combustion Turbine	$900
Aeroderivative Combustion Turbine	$1,538
Combined Cycle	$1,042
Combined Cycle with Carbon Capture Sequestration (CCS) 90%	$2,224
MICROGRID	
Genset	$1,265
ENERGY STORAGE	
Battery Energy Storage System (Li-ion) - 4 Hr.	$1,853
Battery Energy Storage System (Li-ion) - 5 Hr.	$2,223
Compressed Air Energy Storage (CAES)	$4,176
Pumped Storage Hydropower	$3,376
GRID-SCALE SOLAR	
Thin Film Solar - Utility Scale Single Axis Tracking	$1,721
Thin Film Solar - Utility Scale Fixed	$1,426
Solar PV + Battery Energy Storage System (PVS) - 4 Hr.	$3,573
Solar PV + Battery Energy Storage System (PVS) - 5 Hr.	$3,944
Solar Thermal Tower - Concentrating Solar Power (CSP)	$5,888
ROOFTOP SOLAR	
Solar - Distributed Commercial PV	$1,434
Solar - Distributed Residential PV	$2,177
OTHER RENEWABLE ENERGY SOURCES	
Southwest Wind	$1,760
Geothermal	$6,226
Biomass	$4,474

**Notes: Numbers in Table 2-6 are $ per installed kilowatt. Some generation resource options provide less output towards meeting system peak. Overnight construction costs are in 2025 dollars and do not include Allowance for Funds Used During Construction (AFUDC). Storage duration is four hours for each energy storage technology.*

Impact of Inflation Reduction Act

APS ASSESSMENT OF THE INFLATION REDUCTION ACT

On August 16, 2022, President Biden signed the Inflation Reduction Act of 2022 (IRA). The IRA significantly expands the availability of tax credits for investments in clean energy generation technologies and energy storage. Key provisions that are relevant to the Company's generation resource planning and procurement efforts include (i) an extension of tax credits for solar and wind generation, including a new option for solar investments to claim a Production Tax Credit (PTC) in lieu of the Investment Tax Credit (ITC) beginning in 2022; (ii) expansion of the ITC to cover stand-alone energy storage technology beginning in 2023; and (iii) introduction of a new PTC for nuclear energy produced by existing nuclear energy plants, available from 2024 through 2032. The Internal Revenue Service and U.S. Department of the Treasury are expected to issue regulations and other guidance which will provide additional details and clarifications regarding how the Company may be able to claim each of these credits.

APS has included these tax benefits in its resource modeling. Please see Chapter 5 for more information.

Solar: Grid-Scale

OVERVIEW AND RISK CONSIDERATIONS

The grid-scale PV boom is well underway, with developers shifting attention to construction and project delivery. Current forecasts for new construction through 2030 involve up to 272 GW of new solar coming online in the United States.[6] It is expected that most solar projects coming online during this period will utilize the PTC instead of the ITC due to recent legislation.

Many factors previously viewed as risks of grid-scale solar are being addressed by more versatile plant design and by coupling them with energy storage systems. These changes help to curtail output during the low load hours, if necessary, and/or store energy so that it can be put back into the grid to meet peaking needs after the sun has set. This is becoming more important as regional solar penetration increases and stand-alone solar capacity values diminishes.

INVESTMENT TAX CREDIT (ITC)

The IRA, provides either an ITC or PTC for certain solar and other renewable energy property.

TECHNOLOGIES

SOLAR PV FIXED AND SINGLE-AXIS TRACKING (SAT)

Fixed systems are typically angled at latitude for optimum production, while SAT systems rotate to follow the sun from east to west. Adding SAT increases the energy output from the system by approximately 25% in comparison to a fixed system.[7] It also increases the value of the energy delivered, as a portion of that additional output is in the late afternoon hours when load is at its peak. In a grid-scale solar plant, thousands of solar modules are connected together to form large systems connected to the grid. Grid-scale inverters typically range in scale from 500 kW to over 1 MW. Many of these inverters are combined together to form multi-MW solar power systems.

PV WITH STORAGE (PVS)

As noted above, PV systems can be directly paired with energy storage systems such as batteries to increase dispatchability and dependable capacity to the grid. Greater efficiencies are possible with paired systems than with separate PV and storage systems.

SOLAR THERMAL TROUGH TECHNOLOGY WITH SALT STORAGE

Parabolic troughs are the most mature concentrated thermal solar power technology.[8] Parabolic mirrors focus solar energy onto a receiver tube that contains a heat transfer fluid, typically synthetic oil. The fluid then returns to a series of heat exchangers, where it is used to generate superheated steam at about 1,450 psia

6 BNEF H1 2023 U.S. Renewable Energy Market Outlook (April 24, 2023), BloombergNEF.

7 Solar Power World, *How does a new single-axis tracking process increase solar plant efficiency?* (June 16, 2015), http://www.solarpowerworldonline.com/2015/06/how-does-a-new-single-axis-tracking-process-increase-solar-plant-efficiency/.

8 U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy, Parabolic Trough, https://energy.gov/eere/sunshot/parabolic-trough.

and 700°F. The steam is then used to run conventional steam turbines. Spent steam from the turbine is condensed in a standard condenser and returned to the heat exchangers as condensate via the feedwater pumps.

With the addition of molten salt thermal storage, like that used at Solana Generating Station, or gas hybridization, these systems can extend the generation period up to six hours or more after sunset.

CENTRAL RECEIVER (POWER TOWER) – SALT STORAGE

In power tower concentrating solar power systems, flat, sun-tracking mirrors, known as heliostats, direct sunlight onto a receiver located at the top of a tall tower. A heat-transfer fluid is used to heat a working fluid, which then produces electricity in a conventional turbine generator.[9] Power towers can operate by heating water directly, such as the Ivanpah Generation Station in California, or they can heat molten salt directly for thermal storage and steam generation, such as the Crescent Dunes project in Nevada.

Wind

OVERVIEW AND RISK CONSIDERATIONS

Wind generation accounted for 22% of electricity capacity installed in the United States in 2022. The U.S. Energy Information Administration (EIA) projects 95 GW of wind to be built in the United States between 2023 and 2028.[10]

PRODUCTION TAX CREDIT (PTC)

The IRA provides a $26.39/MWh PTC for wind and certain other renewable energy property.

Like other renewable energy resources, the primary challenge of wind energy is its variable generation, depending on the region. High levels of wind energy production often occur in the spring when APS's customer loads are at reduced levels, and low levels of production occur in the summer, resulting in wind energy's contribution to meeting summer peak demand to be a fraction of the rated generation output. However, wind plants are a source of energy to the system and have a complementary generation profile to solar resources. This aids in reducing overnight natural gas burns, especially as coal facilities retire and there are less dispatchable resources available to meet customer needs.

TECHNOLOGY

Wind systems convert the wind's energy into electricity by using rotating blades, typically made of fiberglass, to collect the wind's kinetic energy. The turbines are supported by a conical steel tower that is widest at the base and tapers in diameter to just below the nacelle. The nacelle is attached to the top of the tower and contains the primary mechanical components of a wind turbine. The blades are connected to a drive shaft that turns a generator to produce electricity.

APS has PPAs for four wind farms, two in New Mexico and two in Arizona.

Geothermal

OVERVIEW AND RISK CONSIDERATIONS

The U.S. EIA projects that geothermal net summer capacity will increase from 2.5 GW in 2022 to 3.8 GW in 2038, in its reference case.[11]

Geothermal energy provides carbon-free baseload power, which is primarily addressed in APS's service territory by Palo Verde. Other considerations include the location of geothermal resources, which are generally distant from the Company's load centers and transmission infrastructure. Moreover, a geothermal project must go through identification, exploration, and drilling phases before production can begin, and lead times for these facilities tend to be longer and development costs higher than for other renewable resources.

TECHNOLOGY

To generate electricity, geothermal power uses heat from a variety of sources below the earth's surface

9 U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy, *Power Tower System Concentrating Solar Power Basics* (August 20, 2013), https://energy.gov/eere/energybasics/articles/power-tower-system-concentrating-solar-power-basics.

10 U.S. Energy Information Administration, *Annual Energy Outlook 2023* (March 16, 2023), https://eia.gov/outlooks/aeo/.

11 *Id.*

to generate electricity, including hot water or steam reservoirs deep in the earth and geothermal reservoirs and shallow ground near the surface of the earth.[12]

APS has a 10 MW PPA for geothermal energy from the Salton Sea in California.

Biomass & Biogas

OVERVIEW AND RISK CONSIDERATIONS

The U.S. EIA projects that biomass net summer capacity will decrease from 2.7 GW in 2022 to 2.5 GW in 2038, in its reference case.[13]

Although biomass and biogas facilities utilize a combustion process that emits CO2, they are widely considered "carbon neutral" as carbon emissions are offset by the prior absorption of carbon through photosynthesis that occurred throughout the plant's lifecycle before being harvested to produce the source of waste.

TECHNOLOGIES

BIOMASS

Biomass fuels are primarily wood or wood byproducts. However, they can include dried municipal solid wastes, feedlot and dairy manure, crop wastes, and sewage digester sludge. Biomass can be converted into electricity in one of several processes. The majority of biomass electricity is generated today using a steam cycle where the biomass is burned in a boiler to produce steam. The steam turns a turbine, which is connected to a generator that produces electricity.

APS currently has a PPA with the Snowflake White Mountain Biomass Power Plant for approximately 50% of its output.

BIOGAS

Biogas is a low-BTU gas composed of methane (40-60%), carbon dioxide, water, and miscellaneous contaminates. It is produced through anaerobic digestion processes in landfills, wastewater treatment at municipal water plants, and concentrated animal feeding operation farms. The gas is produced, collected, and then typically flared and/or used for on-site thermal heating. If the amount of biogas produced is sufficient to warrant the development of a biogas-to-energy project, the biogas would be cleaned and dried, and/or thermally oxidized prior to combustion. The biogas can then be converted into electricity by combustion in specific reciprocating engines, microturbines, and fuel cells that have been designed and configured to utilize low-BTU fuels.

APS currently has a PPA with the 3.2 MW Northwest Regional Landfill in Surprise.

Energy Storage

OVERVIEW AND RISK CONSIDERATIONS

Energy storage — including pumped hydroelectric, compressed air, flywheel systems, hydrogen technologies, and various types of batteries — will play a crucial role in harnessing increased levels of production and the intermittency of most renewable resources to meet the energy needs of customers. It has the potential to increase the value of renewable resources while improving grid reliability and stability. In renewable energy integration, storage's value comes in its ability to align solar energy production with peak energy demand and absorb excess renewable energy production in lower load hours, along with evening out the variable nature of renewable production. Solar energy generation is highest during midday hours, when most customers are at work and home energy usage is low. Conversely, when customers come home in the evening and increase their energy usage by turning on their air conditioners, washing machines, lights, and TVs simultaneously, solar energy production has stopped because the sun has set, creating a mismatch between when rooftop solar installations produce energy and when customers need it. Storage addresses this misalignment by harvesting the solar energy that is produced during midday hours and then dispatching it in the evening during peak customer demand.

APS has elected to maintain a cap of 3,000 MW of utility scale battery energy storage through 2027 to

12 National Renewable Energy Laboratory, *Geothermal Energy Basics,* https://www.nrel.gov/research/re-geothermal.html.

13 U.S. Energy Information Administration, *Annual Energy Outlook 2023* (March 16, 2023), https://eia.gov/outlooks/aeo/.

mitigate risks associated with technology maturity, supply chains, and reliability. The Company anticipates significant additional investment into energy storage technologies over the next decade. This cap may be revised as operational experience increases and the technology demonstrates reliability.

TECHNOLOGIES

LITHIUM-ION BATTERY

Lithium-ion battery systems are perhaps the fastest-growing battery technology in the marketplace today. The technology has already matured for cell phones and other stationary consumer electronics and is rapidly being expanded into electric vehicles. As of Q1 2023, there is approximately 1,380 GWh of annual lithium-ion battery production, with 6,100 GWh of annual production announced to be online by 2032, but cancellations are likely as the current demand outlook is significantly less.[14] While a huge portion of these batteries will be utilized by electric vehicles, utilities across the United States are also deploying the technology in grid-scale applications.

In the previous filing, the primary lithium-ion chemistry being utilized by electric consumer vehicles and utilities were made with nickel and cobalt, usually nickel manganese cobalt (NMC). This chemistry provides a high energy density and has had significant investment in manufacturing capacity over the last several years. However, since that filing, lithium iron phosphate (LFP), which does not contain the more expensive raw materials found in NMC, has made significant inroads in all electric vehicles while becoming the chemistry of choice in utility applications.

COMPRESSED AIR ENERGY STORAGE

Compressed air energy storage (CAES) is a bulk energy storage technology that utilizes either a below-ground cavern or above-ground storage tank to store energy as compressed air to later turn that energy into electricity through a natural gas combustion turbine or turbo-expander. One recent variant of CAES compresses air into liquid that can then be stored in above-ground tanks, thus avoiding the geographic restriction of finding a suitable underground cavern. CAES has a relatively high upfront cost with low marginal cost per additional MWh, lending the technology to long duration storage applications (6-plus hours). Due to the geological formations necessary, it is difficult to find generic cost estimates that are accurate for resources within the immediate region.

PUMPED HYDRO ENERGY STORAGE

Pumped hydro energy storage utilizes the pumping of water upwards against gravity during off-peak hours and then discharging the stored potential energy of the elevated water during peak times. This technology is mature. Pumped hydro plants have high efficiencies and a half century of useful life. Water resource and environmental concerns have limited the growth of the technology since the 1980s. However, decarbonization efforts require GW-scale, long-duration energy storage options, and pumped hydro has been receiving renewed attention for this reason. Industry forecasts predict that at least 112 GW of additional pumped storage capacity will be added between 2021 and 2030.[15]

Microgrids

OVERVIEW AND RISK CONSIDERATIONS

A microgrid is a part of the distribution grid that can separate (island) from the grid, continue operation, and reconnect with the grid at a later point in time without customer disruption. Having the ability to generate energy locally is a key benefit for customers in the event of a grid disruption or power quality event. Ongoing industry cost reductions in DER and secure communication platforms that provide the real-time command and management of local loads and resources has made the application of customer microgrids increasingly possible and cost effective for customers.

APS expects microgrids to play an increased role in strengthening the grid while also supporting all customers. Since utility-integrated microgrids are dispatchable, they provide resource adequacy critical for reliability and resiliency. In addition, due to their fast-acting characteristics, microgrids provide ancillary services, such as frequency response, in the event of a grid disturbance. Finally, with the potential to add energy storage to these microgrids, their

14 Wood Mackenzie, *Power & Renewables – Global Li-Ion Battery Supply and Demand Update H1 2023* (Updated 7/2023).

15 BloombergNEF, *Beyond Lithium-Ion: Long-Duration Storage Technologies*, (April 12, 2022).

responsiveness can be improved along with increasing flexibility and emissions reductions as the energy storage system would respond to most events first and potentially avoid unit starts.

Examples of suitable settings for microgrid projects include hospitals, military installations, data centers, universities, critical infrastructure, and other customers with sensitive loads that cannot sustain loss of power. These customers traditionally procure their own back-up power systems to ensure continuous operation in the unlikely event of a power outage. Partnerships with these customers, or third parties who own these resources, results in a more cost effective and reliable solution for resilience due to the shared cost and use of these resources with the participating customer. These microgrids are technology agnostic and can integrate generators, energy storage, and/or renewables meeting the customer resiliency requirements and making them flexible for future technology capabilities.

In many of these applications, microgrid-capable DER installed at customer sites can act in a dual-use mode. One mode of operation provides peaking power to the grid in a grid-connected mode, benefiting all customers by acting as another peaking resource on the system and meeting APS planned resource requirements (plus reserve margin). The other mode of operation can provide backup power to the host customer in the event of a power outage. Microgrids also provide frequency response and load management capabilities for APS customers.

Carbon Capture and Sequestration

OVERVIEW AND RISK CONSIDERATIONS

Effective carbon capture could complement deeper penetration of renewables in a future with substantial decarbonization. Currently, almost all existing fossil-fuel generators do not control carbon emissions the way they control emissions of other air pollutants such as sulfur dioxide or nitrogen oxides. At the same time, these generators are dispatchable — they can supply energy as needed for reliability. As the electricity sector moves toward deeper levels of decarbonization, carbon capture technologies offer the potential to control carbon emissions associated with dispatchable thermal resources.

Carbon capture technologies can isolate atmospheric CO_2 and either sequester it permanently in geologic formations or convert it for use in products. There are a number of projects that show promise, but commercial-scale deployment at existing coal-fired power plants has not yet been achieved. We will continue to monitor this emerging technology carefully.

Reliance on this technology could increase significantly should the U.S. EPA's regulations of greenhouse gas emissions from new and existing power plants be finalized as currently proposed.

Natural Gas

OVERVIEW AND RISK CONSIDERATIONS

In 2022, natural gas generation accounted for 39.8% of total U.S. electricity generation, up 4.8% since 2019. The U.S. EIA projected in its 2022 Annual Energy Outlook that percentage would remain flat through 2035 and only decrease slightly through 2050 under its reference case.[16]

The primary risk associated with natural gas combined cycle technology has been the price of natural gas, which has a history of volatility. In terms of price levels, the latest estimates from the U.S. EIA project natural gas spot prices at Henry Hub ($/MMBtu in 2022 dollars) showing modest and steady decreases from $5.27/MMBtu in 2023 to $2.80 by 2028 and then increasing again to $3.42/MMBTu by 2033.

Natural gas generation will be necessary to reliably and affordably meet customers' energy needs until new, clean-generation technologies are sufficiently developed to offer greater dispatchability. In the long term, natural gas units will need to be retired, converted to hydrogen co-firing or equipped with carbon capture and sequestration technology, which are requirements under U.S. EPA's proposed regulation of greenhouse gas emissions from new and existing gas-fired power plants. In the meantime, potential compliance liabilities related to fracking and increased demand for U.S. exports of this fuel in the transition period are risk

16 U.S. Energy Information Administration, *Annual Energy Outlook 2020* (January 29, 2020), https://www.eia.gov/outlooks/aeo/

considerations. A broader movement to regulate fracking at the state and/or federal level could have material effects on the future prices of natural gas.

Hydrogen

OVERVIEW AND RISK CONSIDERATIONS

Just as switching from coal to natural gas has driven large reductions in the power sector's carbon emissions, large-scale use of hydrogen has the potential to allow deep decarbonization of electricity production by 2050. Today, most industrial methods of manufacturing hydrogen produce CO2 as a byproduct. Emerging technologies for producing hydrogen supports cost-effective and energy efficient carbon capture prior to combustion, creating the potential for natural gas-sourced "blue" hydrogen to serve as a cost-effective, low-carbon fuel alternative. When hydrogen is produced by electrolysis using zero-carbon electricity (from nuclear, solar, or wind energy, for example), the resulting hydrogen is a zero-carbon fuel. Producing hydrogen when there is an excess of zero-carbon electricity effectively creates another energy storage technology for meeting peak demand with carbon-free electricity.

Today's high-efficiency gas turbines can burn fuel containing about 20% to 30% hydrogen by volume with little or no modification. Continued gas turbine development has resulted in hydrogen combustion systems which are currently capable of co-firing with 60% hydrogen by volume while maintaining NOx levels below 9 ppm without diluent (e.g., steam or water) injection. These hydrogen capable combustion systems can be retrofitted to the most common gas turbines currently in operation.

Just as hydrogen shows promise as a decarbonization technology for utilities, clean hydrogen presents an option for industry sectors that are typically considered difficult to decarbonize, including heavy-duty transport, steel, mining, and chemical production. The demand to produce clean hydrogen will likely create a significant amount of new, high-capacity electricity demand, which is reflected in the long term load growth projected in this IRP.

In addition to decarbonizing power production, hydrogen can be potentially distributed through the existing natural gas infrastructure in concentrations up to 15% depending on the pipe material for use in manufacturing and other areas, thus enabling carbon reductions in other sectors. Steel transmission lines as well as cast and wrought iron distribution lines can be susceptible to hydrogen embrittlement and will need to be evaluated.

HYDROGEN HUBS

APS has joined other energy leaders in the southwest including the center for an Arizona Carbon-Neutral Economy (AzCaNE) to launch the Southwest Clean Hydrogen Innovation Network (SHINe). Although it was not awarded DOE hydrogen hub funding, SHINe intends to support the DOE's vision of a regional clean hydrogen hub that provides clean energy in the transportation, industrial and electricity sectors while maintaining a reliable and resilient electric grid. The SHINe network includes salt cavern storage, heavy-duty transportation, and distribution technologies that are intended to accelerate the use of clean hydrogen as a source of low-carbon energy.

HYDROGEN CARRIERS

Because the costs of transporting and storing hydrogen can be high, it can be beneficial to consider synthetic fuels that contain large amounts of hydrogen but are easier to transport and store. Two such examples are ammonia and methanol.

AMMONIA

Ammonia is a 120-octane, carbon-free fuel made of hydrogen and nitrogen (NH3). Relative to pure hydrogen, ammonia is inexpensive to transport and store. Ammonia can be burned in special combustion turbines and reciprocating engine generators to make clean, carbon-free electricity. It is possible to burn a mixture of hydrogen and ammonia in existing natural gas plants, but additional work is needed to reduce emissions of NOX. Progress is being made in the area of using electricity to produce ammonia as a way to store green energy. For many decades, ammonia has been produced in large chemical plants worldwide as fertilizer for the agriculture industry. Pure ammonia is classified as toxic and dangerous for the environment, so safe handling and work practices would be of paramount importance.

METHANOL

Methanol is a carbon-containing hydrogen carrier with the chemical formula CH3OH. Methanol is well suited for burning in internal combustion engines and can be transported and stored in existing petroleum industry infrastructure with minimal upgrades. As emerging technologies for direct air carbon capture mature, methanol could become a viable alternative for carbon-neutral power generation.

TECHNOLOGIES

The following technologies currently use natural gas as fuel but could potentially be fueled by hydrogen or hydrogen carriers such as ammonia and methanol in the future.

CONVENTIONAL AND ADVANCED COMBINED CYCLE (CC)

A CC generating unit consists of one or more combustion turbine (CT) generators equipped with a heat recovery steam generator (HRSG) to capture the otherwise wasted thermal energy remaining in the turbine exhaust gases. Steam produced in the HRSG powers a steam turbine generator to produce electric power, in addition to the power produced by the CT(s). The process significantly increases the efficiency of this electric generating unit, and additional capacity can be obtained using power augmentation technologies, including turbine inlet cooling of the compressed air, duct firing at the inlet of the HRSG, and steam injection.

APS installed three CC units at West Phoenix in 1976. Since then, APS has added two additional units at West Phoenix and two units at Redhawk. Additionally, APS has contracted for the output of merchant CC units in the region for many years. Depending on the development of storage technologies, PPA contract extensions may be one way for APS to bridge to a clean energy future without making additional long-term investments in natural gas generation.

SIMPLE CYCLE COMBUSTION TURBINES

A CT generating system consists of an inlet air filter, inlet cooling system, compressor, combustor, turbine, exhaust environmental controls, stack, generator, and auxiliary systems needed to support the operation of the CT. Many of the newer units are now capable of a 10-minute quick start or sometimes faster. Most are also considered to have low emission combustion and controls, along with improved part-load performance.

APS has owned and operated CTs since the first units were installed at the Yucca Power Plant in 1971. Currently, the Company operates 29 CTs, positioned across its service territory to support local grids. Yucca, Douglas, Saguaro, Ocotillo, West Phoenix and Sundance all have CTs on-site.

AERODERIVATIVE GAS TURBINE

One type of CT is the gas aeroderivative turbine, which is used as a compression device to take in air, compress the natural gas (or potentially hydrogen), and then apply heat to the mixture with a burner. The hot air produced from this process powers the turbine.[17] Some benefits of aeroderivative turbines are fast-starting capabilities, the reduction in fuel consumption (about 10%) and improvement in operating duration (about 2%), as they avoid the long downtime maintenance cycles associated with other turbine types.[18]

APS employs these types of units at Sundance and Yucca (LM6000), and added LMS100 units at Ocotillo as part of the plant's modernization.

RECIPROCATING ENGINES

Reciprocating engines operate by introducing a mixture of fuel and air into a combustion cylinder, which is then compressed as the piston within the cylinder moves upward. As it nears the top, a spark is produced that ignites the air-fuel mixture. The pressure of the resulting exploding gases drives the piston down. The moving piston produces rotational energy used to generate electricity or drive a piece of equipment or machinery. APS currently has many backup power generators at electrical critical sites, including the emergency electric power requirements at Palo Verde.

These units can start and produce power within 15 seconds and are often used in microgrid applications, such as the APS microgrids at Aligned Data Center (in

17 Turbine TECHNICS, *Understanding Aeroderivative Gas Turbines*, http://www.turbinetechnics.com/about-us/understanding-aeroderivative-gas-turbines.

18 U.S. Department of Energy, Office of International Affairs, *Understanding Natural Gas and LNG Options* (current as of October 2017), https://energy.gov/ia/downloads/understanding-natural-gas-and-lng-options.

collaboration with Aligned Data Center, a subsidiary of Aligned Energy) and Marine Corps Air Station Yuma.[19]

STEAM GENERATION UNITS

These turbines operate similarly to coal steam turbines but utilize gas (or potentially hydrogen) instead of pulverized coal as their fuel source. In these units, fuel is burned within the boiler to produce subcritical steam in the boiler tubes at a typical pressure of 1,450 psi and temperature of 1,000°F. The subcritical steam is expanded through a steam turbine to produce electricity. The turbine steam is exhausted into the condenser, is condensed back to water, and then pumped back into the boiler tubes to repeat the cycle. These basic steam generation units have moderate efficiency, typically 33% to 35%,[20] once they are running. Modern CC technology is more efficient, less expensive and more flexible, so it is unlikely that this technology will be deployed in the future. With the retirement of the Ocotillo steam units in 2018, APS no longer has this technology in service.

Nuclear

OVERVIEW AND RISK CONSIDERATIONS

In determining whether to add new nuclear resources to a portfolio, several factors are considered. The use of nuclear power over the past 50 years has reduced carbon dioxide (CO_2) emissions to an amount equivalent to nearly two years' worth of global energy-related emissions.[21] Included in that number is Palo Verde, which will continue to be the foundation of the clean energy portfolio for APS and the Desert Southwest.

Both government and industry are increasingly declaring clean energy goals. Nuclear power provides a unique option for enabling a faster transition to a clean energy future. Globally, there are 60 new reactors under construction, adding nearly 63 GW of capacity, a 16% addition to the world's nuclear capacity.[22] These projects are going forward with strong governmental support and a robust construction infrastructure. In the United States, new nuclear construction is progressing with the completion of Southern Nuclear Operating Company's Vogtle Electric Generating Plant Units 3 and 4. With the inclusion of tax credits for nuclear in the IRA, new nuclear construction announcements are being made. Several companies have made announcements or are considering new nuclear construction.

USED FUEL

In the United States, the long-term nuclear fuel permanent disposal repository is behind schedule, largely due to a lack of political support. Therefore, used fuel is currently safely stored on-site at nuclear plant locations around the country. In 2022, the U.S. inventory of spent nuclear fuel was approximately 90,000 metric tons of uranium (MTU) and is projected to rise at a rate of approximately 1,800 MTU annually, resulting in an estimated 137,000 MTU by 2050.[23]

Countries that allow processing of used fuel are able to gain 25% to 30% more energy from the original uranium. All but 3% of the used fuel can be reused. Additionally, the level of radioactivity in the waste from reprocessing is much smaller than the original used fuel, and after about 100 years, the radioactivity from the used reprocessed fuel declines much more rapidly than in original used fuel.[24] Increasingly, today's used fuel is being seen as a future resource rather than a waste.[25]

19 Microgrid Knowledge, *How to Pay for Utility Microgrids? Arizona May Offer Answers* (October 11, 2016), https://microgridknowledge.com/utility-microgrids-arizona/.

20 NaturalGas.org, *Electrical Uses*, http://naturalgas.org/overview/uses-electrical/.

21 International Energy Agency, Nuclear Power in a Clean Energy System (May 2019), https://www.iea.org/reports/nuclear-power-in-a-clean-energy-system.

22 World Nuclear Association, *Plans for New Reactors Worldwide* (updated August 2023), https://world-nuclear.org/information-library/current-and-future-generation/plans-for-new-reactors-worldwide.aspx.

23 Congressional Research Service, *Advanced Nuclear Reactors: Technology Overview and Current Issues* (Updated February 17, 2023), https://crsreports.congress.gov/product/pdf/R/R45706.

24 World Nuclear Association, *Processing of Used Nuclear Fuel* (Updated December 2020), https://www.world-nuclear.org/information-library/nuclear-fuel-cycle/fuel-recycling/processing-of-used-nuclear-fuel.aspx.

25 World Nuclear Association, *Nuclear Fuel Cycle Overview* (Updated April 2021), https://www.world-nuclear.org/information-library/nuclear-fuel-cycle/introduction/nuclear-fuel-cycle-overview.aspx.

TECHNOLOGIES

ADVANCED NUCLEAR REACTORS

Advanced reactors are considered cutting edge in nuclear technology and are grouped into three primary categories:

- Advanced water-cooled reactors, which provide evolutionary improvements to proven water-based fission technologies through innovations such as simplified design, smaller size or enhanced efficiency
- Non-water-cooled reactors, which are fission reactors that use materials such as liquid metals (e.g., sodium and lead), gases (e.g., helium and carbon dioxide) or molten salts as coolants instead of water
- Fusion reactors, which seek to generate energy by joining small atomic nuclei, as opposed to fission reactors, which generate energy by splitting large atomic nuclei.

The Energy Act of 2020 defines "advanced nuclear reactor" as a fission reactor "with significant improvements compared to reactors operating on the date of enactment of the Energy Act of 2020."[26] Examples of fission reactor improvements listed in the act include:

- Additional inherent safety features
- Lower waste yields
- Improved fuel and material performance
- Greater reliability
- Increased resistance to nuclear weapons proliferation
- Increased thermal efficiency
- Reduced consumption of cooling water and other environmental impacts
- Ability to integrate electricity generation and non-electric applications
- Operational flexibility to change output to match demand and complement intermittent renewable energy output or energy storage
- Modular sizes to match electricity and other energy requirements

The definition of advanced reactors encompasses a wide range of technologies, including next generation water-cooled reactors (e.g., small modular light water reactors (LWRs) and supercritical water-cooled reactors), non-water-cooled reactors (e.g., lead or sodium fast reactors, molten salt reactors, and high temperature gas reactors), and fusion reactors. Some advanced reactor concepts are relatively new, while others have been under consideration for decades and used in research, test, and prototype reactors in the United States and around the world. Reactors using any of these technologies that have electric generating capacity of 300 MW or below are classified as small modular reactors (SMRs) by the International Atomic Energy Agency (IAEA).[27] Proponents of SMRs contend that their smaller size would reduce the financing costs and allow for large-scale factory production. Some designs for improved versions of existing large LWRs could also be considered advanced reactors under this definition if they were not in operation on the date of enactment.

The U.S. advanced nuclear industry has expanded in recent years to encompass an array of developers, suppliers, and supporting institutions. By one count, at least 25 U.S. companies were developing advanced nuclear reactor technologies as of July 2021.[28] Some have projected that the first U.S. advanced reactor could be providing electricity to the grid by the late 2020s. For example, the advanced reactor company NuScale Power, LLC has predicted, "The first NuScale Power Module™ will start generating power in 2029."[29] Support for advanced nuclear reactors is included in the law commonly referred to as the Inflation Reduction Act (IRA, P.L. 117-169). The owners of qualifying plants can receive a 10-year electricity production tax credit of up to 2.6 cents/kilowatt-hour (adjusted for inflation) or a 30% investment tax credit.[30] Additional credit is included for constructing a nuclear plant on a retired coal plant and having sufficient domestic content.

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26 Public Law 116-260, Division Z, Section 2002, enacted December 27, 2020, amended the definition of advanced nuclear reactor in the Energy Policy Act of 2005 at 42 U.S.C. §16271(b)(1).

27 International Atomic Energy Agency, *What Are Small Modular Reactors (SMRs)?* (first published November 4, 2021), https://www.iaea.org/newscenter/news/what-are-small-modular-reactors-smrs.

28 DOE Gateway for Accelerated Innovation in Nuclear (GAIN), *Advanced Nuclear Directory: Developers, Suppliers and National Laboratories* (July 1, 2021), https://gain.inl.gov/SiteAssets/Funding%20Opportunities/GAINAdvancedNuclearDirectory-Seventh%20Edition_07.01.2021-R1.pdf.

29 NuScale Power, LLC, Carbon Free Power Project, https://www.cfppllc.com/.

30 Congressional Research Service, *Advanced Nuclear Reactors: Technology Overview and Current Issues* (Updated February 17, 2023), https://crsreports.congress.gov/product/pdf/R/R45706.

The U.S. EIA estimates that the LCOE for new nuclear reactors is $88.24/MWh, excluding tax credits.[31] This is based on new plants using the most advanced currently available technology. However, recent inflation could increase the uncertainty of this estimate.

Coal

OVERVIEW AND RISK CONSIDERATIONS

According to the U.S. EIA, coal usage is projected to decline in the United States even if natural gas prices remain elevated. The U.S. EIA forecasts that the coal share of total electricity capacity will fall from 198 GW in 2022 to 84 GW in 2038 due to a combination of carbon reduction strategy, emission regulations, low natural gas prices, and increased deployment of renewable generation.[32]

APS plans to exit coal-fired generation by 2031 when the Four Corners Power Plant coal-supply agreement expires.

TECHNOLOGIES

SUBCRITICAL AND SUPERCRITICAL COAL STEAM BOILERS

Both subcritical and supercritical coal steam boiler technologies burn pulverized coal to produce steam in the boiler tubes at varying pressures, which then is expanded through a steam turbine that spins the generator to produce electricity. From there, the turbine exhaust steam is condensed back to water and returned to the boiler tubes for the cycle to start again. Supercritical boilers run at higher pressures and are more efficient than subcritical boilers. These and other generating technologies can be cooled by conventional wet cooling towers or dry air-to-air heat exchangers or a combination of both (hybrid).

TABLE 2-7. COAL STEAM BOILER TECHNOLOGIES

COAL STEAM BOILER TECHNOLOGY	OPERATING CHARACTERISTICS		APS PLANTS
	Pressure	Temperature	
Subcritical	<3,208 psi	1,025°F	Cholla Units 1-3
Supercritical	>3,208 psi	1,000°F–1,050°F	Four Corners Units 4 & 5

31 U.S. Energy Information Administration, *Levelized Costs of New Generation Resources in the Annual Energy Outlook 2022* (March 2022), https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf.

32 U.S. Energy Information Administration, *Annual Energy Outlook 2023* (March 16, 2023), https://eia.gov/outlooks/aeo/.

To Learn More

U.S. Department of Energy
https://www.energy.gov/

U.S. Energy Information Administration
http://www.eia.gov/

National Renewable Energy Laboratory
http://www.nrel.gov/

North American Electric Reliability Corporation
https://www.nerc.com/Pages/default.aspx

World Nuclear Association
http://www.world-nuclear.org/

CHAPTER 3

TRANSMISSION PLANNING AND GRID MODERNIZATION

TRANSMISSION

Approximately 1.4 million customers in 11 of Arizona's 15 counties depend on APS for reliable and affordable electric service. APS delivers electricity by relying on the planned network of transmission and distribution lines that transmit power from multiple large-scale generators to its customers. APS's Transmission Planning team facilitates the development of electric infrastructure that provides access to both resources and markets while ensuring reliable service by employing a planning process that is timely, coordinated, and transparent.

Current transmission facilities provide adequate means to serve present APS load with reliable, economic generation. However, with the rapid influx of large commercial, industrial, and data center load, APS forecasts that existing transmission capacity will be consumed before the end of the decade. Additional investment in transmission infrastructure is required to maintain access to generation resources providing the highest value to customers. Transmission connectivity to neighboring balancing authorities also provides more access to regional diversity and resources that are not available within APS's service territory.

APS considers all technologies, including generation, transmission, distribution resources, and non-wires alternatives, to address the challenges of an increasing array of resource types and significant large customer growth, while remaining committed to providing least-cost and best-fit solutions. Toward this end, APS's Resource Planning and Transmission Planning teams work together, along with counterparts across the state and the Western U.S. region, and actively engage with stakeholders to assure continued delivery of reliable and affordable energy to customers.

In APS's 2023-2032 Ten-Year Transmission System Plan[1] (Transmission Plan), the Company detailed expansion and upgrades of its transmission system for approximately 29 miles of new 500kV transmission lines, one mile of new 345kV transmission lines, 54 miles of new 230kV transmission lines, 11.5 miles of underground 230kV upgrades, 40 miles of 230kV transmission line rebuilds, and three miles of 115kV transmission line upgrades. In addition, the following were included in the Ten-Year Plan: 27 new transformers, two new shunt reactors, nine new shunt capacitors, three transformer replacements, and one series capacitor replacement. These new transmission projects, coupled with additional distribution and sub-transmission investments, will support continued reliable power delivery and load growth in APS's service territory.

TABLE 3-1. SELECT PROJECTS FROM APS'S 2023-2032 TEN-YEAR TRANSMISSION PLAN

PROJECT	DESCRIPTION	CONSTRUCTION START DATE	CONSTRUCTION END DATE
Panda–Freedom 230kV Line Rebuild	To provide electric energy to a new high-load customer in the area. The project will also be used to provide system reliability and serve numerous large-load customers.	2025	2027
Jojoba–Rudd 500kV Line	To provide an additional source to the west Phoenix valley to strengthen the transmission sources serving the Phoenix metropolitan area, which is experiencing rapid economic development.	2025	2028
Sun Valley–TS23 230kV Line	To provide electric energy to growing load demands in the Wittmann area. This project will also bring greater reliability to the Morristown and McMicken areas by adding an additional source to the 69kV system in the area.	2026	2027

KEY ISSUES

EXAMINING THE ABILITY TO IMPORT WIND RESOURCES

Wind resources available to APS are predominately in the northern portion of Arizona or in a neighboring state such as New Mexico. These resources require the use of an extensive transmission system to bring cost-effective energy to customers in load centers. APS is currently examining the ability of the transmission system to deliver

1 Arizona Public Service Company 2023-2032 Ten-Year Transmission System Plan, Docket No. E-99999A-23-0016.

out-of-state wind resources to the Company's system. Today, APS takes delivery from four wind farms, two in Arizona and two in New Mexico, providing locational diversity to a variable resource that benefits APS customers greatly. But with locational diversity comes potential deliverability challenges, and APS's access to wind resources can be limited as a result. Out-of-state, high-capacity factor wind resources are becoming increasingly difficult to secure due to the large number of utilities also seeking access to these resources. This creates challenges for APS's northern transmission system and neighboring utilities alike. With so many parties wanting access, there is not enough transmission capacity available. These constraints will make adding wind to the Company's portfolio complex and competitive. Wind energy is expected to play a key role in Arizona's energy future, and APS is actively working through these dynamic challenges to provide affordable wind resources to customers.

TIMEFRAME FOR TRANSMISSION DEVELOPMENT

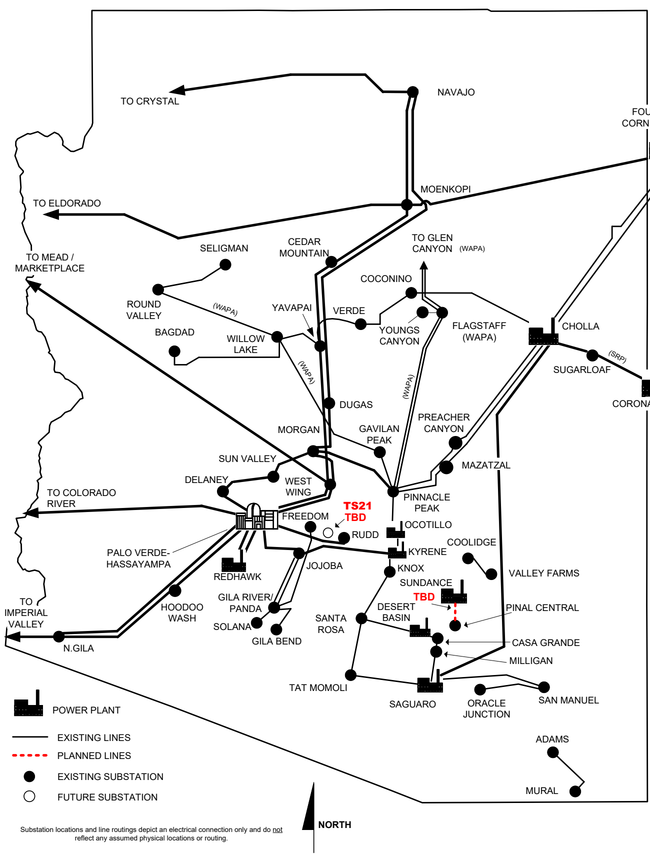
Transmission facilities, which are necessary to add new generation resources to APS's system, must begin development years in advance. The duration for the siting, permitting, and construction of these facilities is heavily dependent on location and the number of circuit miles that need to be built. Projects that require a detailed environmental study or are located in an area with protected wildlife habitats, unique cultural resources, or other land use sensitivities will take significantly more time to develop. S&P Global data shows that the average timeline for small transmission projects (<200kV) is 7.2 years, while large-scale (>200kV) projects have an average development timeframe of 11.8 years.[2] Recent interstate transmission projects in the Western United States have had development periods of over 20 years, with permitting alone taking over a decade. The consequence of these timeframes is that APS must identify where future resources are going to be located, often under a high degree of uncertainty, well in advance of necessary resource in-service dates to allow for transmission development timeframes.

Transmission Planning

APS's electric transmission facilities consist of nearly 6,000 miles of high voltage transmission lines (5,768 miles located in Arizona), approximately 33,000 miles of distribution lines, 469 substations, roughly 300,000 transformers and more than 550,000 power poles and structures.[3] APS owns all or a part of several major transmission paths in the states of Arizona, New Mexico and Nevada which transport electricity from fossil, nuclear and renewable facilities as well as under various long-term power purchase agreements as shown in Figure 3-1.

Sub-transmission systems carry energy reduced from high voltage transmission lines to deliver electricity to customers or the distribution system. APS annually conducts an analysis of its 69kV sub-transmission and identifies where modifications may be needed to accommodate changes in load. More specific information related to sub-transmission and distribution resources can be found in Response to Rule D.1 (f).

FIGURE 3-1. APS EXTRA-HIGH VOLTAGE AND OUTER DIVISION TRANSMISSION SYSTEM



2 Arizona Public Service Company. September 2023 RPAC Presentation, https://www.aps.com/-/media/APS/APSCOM-PDFs/About/Our-Company/Doing-business-with-us/Resource-Planning-and-Management/September_2023_RPAC_Meeting_Presentation.

3 See APS Witness Jacob Tetlow's Direct Testimony, ACC Docket Nos. E-01345A-22-0144.

Distribution systems are the subset of the grid that delivers power to customers. APS focuses its distribution system planning efforts on a five-year basis due to the challenges associated with accurately forecasting the level and location of load growth beyond that timeframe.

Optimizing use of the existing transmission system is crucial to the resource planning process as it manages costs, increases line efficiency, and is the first step to new generation siting initiatives. As adequate transmission must either exist or be planned for construction in support of future generation resources as well as potential contingencies, APS's Resource Planning and Transmission Planning teams coordinate to ensure continued reliability of service. Additionally, new transmission strategies are continuously reviewed to enhance the use of the existing system and improve reliability.

FLOWGATE TRANSITION (MOD-030)

APS has completed its transition to a flowgate (MOD-030) methodology for transmission system utilization. This was the culmination of a multiyear effort and enables the Company to use power flow data to calculate the ability to deliver remote generation to system load and available transmission for power being moved across the Company's lines to other balancing authorities. These studies can be performed more frequently under MOD-030, and it eliminates the overly conservative methods supporting point-to-point transmission segments. This has resulted in additional transmission availability in some areas.

LOCAL TRANSMISSION PLANNING PROCESS

Please refer to APS's Ten-Year Transmission Plan, found on the APS website[4] and filed with the Commission for more information on local transmission planning efforts.

REGIONAL TRANSMISSION PLANNING PROCESS

APS participates in numerous regional planning organizations in recognition that transmission planning has broad implications over the entire Western Electricity Coordinating Council (WECC) region. Through membership and active engagement in these organizations, the needs of multiple entities and the region can be identified and studied, which maximizes the effectiveness and use of new projects. More information on APS's regional transmission planning activities can be found in Attachment E of the Open Access Transmission Tariff (OATT).[5]

TRANSMISSION PLANNING FOR DAY-AHEAD WESTERN MARKETS

As has been discussed previously, transmission is necessary for a variety of reasons, including local reliability, large customer siting, and resource acquisition. Broader regional transmission evaluation takes on another form as APS continues to participate in current regional wholesale electricity markets and pursues future participation in additional market opportunities. As market footprints evolve, transmission alternatives not only allow delivery of remote resources to APS customers, but also can bring significant load and resource diversity to APS customers, ultimately resulting in customer cost savings. In fact, market participation coupled with resource adequacy constructs like WRAP and better transmission connectivity within and between market footprints can allow for reliability and enhanced clean energy integration at a lower customer cost than could have been achieved without it. Additional transmission between balancing authorities, states, and regions can enhance the load and resource diversity benefits and help keep customer costs lower. APS continues to pursue transmission options that provide benefits to customers as it explores and advances participation in markets.

4 https://www.aps.com/-/media/APS/APSCOM-PDFs/About/Construction-and-Power-Line-Siting/Power-Line-Siting/2023-2032_Ten_Year_Transmission_Plan

5 Arizona Public Service Company Pro Forma Open Access Transmission Tariff.

MODERNIZING THE GRID

Defining the Modern Grid

Advanced technologies are driving the transformation to a modernized energy grid. These technologies allow full grid visibility, control and operating flexibility of the core distribution infrastructure while simultaneously supporting integration of renewable energy and customer-connected devices. The grid continues to evolve to meet changing customer needs and facilitate active participation on the grid as customers adopt new technologies — such as EVs, rooftop solar, energy storage, smart appliances, and energy management devices — that affect optimization and operation of the grid itself. With rising levels of technology adoption and customer participation comes increased potential for cybersecurity challenges that must be effectively managed and mitigated to make the modern grid a reliable, resilient reality.

This modern grid must:

- Provide full visibility and control to grid operators;
- Continue to operate at high levels of reliability;
- Have automated capability to quickly detect and isolate problems and restore service;
- Integrate customer technologies including rooftop solar PV (which may be paired with energy storage), EVs, Wi-Fi connected thermostats, and other evolving customer technologies;
- Improve the system's power quality and efficiency through automated volt VAR management;
- Optimize operation considering customer technologies as part of the solution;
- Improve modeling and telemetry of the contributions of load and generation when aggregating; and
- Securely and reliably manage data and information exchange to provide enhanced visibility, control and optimization options.

The path to the modern grid requires strategic, long-term vision and investment in an appropriate technology mix designed to update the decades-old infrastructure to enable integration of these newer technologies.

KEY OBJECTIVES

MAINTAIN RELIABILITY AND OPERATIONAL FLEXIBILITY

At its core, the APS system must be planned and designed to provide high efficiency and availability of electricity to customers. This includes minimizing downtime for unexpected events and providing redundant paths that facilitate continuity of service to customers while faulted equipment is restored. As the volume of distributed energy resources (DER) continues to grow, the ability to monitor and maintain the system within acceptable thermal, voltage, and protection criteria becomes more complex.

EMPOWER CUSTOMERS

Empowering customers to exercise choice and adopt technologies to interactively participate as energy producers and consumers depends on the ability of a utility grid operator to "see" what is happening, much like an air traffic controller. Customer DERs introduce the two-way electricity flow from the customer to the utility. With increased visibility and control, smart grid systems expand situational awareness, letting utilities know about changes in localized customer demand and generation. This can lead to quicker response to adverse grid conditions and maximize the grid's capability while minimizing potential negative impacts on the system or other customers.

INTEGRATE DISTRIBUTED RENEWABLE RESOURCES

DERs such as rooftop solar PV present an opportunity for customer choice but also introduce physical challenges to the system, as energy must be used or stored as it is produced. For example, the energy output of solar PV does not coincide with typical peak customer demand in Arizona. Solar produces the most energy in midday, while customers use the most energy in the late afternoon and early evening. Output variability during cloudy or dusty periods can be high, with loss of up to 90% of solar PV production from minute-to-minute, creating unacceptable power fluctuations from the "masked load" that was being served by solar PV. APS must account for and respond to these challenges in its resource and grid planning and operations.

To Learn More

Arizona Corporation Commission
https://azcc.gov

Arizona Public Service Company Pro Forma Open Access Transmission Tarriff (OATT)
https://www.oasis.oati.com/woa/docs/AZPS/AZPSdocs/APS_OATT_Volume_2_20230711.pdf

Biennial Transmission Assessment (BTA)
https://azcc.gov/utilities/electric/biennial-transmission-assessment

Open Access Same-Time Information System (OASIS)
http://www.oasis.oati.com/azps/index.html

Federal Energy Regulatory Commission (FERC)
https://www.ferc.gov

North American Electric Reliability Corporation (NERC)
http://www.nerc.com/Pages/default.aspx

Western Electricity Coordinating Council (WECC)
https://www.wecc.org/Pages/home.aspx

Southwest Area Transmission
http://regplanning.westconnect.com/swat.htm

WestConnect
http://www.westconnect.com

Northern Tier Transmission Group (NTTG)
https://nttg.biz/site/index.html

California ISO
http://www.caiso.com/

CHAPTER 4

REGULATORY

FEDERAL AND STATE REGULATIONS

Resource planning is governed by a wide range of federal, state and local laws, primarily focused on: planning and standard-setting, environmental, licensing, and permitting. Related planning functions, such as transmission, are covered in the Company's other various regulatory filings.

KEY LEGISLATIVE AND REGULATORY AUTHORITIES GOVERNING APS RESOURCE PLANNING

U.S. CONGRESS

Passes energy and environmental-related legislation from which federal agencies promulgate regulations.

U.S. ENVIRONMENTAL PROTECTION AGENCY (EPA)

Establishes and enforces federal regulations implementing laws passed by the U.S. Congress concerning the protection of natural resources and the prevention, limitation, and cleanup of pollution within the environment.

U.S. NUCLEAR REGULATORY COMMISSION (NRC)

Oversees the safety and licensing of nuclear power plants.

FEDERAL ENERGY REGULATORY COMMISSION (FERC)

The Federal Energy Regulatory Commission regulates interstate transmission of electricity, natural gas, and oil, and also regulates hydropower projects and natural gas terminals. This includes the Open Access Transmission Tariff.

ARIZONA CORPORATION COMMISSION (ACC)

Sets utility rates, governs resource and transmission planning activities, and sets standards to achieve state-wide energy objectives.

ARIZONA DEPARTMENT OF ENVIRONMENTAL QUALITY (ADEQ)

Administers Arizona's environmental laws and delegated federal programs to prevent air, water, and land pollution and ensure cleanup of contaminated properties.

LOCAL AIR QUALITY DEPARTMENTS

Administers delegated authorities to implement the federal Clean Air Act within certain Arizona county jurisdictions (e.g., Maricopa County and Pinal County), including without limitation preconstruction and operating permits for thermal power plants.

TABLE 4-1. KEY REGULATORY AND PERMITTING REQUIREMENTS

RULES AND STANDARDS
Arizona Corporation Commission • Integrated Resource Planning (IRP) Rules • Ten-Year Transmission System Plan • Certificate of Environmental Compatibility • Renewable Energy Standard • Energy Efficiency Standard • Procurement Rules
ENVIRONMENTAL LEGISLATION
U.S. CONGRESS • Clean Air Act (CAA) • Clean Water Act (CWA) • Resource Conservation & Recovery Act (RCRA) • Toxic Substances Control Act (TSCA) • Comprehensive Environmental Response Compensation & Liability Act (CERCLA)

TABLE 4-1 (CONT.). KEY REGULATORY AND PERMITTING REQUIREMENTS

ENVIRONMENTAL REGULATION	
U.S. ENVIRONMENTAL PROTECTION AGENCY • Regional Haze Program • Air Toxics Program • National Ambient Air Quality Standards • Carbon Pollution Standards for Fossil-Fired Electric Generating Units • Cooling Water Intake Structure Regulations • Revised Effluent Limitation Guidelines • Coal Combustion Residual Regulations	**ARIZONA DEPARTMENT OF ENVIRONMENTAL QUALITY** • Arizona laws and delegated federal programs governing air quality, water quality, groundwater protection, and waste programs
ENVIRONMENTAL PERMITTING FOR NEW CONSTRUCTION	
FEDERAL • National Environmental Policy Act Review • Endangered Species Act Consultation and Permitting • CWA Section 404 Permitting • CWA National Pollutant Discharge Elimination System • Right-of-Way for Use of Tribal Lands • NRC Nuclear Generation Licensing Process • New Source Review and Prevention of Significant Deterioration **STATE** • Certificate of Environmental Compatibility • Delegated CAA Permitting	• Arizona Pollutant Discharge Elimination System Permits (CWA Delegated) • Aquifer Protection Permit • CAA preconstruction and Title V air quality operating permits **LOCAL** • Maricopa County Air Quality Department – CAA preconstruction and Title V operating permits for facilities located in Maricopa County • Pinal County Air Quality Control Department – CAA preconstruction and Title V operating permits for facilities located in Pinal County

Arizona Corporation Commission

INTEGRATED RESOURCE PLANNING

The current Arizona Corporation Commission's (ACC or Commission) IRP Rules[1] require regulated electric utilities to file an IRP detailing how customer needs are projected to be met over a 15-year period. The IRP Rules require load-serving entities in Arizona, including APS, to submit to the Commission the following filings:

HISTORICAL FILING (EVERY YEAR BY APRIL 1)

The Historical Filing details demand- and supply-side data for the previous calendar year, except for coincident peak demand and number of customers by customer class, which are reported for the previous ten (10) years.

WORK PLAN (EVERY ODD NUMBERED YEAR BY APRIL 1)

The Work Plan outlines the contents of the upcoming IRP.

INTEGRATED RESOURCE PLAN (EVERY EVEN NUMBERED YEAR BY APRIL 1, UNLESS DIRECTED OTHERWISE BY THE COMMISSION)

The IRP details how a load-serving entity intends to meet peak load over a 15-year Planning Period and includes:

- A coincident peak load and energy consumption forecast for each month and year
- A comparison of a wide set of resource options, taking into consideration fuel and technology diversity
- The selection of a portfolio based on a wide range of considerations of demand- and supply-side options
- Documentation of assumptions, models and methods used in forecasting
- Analysis of the integration costs of renewables
- Expected reductions in environmental impacts
- Comprehensive risk assessments of the IRP components
- A 3-Year Action Plan

1 A.A.C. R14-2-703.

In Decision No. 75068 (May 8, 2015), the Commission ordered Arizona's load-serving entities, with the exception of Arizona Electric Power Cooperative, to file updates to the Three-Year Action Plans contained in their respective IRPs whenever a substantive change occurs in the near-term resource plan.

In Decision No. 75269 (September 16, 2015), the Commission approved an extension for load-serving entities to file their respective 2016 cycle of IRPs until April of 2017. This extension was necessary due to the additional preparation time needed to incorporate the final rule in the Environmental Protection Agency's Clean Power Plan (CPP) Rulemaking. This effectively extended the IRP cycle to three years, instead of the two years required in A.C.C. R14-2-703. This three-year cycle has been continued in subsequent IRP cycles by the Commission approving a waiver of the two-year requirement.

In Decision No. 79017 (June 28, 2023), the Commission approved a deadline extension for load-serving entities to file their respective 2023 IRPs from August 1, 2023 to November 1, 2023.

Decision No. 76632 (March 29, 2018) included several supplemental requirements for APS and TEP to incorporate into Final IRPs. These requirements, listed below along with their location within the 2023 IRP, include:

- Portfolio analyses with forecasted changes in costs for both established and emerging technologies — Chapter 5
- Independent third-party analysis of the scenarios and portfolios
- Detailed discussion of natural gas storage from both a market development and gas cost perspective — Chapter 2
- Sensitivity analysis with a wide range of gas price scenarios — Chapter 5
- Portfolio analysis with a storage alternative as a resource option and consider storage alternative when considering new generation capacity, or upgrades to existing generation, transmission, and distribution systems — Chapter 5
- Scenarios with both no load growth and low growth under one percent (1%) — Chapter 5
- In Decision No. 77512 (December 17, 2019), the Commission required APS to provide all relevant Qualified Facility (QF) data every three years as part of its IRP. The data should include the number of QF contracts entered into to date, nameplate capacity for each interconnected QF and the avoided cost rate for each interconnected QF. APS is currently in discussions with QF counterparties to develop projects in Arizona and will notify the Commission of executed contracts and project specifics on an ongoing basis — Chapter 2.

Decision No. 78499 (March 2, 2022) included further requirements for APS and TEP to incorporate into Final IRPs. These requirements, listed below with their location within the 2023 IRP, include:

- A comprehensive analysis of power system resiliency to extreme weather — Chapters 1, 2, 5, Appendix D
- A dedicated section that explicitly discusses the load serving entities' natural gas price assumptions, the impact of those assumptions on resource procurement decisions, and the implications of declining natural gas usage as the load-serving entities shift resource mixes to achieve emission reductions — Chapters 2, 5
- A discussion of participation in regional markets and the effects of that participation on near- and long-term resource procurement actions — Chapter 1
- Robust retirement analyses and a dedicated, comprehensive analysis describing how the load-serving entities evaluated the operations of its current resources, how retirement dates were selected, and why, and what the economic impact to ratepayers will be — Chapter 5
- A report upon the value of distribution grid-connected resources as compared to transmission-connected, to determine the optimal mix of renewable energy and energy storage interconnected to distribution versus resources interconnected to transmission — Chapter 5
- A comprehensive analysis that presents the costs and benefits of their emissions reduction commitments, compared to an approach absent these commitments, to their ratepayers — Chapter 5
- A comprehensive discussion regarding how the load-serving entities' methods for addressing resource adequacy are being adapted to address concerns with increasing variability on the bulk electric system — Chapters 1, 2, 5, Appendix D

- A full accounting of the sources and costs of the hydrogen fuel and any associated capital expenditures to produce that fuel — Chapter 2
- The extension of key tax credits and its plan to run one of the Four Corners units seasonally — Chapter 2
- At minimum, ten resource portfolios that are designed to evaluate the range of resource procurement actions, and their respective costs and benefits. These portfolios include (Chapter 5):
  - An analysis of a technology agnostic resource portfolio
  - One or more portfolios which eliminate coal unit must-run designations
  - One or more portfolios which remove modeling restrictions that limit the amount of energy efficiency that can be selected as a resource option
  - One or more portfolios which remove modeling restrictions on the economic cycling and economic retirement of coal units
  - One or more portfolios which achieve an annual minimum of 1.5 percent energy savings as a percent of retail sales
  - Multiple portfolios studying the early exit of the Four Corners Power Plant, with dates between 2024 – 2031 considered
  - Information on how each portfolio performs in terms of total cumulative emissions reductions in addition to annual emissions numbers

TEN-YEAR TRANSMISSION SYSTEM PLAN

In compliance with A.R.S. § 40-360.02, the ACC requires Arizona regulated electric utilities to file an annual Ten-Year Transmission System Plan (Ten-Year Plan) for major transmission facilities. Arizona regulated electric utilities are also required to file a Renewable Transmission Action Plan in accordance with ACC Decision No. 70635 (December 11, 2008), a Technical Study on the Effects of DG/EE on Fifth Year Transmission in accordance with ACC Decision No. 74785 (October 24, 2014) and internal planning criteria and system ratings in accordance with ACC Decision No. 63876 (July 25, 2001).

Commission Staff reviews utility Ten-Year Plans every two years as part of the Commission's Biennial Transmission Assessment (BTA). The BTA assesses the adequacy of Arizona's transmission system to reliably meet existing and future energy needs of the state and reviews regional transmission planning issues. Staff conducts a review of the utilities' transmission enhancements and additions, solutions for transmission import constraints where any may exist in various load pockets, and local transmission system mitigation measures where needed.

ACC STANDARDS

RENEWABLE ENERGY AND ENERGY EFFICIENCY STANDARDS

The ACC Renewable Energy Standard (RES)[2] requires fifteen percent (15%) of retail sales be met by renewable energy by 2025. As part of the RES, APS must also meet a portion of the renewable energy requirement with distributed energy resources. The ACC Energy Efficiency Standard (EES)[3] requires a twenty-two percent (22%) cumulative energy savings requirement by 2020 determined as a percent of the prior year's retail sales, which the Company has continued to maintain. Additionally, Decision No. 78499 (March 2, 2022) requires APS to demonstrate 1.3% annual energy efficiency that is measured by megawatt-hour savings over its next three-year planning period.

RENEWABLE ENERGY STANDARD

The ACC's RES requires electric utilities under its jurisdiction to supply an increasing percentage of their retail electric energy sales from eligible renewable resources, including solar, wind, biomass, biogas, and geothermal

2 A.A.C. R14-2-1801 et seq.
3 A.A.C. R14-2-2401 et seq.

technologies. The renewable energy requirement is currently thirteen percent (13%) of retail electric sales in 2023 and increases annually until it reaches fifteen percent (15%) in 2025. The RES also includes a carve-out for distributed energy systems of thirty percent (30%) of the overall RES requirement per year.

TABLE 4-2. RES % REQUIREMENTS

YEAR	RES REQUIREMENT[4]
2023	13%
2024	14%
2025	15%
2026	15%
2027	15%

PROCUREMENT RULES

In compliance with A.A.C. R14-2-705, APS is required to use a Request for Proposal (RFP) process as its primary acquisition process for the wholesale acquisition of energy and capacity. Additionally, in accordance with A.A.C. R14-2-705, APS may use additional approved procurement methods for the acquisition of energy, capacity and physical power hedge transactions. These methods include, but are not limited to:

- Purchase through a third-party online trading system.
- Purchase from a third-party independent energy broker.
- Purchase from a non-affiliated entity through auction or an RFP process.
- Bilateral contract with a non-affiliated entity.
- Bilateral contract with an affiliated entity, provided that non-affiliated entities were provided notice and an opportunity to compete against the affiliated entity's proposal before the transaction was executed.

Federal Energy Regulatory Commission (FERC)

GENERATION INTERCONNECTION PRACTICES

GENERATION INTERCONNECTION QUEUE REFORM

Both nation-wide and within APS's service territory, the number of large generator interconnection requests has increased substantially over the last five years. APS has historically utilized a cluster study process, with two queue windows per year. Projects are grouped together by location and system impact at the end of each cluster window and studied together. Necessary network upgrades are allocated to each of the projects within each cluster. Due to the large volume of both the number and size of projects that have been studied, and are currently in the study queue, the necessary network upgrades required to facilitate these interconnections have increased dramatically. This has increased the complexity and risk of projects and can include the identification of transmission upgrades due to projects that may not move forward. APS submitted revisions to its FERC Approved Open Access Transmission Tariff (OATT) to reform the queue process and incentivize projects that are not commercially viable to withdraw from the queue and help ensure future interconnection projects are commercially viable when making an interconnection request, which FERC approved in part in September 2023. In addition to the approved changes by APS, FERC has recently released Order No. 2023, which addresses interconnection queue reform more broadly.

4 The requirement is calculated each calendar year by applying the applicable annual percentage to the retail kWh sold. See A.A.C. R14-2-1804(B).

Environmental Legislation

U.S. CONGRESS

There have been no recent successful efforts by the United States Congress to pass legislation that materially changes federal environmental statutes. With respect to the 118th Congress, it remains unclear at this time what environmental legislation, if any, will be proposed for consideration and passage. Substantial changes to federal environmental statutes through congressional action by the current U.S. Congress are not expected at this time.

Environmental Regulations

Environmental regulations are promulgated on the federal (EPA), state (ADEQ), and county (Maricopa and Pinal) levels.[5] The EPA, specifically, has promulgated multiple regulations that have an impact on APS's operations. For detailed information on costs and risks of potential new or enhanced environmental regulations, please see Response to Rules section E.1(D) and E.1(E). A few notable regulations are included below.

CLEAN AIR ACT

The CAA regulates air emissions from stationary and mobile sources. Numerous programs have been established to protect public health and welfare by controlling emissions of air pollutants.

CLEAN WATER ACT

The CWA establishes the basic structure for regulating discharges of pollutants into waters of the United States and regulating quality standards for surface waters. Under the CWA, the EPA has implemented pollution control programs, such as setting wastewater standards for industry and water quality standards for all contaminants in surface waters.

RESOURCE CONSERVATION AND RECOVERY ACT

The RCRA gives the EPA the authority to control hazardous waste from "cradle-to-grave." RCRA also regulates the management of non-hazardous solid wastes, such as coal combustion residual wastes (CCR), as well as underground tanks storing petroleum and other hazardous substances.

ENVIRONMENTAL PERMITTING FOR NEW CONSTRUCTION

Construction of new electric facilities, whether for electric generation or for transmission, requires compliance with extensive permitting and environmental impact review processes. Depending on the specifications of the facility and its location, the permitting and review process may take 24 months or more to complete before construction is authorized. The major permits and environmental review obligations required by federal, state and local authorities are described below.

FEDERAL

ENVIRONMENTAL PROTECTION AGENCY

On May 23, 2023, the EPA published a proposed regulation to limit carbon dioxide emissions from new and existing fossil-fuel fired power plants. Unlike EPA's CPP, which took a broad, system-wide approach to regulating carbon emissions from electric utility power plants, the most recent proposal is limited to measures that can be installed at individual power plants to limit planet-warming emissions. As such, this proposal is focused on emission limitations achievable through "Best Systems of Emission Reduction" that apply mechanisms, such as carbon

5 Additional information regarding environmental regulations can be found in Response to Rule D.17.

capture and sequestration or utilization (CCS), “clean” hydrogen gas (H2) co-firing, natural gas co-firing, and efficiency improvements, to various sub-categories of thermal power plants. APS is reviewing the impact of these proposed regulations and is providing additional information in Response to Rules section E.1(D) & Rule E.1(E).

NATIONAL ENVIRONMENTAL POLICY ACT REVIEW

The National Environmental Policy Act (NEPA) requires federal agencies to prepare an Environmental Impact Statement (EIS) on proposals for major federal actions (including authorizations or approvals) significantly affecting the quality of the human environment. The EIS describes the environmental impacts of a proposed action and alternative actions that may be taken instead of the one proposed. An EIS may be required when a development is proposed for a site on undisturbed, environmentally sensitive or federally-protected land, or for projects subject to federal funding or approval. For those projects that are not expected to result in significant environmental impacts, federal decision or action agencies are authorized to prepare an Environmental Assessment (EA) along with a Finding of No Significant Impact (FONSI). An EA/FONSI is typically a more concise document than an EIS and requires significantly less environmental review to complete.

ENDANGERED SPECIES ACT CONSULTATION AND PERMITTING

With respect to projects that may result in harm to species federally designated as threatened or endangered, compliance with the species impact review procedures under the federal Endangered Species Act (ESA) is required. For projects with a federal nexus, such as those involving land under federal jurisdiction or federal funding or authorizations, the federal action or decision agency must consult with the U.S. Fish and Wildlife Service under Section 7 of the ESA, which can result in certain species protection conditions being placed on federal acts of discretionary authority. As for those projects without a federal nexus, Section 9 of the ESA provides for incidental “take” permitting, which authorizes purely private activity that may otherwise harm protected species subject to certain species protection conditions.

CLEAN WATER ACT SECTION 404 PERMITTING

For projects that cross, or otherwise result in the discharge of dredge or fill material within, certain surface water resources under federal jurisdiction (or “Waters of the U.S.”), permitting under Section 404 of the CWA from the U.S. Army Corps of Engineers is required. The current scope and extent of what qualifies as a surface water resource under federal jurisdiction is subject to controversy and dispute, including a recent U.S. Supreme Court decision that significantly narrowed the definition of what is considered a Water of the U.S.

RIGHT-OF-WAY FOR USE OF PUBLIC LANDS

When constructing generation facilities or installing transmission lines on tribal lands, within national forests or parks, or on other federally designated public lands (i.e., under the jurisdiction of the federal Department of the Interior or Department of Agriculture), a right-of-way, permit or other special-use authorization is required. For development within tribal reservation land, including trust lands, approval must be sought from the governing tribe and the U.S. Bureau of Indian Affairs. These types of approval often require NEPA review and ESA consultation.

STATE

CERTIFICATE OF ENVIRONMENTAL COMPATIBILITY

Utilities, with proposed power plants or transmission lines subject to the jurisdiction of the ACC and the Arizona Power Plant and Line Siting Committee (Committee), are required to make an application with the ACC for a Certificate of Environmental Compatibility (CEC).[6] During public evidentiary hearings, the Committee considers the application relative to a series of factors[7] including, among other things, the status of all applicable permits. Following these deliberations, the Committee makes a recommendation to the Commission regarding the CEC. The

6 Applies to construction of a new thermal electric, nuclear, or hydroelectric facility of 100 MW or more or a transmission lines of 115kV or greater.

7 Specified in A.R.S. § 40-360.06.

ACC then makes a final determination on the CEC application complying with A.R.S. § 40-360.06 and balancing, in the public interest, the need for an adequate, economical, and reliable supply of electric power with minimizing environmental impact.[8]

ARIZONA DEPARTMENT OF ENVIRONMENTAL QUALITY

ADEQ is Arizona's primary environmental regulatory agency, with responsibility for developing and enforcing state regulations that implement Arizona environmental laws, and for helping ensure that businesses and regulated sources operate according to federal and state environmental laws and regulations. Three programmatic divisions — Air Quality, Water Quality, and Waste Programs —carry out ADEQ's core responsibilities. In some areas, Arizona's environmental laws go beyond the federal laws.

Similar to the EPA delegation authority, ADEQ may delegate some permitting and enforcement responsibilities to counties within the state. For more detail, please see Response to Rules section E.1(D) and E.1(E).

LOCAL

MARICOPA COUNTY AIR QUALITY DEPARTMENT (MCAQD)

MCAQD issues Clean Air Act (CAA) preconstruction and Title V operating permits for facilities located within Maricopa County, which include APS's Redhawk, West Phoenix, and Ocotillo power plants. As with ADEQ, MCAQD requires a Title V permit for any major stationary source of air emissions. MCAQD also requires a CAA preconstruction permit for any new major source of air emissions or for major modifications to existing sources of air emissions.

PINAL COUNTY AIR QUALITY CONTROL DEPARTMENT

APS's natural gas-fired Saguaro and Sundance power plants are located in Pinal County. Therefore, these plants are under the jurisdiction of the Pinal County Air Quality Control Department, which issues CAA preconstruction and Title V operating permits for facilities located within Pinal County.

8 A.R.S. § 40-360.07.

To Learn More

Arizona Corporation Commission
https://azcc.gov

Arizona Department of Environmental Quality
https://www.azdeq.gov/

Arizona Department of Water Resources
http://www.azwater.gov/

Federal Energy Regulatory Commission
https://www.ferc.gov/

Maricopa County Air Quality Department
https://www.maricopa.gov/1244/Air-Quality

Pinal County Air Quality Department
https://www.pinal.gov/305/Air-Quality

U.S. Bureau of Reclamation
https://www.usbr.gov/

U.S. Environmental Protection Agency
https://www.epa.gov/

U.S. Nuclear Regulatory Commission
https://www.nrc.gov/

CHAPTER 5

PORTFOLIO ANALYSIS

PORTFOLIO ANALYSIS

The IRP process culminates in the creation, evaluation, and comparison of a number of alternative resource plans to reliably meet future electricity needs. This chapter discusses the development and analytical evaluation of alternative resource plans and their associated potential risks. The Company discusses the broad range of portfolios analyzed, modeling approaches and key assumptions used in the development of portfolios, results of the analysis, and concludes with the presentation of APS's Preferred Plan. Consideration is given to many factors to evaluate trade-offs among various portfolios to meet customers' long-term needs of reliable, cost effective electricity.

The portfolio analysis recognizes the importance of the Action Plan window as emphasis is placed on decisions the Company must make today to prepare for the future. While the portfolios studied — and the Preferred Plan itself — provide results for the Planning Period of 15 years, many future decisions beyond the Action Plan period may be altered or updated as customers' needs evolve, the relative costs of resource options change, and new technologies enter the market as viable alternatives to today's mature technologies.

Portfolios Studied

The term "resource portfolio" refers to a complete set of resources over the Planning Period designed to reliably meet customer demand for electric energy. In the IRP, APS constructs and evaluates an expansive range of potential portfolios using advanced modeling tools to optimize APS's future resource mix, evaluating how different choices and changes in key input assumptions would impact customers. By synthesizing learnings across the portfolios studied, APS is able to create a Preferred Plan that meets customers' reliability needs, is robust in the face of significant uncertainty, and positions the Company to adapt to future changes in the planning landscape.

The IRP study produced resource portfolios that fall into one of the following three areas: (1) the Reference Case, or starting point, which reflects previous Company commitments and expected future economic conditions, (2) those driven by requirements included in Decision Nos. 78499 and 76632, and (3) those identified by APS as having potential strategic value to analyze in the IRP. Analysis and progressive insight gained through evaluation of these portfolios collectively serve as the basis for the development of the Company's Preferred Plan.

COMMISSION REQUIREMENTS

Decision No. 78499 established a number of requirements regarding portfolios that utilities must consider in their IRPs. Specifically, this Decision requires the following be included:

- A minimum of ten resource portfolios
- A technology agnostic (neutral) resource portfolio, which is the least-cost method of safely and reliably meeting customers' energy needs without regard for emissions reductions goals or any renewable or carbon emissions standards
- One or more portfolios which eliminate coal unit must-run designations
- One or more portfolios which remove modeling restrictions on economic cycling and retirement of coal units
- One or more portfolios that remove modeling restrictions that limit the amount of energy efficiency that can be selected as a resource option
- One or more portfolios which achieve an annual minimum of 1.5% energy savings as a percent of retail sales from a broad portfolio of energy efficiency measures (consistent with 15% cumulative savings over ten years)
- A portfolio with a demand-side resource capacity equal to at least 35% of APS's 2020 peak demand. The portfolio of demand-side management measures shall include rate-enabled, load-shifting technologies, including, but not limited to, demand response, energy

storage, and smart thermostats, that provide customer bill savings and clean energy benefits

- Sensitivities on the level of load growth expected in our service territory (0% and <1% per year)
- Multiple scenarios studying the early exit of the Four Corners Power Plant, with dates between 2024-2031 considered.

ADDITIONAL STRATEGIC SCENARIOS

These portfolios show the impact of different input assumptions, with changing gas prices and renewable technology costs. These cases demonstrate the durability of resource decisions under a broad subset of future scenarios.

PREFERRED PLAN

APS's Preferred Plan is the final outcome of the portfolio analysis. Like preceding portfolios, it is developed using an optimization-based approach, but also incorporates key learnings from the balance of previous scenarios.

SCENARIO MATRIX

Table 5-1 lists the full range of scenarios that were studied in this IRP. Including the Preferred Plan, 14 different scenarios were developed and evaluated. The Company opted to study more than the Commission required 10 scenarios due to the number of uncertainties inherent to the current planning environment.

TABLE 5-1. SCENARIO MATRIX

ID	SCENARIO	REQUIRED BY COMMISSION
1	Reference Case	
2	Technology Neutral	■
3	No Load Growth	■
4	Low Load Growth	■
5	High Load Growth	
6	High Demand-Side Technology	■
7	Four Corners Coal Exit 2027	■
8	Four Corners Coal Exit 2028	■
9	Four Corners Coal Exit 2029	■
10	Four Corners Coal Exit 2030	■
11	High Gas Prices	
12	High Renewable Technology Costs	
13	Low Renewable Technology Costs	
14	**APS Preferred Plan**	

CLIMATE CHANGE SCENARIO ANALYSIS

Starting in 2022, APS partnered with the Electric Power Research Institute (EPRI) to conduct a Climate Change Scenario Analysis (CCSA). This analysis is a foundational assessment of the risks and uncertainties that APS could potentially face from climate change and the clean energy transition. CCSA is commonly used throughout the electric utility industry as companies and other stakeholders, including investors and customers, seek information to better understand the risks associated with climate change, assets, and long-term investments. Additionally, these analyses are becoming common disclosure expectations in reporting standards like Sustainability Accounting Standards Board (SASB) and Task Force on Climate-related Financial Disclosures (TCFD).

As part of conducting the CCSA, APS and EPRI engaged with a variety of internal and external stakeholders, including the Resource Planning Advisory Committee, to gather feedback on the inputs and variables used in the modeling, and to report progress. Once complete, APS expects to use the information from this analysis to facilitate strategic thinking and risk mitigation planning, to better understand the business risks resulting from climate change, and to ultimately support the development of appropriate long-term climate adaptation and resilience strategies. It is also expected that inclusion of these strategic approaches will help to inform future IRP development.

U.S. EPA PROPOSED RULES ON FOSSIL FUEL-FIRED POWER PLANTS

On May 23, 2023, U.S. EPA published a proposed regulation to limit carbon dioxide emissions from new and existing fossil fuel-fired power plants. Unlike U.S. EPA's previously proposed Clean Power Plan, which took a broad, system-wide approach to regulating carbon emissions from electric utility power plants, the most recent proposal focuses on measures that can be installed at individual power plants to limit planet-warming emissions. As such, this proposal is focused on emission limitations achievable through "Best Systems of Emission Reduction" that apply mechanisms, such as carbon capture and sequestration or utilization (CCS), "clean" hydrogen gas (H2) co-firing, natural gas co-firing, and efficiency improvements. If these rules are approved, APS anticipates limited impact to coal facilities, with Cholla ceasing to burn coal in 2025 and APS exiting from Four Corners in 2031. Natural gas facilities may be impacted by the capacity factor requirements. APS did not include these proposed rules in the IRP analysis; however, the Company did include a carbon tax that serves as a proxy for future legislation impacting emissions-producing facilities. This approach adequately captures potential future changes in regulation and provides a more durable analysis considering likely revisions to the EPA rules between now and finalization. APS will continue to evaluate these rules and will build them into future modeling if they are approved.

Methods and Key Assumptions

APS has made several changes to its modeling process to align with Commission requirements and industry best practices. APS utilized public data sources for input data whenever possible, and applied APS-specific data where appropriate. The following sections describe in further detail how APS approached ensuring sufficient Resource Adequacy (RA), capacity expansion, and load forecasting.

MODELING APPROACH

Over the next two decades, APS's portfolio will transition from one that has predominantly relied on firm generating resources (nuclear, natural gas, and coal) to serve customers' needs to one that encompasses an increasingly diverse mix of technologies with differing characteristics and capabilities. As this transition occurs, the day-to-day operations of APS's portfolio will change dramatically, bringing both new challenges and opportunities. These include:

- Increasing frequency of periods of overgeneration, where the amount of nuclear and renewable energy available at any moment in time exceeds the current load, and the surplus must either be stored, curtailed, or sold in wholesale markets
- Shifting reliability risks, where the increasing penetration of solar generation will cause the most challenging periods for reliability to shift into the evening once the sun has set, after the traditional afternoon peak
- Increased cycling of flexible fossil power plants due to increased net load variability; plants that have historically run on mid-merit or baseload duty cycles will increasingly face economic incentives to reduce output or turn off entirely during periods of higher renewable generation
- New sources of flexibility from energy storage, which is expected to quickly become a significant and important technology category in APS's portfolio.

The complexity of planning a least-cost portfolio that maintains reliability has increased significantly. To ensure that the analytics that inform this plan reflect increasing complexity, APS has integrated new state-of-the-art modeling tools into the planning process. Figure 5-1 illustrates the four stages of analysis that APS undertook in its planning process.

FIGURE 5-1. IRP PLANNING AND ANALYSIS STAGES

Loss of Load Expectation Modeling (SERVM)	**Long-Term Capacity Expansion Modeling (AURORA)**	**Production Cost Modeling (AURORA)**	**Revenue Requirement Modeling (Internal)**

RESOURCE ADEQUACY MODELING

Resource Adequacy modeling is widely recognized throughout the industry as the gold standard for assessing whether a portfolio of resources meets an adequate standard for reliability. Resource Adequacy models simulate the ability of a portfolio of generation resources to meet customer demands across all hours of the year — and repeat that simulation thousands of times in a Monte Carlo process — to provide robust analysis of the potential frequency, magnitude, and duration of reliability events that may occur. One of the standard outputs of a Resource Adequacy model is "Loss of Load Expectation" (LOLE), a statistical measure of the expected number of days per year that would experience reliability events; the common industry reliability standard of "one day in ten years" represents a measurement of LOLE.

In the IRP, APS used SERVM, an industry-leading Resource Adequacy model licensed by Astrapé Consulting, to ensure that the portfolios meet a sufficient standard for reliability. SERVM is used for several purposes: (1) to update APS's planning reserve margin requirement to be consistent with the "one day in ten years" reliability standard (represented as an LOLE standard of 0.1 days per year); and (2) to evaluate the effective load carrying capability (ELCC) of renewable and storage resources. These two study outputs allow for the characterization of the total need for resources to maintain reliability, as well as how much each different technology can contribute to meeting that need. These values serve as inputs to subsequent stages of APS's IRP analysis.

LONG-TERM CAPACITY EXPANSION (LTCE) MODELING

To develop portfolios for each prescribed scenario, APS used Energy Exemplar's Aurora Energy Forecasting Software (Aurora), an LTCE model that optimizes the selection of future resources to meet customers' growing needs. The transition to this platform was motivated both by Decision No. 78499 and the desire to modernize APS's analytical toolkit to develop the most informed, robust plans for customers. The use of Aurora's LTCE functionality identifies least-cost portfolios while accounting for a number of complex and interactive dynamics:

- Optimization across full planning horizon: Aurora's optimization algorithms identify portfolios that minimize the present value revenue requirement across the full planning horizon (through 2038). This long-term perspective identifies portfolios that meet both near- and long-term goals of maintaining reliable service at the least cost while also ensuring that both current and future market conditions are considered. However, the model cannot evaluate the feasibility of bringing online a high volume of resources in a particular timeframe, nor does it recognize the supply chain or nascent nature of some technologies that are being evaluated;
- Endogenous hourly dispatch: Aurora's LTCE module includes a simplified representation of a traditional hourly production cost model. The LTCE is configured to include one representative week of dispatch for each month of the year. The inclusion of this reduced-form hourly operational simulation allows the LTCE to consider the hour-to-hour operational dynamics that will occur as penetrations of renewables and storage resources increase; and
- Dynamic ELCC curves for each technology: Aurora captures the declining ELCCs of resources like wind, solar, and storage derived from the Resource Adequacy analysis. Accounting for the declining marginal capacity value of renewables and storage is essential to ensuring that APS has sufficient capacity to meet reliability standards and that it is selecting the least-cost portfolio of resources to do so.

PRODUCTION COST MODELING (PCM)

While Aurora's LTCE does include a reduced-form simulation of the operations of the APS system in each portfolio, APS takes the additional step of running a full hourly simulation of dispatch across the full planning horizon using Aurora's PCM. This simulation mimics the day-to-day decisions operators would undertake to balance the loads and resources on the system at the least cost to customers, including refinement of metrics such as fuel and O&M costs, market purchases, and renewable curtailment.

REVENUE REQUIREMENT MODELING

This is the final step in APS's analysis that combines APS system production costs (fuel, variable O&M expenses, purchased power expenses, and emissions costs) with the following: (1) carrying costs on existing resources, future resources, future transmission over and above APS's Ten Year Transmission Plan, and capital outlays on existing generation (impact of debt and equity financing, taxes, and depreciation), (2) fixed fuel (commodity and fixed transport), (3) fixed O&M expenses for existing and future resources, (4) EE, DR, and DE expenses.

KEY INPUTS AND ASSUMPTIONS

Each of the resource portfolios assessed incorporate the following criteria:

LOAD FORECAST

The load forecast used throughout the following analysis is based on the best available data as of the end of the first quarter 2023 and is described in more detail in response to Rules C.1 through C.3 and E(a). APS projects annual peak demand and energy needs will increase at compounded annual growth rates of 2.4% and 3.7%, respectively, during the IRP Planning Period of 2023-2038, which is inclusive of distributed generation and DSM/EE.

DISTRIBUTED ENERGY (DE)

DE (e.g., rooftop solar) has grown dramatically over the last few years and is projected to continue to grow at approximately 150 MW per year through 2038. This amounts to more than 2,500 MW of new DE added in APS service territory from 2023 through 2038. Due to the high penetration of solar energy on the APS system and the misalignment between DE production and peak demand, incremental solar energy contributes about 10% of nameplate value toward meeting the summer peak load. The DE forecast, including existing DE, is provided in response to Rule D.5.

DEMAND-SIDE MANAGEMENT (DSM)

During the IRP period, APS can achieve between 175 GWh and 200 GWh in cost effective energy savings at an estimated cost of $37 million to $49 million annually. EE programs and program costs are based on the DSM potential study, performed by Guidehouse and provided in Appendix C, and are assumed to continue at that pace over the Planning Period. Programs focus on peak load reduction and load shifting rather than targeting MWh requirements because peak load reduction and load shifting are most effective at displacing additional supply-side resources. The cost of the DSM programs, including DR, is approximately $74 million in 2023. Additional DSM/customer resources (DR) are included in the portfolios.

In the 2023 IRP, APS retained Guidehouse to develop estimates of potential for EE in the APS service territory over the IRP planning horizon. Guidehouse crafted two bundles of EE measures to be available to the model: one that mirrors the base DSM plan, and a second that reflects the maximum realistically achievable potential using current program structures and regulatory policy. The LTCE model was given the option to select between the two bundles based on their associated costs and their capacity and energy benefits to determine which level of EE would be part of a least-cost resource plan. This is an important step forward in alignment of supply- and demand-side resource planning.

COMPLIANCE WITH STANDARDS

All portfolios developed exceed the state's Energy Efficiency Standard (EES) and exceed compliance with the state's Renewable Energy Standard (RES).

ASSET OWNERSHIP

APS has not determined which assets may be owned by APS or contracted through third-party PPAs. However, for modeling purposes only, new resources are assumed to be APS-owned. This provides for a more straightforward comparison of economic analysis of technologies and resource portfolios that is not clouded by the different cost trajectories of ownership versus PPAs. The actual mix of ownership versus PPAs will be informed by the results of ASRFPs and determined as APS executes its plan over the coming years.

NATURAL GAS PRICES

The natural gas price curve utilized in the base case analyses was derived from an analysis of the forward market price curve for natural gas as of the end of the first quarter 2023 and includes delivery charges. While the Company purchases the majority of its natural gas supply from the San Juan basin, natural gas hedging takes place at the Henry hub, which is reflected in the analysis. APS utilizes Henry Hub Natural Gas Futures settlement prices from the New York Mercantile Exchange (NYMEX) in the development of its natural gas price forecast. These settlement prices currently extend to the end of 2035 and represent monthly financial contracts for natural gas futures. This is not considered a forecast, because it tracks actual forward commodity pricing instead of being based on prior trends or a forecasting model. Pricing beyond 2035 is escalated based on an interest rate factor derived from the U.S. Treasury 10-year yield less the 10-year inflation index yield. APS also includes transportation fees necessary to deliver the natural gas to different locations. These delivery location forward curves are derived using a basis to the Henry Hub Natural Gas Futures forward price curve.

FIGURE 5-2. NATURAL GAS PRICE CURVE

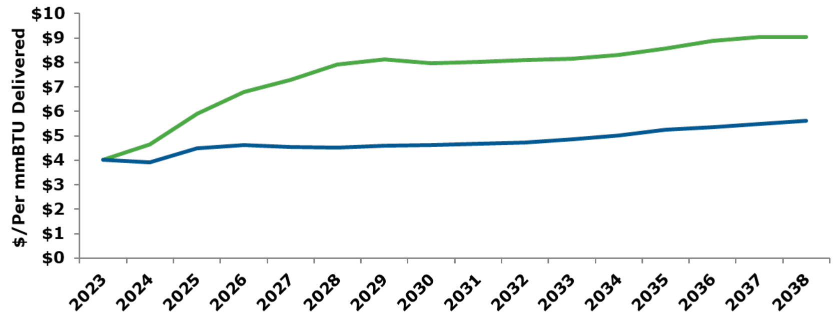
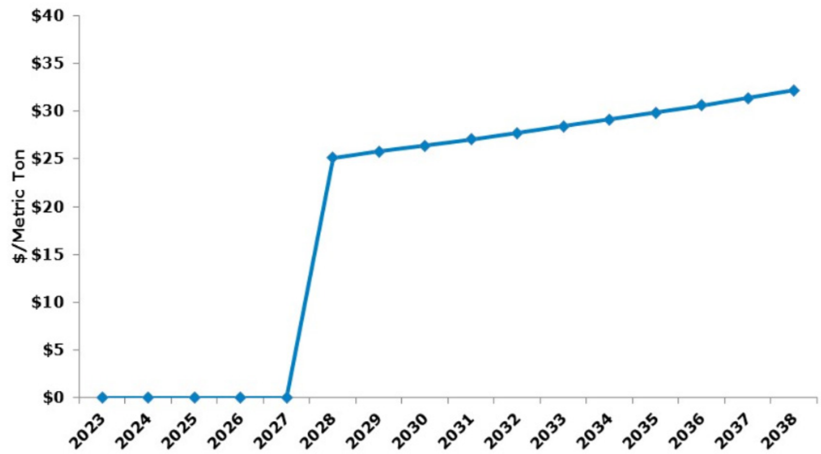


FIGURE 5-3. CARBON PRICE CURVE



CARBON COSTS

APS is incorporating assumed carbon costs based on the actual trading price of CO2 allowances in the California wholesale energy market. The U.S. EPA has proposed additional emission requirements on existing coal and natural gas facilities based on their retirement date, size, and capacity factor. APS continues to analyze the impacts of these proposed regulations, and believes that the inclusion of a carbon tax outside of the Planning Period is a suitable proxy for future legislation and environmental regulation, including the U.S. EPA's currently proposed power plant standards, given that they remain in a state of flux. The 2023 IRP analysis assumes that carbon legislation occurs at either the state or federal level and carbon prices take effect in 2028, escalating at the assumed rate of inflation.

COAL PLANT OPERATIONS

Accurately reflecting both the engineering constraints and economic signals that coal plant operators will respond to is important to understanding how those plants will operate as APS's portfolio evolves in the future. In previous IRPs, APS modeled coal plants as "must-run" units, a designation that ensured that they were "committed" and able to dispatch whenever they were available. This approach was largely consistent with historical experience operating APS's coal plants, where both engineering limitations and the conditions in Western wholesale markets created an environment where it made sense to run the plants throughout the year.

Looking forward, APS recognizes that changes in market conditions and wholesale pricing dynamics may make it such that running the plant at all times may not produce the lowest cost outcomes for customers. At the same time, stakeholders have expressed concerns with the use of the must-run designation, and the Commission has required APS explore at least one portfolio that removes that designation. Based on APS's current understanding of the changing market, stakeholders' concerns, and the Commission's direction, the Company has explored and implemented modeling functionality that enhances the ability to represent the economic dispatch of Four Corners and has allowed for the removal of the must-run designation from all cases.

For the 2023 IRP, APS has improved the representation of the costs associated with the fuel supply agreement for Four Corners, which extends through the Company's planned exit in 2031. The fuel supply agreement specifies a minimum quantity of fuel that must be purchased annually and is based on a Four Corners capacity factor of approximately 65%. If coal use is below this level on an annual basis, there are additional costs incurred. This common contract structure for fuel agreements ensures a stable fuel supply and is reflective of the fixed and variable costs associated with fuel production. This structure also means that a portion of APS's fuel supply costs are fixed, and the effective variable cost of purchasing coal up to the minimum quantity is lower than the contract price. These economic signals have been captured within the modeling of Four Corners by implementing a two-tiered coal price function for commitment and dispatch decisions: (1) up to the minimum quantity as specified in the contract, the variable cost of fuel is equal to 24% of the contract price; and (2) above the minimum quantity, the variable cost is equal to the full contract price. The full cost of the contract is included in the final present value revenue requirement.

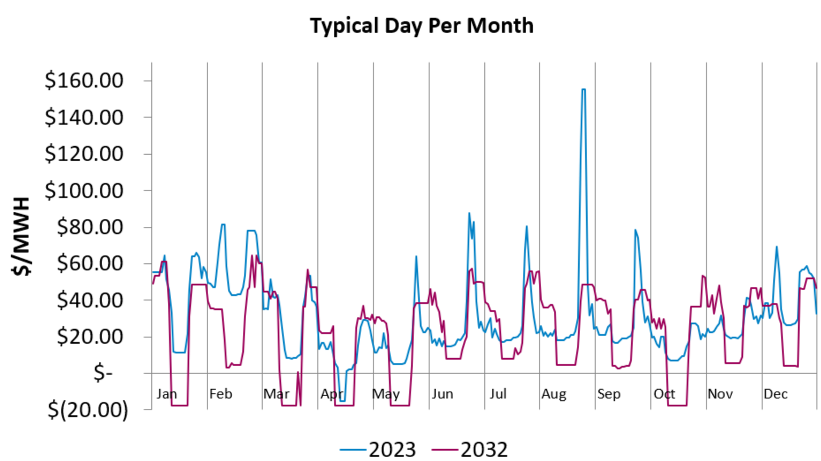
WHOLESALE MARKET PRICES

Hourly wholesale market prices for the Palo Verde Hub were developed for APS by E3. The prices, based on regional electric market fundamentals, include the gas price forecast used in this IRP. These prices show fewer negative priced periods, and overall less magnitude of negative pricing compared to APS's 2020 study work. This is due to the planned investment of energy storage resources throughout the Western U.S. market. Prices assume that, during the 15-year period, neighboring entities will invest in enough resources to maintain reliability for their expected load growth.

TECHNOLOGY COSTS

Capital costs of technologies are based on information obtained from vendors, industry publications, and evaluation of bids in APS's RFP processes. APS leveraged the National Renewable Energy Laboratory's (NREL) Annual Technology Baseline (ATB) heavily in the development of the cost information supporting this IRP. Cost curves are sourced from this data set, with some technologies increasing in cost and others showing declines during the Planning Period. The Company also leveraged any relevant RFP data in the development of these costs to better capture executable resource pricing specific to its service territory. It is essential to evaluate these resources through detailed annual production simulation models such as Aurora because these models offer

FIGURE 5-4. PALO VERDE HUB MARKET PRICES



comprehensive, annual cost estimates of how new resources integrate with the existing resource mix and meet changing load and reliability requirements rather than on a stand-alone levelized cost basis.

APS assumes that tax provisions related to PTCs and ITCs continue as detailed in Chapter 2.

METRICS EVALUATED

APS specifically evaluated each set of resource combinations using a set of key metrics that provide insight into their holistic impacts. A high-level summary of these metrics is included below, while comprehensive and detailed annual values for all are included in Attachments F.1(a) and F.1(b).

RELIABILITY

All portfolios are developed to meet APS reliability requirements of a one day in ten years LOLE. However, there are feasibility aspects to reliability as well, such as the ability to incorporate large amounts of a nascent technology or the obstacles associated with bringing on multiple GW of resources during a period where supply chains are still experiencing significant volatility. Challenges remain as to the timely development of electricity transmission and fuel supply delivery infrastructure to support large quantities of new resources. Quantitative models are not well equipped to determine the feasibility of executing a particular portfolio, and instead focus on optimal mixes of resources given a number of constraints. Some portfolios that were studied may not be feasible but are required by the Commission.

AFFORDABILITY

Portfolio Costs – Portfolio costs represent the total costs of the resource additions from generation and related incremental transmission needed to deliver that generation. While it may be indicative of the increasing costs that will develop into future rates, these costs are not inclusive of all rate components (e.g., distribution costs, other transmission costs, metering/billing costs, etc.).

Portfolio costs are measured in terms of present value of revenue requirements (PVRR) over the Planning Period (a metric that reflects the total discounted costs associated with serving customers over the 15 year horizon), as well as average system generation cost in $/MWh at the end of the Planning Period.[1]

Cumulative Capital Expenditures – Cumulative capital expenditures are an indication of how much capital APS or market participants will need to obtain over the Planning Period to execute each portfolio. Capital expenditures should not be viewed in isolation because in many cases capital expenditures result in lower fuel costs. For example, renewables have relatively high capital costs but benefit from zero-priced fuel and may also lower customer exposure to fuel price volatility.

Natural Gas Usage – Natural gas usage provides an indication of the amount of natural gas cost risk inherent in each portfolio.

ENVIRONMENTAL IMPACT

CO2 Emissions – This metric provides a gage of exposure for each portfolio relative to future climate-related regulations associated with GHG emissions. Tabulation of CO2 emissions is different yet complementary to the clean energy metric.

Clean Energy – “Clean energy” is defined herein as all non-CO2 energy resources (including existing and new EE savings, grid-scale and distributed renewable energy, nuclear, and purchases of excess energy produced from renewable sources) divided by Total Resource Requirement (generation, purchased power, and DSM/EE savings). It is assumed that purchases are produced from excess renewable energy if they are zero or negatively priced;

1 Average system generation cost, represented in $/MWh, is not intended to directly equate to customer rates; rather, it is indicative of the per-unit cost of energy from APS generation resources as outlined in each portfolio, and does not include other components of customer rates such as distribution system costs.

otherwise, they assume the carbon emissions of natural gas generation. As discussed below, DSM and renewable measurements are calculated at the sales level under the Arizona EES and RES rules.

Renewable, Clean Energy and Energy Mix Calculations – APS uses two types of metrics to report the relative shares of different types of generation in its portfolio; these each serve a specific purpose. To report the renewable energy share, the accounting conventions specified in the existing Arizona RES are used, under which each utility's share of renewables is expressed as a percentage of its retail sales.[2] The clean energy percentage is based off of the Company's energy mix, inclusive of DSM. This recognizes that APS's investment in DSM measures is an important tool for maintaining reliable service for customers.

Water Use – Water use is another important factor in analyzing portfolios and is quantified in terms of acre-feet per year.

Analysis Results

Including the Preferred Plan, APS studied 14 different portfolios in this IRP. Summary metrics for reliability, cost, and greenhouse gas emissions are presented in Table 5-2.

TABLE 5-2. RELIABILITY, COST, AND EMISSIONS METRICS ACROSS SCENARIOS

ID	SCENARIO	LOSS OF LOAD EXPECTATION (DAYS PER YEAR)	PRESENT VALUE REVENUE REQUIREMENT ($ BILLIONS)	TOTAL CO2 EMISSIONS (MILLION TONS)
1	Reference	All portfolios are designed to meet or exceed APS's LOLE standard of 0.1 days per year ("one day in ten years")	$37,722	133
2	Technology Neutral		$37,626	132
3	No Load Growth*		$31,461	75
4	Low Load Growth*		$34,013	100
5	High Load Growth*		$39,813	150
6	High Demand-Side Technology		$40,043	119
7	Four Corners Coal Exit 2027		$37,748	124
8	Four Corners Coal Exit 2028		$37,583	127
9	Four Corners Coal Exit 2029		$37,631	130
10	Four Corners Coal Exit 2030		$37,665	132
11	High Gas Prices*		$40,978	130
12	High Renewable Technology Costs*		$38,727	134
13	Low Renewable Technology Costs*		$37,233	131
14	APS Preferred Plan		$37,365	130

* Cost and CO2 emissions results in scenarios that vary input assumptions and are not directly comparable to other scenarios

The 13 portfolios that precede the Preferred Plan are discussed in further depth below; in each case, APS focuses on the key insights learned from the analysis and how that informs the Company's future outlook.

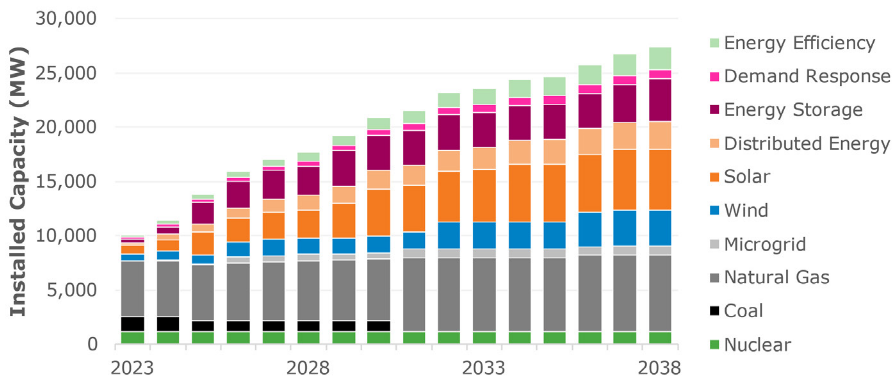
REFERENCE CASE

The Reference Case, which serves as the starting point for portfolio analysis, represents an optimized, least-cost portfolio of resources to meet rapidly growing customer demands and replace currently planned resource retirements over the Planning Period while satisfying reliability needs. It does so with a diverse portfolio of new resources that includes investments in natural gas, microgrids, solar, wind, energy storage, complementary

2 This approach to accounting for renewable generation is similar to the methods used in neighboring states for Renewable Portfolio Standards (RPS) accounting.

transmission facilities needed to deliver new resources to load centers, and demand-side programs. The future cumulative installed capacity mix for this portfolio is shown in Figure 5-5.

FIGURE 5-5. INSTALLED CAPACITY BY TECHNOLOGY TYPE BY YEAR



Over the Planning Period, the total infrastructure needed to meet growth and replace retiring resources is prodigious. The amount of new installed capacity that is added in this portfolio totals nearly 14,000 MW of supply-side resources by 2038 — more than exists on today's system — and nearly 5,000 MW of demand-side resources. These additions can be broken down into three distinct phases:

- Between 2024-2030, most of the new resource additions enable the Company to keep pace with customer growth. During this period, APS adds 8,500 MW of supply-side resources, including 2,900 MW energy storage, 3,500 MW utility-scale solar, 900 MW wind, 600 MW natural gas, and 600 MW of microgrids. Additionally, over this period, APS adds more than 900 MW energy efficiency and 1,400 MW distributed energy resources;
- In 2031, APS exits Four Corners, resulting in the loss of a 970 MW source of dependable capacity in the portfolio. The combination of the loss of this resource and load growth requires a large addition of new capacity, predominantly met by low-cost natural gas combustion turbines (CTs) (over 1,100 MW are added in 2031) and microgrid resources (200 MW); and
- Beyond 2032 through the end of the Planning Period, APS continues to develop new resources to meet load. At this point in time, the availability of new transmission development allows integration of nearly 1,900 MW of new, high-quality wind resources from New Mexico to complement additional local solar, storage, and natural gas resources in Arizona.

In this diverse portfolio of resources, the role of each type of new resource is somewhat unique, and no single resource is capable of meeting all of the needs of the system. For example:

- Natural gas CTs and microgrids provide the lowest-cost sources of dependable capacity. Firm resources that can be dispatched at full capacity whenever necessary for as long as needed are an essential component of APS's strategy to ensure reliability for customers. While these types of resources are not expected to run frequently, the periods that they do operate are essential for grid reliability. Along with existing firm resources, new natural gas CTs and microgrids are critical to the reliability of APS's portfolio;
- Energy storage is a flexible resource that can provide a range of benefits to customers. It allows APS to integrate higher penetrations of renewable generation by storing surplus solar during the middle of the day; it provides financial benefits to customers by charging when prices in Western wholesale markets drop below zero; it contributes to system reliability needs by storing energy to discharge during the evening as the sun sets; and it can quickly adjust its output across a broad range to help meet real-time needs for flexibility and operating reserves. No other resource in the portfolio can provide all these capabilities simultaneously; and
- Solar and wind resources provide a source of low-cost energy to the system. Due to meteorological variability and natural diurnal cycles, the output from these resources varies on an hour-to-hour basis, but when they are available, they reduce costs to customers through avoided fuel purchases, operations and maintenance costs, and/or market purchases.

Over time, this evolving resource mix will change how APS meets customers' needs on a day-to-day basis, but throughout the Planning Period, all elements of the portfolio contribute to the holistic purpose of ensuring reliability across even the most difficult conditions. Figure 5-6 illustrates how these components — and the existing resource portfolio — work together to meet system needs during the hottest summer day of the year at the beginning (2023) and end (2038) of the Planning Period.

While Figure 5-6 illustrates the most constrained day of the year, the energy mix throughout the year shifts dramatically as well. Figure 5-7 shows how the energy mix evolves in the Reference Case on a year-by-year basis over the Planning Period. Between 2023 and 2038, the share of the energy mix served by renewable resources increases from 16% to 43%, while carbon-free resources increase from 55% to 72%. Both of these figures account for the lost production associated with renewable curtailment that occurs during periods when the system has a surplus of renewable generation.

FIGURE 5-6. HOW DIFFERENT RESOURCES ENSURE RELIABILITY

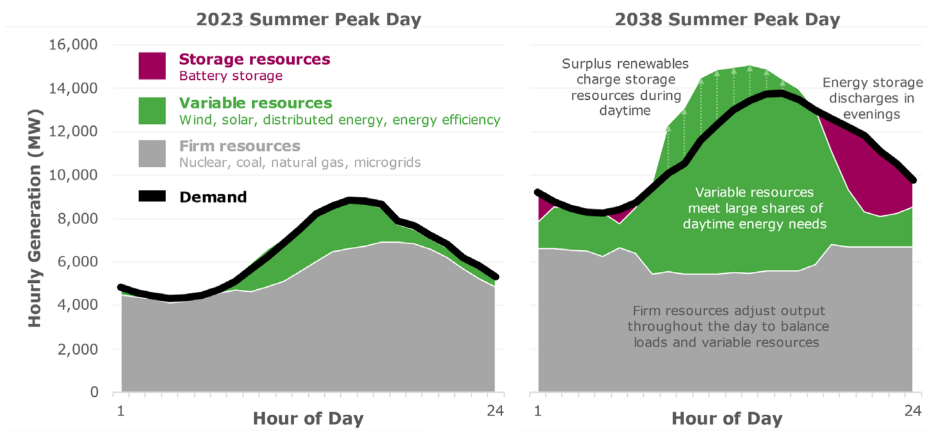
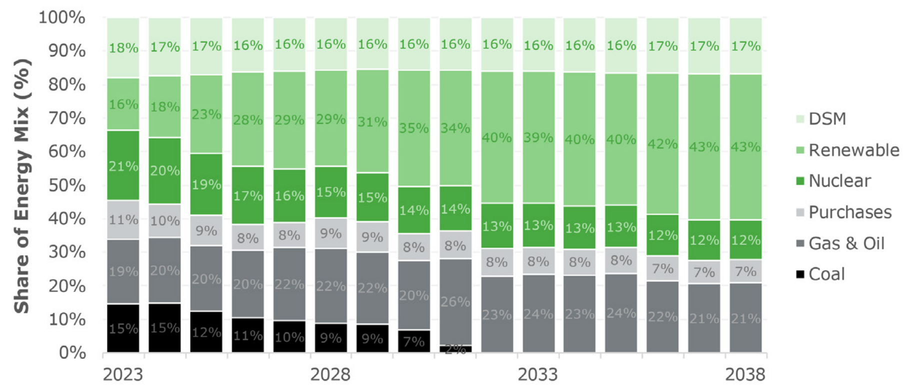


FIGURE 5-7. REFERENCE CASE CHANGES IN ENERGY MIX, 2023-2038



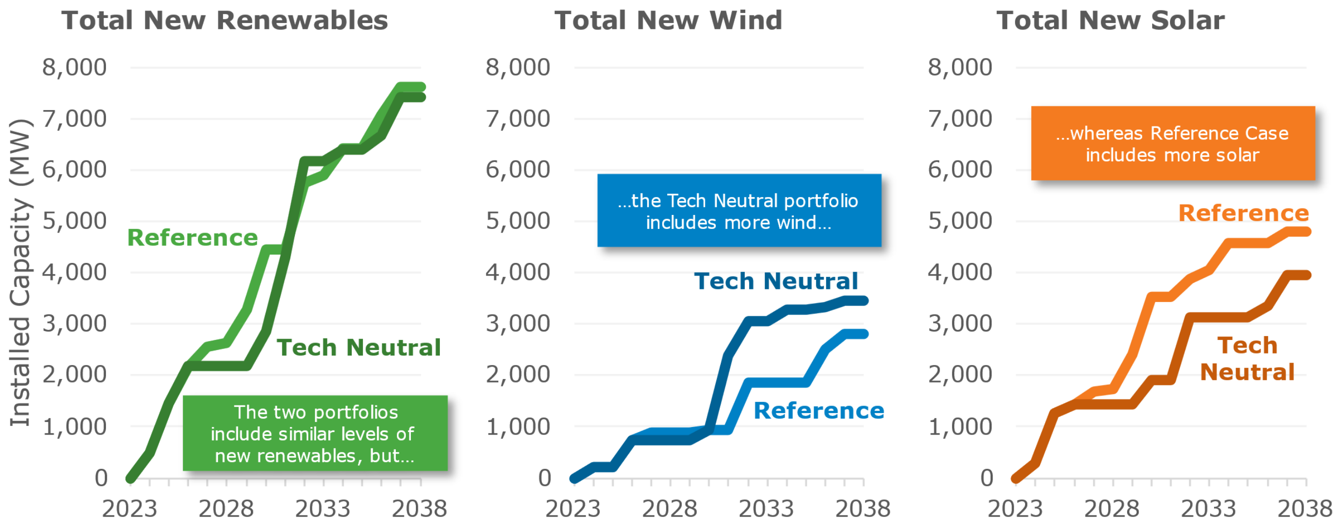
TECHNOLOGY NEUTRAL PORTFOLIO

The Technology Neutral portfolio, studied at the direction of the Commission, is a portfolio without carbon emission standards or any voluntary goals for emission reductions and renewable energy, thereby yielding a truly "least-cost" portfolio to meet customers' future needs. Comparing this portfolio against the Reference Case provides a useful contrast, highlighting when and where constraints related to clean energy influence resource selection in a manner that increases customer costs. Alignment between portfolios suggests that APS has selected an appropriate volume of renewable resources in its Reference Case, and that renewable resources are a cost effective component of each portfolio.

As illustrated in Figure 5-8, the Reference Case and the Technology Neutral portfolios both include significant amounts of new renewable generation capacity; over the 15-year Planning Period, nearly 8,000 MW of new wind and solar generating capacity are added in the two cases.

While the overall levels of renewables added across the Planning Period are similar in the two portfolios, several distinguishing features of the Technology Neutral portfolio provide insights into cost-saving opportunities for customers: (1) relative to the Reference Case, a larger quantity of the renewable additions in the Technology Neutral portfolio are added in the latter half of the Planning Period, and (2) the Technology Neutral portfolio includes a relatively larger share of wind resources and smaller share of solar resources. This outcome, which produces a PVRR in the Technology Neutral portfolio that is $96 million lower than the Reference, is driven by the following factors: In the Reference portfolio, significant quantities of solar generation are added in the near term

FIGURE 5-8. RENEWABLE RESOURCE ADDITIONS IN REFERENCE AND TECHNOLOGY NEUTRAL PORTFOLIOS, 2023-2038



(prior to 2030, when the capability of the existing transmission system limits APS's ability to access remote, high quality wind resources); the Technology Neutral portfolio postpones some of those renewable additions until after 2031. At that point in time, development of new inter-regional transmission needed to deliver new wind resources to load centers is plausible, and the exit from Four Corners creates a larger need for new energy, further increasing the value of renewable energy.

The contrast between these two portfolios provides two important insights that support the development of a Preferred Plan. First, renewable resources are an important part of a least-cost portfolio, and the levels of new renewable generation envisioned by APS's Clean Energy Commitment are aligned with that least-cost outcome. Second, the Technology Neutral portfolio highlights the value to customers of APS aligning the timing of renewable additions with key plant retirements and of coordinating those additions with the timelines for new transmission development.

FOUR CORNERS EARLY EXIT PORTFOLIOS

APS will stop burning coal at Cholla no later than April 2025, and will exit from Four Corners in 2031 after six decades of operation. Sequencing this transition requires careful consideration and coordination with parallel priorities. Significant adjustments to the resource portfolio warrant caution to ensure that consequences are fully understood and that risks are mitigated to the greatest extent possible.

At the direction of the Commission, multiple portfolios that explore accelerated exit timelines for Four Corners were studied. Specifically, in addition to the Reference Case, which models an exit in 2031, APS conducted comprehensive analyses for alternative scenarios in which the Company exits from Four Corners in 2027, 2028, 2029, and 2030.[3] Each scenario represents an optimized portfolio that meets all the modeling constraints — including the replacement of dependable capacity, concurrent with the removal of the 970 MW that Four Corners currently provides. However, the actual development of the resources (along with delivery of electricity) from these scenarios is unlikely to be executable while maintaining reliable service to customers. In addition to uncertainty

3 Decision No. 78499 required that APS explore at least one portfolio that removes modeling constraints on retirement of coal units. To fulfill this requirement, a suite of retirement cases were studied to examine the impacts of Four Corners' retirement across a range of different years, achieving through manual means the Commission's order to evaluate optimal timing of retirements. This approach is necessary because accounting for all aspects of the economic impacts of plant closure endogenously in capacity expansion — including decommissioning costs, fuel-related liquidated damages, fuel contract termination charges, and changes in both capital and O&M costs — is prohibitively challenging. Further, studying the impacts of retirement across a range of years provides more useful information to inform the Company's decision making, as it allows APS to quantify the relative cost impacts of retirement in each year rather than attempt to identify a single "optimal" retirement date.

associated with development timeframes for the volume of resources involved (e.g., as to future supply chains), the development of necessary electricity transmission and gas transportation infrastructure needed to accommodate these new resources likely cannot be built soon enough to accommodate these earlier exit timeframes. For this same reason, exit years from 2024–2026 were not evaluated. In these scenarios, cost projections are influenced by several variables, including the timing and composition of the replacement portfolio, compliance with renewable energy goals, availability of transmission capacity, and facility costs specific to the operation and retirement of Four Corners.

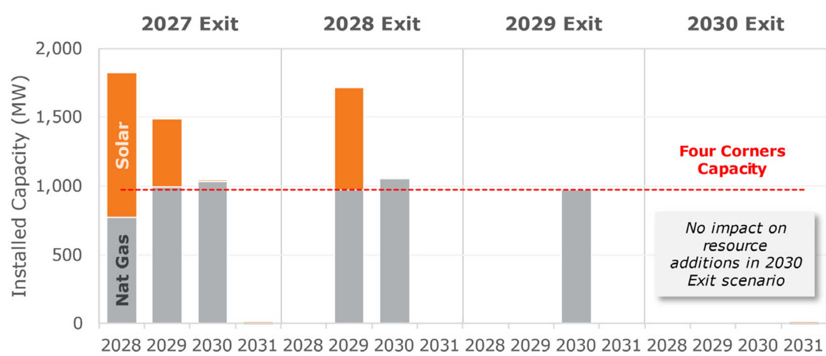
Cost considerations pertaining specifically to Four Corners and its decommissioning also contribute to the merits of each retirement scenario.[4] Deferring the expense of decommissioning and site remediation to a future period is a sound financial strategy; accelerating these costs to an earlier period increases costs for customers. Additionally, APS has a long-term contract in place to deliver the annual fuel requirements to Four Corners through 2031. The intent of this commitment is to secure favorable pricing, enhancing the stability and affordability in a commodity market subject to price volatility. Leveraging this contract through the end of its negotiated term provides Four Corners, and by extension APS customers, with stable and affordable fuel for baseload power.

TABLE 5-3. FOUR CORNERS REVENUE REQUIREMENT COMPARISON

SCENARIO	PVRR ($ MILLIONS)	PVRR RELATIVE TO REFERENCE CASE ($ MILLIONS)
Reference	$37,722	-
Four Corners Coal Exit 2027	$37,748	+$26
Four Corners Coal Exit 2028	$37,583	-$139
Four Corners Coal Exit 2029	$37,631	-$91
Four Corners Coal Exit 2030	$37,665	-$57

The impact of accelerated exit on the composition of the portfolio varies by scenario; the changes in installed capacity from 2028 through 2031 are shown for each of the early retirement scenarios in Figure 5-9. In general, APS observes the following:

FIGURE 5-9. CHANGE IN TOTAL INSTALLED CAPACITY RELATIVE TO REFERENCE CASE



- Exit at the end of 2030 (2030 Exit) results in little direct impact on the portfolio. APS intends to exit Four Corners in mid-2031 (requiring that replacement resources be installed in early 2031 to be online for summer of that year), which is approximately the same timeframe that replacement resources would be needed to ensure reliability if APS exited at the end of 2030
- Exit at the end of 2027, 2028, or 2029 each result in earlier investments in natural gas CTs in quantities roughly equivalent to the Company's current ownership share at Four Corners. These additions ensure that the portfolio would remain sufficiently reliable
- In the scenarios with exit at the end of 2027 and 2028, an acceleration of new solar PV generating capacity was observed, which helps meet the energy needs created by an early plant retirement. As shown in Figure 5-9, the differences in solar buildouts across the portfolios does not persist beyond 2030, indicating that these changes reflect an accelerated procurement of solar resources that are also present in the Reference Case, not an incremental quantity of new solar PV above and beyond the levels observed in the Reference Case

4 Decision No. 78317 requires that APS shall complete a comprehensive retirement analysis for Four Corners "not including any termination liability or restrictions beyond those to which APS was subject under the CSA as of March 3, 2021." Coal termination liabilities were not included in LTCE or PCM activities, but were added as a part of the revenue requirements for these cases because they represent real costs that would be incurred in the event of an earlier exit. The Company can provide numbers without these additional fees upon request.

Exiting Four Corners prior to 2031 innately accelerates the need for replacement resources. While project opportunities for replacement resources certainly exist, accessing them on an earlier timeline is challenging. Though trends appear to be improving, supply chain disruptions are adding excessive uncertainty to project timelines and enhancing the power of suppliers, thereby leading to increases in costs. Inflation has also caused project costs to remain elevated for materials, production, shipping and logistics, as well as financing. According to Lawrence Berkeley National Laboratory (LBNL)[5], projects are taking longer to reach commercial operation, with new projects taking nearly twice as long to develop in 2022 than they did 15 years prior; larger projects, with more onerous interconnection studies, have notably longer timelines.

An additional concern of earlier exit scenarios is the pace at which access to additional transmission capacity can be achieved. New wind and solar resources will likely require transmission investments to connect remote generation sites to population centers. Depending upon the specific timing and location of individual resources, the modeling accounts for transmission enhancements as either an additional expense for purchasing transmission on non-APS systems or as a supplementary fixed cost associated with the additional capital investment. While APS's exit from Four Corners will create some additional headroom on APS's transmission system, transmission contracts for access to resources in New Mexico on non-APS transmission are not anticipated to become available until 2031, and new Company owned transmission investments are not forecasted to be in service until 2036.

Transmission siting and interconnection is an extensive process, requiring years of preparation and planning. Most notably, transmission congestion will restrict access to New Mexico wind until 2031 therefore, replacement wind resources for early retirement scenarios must come in large part from projects within Arizona. Wind generation imported from New Mexico has a capacity factor approximately 50% higher than wind resources located within Arizona, making it comparatively cheaper on an energy basis. Ultimately, the resulting replacement portfolios for an accelerated retirement scenario are less efficient, with respect to cost, and promote system designs and portfolio decisions that would not otherwise be selected.

Maintaining the current 2031 exit plan allows APS to continue pursuing a responsible and efficient replacement portfolio with more favorable resource characteristics. The additional time also allows the Company to navigate the constraints inherent to the transmission interconnection queue. In the coming years, technology costs will likely continue to fall while disruptions brought about by supply chain and inflation are expected to subside. APS remains committed to exiting Four Corners, and the comprehensive evaluation of several scenarios indicates that the existing plan for exiting Four Corners in 2031 remains the optimal case for customers. The Company will continue to evaluate the market drivers, infrastructure development opportunities, and resource costs to assess the viability of an earlier exit if there is a benefit for customers while maintaining reliability. APS will continue to plan across financial and technical areas to responsibly retire coal generation assets while continuing to deliver reliable, affordable electric service to customers.

LOAD GROWTH SENSITIVITIES

To evaluate the impact of customer growth on resource selections, APS modeled high-growth (accelerating the base forecast to account for earlier customer load additions), low-growth (0.9%), and no-growth (0%) scenarios, with respect to load. While the Company has established a trend that Arizona is experiencing strong growth across several sectors, and it is expected for that to extend to load growth across several customer classes, it is important to understand how this growth impacts resource requirements and associated costs.

Logically, resource requirements increase consistent with load growth. The modeling shows that the portfolio scales as expected while maintaining a diversified mix of resources. This indicates that responding to load growth will not be as simple as adding more of a single, preferred resource. Therefore, APS will need to carefully balance its portfolio to ensure that it not only is the correct size, but also has the right composition.

5 Rand, J., Strauss, R., Gorman, W., Seel, J., Kemp, J., Jeong, S., Robson, D., & Wiser, R. (2023), *Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2022*, https://emp.lbl.gov/publications/queued-characteristics-power-plants-1

Additionally, while total system costs increase consistent with load, marginal costs should generally improve with higher load growth as fixed costs are spread across more customers and/or the utilization factor of fixed assets increases. However, these trends and expectations are subject to specific growth characteristics, including location and load factor. Attributes like these will require active monitoring as the portfolio continues to develop. Exercising other tools, such as rate design, customer programs, and distribution planning, can help influence the load profile in a way that benefits the system and its customers.

FIGURE 5-10. LOAD SENSITIVITIES*

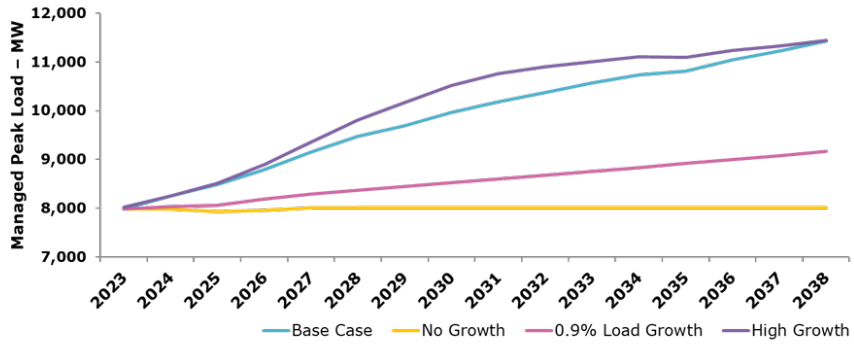


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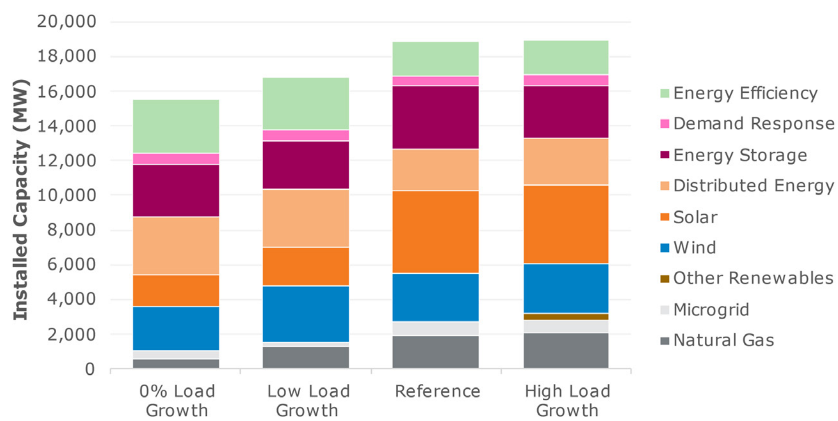
FIGURE 5-11. CUMULATIVE NEW CAPACITY ADDITIONS, 2024-2038



HIGH DEMAND-SIDE TECHNOLOGY SENSITIVITY

DSM is a significant and growing component of the APS resource portfolio. APS is supportive of cost effective DSM measures that benefit all customers. This portfolio stems from a Commission requirement to study 1.5% EE savings per year, which is much higher than current cost effectiveness tests support. The additional investment needed to realize this level of DSM is substantial, and total portfolio costs are much higher than scenarios with a lower level of DSM investment. APS will continue to work with stakeholders and the Commission to determine the appropriate amount of DSM resources that capture the most value for all customers. This portfolio also meets the Commission requirement to study a portfolio with 35% of 2020 peak load served by demand-side resources.

HIGH NATURAL GAS PRICE SENSITIVITY

APS is fortunate to have direct pipeline access to the Permian Basin gas fields in west Texas, which provides a source of long-term, relatively low-priced natural gas. Furthermore, due to APS's proactive hedging strategy, market volatility is mitigated in the first three years of the forward curve; following that horizon, APS relies on a variety of forecasts from reputable sources like the U.S. EIA to guide its planning.

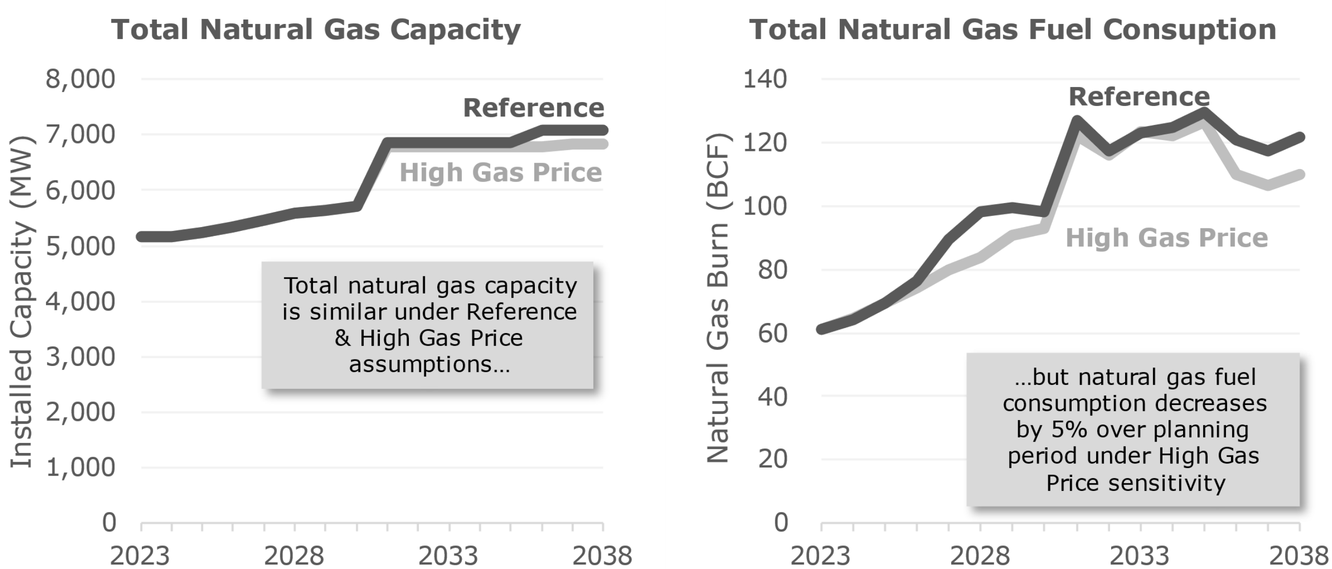
Throughout the previous decade, natural gas exhibited pricing that was notably low and stable. However, higher costs and volatility have been introduced in recent years with a global health crisis and unrest in eastern Europe. This demonstrated that seemingly unrelated events, like geopolitical conflicts or pandemics, can destabilize global markets with unanticipated consequences reverberating across regions and industries. While these disruptions were temporary, they serve as a reminder that assumptions, particularly regarding wholesale pricing, are subject to variation. Therefore, APS stresses its portfolio using the high annual outlook case published by the U.S. EIA.

In addition to unanticipated externalities that can influence natural gas pricing, there are industry trends that are more predictable. Visibility on surrounding markets can help forecast how their behavior might impact APS's access to natural gas and its pricing. Specifically, neighboring states like California have signaled that they expect to significantly reduce natural gas usage in the coming decades. Because Arizona and California are served by the same pipelines, the timing of any such reductions could reduce future investments in natural gas infrastructure. At the same time, interstate pipeline capacity is becoming increasingly constrained. Therefore, pipeline investments or capacity may limit viability of natural gas for future generation.

Whether increases result from predictable market forces, are due to unforeseen externalities, or do not manifest at all, it is prudent to anticipate and understand how higher gas prices might impact portfolio decisions and customer costs. This is particularly true in a scenario where gas generators are used as energy resources in an environment where gas prices are elevated for an extended period. Existing resources in the system, including combined cycle plants, exhibit higher operating costs when natural gas costs are elevated.

Due to the importance of firm capacity in a portfolio with significant amounts of renewable generation, APS finds that natural gas generators are an important part of the least-cost portfolio — even under a High Gas Price sensitivity. As summarized in Figure 5-12, the total amount of natural gas capacity in a least-cost portfolio is relatively insensitive to the Company's natural gas price assumptions; however, the higher prices of gas do result in lower utilization of natural gas generating resources throughout the year, resulting in lower capacity factors and ultimately lower total natural gas fuel consumption. This decrease in utilization is offset by increasing generation from both coal, renewable generation resources, and market purchases.

FIGURE 5-12. NATURAL GAS CAPACITY AND FUEL CONSUMPTION



The reason that the natural gas capacity does not depend upon natural gas pricing is a result of the role that new investments in natural gas capacity play in the portfolio. While it is true that natural gas prices have a significant impact on total cost for energy resources, the gas additions included in the portfolios are primarily CTs, which operate as peaking resources when needed for reliability. Since the generators are expected to operate at relatively low capacity factors throughout the year, fuel consumption is much less significant; therefore, changes in natural gas costs do not substantially impact the overall resource economics. In the context of firm capacity resources, natural gas CTs are the most cost effective selection for the portfolio. For a peaking resource, the cost of fuel is a relatively small portion of the total resource cost (what ultimately drives the inclusion of the resource in a least-cost portfolio).

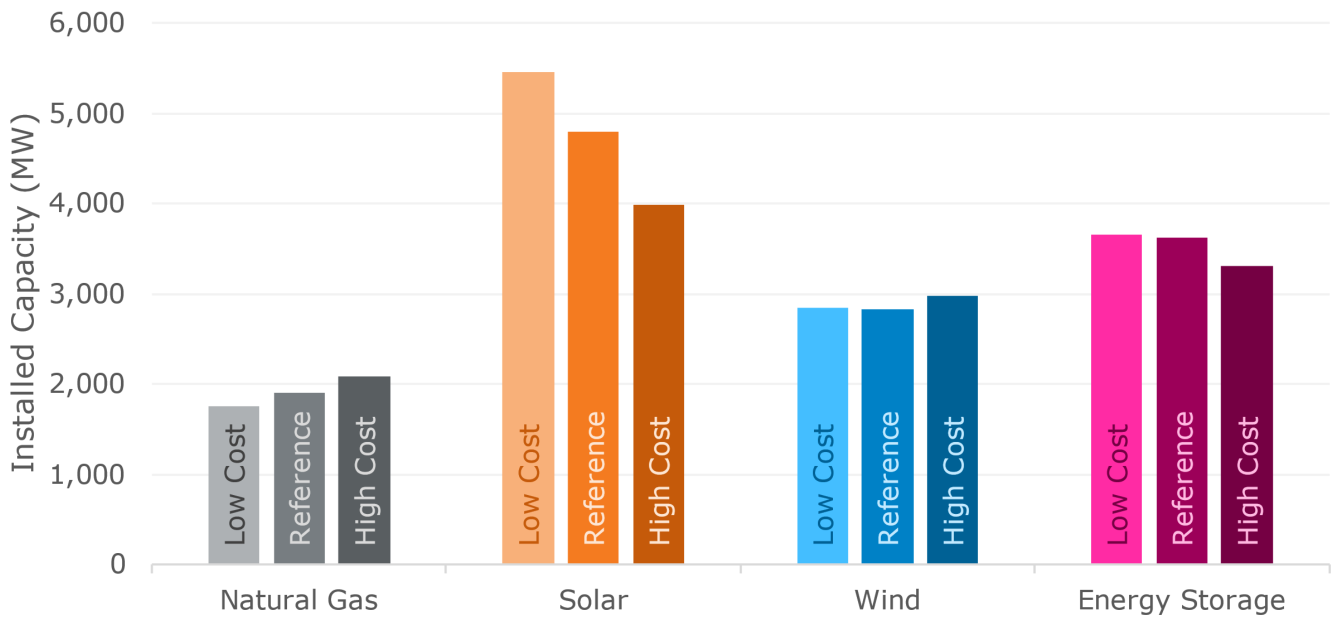
RENEWABLE TECHNOLOGY COST SENSITIVITIES

Although renewable energy technologies such as wind turbines and solar arrays are well established in the commercial marketplace, the maturation of manufacturing processes and related activities continue to improve power density and reduce production costs. In contrast, supply chain disruptions and reduced access to necessary raw materials have put upward pressure on the costs of these technologies in recent years. Despite higher costs compared to pre-pandemic pricing, this analysis indicates these resources are an important part of a least-cost portfolio. APS will continue to evaluate the cost effectiveness of these resources, especially when paired with other technologies, such as battery storage, when determining how to capture the most value for customers.

The substantial integration of new renewable energy projects that is required to account for projected load growth and the retirement of legacy portfolio assets results in renewable energy costs having a high influence over total portfolio cost. With near-zero marginal cost, the economic case for renewable energy is almost entirely based on the initial capital investment. Therefore, the capital cost of renewable energy technologies is a major variable in estimating future portfolio cost. Tools like competitive procurement, as well as subsidies like those made available through the IRA, can help mitigate the potential severity of rising renewable energy project costs. However, elevated costs of upstream attributes like raw materials and financing, as well as higher demand for projects, may put upward pressure on costs and risk overshadowing these financial benefits.

This analysis indicates that while the composition of the optimal portfolio does adjust with changes in assumed capital costs to take advantage of the comparatively lowest cost resource options, those changes are minimal. In other words, the finding that a diverse portfolio of resources will provide the lowest cost and best value to customers is robust, despite the future uncertainties that exist in the costs of those resource options. The impact of the High and Low Renewable Technology Cost sensitivities on the quantities of new natural gas, solar, wind, and energy storage capacity are shown in Figure 5-13.

FIGURE 5-13. DIFFERENCES IN CUMULATIVE NEW INSTALLED CAPACITY (2024-2038) UNDER HIGH/LOW RENEWABLE TECHNOLOGY COST SENSITIVITIES



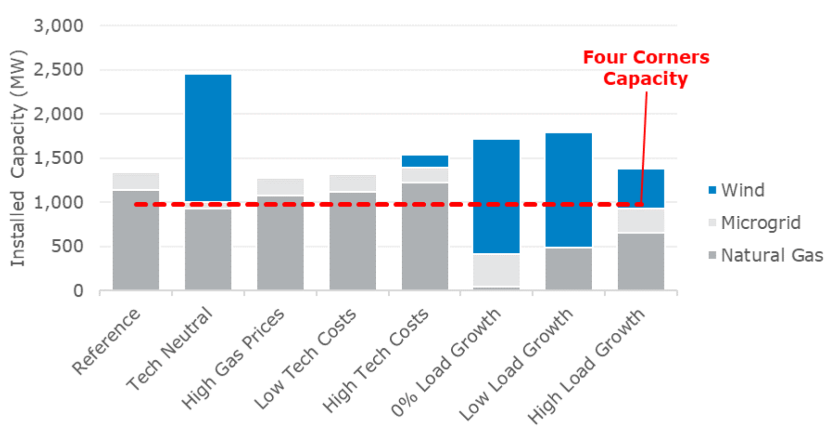
APS PREFERRED PLAN

APS's ultimate objective in the IRP is to identify its Preferred Plan and corresponding Action Plan, which will best meet customers' future needs. To inform the development of that plan, APS holistically analyzed 13 scenarios. Capturing and synthesizing the results of those analyses, APS identified patterns and inputs common to the most favorable outcomes. Those learnings informed the development of the Company's Preferred Plan.

KEY LEARNINGS FROM PORTFOLIO ANALYSIS

Maintaining current plans to exit Four Corners in 2031 is necessary for reliability. In this IRP, APS undertook a detailed analysis of the impacts of an earlier exit from Four Corners. The Company examined four alternative exit dates, developing optimized replacement portfolios of new resources that were sufficient to maintain reliability. Ultimately, despite some early exit scenarios indicating a potential for cost savings, APS's current plans to exit in 2031 remain in the best interest of its customers: given current headwinds facing new resource development and the significant quantity of new resources needed to keep pace with growth, the accelerated timeline required to bring online the quantity of replacement resources needed to ensure reliability after an early exit poses too significant a risk to customers at this time. Nonetheless, based on learnings associated with cost-savings drivers in the Four Corners early exit portfolios, APS will continue to evaluate the feasibility of exiting Four Corners prior to 2031. Key considerations in this evaluation include new resource development costs, timeframes, and supply chains, transmission line development across the Western U.S. region, load growth, and natural gas supply infrastructure.

FIGURE 5-14. NEW UTILITY SCALE RESOURCE ADDITIONS, 2031

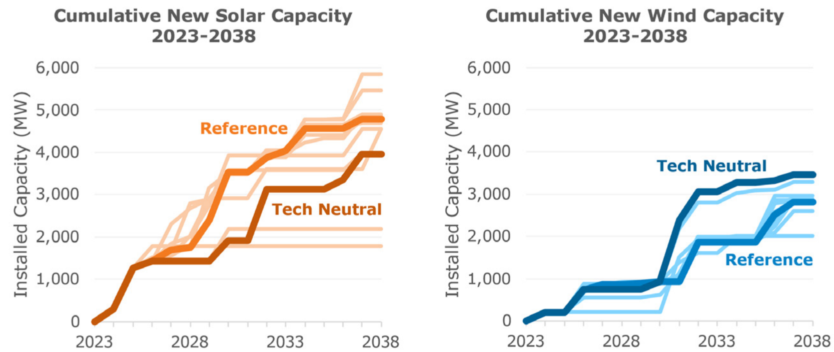


Natural gas CTs are the lowest-cost capacity replacement for Four Corners. In the Reference Case as well as in a range of sensitivities, APS found that the addition of a significant quantity of natural gas peaking capacity upon exiting Four Corners results in the lowest cost outcomes for customers. This holds true even under a "High Gas Price" sensitivity, as the primary use case for the investments in natural gas capacity is for peaking purposes; because they operate at low capacity factors (typically 5-10%), the cost effectiveness of this choice is relatively insensitive to natural gas prices. Figure 5-14 shows the nameplate capacity additions in 2031 in the Reference Case and a range of sensitivities. These are the resources added to the system to replace Four Corners and meet incremental load growth from 2030 to 2031.

Lack of microgrid development will cause higher levels of natural gas investment. Capacity expansion modeling took advantage of available microgrid resources in all cases studied, indicating that this is a cost effective capacity resource for customers. Microgrids leverage partnerships with large customers, such as data centers or large manufacturing facilities, which require a certain amount of on-site generation. In the event that customers do not elect to develop these facilities, APS would likely need to pursue additional natural gas resources to meet the system's dispatchability requirements.

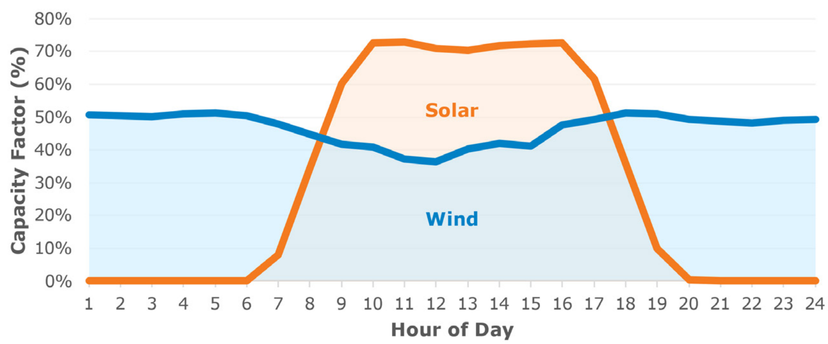
Increasing reliance on renewables is least cost for customers, particularly upon retirement of Four Corners. All scenarios studied include significant additional wind and solar capacity during the Planning Period. In the Technology Neutral scenario — which does not include Company imposed requirements for clean energy or renewables — more than 10,000 MW of new wind and solar additions is part of a least-cost portfolio. This result underpins the idea that the renewable resources included in all portfolios, which reach a similar level by the end of the Planning Period in most cases, provide value to customers. The range of renewable additions included across all scenarios is shown in Figure 5-15.

FIGURE 5-15. CUMULATIVE NEW SOLAR AND WIND CAPACITY



Accessing wind via transmission in the next decade will be important for portfolio diversification. As highlighted in the figure above, one of the notable results common across almost all scenarios APS studied is the appearance of significant quantities of new wind resources in the early 2030s. Wind resources — particularly high capacity factor resources such as those located in New Mexico and other Rocky Mountain states — offer significant value to customers due to their relatively low cost and the output diversity they provide. While wind resources are intermittent, their production tends to be highest during overnight periods when solar does not generate, as illustrated in Figure 5-16. At the same time, APS's ability to integrate and deliver new wind resources from neighboring states to load centers is limited by the transmission system. Today, the transmission systems in the Southwest region are fully subscribed, and new transmission development is necessary to deliver these high-quality resources to customers.

FIGURE 5-16. AVERAGE HOURLY PROFILES, SOLAR AND WIND GENERATION



DEFINING A PREFERRED PLAN

Based on these learnings, APS has defined a Preferred Plan that best reflects customers' needs, limits costs while maintaining reliability, and increases portfolio diversity. In many ways, the Preferred Plan closely resembles the Technology Neutral portfolio — the portfolio that offers customers the lowest energy costs — with several adjustments made based on learnings from other cases. The Preferred Plan includes the following elements:

- Invest in a diverse mix of technologies to meet customers' increasing needs reliably. Like the portfolios developed throughout this analysis, the Preferred Plan is created using optimization that recognizes the value of a technologically diverse portfolio of resources. Across the Planning Period, the Preferred Plan meets growing needs with a combination of natural gas, microgrids, wind, solar (both utility-scale and distributed), battery storage, EE, and incremental DR.
- Exit Four Corners in 2031 and replace with wind firmed by gas. The Preferred Plan leverages a creative solution that allows APS to develop both wind facilities and natural gas CTs to replace Four Corners while maximizing the utilization of existing transmission. By pairing a variable and intermittent wind resource with dispatchable natural gas plants that can generate when the wind is unavailable, the Company is able to replace Four Corners while mitigating costs to customers. Recognizing that development of new transmission will also be a challenge, this solution allows APS to utilize the existing transmission path between Four Corners and customer load centers more efficiently than if the transmission was used for the dedicated purpose of delivering either resource on its own. This delivers a lower-cost solution for customers than retiring the plant in earlier years when this resource

pairing is unavailable. Maintaining plant operations to 2031 allows APS enough time to plan for, and develop, a large portfolio of replacement resources in a manner that ensures reliability during the transition despite the near-term challenges in project development facing the industry today.

Figure 5-17 shows the total installed capacity of all resources in the Preferred Plan at four key milestones in the Planning Period: (1) in 2023, representing the portfolio today; (2) in 2027, at the end of the current Action Plan; (3) in 2032, immediately after the exit and replacement of Four Corners; and (4) in 2038, the final year of the 15-year Planning Period. Together, these snapshots illustrate the dramatic transformation of APS's resource portfolio over time as customer needs are met and aging resources are retired. Over this time horizon, the total installed capacity of resources in APS's portfolio will double, a reflection of the tremendous amount of activity and infrastructure investment that will be necessary over the next 15 years to deliver on commitments to customers. At the same time, the portfolio will become more technologically diverse, a characteristic that protects customers from significant exposure to any individual technology-specific risks.

Figure 5-18 shows another view of the Preferred Plan for the same four milestones, illustrating the annual energy mix. Annual energy mix represents the mix of electricity that is delivered to customers over the course of the year. This perspective illustrates the transition of APS's portfolio towards increasing reliance on carbon-free resources and reducing reliance on traditional fossil-fueled resources. In 2023, APS's energy mix is 55% clean; by the time APS exits Four Corners in 2031, the Preferred Plan is 73% carbon free and remains at that level throughout the remainder of the Planning Period.

FIGURE 5-17. PREFERRED PLAN, TOTAL INSTALLED CAPACITY

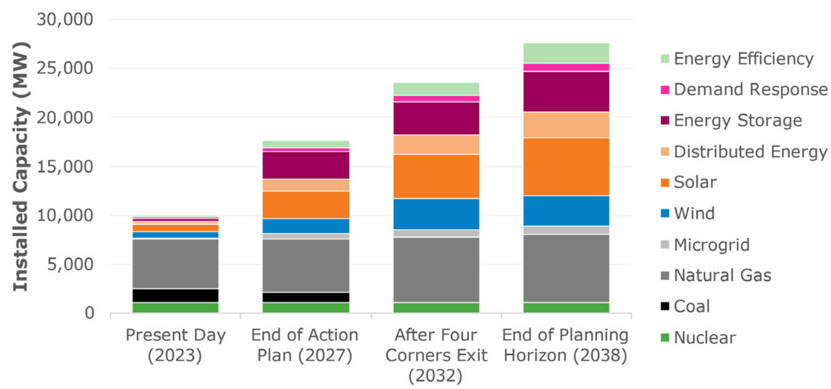
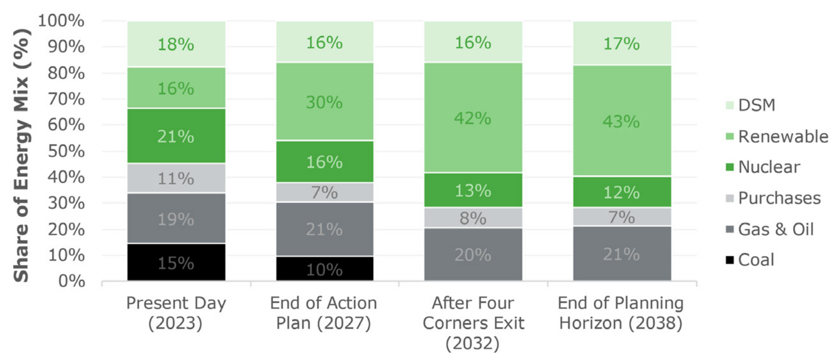


FIGURE 5-18. PREFERRED PLAN, CHANGES IN ENERGY MIX



COST IMPACTS

The Preferred Plan results in low costs for customers, producing the lowest PVRR across all scenarios that rely on comparable input assumptions.[6]

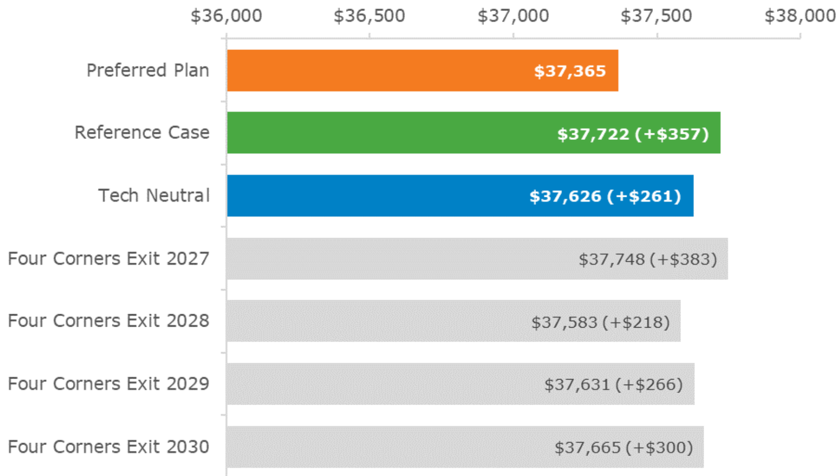
RELIABILITY ASSESSMENT

Like all of the portfolios developed and studied in this IRP, the Preferred Plan is designed to meet the LOLE standard for reliability of 0.1 days per year ("one day in ten years"). This is accomplished by applying an ELCC methodology to count capacity from each different resource to the planning reserve margin, which in turn is derived through probabilistic analysis. Beyond this foundational prerequisite for reliability, the Preferred Plan also has several other prudent elements to ensure reliability considering some of the known risks the industry will face in this period.

6 APS does not compare the PVRR of the Preferred Plan against scenarios that rely on different input assumptions (e.g., high gas prices, low technology costs, or different load levels) as the cost differences when compared against those cases will reflect the impacts of forces that are outside of APS's control.

First, while the portfolio includes large amounts of new battery storage resources, the Company recognizes that there is a limited operational history for lithium-ion storage at grid scale. Only in the past few years have new battery storage resources been developed in significant quantities, and in that short period, there are a number of examples of facilities experiencing unexpected failures for a variety of reasons. APS anticipates that as the technology continues to mature, the industry's understanding of the performance risks for battery storage will improve — but as with any new technology, the Company believes in a measured and balanced approach to integrating storage into its portfolio and relying on it for reliability purposes. For this reason, over the Action Plan period, the penetration of battery storage in our Preferred Plan does not exceed 3,000 MW, demonstrated in Figure 5-20.

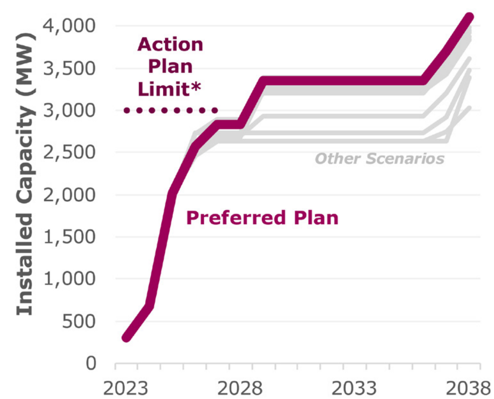
FIGURE 5-19. PRESENT VALUE REVENUE REQUIREMENT*



**Data is shown in $ millions.*

Second, the Company views the operation of Four Corners through 2031 as in the best interest of customers, whose concerns for reliability in the hot summers of Arizona are acute. Transitioning a portfolio away from a resource this size — at 970 MW, over 10% of current peak demand — requires careful, advanced planning. Particularly as supply chain challenges have posed disruptions to the timelines for new resource development, APS believes that accelerating the exit from this plant before 2031 would pose a real threat to customers' reliability.

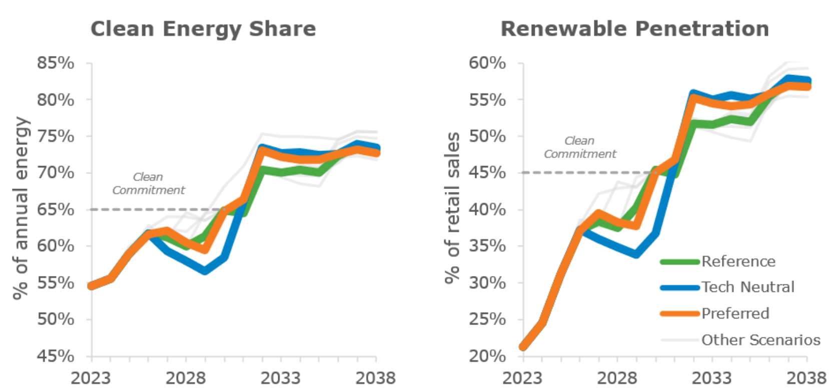
FIGURE 5-20. TOTAL ENERGY STORAGE CAPACITY 2023-2038



ENVIRONMENTAL METRICS

The resources included in the Preferred Plan meet customers' future needs reliably with a least cost outcome, and allow for improvements in environmental performance. As illustrated in Figure 5-21, the Preferred Plan meets APS's Clean Energy Commitment in 2030 (65% carbon-free energy, 45% renewable penetration) and continues to progress towards even higher penetrations of clean energy resources thereafter: by the end of the Planning Period, energy supply in the Preferred Plan is nearly 75% carbon free, and the share of retail sales served by renewable energy resources exceeds 55%. Across most of the Planning Period, these results either match or exceed both the Reference Case and the Technology

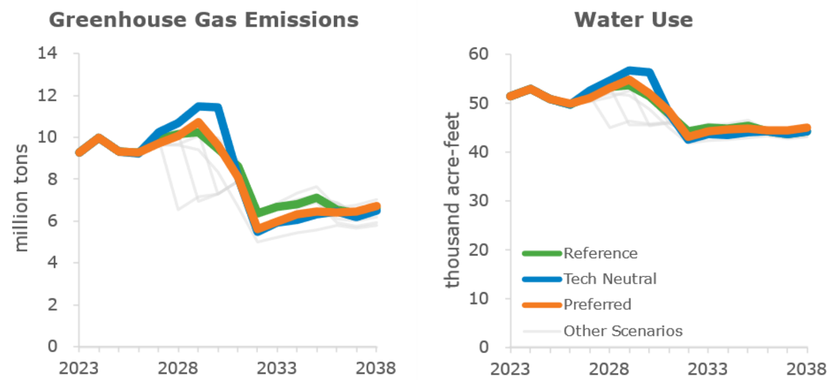
FIGURE 5-21. CLEAN AND RENEWABLE ENERGY PERCENTAGES



Neutral portfolio. Most importantly, the Clean Energy Commitment was not modeled as a constraint in the Preferred Plan, and this result is organically achieved through investing in cost effective resources.

The increasing deployment of renewable energy resources results in continued reductions in both greenhouse gas emissions and water use — both important measurements of impact on the environment — summarized in Figure 5-22. Over the Planning Period, the Preferred Plan enables greenhouse gas emissions reductions from 9.3 million metric tons in 2023 to 6.7 million metric tons in 2038, a 27% reduction despite over 20,000 GWh of energy growth during the Planning Period. The greenhouse gas emissions at the end of the Planning Period, 6.7 million metric tons, represents a 60% reduction in emissions relative to a 2005 baseline.

FIGURE 5-22. GREENHOUSE GAS EMISSIONS AND WATER USE



CONCLUSION

Over the next 15 years, APS anticipates the portfolio will undergo radical transformations at a rapid pace. Developing a Preferred Plan that minimizes costs while maintaining reliability across this Planning Period is a complex exercise, one that requires sophisticated analytics and sound, critical judgement. Only by studying a wide range of future resource options across a broad set of scenarios to capture future uncertainties can APS build confidence that the choices made in the Preferred Plan serve the long-term best interest of customers.

The Preferred Plan is designed to do just that — to serve the interests of customers by delivering affordable electricity and continuing APS's long tradition of reliable service. Drawing upon lessons learned and key findings from the extensive set of scenarios considered in this IRP, APS crafted the Preferred Plan to capitalize on the most promising new resource opportunities as the Company reshapes its resource portfolio. Ultimately, APS is pleased to deliver a Preferred Plan that is responsible and well-balanced.

The analysis demonstrates that the diverse mix of future resources in the Preferred Plan is robust in spite of uncertainty, but APS will also be prepared to adapt in response to change. The very nature of long-term planning will allow APS to refine and update the plan as more is learned about future conditions and the world continues to change. While the plan represents APS's current view of the best path forward for customers, the Company will continue to seek out new and innovative opportunities and solutions to reduce costs and meet customers' expectations for reliable service.

CHAPTER 6

ACTION PLAN

Powering Homes and Businesses

ACTION PLAN

APS's 2023-2027 Action Plan focuses on the near-term steps the Company must be taking today, to ensure the continued reliable delivery of affordable electric service to all APS customers.

Like any forward-looking plan, the Action Plan inputs and assumptions are based on the best-known information available at the time it was created. Inputs such as load forecast, future resource cost and availability, transmission development timeframes, and future environmental legislation are all sensitive to events occurring around the globe. If changes to these inputs occur in a manner that could materially impact the Action Plan, further evaluation will be conducted in collaboration with stakeholders. Although the Action Plan, and the IRP in general, informs resource future acquisition decisions, ultimately a competitive ASRFP process determines the pricing and type of resources procured. The following are the key tenets of the Action Plan:

INVEST IN NEW HYDROGEN-CAPABLE NATURAL GAS GENERATION TO ENSURE RELIABILITY

The analysis demonstrates that hydrogen-capable natural gas resources are essential to a reliable, resilient, and clean energy future. Natural gas supports and accelerates renewables development by providing back-up power when the sun isn't shining and the wind isn't blowing. As renewables continue being added, and the net peak shifts later into the evening, resources that can meet customer demand in the hours after sundown become increasingly important to maintaining a reliable electric grid — especially after the retirement of the Cholla plant and APS's exit from Four Corners.

INVEST IN RENEWABLES AND STORAGE TO SERVE NEAR-TERM GROWTH

APS's Plan demonstrates that investment in additional renewable energy is a cost effective means to meeting customer needs. With more than 2 GW of additions during the Action Plan period, battery storage is an essential element of the Action Plan and one in which APS is investing heavily. Battery storage will enable APS to take advantage of regional excess solar generation that can frequently be purchased at very low prices. In fact, there are times when market participants will pay APS to take excess solar energy, directly offsetting customer costs. APS is dedicated to a responsible integration of this nascent technology, and has committed to a maximum of 3 GW of battery energy storage through 2027. APS will continually evaluate this cap as more industry experience is gained.

PREPARE FOR EXIT FROM FOUR CORNERS IN 2031

APS remains committed to exiting from Four Corners in 2031. Analysis in this IRP shows that even with tax credits available through the IRA, the cost of replacing the capacity and energy of Four Corners before 2031 outweighs the savings. Additionally, as discussed in previous sections, APS does not support the early exit from Four Corners, due to the grid reliability risks associated with the transition to newer, nascent technologies, and increasingly limited excess capacity across the Western U.S. region.

APS is committed to continuing to study the economics relative to continued operation of Four Corners. There are many factors that impact unit economics, such as coal contract pricing and damages, pricing of alternative fuels, future environmental regulations, availability of replacement resources, and sufficient transmission infrastructure to deliver remote generation to load. APS looks to optimize its resource mix to bring the most benefit to customers while ensuring reliability and a responsible transition to other resource types.

LEVERAGE PALO VERDE TO MANAGE COSTS

In addition to its significant contribution to the local economy, the carbon-free energy generated by Palo Verde Generating Station is critical to affordably transitioning to a reliable, resilient, and increasingly clean energy future for Arizona. Additionally, nuclear power resources provide grid reliability advantages over other energy resources, and continuously produces a predictable amount of baseload energy.

USE OF ALL-SOURCE REQUEST FOR PROPOSALS TO PROCURE LEAST-COST RESOURCES

The Preferred Plan identifies the need to add significant amounts of new renewable and battery energy storage resources to APS's generation portfolio, along with hydrogen-capable natural gas generation. APS plans to frequently issue ASRFPs to solicit and procure capacity and energy resources. This approach ensures APS has access to the most current competitive pricing and allows APS to establish long-term partnerships with developers who have proven their ability to deliver on projects within budget and on schedule.

Through its 2023 ASRFP, APS seeks at least 1,000 MW of resources, with 700 MW coming from renewable resources. Resources acquired through this process will support the Action Plan in this IRP. APS will keep stakeholders informed about the results of this ASRFP, including the resource types and capacities acquired.

COORDINATION WITH TRANSMISSION PLANNING EFFORTS

With approximately 1.4 million customers across the state depending on APS for reliable and affordable energy, APS relies on its network of transmission and distribution lines to safely deliver power. In planning the future development of transmission infrastructure, APS considers a broad range of options, including generation, transmission, and distribution resources, and non-wires alternatives to address the opportunities and challenges of an increasingly distributed electric grid powered by a wide variety of resource types.

The 2023-2032 Ten-Year Transmission System Plan includes approximately 29 miles of new 500 kV transmission lines, one mile of new 345 kV transmission lines, 54 miles of new 230 kV transmission lines, 11.5 miles of underground 230 kV upgrades, 40 miles of 230 kV transmission line rebuilds, and three miles of 115 kV transmission line upgrades. APS projects that significant additional transmission capacity will be required to provide sufficient access to renewable energy, especially high-capacity factor wind projects that are located outside Arizona.

In addition to the transmission projects being constructed, APS's ASRFPs are inclusive of transmission projects, which better inform existing transmission development in the Western U.S. region and pricing associated with external projects. These projects also bring the opportunity to partner with other utilities to share resource costs and reduce risk.

WESTERN MARKETS EVALUATION

APS is continuously looking for ways to expand its participation in wholesale energy markets. As a natural next step in market participation, APS has been actively engaged in the development of two western day-ahead market constructs, which are intended to more efficiently forecast and align market needs and resources. By participating in both day-ahead market development efforts, APS is able to compare and identify which will save our customers the most money. In concept, by centralizing participants' anticipated supply and demand information, the day-ahead market allows available resources to balance more effectively, resulting in improved economics, reliability, and carbon-intensity. For several years APS has been involved in multiple efforts to shape and analyze the benefits of different market rules and structures. The creation of a day-ahead market provides additional benefits for customers, especially when paired with additional transmission development, which drives reliability and affordability through increased access to regional diversity.

RESPONSE TO RULES

RESPONSE TO RULES SECTION C – DEMAND

Resource Planning Rule A.A.C. R14-2-703 sets forth the reporting requirements for a load-serving entity. The following items provide responses to section R14-2-703(C), which specifically requires information related to system load forecasts.

RULE C.1

Fifteen-year forecast of system coincident peak load (megawatts) and energy consumption (megawatt-hours) by month and year, expressed separately for residential, commercial, industrial, and other customer classes; for interruptible power; for resale; and for energy losses.

A fifteen-year forecast of peak load by month and year by customer class is provided in Attachment C.1(a) and a fifteen-year forecast of energy consumption is provided in Attachment C.1(b). For the commercial and industrial classes, the information is consolidated into a category for customers with loads less than 3MW, a category for customers with loads greater than or equal to 3MW, and a category for customers with loads greater than 5MW and with a load factor of at least 0.92% ("XHLF"). The loads for electric vehicle charging, which is a growing end-use for residential, commercial, and industrial customers, have been broken out separately. Since demand response programs are treated as a resource, there is no load reduction in the forecast attributed to interruptible power.

RULE C.2

Disaggregation of the load forecast of subsection (C)(1) into a component in which no additional demand management measures are assumed, and a component assuming the change in load due to additional forecasted demand management measures.

The line labeled "Own Load Peak – After DE Before EE/DR" in Attachment C.2 provides a disaggregation of the load forecast by month and year into a component in which no additional demand management measures are assumed. Within the same exhibit, a disaggregation of the load assuming the change in load due to additional forecast demand management measures is provided on the lines labeled "Energy Efficiency Programs" and "Demand Response Programs." Consistent with the definition of Demand Management in R14-2-701 of the Resource Planning Rules, both energy efficiency and demand response are included in the disaggregation because they include programs that could provide a beneficial reduction in the total cost of meeting electric energy service needs by reducing or shifting in time electricity usage.

Time of use (TOU) rates may also be considered demand management measures. TOU energy rates have been in effect at APS since 1982 and have already been accounted for in the Total Own Load Peak forecast in Attachment C.2. APS has eliminated inclining block rates, increased adoption of TOU energy and demand rates, and aligned peak rate hours with system peak hours (4-7pm for residential customers and 3-8pm for non-residential customers) in its past two rate case. These changes are expected to provide additional demand reduction in the future.

RULE C.3

Documentation of all sources of data, analyses, methods, and assumptions used in making the load forecasts, including a description of how the forecasts were benchmarked and justifications for selecting the methods and assumptions used.

The APS load forecast is developed from several different class-level analyses, which account for differences in the way customers use electricity. These analyses reflect the high relative importance of regional population and economic growth as a determinant of future electricity demand. The following discussion outlines the methods used to prepare the load forecasts for each relevant class of customer and, per the requirement of the Rules, provides a description of how the models are benchmarked and the justification for the forecast method.

Residential Load: The residential load forecast is the product of a residential customer forecast and a corresponding electricity-use-per-customer forecast. The residential customer forecast is tied to a forecast of statewide population growth by year and a forecast of the share of a given region of the state which will be served by APS.

The U.S. Census Bureau reports historical population and household data. The change in annual population is disaggregated into a component driven by net natural increase (number of births each year less the number of deaths each year) and a component driven by net migration. Each of these components is provided in the population forecast modeled by the University of Arizona Forecasting Project. Historical annual population increases are regressed against annual APS customer changes for both the state and the Phoenix Metro area. A percentage of the projected new customers at the state and Phoenix metro area is assigned to APS or other service providers based on analysis of recent customer additions. A first-differencing model is used, which APS has found to stabilize the forecast in the near term compared to other modeling methods.

Forecasted population growth is the primary driver of APS's customer forecast, and recent population growth has been dominated by positive net migration to Arizona. The number of residential electric customers expected in the future is predominately influenced by the expected growth in residential households, adjusted for service territory shares of various regions within the state. For example, APS serves approximately 45 percent of Maricopa County, but has been receiving about 50 percent of the new households each year. APS serves none of Pima and Mohave counties, but almost all of Yuma, Yavapai, and Coconino counties. These historic trends in the share of new households within a region are extrapolated into the future and reflect an assessment of the degree to which those trends may continue. The result is a forecast of APS residential customers by year which reflects anticipated changes in migration rates and the regional location of new households.

The forecast of residential electricity use per customer is developed with a regression analysis of historical usage, coupled with short-run forecast dynamics that are expected to occur along with the business cycle. The statistical modeling approach to forecasting usage is a multiple linear regression model, which estimates the historical relationship between residential electricity usage and the following independent variables: heating degree-days, cooling degree-days, humidity, and real personal income per capita for Arizona.

The historical relationships from the regression model are applied to forecasts of the cooling and heating variables and to Arizona real personal income per capita. Electricity use for cooling and heating is projected based on an assumption of normal weather, which reflects the most recent 10-year average of cooling degree-days, heating degree-days, and humidity. The forecasts for Arizona real personal income and population are produced by the University of Arizona Forecasting Project and are combined to produce a forecast for real personal income per capita. Personal income is included to capture the effects of the business cycle and long-run growth on residential electricity usage.

Total projected annual residential electricity demand is the product of the projected average use per customer and the projected number of residential customers.

Commercial and Industrial Customers Less Than 3 MW Load: The load forecast for the group of commercial and industrial customers with electric demand less than 3 MW is developed with a regression analysis of historical sales growth. A customer forecast is also produced, and the two together provide an implied use-per-customer forecast that serves as a useful diagnostic tool. The total class customer forecast is tied to the residential customer forecast in the long run and so anticipates the population and household growth explicitly accounted for in that forecast.

The regression analysis is a statistical multiple linear regression model which estimates the historical relationship between total commercial and industrial electricity demand and overall economic growth in APS service territory as measured by total nonfarm employment in Arizona. The regression model also includes variables for weather. The historical relationship is applied to a forecast of total nonfarm employment to arrive at a projected electricity demand level for commercial and industrial customers. The forecast for Arizona total nonfarm employment is produced by the University of Arizona Forecasting Project. As with the residential model, normal weather is defined as the average of the last 10 years.

Once the forecast for total commercial and industrial demand has been completed, the forecast for specific customers with load greater than 3 MW is subtracted from the total.

Commercial and Industrial Customers Greater Than 3 MW Load: For customers with loads in excess of 3 MW, electricity demand forecasts are prepared individually. These forecasts are developed with input provided by customer account managers who are in routine communication with the customers and are knowledgeable about those customers' substantive near-term plans. In the absence of any additional information, these customers' loads are generally held constant in the outer years of the forecast. APS would be unlikely to find reliable independent causal variables to substitute for this method. No new customers are forecast for this group unless a specific new customer has been identified and it has been determined that the customer has a high probability of connecting to the system in the near future. Longer-term potential growth is captured in the econometric model of total commercial and industrial sales.

Commercial and Industrial Customers – Extra High Load Factor (XHLF): For customers with loads in excess of 5 MW and with a load factor of at least 0.92% ("XHLF"), such as new data centers and new, large industrial customers, electricity demand forecasts are prepared individually. Similarly to customers with loads greater than 3 MW, these forecasts are developed with input provided by customer account managers. These customers' loads often ramp-up significantly during the first 3-7 years of their forecast, and then are held constant in the outer years of the forecast. APS would be unlikely to find reliable independent causal variables to substitute for this method; however, this class of customers is relatively new, and APS will continue to monitor and explore forecasting options. No new customers are forecast for this group unless a specific new customer has been identified.

Electric Vehicle Charging Load: The load for electric vehicle charging, which is a growing end-use for residential, commercial, and industrial customers, has been broken out separately in Attachments C.1 (a) and (b). The electric vehicle charging forecast was produced by Guidehouse Inc. in 2023 and includes vehicle counts and charging for light-, medium-, and heavy-duty vehicles. In the model, charging can occur at home, the workplace, or at public charging stations, and L1, L2, and DC Fast charging technologies are included.

Irrigation and Street Light Customer Load: The irrigation and street light classes represent two very small components of the APS load requirement. The number of irrigation accounts has declined substantially over the last couple of decades as population growth has driven the conversion of agricultural land into residential and commercial uses. Street light electricity demand typically grows in line with overall electricity demand reflecting the natural expansion in cities and towns. The electricity demand for each of these classes is projected by trending both the number of customers and the average use per customer in the class.

Resale Customer Load: While APS historically had sales contracts with a number of wholesale customers who were partial requirements customers, these contracts have expired, and APS no longer includes resale customer loads in the load forecast.

Line Losses: Transmission and distribution line losses coupled with company use are measured as the difference between the total amount of electricity generated or purchased to meet APS system demands and the total amount of electricity consumed by APS customers at the customer meter level. The most recent five-year average of these energy losses is about 6.5 percent.

Own Load Energy: Own load energy is the summation of the class-level electricity demands plus energy losses.

Peak Demand: The annual peak demands on the APS system are forecasted using a combination of regression analysis. The peak demand for residential, irrigation, and commercial and industrial customers not on Extra High Load Factor rates is derived from a regression analysis of historical monthly peaks. The regression is a statistical multiple regression model which estimates the historical relationship between actual peak demand, weather on the peak day, and the overall sales level. In the forecast, a maximum temperature of 117 degrees on the annual peak day is used to ensure resource adequacy. This forecasted peak day exceeds the average peak day temperature over both the past 5 and past 10 years.

This model produces a forecast of the peak energy demand on the peak day for the respective customer classes. The contribution to the peak of Extra High Load Factor customers is derived separately using a statistical analysis of the hourly loads at existing data center premises and weather, which is interacted with monthly demand projections for these customers. Finally, the Electric Vehicle contribution to peak demand is derived from the additive contribution of all forecasted vehicle types and ownership.

RESPONSE TO RULES SECTION D – SUPPLY

Resource Planning Rule A.A.C. R14-2-703 sets forth the reporting requirements for a load-serving entity. The following items provide responses to section R14-2-703(D), which specifically requires information related to system resources.

RULE D.1(A)

A 15-year resource plan, providing for each year: (a) Projected data for each of the items listed in subsection (B)(1), for each generating unit and purchased power source, including each generating unit that is expected to be new or refurbished during the period, which shall be designated as new or refurbished, as applicable, for the year of purchase or the period of refurbishment.

Projected data for each generating unit and purchased power resource is provided in the attachments referenced in Table D-1.

RULE D.1(B) – B.2(A)

A 15-year resource plan, providing for each year: (b) Projected data for each of the items listed in subsection (B)(2), for the power supply system. Rule B.2(a): A description of generating unit commitment procedures.

APS optimizes the use of its resources to serve its customers in the most affordable manner possible, while maintaining grid reliability. The process begins by forecasting the load on a day-ahead basis. The load forecast is entered into a unit commitment and dispatch model (PCI GenTrader®/GenPortal®) that determines the most economic unit commitment plan for serving load, taking into account generating unit capabilities, intermittent resource production forecasts (e.g., wind and solar), fuel prices, contractual requirements, and transmission constraints. This commitment plan shows the units to be committed each hour, their projected loading level and the quantity of natural gas to be scheduled.

As part of the process, the model calculates prices for blocks of energy to

TABLE D-1. LIST OF D.1(A) ATTACHMENTS

PROJECTED DATA FOR GENERATING UNITS	ATTACHMENT
B.1(a) In service date and book life	D.1(a)(1)
B.1(b) Type of generating unit or contract	D.1(a)(1)
B.1(c) Share of generating unit capacity in MW	D.1(a)(1)
B.1(d) Maximum generating unit capacity	D.1(a)(1)
B.1(e) Annual capacity factor	D.1(a)(2)
B.1(f) Average heat rate	D.1(a)(3)
B.1(g) Average fuel cost Attachment	D.1(a)(4)
B.1(h) Other variable O&M Attachment	D.1(a)(1)
B.1(i) Purchased power energy costs -long-term contracts	D.1(a)(5)
B.1(j) Fixed O&M of generating units ($/MW)	D.1(a)(6)
B.1(k) Demand charges for purchased power	D.1(a)(7)
B.1(l) Fuel type for each generating unit	D.1(a)(1)
B.1(m) Minimum capacity	D.1(a)(1)
B.1(n) Whether the generating unit must run if available	D.1(a)(1)
B.1(o) Description of each generating unit	D.1(a)(1)
B.1(p) Environmental impacts – CO2	D.1(a)(8)
B.1(p) Environmental impacts – CO	D.1(a)(8)
B.1(p) Environmental impacts – VOC	D.1(a)(8)
B.1(p) Environmental impacts – NOx	D.1(a)(8)
B.1(p) Environmental impacts – SO2	D.1(a)(8)
B.1(p) Environmental impacts – Hg	D.1(a)(8)
B.1(p) Environmental impacts – PM	D.1(a)(8)
B.1(q) Water consumption quantities and rates	D.1(a)(8)
B.1(r) Tons of coal ash collected per unit (fly ash)	D.1(a)(8)
B.1(r) Tons of coal ash collected per unit (bottom ash)	D.1(a)(8)

help determine if it would be cheaper to buy power from the market rather than to run generating units. The day-ahead trader compares these calculated block energy prices with actual power prices being offered in the market, then purchases either on-peak or off-peak blocks of energy, if economical. The model also calculates the breakeven price for making sales out of the Company's generating resources, after taking into account native load and any other pre-existing power sales commitments. If economical, the day-ahead trader will make power sales in the market.

The day-ahead commitment plan is turned over to the real-time operations team to take forward into the intraday markets. The real-time traders update the load and available resource forecasts and re-run the unit commitment and dispatch model to fine-tune the commitment plan. They also check the intraday market to make purchases and sales of power to further optimize the system.

Within the sub-hourly window, the real-time traders proceed to further refine the Company's generation plan by interacting with the CAISO Western Energy Imbalance Market (WEIM) to transfer energy when economically beneficial to customers. Through calculated cost curves of each unit, the real-time traders determine which generators may be incremented, decremented, committed (start) and de-committed (shutdown) as part of a greater WEIM footprint solution. While considering available transmission resources, fuel supplies, and reliability needs, APS participates in both the 5-minute and 15-minute markets while maintaining the NERC required reserves and system stability requirements. Each of these markets use dynamic meter and load data as well as 5-minute renewable forecasting to dispatch all participating units with the goal of reducing the production cost for APS customers and the greater EIM footprint.

As the final step in this process, the real-time traders issue the commitment instructions to generating units as needed to meet load and sales commitments. Additionally, they respond to dynamic changes by updating the plan as needed for generating unit or transmission outages and forecast updates; continuously optimizing usage of available resources.

For the duration of the Planning Period, the generating unit commitment procedures are not expected to change from one year to the next.

RULE D.1(B) – B.2(B)

A 15-year resource plan, providing for each year: (b) Projected data for each of the items listed in subsection (B)(2), for the power supply system. Rule B.2(b): Production cost.

The production costs for the 15-year plan are provided in Table D-2 "Production Costs" (defined in R14-2-701(33)) include variable O&M costs of producing electricity through APS-owned generation. "Fuel" includes the commodity portion of fuel costs for APS-owned generating units to meet APS native load plus a long-term sales contract. "Emissions" refers to the costs associated with any CO_2 emissions. "Purchases" includes the variable O&M and commodity portion of fuel costs for tolled generating units, costs for existing PPAs, and short-term market purchases represented in response to Rule D.1(b) – B.2(f).

TABLE D-2. TOTAL PRODUCTION COSTS FOR 2023 RESOURCE PLAN ($MILLIONS)

	Generation		Emissions	Purchases		Total
	FUEL	VARIABLE O&M	CO2	DEMAND	ENERGY	$MILLIONS
2023	508.4	70.7	0.0	118.1	572.7	1,269.8
2024	555.6	75.7	0.0	190.6	495.9	1,317.8
2025	583.6	72.0	0.0	469.4	495.6	1,620.6
2026	605.2	71.2	0.0	602.2	492.3	1,770.9
2027	648.7	77.1	0.0	648.2	486.8	1,860.7
2028	694.1	84.9	253.2	675.8	524.5	2,232.6
2029	765.4	91.9	276.7	679.9	476.8	2,290.6
2030	727.3	93.2	253.6	684.0	469.9	2,228.0
2031	738.1	90.6	218.9	688.2	469.4	2,205.3
2032	561.6	79.0	155.3	717.9	456.7	1,970.4
2033	613.9	96.4	170.3	730.8	456.9	2,068.4
2034	667.3	105.3	184.1	736.8	457.0	2,150.5
2035	711.1	122.6	193.0	761.2	452.8	2,240.6
2036	727.4	130.2	196.6	767.6	462.7	2,284.5
2037	748.9	135.5	202.4	774.2	439.6	2,300.7
2038	796.9	137.6	215.8	781.0	454.1	2,385.4

RULE D.1(B) – B.2(C)

A 15-year resource plan, providing for each year: (b) Projected data for each of the items listed in subsection (B)(2), for the power supply system. Rule B.2(c): Reserve requirements.

The reserve requirements for the 2023 Resource Plan are provided in Attachment F.9(b) on line 3 of the attachment.

RULE D.1(B) – B.2(D)

A 15-year resource plan, providing for each year: (b) Projected data for each of the items listed in subsection (B)(2), for the power supply system. Rule B.2(c): Spinning reserve.

APS is one of 15 members of the Southwest Reserve Sharing Group (SRSG).[1] Individual members' spinning reserve requirements are calculated using a formula that takes into account factors such as each member's hourly loads, purchase and sale transactions, and thermal generation. Currently, APS's SRSG spinning reserve requirement is normally supplied by units fueled by natural gas, depending on economics. If APS was not an SRSG member, this requirement would increase to at least 560 MW to cover the system's largest single hazard. Because SRSG calculations are dependent upon each member's system conditions and the interaction of those systems working together, each member's contribution to SRSG spinning reserve may change over time.

Forecast spinning reserves over the planning horizon are illustrated in Table D-3. Half of these requirements can be met with units designed to start within 10 minutes.

[1] Additional information regarding SRSG can be found at www.srsg.org.

RULE D.1(B) – B.2(E)

A 15-year resource plan, providing for each year: (b) Projected data for each of the items listed in subsection (B)(2), for the power supply system. Rule B.2(e): Reliability of generating, transmission, and distribution systems.

GENERATION RELIABILITY

APS adopted the Loss of Load Expectation (LOLE) reliability target of one day in ten years as the minimum threshold of resource adequacy across all scenarios studied, which is widely used across the electric utility industry as a core reliability metric. To fully capture the impact of intermittent resources on resource adequacy, APS leveraged the Astrape consulting firm and its Strategic Energy and Risk Evaluation Model (SERVM) software to determine reliability contributions for each resource type included in the IRP, and the APS system Planning Reserve Margin (PRM) needed to achieve a LOLE of one day in ten years.

The resulting Installed Capacity (ICAP) PRM requires an increase from the previously calculated 15% to 20.2% in 2026. This increase is required to maintain an equivalent level of reliability for APS customers under changing system conditions, extreme weather events and changing industries practices for operating reserves. To align with industry best practice, going forward APS is adopting the Perfect Capacity (PCAP) PRM accounting methodology, which evaluates the reliability contribution of all resources – both conventional and intermittent - on a level playing field. ICAP and PCAP PRM values cannot be directly compared, as the methodologies used to calculate them are not the same. The PCAP PRM produced by the SERVM-based Astrape study is 6.9%. Table D-4 shows the annual reserve requirement amounts (also shown on Attachment F.9(b), line 3).

TRANSMISSION AND DISTRIBUTION RELIABILITY

APS follows the Institute of Electrical and Electronics Engineers (IEEE) 1366 – 2012, "Guide for Electric Power Distribution Reliability Indices" for measuring reliability. Three of the most common indicators used for measuring reliability are System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI), Momentary Average Interruption Frequency Index (MAIFI), and Customer Average Interruption Duration Index (CAIDI).

Forecasts for transmission and distribution reliability are provided in Attachment D.1(b). Transmission reliability represents projections of the portion of total SAIFI, SAIDI, MAIFI, and CAIDI, respectively, due to outages at the transmission level and illustrates a general flat trend in transmission reliability during the 15-year Planning Period with improvement over current reliability.

TABLE D-3. FORECAST SPINNING RESERVE REQUIREMENT

2022	SPINNING RESERVE CAPACITY (MW)
January	232
February	217
March	225
April	218
May	239
June	277
July	289
August	288
September	280
October	232
November	228
December	228

TABLE D-4. FORECAST RESERVE REQUIREMENTS

YEAR	RESERVE REQUIREMENT
2023	1,201
2024	1,247
2025	1,304
2026	1,349
2027	1,330
2028	1,124
2029	1,122
2030	1,142
2031	1,413
2032	1,450
2033	1,165
2034	1,295
2035	1,254
2036	1,605
2037	1,685
2038	1,703

Distribution reliability represents projections of the portion of total SAIFI, SAIDI, MAIFI, and CAIDI, respectively, due to outages at the distribution level and illustrates a general improvement in APS's reliability. The improving effectiveness of current Reliability Programs with proactive and strategic approaches suggests slight improvements to reliability year over year. Forecast vs. actual data may vary depending upon weather patterns and unusual events.

As of 2018 new safety efforts have been put in place in response to fire mitigation. These new safety efforts have driven the reliability numbers, SAIFI, SAIDI, and CAIDI up in efforts to prevent wildfires during dry seasons.

RULE D.1(B) – B.2(F)

A 15-year resource plan, providing for each year: (b) Projected data for each of the items listed in subsection (B)(2), for the power supply system. Rule B.2(f): Purchase and sale prices, averaged by month, for the aggregate of all purchases and sales related to short-term contracts.

APS does not forecast specific short-term purchase or sales contracts in the 15-year forecast; however, APS does anticipate a certain level of short-term market purchases during the first five years as depicted in Attachment F.9(b) at line 33. These are assumed to be four-month summer purchases (June to September) with capacity and energy prices based on anticipated available market generation costs as indicated in Table D-5. These purchases provide added flexibility to the 2023 Resource Plan and may be procured a year at a time, if needed, in the year prior to the need.

TABLE D-5. COSTS OF FORECASTED SHORT-TERM MARKET PURCHASES

YEAR	CAPACITY (MW)	DEMAND COST ($/KW-YR)	ENERGY COST ($/MWH)
2023	0	N/A	N/A
2024	199	85.12	44.20
2025	0	N/A	N/A
2026	43	89.43	51.83
2027	1	91.66	51.11

Notes: Currently there are no contracts in place for the capacity shown.
The capacity is assumed to be available from June to September each year.
The demand costs are based on microgrid costs.
The energy costs are based on fuel and O&M costs for a peaking unit.

RULE D.1(B) – B.2(G)

A 15-year resource plan, providing for each year: (b) Projected data for each of the items listed in subsection (B)(2), for the power supply system. Rule B.2(g): Energy losses.

Energy losses for the 15-year forecast are provided in Attachment C.1(b) on the line labeled "Energy Losses".

RULE D.1(C)

A 15-year resource plan, providing for each year: (c) The capital cost, construction time, and construction spending schedule for each generating unit expected to be new or refurbished during the period.

Capital cost, construction time, and construction spending schedules are provided in Attachment D.1(c).

RULE D.1(D)

A 15-year resource plan, providing for each year: (d) The escalation levels assumed for each component of cost, such as, but not limited to, operating and maintenance, environmental compliance, system integration, backup capacity, and transmission delivery, for each generating unit and purchased power source.

The current estimate of future inflation is 2.5% per year, which is used for the escalation of capital, O&M and environmental compliance costs. Exceptions are: (1) fuel prices which are determined either through the forward market or contractual terms; (2) purchased power prices that are determined through contractual terms; (3) solar, battery energy storage, and wind capital costs and solar photovoltaic O&M, which are expected to decline, then escalate at the rates of inflation provided by NREL; (4) remaining future resources (excluding CAES and pumped storage hydro power) capital costs, which escalate at inflation rates provided by NREL; and (5) CSP, wind and geothermal O&M, which also escalate at the rates of inflation provided by NREL.

RULE D.1(E)

A 15-year resource plan, providing for each year: (e) If discontinuation, decommissioning, or mothballing of any power source or permanent derating of any generating facility is expected: (i) Identification of each power source or generating unit involved; (ii) The costs and spending schedule for each discontinuation, decommissioning, mothballing, or derating; and (iii) The reasons for discontinuation, decommissioning, mothballing, or derating.

(i) Identification of each power source or generating unit involved:

Four Corners Units 1-2-3 were retired December 31, 2013, Saguaro Steam Units 1-2 were retired June 30, 2013, Ocotillo Steam Units 1-2 were retired March 22, 2019, and Cholla 2 was retired October 1, 2015. Cholla 1 & 3 will no longer burn coal past 2025 and APS will exit Four Corners Units 4-5 no later than 2031.

(ii) The costs and spending schedule for each discontinuation, decommissioning, mothballing, or derating

The cost to decommission Four Corners Units 1-3 was approximately $56 million. APS finished dismantling Units 1-3 in November 2016 and is not planning to fully decommission the site until after the retirement of Units 4-5.

The estimated cost to decommission the Saguaro Steam Units is approximately $9.9 M.

The total cost to decommission the Ocotillo Steam Units was approximately $11.5 M.

The estimated cost to decommission the Cholla 2 Steam Unit is between $13 and $15 M.

(iii) The reasons for discontinuing, decommissioning, or mothballing, or derating

The retirement of Four Corners Units 1-3 was part of a plan that included APS purchasing SCE's share of Four Corners 4-5. Details of that transaction are provided in Decision No. 73130[2]. Four Corners Units 1-3 were retired 1) so that APS ownership in coal would not increase appreciably as a result of the transaction, 2) to satisfy BART provisions with the EPA, and 3) APS does not have enough transmission to deliver its new share of Units 4-5 plus Units 1-3.

The Saguaro Steam Units were constructed in 1954 and 1955 and have reached the end of their useful life. The units are old, inefficient technology that had become increasingly difficult to maintain. APS anticipates preserving the site for remaining generation and for potential new generation in the future.

The Ocotillo Steam Units were installed in 1960 and have also reached the end of their useful lives. It had become increasingly difficult to maintain the units and acquire necessary parts for repair. Due to the importance of the location of the power plant in the Valley and its impact on ability to serve Valley load, new generating units were built on the site. Five fast start combustion turbines were built at Ocotillo and came on-line in 2019.

Cholla 2 Steam Unit was retired 1) due to the age of the unit, reaching the end of its useful life 2) potential capital cost associated with environment compliance and 3) the additional generation associated with the purchase of SCE's share of Four Corner Units 4-5.

[2] ACC Decision No. 73130 (April 24, 2012)

Cholla 1 & 3 will no longer burn coal past 2025; however, APS is continuing to evaluate its options related to Cholla and will inform the Commission upon making any decisions in this matter.

The exit of Four Corners Units 4-5 in 2031 is done to meet the goal of ending APS's use of coal-fired generation as part of the APS clean energy commitment.

RULE D.1(F)

A 15-year resource plan, providing for each year: (f) The capital costs and operating and maintenance costs of all new or refurbished transmission and distribution facilities expected during the 15-year period.

TRANSMISSION AND DISTRIBUTION

The forecasted expenditures for capital and O&M provided below were developed based upon APS's 2023-2032 Ten-Year Transmission System Plan, past expenditures and its system coincident peak load forecast for 2023 to 2038.

O&M costs provided in Table D-6 are not assigned to individual projects and are planned as a total of all projected transmission and distribution O&M during budgeting activities. As new transmission and distribution facilities are added to the system, they are incorporated into normal activities per APS's various processes. The O&M costs shown are those associated with newly added transmission and distribution facilities.

Table D-7 shows forecasted capital expenditures for all newly added transmission and distribution facilities expected to be completed during the 15-year Planning Period. APS's 2023-2032 Ten-Year Transmission System Plan describes planned expansion and upgrades of its transmission system. A list of transmission projects, which includes capital costs for new or refurbished transmission facilities, is provided in Attachment D.1(f). Capital costs are not assigned to individual distribution projects. APS plans its distribution system on a three-year basis. Because the dynamics of a distribution system are so heavily dependent on the level and location of electric load growth or reduction, forecasting with a high degree of accuracy beyond the three-year time frame is difficult and subject to the variations of economic activity. Also, distribution system improvements must be made in a very small geographic location so pinpointing exactly where the load changes will occur is problematic very far into the future.

TABLE D-6. O&M COSTS FOR TRANSMISSION AND DISTRIBUTION FACILITIES

YEAR	O&M ($000)
2023	[redacted]
2024	[redacted]
2025	[redacted]
2026	[redacted]
2027	[redacted]
2028	[redacted]
2029	[redacted]
2030	[redacted]
2031	[redacted]
2032	[redacted]
2033	[redacted]
2034	[redacted]
2035	[redacted]
2036	[redacted]
2037	[redacted]
2038	[redacted]

TABLE D-7. CAPITAL COSTS FOR TRANSMISSION AND DISTRIBUTION FACILITIES

YEAR	CAPITAL ($000)
2023	[redacted]
2024	[redacted]
2025	[redacted]
2026	[redacted]
2027	[redacted]
2028	[redacted]
2029	[redacted]
2030	[redacted]
2031	[redacted]
2032	[redacted]
2033	[redacted]
2034	[redacted]
2035	[redacted]
2036	[redacted]
2037	[redacted]
2038	[redacted]

ADVANCED GRID TECHNOLOGY

APS is likely to invest $315M in new grid technologies through 2027 to support reliability, power quality, and public safety while facilitating the integration of distributed energy resources. A list of technologies includes but is not limited to, Advanced Operational Platforms, Automated Switches, Automated Capacitors and Regulators, Communicating Line Sensors, Advanced Analytics, Substation Health Monitors, Communication Infrastructure, Downed Conductor Detection, Advanced Metering Infrastructure, Phasor Measurement Units, and Network Protectors. These technologies are described in Chapter 2 Assessing Needs & Resources.

RULE D.1(G)

A 15-year resource plan, providing for each year: (g) An explanation of the need for and purpose of all expected new or refurbished transmission and distribution facilities, which explanation shall incorporate the load-serving entity's most recent transmission plan filed under A.R.S. § 40-360.02(A) and any relevant provisions of the Commission's most recent Biennial Transmission Assessment decision regarding the adequacy of transmission facilities in Arizona.

An explanation of the need for and purpose of all expected new or refurbished transmission is provided in Attachment D.1(f). The need and purpose of distribution facilities is discussed in response to D.1(f) above.

RULE D.1(H)

A 15-year resource plan, providing for each year: (h) Cost analyses and cost projections, including the cost of compliance with existing and expected environmental regulations.

Cost analyses and projections for the 2023 Resource Plan are provided in Attachment D.10. The cost of existing and expected environmental regulations is embedded within the capital, O&M and emissions figures.

RULE D.2

Documentation of the data, assumptions, and methods or models used to forecast production costs and power production for the 15-year resource plan, including the method by which the forecast was benchmarked.

PRODUCTION MODEL

Data and assumptions related to resource dispatch and O&M costs as well as other system assumptions are well documented in response to rule D.1(a) and D.1(b) above. APS utilized Energy Exemplar's AURORA to analyze the resource plans in the IRP. AURORA is an hourly (with sub-hourly capability) production cost model that optimizes the commitment and dispatch of existing and future resources on the APS system. AURORA is widely used across the industry and is continually enhanced for the evolving needs of electric utilities. Inputs to AURORA include hourly load, unit characteristics (including capacity, heat rates, startup energy costs and maintenance), fuel price, environmental and regional constraints, renewable shapes and transactions. AURORA has enhanced storage logic, enabling an efficient integration of energy storage on systems with large renewable penetrations. AURORA outputs hourly (or aggregated) system production cost, unit costs and operating statistics (startups, energy output, runtime, capacity factor, fuel consumption and cost, emission production and cost as well as variable and fixed O&M).

BENCHMARKS

APS benchmarks the production simulation against the Company's budgeting tool, which itself is reconciled with actual system operations and production costs on a monthly basis. One important difference between resource planning and budgeting is that resource planning does not model the market, which changes significantly from one year to the next and over which APS has no control. Decisions are made to optimize resources within the Company's control to serve native load. In real-time, however, APS of course takes advantage of market opportunities for the benefit of customers.

ASSUMPTIONS

Data and system assumptions related to resource dispatch, fuel and O&M costs are thoroughly documented in the response to Rule D.1(a) and D.1(b). Resource capital costs are documented in the response to Rule D.3. Financial assumptions and emissions costs used to forecast production costs and power production for the 2023 IRP are included in Table D-8, Table D-9, Table D-10 and Table D-11.

TABLE D-8. COST OF CAPITAL

	CAPITAL RATIO	COST RATE	WEIGHTED COST OF CAPITAL	AFTER-TAX WEIGHTED COST OF CAPITAL
Debt	49.65%	6.35%	3.15%	2.36%
Equity	50.35%	8.70%	4.38%	4.38%
Totals	100%		7.53%	6.74%
AFUDC Rate	6.36%			
Composite Income Tax Rate	24.93%			

TABLE D-9. DEPRECIATION

	BOOK LIFE	TAX LIFE
Advanced Nuclear	40 Years	15 Years
Small Modular Reactor	40 Years	15 Years
Combustion Turbine	35 Years	15 Years
Combined Cycle	35 Years	15 Years
Combined Cycle with CCS	35 Years	15 Years
Microgrid	30 Years	15 Years
Transmission	50 Years	15 Years
Battery Energy Storage	20 Years	5 Years
CAES	30 Years	15 Years
Pumped Storage	30 Years	15 Years
Solar	40 Years	5 Years
CSP	40 Years	5 Years
Wind	40 Years	5 Years
Geothermal	30 Years	5 Years
Biomass	30 Years	5 Years

TABLE D-10(1). INVESTMENT TAX

	2023-2038
Energy Storage System	30%
Pumped Storage Hydropower	30%
Solar Thermal Tower - Concentrating Solar Power (CSP)	30%
Nuclear	30%
Geothermal	30%
Biomass	30%

Note: The 30% ITC lowers rate base and is amortized over the book life of the resource.

TABLE D-10(2). PRODUCTION TAX

	2023-2038
Solar (Fixed, SAT, and Solar Portion of PVS)	$26.39/MWh
Wind	$26.39/MWh
Carbon Capture Sequestration (CCS)	$85/Metric Ton of CO2

Note: Production Tax Credits are limited to the first 10 years of revenue requirements. No inflation will be assessed on the PTC amount.

TABLE D-11. CARBON DIOXIDE

YEAR	CO2 COST ($/METRIC TON)
2023	$0.0
2024	$0.0
2025	$0.0
2026	$0.0
2027	$0.0
2028	$25.1
2029	$25.8
2030	$26.4
2031	$27.1
2032	$27.7
2033	$28.4
2034	$29.1
2035	$29.9
2036	$30.6
2037	$31.4
2038	$32.2

Note: CO2 numbers based on CA 2023 CO2 cost escalated at 2.5% (begin in 2028)

RULE D.3

A description of each potential power source that was rejected; the capital costs, operating costs, and maintenance costs of each rejected source; and an explanation of the reasons for rejecting each source.

APS estimated the delivered cost of a broad spectrum of potential power sources, including conventional baseload, intermediate, peaking and energy storage resources as well as renewable solar photovoltaic, solar thermal, solar plus energy storage, wind, biomass, and geothermal resources. A number of these are represented in the fourteen portfolios presented in the 2023 IRP based on resource need, economics, diversity, reliability, and operational characteristics. Attachment D.3 includes the description, capital costs, O&M costs, and performance characteristics for the resource technologies that were selected to be included in the 2023 Resource Plan and portfolios as well as those technologies that were not selected.

In addition to these resources, APS is evaluating a wide range of energy storage and future generation resource options on an ongoing basis. These include, but are not limited to, compressed air storage, pumped storage, advanced nuclear and small modular reactor (SMR). At the time of the 2023 Integrated Resource Plan these technologies are either economically or commercially infeasible. APS will continue to evaluate these and other resource options on an ongoing basis.

Actual power sources will be acquired through the competitive procurement process. Furthermore, actual power sources procured may be different than those currently represented in the plan.

RULE D.4

A 15-year forecast of self-generation by customers of the load-serving entity, in terms of annual peak production (megawatts) and annual energy production (megawatt-hours).

The 15-year forecast of self-generation in terms of annual peak production (MW) is provided in Attachment F.9(b) on line 25 of the Loads & Resources table. The forecast of annual energy production (MWh) is provided in Attachment C.1(b) on the line labeled "Distributed Energy Programs."

TABLE D-12. RENEWABLE ENERGY CAPACITY AND PRODUCTION

	NAMEPLATE CAPACITY (MW)		ENERGY PRODUCTION (MWH)	
Year	Non-Residential	Residential	Non-Residential	Residential
2023	287	1,316	474,890	2,350,249
2024	296	1,494	489,372	2,522,068
2025	304	1,673	503,854	2,693,887
2026	313	1,851	518,335	2,865,706
2027	321	2,029	532,817	3,037,525
2028	329	2,208	547,299	3,209,343
2029	338	2,386	561,781	3,381,162
2030	346	2,565	576,263	3,552,981
2031	355	2,743	590,745	3,724,800
2032	363	2,922	607,208	3,896,619
2033	372	3,100	623,953	4,068,437
2034	380	3,278	639,204	4,249,888
2035	389	3,457	653,914	4,422,059
2036	397	3,635	667,441	4,594,004
2037	406	3,814	681,923	4,765,874
2038	414	3,992	696,405	4,937,693

RULE D.5

Disaggregation of the forecast of subsection (D)(4) into two components, one reflecting the self generation projected if no additional efforts are made to encourage self generation, and one reflecting the self generation projected to result from the load-serving entity's institution of additional forecasted self generation measures.

At this time, APS does not offer an up-front cash incentive for self-generation. The response provided in Rule D.4 depicts the current outlook for adoption of self-generation. The future of DE penetration is impacted by many factors and is therefore highly uncertain. See Table D-12 for the renewable energy capacity and production for the selected plan.

RULE D.6

A 15-year forecast of the annual capital costs and operating and maintenance costs of the self generation identified under subsections (D)(4) and (D)(5).

Table D-13 shows the forecast of total annual customer costs that may potentially be incurred by customer investments in self-generation for the select plan during the 15-year Planning Period.

TABLE D-13. FORECAST OF ANNUAL SELF-GENERATION COST INCURRED BY APS CUSTOMERS FOR THE SELECTED PLAN

	CAPITAL ($/Watt$_{ac}$)		O&M ($/kW-yr$_{ac}$)	
Year	**Non-Residential**	**Residential**	**Non-Residential**	**Residential**
2023	[redacted]			
2024				
2025				
2026				
2027				
2028				
2029				
2030				
2031				
2032				
2033				
2034				
2035				
2036				
2037				
2038				

RULE D.7

Documentation of the analysis of the self generation under subsections (D)(4) through (6).

The 2023 Resource Plan reflects the estimation of the energy output reflected in this case. The D5 Response Scenario estimates the projected level of self-generation in 2023 through 2038. The development of the D5 Response Scenario was based upon the best information available to APS at the time; however, the future of DE penetration is highly uncertain.

For each response given to Rules D.4 through D.6, APS assumes self-generation to be solely renewable-based. APS does not forecast the penetration of diesel- or natural gas-fired standby and emergency generation at this time.

RULE D.8

A plan that considers using a wide range of resources and promotes fuel and technology.

The 2023 Resource Plan employs a wide range of resources, both supply and demand side, and promotes fuel and technology diversity within the portfolio. Supply side and demand side resources are an important part of the selected portfolio, with diverse technologies playing a role in maintaining long term reliability and affordability for customers. For more details about the plans considered and the plan selected, see Chapter 5 – Portfolio Analysis.

RULE D.9

A calculation of the benefits of generation using renewable energy resources.

The estimated benefits of renewable energy resources (including distributed energy as well as energy from renewable contracts and resources) are listed in Table D-14.

TABLE D-14. RENEWABLE ENERGY BENEFITS

TOTAL RENEWABLE				AVOIDED EMISSIONS							
	Peak Capacity (MW)	Energy (GWh)	Avoided Gas Burn (BCF)	CO2 (Metric Tons)	SO2 (Tons)	CO (Tons)	NOx (Tons)	PM10 (Tons)	HG (Lbs)	VOC (Tons)	Avoided Water Usage (Acre Feet)
2023	1,659	6,975	47	2,809,580	16	224	258	87	13	8	5,618
2024	2,014	8,625	59	3,474,084	19	277	319	107	16	10	7,171
2025	3,015	11,709	80	4,716,327	26	376	433	145	22	14	10,078
2026	3,538	15,141	103	6,098,701	34	486	560	188	29	18	13,311
2027	3,868	17,393	118	7,005,679	39	558	644	216	33	20	15,433
2028	3,934	17,804	121	7,171,203	40	572	659	221	34	21	15,818
2029	4,070	18,364	125	7,396,925	41	589	679	228	35	22	16,348
2030	4,272	22,695	154	9,141,472	50	729	840	282	43	27	20,490
2031	4,512	24,187	165	9,742,430	54	776	895	301	46	28	21,896
2032	4,783	29,213	199	11,766,629	65	938	1,081	363	56	34	26,637
2033	4,831	29,431	200	11,854,586	65	945	1,089	366	56	35	26,858
2034	4,881	29,822	203	12,011,874	66	957	1,103	371	57	35	27,329
2035	4,942	30,484	207	12,278,710	68	979	1,128	379	58	36	27,953
2036	5,038	31,876	217	12,839,203	71	1,023	1,179	396	61	37	29,264
2037	5,210	33,102	225	13,333,061	74	1,063	1,225	411	63	39	30,420
2038	5,233	33,642	229	13,550,754	75	1,080	1,245	418	64	40	30,929
		TOTAL	**2,452**	**145,191,218**	**803**	**11,572**	**13,337**	**4,479**	**686**	**424**	**325,553**

RULE D.10

A plan that factors in the delivered cost of all resource options, including costs associated with environmental compliance, system integration, backup capacity, and transmission delivery.

Revenue requirements for the 2023 Resource Plan are shown in Attachment D.10 and include the delivered costs of all the resource options as described above.

The attached revenue requirements reflect the annual revenue level required to supply APS customers' energy needs, including: (1) carrying costs on existing and future generation, future transmission over and above APS Ten Year Transmission Plan, and capital expenditures on existing generation; (2) fuel costs (commodity and fixed transport); (3) purchase power costs; (4) operating and maintenance costs for existing and future generation; (5) energy efficiency and distributed energy program and incentive costs; and, (6) power plant emission costs including CO2. Revenue requirements as used in the IRP do not include costs associated with existing transmission, existing and future distribution, or sales tax on retail electric sales.

Environmental compliance costs are embedded within the capital and O&M figures, and system integration costs are embedded in the purchased power costs for solar photovoltaic and wind technologies. The loads and resources plan factors in backup capacity and those costs are included within the total revenue requirement costs.

RULE D.11

Analysis of integration costs for intermittent resources.

System integration costs may be incurred by operation of some non-dispatchable resources such as wind or solar due to their variable nature. Additional operating reserves may need to be carried on the rest of the system to effectively follow APS load and meet NERC reliability requirements. System integration costs depend upon many factors, including the accuracy of forecasted intermittent generation, real-time generation fluctuation, renewable penetration levels and resource mix. APS commissioned E3 to conduct both the solar photovoltaic (PV) and wind integration cost studies. The results of these studies were included in the IRP and are further detailed in Chapter 2.

RULE D.12

A plan to increase the efficiency of the load-serving entity's generation using fossil fuel.

APS operates and maintains the fleet of generating units to optimize efficiency by balancing expenditures with benefits achieved by those expenditures. Opportunities to increase unit efficiency are evaluated on a regular basis from both economic justification and environmental permitting perspectives.

APS's objective is to ensure unit reliability is maintained so that the units are available to meet the load demand. O&M and capital expenditures are planned to maximize equipment reliability, thus reducing the amount of time the units are unavailable due to equipment failures. For baseload units, this reduces fuel costs that are incurred during unplanned startups and shutdowns. In addition, proper and timely maintenance reduces replacement power costs that can be incurred during forced outage events.

Plant components are maintained with the objective of meeting the original design performance specifications. When O&M expenditures to maintain the equipment become too high or the component condition is showing signs of degradation that may threaten unit reliability, the component will be evaluated for replacement. In these circumstances, the component will be evaluated for any changes that can be made that will result in improved unit efficiency. This evaluation considers environmental permit impacts to ensure compliance with regulatory requirements.

APS also increases the efficiency of its fossil generation fleet by its resource decisions going forward. APS is implementing a Thermal Performance Upgrades (TPU) on the Siemens legacy gas turbines at the West Phoenix Power Plant which will convert the turbines to the most advanced frames currently available from the OEM and result in an additional 55 MW of generating capacity at an improved heat rate. Ultra-Low NOx (ULN) combustion systems will also be installed in the turbines which will reduce NOx emission levels to less than 9 ppm and allow for the co-firing of up to 30% hydrogen fuel which is another step towards our clean energy goals.

To meet the increasing demand for power without adding additional gas generating units, APS is installing Turbine Inlet Air Chillers (TIAC) along with Thermal Energy Storage (TES) on all units at the Redhawk and Sundance Power Plants. The addition of TIAC and TES will result in the recovery of an estimated 103 MW of additional power which otherwise would not be available during peak summer ambient conditions when the power is needed the most.

Another aspect of efficiency applies to water consumption. APS has announced clean energy goals that will increase reliance on renewable energy such as PV solar and wind generation and on increased energy efficiency programs. Energy efficiency and wind generation consume no water, while photovoltaic solar has very low consumption rates. APS is also investing significantly in battery storage technologies that will reduce the need for peak generation from combustion turbines, further reducing fleet water intensity. A forecast of the reduction in water intensity measured as gallons per MWh for the Resource Plan is included in the response to Rule D.17.

RULE D.13

Data to support technology choices for supply-side resources.

Data to support technology choices for supply-side resources has been provided in Attachment D.3.

RULE D.14(A)

A description of the demand management programs or measures included in the 15-year resource plan, including for each demand management program or measure: (a) How and when the program or measure will be implemented

CURRENT PROGRAMS

There are currently thirteen EE programs and thirty-two DR programs and initiatives (including twenty rates). This included twenty-one residential programs and twenty-four non-residential programs. These programs are detailed in Attachment D.14(a).

FUTURE PROGRAMS

The Company will continue to evaluate existing and emerging technologies and measures to identify cost-effective programs that align with long-term resource planning needs. Because of the rapid advance in distributed energy technologies and products, constant evaluation is required. When new, unproven measures or technologies are identified, APS may request approval of new programs, measures, or pilots to assist APS in quantifying the resource potential to support future resource planning needs, as well as assist in refining the resource cost-effectiveness calculations. Through pilots, APS will be able to gather data regarding the societal and program costs and benefits that can then be used to more accurately depict the program cost-effectiveness and viability. APS has currently proposed and/or is currently implementing a number of innovative new DSM technology pilots and programs including the Residential Energy Storage pilot, Commercial Advanced Rooftop Controls, and the Managed EV Charging pilot.

In planning for the future, APS applies the concepts described in Chapter 2 to develop its long-term DSM plans for the 2023-2038 period. APS developed long-term DSM goals while balancing the benefits and costs of DSM under various perspectives reflected in the context of the required SCT and other cost effectiveness tests for informational purposes. In this IRP, it is assumed that APS will continue its current portfolio of programs while also adding incremental peak capacity from both Residential and Commercial/Industrial demand response during the Planning Period. APS commits to continue working with stakeholders to develop strategies and programs for future DSM. Energy efficiency and demand response peak demand and energy reductions for the 2023 Resource Plan are shown in Table -15. For details on DSM program additions in each portfolio, refer to Chapter 5 and D.14(c) of this section.

TABLE D-15(1). DEMAND AND ENERGY REDUCTION

	Peak Demand Reduction (MW)		Energy Reduction (MWh)	
YEAR	ENERGY EFFICIENCY	DEMAND RESPONSE	ENERGY EFFICIENCY	DEMAND RESPONSE
2023	132	90	361,177	8,064
2024	234	95	313,721	8,514
2025	319	144	325,695	12,992
2026	327	145	333,389	13,014
2027	404	145	341,739	13,014
2028	489	195	349,984	17,514
2029	581	192	356,256	17,289
2030	687	240	363,069	21,564
2031	780	275	366,734	24,714
2032	852	320	369,094	28,764
2033	931	310	371,110	27,864
2034	1,035	300	374,450	26,964
2035	1,127	305	377,054	27,414
2036	1,244	310	379,696	27,864
2037	1,322	315	381,364	28,314
2038	1,412	320	384,374	28,764

RULE D.14(B)

A description of the demand management programs or measures included in the 15-year resource plan, including for each demand management program or measure: (b) The projected participation level by customer class for the program or measure.

The projected participation level by customer class for energy efficiency programs and measures is extremely difficult to quantify due to the characteristics and nature of the program in question, as these programs may not exist 15 years into the future, or their components may be markedly different. For these reasons, projecting customer participation is not currently feasible. However, APS does estimate the participation needed to meet its goal for each year on a going-forward basis in the DSM Implementation Plan. Actual 2022 participation on a measure level is provided at Attachment D.14(b).

Projected demand response and time-of-use program participation is forecast in Table D-16 and Table D-17.

TABLE D-16. EXPECTED RESIDENTIAL DR PROGRAM PARTICIPATION

2023 RESIDENTIAL DR PROGRAMS		
Time-Differentiated Rates	Expected Participants	
	2023*	15 Year Horizon
1. ET-1 Time Advantage (9am -9pm)[1]	9,005	0
2. ET-2 Time Advantage (Noon - 7pm)[1]	33,986	0
3. ECT-1R Combined Advantage (9am-9pm)[1]	513	0
4. ECT-2 Combined Advantage (Noon - 7pm)[1]	2,755	0
5. R-2 (3pm – 8pm)	70,297	95,156
6. R-3 (3pm – 8pm)	167,115	226,212
7. R-TECH (3pm – 8pm)	36	49
8. R-TOUE-E (3pm – 8pm)	387,516	524,554
9. Peak Event Pricing[2]	180	Unknown
10. Cool Rewards Load Management Program[3]	74,000	Unknown
11. Residential Battery Pilot	251	Unknown

Notes:
1. APS has filed a request to freeze and limit this rate to only existing customers on the rate with distributed generation effective July 1, 2017 in ACC Docket E-01345A-16-0036.
2. Customers are included in the parent rate schedule.
3. The number of smart thermostats enrolled in the Cool Rewards DR program.
* Total average participants as of December, 2022.

TABLE D-17. EXPECTED NON-RESIDENTIAL DR PROGRAM PARTICIPATION

2023 NON-RESIDENTIAL DR PROGRAMS		
Time-Differentiated Rates	Expected Participants	
	2023*	15 Year Horizon
1. E-20	377	0
2. E-32 XS TOU	705	864
3. E-35	28	28
4. GS-Schools M	139	155
5. Interruptible Rate	0	Unknown
6. Peak Solutions[1]	75	N/A

Notes:
1. The underlying contract that supports this program expires at the end of 2024.
*Total average participants as of December, 2022

As more cost-effective DSM measures and technologies are identified and new programs such as load management, energy storage, and other innovative new pilots are evaluated and deployed, additional customer participation over time is likely. All new programs and/or pilots will include estimates of potential customer participation and customer demand offsets per event. As more information becomes available, estimated participation numbers will be included in the APS DSM Implementation Plan filings.

RULE D.14(C)

A description of the demand management programs or measures included in the 15-year resource plan, including for each demand management program or measure: (c) The expected change in peak demand and energy consumption resulting from the program or measure.

Depicted in Table D-18 are the capacity and annual energy savings for 2022 energy efficiency programs. As stated in response to Rule D.14(b), projecting a programmatic breakdown out 15 years into the future is not currently feasible; however, Attachments C.1(a) and C.1(b) provide annual aggregate capacity and energy savings forecasts.

Projections of future demand response and time-of-use impacts are located in Table D-19. The savings represented in the 2023 Resource Plan reflect the 2022 EE and DR program results.

TABLE D-18. ENERGY EFFICIENCY CAPACITY AND ENERGY CONTRIBUTIONS

2022 Residential and Non-Residential EE Programs[1]		
PROGRAM NAME	**CAPACITY SAVINGS (MW)**	**ANNUAL ENERGY SAVINGS (MWH)**
Residential		
Existing Homes	18.3	23,416
New Construction	17.6	26,116
Conservation Behavior	63.8	54,476
Multi-Family	2.4	12,873
Limited Income	1.4	2,736
Energy Storage Pilot	0.5	0
Residential Sub-Total	**104.0**	**119,617**
Non-Residential		
Existing Facilities	12.3	67,444
New Construction & Major Renovation	19.0	76,952
Energy Information Services	2.0	1,954
Schools	2.7	10,171
Advanced Rooftop Controls Pilot	1.4	4,069
Non-Residential Sub-Total	**37.4**	**160,590**
Energy Storage and Load Mgmt-Rewards Program	123.0	0
Energy and Demand Education	0.0	0
Codes & Standards	5.4	26,960
System Savings	0.0	6,020
EV Managed Charging	0.8	132
DR Contribution	51.8	40,500
Tribal Communities	0.1	331
Total Initiatives	**181.1**	**73,943**
TOTAL	**322.5**	**354,150**

Note:
1. Numbers represent peak demand and energy reduction goals, with DR contribution, for 2022 as reported in the APS DSM Annual Progress Report filed with the ACC on March 1, 2023.

TABLE D-19. EXPECTED DR PROGRAM ENERGY AND DEMAND CONTRIBUTIONS

2023 Residential and Non-Residential DR Programs				
PROGRAM NAME	2023		15-YEAR HORIZON	
	PEAK DEMAND REDUCTION (MW)	ANNUAL ENERGY REDUCTION (MWH)	PEAK DEMAND REDUCTION (MW)	ANNUAL ENERGY REDUCTION (MWH)
Residential				
Future Direct Load Control	152	N/A	375	N/A
Non-Residential				
Peak Solutions [1]	67	N/A	275	N/A
Unspecified Future Programs	N/A	N/A	285	N/A
Time-of-Use Rates [2]	117	75	N/A	N/A

Notes:
1. APS is currently contracted with a C&I demand response provider through 2025.
2. Demand reductions are estimated for all current residential rates, and energy reduction is estimated only for ET-SP,CPP-RES and PTR. APS has not at this time completed energy reduction analyses for the remaining residential rates, and has not conducted energy or demand reduction analyses for the non-residential rates.

RULE D.14(D)

A description of the demand management programs or measures included in the 15-year resource plan, including for each demand management program or measure: (d) The expected reductions in environmental impacts including air emissions, solid waste, and water consumption attributable to the program or measure.

EE programs as well as APS's non-residential load control and demand response pricing programs are all assumed to displace natural gas-fired generation. Because DR programs are designed to reduce only the top 1-2% of hours in the year, their direct impact on emissions is very small compared to EE programs that encompass more hours. However, DR and other flexible distributed capacity programs are becoming increasingly important to align energy demand with intermittent renewable resources when they are available and allow greater quantities of renewable energy to be integrated onto the grid. This indirectly helps to reduce overall emissions intensity.

Table D-20 provides estimates of 2022 energy efficiency environmental impacts. The estimated impacts on air emissions for the experimental residential peak event pricing programs and demand rates are shown in Table D-21.

TABLE D-20. EE ESTIMATED ENVIRONMENTAL IMPACT

2022 Residential and Non-Residential EE Programs Reduction of Environmental Impact[1]					
	WATER (MIL GAL)	SOX (LBS)	NOX (LBS)	CO2 (MIL LBS)	PM10 (LBS)
Residential					
Existing Homes	111	1,563	26,092	309	11,639
New Construction	160	2,255	37,630	445	16,786
Conservation Behavior	17	245	4,091	48	1,825
Multi Family	74	1,038	17,315	205	7,724
Limited Income	16	222	3,698	44	1,650
Tribal Communities	2	22	374	4	167
TOTAL - Residential	**380**	**5,345**	**89,200**	**1,055**	**39,791**
Non-Residential					
Existing Facilities	277	3,890	64,919	768	28,959
New Construction & Major Renovation	330	4,645	77,518	918	34,579
Energy Information Services	3	44	734	9	327
Schools	47	662	11,044	131	4,926
Advanced Rooftop Controls Pilot	15	211	3,519	42	1,570
Managed EV Charging Pilot	-	6	99	1	44
TOTAL – Non-Residential	**672**	**9,458**	**157,833**	**1,869**	**70,405**

Note:
1. Based on lifetime MWh savings

TABLE D-21. ESTIMATED ENVIRONMENTAL IMPACT FROM SELECT RATES AND PEAK SOLUTIONS

2022 Residential Peak Event Pricing Programs and Demand Rates Estimated Reduction in Air Emissions					
	WATER (MIL GAL)	SOX (LBS)	NOX (LBS)	CO2 (MIL LBS)	PM10 (LBS)
ET-1	3.4	47.3	789.5	9.3	352.2
ET-2	12.2	171.5	2,861.8	33.9	1,276.6
ECT-1R	0.1	2.0	32.9	0.4	14.7
ECT-2	0.6	7.9	131.6	1.6	58.7
R-2	33.5	471.1	7,861.6	93.1	3,506.8
R-3	107.6	1,513.7	25,262.4	299.0	11,268.9
R-TECH	0.0	0.0	0.0	0.0	0.0
R-TOU-E	107.6	1,513.7	25,262.4	299.0	11,268.9
Critical Peak Pricing	0.2	2.5	42.2	0.5	18.8
Peak Solutions	13.0	182.3	3,041.6	36.0	1,356.8
TOTAL	278.2	3,911.9	65,285.9	772.8	29,122.2

RULE D.14(E)

A description of the demand management programs or measures included in the 15-year resource plan, including for each demand management program or measure: (e) The expected societal benefits, societal costs, and cost-effectiveness of the program or measure.

All DSM programs implemented must be proven cost-effective through the societal benefit-cost test (SCT). The SCT is structurally similar to the Total Resource Cost Test (TRC) but goes beyond the TRC test in that it attempts to quantify the change in the total resource costs to society as a whole rather than to only the service territory (the utility and its ratepayers).

In Decision No. 73089, APS was ordered "that in all future DSM Implementation Plans, the Company use the same input values and methodology as Staff for calculating the present value benefits and costs to determine benefit-cost ratios."

Table D-22 provides details on the societal benefits, societal costs, and cost-effectiveness of the existing DSM programs.

TABLE D-22. BENEFIT-COST RATIOS FOR EE PROGRAMS

2022 Residential and Non-Residential EE Programs Societal Costs, Benefits and Cost-Effectiveness				
	SOCIETAL BENEFITS ($1,000S)	SOCIETAL COSTS ($1,000S)	NET BENEFITS ($1,000S)	BENEFIT-COST RATIO
Residential				
Existing Homes	$13,342	$6,993	$6,349	1.91
New Construction	$17,153	$14,418	$2,735	1.19
Conservation Behavior	$5,409	$2,417	$2,992	2.24
Multi Family	$5,060	$4,187	$873	1.21
Limited Income [1]	$403	$403	$0	1.00
Energy Storage Pilot	$0	$375	-$375	0.00
Tribal Communities [2]	$243	$445	-$202	0.00
TOTAL- Residential	**$41,367**	**$28,793**	**$12,574**	**1.44**
Non-Residential				
Existing Facilities	$25,461	$15,394	$10,067	1.65
New Construction & Major Renovation	$29,413	$19,734	$9,679	1.49
Energy Information Systems	$766	$239	$527	3.21
Schools	$5,038	$2,425	$2,613	2.08
Advanced Rooftop Controls Pilot	$1,429	$1,219	$210	1.17
Managed EV Charging Pilot	$401	$1,054	-$653	0.00
TOTAL - Non-Residential	**$62,508**	**$40,065**	**$22,443**	**1.56**

Notes:
1. APS analysis is consistent with Decision No. 68647. Program costs include weatherization. Societal costs do not include bill assistance because it does not contribute to electric saving.
2. Tribal Communities includes both residential and non-residential segments

The societal benefits, societal costs, and cost-effectiveness of future demand response programs are currently not known, as those programs have yet to be developed. Time-of-Use pricing programs are inherently designed to be revenue neutral. The societal benefits, societal costs and cost-effectiveness of APS's non-residential load management program, Peak Solutions, can be found in Table D-23.

TABLE D-23. APS PEAK SOLUTIONS COST-BENEFIT RATIO

APS Peak Solutions Program Societal Costs, Benefits and Cost-Effectiveness				
	SOCIETAL BENEFITS ($1,000S)	SOCIETAL COSTS ($1,000S)	NET BENEFITS ($1,000S)	BENEFIT-COST RATIO
Rewards Program	9,817	5,619	4,198	1.7
APS Peak Solutions Program	NA	NA	NA	NA

TABLE D-24. EXPECTED LIFE OF EE PROGRAMS

2022 Residential and Non-Residential EE Programs Program and Measure Life	
PROGRAM	**YEARS**
Residential	
1. Existing Homes	14.8
2. New Construction	19.2
3. Conservation Behavior	1.0
4. Multi Family	17.9
5. Limited Income	18.0
Non-Residential	
1. Existing Facilities	12.8
2. New Construction & Major Renovation	13.4
3. Energy Information Systems	5.0
4. Schools	14.5
5. Advanced Rooftop Controls Pilot	11.5
6. EV Managed Charging Pilot	10.0

TABLE D-25. EE PROGRAM COSTS

2022 Residential and Non-Residential EE Programs [1] Program Costs	
PROGRAM	**COST ($1,000S)**
Residential	
1. Existing Homes	9,032
2. New Construction	3,512
3. Conservation Behavior	2,417
4. Multi Family	1,620
5. Limited Income	5,485
6. Energy Storage Pilot	944
TOTAL:	**23,010**
Non-Residential	
1. Existing Facilities	7,319
2. New Construction & Major Renovation	8,015
3. Energy Information Systems	180
4. Schools	1,170
5. Advanced Rooftop Controls Pilot	834
TOTAL:	**17,518**
DSM Initiatives	
1. Energy Storage and Load Management - Rewards program	5,646
2. Managed EV Charging Pilot	438
3. Energy and Demand Education Pilot	4,087
4. Codes & Standards	93
5. Tribal Communities	877
TOTAL:	**11,141**

Notes:
1. MER costs were an additional $2,568,655
2. DR costs were an additional $1,303,540

RULE D.14(F)

A description of the demand management programs or measures included in the 15-year resource plan, including for each demand management program or measure: (f) The expected life of the measure.

Demand response pricing programs do not have a "measure life"; however, the established rate plans are expected to be in place throughout the Planning Period. The APS Peak Solutions program has been contracted through 2025. Table D-24 presents the estimated measure life (in years) by EE program.

RULE D.14(G)

A description of the demand management programs or measures included in the 15-year resource plan, including for each demand management program or measure: (g) The capital costs, operating costs, and maintenance costs of the measure, and the program costs.

The estimated costs for EE programs are included in Table D-25.

The APS Peak Solutions program is administered through a contract with a third-party provider (currently contracted through 2024) that includes both energy and capacity payments. The expected program costs through the term of the Peak Solutions contract can be found in the Table D-26. In 2022, approximately 50% of the capacity reduction contracted for was achieved.

TABLE D-26. FORECASTED COSTS FOR APS PEAK

Peak Solutions Program Costs	
YEAR	**COSTS [1] ($1,000S)**
2023	4,774
2024	5,127
2025	5,481
2026	Unknown
2027	Unknown

Note:
1. APS is currently contracted with a third-party provider to implement the Peak Solutions program through 2025. Costs after this time are currently unknown.

Capital and O&M costs for potential customer load management and generation programs such as residential direct load control, thermal energy storage, or standby generation have been estimated in the Company's 2008 Demand Response Study. APS is currently conducting an EE/DR market potential study to inform future costs. APS also conducts periodic RFP solicitations seeking bids for additional demand response program capacity which are used to help inform future costs.

RULE D.15

For each demand management measure that was considered but rejected: (a) A description of the measure; (b) The estimated change in peak demand and energy consumption from the measure; (c) The estimated cost-effectiveness of the measure; (d) The capital costs, operating costs and maintenance costs of the measure, and the program costs; and, (e) The reasons for rejecting the measure.

As required by the EE Rules, the societal cost test was applied to all measures submitted for approval by APS. If the benefit-cost ratio was not greater than 1.0, the measure was rejected or in some cases, measures with a benefit-cost ratio of less than 1.0 are submitted for consideration as a pilot measure which does not need to be cost effective. Table D-27 details the response to Rules D.15(a) through D.15(d) for the EE measures that were considered but rejected. In response to D.15(e), all of the measures listed were not approved due to their not passing the SCT requirement. APS will continue to reevaluate beneficial measures and propose those that improve the DSM portfolio in subsequent DSM filings.

DEMAND RESPONSE PROGRAMS
To date, no specific DR program has been rejected.

TABLE D-27. REJECTED EE MEASURES AND PROGRAMS

Residential and Non-Residential EE Programs - Rejected Measures and Programs				
RULE D.15(A)	RULE D.15(B)		RULE D.15(C)	RULE D.15(D)
DESCRIPTION	PEAK DEMAND SAVINGS (KW/UNIT)	ENERGY SAVINGS (KWH/UNIT)	ESTIMATED COST-EFFECTIVENESS (SCT RESULT)	INCREMENTAL MEASURE COST ($/UNIT)
Residential				
Air Sealing and Attic Insulation(R7 to R43)	0.23	1,631	0.61	$1,487.40
Connected Pool Pumps	0.12	1,931	0.70	$354.86
Occupancy Sensor - In Unit	0.01	49	0.15	$68.11
Shade Screens	0.00	5	0.62	$3.60
Smart_App_2020_DFC_MAS_Dryer_Electric	0.07	0	0.33	$125.00
Smart_App_2020_DFC_MAS_Dryer_Gas	0.01	0	0.05	$75.00
Smart_App_2020_DFC_MAS_Washer_Electric	0.04	0	0.54	$40.00
Smart_App_2020_DFC_MAS_Washer_Gas	0.02	0	0.27	$40.00
Non-Residential				
Advanced Lighting Controls	0.34	1,607	0.36	$1,000.00
Air Dryer Upgrade	0.00	13	0.84	$5.00
CO2 Sensor | Warehouse	0.16	423	0.44	$444.06
Construction >= 70% < 80%	0.00	18	0.97	$7.61
Construction >= 80% <90%	0.00	20	0.93	$8.99
Construction >= 90% <100%	0.01	23	0.90	$10.47
Refrigeration HiE Compressor - Walk In Freezer	0.78	3,828	0.81	$1,611.36
Refrigeration High-Efficiency Freezer (1 Door)	0.28	1,378	0.74	$630.66
Refrigeration High-Efficiency Freezer (2 Door)	0.49	2,436	0.61	$1,355.12
Refrigeration High-Efficiency Freezer (3 Door)	0.37	1,811	0.50	$1,229.94
Refrigeration High-Efficiency Refrigerator (1 Door)	0.05	252	0.53	$163.28
Refrigeration High-Efficiency Refrigerator (2 Door)	0.09	451	0.11	$1,407.46
Refrigeration High-Efficiency Refrigerator (3 Door)	0.09	446	0.12	$1,241.30
Regular 2x2 LED to Smart 2x2 LED <30W	0.01	38	0.47	$28.59

Residential and Non-Residential EE Programs - Rejected Measures and Programs				
RULE D.15(A)	RULE D.15(B)		RULE D.15(C)	RULE D.15(D)
DESCRIPTION	PEAK DEMAND SAVINGS (KW/UNIT)	ENERGY SAVINGS (KWH/UNIT)	ESTIMATED COST-EFFECTIVENESS (SCT RESULT)	INCREMENTAL MEASURE COST ($/UNIT)
Non-Residential				
Regular 2x2 LED to Smart 2x2 LED >=30W	0.01	55	0.71	$27.38
Regular 2x4 LED to Smart 2x4 LED <40W	0.01	50	0.79	$22.21
Smart Screw-in LED replace regular Screw-in LED	0.00	14	0.51	$7.90

RULE D.16

Analysis of future fuel supplies that are part of the resource plan.

In 2019, Concentric Energy Advisors completed a study for APS that analyzed the supply outlook for natural gas and gas infrastructure, informing the preparation of the 2023 Integrated Resource Plan. As part of this study, coal generation outlook, gas and renewables generation, regulations and cost competitiveness were analyzed for the Southwestern US (including Mexico), and on a national level. Concentric's supply and demand outlook for the North American gas and energy infrastructure covered the technological, environmental, and economic factors driving the expectations for fuels and infrastructure of significant interest to APS: natural gas, gas pipelines, renewables, and impacts to coal generation. In addition to the report providing an outlook for North America (48 states and Mexico) as a whole, there is specific detail on gas delivery infrastructure from western production basins to Arizona, New Mexico and California. Since 2019, APS has held several discussions with Arizona utilities and pipeline transport providers regarding future supply and options considered in the APS resource plan. With the recent growth in the LNG markets, increased reliance on natural gas to back up renewables, and strong customer growth, the demand for natural gas continues to increase in the desert southwest.

Natural gas supply includes existing contract capacity, future extension of existing contracts, additional seasonal and annual contracts as well as short term contracts. All APS natural gas contracts are firm fixed delivery to assure adequate gas supply for peak seasonal demands. The natural gas supply and demand analysis was used to assess the APS gas use projection and gas infrastructure portfolio to ensure that current and future generation needs are fully met. This analysis was an input to APS resource planning effort. This assessment is designed to project peak seasonal natural gas use and identify the supply of gas for each of these seasonal peaks during the Planning Period. An example of this analysis can be found in Attachment D.16.

Based on these studies, APS reaffirms that the ongoing practice of procuring firm fixed gas fuel delivery contracts is appropriate and adequately addresses potential fuel supply and delivery during the Planning Period. See Rule E(f) for more information about future fuel supplies.

RULE D.17

A plan for reducing environmental impacts related to air emissions, solid waste, and other environmental factors, and for reducing water consumption.

COMPANY RESPONSE TO AIR EMISSIONS AND CLIMATE CHANGE INITIATIVES

APS has undertaken numerous initiatives to address concerns about emissions of air pollution including greenhouse gas emissions. These initiatives focus on the following:

- Increase Reliance on Clean Energy Resources. Ensure steady production from Palo Verde Generating Station and add new renewable resources and energy storage.
- Reduce Reliance on Higher Emitting Sources. Add an option to operate Four Corners seasonally, and plan to exit all coal-fired generation by 2031.

- Empower Customers. Develop and implement demand response programs that benefit customers and allow APS to shed load in times of high demand.
- Support Innovation. Establish programs that provide businesses with options to reach their clean energy goals and participate in initiatives like the Center for an Arizona Carbon Neutral Economy.
- Other Company Initiatives. Transition APS-owned light-duty vehicles and equipment to electric; improve the energy efficiency of APS-owned buildings; and establish an ACC-approved statewide transportation electrification strategy and plan.

APS prepares and reports an annual inventory of air pollution emissions from its operations. This inventory includes traditional air pollution emissions, as well as the company's overall carbon intensity, Scope 1 and Scope 2 greenhouse gas emissions. These inventories are reported to EPA under Title V of the Clean Air Act as well as EPA's GHG Reporting Program. This same information is voluntarily communicated to the public in Pinnacle West's annual Corporate Responsibility Report, which is available on the Pinnacle West website (*pinnaclewest.com/corporate-responsibility*). This report provides information including the company's approach to and performance regarding sustainability, corporate governance, social responsibility and environmental stewardship.

ENVIRONMENTAL MANAGEMENT

Our Environmental department, which reports to the Executive Vice President of Operations, provides environmental leadership to the Company through establishing sound environmental policies, managing environmental risks, implementing world-class environmental management systems, and driving the adoption of sustainable concepts. The department activities include:

- EMS Program. Implement and maintain an Environmental Management System.
- Training. Conduct environmental training on environmental compliance and risk identification and reduction.
- Audits. Interface with agency inspectors during site compliance audits and inspections.
- Corrective Action Program. Engage with the APS Corrective Action Program and work for continuous improvement.
- Policy, Process and Procedure. Develop, implement and maintain environmental processes and procedures to maintain environmental compliance.
- Regulatory Compliance. Complete required reporting by EPA and local regulatory governing agencies.

SOLID WASTE

As stewards of Arizona, we are committed to pollution prevention and waste minimization in our daily operations. We are committed to preserving our planet through environmental stewardship by following company policies, processes, and procedures for sustainability and considering the environmental impact and risk assessment of each decision we make. In addition, we comply with all environmental laws and regulations, going beyond compliance when appropriate.

More than 30 years ago, we began to identify and minimize all forms of solid waste, including universal and hazardous waste. We focused on reducing waste materials, using product substitution to eliminate hazardous waste, and recycling whenever possible. This effort dramatically reduced the amount of waste generated through our company and led us to create a waste reduction metric that continues today.

We also developed Pollution Prevention (P2) Plans for our power plants. These P2 plans are implemented and maintained by the company, and some are filed with the Arizona Department of Environmental Quality (ADEQ), as required. For nearly 10 years, we have enhanced our pollution prevention and waste minimization commitment through our Environmental Management Systems.

WATER SUPPLY

Water is used for power generation primarily to cool the steam-cycle by removing waste heat. It is also used for power augmentation, emissions control, auxiliary cooling, supporting chemical treatment processes, domestic purposes, and for other miscellaneous plant uses. APS manages water resources using a multi-layered approach to reduce water intensity. APS's plan for reducing water consumption includes the following actions:

- Employment of alternative cooling technologies for new generating resources;
- Improving the efficiency of water use during the Planning Period;
- New power plant construction, water saving alternatives;
- Retirement of existing power plant generating units, associated water savings;
- Reduce quantity of non-renewable groundwater consumed;
- Improve the efficiency of water utilization at APS's existing facilities; and
- Increase reliance on energy efficiency and renewable energy resources.

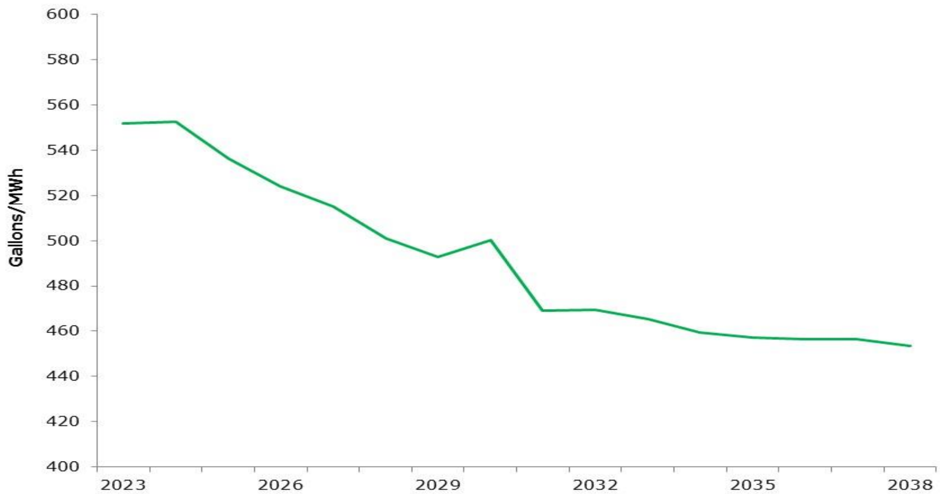
EMPLOYMENT OF ALTERNATIVE COOLING TECHNOLOGIES FOR NEW RESOURCES

For new facilities, APS evaluates alternative cooling technologies, water sources, and operating strategies in the best interests of the state, environment, and customers on a case-by-case basis; however, the use of alternative water supplies, such as effluent and alternative cooling technologies to reduce potable water usage comes with an additional cost in terms of capital investment and O&M costs, and may have an impact on unit efficiency. The factors influencing these decisions are diverse, including location, generator type, and renewable and alternative water availability. APS is developing a water supply portfolio that will provide a reliable mix of traditional, renewable, and reclaimed sources, minimizing where possible usage of groundwater and other potable water sources in favor of more sustainable resources. This approach is aimed at providing secure water supplies for power generation while fostering responsible water use. APS has a commitment to maximize use of renewable effluent and surface water and minimize use of non-renewable groundwater.

IMPROVING CONSUMPTION AND EFFICIENCY OF WATER USE DURING PLANNING PERIOD

Even though energy generation is forecast to significantly increase during the Planning Period to meet new customer demand, water consumption will decrease due to retiring older plants (replacing them with more water efficient plants), increasing energy efficiency, and increasing renewable energy resources envisioned in the 2023 Resource Plan. This can be seen in Figure D-1, which shows the rate of water usage decreases 18% between 2023 and 2038.

FIGURE D-1. ANNUAL WATER RATE (INTENSITY)



NEW POWER PLANT CONSTRUCTION, WATER SAVING ALTERNATIVES

When new power plant generating unit options are being evaluated, the water consumption rates for each technology option are considered. The most significant water-saving device that can be installed on new power plants with steam turbines is air-cooled condensers in lieu of conventional wet-cooling towers. Technology for new dry-cooled combined cycle plants is estimated to use 20 gallons/MWh as compared to wet-cooled combined cycle plants such as Redhawk, which use approximately 307 gallons/MWh.

RETIREMENT OF EXISTING POWER PLANT GENERATING UNITS, ASSOCIATED WATER SAVINGS

- Retirement of Four Corners Units 1-3
  - In addition to evaluating alternative cooling technologies, further reductions in regional water consumption were achieved through the retirement of Four Corners Units 1-3, effective December 30, 2013. Retirement of these three units saves approximately 4,000-6,000 acre-feet of water annually. APS has announced retirement of the Four Corners plant in 2031.

- Retirement of Cholla Unit 2
  - Cholla Unit 2 was retired effective October 1, 2015, resulting in a decrease of approximately 3,000-4,000 acre-feet annually. Cholla remains the largest user of non-renewable groundwater in the APS fleet; however, APS has committed to cease coal generation at that site in 2025.

REDUCE QUANTITY OF NON-RENEWABLE GROUNDWATER CONSUMED

In 2016, APS developed and implemented a new Tier 1 metric, later transitioned to a Tier 2 metric, designed to reduce consumption of non-renewable groundwater by 8%, compared to the reference year of 2014. Further reductions were planned in 2017 (10%), 2018 (12%), in 2019 (14%), in 2020 (16%), and then adjusted based on projected shifts in generation for 2021 and 2022 (31% and 22%, respectively). Actual 2019 results were 22.4% below 2014 consumption. This metric is achieved by retiring older water-intensive units and replacing them with more efficient units, by implementing water conservation measures at APS plants, and increasing reliance on RE and DE.

IMPROVING THE EFFICIENCY OF WATER USE AT EXISTING FACILITIES

APS manages water resources using a multi-layered approach to reduce water intensity. One approach has been to pursue projects targeted to improve the efficiency of water utilization at APS's existing plants. A primary example is Palo Verde Nuclear Generating Station, which not only uses reclaimed wastewater effluent as its cooling water source, but has focused on continual improvement in water treatment and operations to achieve over 27 cycles of concentration (on average) through the cooling water system. Redhawk also operates its cooling system using reclaimed water. In 2022, 71% of all water used by APS was reclaimed water, conserving fresh water for other purposes.

When considering water use and water efficiencies at power plants, APS considers not only the cost of projects, but also the potential impacts on society and the local environment. Understanding local and regional water use and trends is important to this decision-making. With that in mind, in 2009, APS formed its Water Resource Management Department, consolidating many existing water-oriented functions and experience into a centralized, enterprise-wide function. The vision of this department is "to secure a sustainable and cost-effective supply of water to enable reliable energy production for APS customers." A primary initiative of the Water Resource Management Department is to create a l comprehensive database and computing infrastructure to allow modeling of groundwater supplies, surface water availability, and the characteristics of other water sources in conjunction with a variety of long-term energy production forecasts. By utilizing this quantitative approach in conjunction with geographic information systems, analysts and stakeholders can interactively assess the impacts of various decisions and scenarios.

APS has performed modeling of groundwater withdrawals and evaluated potential impacts of the withdrawals and has developed wellfield management plans at the largest water-consuming plants to enable more efficient use of the resource.

APS has also become more integrated into the Arizona water community enabling improved communication with other water stakeholders, including regulators, municipalities, agricultural users and other industries. APS is a member of the ADWR Management Plan Workgroups and the Post-2025 Active Management Area Committee. APS is a supporter of the Kyl Center for Water Policy, a research analysis and collaboration entity at the Morrison Institute for Public Policy at Arizona State University, promoting sound water policy and stewardship in Arizona. APS is a member of the Governor's Water Augmentation, Innovation, and Conservation Council, engaging in statewide, regional and international water planning. APS also provides a board member at the Water Resource Research Center at the University of Arizona, focused on improving water use and conservation in Arizona. This integration into the broader water community has opened communication and facilitated partnering opportunities for the future.

ENERGY EFFICIENCY, RENEWABLE ENERGY RESOURCES, AND AVOIDED WATER USAGE

Demand-side management programs and renewable energy resources generally consume little or no water. The expansion of these programs in the 2023 Resource Plan contributes to a reduction in water consumption over the Planning Period.

RESPONSE TO RULES SECTION E – RISK

Resource Planning Rule A.A.C. R14-2-703 sets forth the reporting requirements for a load-serving entity. The following items provide responses to section R14-2-703(E), which specifically requires information related to risk analysis and mitigation.

RULE E.1(A)

Analyses to identify and assess errors, risks, and uncertainties in the following, completed using methods such as sensitivity analysis and probabilistic analysis: (a) demand forecasts.

The risks involved with developing a demand forecast involve uncertainties related to: (1) Customer growth and changes in the size and pace of load ramps among Extra High Load Factor (XHLF) customers; and (2) weather. Table E-1 illustrates the results of a probabilistic approach.

TABLE E-1. PROBABILISTIC ANALYSIS OF PEAK DEMAND FORECAST

APS System Peak Demand Forecast (Probabilistic Analysis)								
PERCENTILE	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
10th	7,698	7,841	7,943	8,075	8,263	8,451	8,561	8,741
20th	7,743	7,947	8,112	8,329	8,595	8,838	8,994	9,205
30th	7,756	7,984	8,176	8,429	8,731	9,002	9,182	9,412
40th	7,844	8,085	8,292	8,566	8,888	9,175	9,369	9,610
Forecast	7,978	8,247	8,483	8,796	9,157	9,475	9,695	9,958
60th	8,046	8,316	8,555	8,873	9,240	9,565	9,793	10,064
70th	8,046	8,317	8,556	8,875	9,245	9,573	9,804	10,078
80th	8,073	8,344	8,586	8,909	9,284	9,618	9,856	10,137
90th	8,181	8,456	8,703	9,035	9,426	9,777	10,031	10,332

APS System Peak Demand Forecast (Probabilistic Analysis)								
PERCENTILE	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
10th	8,905	9,049	9,178	9,301	9,336	9,507	9,636	9,786
20th	9,388	9,543	9,679	9,806	9,844	10,015	10,144	10,295
30th	9,609	9,777	9,931	10,072	10,121	10,309	10,457	10,624
40th	9,815	9,992	10,156	10,306	10,363	10,560	10,720	10,897
Forecast	10,179	10,374	10,563	10,737	10,815	11,037	11,223	11,423
60th	10,292	10,501	10,716	10,918	11,024	11,275	11,490	11,715
70th	10,309	10,525	10,752	10,967	11,085	11,350	11,579	11,816
80th	10,375	10,604	10,856	11,098	11,242	11,536	11,793	12,055
90th	10,587	10,850	11,165	11,476	11,686	12,052	12,381	12,705

RULE E.2(A)

A description and analysis of available means for managing the errors, risks, and uncertainties identified and analyzed in subsection (E)(1), such as obtaining additional information, limiting risk exposure, using incentives, creating additional options, incorporating flexibility, and participating in regional generation and transmission projects: (a) demand forecasts.

A probabilistic analysis can be used to understand risk by providing a range of demand scenarios consistent with historical variations that APS has seen in customer growth, electricity consumption, and weather. Levels of demand can be illustrated by using percentiles ranging from 10% to 90%. The 10th percentile represents the likelihood of a lower demand outcome which would minimize the costs associated with procuring additional resources but contains a risk of not building a sufficient amount of resources if the actual demand exceeded the forecast. At the other end of the spectrum is the 90th percentile, a scenario with a higher demand outcome than is currently planned for and greater costs for procuring additional resources, which carries the risk of building too many resources than what might be needed if the actual demand was less than the forecast.

In the near term, weather presents the greatest risk to the forecast. Peak demand typically occurs during July or August when temperatures exceed 110°F. In the last ten years, the temperature on peak day has been as high as 119°F and as low as 113°F. Temperatures 2°F above the 10-year average of 116°F can add nearly 280 MW to peak.

Customer growth and changes in the size and pace of load ramps among Extra High Load Factor (XHLF) customers such as new data centers, large industrial customers, and hydrogen production facilities are the most important long-term risks to the demand forecast. The number and types of new XHLF customers and their associated peak demands over the next 15 years could be quite different from the assumptions in the current forecast and will likely reflect changing economic conditions such as incentives for large customers to locate in APS service territory, the pace of construction, and IT and manufacturing equipment installations, for a few examples. Among XHLF customers currently in the forecast, peak demands at full build-out may range from less than 100 MW to potentially greater than 1,000 MW. The current forecast assumes a compound annual growth rate in annual peak demand of 2.4%.

Methods for managing these risks and uncertainties include utilizing resource options that have relatively shorter development lead times. Shorter development lead times allow utilities to respond quickly to changes in demand scenarios. Also, timely updates to the forecast with new information help ensure forecasts remain current. Lastly, having access to liquid wholesale power market trading hubs allows utilities to either buy or sell energy as needed to balance energy demands with resources.

RULE E.3(A)

A plan to manage the errors, risks, and uncertainties identified and analyzed in subsection (E)(1): (a) demand forecasts.

APS manages demand forecast risk in several ways. The Company has the ability to add short-lead-time resources, including battery storage and natural gas combustion turbines. The development time for these resource types can be anywhere from one to five years. Utilizing short-lead-time resources allows APS to respond quickly as demand scenarios change. APS currently carries a 15% reserve margin of additional capacity, over the amount of forecasted demand, to be available should customer load exceed expectations or generating units do not perform as designed. In 2026 this is increasing to 20.2% on an ICAP basis. Furthermore, APS benefits from transmission access to the Palo Verde wholesale trading hub. Because there are many wholesale market participants with access to Palo Verde, APS is able to buy and sell capacity and electricity as needed to balance demand with resources.

RULE E.1(B)

Risk Identification: (b) the costs of demand management measures and power supply.

DEMAND MANAGEMENT MEASURES

Within the DSM market, the cost trajectory will vary depending on the program or measure, timing, and market saturation.

It is expected that as a whole, the cost per unit of energy saved through EE programs and measures will increase over time; the rate at which it increases will vary depending on technical developments, progression of building codes and appliance standards, persistence of behavioral changes after incentives disappear, and overall market penetration. That said, as future DSM programs are designed and proposed, cost-effectiveness must still be proven, which will likely change the landscape of future DSM measures as the current "low-hanging fruit" technologies are replaced by the next-generation, more efficient products and DSM programs.

In preparation for this Integrated Resource Plan, APS conducted an Energy Efficiency and Demand Response Market Opportunity Study to identify the technical, economic, and achievable energy efficiency and demand response savings potential, and the estimated range of costs to acquire these savings. The results of this study helped inform DSM modeling for this IRP and are also being used in ongoing DSM program planning efforts.

As with EE measures, the cost volatility of load management and demand response solutions continues to be an identified risk. Costs will be largely influenced by the development of new communication standards, increased technical efficiencies, and environmental considerations.

Demand response programs typically include the need for real time communication of data during load management events. As these demand response programs scale, there are potential ongoing risks of communications failures and cybersecurity threats. To mitigate these risks, APS deploys a Resource Operating Platform that serves as a distributed energy resource aggregator to help manage and report on demand response activity by device. In addition to this platform, future investments will be needed to integrate the utility distribution management system with the resource operating platform, and to integrate each future type of distributed energy resource technology into the platform. In the near-term of the Planning Period, this may lead to an increase in IT costs, although the identified system efficiencies and customer services gained are expected to be positive investments from a financial, customer and technical perspective. These investments can provide an IT backbone to help improve reliability, decrease outage and response time, and provide tailored energy management solutions for customers.

Other customer load response resources, such as microgrids and energy storage, have demonstrated a downward trend in equipment and integration costs, although battery storage is still not currently a cost-effective DSM measure due to high upfront costs. The costs for new customer-sited generators such as microgrids have trended downward despite increased emission regulations and fuel costs. Ongoing industry cost reductions in DER and secure communication platforms that provide the real-time command and management of local loads and resources has made the application of utility-led microgrids increasingly possible and cost-effective for customers. Examples of suitable settings for microgrid projects include hospitals, military installations, data centers, universities, critical infrastructure, remote feeder locations and other customers with sensitive loads that cannot sustain loss of power. These customers traditionally procure their own back-up power systems to ensure continuous operation in the unlikely event of a power outage. In some cases, APS partners with these customers, sharing in the cost in exchange for use of these resources to respond to grid reliability and flexibility needs. By providing customers with needed backup power and APS with increased flexible capacity on its system, microgrids provide benefits to all customers and may defer future capacity needs on the APS system, depending on cost and operational performance going forward.

POWER SUPPLY

Analyses to identify construction cost- and fuel cost-related risks and uncertainties are addressed in subsequent sections.

Other risks associated with costs of power supply involve surplus or shortfalls in meeting reserve requirements. APS incorporates three types of reserves at three different time intervals: planning reserves – these are the reserve requirements calculated at annual timescales and encapsulated in Attachment F.9(b) line 3; contingency reserves – these are made up of spinning and non-spinning reserves and are managed on an hourly basis, and; frequency response reserves – these are managed at a sub-minute level and help to maintain frequency on the regional transmission system after contingencies. Surplus and shortfalls in any of these categories can bring about financial risk in terms of surplus variable or capacity costs, if reserves are in surplus, or risk of overpaying during states of emergency or from paying fines for failing to meet requirements, if reserves are too low. Surpluses and shortfalls are also affected by regional availability of capacity resources.

Planning Reserves: APS has increased its planning reserve margin to 20.2% in 2026 as a result of extensive reliability study work performed by Astrape Consulting. These additional resources cover the needed frequency and contingency reserves needed for APS's balancing area.

RULE E.2(B)

Risk Analysis: (b) the costs of demand management measures and power supply.

DEMAND MANAGEMENT MEASURES

Annually, on-going analyses will be performed as part of each DSM Implementation Plan filing to ensure that proposed and existing DSM programs are cost-effective and advantageous for APS and its customers. The results of the most current analyses are provided in Rule D.14.

POWER SUPPLY

Specific methods to manage construction cost and fuel cost-related risks and uncertainties of the costs of power supply are addressed in subsequent sections.

Real-time operations power supply cost risks have traditionally been managed through NERC reliability requirements. Many compliance costs associated with these NERC requirements have been managed through APS's participation in regional reserve sharing groups, such as the Southwest Reserve Sharing Group. Continued increases in the amount of intermittent generation, such as wind and solar, on the electric grid are expected to increase frequency and contingency reserve-related costs. APS employed E3 to analyze solar and wind integration costs in order to quantify cost impacts related to carrying additional operations reserves. These analyses are discussed in more detail in response to Rule D.11.

Power supply cost impacts related to forecast error is often situation dependent and are expected to increase with increasing additions of solar and wind generation. APS analyzes weather, load and renewable forecasts on a daily basis and analyzes patterns so that forecasts can be improved. Over the past several years, APS has vastly improved their renewable forecasting capabilities. These improvements can be attributed to:

- Localized (at the generation site) weather forecasts in partnership with the University of Arizona, leaders in Desert Southwest regional weather and climate forecasting;
- Cloud cover and irradiance forecasting improvements due to the addition of several algorithms to better anticipate cloud cover movement;
- Fine tuning of APS internal systems to significantly reduce latency; and
- Latency improvements to CAISO market systems that APS interacts with.

Planning reserve cost impacts depend upon the magnitude and direction of the difference in annual forecasted distributed energy additions and actual.

RULE E.3(B)

Risk Mitigation Plan: (b) the costs of demand management measures and power supply.

DEMAND MANAGEMENT MEASURES

Embedded within Arizona's EE/DSM Rules is a cost-effectiveness requirement which acts as a mechanism to ensure that all DSM programs that are implemented provide a net benefit to APS and its customers. APS uses cost tests to rank DSM programs in order of effectiveness in reducing peak, however these tests alone are not enough. In addition, APS has worked to develop hourly load shapes for each DSM program and measure that show the energy impacts of the program broken down by each hour of the year. These program impact load shapes are used to optimize the DSM portfolio to best align with APS resource needs and to better inform the load forecast of future DSM savings.

Annually, APS seeks to manage EE program costs by exploring innovative incentive models, creating additional technology options, deploying new marketing and outreach strategies, and conducting Measurement and Evaluation Research (MER) on the programs to identify opportunities for improvements.

Due to the varied nature of load management and demand response solutions, cost volatility can be more closely managed by strategically timing deployment of resources and diversifying procurement methods. The APS Peak Solutions program is managed through a contract with a demand response program implementer that has fixed energy and capacity payments through the term of the agreement, with the current term set to expire after the 2025 summer season. APS intends to issue an RFP for demand response capacity beyond 2025, which could result in changes to pricing and other terms as well as potential for additional capacity to be added to the program. This process provides APS with an opportunity to explore current market pricing and further manage future costs.

Additionally, time-differentiated rate schedules and tariffs are eligible to be re-filed as necessary to assist in managing customer and Company impact. APS will have the opportunity to revisit these rates in the annual DSM Implementation Plan filings or through rate cases.

POWER SUPPLY

APS optimizes the use of its resources to serve its customers in the most affordable manner possible, while maintaining grid reliability. The process begins by forecasting the load on a day-ahead basis. The load forecast is entered into a unit commitment and dispatch model (PCI GenTrader®/GenPortal®) that determines the most economic unit commitment plan for serving load, taking into account generating unit capabilities, intermittent resource production forecasts (e.g., wind and solar), fuel prices, contractual requirements, and transmission constraints. This commitment plan shows the units to be committed each hour, their projected loading level and the quantity of natural gas to be scheduled.

As part of the process, the model calculates prices for blocks of energy to help determine if it would be cheaper to buy power from the market rather than to run generating units. The day-ahead trader compares these calculated block energy prices with actual power prices being offered in the market, then purchases either on-peak or off-peak blocks of energy, if economical. The model also calculates the breakeven price for making sales out of the Company's generating resources, after taking into account native load and any other pre-existing power sales commitments. If economical, the day-ahead trader will make power sales in the market.

The day-ahead commitment plan is turned over to the real-time operations team to take forward into the intraday markets. The real-time traders update the load and available resource forecasts and re-run the unit commitment and dispatch model to fine-tune the commitment plan. They also check the intraday market to make purchases and sales of power to further optimize the system.

Within the sub-hourly window, the real-time traders proceed to further refine the Company's generation plan by interacting with the CAISO Western Energy Imbalance Market (WEIM) to transfer energy when economically beneficial to customers. Through calculated cost curves of each unit, the real-time traders determine which generators may be incremented, decremented, committed (start) and de-committed (shutdown) as part of a greater WEIM footprint solution. While considering available transmission resources, fuel supplies, and reliability needs, APS participates in both the 5-minute and 15-minute markets while maintaining the NERC required reserves and system stability requirements. Each of these markets use dynamic meter and load data as well as 5-minute renewable forecasting to dispatch all participating units with the goal of reducing the production cost for APS customers and the greater EIM footprint.

As the final step in this process, the real-time traders issue the commitment instructions to generating units as needed to meet load and sales commitments. Additionally, they respond to dynamic changes by updating the plan as needed for generating unit or transmission outages and forecast updates; continuously optimizing usage of available resources.

For the duration of the Planning Period, the generating unit commitment procedures are not expected to change from one year to the next.

RULE E.1(C)

Risk Identification: (c) the availability of sources of power.

Risks involved in the availability of sources of power include the availability of the supply resource itself, availability of new generation equipment, timing of construction schedules, availability of credit-worthy counterparties, the commercial viability of certain technologies, and the availability of adequate transmission capacity to move the power to the load center where it is needed.

RULE E.2(C)

Risk Analysis: (c) the availability of sources of power.

One of the key risks that APS addresses on a daily basis is the potential of reduced generating availability and outages in the fleet of existing supply resources. This risk of an equipment or plant malfunction and unplanned shutdown is present on a continuous basis but is generally minimized through high standards in plant maintenance and operations. In addition, APS plant designs incorporate a reasonable level of redundancy at the equipment level so that single failures do not generally result in plant outages.

Providing for an allowance in the timing of construction schedules for planned generation is one way the construction schedule risk can be mitigated. When planning for summer peak resource requirements, an allowance can be made for the level of capacity a particular resource is allowed to contribute toward meeting that summer peak demand. For projects that are anticipated to reach commercial operation during the summer period of June-September, a risk-reducing strategy may be to not rely upon those projects' capacity for meeting that particular summer peak. In this way, construction schedule risk is mitigated.

Having additional resources available is another means of managing risk in the availability of sources of power. Utilities carry capacity reserve margins (surplus reserve capacity) in the event of resources being unavailable or customer demand being higher than anticipated. Capacity reserve margins are an effective means to help ensure sufficient power sources are available when needed.

Following robust procurement practices is another way to mitigate risk of availability of sources of power. Soliciting bids from a large number of third-party developers allows the Company to select projects that are more likely to be completed on time. Developers often may already own property, have permits in place, and have good queue positions for equipment.

When procuring energy from third-party vendors, an analysis of vendor credit quality is crucial to the success of a transaction. Poor credit quality or the inability of a vendor to obtain cost-effective and timely financing for their project will, in most circumstances, exclude that vendor from being considered. A thorough analysis of vendor credit quality helps to mitigate these impacts.

Consideration of a wide range of technologies increases resource diversity and reduces technology performance risk. Being overly dependent on a single technology or depending on technologies that have yet to be proven in commercial applications may increase performance risk.

One of the single best, and simplest, means of managing risk in sources of power is resource diversity (i.e., not being overly reliant on one fuel source). Utilities with diverse sources of power supply are situated better when unforeseen problems emerge because they have other alternative sources of power to rely upon.

To optimize the economic alternatives of running generating units versus procuring energy from the market, having transmission access to liquid trading hubs is another means of helping to ensure availability of sources of power.

RULE E.3(C)

Risk Mitigation Plan: (c) the availability of sources of power.

Existing plant availability is maintained at very high levels through the application of effective preventative and predictive equipment maintenance. APS maintains an operational staff which is capable and highly trained. Programs are in place which promote the capture of data and evaluation of equipment failures and operational incidents to help prevent recurrence and reduce the risk of unexpected outages.

APS mitigates risk due to the timing of construction schedules by not including those projects' capacity as contributing toward meeting summer peak demand when their initial commercial operation date is anticipated to be during the summer (June – September). By mitigating construction schedule risk in this manner, system reliability is not compromised if projects are delayed.

As described in response to Rules E.1(a) – E.3(a), APS continues to carry a planning capacity reserve requirement that helps ensure sufficient power sources are available. APS's capacity reserve requirement for 2023 is 1,201 MW, as shown on line 3 of Attachment F.9(b).

The Company also mitigates risk by engaging in best practice procurement procedures. Whether APS signs a purchase power agreement, purchases an existing asset, or constructs new generation, the best projects are identified through well participated, open solicitations.

APS employs credit risk management practices that ensure the creditworthiness of all counterparties in energy procurement transactions has been thoroughly analyzed prior to making a transaction. In addition to determining the credit quality of potential counterparties, APS also may require a letter of credit, guarantee, or some other form of acceptable collateral prior to completing a transaction. In this manner, if a counterparty were to default on their contractual obligations, APS could retain the collateral of the defaulting counterparty to help offset any damages APS may have incurred as a result of the counterparty default.

APS employs a wide range of resources and is not overly dependent on any one specific resource, as illustrated by the diversity of the supply-side resources included in the 2023 Resource Plan. APS limits risk exposure by considering only sources of power reasonably believed to be commercially available within the planning time frame.

APS has taken steps to promote a contingency planning process that is designed to identify uncertainties in the existing portfolios and develop options for new resources and transmission capacity, which can be implemented in the identified timeframes. These options are intended to be executable compensatory measures in the event of failure of specific elements of the current resource plans.

In terms of renewable energy, the 2023 IRP Resource Plan includes solar photovoltaic, solar thermal, solar plus energy storage, wind, biomass, and geothermal. By considering commercially available resources such as those mentioned, APS mitigates technology performance risk.

With the revised battery project timelines, APS may use existing generation in the region as a bridging strategy to meet the projected load plus reserve margin. These short-term purchases ensure that we can meet summer reliability requirements and will be structured not to impact longer-term resource planning strategies. Currently, we expect short-term needs will be met with wholesale market purchases from a combination of existing merchant natural gas units, neighboring utilities, wholesale market participants and demand response. When APS chooses to construct new capacity, it is anticipated that there will be many manufacturers and many technology options to choose from, along with sufficient availability of new equipment.

Through its ownership interest in PVNGS, APS benefits from transmission access to the wholesale power market at the Palo Verde hub. Many market participants, as well as merchant generators, buy and sell wholesale power at the Palo Verde hub making access to that facility one of the means APS uses to manage the risk of power source availability.

RULE E.1(D) & RULE E.1(E)

Risk Identification: (d) the costs of compliance with existing and expected environmental regulations.

Risk Identification: (e) any analysis by the load-serving entity to identify and assess errors, risks, and uncertainties in anticipation of potential new or enhanced environmental regulations.

EPA is currently in various stages of promulgating environmental regulations, which are expected to impact APS. Most of these potential regulations are only partially defined at this time, and some may not be finalized for years. Over the 15-year Planning Period, these regulations could be modified, further resulting in changes to the technology needed for compliance, which would impact the forecast for compliance costs. In addition to proposed regulations of which APS is currently aware, there are potential new regulations. Compliance costs could increase to an extent that is unknown at this time. Factors that will impact future costs of compliance include:

- Capital and O&M costs pertaining to existing regulations are subject to cost increases triggered by inflation or limited supply;
- Existing regulations may change during the Planning Period;
- The requirements to comply with many of the proposed regulations have not been finalized, so it is difficult to estimate precise costs of unknown regulations; and
- New technology may be required to achieve compliance with proposed regulations, and the cost of the new technology may be unknown.

APS monitors the regulatory landscape as potential environmental regulations evolve and become better defined. Throughout this process, APS develops refined cost analyses using scenarios containing a range of potential technology requirements to forecast the cost of possible outcomes.

REGIONAL HAZE REGULATIONS (BART)

In 1999, EPA published a new rule regarding regional haze, which includes decreasing NO_x, SO_2, and PM emissions at various major stationary sources of air pollution, including the Four Corners and Cholla Power Plants. Low NO_x Burners and Over-Fired Air were installed at these plants during the 2007 to 2009 timeframe. Thereafter, EPA proposed Best Available Retrofit Technology ("BART") pollution control requirements for the Four Corners and Cholla Power Plants that would have required Selective Catalytic Reduction ("SCR") controls to achieve compliance with the contemplated NOx limits.

As an alternative to the SCRs at Cholla, APS offered to shut down Unit 2 by October 2015 and either shut-down or convert the other units to natural gas by April 1, 2025 if EPA agrees to Low NO_x Burners and Over-Fired Air. EPA has accepted this alternative and finalized the revised state implementation plan (SIP) containing requirements to this effect in 2017. Given the finalizations of the SIP, and APS's plan to cease coal burning at Cholla by April of 2025, there is no risk that BART-driven SCRs would be required at Cholla.

On December 30, 2013, APS, on behalf of itself and the other co-owners, notified EPA that they had selected an alternative BART compliance strategy for the Four Corners facility, which required the closure of Units 1-3 by January 1, 2014 and installation of SCR controls on Units 4 and 5 by July 31, 2018. The risk for additional costs from BART at Four Corners lies mainly in the cost estimate for reagent usage. Increased reagent usage could increase O&M by $5.4M per year to $6.5M per year. Also, there is a potential of high volatility in the urea market. APS works with a long-term supply contractor for urea, and that contract(s) is periodically reviewed and renewed, but the volatility in the urea market impacts cost, no matter the supplier.

During the next (i.e., second) planning period, which will run from 2019 through 2028, the state of Arizona must consider man-made sources of visibility-impairing pollutants for potential reasonable progress controls. In determining what constitutes reasonable progress, the regional haze rule requires that the analysis consider the cost of compliance, and the remaining useful life of any existing source subject to the analysis. This analysis is commonly referred to as the four-factor analysis. In August 2022, the Arizona Department of Environmental Quality submitted a revision to state's regional haze implementation plan to address the requirements of the regional haze second planning period. Cholla was not included in the list of sources required to undergo four-factor analysis, based on screening results. To date, EPA has not acted on the revised SIP. Separately, EPA may establish the regional haze process for Four Corners. The EPA has indicated it will ramp up its regional haze process, but so far has not held any stakeholder meetings. APS does not anticipate any additional regulatory actions or costs impacting Cholla or Four Corners related to the second implementation period of EPA Regional Haze program.

MERCURY AND AIR TOXICS STANDARDS (MATS) REGULATIONS

In 2011, EPA issued rules establishing maximum achievable control technology standards to regulate emissions of mercury and other hazardous air pollutants from fossil-fired plants. Both Cholla and Four Corners achieved compliance with the standard by the 2016 deadline.

In 2023, as a result of required Risk and Technology Review (RTR), EPA released a proposal that includes a significantly more stringent emission rate. In addition, the RTR proposal would eliminate the option for utilities to demonstrate compliance using quarterly stack testing and instead require continuous emissions monitoring systems, which would add substantial complexity to maintaining and demonstrating MATS compliance. We cannot at this time predict the outcome of this regulatory proceedings or when the EPA will take final action on this proposal. If finalized as proposed, the rule would take effect for existing coal plants within three years of the promulgation date. Cholla is required to cease burning coal no later than April 2025 and therefore would not be impacted by this rulemaking. Depending on the eventual outcome, a requirement to meet a lower emission rate could result in additional costs associated with APS's controls for filterable particulate matter at Four Corners.

NEW SOURCE REVIEW (NSR) REGULATIONS

NSR rules require industrial facilities to install modern pollution control equipment when they are built or when making a change that increases emissions significantly. Projects considered to be "routine maintenance, repair, and replacement" are categorically excluded. There is still the possibility of new alleged NSR violations at any APS facility that combusts fossil fuels, and the Company cannot at this time predict the outcome of any proceedings necessary to resolve such allegations.

OZONE NATIONAL AMBIENT AIR QUALITY STANDARD (NAAQS) REGULATIONS

The NAAQS for Ozone are the most significant driver of regulatory risk as it concerns NOx emissions control from gas-fired APS facilities located within Maricopa County, these include the 2008 Ozone NAAQS set at 75ppb and the 2015 Ozone NAAQS set at 70ppb. As a result of Moderate Area nonattainment status for the 2008 ozone NAAQS, units CC1 and CC2 at West Phoenix Power Plant were required to install NOx controls. The installation of selective catalytic reduction systems on both units was completed in 2022.

As for the 2015 Ozone NAAQS, on April 30, 2018, EPA designated the geographic areas containing Yuma and Phoenix, Arizona as in non-attainment with the 2015 70ppb Ozone NAAQS. With ozone standards becoming more stringent, APS's fossil generation units will come under increasing pressure to reduce emissions of NOx and volatile organic compounds, and to generate emission offsets for new and modified sources of air pollution, including new and modified generating sources, within in the ozone nonattainment areas. APS anticipates that revisions to the SIPs and FIPs implementing required controls to achieve the new 70 ppb standard will be in place between 2024 and 2025. At this time, because proposed SIPs and FIPs implementing the revised ozone NAAQSs have yet to be released, APS is unable to predict what impact the adoption of these standards may have on the Company. APS will continue to monitor these standards as they are implemented within the jurisdictions affecting APS.

PARTICULATE MATTER (PM) NAAQS REGULATION

On January 27, 2023, the EPA published a proposed decision to revise the primary (health-based) annual $PM_{2.5}$ standard from its current level previously set in 2013 of 12.0 $\mu g/m^3$ to within the range of 9.0 to 10.0 $\mu g/m^3$. The impacts of a lower standard could be significant in Arizona where many counties would likely be designated as nonattainment areas or be reclassified as serious nonattainment areas. With standards becoming more stringent, APS's fossil generation units located within nonattainment areas would come under increasing pressure to reduce emissions of $PM_{2.5}$, and to generate emission offsets for new and modified sources of air pollution, including new and modified generating sources within these area(s). Within the same decision, EPA also proposed not to change the current secondary annual $PM_{2.5}$ standard, primary and secondary 24-hour $PM_{2.5}$ standards, and the primary and secondary PM_{10} standards. At this time, APS is unable to predict what impact the adoption of lower standards may have on the Company. APS will continue to monitor these standards as they are implemented within the jurisdictions affecting APS.

CLIMATE CHANGE REGULATION

On June 19, 2019, EPA took final action on its proposals to repeal EPA's 2015 Clean Power Plan ("CPP") and replace those regulations with a new rule, the Affordable Clean Energy ("ACE") regulations. EPA originally finalized the CPP on August 3, 2015, and such rules would have had far broader impact on the electric power sector than the ACE regulations. On January 19, 2021, the U.S. Court of Appeals for the D.C. Circuit vacated the ACE regulations and remanded them back to EPA to develop new existing power plant carbon regulations consistent with the court's ruling. That decision, which endorsed an expansive view of the federal Clean Air Act consistent with EPA's 2015 CPP, was subsequently reversed by the U.S. Supreme Court on June 30, 2022 (*West Virginia v. EPA*).

On May 23, 2023, EPA published a proposed a regulation to limit carbon dioxide emissions from new and existing fossil-fuel fired power plants. Unlike EPA's CPP, which took a broad, system-wide approach to regulating carbon emissions from electric utility power plants, the most recent proposal is limited to measures that can be installed at individual power plants to limit planet-warming emissions. As such, this proposal is focused on emission limitations achievable through "Best Systems of Emission Reduction" that apply mechanisms, such as carbon capture and sequestration or utilization ("CCS"), "clean" hydrogen gas ("H2") co-firing, natural gas co-firing, and efficiency improvements, to various sub-categories of thermal power plants.

More specifically, for new natural gas-fired combustion turbine power plants, EPA is proposing that carbon emission performance standards apply based on annual capacity factors. For the highest utilization combustion turbines, EPA is proposing to require such facilities be retrofitted for CCS (with a 90% capture rate) or varying levels of H2 co-firing (between 32% and 96%). As for existing natural gas-fired combustion turbines, EPA is imposing similar control requirements for large, high utilization generating units, but is otherwise not proceeding at this time with further regulation. Therefore, under EPA's proposal, this means that, both, new and existing peaking gas-fired combustion turbines (i.e., those with a 20% or less annual capacity factor) are effectively unregulated.

For coal-fired power plants, instead of imposing regulations based on capacity and utilization, EPA has developed subcategories based on planned retirement dates. This means that facilities retiring between 2030 and before 2040 must meet increasingly stringent emission limits up to natural-gas co-firing starting in 2030. However, for those facilities with no planned retirement date prior to 2040, EPA is requiring those plants to be retrofitted with CCS controls by 2030 (with a 90% capture rate).

EPA expects to take final action on this proposal by spring or summer of 2024. At this time, APS cannot predict the outcome of this rulemaking or when EPA will take final action. In addition, APS is continuing to evaluate this proposal and its potential impact on Company operations. Depending on the eventual outcome, the costs associated with APS's operation of its current and future thermal power plants could materially increase.

In addition to federal legislative initiatives, state-specific initiatives may also impact our business. While Arizona has no pending legislation regulating GHGs, the California legislature enacted AB 32 and SB 1368 in 2006 to address GHG emissions. In October 2011, the California Air Resources Board approved final regulations that established a state-wide cap on GHG emissions beginning on January 1, 2013, and established a GHG allowance trading program under that cap. The first phase of the program, which applies to, among other entities, importers of electricity, commenced on January 1, 2013. Under the program, entities selling electricity into California, including APS, must hold carbon allowances to cover GHG emissions associated with electricity sales into California from outside the state.

RESOURCE CONSERVATION RECOVERY ACT (RCRA) SUBTITLE D

On December 19, 2014, EPA issued its final regulations governing the handling and disposal of CCR, such as fly ash and bottom ash. The rule regulates CCR as a non-hazardous waste under Subtitle D of the Resource Conservation and Recovery Act ("RCRA") and establishes national minimum criteria for existing and new CCR landfills and surface impoundments and all lateral expansions. These criteria include standards governing location restrictions, design and operating criteria, groundwater monitoring and corrective action, closure requirements and post closure care, and recordkeeping, notification, and internet posting requirements. The rule generally requires any existing unlined CCR surface impoundment that is contaminating groundwater above a regulated constituent's groundwater protection standard to stop receiving CCR and either retrofit or close, and further requires the closure of any CCR landfill or surface impoundment that cannot meet the applicable performance criteria for location restrictions or structural integrity. Such closure requirements are deemed "forced closure" or "closure for cause" of unlined surface impoundments and are the subject of recent regulatory and judicial activities described below.

Since these regulations were finalized, EPA has taken steps to substantially modify the federal rules governing CCR disposal. While certain changes have been prompted by utility industry petitions, others have resulted from judicial review, court-approved settlements with environmental groups, and statutory changes to RCRA. The following lists the pending regulatory changes that, if finalized, could have a material impact as to how APS manages CCR at its coal-fired power plants:

- On March 1, 2018, as a result of a settlement with certain environmental groups, EPA proposed adding boron to the list of constituents that trigger corrective action requirements to remediate groundwater impacted by CCR disposal activities. Apart from a subsequent proposal issued on August 14, 2019 to add a specific, health-based groundwater protection standard for boron, EPA has yet to take action on this proposal.

- Based on an August 21, 2018 D.C. Circuit decision, which vacated and remanded those provisions of the EPA CCR regulations that allow for the operation of unlined CCR surface impoundments as well as an additional proposal published on November 4, 2019, where EPA proposed change the manner by which facilities that have committed to cease burning coal in the near-term may qualify for alternative closure, APS submitted an application for alternative closure on November 20, 2020. While EPA has deemed APS's application administratively "complete," the Agency's approval remains pending. If granted, this application would allow the continued disposal of CCR within Cholla's existing unlined CCR surface impoundments until the required date for ceasing coal-fired boiler operations in April 2025. This application will be subject to public comment and, potentially, judicial review. We expect to have a proposed decision from EPA regarding Cholla sometime in 2023 or 2024.

- On May 18, 2023, EPA published a proposal that expands the scope of federal CCR regulations to address the impacts from historical CCR disposal activities that would have ceased prior to 2015. EPA proposes to define a new class of CCR management units ("CCRMUs") that broadly encompass any location at an operating coal-fired power plant where CCR would have been placed on land. As proposed, this would include not only historically closed landfills and surface impoundments but also prior applications of CCR beneficial use. The Agency is proposing that these CCRMUs be subject to groundwater monitoring, corrective action, and closure requirements. EPA expects to finalize this proposal by Spring of 2024.

APS cannot at this time predict the outcome of these regulatory proceedings or when EPA will take final action. Depending on the eventual outcome, the costs associated with APS's management of CCR could materially increase.

APS currently disposes of CCR in ash ponds and dry storage areas at Cholla and Four Corners. As of November 2018, APS has completed the statistical analyses for its CCR disposal units that triggered assessment monitoring. APS determined that several of its CCR disposal units at Cholla and Four Corners will need to undergo corrective action. In accordance with CCR regulations, these disposal units must have ceased receiving CCR and initiated closure by no later than October 31, 2020 (except for units at facilities undergoing alternative closure, such as APS's Cholla facility). APS initiated an assessment of corrective measures on January 14, 2019 which summarized groundwater impacts, assessed applicable corrective measures, and identified various data gaps necessary to proceed with selecting appropriate remedies. Since that time, APS has implemented interim corrective measures at both facilities and continued to gather additional groundwater data and perform remedial evaluations as to the CCR disposal units at Cholla and Four Corners undergoing corrective action. In addition, APS has solicited input from the public, hosted public hearings, and will select remedies as part of this process. Given uncertainties that may exist until the Company has fully completed the corrective action assessment process, the final remediation requirements cannot yet be predicted with certainty.

EFFLUENT LIMITATION GUIDELINES (ELG)

The Clean Water Act (CWA) regulates discharges to "waters of the U.S." through water quality standards and technology-based standards. Effluent Limitation Guidelines (ELG) are technology-based standards developed by EPA on an industry-by-industry basis. The CWA requires EPA to review periodically and revise these standards as appropriate. These EPA regulations have undergone numerous changes over the last eight years. Starting in 2015, EPA established updated ELGs for steam-electric power plants that discharge wastewater under federal National Pollutant Discharge Elimination System (NPDES) permits, such as Four Corners (operations at Cholla do not require NPDES permitting). As to the waste streams impacting Four Corners, the 2015 ELG regulations required zero-liquid discharge (ZLD) for bottom-ash transport wastewater. While EPA substantially relaxed the bottom-ash transport water ZLD requirements in regulations finalized in 2020, more recently EPA proposed further revisions to these standards on March 29, 2023. In the latest proposal, EPA proposes a return to ZLD requirements for bottom-ash transport water.

In January 2021, APS applied to modify its NPDES permit to implement the more relaxed standards finalized in 2020. That permit modification application remains pending at this time. APS anticipates further permit modifications to the extent that the March 2023 proposal is finalized. APS cannot at this time predict the outcome of either the pending permit modification request or EPA's latest ELG rulemaking proposal.

PER- AND POLY-FLUOROALKYL SUBSTANCES (PFAS)

In 2021, EPA issued its PFAS Strategic Roadmap, laying the groundwork for its regulation of PFAS. EPA initiated the rulemaking process to designate two PFAS, perfluorooctanoic acid (PFOA) and perfluorooctanesulfonic acid (PFOS), as hazardous substances under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA). The proposed rule would impose stringent reporting requirements for releases of PFOA and PFOS and will enable EPA or potentially responsible parties to seek cost recovery for incurred response costs necessary to address releases of these substances. In addition to pursuing new facilities contaminated with PFOA and PFAS, EPA could also reopen previously remediated sites when it suspects these substances could be found.

On February 28, 2022, EPA provided APS with a request for information under CERCLA related to APS's Ocotillo power plant site located in Tempe, Arizona. In particular, EPA sought information from APS regarding the Company's use, storage, and disposal of substances containing PFAS compounds at the site in order to aid EPA's investigation into actual or threatened releases of PFAS into groundwater within the South Indian Bend Wash ("SIBW") Superfund site. The SIBW Superfund site includes the APS Ocotillo power plant site. APS filed its response to this information request on April 29, 2022. On January 17, 2023, EPA contacted APS to inform the Company that it would be commencing on-site investigations within the SIBW site, including the Ocotillo power plant, and performing a remedial investigation and feasibility study related to potential PFAS impacts to groundwater over the next two to three years. At the present time, we are unable to predict the outcome of this matter.

RULE E.2(D) & RULE E.2(E)

Risk Analysis: (d) the costs of compliance with existing and expected environmental regulations.

Risk Analysis: (e) any analysis by the load-serving entity to identify and assess errors, risks, and uncertainties in anticipation of potential new or enhanced environmental regulations.

Available means for managing the risks and uncertainties with the analysis of new environmental regulations and errors, risks, and uncertainties related to the cost of compliance include the following strategies:

- Obtain current information from sources, such as federal and state agencies, industry publications, vendor presentations, discussions with other utilities, market research, and third-party consulting organizations, to maintain awareness of proposed changes to existing and expected regulations, which will impact technology choices and cost;
- Evaluate commercially viable options for technologies that will enable environmental compliance;
- Serve on environmental control technology committees within industry organizations;
- Analyze commercially-viable options for technologies that will enable environmental compliance;
- Negotiate solutions with government agencies that balance cost and environmental impact;
- Update costs of technology needed for compliance throughout the development of the regulation and as expected regulations become finalized, including increases in cost due to inflation or limited supply;
- Monitor executive, legislative and judicial activities related to regulatory changes and develop cost sensitivities to evaluate the potential impact;
- Develop additional options, including scenarios containing minimum and maximum technology requirements to evaluate the range of possible outcomes;
- Maintain formal regulatory review process to ensure review of, identification of impacts from, and when necessary, provision of comment on, all new and revised environmental regulations;
- Maintain and continuously improve the Environmental Management Information System to ensure all required activities are completed and recorded; and
- Pursue an expanded portfolio of non-emitting resources that includes energy efficiency, demand response, and renewable energy.

RULE E.3(D) & RULE E.3(E)

Risk Mitigation Plan: (d) the costs of compliance with existing and expected environmental regulations

Risk Mitigation Plan: (e) any analysis by the load-serving entity to identify and assess errors, risks, and uncertainties in anticipation of potential new or enhanced environmental regulations.

To manage risks and uncertainties with the analysis and cost of existing and expected environmental regulations, APS uses a multi-faceted plan, which includes actions discussed in sections Rule E.2.(D) & Rule E.2(E) above, as well as section in further detail in section Rule D.17.

APS monitors the regulatory and judicial landscape as potential environmental regulations evolve and become more clearly defined. APS reviews and updates cost estimates based on the latest information available and utilizes the services of outside engineering firms as appropriate. APS also comments, both through industry groups and independently, on regulations when they are proposed in order to help influence the final form of the regulation.

RULE E.1(F)

Risk Identification: (f) changes in fuel prices and availability.

Coal for APS power plants is currently purchased under long-term contracts with fixed prices and inflation-related escalators. Should APS have the need to decrease coal deliveries to a level below coal contract terms, APS would be subject to liquidated damages for the amount of the coal that was contracted, but not taken. Risks for coal supply to power plants include rail service interruptions, mine permit extensions, force majeures and viability of coal mine operations driven by coal plant closures throughout the west.

Natural gas supplies in North America have kept up with demand, but pipeline disruptions, extreme weather events, and increase demand for LNG exports has constrained regional markets. The primary reliability risk for natural gas supplies in the Southwest is disruption in natural gas pipeline transportation between the gas production basins and APS power plants. A disruption could involve extreme weather events and subsequent well-head freeze-off, pipeline rupture or lack of pipeline compression needed to move fuel through pipelines. Winter Storm Uri, in February 2021, and the rupture of the El Paso Natural Gas Line 2000, in August 2021, are both recent examples involving supply disruptions that APS has utilized to document lessons learned.

Natural gas pipeline capacity presents the greatest long-term fuel risk to APS. Available natural gas transportation in the Southwest has decreased in recent years due to an increase in domestic and Mexican demand. Since 2013, Mexico has continually added substantial incremental subscriptions for long term gas capacity with pipeline networks in the Southwest and Texas. Increased local customer demand, Mexican and domestic LNG development, and coal retirements are some major drivers for the increased gas transportation demand in the Southwest. However, with California's aggressive RPS standards there is potential for some capacity to free up as transport contracts providing supply to California come up for renewal. APS monitors future demand growth and current pipeline infrastructure to determine any shortfalls for the next five years.

In order to identify how natural gas transportation availability will affect future demand growth, APS analyzes various load growth and resource mix scenarios in conjunction with the IRP to balance utilization of APS gas transportation contracts. The analysis compares current pipeline contracts with forecasted utilization by resource to identify potential contractual exceedances in the 5-10-year period.

RULE E.2(F)

Risk Analysis: (f) changes in fuel prices and availability.

The primary means for managing fuel price and supply risk include contracting for longer periods, contracting under fixed price arrangements, utilizing multiple vendors, and engaging in hedging activity. The primary means for managing exposure to any one particular type of fuel is to develop and maintain a diverse portfolio of resources that does not overly depend on any one fuel source.

Coal is typically contracted for under longer-term supply arrangements. Coal supply agreements contain provisions that provide supply and price protections in the event of a shortfall. APS also assesses alternative sources of coal that could be executed in the event of supply shortfall.

Natural gas supply is typically contracted for under shorter-term fuel supply arrangements. Even though natural gas supplies are typically contracted on a shorter-term basis, prices may be locked in for longer periods of time using forward financial swap instruments or futures contracts that lock in prices for specified delivery periods in the future.

Natural gas transportation is typically contracted for using fixed rates under longer-term arrangements. Additional gas transport capabilities are procured as necessary based on customer demand and changes in APS resource mix. If necessary, to meet customer demand, APS may consider a pipeline infrastructure build-out or adding incremental gas transportation, which follows this general sequence:

- APS recognizes a need for additional transport capacity. An APS example may be due to the construction of a new natural gas generation facility, increased usage of gas at an existing APS facility, or the signing of a new gas PPA.

- APS contracts for only firm transport based on APS business model and reliability responsibilities.
- APS analyzes the appropriate services based on both seasonal daily and hourly gas burn forecasts and overall energy balance needed to serve APS customers. These services differ based on carrier.
- When a firm transport contract is requested that is beyond the existing natural gas infrastructure capabilities, it triggers an infrastructure build-out study and balance of cost, capability, type, etc. Typical examples include adding additional horsepower to existing compressor stations, adding compressor stations, gas storage, or adding new transport pipeline.
- The lead time and cost of additions is dependent on the stated need (firm contract request), availability of options to satisfy the need, and securing needed regulatory permits or approvals.

Over the next 10 years APS will be retiring or exiting all of its coal fired plants and transitioning to more renewable and battery storage resources. During this period APS will continue to have a high reliance on the natural gas transportation system. As more renewable resources and battery storage are added to the APS portfolio the need for incremental transport moving forward will lessen. Renewals of existing contracts will be closely evaluated on an on-going basis and will be expired as the loads and resource mix evolves.

RULE E.3(F)

Risk Mitigation Plan: (f) changes in fuel prices and availability.

Coal for APS power plants is currently purchased under long-term contracts with fixed price adjustments. Disruption of coal supply due to rail interruptions is managed by keeping additional inventory of coal on power plant sites. In order to accommodate interruptions in coal supply, APS typically maintains a 45-day reserve of coal at the Cholla plant and a 60-day reserve of coal at the Four Corners plant.

For the Cholla Power Plant, transportation of coal is provided through a firm long-term contract with the Burlington Northern Santa Fe Railway. In the case of the Four Corners Power Plant, the coal mine is located adjacent to Four Corners, mitigating the risk of rail disruptions, and providing alternate transportation options such as trucking.

APS mitigates the risk of disruption in gas supply due to pipeline interruptions by contracting for natural gas transportation through long-term firm contracts over three separate pipelines – El Paso Natural Gas, TC Energy (North Baja), and Transwestern, to transport 100% of the gas needed to meet the system peak generation demand. An example of this planning can be found in Attachment D.16. In addition, APS benefits from dual pipeline supply capability at the following power plants: Redhawk, Yucca, Sundance, Arlington, and Griffith. All other power plants are served by the El Paso or North Baja pipelines. Individual pipeline risk to those plants is mitigated since El Paso pipeline utilizes a redundant system that consists of multiple pipes. Having multiple pipes assists in mitigating risk of a single pipe rupture since remaining pipes continue operating. An example of this occurred in August 2021 with the rupture of the El Paso Natural Gas Line 2000.

In order to manage natural gas price volatility risk, APS employs a five-year hedge plan. The hedging parameters are 80-90% for year 1, 50-60% for year 2, ~45% for year 3, ~30% for year 4 and ~15% for year 5. In hedging fuel supplies and prices, APS utilizes many different creditworthy counterparties to reduce concentration risk of a counterparty failing to perform their contractual obligations.

Nuclear refueling outages normally avoid the summer months to meet the peak demand for power. Sufficient fuel is maintained on-site to meet the summer peak demand periods.

RULE E.1(G)

Risk Identification: (g) construction costs, capital costs, and operating costs.

The primary construction, capital, and operating cost risks are associated with the engineering, procurement, and construction (EPC) of new generating units. Engineering, procurement, and construction of modifications to generating units also have similar risks but the total costs at risk are typically smaller.

There are many factors that have the potential to negatively impact cost, scope, and schedule of construction projects. These factors include but are not limited to the following:

- Escalating material or labor costs beyond what has been anticipated;
- Force majeure, inclement weather, labor strikes, craft availability, productivity risks;
- Federal, state or municipality permitting process;
- Quality assurance failure of one-of-a-kind engineered equipment or failure to pass customer and factory acceptance tests;
- Major equipment performance failure to operate at minimum guaranteed ratings;
- Material availability issues due to industry shift in technology selection; and,
- Contractor non-performance.

In addition, if land acquisition is a prerequisite to a construction project, there are potential risks. Acquisition of private land is systematic and is approached with an offer letter, appraisal, and negotiations. Timing is critical to managing risk if condemnation is necessary and a court settlement is required. Generally, a timeframe of 2 years is estimated for land acquisition if condemnation is necessary.

Federal and state lands are secured through leases, or rights-of-way with each agency. Federal lands require a NEPA process that includes archaeological and biological studies for project impacts to threatened and endangered species. The estimated processing timeframe for a typical right-of-way application with Arizona State Land Department requires 24 months. A federal application (such as with the Forest Service or Bureau of Land Management) will typically require 36 months or longer, depending on impacts to species or archaeological sites.

RULE E.2(G)

Risk Analysis: (g) construction costs, capital costs, and operating costs.

Methods for managing risks and uncertainties include requiring liquidated damage provisions in contracts for EPC activities so as to mitigate the risk of various scenarios that may impact cost and schedule. Vendor selection is key; contracting with an experienced EPC that takes responsibility for and has a proven track record with the total design, including equipment integration, mitigates risks that all of the process system components will fit and work together when the project is commissioned. The risks of long-term reliability and maintainability are also mitigated by ensuring that personnel with power plant engineering and operations experience are integrated in the design review process.

Not all schedule impacts may be mitigated, however, especially if the impact is due to one-of-a-kind specifically engineered and manufactured equipment being damaged beyond repair or lost during shipping. Typically, this risk is mitigated through purchasing of insurance for compensation of loss. It is also beneficial to include project milestones to document progress and determine contractor performance to those milestones.

To ensure vendors have the capability to perform the scope of work expected, a vendor analysis may be completed prior to contracting for services. Vendor analysis includes an examination of experience and capability to perform, as well as a thorough credit analysis to help determine which vendors have the financial capability to perform. As a result of this review, it may be appropriate to request letters of credit or other performance guarantees to serve as collateral from vendors. If a vendor fails to perform required services, they must forfeit any collateral they have provided.

When it is determined that equipment replacement or modifications are needed, it is important that project processes and controls are in place, well documented and communicated in order to guide project work, set expectations and measure progress against project milestones. Project control processes include the review of Environmental and Critical Infrastructure Protection regulations in order to ensure technology choices are meet or exceed regulatory requirements.

When the need to retire, expand or build new generating assets is the planned course of action, external stakeholder analysis is an integral part of the planning process. Project control documents that are well communicated and measured against help serve to mitigate project cost and schedule risk.

In addition to vendor analysis and project control documents, it is also possible to conduct sensitivity analyses on project component costs to determine the overall magnitude of potential cost uncertainty. Sensitivities may be helpful in highlighting those cost components with the greatest potential to impact overall project cost uncertainty.

RULE E.3(G)

Risk Mitigation Plan: (g) construction costs, capital costs, and operating costs.

In the event of a delay in completing individual project tasks or in receiving project components, APS analyzes the overall project schedule to determine if the schedule can be reworked to avoid direct impact on the overall project completion date. Schedules are regularly analyzed for existing or potential problems that would affect the schedule or cost. The frequency of schedule analysis will vary from as often as daily to as infrequently as monthly depending on the type, complexity and phase of the project. APS uses schedule analysis and progress measurement to identify potential risks as early as possible. Identifying potential delays as early as possible improves the probability that a corrective action or contingency plan will have the desired effect of maintaining originally scheduled completion dates.

Examples of schedule impacts and actions to mitigate include:

- **Construction completion after contract completion date –** This risk is normally mitigated by regular schedule reviews and progress milestone measurement. APS also mitigates this risk by including contract provisions for liquidated damages, whereby vendors must forfeit collateral to APS in the event of missing contractually-agreed-to milestones or completion dates.
- **Contractor productivity less than planned due to factors such as inclement weather, labor strikes, and craft availability –** In many instances, this risk is mitigated by requesting an increase in the number of critical craft personnel on site or the number of shifts being worked to return to the original completion schedule.
- **Permitting delays –** This risk may result from the need to satisfy local aesthetic or other preferences in order to obtain municipal construction permits; address concerns of non-governmental organizations or other interveners in order to obtain environmental permits. To mitigate this risk, APS is an active participant in Federal, state, local community and regulatory forums which enables a project team to identify external stakeholders concerns early and incorporate into project timelines and budgets.

- **Equipment delivery delays –** Some negative schedule impacts cannot be totally recovered. Examples are when one-of-a-kind specifically engineered and manufactured equipment is lost or damaged during shipping to the construction site. To mitigate this risk, APS purchases insurance to compensate for a potential loss of this nature.

Impacts from uncertainties are mitigated by the regular review and updating of project plans and cost estimates based on the latest industry information available. As the project start date approaches, consistently more rigorous cost estimates are produced to reduce the level of cost uncertainty.

In addition to assessing capital cost risk pertaining to the construction and installation of facilities, as well as land, land rights, structures, and equipment, APS also includes an allowance for funds used during construction in its capital cost estimates.

When it is determined that equipment replacements or modifications at existing power plants are required to improve plant efficiency or reliability, or to comply with new environmental regulations, APS has guidelines which are used to establish consistent, orderly and efficient inter-discipline and inter-department communication for these projects. The project guidelines establish the level of project control needed to reduce the project risks, which could in turn increase costs or delay project completion.

Very large projects of sufficient size are controlled in a similar fashion; however, these projects may be so large and demanding that a new project organization with a separate dedicated staff will be created for the duration of the project.

Where capital or fuel costs can represent up to 75% of the total delivered cost of power for many technologies, non-fuel operating costs generally represent less than 10% of the delivered cost. Consequently, the sensitivity of power costs to non-fuel operating costs is typically far less than it is to capital or fuel.

RULE E.1(H)

Risk Identification: (h) other factors the load-serving entity wishes to consider.

Several risks, uncertainties and errors have been discussed independently in Rules E(a) through E(g) above. APS has chosen to consider these and other parameters in tandem with each other by creating fourteen cases. Assumptions were varied around the following parameters: economic outlook including load growth, gas prices, resource retirement dates, and EPA's proposed Greenhouse Gas rules.

RULE E.2(H)

Risk Analysis: (h) other factors the load-serving entity wishes to consider.

The resources that make up APS's action plan constitute the most durable options for a variety of potential future states. As the Company receives new information, it will update this resource portfolio and will ultimately identify the most economic resources through the All-Source Request for Proposal (RFP) process. For the 2023 IRP, fourteen resource portfolios were evaluated and compared in order to assess their robustness, or ability to perform under different circumstances. They were evaluated in terms of their fuel diversity, capital expenditure requirements, gas burn, revenue requirements, carbon emissions and water consumption. Please see Chapter 5 for results of the analysis.

RULE E.3(H)

Risk Mitigation Plan: (h) other factors the load-serving entity wishes to consider.

Due to the inherent risks in future scenarios, APS has mitigated risk by selecting resources as a part of its action plan that are durable for various states. For a complete discussion about the portfolios, scenarios or risks, APS analysis and results, please refer to Chapter 5 – Portfolio Analysis.

RESPONSE TO RULES SECTION F – 2023 IRP

Resource Planning Rule A.A.C. R14-2-703 sets forth the reporting requirements for a load-serving entity. The following items provide responses to section R14-2-703(F), which specifically requires information related to the selected 15-year resource plan.

RULE F.1

Selects a portfolio of resources based upon comprehensive consideration of a wide range of supply – and – demand-side options.

In creating the 2023 Resource Plan, APS analyzed fourteen distinct portfolios for consideration composed of a mixture of technologies (as described further in Attachment D.3). APS monitored how each portfolio performed based on certain key metrics, including: renewable penetration; carbon emissions; natural gas burn; revenue requirements; average system cost; and water use. The results of the analytics can be found at:

- Attachment F.1(a) – Analysis of fourteen Portfolios (Loads and Resources Tables and Energy Mixes)
- Attachment F.1(b) – Analysis of fourteen Portfolios (Key Metrics)

Description of portfolios and sensitivities can be found in Chapter 5 – Portfolio Analysis.

RULE F.2

Will result in the load-serving entity's reliably serving the demand for electric energy services.

The APS 2023 Resource Plan is designed to provide reliable power to its customers with the required operating reserves while allowing for unforeseen events such as higher-than-forecast customer demand and forced outages of several generators at one time.

APS adopted the Loss of Load Expectation (LOLE) reliability target of one day in ten years as the minimum threshold of resource adequacy across all scenarios studied, which is widely used across the electric utility industry as a core reliability metric. To fully capture the impact of intermittent resources on resource adequacy, APS leveraged the Astrape consulting firm and its Strategic Energy and Risk Evaluation Model (SERVM) software to determine reliability contributions for each resource type included in the IRP, and the APS system Planning Reserve Margin (PRM) needed to achieve a LOLE of one day in ten years.

The resulting Installed Capacity (ICAP) PRM requires an increase from the previously calculated 15% to 20.2% in 2026. This increase is required to maintain an equivalent level of reliability for APS customers under changing system conditions, extreme weather events and changing industries practices for operating reserves. To align with industry best practice, going forward APS is adopting the Perfect Capacity (PCAP) PRM accounting methodology, which evaluates the reliability contribution of all resources – both conventional and intermittent - on a level playing field. ICAP and PCAP PRM values cannot be directly compared, as the methodologies used to calculate them are not the same. The PCAP PRM produced by the SERVM-based Astrape study is 6.9%.

In addition to the reliability discussed above, since 2003, APS has performed numerous Reliability Must Run (RMR) studies of its Phoenix and Yuma load pockets as part of the ACC's Biennial Transmission Assessment (BTA). The ACC Seventh BTA suspended the requirement for performing RMR studies in every BTA and implemented criteria for restarting such studies based on a biennial review. When performed, this study specifically looks at transmission-constrained load pockets and is done in conjunction with Southwest Area Transmission and other Arizona utilities. The last report, filed in January 2022, indicated that planned transmission along with existing transmission and local generation will be sufficient to provide better than 1-in-10 Loss of Load Probability (LOLP) for the years studied. Because the Phoenix Metro load forecast has increased more than 2.5% since the last BTA, an RMR study will be included in the next BTA filing in January 2024.

RULE F.3

Will address the adverse environmental impacts of power production.

Arizona's water challenges balance increasing demand for water due to high growth rates and limited supply of water given the arid conditions of the Desert Southwest. Towards that end, each APS power plant has a unique water strategy, which is developed to promote efficient and sustainable use of water. Other water conservation efforts over the 2023-2038 Planning Period include retiring or upgrading existing water-intensive power plants, increasing the use of renewable energy that does not use water (wind and PV solar) and implementing DSM programs.

Rule D.17, details APS's plans to reduce environmental impacts related to a) air emissions and solid waste to ensure full compliance with known environmental regulations and b) regulations impacting water and a plan for reducing impacts. For more details about environmental impacts for multiple emissions and water consumption for the 2023 Resource Plan, see Attachment D.1(a)(8).

RULE F.4

Will include renewable energy resources so as to meet or exceed the greater of the Annual Renewable Energy Requirement in R14-2-1804 or the following annual percentages of retail kWh sold by the load-serving entity.

As indicated in Table F-1 below, the selected portfolio presented in the 2023 IRP exceeds the amount of renewable energy required under the ACC RES for all years during the Planning Period. Note that in addition to the RES requirement, APS was required to achieve 1,700,000 MWh of incremental renewable generation by December 31, 2015, per ACC Decision No. 71448.

The percentages for renewable energy production presented in Table F-1 do not include market purchases of renewable energy.

TABLE F-1. RENEWABLE GENERATION INCLUDED IN 2023 RESOURCE PLAN

CALENDAR YEAR	ACC RES REQUIREMENT (PERCENT OF RETAIL SALES DURING CALENDAR YEAR)	RENEWABLE GENERATION IN APS 2023 PREFERRED PORTFOLIO
2023	30%	82%
2024	30%	80%
2025	30%	78%
2026	30%	80%
2027	30%	81%
2028	30%	82%
2029	30%	83%
2030	30%	83%

TABLE F-1. RENEWABLE GENERATION INCLUDED IN 2023 RESOURCE PLAN (CONTINUED)

CALENDAR YEAR	ACC RES REQUIREMENT (PERCENT OF RETAIL SALES DURING CALENDAR YEAR)	RENEWABLE GENERATION IN APS 2023 PREFERRED PORTFOLIO
2031	30%	84%
2032	30%	86%
2033	30%	86%
2034	30%	87%
2035	30%	88%
2036	30%	89%
2037	30%	89%
2038	30%	90%

RULE F.5

Will include distributed generation energy resources so as to meet or exceed the greater of the Distributed Renewable Energy Requirement in R14-2-1805 or the following annual percentages as applied to the load-serving entity's Annual Renewable Energy Requirement.

The Distributed Renewable Energy Requirement in R14-2-1805 and the annual percentages in the Resource Planning Rules are the same and have been set at 30% since 2011. As indicated in Table F-2 the distributed energy represented in the 2023 Resource Plan meets or exceeds the requirements in all years of the Planning Period.

TABLE F-2. DISTRIBUTED RENEWABLE ENERGY INCLUDED IN THE 2023 RESOURCE PLAN (PREFERRED PORTFOLIO)

CALENDAR YEAR	DISTRIBUTED GENERATION REQUIREMENT (PERCENT OF ANNUAL RENEWABLE REQUIREMENT)	DISTRIBUTED GENERATION IN APS 2023 RESOURCE PLAN (PERCENT OF ANNUAL RENEWABLE REQUIREMENT)
2023	30%	82%
2024	30%	80%
2025	30%	78%
2026	30%	80%
2027	30%	81%
2028	30%	82%
2029	30%	83%
2030	30%	83%
2031	30%	84%
2032	30%	86%
2033	30%	86%
2034	30%	87%
2035	30%	88%
2036	30%	89%
2037	30%	89%
2038	30%	90%

RULE F.6

Will address energy efficiency so as to meet any requirements set in rule by the Commission, or in an order of the Commission.

ACC Decision No. 71819 (August 10, 2010) set forth Energy Efficiency Requirements, which became effective January 1, 2011. The ACC's Energy Efficiency (EE) rules increased yearly up to an EES of 22% of cumulative annual energy savings by 2020. The requirement is a percentage of the previous year's retail sales. APS achieved the 22% EES requirement in 2022 and continues to meet this requirement as part of its Demand Side Management (DSM) efforts.

Additionally, Decision No. 78499 (March 2, 2022) requires APS to demonstrate 1.3% annual energy efficiency that is measured by megawatt-hour savings over its next three-year planning period. This target is based on achieving incremental annual EE savings that are equal to at least 1.3% of the prior year's adjusted retail sales.

TABLE F-3. CUMULATIVE ENERGY EFFICIENCY BY YEAR % OF RETAIL SALES

Cumulative Energy Efficiency		
CALENDAR YEAR	ACC DECISION NO. 71819 EE STANDARD (PERCENTAGE OF RETAIL SALES)	EE INCLUDED IN APS 2023 RESOURCE PLAN
2023	22.00%	26.17%

TABLE F-4. ANNUAL 1.3% ENERGY EFFICIENCY OVER THREE-YEAR PLANNING PERIOD

Annual Energy Efficiency Savings Targets Over Three-Year Planning Period			
CALENDAR YEAR	FORECAST OF ADJUSTED RETAIL SALES (MWh)*	ANNUAL SAVINGS TARGET (Percent)**	ANNUAL SAVINGS TARGET (MWh)**
2023	30,029,997	1.4%	421,490
2024	30,700,766	1.4%	429,811
2025	32,778,906	1.3%	426,126

* Annual savings targets are based on the prior year retail sales forecast at the time the DSM Implementation Plan is filed, adjusted to remove sales to Freeport McMoRan. The 2023 value shown is the actual adjusted retail sales in 2022. Savings goals for 2024 and 2025 are based on the adjusted retail sales forecasted in the Q3 2022 Long Range Forecast.

**Future savings targets filed in DSM Implementation Plans will be based on forecasted retail sales at the time of filing. Actual EE performance will be reported each year in APS's DSM Annual Progress Reports, filed in Docket No. E-00000U-18-0055.

RULE F.7

Will effectively manage the uncertainty and risks associated with costs, environmental impacts, load forecasts, and other factors.

As described in response to Rule F.1, APS performed a rigorous series of analytics on all of the potential portfolios under consideration. By expanding its position in cost effective renewable energy and its plans to increase energy storage, APS is reducing fuel price volatility and risk by diversifying the portfolio.

Regardless of fuel price outcomes, APS relies on the output of Palo Verde Nuclear Generation Station to maintain a reliable and diverse low carbon mix of resources. APS also manages future cost and environmental risks by either assuming compliance or exceeding the EE Standard and the RES. Finally, APS has significant flexibility in how it meets future load forecast fluctuations by relying on resources that have relatively short development lead times, such as solar plus energy storage, wind, existing generation resources in the region and market purchase opportunities for energy.

RULE F.8

Will achieve a reasonable long-term total cost, taking into consideration the objectives set forth in subsections (F)(2)-(7) and the uncertainty of future costs.

The 2023 Resource Plan, as outlined in Attachment F.9(b), meet the objectives set forth in Rules F.2 thru F.7 of the Resource Planning Rules, and are each expected to achieve a reasonable long-term cost as shown in Attachment D.10. This plan contains fuel- and technology-diverse resources that meet or exceeds reliability criteria, the EE Standard, the RES and manage risk through the planning of flexible resource options and limiting exposure to natural gas prices and carbon emissions. As the future unfolds and conditions change, this plan can be easily modified to address changes. It provides a road map for the future and will guide APS procurement efforts. Those efforts will ultimately result in the specific choices of resources to meet APS customer energy needs in a manner that balances reliability, cost, and risk.

RULE F.9(A)

Contains all of the following: (a) a complete description and documentation of the plan, including supply and demand conditions, availability of transmission, costs, and discount rates utilized.

A complete description and documentation of the plan are contained in the following sections of this report:

- **Supply Conditions:** All of the elements of APS's existing resource portfolio, including owned generation and purchase power contracts, are described and documented in the responses to Rule D.1. Information related to energy efficiency measures is included in the responses to Rule D.14.
- **Demand Conditions:** Customer demand conditions are provided and documented in the responses to Rules C.1, C.2, and C.3.
- **Availability of Transmission:** Transmission necessary to ensure availability for resource delivery is discussed in the responses to Rules D.1(b), D.1(d), D.1(f), D.1(g), and D.10.
- **Costs:** Costs of individual supply-side resource technologies are contained in the response to Rules D.1 and D.3, while costs of individual demand side management measures are contained in the response to Rule D.14. Costs and system revenue requirements associated with the 2023 Resource Plan are contained in Attachment D.10.
- **Discount Rate:** APS uses 6.74%, the Company's after-tax weighted cost of capital, as its discount rate.

RULE F.9(B)

Contains all of the following: (b) a comprehensive, self-explanatory load and resources table summarizing the plan.

The loads and resources tables are provided at Attachment F.9(b).

RULE F.9(C)

Contains all of the following: (c) a brief executive summary.

The Executive Summary is included at the beginning of this document.

RULE F.9(D)

Contains all of the following: (d) an index to indicate where the responses to each filing requirement of these rules can be found.

APS has included a high-level Table of Contents for this document and its related Attachments and Appendices throughout this document.

RULE F.9(E)

Contains all of the following: (e) definitions of the terms used in the plan.

The definitions of the terms used in the filing are contained in the Glossary included herein.

RESPONSE TO RULES SECTION H – ACTION PLAN

Resource Planning Rule A.A.C. R14-2-703 sets forth the reporting requirements for a load-serving entity. The following items provide responses to section R14-2-703(H), which specifically requires information related to the Action Plan for the following three-year period.

RULE H.1-H.3

Includes a summary of actions to be taken on future resource acquisitions; Includes details on resource types, resources capacity, and resource timing; Covers the three-year period following the Commission's acknowledgement of the resource plan.

This response is included in Chapter 6.

RESPONSE TO RULES SECTION I – OTHER FACTORS

Resource Planning Rule A.A.C. R14-2-703 sets forth the reporting requirements for a load-serving entity. The following items provide responses to section R14-2-703(I), which allows the utility to provide additional information related to environmental impacts for the Commission's considerations.

RULE I

A load-serving entity or any interested parties may also provide, for the Commission's consideration, analyses and supporting data pertaining to environmental impacts associated with the generation or delivery of electricity, which may include monetized estimates of environmental impacts that are not included as costs for compliance. Values or factors for compliance costs, environmental impacts, or monetization of environmental impacts may be developed and reviewed by the Commission in other proceedings or stakeholder workshops.

APS has included data related to environmental impacts of its 2023 Resource Plan in multiple locations within this document. Environmental issues and water usage are discussed in Chapter 4. Environmental plans are discussed at length in response to Rules D.17, E.1(d)-E.3(d), and E.1(e)-E.3(e). A table of emissions for each generator is found at Attachment D.1(a)(8). Attachment F.1(b) contains information for model runs performed in support of this resource plan.

RESPONSE TO RULES
OTHER COMPLIANCE REQUIREMENTS

The ACC included compliance requirements for this and future IRPs in APS's 2020 IRP Decision ACC Docket Number E-00000V-19-0034 Decision No. 78499 (March 2, 2022), as well as in ACC dockets numbered E-00000A-11-0113 Decision No. 73884 (May 8, 2013), E-01345A-16-0272 Decision No. 77512 (December 17, 2019), E-01345A-19-0236 Decision No. 78317 (November 19, 2021), E-00000V-19-0034 Decision No. 76632 (March 29, 2018), and RU-00000A-18-0284 Decision Nos. 77044 and 77289 (January 15, 2019 and July 19, 2019).

See Table OCR-1 below, for a list of each filing requirement and chapter in the 2023 IRP where it is addressed.

TABLE OCR-1. OTHER COMPLIANCE

Docket #	Decision #	Filing Requirement	Chapter in IRP
E-00000V-19-0034	78499	IT IS THEREFORE ORDERED that Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc. include in future Integrated Resource Plans a comprehensive analysis of power system resiliency to extreme weather, including correlated risks to both the power and gas systems.	Appendix
E-00000V-19-0034	78499	IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc. include in future Integrated Resource Plans a dedicated section that explicitly discusses the load serving entities' natural gas price assumptions, the resulting impact of those assumptions on the load-serving entity's short- and long-term resource procurement decisions, and the implications of declining natural gas usage as the load-serving entities shift resource mixes to achieve emissions reductions.	Portfolio Analysis
E-00000V-19-0034	78499	IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc. shall closely monitor federal legislation, and any other relevant legislation, related to a carbon tax and include in future Integrated Resource Plans a relevant discussion of the impacts of such legislation on the development of the Integrated Resource Plan.	Regulatory Portfolio Analysis
E-00000V-19-0034	78499	IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc. shall include in future Integrated Resource Plans a discussion of participation in regional markets and the effects of that participation on near- and long-term resource procurement actions.	Assessing Needs and Resources
E-00000V-19-0034	78499	IT IS FURTHER ORDERED by June 1, 2023, Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc. shall each file in the 2023 Resource Planning and Procurement docket a Market Report on the status of their engagement in regional market development forums including, but not limited to, the Energy Imbalance Market, the Western Market Exploratory Group, the Enhanced Day Ahead Market of the California Independent System Operator, and the Western Resource Adequacy Program. The Market Report shall discuss their participation and intentions for further participation including cost savings arid other benefits, barriers and concerns related to governance of western market proposals, transmission planning, coordination, open-access tariff consolidation, cost allocation and utilization arrangements, planning for resource adequacy and shall identify information the Commission needs to aide in future enabling decision-making. The Market Report shall include their anticipated development steps, including timelines and decision points from all parties leading to, among other things, obtaining lower costs for customers through greater cooperation and coordination in the Western Interconnection.	Appendix

TABLE OCR-1. OTHER COMPLIANCE REQUIREMENTS (CONTINUED)

Docket #	Decision #	Filing Requirement	Chapter in IRP
E-00000V-19-0034	78499	IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc. shall include robust retirement analyses in future Integrated Resource Plans including specific estimated retirement dates for each resource. Future Integrated Resource Plans should include a dedicated, comprehensive, analysis describing how the load-serving entity evaluated the operations of its current resources, how retirement dates were selected, and why, and what the economic impact to ratepayers will be.	Portfolio Analysis
E-00000V-19-0034	78499	IT IS FURTHER ORDERED in its next Resource Planning process, Tucson Electric Power Company shall file a comprehensive early retirement analysis for Springerville Generating Station Units 1 and 2 and of its stake in Four Corners Power Plant, and Arizona Public Service Company for its stake in Four Corners Power Plant. In the case of both facilities, retirement dates in 2024, 2025, 2026, 2027, 2028, 2029, 2030, and 2031 shall be considered ("Early Retirement Analysis"). This analysis shall include an evaluation of the economic costs and benefits to customers from the retirement and possible necessary replacement of energy and capacity and impacts to electric reliability. Tucson Electric Power Company and Arizona Public Service Company shall consult with Staff on at least a quarterly basis in order for Staff to ensure the Early Retirement Analysis is not unfairly favoring or disfavoring any technology, skewing its analysis in such a way to over-weight or under-weight any particular resource, using an industry-accepted capacity valuation for battery storage, incorporating any changes in federal tax credit policy, and using reasonable assumptions for future Springerville Generating Station and Four Corners Power Plant capacity factors, outage rates, operations and maintenance costs, fuel costs, carbon taxes, capital expenditures, reliability/technology risks, and operating performance given recent trends in performance for each generator. Staff may consider any other factor considered relevant to ensure a fair Early Retirement Analysis occurs. Arizona Public Service Company shall not include in its Early Retirement Analysis any additional coal contract and operating agreement termination liability or restrictions beyond those the company was subject to on March 3, 2021.	Portfolio Analysis

TABLE OCR-1. OTHER COMPLIANCE REQUIREMENTS (CONTINUED)

Docket #	Decision #	Filing Requirement	Chapter in IRP
E-00000V-19-0034	78499	IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc. shall include in future Integrated Resource Plans an analysis of at minimum, 10 resource portfolios that are designed to evaluate the range of resource procurement actions, and their respective costs and benefits, that can be taken to achieve the emissions reductions goals specified by each in its 2020 Integrated Resource Plan. The analysis and presentation of these resource portfolios should be used to support Arizona Public Service Company's, Tucson Electric Power Company's, and UNS Electric, Inc.'s desire to achieve significant emissions reductions.	Portfolio Analysis
E-00000V-19-0034	78499	IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc. shall include in future Integrated Resource Plans an analysis of a technology agnostic resource portfolio, which is the least-cost method of safely and reliably meeting customers' energy needs without regard for their emissions reduction goals or any renewable or carbon emissions standards.	Portfolio Analysis
E-00000V-19-0034	78499	IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc. shall in future Integrated Resource Plans study and report upon the value of distribution grid-connected resources as compared to transmission-connected, to determine the optimal mix of renewable energy and energy storage interconnected to distribution versus resources interconnected to transmission. Factors to consider include constraints in the transmission grid, the cost and process of siting and building new transmission, and the benefits of distribution connected resources such as reduced line loss and resiliency.	Transmission & Distribution Planning
E-00000V-19-0034	78499	IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc. shall include in future Integrated Resource Plans a comprehensive analysis that presents the costs and benefits of their emissions reduction commitments, compared to an approach absent these commitments, to their ratepayers.	Portfolio Analysis
E-00000V-19-0034	78499	IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc. shall include in future Integrated Resource Plans, a comprehensive discussion regarding how the load serving entities' methods for addressing resource adequacy are being adapted to address concerns with increasing variability on the bulk electric system.	Assessing Needs and Resources Appendix

TABLE OCR-1. OTHER COMPLIANCE REQUIREMENTS (CONTINUED)

Docket #	Decision #	Filing Requirement	Chapter in IRP
E-00000V-19-0034	78499	IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc. shall in future Integrated Resource Plans negotiate a project-based licensing fee that permits up to 12 Resource Planning Advisory Council members and Staff the ability to perform their own modeling runs in the same software package as these load serving entities, and to provide all necessary data and support to fully utilize the models. The load serving entities shall absorb the cost of the licensing fees.	Assessing Needs and Resources
E-00000V-19-0034	78499	IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc. shall in future Integrated Resource Plans include one or more portfolios which eliminate coal unit must-run designations.	Portfolio Analysis
E-00000V-19-0034	78499	IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc. shall in future Integrated Resource Plans include one or more portfolios which remove modeling restrictions that limit the amount of energy efficiency that can be selected as a resource option.	Portfolio Analysis
E-00000V-19-0034	78499	IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc. shall in future Integrated Resource Plans include one or more portfolios which remove modeling restrictions on the economic cycling and economic retirement of coal units.	Portfolio Analysis
E-00000V-19-0034	78499	IT IS FURTHER ORDERED that Arizona Public Service Company shall in future Integrated Resource Plans include a full accounting of the sources and costs of the hydrogen fuel and any associated capital expenditures to produce that fuel.	Assessing Needs and Resources
E-00000V-19-0034	78499	IT IS FURTHER ORDERED that Arizona Public Service Company shall in future Integrated Resource Plans include the extension of key tax credits (i.e., the Investment Tax Credit and the Production Tax Credit) and its plan to run one of the Four Corners units seasonally.	Assessing Needs and Resources
E-00000V-19-0034	78499	IT IS FURTHER ORDERED that Arizona Public Service Company shall in future Integrated Resource Plans include information on how each portfolio performs in terms of total cumulative emissions reductions in addition to annual emissions numbers.	Portfolio Analysis
E-00000V-19-0034	78499	IT IS FURTHER ORDERED that Arizona Public Service Company shall in future Integrated Resource Plans include one or more portfolios which achieve an annual minimum of 1.5 percent energy savings as a percent of retail sales from a broad portfolio of energy efficiency measures (consistent with 15 percent cumulative savings over 10 years).	Portfolio Analysis

TABLE OCR-1. OTHER COMPLIANCE REQUIREMENTS (CONTINUED)

Docket #	Decision #	Filing Requirement	Chapter in IRP
E-00000V-19-0034	78499	IT IS FURTHER ORDERED that by January 1, 2030, Arizona Public Service Company's resource portfolio shall include a demand-side resource capacity equal to at least 35 percent of Arizona Public Service Company's 2020 peak demand. The portfolio of demand-side management measures shall include rate-enabled, load-shifting technologies, including, but not limited to, demand response, energy storage, and smart thermostats, that provide customer bill savings and clean energy benefits.	Portfolio Analysis
E-00000V-19-0034	78499	IT IS FURTHER ORDERED that Arizona Public Ser vice Company shall demonstrate 1.3 percent annual energy efficiency measured by megawatt-hour savings over its next three-year planning period and shall report its annual energy efficiency savings in its 2023 Integrated Resource Plan.	Assessing Needs and Resources Action Plan
E-00000V-19-0034	78499	IT IS FURTHER ORDERED that the Commission adopt Ascend Analytics recommendations as detailed on pages 10 and 11 of its Redacted Revised Report dated August 12, 2021, including the recommendation that Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc. use capacity expansion model in future Integrated Resource Plans (See Section 3.3.5, Supply Side, of Ascend Analytics' Revised Report).	Planning for the Future Assessing Needs & Resources Portfolio Analysis Appendix
E-00000V-19-0034	78499	IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc. shall use and provide to the Commission the capacity expansion model used in their next Integrated Resource Plans, in addition to any hand-selected portfolio.	Planning for the Future
E-00000V-19-0034	76632	IT IS FURTHER ORDERED that the Load Serving Entities, except Arizona Electric Power Cooperative, shall address natural gas storage in greater detail in future IRPs, including a discussion of efforts to develop natural gas storage, the costs and benefits of natural gas storage, and risks resulting from a lack of market area natural gas storage in Arizona. In addition, natural gas pricing issues are a key driver in future resource planning decisions by Arizona utilities. Thus a very robust sensitivity analysis, considering a wide variety of natural gas price scenarios, shall be a cornerstone of utility resource planning in Arizona. Consequently, the Load Serving Entities, except Arizona Electric Cooperative, shall include a wide variety of natural gas price scenarios in future IRPs.	Assessing Needs and Resources

TABLE OCR-1. OTHER COMPLIANCE REQUIREMENTS (CONTINUED)

Docket #	Decision #	Filing Requirement	Chapter in IRP
E-00000V-19-0034	76632	IT IS FURTHER ORDERED that all Load Serving Entities, except Arizona Electric Power Cooperative, shall include, in future Integrated Resource Plans, an analysis of a reasonable range of storage technologies and chemistries; and an analysis of anticipated future energy storage cost declines as further discussed in Decision No. 76295.	Assessing Needs and Resources
E-00000V-19-0034	76632	IT IS FURTHER ORDERED that all Load Serving Entities, except Arizona Electric Power Cooperative, shall include a storage alternative as a resource option in future Integrated Resource Plans, and shall include an analysis of storage alternatives into their respective processes when considering upgrades to transmission or distribution systems, or when considering new build or capacity upgrades for existing generation resources.	Assessing Needs and Resources
E-00000V-19-0034	76632	IT IS FURTHER ORDERED that all Load Serving Entities, except Arizona Electric Power Cooperative, shall include "no-growth" and "low-growth (<1%)" scenarios in future Integrated Resource Plans, until further order of the Commission.	Portfolio Analysis
E-01345A-19-0236	78317	IT IS FURTHER ORDERED that APS shall complete, and include in its next IRP, a comprehensive retirement assessment for the 4CPP, which shall include (1) evaluation of retirement of either or both units before 2031, prepared using realistic numbers for items such as carbon costs, avoidable O&M and capital expenditures, and capacity credits for storage and not including any termination liability or restrictions beyond those to which APS was subject under the CSA as of March 3, 2021, and (2) APS's justification for using the numbers selected.	Portfolio Analysis
RU-00000A-18-0284	77289	PSCs should include EV infrastructure plans, needs and costs in their future Integrated Resource Plans.	Assessing Needs and Resources
RU-00000A-18-0284	77044	The proliferation of EVs will have an impact on certain infrastructure needs and expenses of Public Service Corporations. This information should be included in their Integrated Resource Plans in the future.	Assessing Needs and Resources
E-01345A-16-0272	77512	41. It is reasonable to track the actual impact of QF development on APS's Integrated Resource Plan. Thus, we shall require APS to report all relevant QF data, including but not limited to the following, every three years in tandem with, or as part of, the Integrated Resource Plan: - number of QF contracts entered into to date; - nameplate capacity for each interconnected QF to date; and - the avoided cost rate for each QF interconnected to date.	Assessing Needs and Resources

TABLE OCR-1. OTHER COMPLIANCE REQUIREMENTS (CONTINUED)

Docket #	Decision #	Filing Requirement	Chapter in IRP
E-00000A-11-0113	73884	IT IS FURTHER ORDERED that, in all future Integrated Resource Plans filed with the Commission, each load-serving entity with possible extra capacity resulting in a reserve margin beyond 20% over a period of two years shall include an alternative scenario in which any incremental additions of capacity, mandated or not, that contribute to the possible extra capacity are delayed until such additions do not contribute to the possible extra capacity. Each load-serving entity's IRP shall also include a comparison of all projected costs under this alternative scenario relative to the load-serving entity's other resource scenarios in the plan, including a comparison of projected revenue requirements.	Portfolio Analysis

ATTACHMENTS

TABLE OF ATTACHMENTS

Indicates confidential information

ATTACHMENT C.1(A): COINCIDENT PEAK DEMAND BY MONTH AND CUSTOMER CLASS

PEAK DEMAND (MW)													
YEAR: 2023	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Residential	2,213	2,146	2,030	2,386	3,217	4,267	4,744	4,594	3,982	2,980	1,767	1,962	4,594
Comm+Ind <3 MW	1,547	1,504	1,313	1,763	1,835	2,085	2,316	2,409	2,112	1,534	1,523	1,406	2,409
Comm+Ind >3 MW	365	381	395	460	399	437	460	518	461	432	434	346	518
Comm+Ind XHLF	61	67	79	79	86	96	108	121	140	170	193	221	121
Electric Vehicles	5	5	5	17	16	18	19	19	18	16	20	22	19
Irrigation	3	4	4	4	4	4	4	4	4	4	3	4	4
Streetlights	15	7	13	1	1	1	1	1	1	4	1	9	1
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Prior to Losses	4,209	4,114	3,838	4,709	5,557	6,907	7,652	7,665	6,718	5,139	3,941	3,970	7,665
Losses On Peak	291	284	265	321	374	467	518	519	456	348	271	273	519
Total Own Load Peak	4,500	4,398	4,102	5,031	5,932	7,374	8,170	8,184	7,173	5,487	4,212	4,243	8,184
Energy Efficiency Programs	(26)	(22)	(27)	(73)	(106)	(147)	(152)	(147)	(120)	(83)	(45)	(40)	(147)
Distributed Energy Programs	0	(2)	0	(16)	(68)	(43)	(45)	(59)	(42)	(52)	(1)	0	(59)
Own Load After EE/DE	4,474	4,373	4,075	4,941	5,758	7,184	7,973	7,978	7,012	5,352	4,165	4,203	7,978

PEAK DEMAND (MW)													
YEAR: 2024	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Residential	2,249	2,190	2,100	2,477	3,312	4,362	4,841	4,688	4,059	3,073	1,835	1,989	4,841
Comm+Ind <3 MW	1,573	1,534	1,358	1,830	1,889	2,132	2,363	2,459	2,153	1,582	1,582	1,425	2,363
Comm+Ind >3 MW	371	389	408	477	410	446	470	529	470	445	450	351	470
Comm+Ind XHLF	241	259	262	260	277	302	322	352	355	382	412	418	322
Electric Vehicles	7	7	8	23	22	25	26	26	25	22	28	41	26
Irrigation	3	4	4	4	4	4	4	4	4	4	3	4	4
Streetlights	15	7	14	1	1	1	1	1	1	4	1	9	1
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Prior to Losses	4,459	4,389	4,154	5,072	5,915	7,271	8,026	8,059	7,067	5,512	4,311	4,239	8,026
Losses On Peak	307	302	282	339	390	479	536	535	471	366	294	290	536
Total Own Load Peak	4,766	4,691	4,436	5,411	6,305	7,750	8,562	8,594	7,538	5,878	4,605	4,528	8,562
Energy Efficiency Programs	(48)	(42)	(46)	(144)	(173)	(257)	(270)	(240)	(213)	(154)	(84)	(69)	(270)
Distributed Energy Programs	0	(5)	(57)	(56)	(126)	(131)	(45)	(122)	(83)	(91)	0	0	(45)
Own Load After EE/DE	4,717	4,645	4,333	5,211	6,006	7,362	8,247	8,232	7,242	5,634	4,520	4,460	8,247

PEAK DEMAND (MW)													
YEAR: 2025	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Residential	2,303	2,287	2,131	2,539	3,392	4,478	4,935	4,780	4,124	3,143	1,870	2,034	4,780
Comm+Ind <3 MW	1,611	1,603	1,378	1,876	1,935	2,189	2,409	2,507	2,187	1,618	1,612	1,457	2,507
Comm+Ind >3 MW	380	406	414	489	420	458	479	539	478	455	459	359	539
Comm+Ind XHLF	417	457	457	458	485	511	547	594	598	629	672	681	594
Electric Vehicles	10	10	43	31	31	34	32	36	34	30	38	58	36
Irrigation	3	4	4	4	4	4	4	4	4	4	3	4	4
Streetlights	15	7	14	1	1	1	1	1	1	4	1	10	1
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Prior to Losses	4,740	4,775	4,442	5,398	6,268	7,675	8,408	8,461	7,426	5,884	4,655	4,602	8,461
Losses On Peak	325	325	300	352	401	494	551	551	483	385	315	313	551
Total Own Load Peak	5,064	5,099	4,742	5,749	6,669	8,169	8,959	9,012	7,909	6,269	4,970	4,915	9,012
Energy Efficiency Programs	(65)	(59)	(121)	(202)	(302)	(377)	(331)	(346)	(365)	(214)	(128)	(100)	(346)
Distributed Energy Programs	(4)	(45)	0	(138)	(199)	(196)	(154)	(183)	(113)	(126)	0	0	(183)
Own Load After EE/DE	4,995	4,996	4,621	5,410	6,167	7,597	8,474	8,483	7,431	5,930	4,842	4,815	8,483

ATTACHMENT C.1(A): COINCIDENT PEAK DEMAND BY MONTH AND CUSTOMER CLASS (CONTINUED)

PEAK DEMAND (MW)													
YEAR: 2026	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**ANNUAL CP**
Residential	2,346	2,335	2,180	2,592	3,462	4,593	5,043	4,874	4,251	3,192	1,910	2,047	4,874
Comm+Ind <3 MW	1,641	1,636	1,410	1,916	1,975	2,245	2,462	2,557	2,255	1,643	1,647	1,467	2,557
Comm+Ind >3 MW	387	415	424	499	429	470	489	549	493	463	469	361	549
Comm+Ind XHLF	664	742	732	728	777	802	858	921	926	959	1,021	1,030	921
Electric Vehicles	14	15	59	43	42	46	44	48	46	54	51	78	48
Irrigation	3	4	4	4	4	4	4	4	4	4	3	4	4
Streetlights	15	7	14	1	1	1	1	1	1	4	1	10	1
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Prior to Losses	5,072	5,153	4,823	5,782	6,690	8,161	8,902	8,953	7,976	6,319	5,102	4,996	8,953
Losses On Peak	346	348	324	374	427	516	552	572	511	416	343	339	572
Total Own Load Peak	5,418	5,501	5,147	6,156	7,116	8,677	9,454	9,525	8,487	6,735	5,444	5,335	9,525
Energy Efficiency Programs	(88)	(78)	(157)	(287)	(390)	(481)	(425)	(500)	(472)	(266)	(169)	(120)	(500)
Distributed Energy Programs	(1)	(69)	0	(112)	(161)	(260)	(536)	(229)	(150)	(63)	0	0	(229)
Own Load After EE/DE	5,329	5,354	4,990	5,758	6,565	7,937	8,493	8,796	7,866	6,406	5,275	5,215	8,796

PEAK DEMAND (MW)													
YEAR: 2027	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**ANNUAL CP**
Residential	2,392	2,383	2,230	2,644	3,538	4,697	5,135	4,964	4,344	3,278	1,960	2,052	4,964
Comm+Ind <3 MW	1,673	1,670	1,443	1,954	2,018	2,296	2,507	2,604	2,304	1,688	1,691	1,470	2,604
Comm+Ind >3 MW	395	423	434	509	439	481	498	560	503	475	481	362	560
Comm+Ind XHLF	1,021	1,114	1,074	1,049	1,089	1,115	1,164	1,229	1,219	1,247	1,287	1,298	1,229
Electric Vehicles	19	20	79	57	56	61	56	64	60	54	67	108	64
Irrigation	3	4	4	4	4	4	4	4	4	4	3	4	4
Streetlights	16	7	14	1	1	1	1	1	1	4	1	10	1
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Prior to Losses	5,519	5,621	5,278	6,217	7,145	8,655	9,365	9,425	8,436	6,749	5,491	5,303	9,425
Losses On Peak	376	381	353	408	456	544	577	595	535	437	366	360	595
Total Own Load Peak	5,894	6,002	5,631	6,625	7,600	9,199	9,942	10,020	8,971	7,186	5,857	5,663	10,020
Energy Efficiency Programs	(111)	(107)	(201)	(349)	(479)	(629)	(523)	(615)	(564)	(391)	(224)	(131)	(615)
Distributed Energy Programs	(6)	(38)	0	(0)	(113)	(207)	(545)	(248)	(175)	(71)	(5)	0	(248)
Own Load After EE/DE	5,777	5,857	5,430	6,276	7,008	8,363	8,874	9,157	8,231	6,724	5,628	5,532	9,157

PEAK DEMAND (MW)													
YEAR: 2028	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**ANNUAL CP**
Residential	2,447	2,384	2,242	2,698	3,625	4,802	5,222	5,053	4,444	3,356	2,006	2,176	5,053
Comm+Ind <3 MW	1,712	1,670	1,450	1,994	2,068	2,347	2,549	2,651	2,358	1,728	1,730	1,559	2,651
Comm+Ind >3 MW	404	423	436	520	449	492	507	570	515	486	492	384	570
Comm+Ind XHLF	1,318	1,368	1,300	1,272	1,302	1,330	1,387	1,451	1,428	1,451	1,502	1,526	1,451
Electric Vehicles	26	27	104	80	73	80	83	83	78	70	87	94	83
Irrigation	3	4	4	4	4	4	4	4	4	4	3	4	4
Streetlights	16	7	14	1	1	1	1	1	1	4	1	10	1
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Prior to Losses	5,926	5,883	5,549	6,567	7,521	9,055	9,752	9,811	8,827	7,098	5,823	5,753	9,811
Losses On Peak	402	399	374	431	478	568	607	616	564	454	386	386	616
Total Own Load Peak	6,328	6,283	5,923	6,998	7,999	9,623	10,359	10,427	9,391	7,552	6,208	6,139	10,427
Energy Efficiency Programs	(146)	(127)	(172)	(371)	(574)	(713)	(772)	(738)	(632)	(469)	(267)	(199)	(738)
Distributed Energy Programs	0	(13)	0	0	(76)	(175)	(254)	(215)	(79)	(105)	(6)	0	(215)
Own Load After EE/DE	6,182	6,142	5,751	6,627	7,349	8,734	9,333	9,475	8,679	6,978	5,936	5,941	9,475

ATTACHMENT C.1(A): COINCIDENT PEAK DEMAND BY MONTH AND CUSTOMER CLASS (CONTINUED)

PEAK DEMAND (MW)													
YEAR: 2029	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Residential	2,502	2,479	2,377	2,749	3,701	4,900	5,313	5,144	4,535	3,430	2,048	2,207	5,144
Comm+Ind <3 MW	1,750	1,737	1,538	2,032	2,111	2,395	2,594	2,698	2,406	1,766	1,767	1,581	2,698
Comm+Ind >3 MW	413	440	462	529	459	502	516	580	525	497	503	389	580
Comm+Ind XHLF	1,530	1,579	1,528	1,452	1,489	1,516	1,572	1,642	1,602	1,625	1,676	1,681	1,642
Electric Vehicles	35	37	33	95	93	102	107	105	99	89	111	169	105
Irrigation	3	4	4	4	4	4	4	4	4	4	3	4	4
Streetlights	16	8	15	1	1	1	1	1	1	4	1	10	1
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Prior to Losses	6,250	6,283	5,958	6,861	7,858	9,420	10,106	10,175	9,172	7,416	6,109	6,041	10,175
Losses On Peak	423	425	401	448	497	585	625	630	583	470	402	404	630
Total Own Load Peak	6,673	6,708	6,359	7,310	8,355	10,005	10,731	10,805	9,756	7,886	6,511	6,446	10,805
Energy Efficiency Programs	(172)	(151)	(184)	(416)	(653)	(867)	(901)	(864)	(746)	(541)	(314)	(224)	(864)
Distributed Energy Programs	0	(15)	(6)	0	(52)	(141)	(213)	(245)	(34)	(107)	(7)	0	(245)
Own Load After EE/DE	6,500	6,543	6,169	6,893	7,650	8,998	9,617	9,695	8,975	7,238	6,191	6,222	9,695

PEAK DEMAND (MW)													
YEAR: 2030	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Residential	2,552	2,530	2,424	2,810	3,770	4,992	5,400	5,231	4,632	3,501	2,085	2,249	5,231
Comm+Ind <3 MW	1,785	1,773	1,568	2,076	2,151	2,440	2,637	2,744	2,457	1,803	1,798	1,612	2,744
Comm+Ind >3 MW	421	449	471	541	467	511	524	590	537	507	512	397	590
Comm+Ind XHLF	1,697	1,714	1,667	1,586	1,638	1,655	1,704	1,778	1,727	1,748	1,818	1,801	1,778
Electric Vehicles	46	48	49	120	118	129	134	133	125	112	139	212	133
Irrigation	3	4	4	4	4	4	4	4	4	4	3	4	4
Streetlights	17	8	16	1	1	1	1	1	1	4	1	11	1
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Prior to Losses	6,521	6,527	6,199	7,138	8,148	9,732	10,404	10,480	9,482	7,679	6,356	6,285	10,480
Losses On Peak	439	436	411	461	515	607	646	647	601	483	417	419	647
Total Own Load Peak	6,961	6,962	6,610	7,599	8,663	10,339	11,049	11,127	10,083	8,163	6,774	6,705	11,127
Energy Efficiency Programs	(201)	(164)	(188)	(509)	(681)	(1,003)	(1,002)	(925)	(839)	(619)	(351)	(252)	(925)
Distributed Energy Programs	0	(97)	(101)	0	(60)	0	(114)	(245)	0	(106)	0	0	(245)
Own Load After EE/DE	6,759	6,701	6,321	7,090	7,922	9,336	9,934	9,958	9,244	7,437	6,422	6,452	9,958

PEAK DEMAND (MW)													
YEAR: 2031	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Residential	2,601	2,579	2,405	2,864	3,849	5,101	5,494	5,316	4,697	3,572	2,121	2,292	5,316
Comm+Ind <3 MW	1,820	1,807	1,556	2,117	2,196	2,493	2,682	2,789	2,492	1,839	1,829	1,643	2,789
Comm+Ind >3 MW	429	458	468	552	477	522	533	599	544	518	521	404	599
Comm+Ind XHLF	1,727	1,820	1,747	1,694	1,726	1,744	1,794	1,862	1,816	1,836	1,900	1,868	1,862
Electric Vehicles	59	62	211	150	146	160	153	164	154	139	171	261	164
Irrigation	3	4	4	4	4	4	4	4	4	4	3	4	4
Streetlights	17	8	16	1	1	1	1	1	1	4	1	11	1
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Prior to Losses	6,655	6,738	6,405	7,382	8,399	10,024	10,660	10,736	9,709	7,911	6,546	6,482	10,736
Losses On Peak	447	448	419	472	524	623	652	662	598	495	427	431	662
Total Own Load Peak	7,103	7,185	6,824	7,854	8,923	10,648	11,312	11,398	10,307	8,406	6,974	6,914	11,398
Energy Efficiency Programs	(210)	(188)	(382)	(585)	(858)	(1,056)	(934)	(1,033)	(981)	(628)	(397)	(278)	(1,033)
Distributed Energy Programs	(9)	(113)	0	(7)	0	0	(354)	(186)	(125)	(165)	0	0	(186)
Own Load After EE/DE	6,884	6,885	6,442	7,262	8,065	9,592	10,024	10,179	9,201	7,613	6,577	6,635	10,179

ATTACHMENT C.1(A): COINCIDENT PEAK DEMAND BY MONTH AND CUSTOMER CLASS (CONTINUED)

PEAK DEMAND (MW)													
YEAR: 2032	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Residential	2,644	2,569	2,424	2,909	3,916	5,214	5,586	5,401	4,814	3,619	2,166	2,257	5,401
Comm+Ind <3 MW	1,850	1,801	1,568	2,150	2,234	2,549	2,727	2,834	2,554	1,864	1,869	1,618	2,834
Comm+Ind >3 MW	437	456	471	560	485	534	542	609	558	524	532	398	609
Comm+Ind XHLF	1,756	1,885	1,811	1,745	1,781	1,795	1,853	1,923	1,880	1,898	1,934	1,929	1,923
Electric Vehicles	74	75	259	198	179	196	187	200	188	169	208	334	200
Irrigation	3	4	4	4	4	4	4	4	4	4	3	4	4
Streetlights	17	8	16	1	1	1	1	1	1	4	1	11	1
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Prior to Losses	6,782	6,798	6,552	7,566	8,601	10,292	10,900	10,972	10,000	8,083	6,714	6,549	10,972
Losses On Peak	455	454	427	487	538	629	652	674	612	516	435	439	674
Total Own Load Peak	7,237	7,252	6,980	8,053	9,139	10,921	11,552	11,646	10,612	8,598	7,149	6,988	11,646
Energy Efficiency Programs	(236)	(210)	(408)	(556)	(862)	(1,207)	(1,029)	(1,256)	(1,087)	(665)	(451)	(237)	(1,256)
Distributed Energy Programs	(2)	(59)	0	0	0	(30)	(491)	(17)	(108)	0	0	0	(17)
Own Load After EE/DE	6,999	6,983	6,571	7,497	8,277	9,684	10,033	10,374	9,416	7,933	6,698	6,751	10,374

PEAK DEMAND (MW)													
YEAR: 2033	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Residential	2,694	2,670	2,503	2,973	3,995	5,316	5,670	5,486	4,914	3,700	2,212	2,335	5,486
Comm+Ind <3 MW	1,885	1,872	1,620	2,197	2,279	2,598	2,769	2,878	2,607	1,906	1,908	1,674	2,878
Comm+Ind >3 MW	445	474	487	573	495	544	550	619	569	536	543	412	619
Comm+Ind XHLF	1,931	1,986	1,872	1,809	1,834	1,855	1,916	1,987	1,937	1,963	2,001	1,995	1,987
Electric Vehicles	93	97	313	238	216	236	244	241	225	272	249	377	241
Irrigation	3	4	4	4	4	4	4	4	4	4	3	4	4
Streetlights	18	8	16	1	1	1	1	1	1	4	1	11	1
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Prior to Losses	7,068	7,111	6,814	7,795	8,824	10,554	11,154	11,216	10,258	8,385	6,918	6,809	11,216
Losses On Peak	472	476	442	500	551	642	677	687	639	517	445	450	687
Total Own Load Peak	7,540	7,587	7,256	8,294	9,375	11,196	11,830	11,903	10,897	8,902	7,363	7,259	11,903
Energy Efficiency Programs	(266)	(250)	(458)	(609)	(896)	(1,323)	(1,274)	(1,340)	(1,059)	(872)	(514)	(333)	(1,340)
Distributed Energy Programs	(18)	(19)	(0)	0	0	0	(147)	0	0	(76)	(9)	0	0
Own Load After EE/DE	7,256	7,318	6,798	7,685	8,479	9,873	10,409	10,563	9,838	7,955	6,840	6,926	10,563

PEAK DEMAND (MW)													
YEAR: 2034	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Residential	2,742	2,717	2,546	3,013	4,075	5,417	5,758	5,571	5,000	3,773	2,252	2,413	5,571
Comm+Ind <3 MW	1,919	1,904	1,647	2,227	2,325	2,648	2,811	2,923	2,653	1,943	1,943	1,729	2,923
Comm+Ind >3 MW	453	483	495	580	505	554	559	628	579	547	553	426	628
Comm+Ind XHLF	2,000	2,050	1,926	1,864	1,887	1,906	1,967	2,037	1,984	1,996	2,048	2,061	2,037
Electric Vehicles	113	118	372	281	256	279	289	284	266	239	293	443	284
Irrigation	3	4	4	4	4	4	4	4	4	4	3	4	4
Streetlights	18	8	16	1	1	1	1	1	1	4	1	11	1
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Prior to Losses	7,248	7,284	7,006	7,971	9,052	10,809	11,388	11,448	10,487	8,507	7,093	7,087	11,448
Losses On Peak	482	486	455	511	562	656	687	698	653	521	453	464	698
Total Own Load Peak	7,730	7,770	7,461	8,481	9,614	11,465	12,076	12,146	11,140	9,028	7,547	7,551	12,146
Energy Efficiency Programs	(313)	(275)	(427)	(624)	(968)	(1,374)	(1,424)	(1,409)	(1,091)	(934)	(562)	(406)	(1,409)
Distributed Energy Programs	0	(21)	(33)	0	0	0	(76)	0	0	(72)	(9)	0	0
Own Load After EE/DE	7,417	7,474	7,001	7,857	8,646	10,092	10,576	10,737	10,050	8,022	6,976	7,145	10,737

ATTACHMENT C.1(A): COINCIDENT PEAK DEMAND BY MONTH AND CUSTOMER CLASS (CONTINUED)

PEAK DEMAND (MW)													
YEAR: 2035	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Residential	2,796	2,764	2,524	3,057	4,148	5,510	5,846	5,659	5,087	3,845	2,293	2,440	5,659
Comm+Ind <3 MW	1,956	1,937	1,633	2,260	2,367	2,694	2,854	2,969	2,700	1,980	1,978	1,749	2,969
Comm+Ind >3 MW	462	491	491	589	514	564	567	638	589	557	563	430	638
Comm+Ind XHLF	2,048	2,095	1,958	1,901	1,926	1,946	2,005	2,081	2,017	2,034	2,086	2,080	2,081
Electric Vehicles	135	141	434	329	299	325	337	330	308	278	339	540	330
Irrigation	3	4	4	4	4	4	4	4	4	4	3	4	4
Streetlights	18	9	16	1	1	1	1	1	1	5	1	11	1
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Prior to Losses	7,419	7,441	7,061	8,140	9,259	11,044	11,614	11,683	10,707	8,703	7,264	7,256	11,683
Losses On Peak	492	495	463	520	572	665	698	703	664	531	462	480	703
Total Own Load Peak	7,911	7,936	7,523	8,660	9,832	11,708	12,312	12,386	11,371	9,233	7,726	7,735	12,386
Energy Efficiency Programs	(342)	(301)	(361)	(654)	(1,026)	(1,482)	(1,579)	(1,571)	(1,151)	(1,005)	(610)	(357)	(1,571)
Distributed Energy Programs	0	(22)	(40)	0	0	0	0	0	0	(67)	(10)	0	0
Own Load After EE/DE	7,569	7,614	7,123	8,006	8,805	10,227	10,733	10,815	10,220	8,162	7,106	7,378	10,815

PEAK DEMAND (MW)													
YEAR: 2036	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Residential	2,844	2,760	2,590	3,129	4,218	5,602	5,933	5,742	5,153	3,916	2,322	2,480	5,742
Comm+Ind <3 MW	1,990	1,935	1,676	2,313	2,407	2,739	2,897	3,013	2,734	2,017	2,004	1,778	3,013
Comm+Ind >3 MW	470	490	504	603	523	573	576	647	597	567	570	437	647
Comm+Ind XHLF	2,092	2,105	2,010	1,947	1,982	2,000	2,055	2,131	2,075	2,096	2,166	2,128	2,131
Electric Vehicles	159	161	500	354	344	374	359	378	353	318	387	618	378
Irrigation	3	4	4	4	4	4	4	4	4	4	3	4	4
Streetlights	19	9	17	1	1	1	1	1	1	5	1	12	1
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Prior to Losses	7,577	7,463	7,299	8,350	9,478	11,293	11,824	11,917	10,918	8,923	7,454	7,456	11,917
Losses On Peak	501	491	466	526	582	688	709	717	657	538	474	492	717
Total Own Load Peak	8,078	7,954	7,765	8,876	10,060	11,981	12,533	12,634	11,575	9,461	7,928	7,948	12,634
Energy Efficiency Programs	(373)	(305)	(596)	(787)	(1,112)	(1,395)	(1,391)	(1,597)	(1,464)	(1,025)	(643)	(375)	(1,597)
Distributed Energy Programs	0	(100)	0	0	0	0	(240)	0	0	(165)	0	0	0
Own Load After EE/DE	7,705	7,549	7,169	8,089	8,948	10,586	10,901	11,037	10,111	8,270	7,285	7,573	11,037

ATTACHMENT C.1(A): COINCIDENT PEAK DEMAND BY MONTH AND CUSTOMER CLASS (CONTINUED)

PEAK DEMAND (MW)													
YEAR: 2037	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Residential	2,886	2,862	2,677	3,183	4,285	5,715	6,029	5,826	5,278	3,941	2,355	2,494	5,826
Comm+Ind <3 MW	2,019	2,006	1,732	2,353	2,445	2,794	2,944	3,057	2,801	2,030	2,032	1,788	3,057
Comm+Ind >3 MW	476	508	521	613	531	585	585	657	611	571	578	440	657
Comm+Ind XHLF	1,997	2,151	2,053	1,970	2,036	2,033	2,101	2,174	2,124	2,132	2,212	2,179	2,174
Electric Vehicles	186	193	569	403	390	424	408	428	400	485	437	696	428
Irrigation	3	4	4	4	4	4	4	4	4	4	3	4	4
Streetlights	19	9	17	1	1	1	1	1	1	5	1	12	1
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Prior to Losses	7,587	7,732	7,572	8,526	9,691	11,556	12,071	12,147	11,218	9,168	7,618	7,613	12,147
Losses On Peak	501	506	481	532	594	693	706	729	672	559	485	502	729
Total Own Load Peak	8,089	8,238	8,053	9,058	10,285	12,249	12,777	12,877	11,890	9,727	8,103	8,116	12,877
Energy Efficiency Programs	(372)	(330)	(648)	(871)	(1,152)	(1,586)	(1,522)	(1,654)	(1,556)	(1,049)	(641)	(385)	(1,654)
Distributed Energy Programs	(2)	(128)	0	0	0	0	(393)	0	0	(73)	0	0	0
Own Load After EE/DE	7,714	7,780	7,405	8,187	9,133	10,663	10,861	11,223	10,334	8,605	7,462	7,731	11,223

PEAK DEMAND (MW)													
YEAR: 2038	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Residential	2,929	2,908	2,724	3,220	4,358	5,817	6,113	5,909	5,342	3,984	2,406	2,495	5,909
Comm+Ind <3 MW	2,049	2,038	1,763	2,380	2,486	2,844	2,985	3,101	2,835	2,052	2,076	1,789	3,101
Comm+Ind >3 MW	483	516	530	620	540	595	593	666	619	577	591	440	666
Comm+Ind XHLF	2,069	2,219	2,102	2,023	2,062	2,075	2,139	2,217	2,132	2,193	2,223	2,215	2,217
Electric Vehicles	213	221	639	481	437	475	456	479	527	458	487	775	479
Irrigation	3	4	4	4	4	4	4	4	4	4	3	4	4
Streetlights	19	9	18	1	1	1	1	1	1	5	1	12	1
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Prior to Losses	7,766	7,915	7,779	8,730	9,888	11,811	12,292	12,377	11,460	9,273	7,788	7,730	12,377
Losses On Peak	511	518	496	550	605	702	715	742	681	574	492	511	742
Total Own Load Peak	8,278	8,432	8,275	9,280	10,493	12,513	13,007	13,119	12,141	9,847	8,280	8,241	13,119
Energy Efficiency Programs	(398)	(381)	(640)	(813)	(1,186)	(1,708)	(1,597)	(1,697)	(1,658)	(1,009)	(706)	(381)	(1,697)
Distributed Energy Programs	(13)	(84)	0	0	0	0	(409)	0	0	0	0	0	0
Own Load After EE/DE	7,866	7,968	7,635	8,467	9,307	10,805	11,001	11,423	10,483	8,838	7,574	7,861	11,423

ATTACHMENT C.1(B): ENERGY CONSUMPTION BY MONTH AND CUSTOMER CLASS

	ENERGY DEMAND (MWH)												
YEAR: 2023	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	983,307	816,663	819,372	873,756	1,148,714	1,627,011	2,020,323	1,970,313	1,562,890	1,081,472	832,701	989,695	14,726,218
Comm+Ind <3 MW	834,197	770,673	864,414	866,982	984,479	1,154,990	1,280,241	1,304,481	1,152,482	965,057	887,380	888,911	11,954,287
Comm+Ind >3 MW	292,830	289,819	289,821	298,193	305,408	326,202	338,581	344,015	346,726	327,805	314,053	305,684	3,779,137
Comm+Ind XHLF	44,273	43,472	57,354	58,424	64,535	69,924	80,645	88,078	100,895	125,474	135,905	160,279	1,029,259
Electric Vehicles	7,954	7,677	8,782	8,625	8,970	9,632	10,439	10,389	9,491	10,267	10,503	11,815	114,545
Irrigation	328	450	718	929	1,228	1,284	785	894	869	867	824	281	9,457
Streetlights	8,742	9,089	10,139	9,068	9,590	9,181	7,685	9,340	8,582	9,719	9,783	9,448	110,366
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/DE	2,171,631	1,937,843	2,050,601	2,115,978	2,522,924	3,198,225	3,738,699	3,727,510	3,181,934	2,520,661	2,191,149	2,366,113	31,723,269
Energy Efficiency Programs	(13,734)	(11,996)	(18,544)	(22,994)	(31,345)	(45,097)	(51,677)	(48,688)	(39,465)	(25,387)	(17,672)	(12,535)	(339,134)
Distributed Energy Programs	(24,315)	(26,725)	(37,970)	(42,128)	(46,467)	(45,422)	(40,108)	(40,240)	(35,850)	(33,018)	(23,837)	(21,586)	(417,664)
Total Sales	2,133,582	1,899,122	1,994,087	2,050,856	2,445,113	3,107,707	3,646,914	3,638,581	3,106,620	2,462,257	2,149,640	2,331,992	30,966,471
Energy Losses	170,395	123,943	145,894	139,868	173,241	210,991	222,786	234,823	187,257	154,119	133,329	147,098	2,043,744
Total Own Load Energy	2,303,977	2,023,065	2,139,981	2,190,724	2,618,354	3,318,698	3,869,700	3,873,404	3,293,877	2,616,376	2,282,969	2,479,090	33,010,215

	ENERGY DEMAND (MWH)												
YEAR: 2024	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	1,040,499	882,550	812,160	881,544	1,120,250	1,649,643	2,135,334	2,019,044	1,634,587	1,115,866	867,111	1,024,117	15,182,705
Comm+Ind <3 MW	817,123	803,709	927,984	944,702	1,065,659	1,187,959	1,211,883	1,257,304	1,143,439	999,784	930,066	906,765	12,196,378
Comm+Ind >3 MW	297,888	295,010	293,518	301,593	308,770	329,163	342,080	348,731	352,277	334,148	320,722	312,725	3,836,626
Comm+Ind XHLF	175,363	173,665	190,854	193,199	208,850	218,875	241,199	255,707	256,874	282,259	286,909	303,616	2,787,371
Electric Vehicles	11,183	10,782	12,318	12,087	12,574	13,493	14,635	14,569	13,336	14,418	14,775	16,636	160,805
Irrigation	332	451	701	933	1,235	1,283	799	895	860	864	818	288	9,459
Streetlights	8,955	9,211	9,968	9,302	9,808	9,306	7,911	9,485	8,601	9,809	9,842	9,642	111,840
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/DE	2,351,344	2,175,378	2,247,503	2,343,359	2,727,146	3,409,722	3,953,841	3,905,735	3,409,974	2,757,149	2,430,243	2,573,790	34,285,185
Energy Efficiency Programs	(27,471)	(25,057)	(36,165)	(44,059)	(58,137)	(82,474)	(93,314)	(88,016)	(71,637)	(48,031)	(34,139)	(25,208)	(633,708)
Distributed Energy Programs	(47,725)	(54,545)	(74,529)	(82,689)	(91,208)	(89,157)	(78,724)	(78,987)	(70,367)	(64,808)	(46,789)	(42,370)	(821,897)
Total Sales	2,276,148	2,095,776	2,136,809	2,216,611	2,577,802	3,238,091	3,781,804	3,738,732	3,267,970	2,644,310	2,349,316	2,506,212	32,829,580
Energy Losses	168,133	138,943	166,577	157,341	195,200	225,076	218,692	240,422	183,755	161,508	139,290	156,238	2,151,176
Total Own Load Energy	2,444,281	2,234,719	2,303,386	2,373,952	2,773,002	3,463,167	4,000,496	3,979,154	3,451,725	2,805,818	2,488,606	2,662,450	34,980,756

ATTACHMENT C.1(B): ENERGY CONSUMPTION BY MONTH AND CUSTOMER CLASS (CONTINUED)

	ENERGY DEMAND (MWH)												
YEAR: 2025	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	1,070,241	895,750	837,759	903,610	1,144,290	1,698,600	2,205,328	2,076,845	1,690,339	1,151,080	895,898	1,058,028	15,627,766
Comm+Ind <3 MW	831,702	802,846	958,339	960,311	1,080,151	1,208,291	1,233,931	1,278,746	1,168,325	1,020,753	947,033	927,385	12,417,813
Comm+Ind >3 MW	304,279	300,497	300,214	307,533	314,350	334,023	345,986	350,963	353,357	334,706	320,722	312,725	3,879,356
Comm+Ind XHLF	318,635	300,505	342,421	337,213	363,614	371,006	408,813	431,783	430,820	461,914	468,047	494,109	4,728,879
Electric Vehicles	15,801	15,191	17,304	16,943	17,618	18,871	20,469	20,371	18,673	20,164	20,686	23,299	225,390
Irrigation	332	445	707	934	1,233	1,285	798	894	860	865	817	289	9,459
Streetlights	9,044	9,163	10,198	9,417	9,910	9,439	7,999	9,589	8,700	9,924	9,940	9,765	113,088
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/DE	2,550,034	2,324,397	2,466,942	2,535,961	2,931,167	3,641,515	4,223,325	4,169,190	3,671,074	2,999,405	2,663,143	2,825,599	37,001,750
Energy Efficiency Programs	(41,935)	(37,195)	(54,421)	(65,700)	(85,519)	(119,812)	(136,258)	(129,158)	(106,026)	(72,284)	(51,885)	(39,332)	(939,527)
Distributed Energy Programs	(71,677)	(78,784)	(111,932)	(124,190)	(136,984)	(133,902)	(118,234)	(118,628)	(105,685)	(97,335)	(70,270)	(63,635)	(1,231,256)
Total Sales	2,436,421	2,208,418	2,300,589	2,346,070	2,708,663	3,387,800	3,968,833	3,921,404	3,459,363	2,829,787	2,540,987	2,722,632	34,830,967
Energy Losses	179,764	143,740	194,294	171,867	215,599	240,702	219,263	251,296	183,869	169,358	144,388	166,922	2,281,062
Total Own Load Energy	2,616,185	2,352,158	2,494,883	2,517,937	2,924,262	3,628,502	4,188,096	4,172,700	3,643,232	2,999,145	2,685,375	2,889,554	37,112,029

	ENERGY DEMAND (MWH)												
YEAR: 2026	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	1,097,900	921,070	853,949	925,814	1,169,216	1,746,786	2,275,059	2,135,898	1,744,204	1,184,106	928,710	1,088,695	16,071,407
Comm+Ind <3 MW	844,364	817,417	974,958	976,110	1,095,134	1,229,527	1,256,206	1,301,774	1,192,892	1,039,688	968,995	943,832	12,640,896
Comm+Ind >3 MW	305,395	301,073	301,330	308,613	315,466	337,803	349,892	354,869	359,297	340,844	326,662	318,863	3,920,108
Comm+Ind XHLF	513,440	486,565	549,600	542,063	582,331	583,541	641,715	671,954	667,106	711,838	711,122	747,069	7,408,344
Electric Vehicles	22,147	21,176	23,999	23,402	24,275	25,915	28,057	27,865	25,524	27,491	28,176	31,690	309,717
Irrigation	331	445	709	933	1,233	1,286	798	894	859	863	820	288	9,459
Streetlights	9,108	9,251	10,313	9,533	10,016	9,561	8,084	9,696	8,789	10,019	10,074	9,852	114,296
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/DE	2,792,685	2,556,997	2,714,858	2,786,468	3,197,672	3,934,418	4,559,811	4,502,951	3,998,670	3,314,848	2,974,560	3,140,289	40,474,226
Energy Efficiency Programs	(56,977)	(50,791)	(73,732)	(88,234)	(113,984)	(158,379)	(179,830)	(170,735)	(140,210)	(96,605)	(69,771)	(53,316)	(1,252,565)
Distributed Energy Programs	(94,848)	(104,252)	(148,118)	(164,336)	(181,266)	(177,188)	(156,455)	(156,977)	(139,849)	(128,801)	(92,987)	(84,206)	(1,629,282)
Total Sales	2,640,859	2,401,955	2,493,007	2,533,898	2,902,422	3,598,851	4,223,525	4,175,239	3,718,611	3,089,443	2,811,802	3,002,767	37,592,379
Energy Losses	193,049	156,372	221,233	190,015	239,808	260,457	224,443	266,823	188,346	181,634	155,403	181,354	2,458,937
Total Own Load Energy	2,833,908	2,558,327	2,714,240	2,723,913	3,142,230	3,859,308	4,447,968	4,442,062	3,906,957	3,271,077	2,967,205	3,184,121	40,051,316

ATTACHMENT C.1(B): ENERGY CONSUMPTION BY MONTH AND CUSTOMER CLASS (CONTINUED)

	ENERGY DEMAND (MWH)												
YEAR: 2027	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	1,125,818	945,897	870,198	947,843	1,195,132	1,793,559	2,342,575	2,196,084	1,798,413	1,216,973	961,547	1,118,439	16,512,476
Comm+Ind <3 MW	858,563	834,363	994,461	994,912	1,115,021	1,251,005	1,281,160	1,329,980	1,220,941	1,061,347	993,872	961,934	12,897,559
Comm+Ind >3 MW	305,395	301,073	301,330	308,613	315,466	337,803	349,892	354,869	359,297	340,844	326,662	318,863	3,920,108
Comm+Ind XHLF	779,584	725,104	804,887	780,976	816,289	811,022	875,251	897,413	877,957	920,368	906,470	942,902	10,138,223
Electric Vehicles	30,112	28,678	32,380	31,476	32,579	34,688	37,490	37,165	34,003	36,549	37,415	42,022	414,556
Irrigation	331	445	709	934	1,233	1,287	795	895	859	862	822	287	9,459
Streetlights	9,179	9,330	10,427	9,641	10,131	9,669	8,152	9,806	8,877	10,108	10,203	9,927	115,450
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/DE	3,108,982	2,844,891	3,014,392	3,074,394	3,485,852	4,239,032	4,895,315	4,826,212	4,300,347	3,587,051	3,236,991	3,394,374	44,007,832
Energy Efficiency Programs	(72,426)	(64,765)	(93,537)	(111,319)	(143,069)	(197,920)	(224,568)	(213,051)	(175,273)	(121,593)	(88,199)	(67,724)	(1,573,445)
Distributed Energy Programs	(118,100)	(129,810)	(184,430)	(204,624)	(225,705)	(220,628)	(194,812)	(195,461)	(174,134)	(160,377)	(115,784)	(104,849)	(2,028,715)
Total Sales	2,918,455	2,650,316	2,736,424	2,758,450	3,117,078	3,820,484	4,475,934	4,417,700	3,950,939	3,305,081	3,033,008	3,221,802	40,405,671
Energy Losses	212,012	172,552	251,546	210,664	265,801	280,750	228,991	281,670	191,378	190,696	163,296	191,377	2,640,733
Total Own Load Energy	3,130,467	2,822,868	2,987,970	2,969,114	3,382,879	4,101,234	4,704,925	4,699,370	4,142,317	3,495,777	3,196,304	3,413,179	43,046,404

	ENERGY DEMAND (MWH)												
YEAR: 2028	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	1,158,853	981,121	876,296	967,684	1,224,522	1,840,960	2,409,225	2,256,474	1,851,094	1,253,694	991,420	1,148,712	16,960,053
Comm+Ind <3 MW	878,198	867,609	996,328	1,009,320	1,139,018	1,273,016	1,306,158	1,358,368	1,248,395	1,086,874	1,016,186	980,668	13,160,139
Comm+Ind >3 MW	305,395	301,073	301,330	308,613	315,466	337,803	349,892	354,869	359,297	340,844	326,662	318,863	3,920,108
Comm+Ind XHLF	959,069	915,778	975,566	944,434	979,611	967,211	1,038,642	1,059,597	1,031,792	1,072,986	1,058,106	1,107,375	12,110,168
Electric Vehicles	39,898	37,893	42,672	41,387	42,763	45,442	49,040	48,541	44,360	47,606	48,678	54,604	542,884
Irrigation	331	451	704	931	1,237	1,287	793	895	858	864	822	285	9,458
Streetlights	9,277	9,557	10,378	9,714	10,273	9,776	8,217	9,910	8,959	10,224	10,310	9,999	116,594
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/DE	3,351,020	3,113,483	3,203,274	3,282,082	3,712,891	4,475,495	5,161,967	5,088,654	4,544,755	3,813,092	3,452,184	3,620,506	46,819,403
Energy Efficiency Programs	(88,436)	(82,115)	(114,315)	(135,930)	(173,733)	(239,364)	(270,690)	(255,394)	(209,321)	(146,304)	(106,261)	(80,208)	(1,902,071)
Distributed Energy Programs	(137,744)	(157,428)	(215,105)	(238,660)	(263,246)	(257,324)	(227,216)	(227,973)	(203,097)	(187,053)	(135,042)	(122,288)	(2,372,176)
Total Sales	3,124,841	2,873,939	2,873,854	2,907,492	3,275,912	3,978,807	4,664,061	4,605,287	4,132,337	3,479,735	3,210,881	3,418,010	42,545,156
Energy Losses	225,141	194,998	265,413	224,878	288,645	297,474	230,006	292,118	191,490	198,194	168,293	198,867	2,775,517
Total Own Load Energy	3,349,982	3,068,937	3,139,267	3,132,370	3,564,557	4,276,281	4,894,067	4,897,405	4,323,827	3,677,929	3,379,174	3,616,877	45,320,673

ATTACHMENT C.1(B): ENERGY CONSUMPTION BY MONTH AND CUSTOMER CLASS (CONTINUED)

	ENERGY DEMAND (MWH)												
YEAR: 2029	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	1,191,345	995,987	902,280	992,137	1,252,321	1,885,692	2,479,041	2,315,228	1,902,303	1,290,463	1,021,452	1,179,988	17,408,237
Comm+Ind <3 MW	896,747	868,443	1,027,041	1,030,043	1,158,575	1,291,782	1,334,730	1,384,541	1,274,553	1,111,922	1,038,608	1,000,292	13,417,277
Comm+Ind >3 MW	305,395	301,073	301,330	308,613	315,466	337,803	349,892	354,869	359,297	340,844	326,662	318,863	3,920,108
Comm+Ind XHLF	1,113,757	1,020,512	1,116,486	1,077,573	1,120,118	1,102,408	1,177,963	1,196,999	1,157,309	1,202,201	1,180,533	1,219,471	13,685,331
Electric Vehicles	51,798	49,105	55,204	53,459	55,164	58,540	63,101	62,387	56,953	61,053	62,364	69,887	699,016
Irrigation	333	444	709	933	1,237	1,285	794	895	857	865	822	285	9,459
Streetlights	9,376	9,486	10,592	9,837	10,380	9,859	8,313	10,004	9,035	10,331	10,417	10,083	117,713
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/DE	3,568,751	3,245,050	3,413,642	3,472,594	3,913,261	4,687,369	5,413,835	5,324,923	4,760,307	4,017,679	3,640,859	3,798,870	49,257,140
Energy Efficiency Programs	(104,924)	(93,740)	(134,331)	(159,115)	(202,735)	(279,151)	(316,626)	(300,090)	(247,921)	(173,617)	(126,619)	(97,715)	(2,236,584)
Distributed Energy Programs	(154,441)	(169,754)	(241,181)	(267,591)	(295,158)	(288,517)	(254,760)	(255,607)	(227,716)	(209,727)	(151,411)	(137,113)	(2,652,976)
Total Sales	3,309,385	2,981,556	3,038,130	3,045,888	3,415,368	4,119,701	4,842,449	4,769,226	4,284,669	3,634,336	3,362,829	3,564,042	44,367,580
Energy Losses	238,876	193,855	293,615	239,551	307,632	311,977	234,575	302,175	191,461	203,301	172,032	204,938	2,893,987
Total Own Load Energy	3,548,261	3,175,411	3,331,745	3,285,439	3,723,000	4,431,678	5,077,024	5,071,401	4,476,130	3,837,637	3,534,861	3,768,980	47,261,567

	ENERGY DEMAND (MWH)												
YEAR: 2030	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	1,222,339	1,021,305	919,451	1,016,704	1,280,805	1,929,858	2,548,327	2,373,014	1,955,373	1,325,770	1,048,961	1,213,904	17,855,812
Comm+Ind <3 MW	914,041	885,299	1,041,869	1,050,323	1,178,032	1,309,742	1,363,545	1,409,777	1,302,579	1,135,332	1,057,904	1,023,179	13,671,621
Comm+Ind >3 MW	305,395	301,073	301,330	308,613	315,466	337,803	349,892	354,869	359,297	340,844	326,662	318,863	3,920,108
Comm+Ind XHLF	1,235,277	1,124,694	1,225,331	1,177,749	1,225,193	1,201,006	1,275,339	1,292,854	1,247,762	1,293,226	1,267,059	1,306,569	14,872,059
Electric Vehicles	66,201	62,656	70,330	68,008	70,077	74,268	79,948	78,945	71,976	77,070	78,631	88,016	886,126
Irrigation	333	444	708	934	1,239	1,282	795	894	858	865	821	287	9,460
Streetlights	9,452	9,562	10,658	9,955	10,484	9,937	8,405	10,092	9,119	10,429	10,497	10,189	118,779
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/DE	3,753,037	3,405,034	3,569,676	3,632,285	4,081,296	4,863,896	5,626,252	5,520,444	4,946,964	4,183,537	3,790,535	3,961,007	51,333,964
Energy Efficiency Programs	(121,737)	(108,836)	(155,730)	(183,749)	(233,444)	(321,008)	(363,520)	(344,835)	(284,866)	(200,140)	(146,369)	(113,259)	(2,577,493)
Distributed Energy Programs	(168,807)	(185,545)	(263,615)	(292,481)	(322,612)	(315,354)	(278,455)	(279,383)	(248,898)	(229,236)	(165,496)	(149,866)	(2,899,746)
Total Sales	3,462,494	3,110,653	3,150,331	3,156,055	3,525,240	4,227,533	4,984,277	4,896,227	4,413,201	3,754,162	3,478,670	3,697,882	45,856,725
Energy Losses	247,892	202,250	309,675	252,245	324,281	324,308	237,296	308,960	190,630	206,056	173,181	209,979	2,986,753
Total Own Load Energy	3,710,386	3,312,903	3,460,006	3,408,300	3,849,521	4,551,841	5,221,573	5,205,187	4,603,831	3,960,218	3,651,851	3,907,861	48,843,478

ATTACHMENT C.1(B): ENERGY CONSUMPTION BY MONTH AND CUSTOMER CLASS (CONTINUED)

	ENERGY DEMAND (MWH)												
YEAR: 2031	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	1,252,718	1,046,562	939,071	1,040,203	1,308,502	1,978,210	2,613,793	2,430,748	2,007,625	1,361,674	1,076,082	1,247,808	18,302,996
Comm+Ind <3 MW	929,860	901,590	1,058,426	1,067,850	1,194,666	1,332,365	1,388,500	1,434,238	1,329,766	1,158,703	1,076,671	1,045,536	13,918,173
Comm+Ind >3 MW	305,395	301,073	301,330	308,613	315,466	337,803	349,892	354,869	359,297	340,844	326,662	318,863	3,920,108
Comm+Ind XHLF	1,318,912	1,196,948	1,308,279	1,247,155	1,293,685	1,265,085	1,339,604	1,354,206	1,307,667	1,348,047	1,323,609	1,355,624	15,658,821
Electric Vehicles	83,141	78,577	88,081	85,059	87,522	92,640	99,588	98,211	89,414	95,637	97,445	108,946	1,104,261
Irrigation	332	444	709	934	1,237	1,284	795	893	857	866	820	288	9,459
Streetlights	9,525	9,637	10,741	10,051	10,567	10,051	8,475	10,175	9,202	10,524	10,575	10,292	119,815
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/DE	3,899,882	3,534,832	3,706,637	3,759,866	4,211,645	5,017,438	5,800,648	5,683,340	5,103,827	4,316,295	3,911,865	4,087,357	53,033,632
Energy Efficiency Programs	(138,871)	(124,198)	(177,413)	(208,658)	(264,531)	(362,924)	(410,711)	(390,161)	(322,091)	(226,914)	(166,349)	(129,024)	(2,921,846)
Distributed Energy Programs	(180,985)	(198,931)	(282,634)	(313,581)	(345,886)	(338,105)	(298,545)	(299,539)	(266,854)	(245,773)	(177,436)	(160,678)	(3,108,946)
Total Sales	3,580,026	3,211,703	3,246,590	3,237,626	3,601,227	4,316,409	5,091,392	4,993,641	4,514,881	3,843,609	3,568,080	3,797,655	47,002,840
Energy Losses	256,266	208,831	324,108	262,047	336,950	337,636	237,702	313,960	188,779	206,812	172,791	212,736	3,058,617
Total Own Load Energy	3,836,292	3,420,534	3,570,698	3,499,673	3,938,177	4,654,045	5,329,094	5,307,601	4,703,660	4,050,421	3,740,871	4,010,391	50,061,457

	ENERGY DEMAND (MWH)												
YEAR: 2032	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	1,279,595	1,079,254	953,327	1,063,636	1,336,059	2,026,886	2,677,311	2,491,531	2,059,159	1,393,322	1,110,190	1,278,245	18,748,515
Comm+Ind <3 MW	943,162	931,046	1,063,687	1,085,063	1,210,684	1,354,505	1,411,191	1,460,820	1,355,957	1,177,071	1,102,966	1,063,089	14,159,241
Comm+Ind >3 MW	305,395	301,073	301,330	308,613	315,466	337,803	349,892	354,869	359,297	340,844	326,662	318,863	3,920,108
Comm+Ind XHLF	1,357,467	1,285,946	1,356,686	1,295,849	1,334,556	1,305,159	1,387,438	1,403,549	1,353,991	1,401,101	1,362,619	1,400,792	16,245,153
Electric Vehicles	102,736	96,974	108,574	104,721	107,605	113,766	122,137	120,299	109,370	116,861	118,918	132,799	1,354,761
Irrigation	331	450	704	935	1,236	1,287	791	894	857	863	824	286	9,458
Streetlights	9,577	9,836	10,716	10,145	10,648	10,160	8,528	10,269	9,276	10,586	10,709	10,349	120,799
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/DE	3,998,262	3,704,579	3,795,025	3,868,961	4,316,255	5,149,566	5,957,289	5,842,232	5,247,906	4,440,649	4,032,888	4,204,424	54,558,035
Energy Efficiency Programs	(156,153)	(145,096)	(200,287)	(235,229)	(297,904)	(406,788)	(458,899)	(434,157)	(356,232)	(252,140)	(184,882)	(140,646)	(3,268,412)
Distributed Energy Programs	(193,394)	(221,031)	(302,012)	(335,083)	(369,602)	(361,287)	(319,015)	(320,076)	(285,152)	(262,625)	(189,601)	(171,695)	(3,330,574)
Total Sales	3,648,715	3,338,452	3,292,725	3,298,649	3,648,749	4,381,491	5,179,375	5,087,999	4,606,522	3,925,884	3,658,405	3,892,083	47,959,049
Energy Losses	262,344	228,064	325,563	271,077	348,187	349,190	235,167	318,275	185,606	206,232	174,531	212,204	3,116,440
Total Own Load Energy	3,911,059	3,566,516	3,618,288	3,569,726	3,996,936	4,730,681	5,414,542	5,406,274	4,792,128	4,132,116	3,832,936	4,104,287	51,075,489

ATTACHMENT C.1(B): ENERGY CONSUMPTION BY MONTH AND CUSTOMER CLASS (CONTINUED)

ENERGY DEMAND (MWH)													
YEAR: 2033	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	1,307,598	1,096,629	982,881	1,085,864	1,366,840	2,073,211	2,739,493	2,551,189	2,109,497	1,429,312	1,139,231	1,309,488	19,191,232
Comm+Ind <3 MW	957,197	932,698	1,096,114	1,100,028	1,231,456	1,373,796	1,433,033	1,486,115	1,381,015	1,200,214	1,123,835	1,081,692	14,397,193
Comm+Ind >3 MW	305,395	301,073	301,330	308,613	315,466	337,803	349,892	354,869	359,297	340,844	326,662	318,863	3,920,108
Comm+Ind XHLF	1,405,407	1,283,705	1,402,311	1,343,437	1,379,903	1,349,452	1,435,210	1,450,774	1,400,248	1,458,794	1,409,289	1,453,624	16,772,154
Electric Vehicles	124,971	117,781	131,677	126,813	130,092	137,343	147,213	144,781	131,410	140,228	142,478	158,888	1,633,673
Irrigation	332	444	711	933	1,238	1,287	790	894	857	863	825	286	9,460
Streetlights	9,644	9,768	10,939	10,216	10,759	10,246	8,583	10,359	9,348	10,673	10,799	10,424	121,758
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/DE	4,110,543	3,742,098	3,925,962	3,975,903	4,435,755	5,283,138	6,114,215	5,998,980	5,391,672	4,580,929	4,153,118	4,333,266	56,045,578
Energy Efficiency Programs	(173,652)	(155,137)	(220,598)	(258,728)	(326,875)	(446,962)	(506,497)	(481,208)	(397,847)	(281,376)	(207,073)	(160,921)	(3,616,873)
Distributed Energy Programs	(204,886)	(225,202)	(319,960)	(354,995)	(391,565)	(382,758)	(337,972)	(339,098)	(302,097)	(278,231)	(200,869)	(181,898)	(3,519,530)
Total Sales	3,732,005	3,361,759	3,385,404	3,362,180	3,717,314	4,453,418	5,269,747	5,178,675	4,691,728	4,021,322	3,745,176	3,990,447	48,909,175
Energy Losses	272,051	218,684	349,103	278,764	361,114	360,661	236,100	324,664	184,591	206,151	174,531	215,372	3,181,786
Total Own Load Energy	4,004,056	3,580,443	3,734,507	3,640,944	4,078,428	4,814,079	5,505,847	5,503,339	4,876,319	4,227,473	3,919,707	4,205,819	52,090,961

ENERGY DEMAND (MWH)													
YEAR: 2034	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	1,337,183	1,121,038	1,003,204	1,107,628	1,397,134	2,119,192	2,802,490	2,608,610	2,157,702	1,466,036	1,167,812	1,338,910	19,626,938
Comm+Ind <3 MW	974,268	948,291	1,112,866	1,114,896	1,252,082	1,393,672	1,456,752	1,510,760	1,405,398	1,224,396	1,144,905	1,098,914	14,637,198
Comm+Ind >3 MW	305,395	301,073	301,330	308,613	315,466	337,803	349,892	354,869	359,297	340,844	326,662	318,863	3,920,108
Comm+Ind XHLF	1,455,436	1,324,788	1,445,597	1,383,789	1,419,590	1,386,564	1,473,236	1,487,465	1,433,915	1,476,755	1,442,422	1,495,433	17,224,989
Electric Vehicles	149,363	140,594	156,992	151,005	154,693	163,118	174,601	171,496	155,436	165,681	168,118	187,255	1,938,351
Irrigation	331	444	711	932	1,240	1,287	789	894	856	865	824	285	9,458
Streetlights	9,704	9,830	11,009	10,280	10,861	10,329	8,639	10,431	9,407	10,763	10,881	10,476	122,610
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/DE	4,231,680	3,846,058	4,031,710	4,077,142	4,551,066	5,411,964	6,266,399	6,144,524	5,522,011	4,685,339	4,261,622	4,450,135	57,479,651
Energy Efficiency Programs	(191,369)	(170,903)	(242,600)	(284,161)	(358,346)	(489,669)	(554,957)	(527,189)	(435,979)	(308,787)	(227,518)	(176,990)	(3,968,468)
Distributed Energy Programs	(215,569)	(236,943)	(336,640)	(373,502)	(411,980)	(402,713)	(355,592)	(356,777)	(317,847)	(292,736)	(211,341)	(191,381)	(3,703,021)
Total Sales	3,824,742	3,438,212	3,452,469	3,419,480	3,780,739	4,519,583	5,355,851	5,260,559	4,768,185	4,083,816	3,822,763	4,081,764	49,808,163
Energy Losses	277,739	223,905	359,816	286,071	373,941	372,020	236,423	328,706	181,935	205,039	173,928	216,084	3,235,607
Total Own Load Energy	4,102,481	3,662,117	3,812,285	3,705,551	4,154,680	4,891,603	5,592,274	5,589,265	4,950,120	4,288,855	3,996,691	4,297,848	53,043,770

ATTACHMENT C.1(B): ENERGY CONSUMPTION BY MONTH AND CUSTOMER CLASS (CONTINUED)

	ENERGY DEMAND (MWH)												
YEAR: 2035	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	1,367,307	1,145,519	1,022,296	1,132,167	1,426,188	2,162,472	2,868,336	2,666,249	2,205,711	1,502,567	1,196,694	1,370,116	20,065,622
Comm+Ind <3 MW	992,010	964,007	1,127,639	1,134,351	1,270,604	1,410,747	1,483,511	1,535,629	1,429,680	1,248,443	1,166,372	1,118,320	14,881,311
Comm+Ind >3 MW	305,395	301,073	301,330	308,613	315,466	337,803	349,892	354,869	359,297	340,844	326,662	318,863	3,920,108
Comm+Ind XHLF	1,490,957	1,354,377	1,469,146	1,406,015	1,449,538	1,415,044	1,502,389	1,517,023	1,457,542	1,505,119	1,469,326	1,508,868	17,545,342
Electric Vehicles	175,713	165,190	184,235	176,987	181,063	190,692	203,844	199,964	180,989	192,702	195,285	217,257	2,263,921
Irrigation	332	445	709	934	1,241	1,284	790	894	855	866	825	284	9,459
Streetlights	9,781	9,888	11,060	10,379	10,940	10,389	8,714	10,504	9,462	10,847	10,963	10,541	123,468
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/DE	4,341,494	3,940,499	4,116,413	4,169,445	4,655,041	5,528,431	6,417,476	6,285,132	5,643,535	4,801,388	4,366,126	4,544,249	58,809,231
Energy Efficiency Programs	(209,255)	(186,801)	(264,835)	(309,686)	(389,987)	(532,731)	(603,591)	(573,422)	(474,366)	(336,367)	(248,124)	(193,347)	(4,322,512)
Distributed Energy Programs	(226,173)	(248,597)	(353,199)	(391,875)	(432,245)	(422,521)	(373,084)	(374,326)	(333,481)	(307,137)	(221,736)	(200,795)	(3,885,169)
Total Sales	3,906,066	3,505,101	3,498,380	3,467,884	3,832,809	4,573,179	5,440,802	5,337,385	4,835,688	4,157,884	3,896,266	4,150,107	50,601,550
Energy Losses	286,268	228,631	367,969	294,739	384,901	380,962	238,530	332,553	178,875	204,489	173,112	215,665	3,286,695
Total Own Load Energy	4,192,334	3,733,732	3,866,349	3,762,623	4,217,710	4,954,141	5,679,332	5,669,938	5,014,563	4,362,373	4,069,378	4,365,772	53,888,245

	ENERGY DEMAND (MWH)												
YEAR: 2036	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	1,395,572	1,179,527	1,032,139	1,156,492	1,453,798	2,207,263	2,934,586	2,721,877	2,257,626	1,537,684	1,220,639	1,407,117	20,504,319
Comm+Ind <3 MW	1,007,336	996,287	1,126,061	1,153,426	1,286,900	1,430,132	1,511,019	1,559,357	1,457,383	1,271,365	1,182,121	1,144,965	15,126,352
Comm+Ind >3 MW	305,395	301,073	301,330	308,613	315,466	337,803	349,892	354,869	359,297	340,844	326,662	318,863	3,920,108
Comm+Ind XHLF	1,522,380	1,430,238	1,505,733	1,433,705	1,485,465	1,450,942	1,534,638	1,549,589	1,494,514	1,538,917	1,509,315	1,543,987	17,999,423
Electric Vehicles	203,539	191,127	212,920	204,307	208,749	219,602	234,460	229,728	207,666	220,873	223,570	248,452	2,604,994
Irrigation	332	451	703	934	1,240	1,285	791	892	856	866	823	287	9,460
Streetlights	9,837	10,102	10,953	10,474	11,003	10,461	8,787	10,561	9,533	10,924	11,000	10,647	124,282
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/DE	4,444,391	4,108,806	4,189,839	4,267,952	4,762,622	5,657,488	6,574,173	6,426,872	5,786,875	4,921,473	4,474,130	4,674,317	60,288,938
Energy Efficiency Programs	(227,312)	(210,746)	(289,034)	(337,489)	(424,869)	(578,729)	(652,821)	(618,390)	(507,952)	(361,492)	(266,531)	(203,669)	(4,679,034)
Distributed Energy Programs	(236,076)	(269,813)	(368,666)	(409,035)	(451,172)	(441,023)	(389,421)	(390,716)	(348,084)	(320,585)	(231,445)	(209,587)	(4,065,623)
Total Sales	3,981,003	3,628,246	3,532,140	3,521,428	3,886,580	4,637,736	5,531,932	5,417,766	4,930,839	4,239,396	3,976,153	4,261,062	51,544,281
Energy Losses	293,690	251,320	361,969	303,864	395,541	391,579	239,667	334,629	177,674	205,101	171,396	217,046	3,343,476
Total Own Load Energy	4,274,693	3,879,566	3,894,109	3,825,292	4,282,121	5,029,315	5,771,599	5,752,395	5,108,513	4,444,497	4,147,549	4,478,108	54,887,757

ATTACHMENT C.1(B): ENERGY CONSUMPTION BY MONTH AND CUSTOMER CLASS (CONTINUED)

	ENERGY DEMAND (MWH)												
YEAR: 2037	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	1,419,064	1,194,771	1,063,830	1,179,514	1,481,455	2,254,440	2,996,616	2,778,231	2,306,127	1,571,356	1,251,851	1,437,442	20,934,696
Comm+Ind <3 MW	1,018,033	995,603	1,162,079	1,170,631	1,303,677	1,452,180	1,533,546	1,582,982	1,481,660	1,292,960	1,206,067	1,163,402	15,362,822
Comm+Ind >3 MW	305,395	301,073	301,330	308,613	315,466	337,803	349,892	354,869	359,297	340,844	326,662	318,863	3,920,108
Comm+Ind XHLF	1,544,284	1,411,047	1,540,783	1,467,387	1,525,828	1,478,493	1,570,528	1,586,911	1,529,648	1,582,483	1,541,455	1,580,669	18,359,515
Electric Vehicles	232,438	218,029	242,634	232,569	237,355	249,434	266,013	260,365	235,097	249,802	252,585	280,414	2,956,734
Irrigation	331	444	710	935	1,239	1,286	790	892	856	865	824	287	9,459
Streetlights	9,872	10,000	11,186	10,545	11,060	10,551	8,835	10,626	9,589	10,980	11,093	10,707	125,044
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/DE	4,529,416	4,130,968	4,322,552	4,370,193	4,876,081	5,784,186	6,726,220	6,574,875	5,922,274	5,049,290	4,590,538	4,791,785	61,668,378
Energy Efficiency Programs	(245,505)	(218,742)	(309,275)	(360,869)	(453,747)	(618,571)	(701,117)	(667,593)	(552,143)	(392,471)	(290,226)	(226,863)	(5,037,123)
Distributed Energy Programs	(247,054)	(271,550)	(385,808)	(428,054)	(472,153)	(461,531)	(407,529)	(408,885)	(364,269)	(335,493)	(242,208)	(219,333)	(4,243,869)
Total Sales	4,036,857	3,640,676	3,627,468	3,581,270	3,950,180	4,704,084	5,617,574	5,498,397	5,005,861	4,321,326	4,058,104	4,345,588	52,387,386
Energy Losses	304,073	238,314	387,383	312,370	405,272	403,983	242,470	340,638	176,865	202,829	171,865	219,821	3,405,882
Total Own Load Energy	4,340,930	3,878,990	4,014,851	3,893,640	4,355,452	5,108,067	5,860,044	5,839,035	5,182,726	4,524,155	4,229,969	4,565,409	55,793,268

	ENERGY DEMAND (MWH)												
YEAR: 2038	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	1,446,265	1,219,042	1,086,433	1,202,510	1,510,399	2,299,548	3,056,870	2,837,125	2,355,281	1,604,013	1,282,911	1,466,262	21,366,659
Comm+Ind <3 MW	1,032,627	1,010,888	1,181,857	1,187,808	1,322,499	1,471,529	1,555,506	1,609,018	1,506,835	1,313,668	1,230,029	1,180,526	15,602,792
Comm+Ind >3 MW	305,395	301,073	301,330	308,613	315,466	337,803	349,892	354,869	359,297	340,844	326,662	318,863	3,920,108
Comm+Ind XHLF	1,579,951	1,444,164	1,575,223	1,502,484	1,545,208	1,509,076	1,601,998	1,618,374	1,558,981	1,611,801	1,566,156	1,608,623	18,722,038
Electric Vehicles	262,009	245,510	272,936	261,342	266,433	279,708	297,987	291,363	262,813	278,987	281,815	312,567	3,313,469
Irrigation	330	445	710	936	1,239	1,286	789	892	856	863	827	285	9,458
Streetlights	9,903	10,048	11,267	10,615	11,133	10,615	8,873	10,695	9,643	11,031	11,182	10,744	125,749
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/DE	4,636,480	4,231,169	4,429,756	4,474,307	4,972,377	5,909,565	6,871,915	6,722,337	6,053,706	5,161,207	4,699,583	4,897,869	63,060,273
Energy Efficiency Programs	(263,855)	(235,019)	(331,923)	(386,732)	(485,978)	(662,064)	(750,626)	(714,841)	(591,192)	(420,653)	(311,432)	(243,719)	(5,398,035)
Distributed Energy Programs	(257,287)	(282,796)	(401,788)	(445,784)	(491,708)	(480,648)	(424,408)	(425,821)	(379,357)	(349,389)	(252,240)	(228,417)	(4,419,642)
Total Sales	4,115,338	3,713,354	3,696,046	3,641,791	3,994,691	4,766,853	5,696,882	5,581,675	5,083,158	4,391,165	4,135,911	4,425,733	53,242,596
Energy Losses	307,521	243,479	397,987	320,985	415,874	414,897	242,343	345,865	175,236	200,643	172,315	219,688	3,456,834
Total Own Load Energy	4,422,859	3,956,833	4,094,033	3,962,776	4,410,565	5,181,750	5,939,225	5,927,540	5,258,394	4,591,808	4,308,226	4,645,421	56,699,430

ATTACHMENT C.2: COINCIDENT PEAK DEMAND DISAGGREGATED BY DSM

PEAK DEMAND (MW)													
YEAR: 2023	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak (BAU+EV+DATA)	4,500	4,398	4,102	5,031	5,932	7,374	8,170	8,184	7,173	5,487	4,212	4,243	8,184
Energy Efficiency Programs	(26)	(22)	(27)	(73)	(106)	(147)	(152)	(147)	(120)	(83)	(45)	(40)	(147)
Own Load Peak After EE Before DE	4,474	4,375	4,075	4,957	5,825	7,227	8,018	8,037	7,054	5,404	4,166	4,203	8,037
Distributed Energy Programs	0	(2)	0	(16)	(68)	(43)	(45)	(59)	(42)	(52)	(1)	0	(59)
Own Load Peak - After DE/EE	4,474	4,373	4,075	4,941	5,758	7,184	7,973	7,978	7,012	5,352	4,165	4,203	7,978

PEAK DEMAND (MW)													
YEAR: 2024	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak (BAU+EV+DATA)	4,766	4,691	4,436	5,411	6,305	7,750	8,562	8,594	7,538	5,878	4,605	4,528	8,562
Energy Efficiency Programs	(48)	(42)	(46)	(144)	(173)	(257)	(270)	(240)	(213)	(154)	(84)	(69)	(270)
Own Load Peak After EE Before DE	4,717	4,649	4,390	5,267	6,132	7,493	8,292	8,353	7,324	5,724	4,520	4,460	8,292
Distributed Energy Programs	0	(5)	(57)	(56)	(126)	(131)	(45)	(122)	(83)	(91)	0	0	(45)
Own Load Peak - After DE/EE	4,717	4,645	4,333	5,211	6,006	7,362	8,247	8,232	7,242	5,634	4,520	4,460	8,247

PEAK DEMAND (MW)													
YEAR: 2025	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak (BAU+EV+DATA)	5,064	5,099	4,742	5,749	6,669	8,169	8,959	9,012	7,909	6,269	4,970	4,915	9,012
Energy Efficiency Programs	(65)	(59)	(121)	(202)	(302)	(377)	(331)	(346)	(365)	(214)	(128)	(100)	(346)
Own Load Peak After EE Before DE	4,999	5,041	4,621	5,548	6,367	7,792	8,627	8,666	7,544	6,055	4,842	4,815	8,666
Distributed Energy Programs	(4)	(45)	0	(138)	(199)	(196)	(154)	(183)	(113)	(126)	0	0	(183)
Own Load Peak - After DE/EE	4,995	4,996	4,621	5,410	6,167	7,597	8,474	8,483	7,431	5,930	4,842	4,815	8,483

PEAK DEMAND (MW)													
YEAR: 2026	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak (BAU+EV+DATA)	5,418	5,501	5,147	6,156	7,116	8,677	9,454	9,525	8,487	6,735	5,444	5,335	9,525
Energy Efficiency Programs	(88)	(78)	(157)	(287)	(390)	(481)	(425)	(500)	(472)	(266)	(169)	(120)	(500)
Own Load Peak After EE Before DE	5,330	5,423	4,990	5,870	6,726	8,196	9,029	9,025	8,015	6,469	5,275	5,215	9,025
Distributed Energy Programs	(1)	(69)	0	(112)	(161)	(260)	(536)	(229)	(150)	(63)	0	0	(229)
Own Load Peak - After DE/EE	5,329	5,354	4,990	5,758	6,565	7,937	8,493	8,796	7,866	6,406	5,275	5,215	8,796

ATTACHMENT C.2: COINCIDENT PEAK DEMAND DISAGGREGATED BY DSM (CONTINUED)

PEAK DEMAND (MW)													
YEAR: 2027	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak (BAU+EV+DATA)	5,894	6,002	5,631	6,625	7,600	9,199	9,942	10,020	8,971	7,186	5,857	5,663	10,020
Energy Efficiency Programs	(111)	(107)	(201)	(349)	(479)	(629)	(523)	(615)	(564)	(391)	(224)	(131)	(615)
Own Load Peak After EE Before DE	5,783	5,895	5,430	6,276	7,121	8,570	9,419	9,405	8,406	6,795	5,633	5,532	9,405
Distributed Energy Programs	(6)	(38)	0	(0)	(113)	(207)	(545)	(248)	(175)	(71)	(5)	0	(248)
Own Load Peak - After DE/EE	5,777	5,857	5,430	6,276	7,008	8,363	8,874	9,157	8,231	6,724	5,628	5,532	9,157

PEAK DEMAND (MW)													
YEAR: 2028	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak (BAU+EV+DATA)	6,328	6,283	5,923	6,998	7,999	9,623	10,359	10,427	9,391	7,552	6,208	6,139	10,427
Energy Efficiency Programs	(146)	(127)	(172)	(371)	(574)	(713)	(772)	(738)	(632)	(469)	(267)	(199)	(738)
Own Load Peak After EE Before DE	6,182	6,155	5,751	6,627	7,425	8,910	9,587	9,689	8,758	7,083	5,942	5,941	9,689
Distributed Energy Programs	0	(13)	0	0	(76)	(175)	(254)	(215)	(79)	(105)	(6)	0	(215)
Own Load Peak - After DE/EE	6,182	6,142	5,751	6,627	7,349	8,734	9,333	9,475	8,679	6,978	5,936	5,941	9,475

PEAK DEMAND (MW)													
YEAR: 2029	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak (BAU+EV+DATA)	6,673	6,708	6,359	7,310	8,355	10,005	10,731	10,805	9,756	7,886	6,511	6,446	10,805
Energy Efficiency Programs	(172)	(151)	(184)	(416)	(653)	(867)	(901)	(864)	(746)	(541)	(314)	(224)	(864)
Own Load Peak After EE Before DE	6,500	6,557	6,175	6,893	7,701	9,138	9,830	9,941	9,010	7,345	6,197	6,222	9,941
Distributed Energy Programs	0	(15)	(6)	0	(52)	(141)	(213)	(245)	(34)	(107)	(7)	0	(245)
Own Load Peak - After DE/EE	6,500	6,543	6,169	6,893	7,650	8,998	9,617	9,695	8,975	7,238	6,191	6,222	9,695

ATTACHMENT C.2: COINCIDENT PEAK DEMAND DISAGGREGATED BY DSM (CONTINUED)

PEAK DEMAND (MW)													
YEAR: 2030	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak (BAU+EV+DATA)	6,961	6,962	6,610	7,599	8,663	10,339	11,049	11,127	10,083	8,163	6,774	6,705	11,127
Energy Efficiency Programs	(201)	(164)	(188)	(509)	(681)	(1,003)	(1,002)	(925)	(839)	(619)	(351)	(252)	(925)
Own Load Peak After EE Before DE	6,759	6,798	6,421	7,090	7,982	9,336	10,047	10,202	9,244	7,543	6,422	6,452	10,202
Distributed Energy Programs	0	(97)	(101)	0	(60)	0	(114)	(245)	0	(106)	0	0	(245)
Own Load Peak - After DE/EE	6,759	6,701	6,321	7,090	7,922	9,336	9,934	9,958	9,244	7,437	6,422	6,452	9,958

PEAK DEMAND (MW)													
YEAR: 2031	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak (BAU+EV+DATA)	7,103	7,185	6,824	7,854	8,923	10,648	11,312	11,398	10,307	8,406	6,974	6,914	11,398
Energy Efficiency Programs	(210)	(188)	(382)	(585)	(858)	(1,056)	(934)	(1,033)	(981)	(628)	(397)	(278)	(1,033)
Own Load Peak After EE Before DE	6,893	6,998	6,442	7,268	8,065	9,592	10,378	10,365	9,326	7,778	6,577	6,635	10,365
Distributed Energy Programs	(9)	(113)	0	(7)	0	0	(354)	(186)	(125)	(165)	0	0	(186)
Own Load Peak - After DE/EE	6,884	6,885	6,442	7,262	8,065	9,592	10,024	10,179	9,201	7,613	6,577	6,635	10,179

PEAK DEMAND (MW)													
YEAR: 2032	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak (BAU+EV+DATA)	7,237	7,252	6,980	8,053	9,139	10,921	11,552	11,646	10,612	8,598	7,149	6,988	11,646
Energy Efficiency Programs	(236)	(210)	(408)	(556)	(862)	(1,207)	(1,029)	(1,256)	(1,087)	(665)	(451)	(237)	(1,256)
Own Load Peak After EE Before DE	7,001	7,042	6,571	7,497	8,277	9,714	10,524	10,391	9,524	7,933	6,698	6,751	10,391
Distributed Energy Programs	(2)	(59)	0	0	0	(30)	(491)	(17)	(108)	0	0	0	(17)
Own Load Peak - After DE/EE	6,999	6,983	6,571	7,497	8,277	9,684	10,033	10,374	9,416	7,933	6,698	6,751	10,374

ATTACHMENT C.2: COINCIDENT PEAK DEMAND DISAGGREGATED BY DSM (CONTINUED)

PEAK DEMAND (MW)													
YEAR: 2033	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak (BAU+EV+DATA)	7,540	7,587	7,256	8,294	9,375	11,196	11,830	11,903	10,897	8,902	7,363	7,259	11,903
Energy Efficiency Programs	(266)	(250)	(458)	(609)	(896)	(1,323)	(1,274)	(1,340)	(1,059)	(872)	(514)	(333)	(1,340)
Own Load Peak After EE Before DE	7,274	7,337	6,798	7,685	8,479	9,873	10,556	10,563	9,838	8,031	6,849	6,926	10,563
Distributed Energy Programs	(18)	(19)	(0)	0	0	0	(147)	0	0	(76)	(9)	0	0
Own Load Peak - After DE/EE	7,256	7,318	6,798	7,685	8,479	9,873	10,409	10,563	9,838	7,955	6,840	6,926	10,563

PEAK DEMAND (MW)													
YEAR: 2034	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak (BAU+EV+DATA)	7,730	7,770	7,461	8,481	9,614	11,465	12,076	12,146	11,140	9,028	7,547	7,551	12,146
Energy Efficiency Programs	(313)	(275)	(427)	(624)	(968)	(1,374)	(1,424)	(1,409)	(1,091)	(934)	(562)	(406)	(1,409)
Own Load Peak After EE Before DE	7,417	7,495	7,034	7,857	8,646	10,092	10,652	10,737	10,050	8,094	6,985	7,145	10,737
Distributed Energy Programs	0	(21)	(33)	0	0	0	(76)	0	0	(72)	(9)	0	0
Own Load Peak - After DE/EE	7,417	7,474	7,001	7,857	8,646	10,092	10,576	10,737	10,050	8,022	6,976	7,145	10,737

PEAK DEMAND (MW)													
YEAR: 2035	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak (BAU+EV+DATA)	7,911	7,936	7,523	8,660	9,832	11,708	12,312	12,386	11,371	9,233	7,726	7,735	12,386
Energy Efficiency Programs	(342)	(301)	(361)	(654)	(1,026)	(1,482)	(1,579)	(1,571)	(1,151)	(1,005)	(610)	(357)	(1,571)
Own Load Peak After EE Before DE	7,569	7,636	7,163	8,006	8,805	10,227	10,733	10,815	10,220	8,229	7,116	7,378	10,815
Distributed Energy Programs	0	(22)	(40)	0	0	0	0	0	0	(67)	(10)	0	0
Own Load Peak - After DE/EE	7,569	7,614	7,123	8,006	8,805	10,227	10,733	10,815	10,220	8,162	7,106	7,378	10,815

ATTACHMENT C.2: COINCIDENT PEAK DEMAND DISAGGREGATED BY DSM (CONTINUED)

PEAK DEMAND (MW)													
YEAR: 2036	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak (BAU+EV+DATA)	8,078	7,954	7,765	8,876	10,060	11,981	12,533	12,634	11,575	9,461	7,928	7,948	12,634
Energy Efficiency Programs	(373)	(305)	(596)	(787)	(1,112)	(1,395)	(1,391)	(1,597)	(1,464)	(1,025)	(643)	(375)	(1,597)
Own Load Peak After EE Before DE	7,705	7,648	7,169	8,089	8,948	10,586	11,142	11,037	10,111	8,436	7,285	7,573	11,037
Distributed Energy Programs	0	(100)	0	0	0	0	(240)	0	0	(165)	0	0	0
Own Load Peak - After DE/EE	7,705	7,549	7,169	8,089	8,948	10,586	10,901	11,037	10,111	8,270	7,285	7,573	11,037

PEAK DEMAND (MW)													
YEAR: 2037	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak (BAU+EV+DATA)	8,089	8,238	8,053	9,058	10,285	12,249	12,777	12,877	11,890	9,727	8,103	8,116	12,877
Energy Efficiency Programs	(372)	(330)	(648)	(871)	(1,152)	(1,586)	(1,522)	(1,654)	(1,556)	(1,049)	(641)	(385)	(1,654)
Own Load Peak After EE Before DE	7,716	7,908	7,405	8,187	9,133	10,663	11,254	11,223	10,334	8,678	7,462	7,731	11,223
Distributed Energy Programs	(2)	(128)	0	0	0	0	(393)	0	0	(73)	0	0	0
Own Load Peak - After DE/EE	7,714	7,780	7,405	8,187	9,133	10,663	10,861	11,223	10,334	8,605	7,462	7,731	11,223

PEAK DEMAND (MW)													
YEAR: 2038	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak (BAU+EV+DATA)	8,278	8,432	8,275	9,280	10,493	12,513	13,007	13,119	12,141	9,847	8,280	8,241	13,119
Energy Efficiency Programs	(398)	(381)	(640)	(813)	(1,186)	(1,708)	(1,597)	(1,697)	(1,658)	(1,009)	(706)	(381)	(1,697)
Own Load Peak After EE Before DE	7,880	8,052	7,635	8,467	9,307	10,805	11,409	11,423	10,483	8,838	7,574	7,861	11,423
Distributed Energy Programs	(13)	(84)	0	0	0	0	(409)	0	0	0	0	0	0
Own Load Peak - After DE/EE	7,866	7,968	7,635	8,467	9,307	10,805	11,001	11,423	10,483	8,838	7,574	7,861	11,423

ATTACHMENT D.1(A)(1): POWER SUPPLY

POWER SUPPLY - ESTIMATES FOR 2023-2038																
	B.1(a)		B.1(b)	B.1(c)	B.1(d)				B.1(f)(a)			B.1(h)	B.1(l)	B.1(m)	B.1(n)	B.1(o)
Plant/ Unit/ Contract	In Service Year	Book Life/ Period	Type	Owned Capacity (MW)	Max Capacity (MW)	Winter Capacity (MW) [13]	Summer Capacity (MW) [13]	50% Load Heat Rate (Btu/kWh)	75% Load Heat Rate (Btu/kWh)	100% Load Heat Rate (Btu/kWh)	Variable O&M Cost ($/MWh) [1,12]	Fuel	Min Cap (MW)	Must Run?	Baseload Intermediate Peaking [11]
Palo Verde															
Unit 1	1986	2047	Steam	382	1,311	382	382					Uranium	382	Must Run	Baseload
Unit 2	1986	2047	Steam	382	1,314	382	382					Uranium	382	Must Run	Baseload
Unit 3	1988	2047	Steam	382	1,312	382	382					Uranium	382	Must Run	Baseload
Four Corners															
Unit 4	1969	2038	Steam	485	770	473	485					Coal	276	No	Baseload
Unit 5	1970	2038	Steam	485	770	473	485					Coal	276	No	Baseload
Cholla															
Unit 1	1962	2025	Steam	116	112	112	112					Coal	30	No	Baseload
Unit 3	1980	2025	Steam	271	265	265	265					Coal	75	No	Baseload
Ocotillo															
Unit 1 CT	1972	2030	Combustion Turbine	55	56	56	50					Gas	3	No	Peaking
Unit 2 CT	1973	2030	Combustion Turbine	55	56	56	49					Gas	3	No	Peaking
Unit 3 CT	2019	2049	Combustion Turbine	104	107	107	105					Gas	53	No	Peaking
Unit 4 CT	2019	2049	Combustion Turbine	104	100	96	100					Gas	48	No	Peaking
Unit 5 CT	2019	2049	Combustion Turbine	104	105	105	103					Gas	51	No	Peaking
Unit 6 CT	2019	2049	Combustion Turbine	104	96	96	95					Gas	47	No	Peaking
Unit 7 CT	2019	2049	Combustion Turbine	104	105	105	104					Gas	52	No	Peaking
Saguaro															
Unit 1 CT	1972	2030	Combustion Turbine	55	56	56	50					Gas	3	No	Peaking
Unit 2 CT	1973	2030	Combustion Turbine	55	56	56	49					Gas	3	No	Peaking
Unit 3 CT	2002	2037	Combustion Turbine	79	79	79	71					Gas	38	No	Peaking
West Phoenix															
Unit 1 CC	1976	2030	Combined Cycle	88	85	85	85					Gas	18	No	Intermediate
Unit 2 CC	1976	2030	Combined Cycle	88	85	85	85					Gas	18	No	Intermediate
Unit 3 CC	1976	2030	Combined Cycle	88	85	85	85					Gas	46	No	Intermediate
Unit 4 CC	2001	2036	Combined Cycle	117	112	108	102					Gas	65	No	Intermediate
Unit 5 CC	2003	2038	Combined Cycle	516	504	504	445					Gas	242	No	Intermediate
Unit 1 CT	1972	2030	Combustion Turbine	55	55	50	45					Gas	3	No	Peaking
Unit 2 CT	1973	2030	Combustion Turbine	55	55	50	50					Gas	3	No	Peaking

ATTACHMENT D.1(A)(1): POWER SUPPLY (CONTINUED)

POWER SUPPLY - ESTIMATES FOR 2023-2038															
	B.1(a)		B.1(b)	B.1(c)	B.1(d)			B.1(f)(a)			B.1(h)	B.1(l)	B.1(m)	B.1(n)	B.1(o)
Plant/ Unit/ Contract	In Service Year	Book Life/ Period	Type	Owned Capacity (MW)	Max Capacity (MW)	Winter Capacity (MW) [13]	Summer Capacity (MW) [13]	50% Load Heat Rate (Btu/kWh)	75% Load Heat Rate (Btu/kWh)	100% Load Heat Rate (Btu/kWh)	Variable O&M Cost ($/MWh) [1,12]	Fuel	Min Cap (MW)	Must Run?	Baseload Intermediate Peaking [11]
Redhawk															
Unit 1 CC	2002	2037	Combined Cycle	538	574	574	521	[redacted]				Gas	256	No	Intermediate
Unit 2 CC	2002	2037	Combined Cycle	538	574	574	521	[redacted]				Gas	256	No	Intermediate
Sundance															
Unit 1 CT	2002	2037	Combustion Turbine	42	43	43	40	[redacted]				Gas	18	No	Peaking
Unit 2 CT	2002	2037	Combustion Turbine	42	43	43	40	[redacted]				Gas	18	No	Peaking
Unit 3 CT	2002	2037	Combustion Turbine	42	43	43	40	[redacted]				Gas	18	No	Peaking
Unit 4 CT	2002	2037	Combustion Turbine	42	43	43	40	[redacted]				Gas	18	No	Peaking
Unit 5 CT	2002	2037	Combustion Turbine	42	43	43	40	[redacted]				Gas	18	No	Peaking
Unit 6 CT	2002	2037	Combustion Turbine	42	43	43	40	[redacted]				Gas	18	No	Peaking
Unit 7 CT	2002	2037	Combustion Turbine	42	43	43	40	[redacted]				Gas	18	No	Peaking
Unit 8 CT	2002	2037	Combustion Turbine	42	43	43	40	[redacted]				Gas	18	No	Peaking
Unit 9 CT	2002	2037	Combustion Turbine	42	43	43	40	[redacted]				Gas	18	No	Peaking
Unit 10 CT	2002	2037	Combustion Turbine	42	43	43	40	[redacted]				Gas	18	No	Peaking
Yucca															
Unit 1 CT	1971	2030	Combustion Turbine	19	19	19	17	[redacted]				Gas	2	No	Peaking
Unit 2 CT	1971	2030	Combustion Turbine	19	19	19	16	[redacted]				Gas	1	No	Peaking
Unit 3 CT	1973	2030	Combustion Turbine	55	55	55	51	[redacted]				Gas	4	No	Peaking
Unit 4 CT	1974	2030	Combustion Turbine	54	54	54	49	[redacted]				Oil	4	No	Peaking
Unit 5 CT	2008	2043	Combustion Turbine	48	45	45	45	[redacted]				Gas	18	No	Peaking
Unit 6 CT	2008	2043	Combustion Turbine	48	45	45	44	[redacted]				Gas	18	No	Peaking
Douglas															
Unit 1 CT	1972	2030	Combustion Turbine	16	18	18	16	[redacted]				Oil	2	No	Peaking
Microgrids															
Aligned	2016	2038	Diesel Gen Set	11	11	11	11	[redacted]				Oil	1	No	Peaking
MCASY	2016	2038	Diesel Gen Set	22	22	22	22	[redacted]				Oil	2	No	Peaking
Punkin Center	2021	2041	Diesel Gen Set	2	2	2	2	[redacted]				Oil	0.2	No	Peaking

ATTACHMENT D.1(A)(1): POWER SUPPLY (CONTINUED)

POWER SUPPLY - ESTIMATES FOR 2023-2038															
	B.1(a)		B.1(b)	B.1(c)	B.1(d)			B.1(f)(a)			B.1(h)	B.1(l)	B.1(m)	B.1(n)	B.1(o)
Plant/ Unit/ Contract	In Service Year	Book Life/ Period	Type	Owned Capacity (MW)	Max Capacity (MW)	Winter Capacity (MW) [13]	Summer Capacity (MW) [13]	50% Load Heat Rate (Btu/kWh)	75% Load Heat Rate (Btu/kWh)	100% Load Heat Rate (Btu/kWh)	Variable O&M Cost ($/MWh) [1,12]	Fuel	Min Cap (MW)	Must Run?	Baseload Intermediate Peaking [11]
Renewables															
APS Existing Solar[2]	1997-2006	2037	Renewable	4	4	0	2					Solar	N/A	No	Intermittent
Aragonne Mesa Wind, New Mexico	2006	2042	Renewable	193	200	44	44					Wind	N/A	Must Run	Intermittent
Salton Sea CE Turbo	2006	2029	Renewable	10	10	10	10					Geothermal	N/A	Must Run	Baseload
SWMP Biomass (Snowflake Abitibi)	2008	2023	Renewable	14	14	13	13					Biomass	N/A	Must Run	Baseload
High Lonesome Wind, New Mexico	2009	2039	Renewable	97	100	15	15					Wind	N/A	Must Run	Intermittent
Perrin Ranch Wind	2012	2036	Renewable	99	99	28	28					Wind	N/A	Must Run	Intermittent
Solana CSP	2013	2043	Renewable	250	250	215	215					Solar	N/A	Must Run	Intermittent
AZ Sun: Hyder II	2013	2043	Renewable	14	14	0	9					Solar	N/A	No	Intermittent
AZ Sun: Cotton Center	2011	2041	Renewable	17	17	0	8					Solar	N/A	No	Intermittent
AZ Sun: Hyder	2011	2041	Renewable	16	16	0	7					Solar	N/A	No	Intermittent
AZ Sun: Chino Valley	2012	2042	Renewable	19	19	0	6					Solar	N/A	No	Intermittent
AZ Sun: Paloma	2011	2041	Renewable	17	17	0	7					Solar	N/A	No	Intermittent
AZ Sun: Yuma Foothills	2013	2043	Renewable	35	35	0	21					Solar	N/A	No	Intermittent
AZ Sun: Gila Bend	2014	2044	Renewable	32	32	0	20					Solar	N/A	No	Intermittent
AZ Sun: Luke AFB	2015	2045	Renewable	10	10	0	7					Solar	N/A	No	Intermittent
AZ Sun: Desert Star	2015	2045	Renewable	10	10	0	6					Solar	N/A	No	Intermittent
Red Rock Solar	2016	2046	Renewable	40	40	0	24					Solar	N/A	No	Intermittent
Small Gen RFP (Ajo)	2011	2036	Renewable	5	5	0	2					Solar	N/A	Must Run	Intermittent
Small Gen RFP (Prescott)	2011	2041	Renewable	10	10	0	4					Solar	N/A	Must Run	Intermittent
Small Gen RFP (Saddle Mt Tonopah)	2012	2042	Renewable	15	15	0	6					Solar	N/A	Must Run	Intermittent
Small Gen RFP (WM Landfill)	2012	2032	Renewable	3	3	3	3					Biogas	N/A	Must Run	Baseload
Badger-Desert Sky	2013	2042	Renewable	15	15	0	7					Solar	N/A	Must Run	Intermittent
Recurrent Gillespie	2013	2042	Renewable	15	15	0	8					Solar	N/A	Must Run	Intermittent
Utility Scale DE															
Bagdad	2011	2036	Renewable	13	13	0	5					Solar	N/A	Must Run	Intermittent
Schools and Gov't & Other DE Programs	2012-2023	2038	Renewable	35	35	0	1					Solar	N/A	Must Run	Intermittent
Contracts															
[redacted]	1955	2025	Contract	45	45	45	45					N/A	N/A	Must Run	Baseload
AGX Load	2017	2038	Contract	145	145	129	129					N/A	N/A	Must Run	Baseload
DR Contract (on-peak) # 1	2010	2025	Contract	55	55	0	55					N/A	N/A	No	Peaking
DR Contract (on-peak) # 2	2010	2038	Contract	173	173	0	35					N/A	N/A	No	Peaking

ATTACHMENT D.1(A)(1): POWER SUPPLY (CONTINUED)

POWER SUPPLY - ESTIMATES FOR 2023-2038															
	B.1(a)		B.1(b)	B.1(c)	B.1(d)			B.1(f)(a)			B.1(h)	B.1(l)	B.1(m)	B.1(n)	B.1(o)
Plant/ Unit/ Contract	In Service Year	Book Life/ Period	Type	Owned Capacity (MW)	Max Capacity (MW)	Winter Capacity (MW) [13]	Summer Capacity (MW) [13]	50% Load Heat Rate (Btu/kWh)	75% Load Heat Rate (Btu/kWh)	100% Load Heat Rate (Btu/kWh)	Variable O&M Cost ($/MWh) [1,12]	Fuel	Min Cap (MW)	Must Run?	Baseload Intermediate Peaking [11]
Contracts (Continued)															
CC Tolling # 1 [3]	2020	2031	Tolling	565	565	0	565	[redacted]	[redacted]	[redacted]	[redacted]	Gas	315	No	Intermediate
CC Tolling # 2 [4]	2020	2034	Tolling	570	570	0	570	[redacted]	[redacted]	[redacted]	[redacted]	Gas	362	No	Intermediate
CC Tolling # 3 [5]	2021	2032	Tolling	463	463	0	463	[redacted]	[redacted]	[redacted]	[redacted]	Gas	333	No	Intermediate
Future Units															
Future CT 1	2026	2061	Combustion Turbine	42	42	42	41	[redacted]	[redacted]	[redacted]	[redacted]	Gas	19	No	Peaking
Future CT 2	2026	2061	Combustion Turbine	42	42	42	41	[redacted]	[redacted]	[redacted]	[redacted]	Gas	19	No	Peaking
Future CT 3	2029	2064	Combustion Turbine	42	42	42	41	[redacted]	[redacted]	[redacted]	[redacted]	Gas	19	No	Peaking
Future CT 4	2030	2065	Combustion Turbine	42	42	42	41	[redacted]	[redacted]	[redacted]	[redacted]	Gas	19	No	Peaking
Future CT 5	2030	2065	Combustion Turbine	42	42	42	41	[redacted]	[redacted]	[redacted]	[redacted]	Gas	19	No	Peaking
Future CT 6	2031	2066	Combustion Turbine	42	42	42	41	[redacted]	[redacted]	[redacted]	[redacted]	Gas	19	No	Peaking
Future CT 7	2037	2072	Combustion Turbine	42	42	42	41	[redacted]	[redacted]	[redacted]	[redacted]	Gas	19	No	Peaking
Future CT 8	2037	2072	Combustion Turbine	42	42	42	41	[redacted]	[redacted]	[redacted]	[redacted]	Gas	19	No	Peaking
Future CT 9	2031	2066	Combustion Turbine	222	222	222	216	[redacted]	[redacted]	[redacted]	[redacted]	Gas	96	No	Peaking
Future CT 10	2031	2066	Combustion Turbine	222	222	222	216	[redacted]	[redacted]	[redacted]	[redacted]	Gas	96	No	Peaking
Future CT 11	2031	2066	Combustion Turbine	222	222	222	216	[redacted]	[redacted]	[redacted]	[redacted]	Gas	96	No	Peaking
Future CT 12	2031	2066	Combustion Turbine	222	222	222	216	[redacted]	[redacted]	[redacted]	[redacted]	Gas	96	No	Peaking
Future CT 13	2036	2071	Combustion Turbine	222	222	222	216	[redacted]	[redacted]	[redacted]	[redacted]	Gas	96	No	Peaking
Future Microgrids															
Preacher	2023	2043	Diesel Gen Set	2	2	2	2	[redacted]	[redacted]	[redacted]	[redacted]	Oil	0.2	No	Peaking
City of Phx	2023	2043	Diesel Gen Set	6	6	6	6	[redacted]	[redacted]	[redacted]	[redacted]	Oil	1	No	Peaking
Forest Lakes	2024	2044	Diesel Gen Set	2	2	2	2	[redacted]	[redacted]	[redacted]	[redacted]	Oil	0.2	No	Peaking
TSMC	2024	2044	Diesel Gen Set	49	49	49	49	[redacted]	[redacted]	[redacted]	[redacted]	Oil	5	No	Peaking
Future Microgrid 1	2026	2056	Diesel Gen Set	500	500	500	500	[redacted]	[redacted]	[redacted]	[redacted]	Oil	50	No	Peaking
Future Microgrid 2	2031	2061	Diesel Gen Set	200	200	200	200	[redacted]	[redacted]	[redacted]	[redacted]	Oil	20	No	Peaking
Future Microgrid 3	2037	2067	Diesel Gen Set	25	25	25	25	[redacted]	[redacted]	[redacted]	[redacted]	Oil	3	No	Peaking
Future Energy Storage Systems PPA															
Westwing I	2023-2024	2043	Battery ESS	80	80	55	55	[redacted]	[redacted]	[redacted]	[redacted]	N/A	N/A	No	Peaking
Westwing II	2024-2025	2044	Battery ESS	120	120	89	89	[redacted]	[redacted]	[redacted]	[redacted]	N/A	N/A	No	Peaking
Scatterwash 1 & 2	2025	2045	Battery ESS	255	255	189	189	[redacted]	[redacted]	[redacted]	[redacted]	N/A	N/A	No	Peaking
Future Energy Storage System 1	2026	2046	Battery ESS	300	300	232	232	[redacted]	[redacted]	[redacted]	[redacted]	N/A	N/A	No	Peaking

ATTACHMENT D.1(A)(1): POWER SUPPLY (CONTINUED)

POWER SUPPLY - ESTIMATES FOR 2023-2038															
	B.1(a)		B.1(b)	B.1(c)	B.1(d)			B.1(f)(a)			B.1(h)	B.1(l)	B.1(m)	B.1(n)	B.1(o)
Plant/ Unit/ Contract	In Service Year	Book Life/ Period	Type	Owned Capacity (MW)	Max Capacity (MW)	Winter Capacity (MW) [13]	Summer Capacity (MW) [13]	50% Load Heat Rate (Btu/kWh)	75% Load Heat Rate (Btu/kWh)	100% Load Heat Rate (Btu/kWh)	Variable O&M Cost ($/MWh) [1,12]	Fuel	Min Cap (MW)	Must Run?	Baseload Intermediate Peaking [11]
Future Energy Storage Systems															
Future Energy Storage System 2	2026	2046	Battery ESS	106	106	72	72					N/A	N/A	No	Peaking
Future Energy Storage System 3	2029	2049	Battery ESS	409	409	221	221					N/A	N/A	No	Peaking
Future Energy Storage System 4	2038	2058	Battery ESS	408	408	237	237					N/A	N/A	No	Peaking
Future PVS PPA															
Mesquite	2023	2043	Renewable + Battery ESS	60	60	60	60					N/A	N/A	No	Peaking
Sunstreams 3	2024	2044	Renewable + Battery ESS	215	215	215	215					N/A	N/A	No	Peaking
Sunstreams 4	2025	2045	Renewable + Battery ESS	300	300	300	300					N/A	N/A	No	Peaking
Serrano [6]	2025	2045	Renewable + Battery ESS	170	170	208	208					N/A	N/A	No	Peaking
Yuma [7]	2024	2044	Renewable + Battery ESS	70	70	70	70					N/A	N/A	No	Peaking
Harquahala	2025	2045	Renewable + Battery ESS	300	300	300	300					N/A	N/A	No	Peaking
CO Bar C	2025	2045	Renewable + Battery ESS	206	206	206	206					N/A	N/A	No	Peaking
Future PVS															
AZSun BESS Retrofit Phase 1 [8]	2023	2043	Renewable + Battery ESS	140	140	75	75					N/A	N/A	No	Peaking
AZSun BESS Retrofit Phase 2 [8]	2023	2043	Renewable + Battery ESS	60	60	32	32					N/A	N/A	No	Peaking
Agave PVS [9]	2023	2063	Renewable + Battery ESS	150	150	150	150					N/A	N/A	No	Peaking
Ironwood [10]	2026	2066	Renewable + Battery ESS	168	168	168	168					N/A	N/A	No	Peaking
Solar + Storage System 1	2027	2067	Renewable + Battery ESS	98	98	60	60					N/A	N/A	No	Peaking
Solar + Storage System 2	2029	2069	Renewable + Battery ESS	106	106	57	57					N/A	N/A	No	Peaking
Solar + Storage System 3	2037	2077	Renewable + Battery ESS	342	342	215	215					N/A	N/A	No	Peaking
Future Renewables PPA															
Chevelon Butte 1	2023	2042	Renewable	233	233	62	62					Wind	N/A	Must Run	Intermittent
Chevelon Butte 2	2024	2043	Renewable	211	211	54	54					Wind	N/A	Must Run	Intermittent

ATTACHMENT D.1(A)(1): POWER SUPPLY (CONTINUED)

POWER SUPPLY - ESTIMATES FOR 2023-2038															
	B.1(a)		B.1(b)	B.1(c)	B.1(d)			B.1(f)(a)			B.1(h)	B.1(l)	B.1(m)	B.1(n)	B.1(o)
Plant/ Unit/ Contract	In Service Year	Book Life/ Period	Type	Owned Capacity (MW)	Max Capacity (MW)	Winter Capacity (MW) [13]	Summer Capacity (MW) [13]	50% Load Heat Rate (Btu/kWh)	75% Load Heat Rate (Btu/kWh)	100% Load Heat Rate (Btu/kWh)	Variable O&M Cost ($/MWh) [1,12]	Fuel	Min Cap (MW)	Must Run?	Baseload Intermediate Peaking [11]
Future Renewables															
New Wind 1	2026	2066	Renewable	150	150	37	37					Wind	N/A	No	Intermittent
New Wind 2	2032	2072	Renewable	900	900	208	208					Wind	N/A	No	Intermittent
New Wind 3	2036	2076	Renewable	35	35	9	9					Wind	N/A	No	Intermittent
New Wind 4	2026	2066	Renewable	367	367	89	89					Wind	N/A	No	Intermittent
New Wind 5	2027	2067	Renewable	148	148	32	32					Wind	N/A	No	Intermittent
New Wind 6	2030	2070	Renewable	54	54	14	14					Wind	N/A	No	Intermittent
New Wind 7	2033	2073	Renewable	9	9	2	2					Wind	N/A	No	Intermittent
New Wind 8	2036	2076	Renewable	7	7	2	2					Wind	N/A	No	Intermittent
New Solar 1	2027	2067	Renewable	346	346	40	40					Solar	N/A	No	Intermittent
New Solar 2	2030	2070	Renewable	1515	1515	137	137					Solar	N/A	No	Intermittent
New Solar 3	2031	2071	Renewable	25	25	2	2					Solar	N/A	No	Intermittent
New Solar 4	2032	2072	Renewable	9	9	1	1					Solar	N/A	No	Intermittent
New Solar 5	2034	2074	Renewable	156	156	18	18					Solar	N/A	No	Intermittent
New Solar 6	2035	2075	Renewable	214	214	25	25					Solar	N/A	No	Intermittent
New Solar 7	2036	2076	Renewable	563	563	50	50					Solar	N/A	No	Intermittent
New Solar 8	2037	2077	Renewable	152	152	11	11					Solar	N/A	No	Intermittent
Future Contracts															
Future CC Tolling #1	2032	2038	Tolling	600	600	600	600					Gas	333	No	Intermediate
Future CC Tolling #2	2035	2038	Tolling	570	570	570	570					Gas	362	No	Intermediate
Future CC Tolling #3	2033	2038	Tolling	525	525	525	525					Gas	377	No	Intermediate
Future CT Tolling #1	2027	2038	Tolling	42	42	42	41					Gas	19	No	Peaking
Future CT Tolling #2	2027	2038	Tolling	42	42	42	41					Gas	19	No	Peaking
Future CT Tolling #3	2027	2038	Tolling	42	42	42	41					Gas	19	No	Peaking
Future CT Tolling #4	2028	2038	Tolling	42	42	42	41					Gas	19	No	Peaking
Future CT Tolling #5	2028	2038	Tolling	42	42	42	41					Gas	19	No	Peaking
Future CT Tolling #6	2028	2038	Tolling	42	42	42	41					Gas	19	No	Peaking

ATTACHMENT D.1(A)(1): POWER SUPPLY (CONTINUED)

POWER SUPPLY - ESTIMATES FOR 2023-2038															
	B.1(a)		B.1(b)	B.1(c)	B.1(d)			B.1(f)(a)			B.1(h)	B.1(l)	B.1(m)	B.1(n)	B.1(o)
Plant/ Unit/ Contract	In Service Year	Book Life/ Period	Type	Owned Capacity (MW)	Max Capacity (MW)	Winter Capacity (MW) [13]	Summer Capacity (MW) [13]	50% Load Heat Rate (Btu/kWh)	75% Load Heat Rate (Btu/kWh)	100% Load Heat Rate (Btu/kWh)	Variable O&M Cost ($/MWh) [1,12]	Fuel	Min Cap (MW)	Must Run?	Baseload Intermediate Peaking [11]
Future Contracts (Continued)															
Future DR Contract (on-peak) # 1	2024	2038	Contract	25	25	0	5					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 2	2025	2038	Contract	75	75	0	53					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 3	2026	2038	Contract	75	75	0	53					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 4	2027	2038	Contract	25	25	0	5					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 5	2028	2038	Contract	75	75	0	50					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 6	2029	2038	Contract	25	25	0	5					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 7	2030	2038	Contract	75	75	0	48					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 8	2031	2038	Contract	75	75	0	45					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 9	2032	2038	Contract	75	75	0	45					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 10	2033	2038	Contract	25	25	0	5					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 11	2034	2038	Contract	25	25	0	5					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 12	2035	2038	Contract	25	25	0	5					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 13	2036	2038	Contract	25	25	0	5					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 14	2037	2038	Contract	25	25	0	5					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 15	2038	2038	Contract	25	25	0	5					N/A	N/A	No	Peaking

Notes:
(1) Fuel not included
(2) Consists of several small solar projects of 17.36 yrs book life
(3) Jun - Sep Summer months only thru 2025, then May - Oct months only
(4) Jun - Sep months only thru 2026, then May - Oct months only
(5) May - Oct Summer months only
(6) 170 MW PV & 213.75 MW ESS
(7) 70 MW PV & 67 MW ESS
(8) Battery energy storage added to existing AZ Sun solar sites
(9) PV in 2023, ESS in 2026
(10) PV in 2026, ESS in 2027
(11) For purposes of compliance with Rule B.1(o), intermittent is considered intermediate.
(12) 2023$
(13) Capacity shown are values for in-service year (if future resource) or 2023 (if existing resource)

ATTACHMENT D.1(A)(2): ANNUAL CAPACITY FACTOR

Annual Capacity Factor - B.1(e)																
Plant/ Unit/ Contract	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
Palo Verde																
Unit 1	[redacted]															
Unit 2	[redacted]															
Unit 3	[redacted]															
Four Corners																
Unit 4	[redacted]															
Unit 5	[redacted]															
Cholla																
Unit 1	[redacted]															
Unit 3	[redacted]															
Ocotillo																
Unit 1 CT	[redacted]															
Unit 2 CT	[redacted]															
Unit 3 CT	[redacted]															
Unit 4 CT	[redacted]															
Unit 5 CT	[redacted]															
Unit 6 CT	[redacted]															
Unit 7 CT	[redacted]															
Saguaro																
Unit 1 CT	[redacted]															
Unit 2 CT	[redacted]															
Unit 3 CT	[redacted]															
West Phoenix																
Unit 1 CC	[redacted]															
Unit 2 CC	[redacted]															
Unit 3 CC	[redacted]															
Unit 4 CC	[redacted]															
Unit 5 CC	[redacted]															
Unit 1 CT	[redacted]															
Unit 2 CT	[redacted]															
Redhawk																
Unit 1 CC	[redacted]															
Unit 2 CC	[redacted]															
Sundance																
Unit 1 CT	[redacted]															
Unit 2 CT	[redacted]															
Unit 3 CT	[redacted]															
Unit 4 CT	[redacted]															
Unit 5 CT	[redacted]															
Unit 6 CT	[redacted]															
Unit 7 CT	[redacted]															
Unit 8 CT	[redacted]															
Unit 9 CT	[redacted]															
Unit 10 CT	[redacted]															
Yucca																
Unit 1 CT	[redacted]															
Unit 2 CT	[redacted]															
Unit 3 CT	[redacted]															
Unit 4 CT	[redacted]															
Unit 5 CT	[redacted]															
Unit 6 CT	[redacted]															

ATTACHMENT D.1(A)(2): ANNUAL CAPACITY FACTOR (CONTINUED)

Annual Capacity Factor - B.1(e)																
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Douglas																
Unit 1 CT																
Mircrogrids																
Aligned																
MCASY																
Punkin Center																
Preacher																
Forest Lakes																
TSMC																
City of Phx																
Renewables																
Aragonne Mesa Wind, New Mexico																
High Lonesome Wind, New Mexico																
Perrin Ranch Wind																
Salton Sea CE Turbo																
Solana CSP																
SWMP Biomass (Snowflake Abitibi)																
AZ Sun: Hyder II																
AZ Sun: Cotton Center																
AZ Sun: Hyder																
AZ Sun: Chino Valley																
AZ Sun: Paloma																
AZ Sun: Yuma Foothills																
AZ Sun: Gila Bend																
AZ Sun: Luke AFB																
AZ Sun: Desert Star																
Red Rock Solar																
Legacy Solar																
Small Gen RFP (Ajo)																
Small Gen RFP (Prescott)																
Small Gen RFP (Saddle Mt Tonopah)																
Small Gen RFP (WM Landfill)																
Badger-Desert Sky																
Recurrent Gillespie																
Utility Scale DE																
Bagdad																
Schools and Gov't & Other DE Programs																
Contracts																
SRP - Firm / Eastern Mining Load																
AGX Load																
CC Tolling # 1																
CC Tolling # 2																
CC Tolling # 3																
Short term Purchases																

ATTACHMENT D.1(A)(2): ANNUAL CAPACITY FACTOR (CONTINUED)

Annual Capacity Factor - B.1(e)																
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Future Units																
New CT 1																
New CT 2																
New CT 3																
New CT 4																
New CT 5																
New CT 6																
New CT 7																
New CT 8																
New CT 9																
New CT 10																
New CT 11																
New CT 12																
New CT 13																
Future Microgrids																
Future Renewables																
Chevelon Butte Wind																
Chevelon Butte Phase 2 Wind																
Future AZ Wind																
Future NM Wind																
Future Solar																
Future NM Wind 2																
Future Energy Storage Systems																
AES Westwing I																
AES Westwing II																
Strata Scatter Wash 1																
Strata Scatter Wash 2																
RE Papago ESS																
Future ESS																
Hyder II ESS																
Cotton Center Solar ESS																
Hyder I ESS																
Chino Solar Valley ESS																
Paloma Solar ESS																
Foothills Solar Plant ESS																
Gila Bend ESS																
Desert Star ESS																
Red Rock ESS																

ATTACHMENT D.1(A)(2): ANNUAL CAPACITY FACTOR (CONTINUED)

Annual Capacity Factor - B.1(e)																
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Future Solar + Storage System (PVS)																
Agave PVS Solar	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Agave PVS Battery	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mesquite PVS Solar	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mesquite PVS Battery	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SunStreams 3 PVS Solar	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SunStreams 3 PVS Battery	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SunStreams 4 PVS Solar	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SunStreams 4 PVS Battery	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Serrano PVS Solar	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Serrano PVS Battery	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Invenergy Yuma PVS Solar	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Invenergy Yuma PVS Battery	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Harquhala Sun 2 PVS Solar	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Harquhala Sun 2 PVS Battery	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CO Bar C PVS Solar	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CO Bar C PVS Battery	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ironwood PVS Solar	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ironwood PVS Battery	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Future PVS Solar	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Future PVS Battery	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Future Contracts																
Future CC Tolling #1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Future CC Tolling #2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Future CC Tolling #3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CT Tolling #1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CT Tolling #2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CT Tolling #3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CT Tolling #4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CT Tolling #5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CT Tolling #6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Existing Short term Purchases	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

ATTACHMENT D.1(A)(3): AVERAGE HEAT RATE

Average Heat Rate - B.1(f)(b) (Btu/kWh)																
UNIT	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
Palo Verde																
Unit 1	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385
Unit 2	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361
Unit 3	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377
Four Corners																
Unit 4	9,687	9,687	9,687	9,687	9,687	9,687	9,687	9,687	9,687							
Unit 5	9,687	9,687	9,687	9,687	9,687	9,687	9,687	9,687	9,687							
Cholla																
Unit 1	10,591	10,558	10,443													
Unit 3	10,783	10,781	10,699													
Ocotillo																
Unit 1 CT	14,297	14,309	-	-	-	-	14,480	14,555	-	-	-	-	-	-	-	-
Unit 2 CT	14,127	14,336	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Unit 3 CT	9,171	9,015	9,012	8,982	8,978	8,983	8,974	8,987	8,992	9,035	9,073	9,037	9,041	9,008	9,012	9,013
Unit 4 CT	9,183	9,128	9,112	9,096	9,120	9,120	9,115	9,128	9,187	9,180	9,167	9,139	9,126	9,170	9,141	9,120
Unit 5 CT	9,068	9,021	9,021	9,016	9,010	9,012	9,010	9,010	9,035	9,108	9,078	9,067	9,072	9,057	9,053	9,071
Unit 6 CT	9,267	9,210	9,191	9,192	9,185	9,184	9,187	9,185	9,217	9,257	9,245	9,272	9,242	9,240	9,283	9,240
Unit 7 CT	9,137	9,016	9,018	9,006	9,001	9,006	9,003	9,003	9,045	9,052	9,057	9,059	9,063	9,065	9,043	9,029
Saguaro																
Unit 1 CT	14,692	14,309	-	-	-	-	-	14,503	-	-	-	-	-	-	-	-
Unit 2 CT	14,699	14,377	-	-	-	14,024	-	-	-	-	-	-	-	-	-	-
Unit 3 CT	12,131	11,884	11,984	11,974	11,997	11,932	11,945	11,784	11,825	13,385	11,938	13,574	12,126	11,938	11,938	11,938
West Phoenix																
Unit 1 CC	9,285	9,185	9,138	9,135	9,140	9,126	9,136	9,130	9,163	9,162	9,196	9,182	9,188	9,197	9,192	9,193
Unit 2 CC	9,380	9,222	9,137	9,135	9,141	9,127	9,132	9,136	9,165	9,157	9,168	9,170	9,179	9,190	9,184	9,182
Unit 3 CC	9,241	9,171	9,136	9,137	9,138	9,128	9,133	9,135	9,144	9,154	9,158	9,156	9,166	9,169	9,174	9,166
Unit 4 CC	8,263	8,175	8,192	8,143	8,144	8,139	8,143	8,159	8,148	8,166	8,176	8,172	8,183	8,183	8,179	8,182
Unit 5 CC	7,446	7,389	7,372	7,355	7,358	7,357	7,363	7,376	7,377	7,367	7,368	7,369	7,372	7,373	7,376	7,371
Unit 1 CT	14,551	14,537	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Unit 2 CT	14,627	14,277	14,277	-	-	14,277	14,517	-	-	-	-	-	-	-	-	-
Redhawk																
Unit 1 CC	6,868	6,861	6,832	6,822	6,829	6,826	6,824	6,831	6,835	6,840	6,842	6,847	6,849	6,852	6,851	6,853
Unit 2 CC	6,900	6,895	6,854	6,840	6,853	6,849	6,840	6,866	6,860	6,854	6,859	6,861	6,867	6,870	6,869	6,866
Sundance																
Unit 1 CT	9,971	9,848	9,862	9,865	9,839	9,823	9,820	9,812	9,819	9,853	9,848	9,866	9,858	9,891	9,852	9,961
Unit 2 CT	10,676	10,779	10,644	10,644	10,762	10,638	10,697	10,636	10,594	-	10,644	12,768	11,365	10,644	10,644	11,822
Unit 3 CT	9,883	9,872	9,887	9,859	9,846	9,824	9,828	9,815	9,852	9,845	9,845	9,954	9,885	9,903	9,954	9,845
Unit 4 CT	10,725	10,921	10,644	10,644	10,762	10,654	10,700	10,663	10,618	-	10,644	-	10,777	10,644	10,699	13,055
Unit 5 CT	9,864	9,836	9,899	9,845	9,862	9,841	9,868	9,830	10,081	12,232	10,725	9,992	9,852	10,155	9,965	9,903
Unit 6 CT	9,920	9,834	9,892	9,845	9,862	9,849	9,913	9,835	9,842	-	9,845	9,845	9,889	9,845	9,845	9,850
Unit 7 CT	9,857	9,839	9,841	9,864	9,830	9,829	9,823	9,819	9,817	9,883	9,850	9,875	9,883	9,968	9,882	9,892
Unit 8 CT	9,946	9,862	9,899	9,859	9,847	9,825	9,839	9,813	9,815	10,486	9,845	9,845	9,854	9,894	9,845	9,845
Unit 9 CT	9,951	9,851	9,846	9,868	9,848	9,825	9,828	9,818	9,815	9,950	9,882	9,924	9,845	9,897	9,876	9,933
Unit 10 CT	9,915	9,870	9,854	9,857	9,842	9,819	9,827	9,813	9,815	9,895	9,897	9,845	9,957	9,855	9,855	9,845
Yucca																
Unit 1 CT	14,351	14,728	-	-	-	14,180	-	14,728	-	-	-	63,506	14,728	-	14,728	68,169
Unit 2 CT	14,411	14,933	-	-	-	14,180	-	14,437	-	-	-	146,287	14,933	-	14,933	-
Unit 3 CT	13,906	13,764	13,809	13,846	14,132	13,721	13,865	13,799	13,579	71,562	18,632	120,906	13,809	14,921	13,809	-
Unit 4 CT	41,166	20,402	-	-	-	-	-	-	13,728	69,304	-	62,917	-	69,510	69,992	-
Unit 5 CT	10,256	9,931	9,895	9,913	9,905	9,896	9,891	9,892	9,925	9,906	9,971	9,909	9,950	9,935	9,913	9,994
Unit 6 CT	10,257	9,934	9,948	9,967	9,918	9,905	9,920	9,909	9,919	9,930	9,997	10,047	10,025	10,019	10,109	10,041

ATTACHMENT D.1(A)(3): AVERAGE HEAT RATE (CONTINUED)

Average Heat Rate - B.1(f)(b) (Btu/kWh)																
UNIT	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
Douglas																
Unit 1 CT	56,602	33,465	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mircrogrids																
Aligned	8,300	8,300	-	-	-	-	-	-	8,300	8,300	8,300	8,300	8,300	8,300	8,300	8,300
MCASY	8,300	8,300	8,300	8,300	8,300	8,300	8,300	8,300	8,300	8,300	8,300	8,300	8,300	8,300	8,300	8,300
Punkin Center	8,300	8,300	8,300	-	-	-	-	-	8,300	8,300	8,300	8,300	8,300	8,300	8,300	8,300
Preacher	8,300	8,300	8,300	-	-	-	-	-	8,300	8,300	8,300	8,300	8,300	8,300	8,300	8,300
Forest Lakes	-	8,300	8,300	-	-	-	-	-	8,300	8,300	8,300	8,300	8,300	8,300	8,300	8,300
TSMC	-	8,300	8,300	-	-	-	-	-	8,300	8,300	8,300	8,300	8,300	8,300	8,300	8,300
City of Phx	8,300	8,300	-	-	-	-	-	-	8,300	8,300	8,300	8,300	8,300	8,300	8,300	8,300
Future Units																
New CT 1	-	-	-	9,854	9,832	9,819	9,825	9,815	9,861	9,831	9,897	9,883	9,878	9,921	9,880	9,895
New CT 2	-	-	-	9,874	9,847	9,822	9,818	9,820	9,819	9,845	9,933	9,852	9,882	9,852	10,002	9,894
New CT 3	-	-	-	-	-	-	9,848	9,815	9,843	-	9,845	9,863	9,873	9,879	9,929	9,945
New CT 4	-	-	-	-	-	-	-	9,842	9,855	9,895	9,937	9,955	9,910	9,861	9,937	9,924
New CT 5	-	-	-	-	-	-	-	9,896	9,816	9,845	9,954	9,845	9,849	9,885	9,986	9,943
New CT 6	-	-	-	-	-	-	-	-	9,844	9,981	9,955	9,957	9,851	9,906	9,867	9,931
New CT 7	-	-	-	-	-	-	-	-	9,138	9,138	9,138	9,138	9,138	9,138	9,138	9,138
New CT 8	-	-	-	-	-	-	-	-	9,138	9,138	9,138	9,138	9,138	9,138	9,138	9,138
New CT 9	-	-	-	-	-	-	-	-	9,138	9,138	9,138	9,138	9,138	9,138	9,138	9,138
New CT 10	-	-	-	-	-	-	-	-	9,138	9,138	9,138	9,138	9,138	9,138	9,138	9,138
New CT 11	-	-	-	-	-	-	-	-	-	-	-	-	-	9,138	9,138	9,138
New CT 12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9,886	9,943
New CT 13	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9,886	9,923
Future Microgrids	-	-	-	8,300	8,300	8,300	8,300	8,300	8,300	8,300	8,300	8,300	8,300	8,300	8,300	8,300

ATTACHMENT D.1(A)(4): AVERAGE FUEL COST

Average Fuel Cost - B.1 ($/MMBtu)																
FUEL	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Uranium	[redacted]															
Coal - Four Corners	[redacted]															
Coal - Cholla	[redacted]															
Gas	[redacted]															

ATTACHMENT D.1(A)(5): PURCHASED POWER ENERGY COSTS FOR LONG-TERM CONTRACTS

Energy Cost for Long Term Contract B.1(i) ($/MWh)																
UNIT	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Renewables																
Aragonne Mesa Wind, New Mexico	[redacted]															
Salton Sea CE Turbo #1	[redacted]															
SWMP Biomass (Snowflake Abitibi)	[redacted]															
High Lonesome Wind, New Mexico	[redacted]															
Perrin Ranch Wind	[redacted]															
Solana CSP	[redacted]															
Small Gen RFP (Ajo)	[redacted]															
Small Gen RFP (Prescott)	[redacted]															
Small Gen RFP (Saddle Mt Tonopah)	[redacted]															
Small Gen RFP (WM Landfill)	[redacted]															
Badger-Desert Sky	[redacted]															
Recurrent Gillespie	[redacted]															
Bagdad	[redacted]															
Chevelon Butte Wind 1	[redacted]															
Chevelon Butte Wind 2	[redacted]															
Contracts																
[redacted]																
AGX Load	[redacted]															
CC Tolling # 1	[redacted]															
CC Tolling # 2	[redacted]															
CC Tolling # 3	[redacted]															
Future CC Tolling #1	[redacted]															
Future CC Tolling #2	[redacted]															
Future CC Tolling #3	[redacted]															
Future CT Tolling #1	[redacted]															
Future CT Tolling #2	[redacted]															
Future CT Tolling #3	[redacted]															
Future CT Tolling #4	[redacted]															
Future CT Tolling #5	[redacted]															
Future CT Tolling #6	[redacted]															

Notes
(1) Based on Palo Verde Day-Ahead Index

ATTACHMENT D.1(A)(6): FIXED O&M

Fixed Operating and Maintenance - B.1(j) ($/MW)																
PLANT	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Palo Verde	[redacted]															
Cholla																
Four Corners																
Ocotillo																
Douglas																
Saguaro																
Sundance																
Redhawk																
West Phoenix																
Yucca																
AZ Sun: Hyder II																
AZ Sun: Cotton Center																
AZ Sun: Hyder I																
AZ Sun: Chino Valley																
AZ Sun: Paloma																
AZ Sun: Yuma Foothills																
AZ Sun: Gila Bend																
AZ Sun: Luke																
AZ Sun: Desert Star																
Red Rock Solar																

ATTACHMENT D.1(A)(6): FIXED O&M (CONTINUED)

Fixed Operating and Maintenance - B.1(j) ($/MW)																
PLANT	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
Future Units																
Future CT (2)	[redacted]															
Future CT (1)	[redacted]															
Future CT (2)	[redacted]															
Future CT (1)	[redacted]															
Future CT (4)	[redacted]															
Future CT (1)	[redacted]															
Future CT (2)	[redacted]															
Solar + Storage System (ESS added to Existing Solar)	[redacted]															
Solar + Storage System (ESS added 2027)	[redacted]															
Solar + Storage System	[redacted]															
Solar + Storage System	[redacted]															
Solar + Storage System	[redacted]															
Energy Storage System	[redacted]															
Energy Storage System	[redacted]															
Energy Storage System	[redacted]															
Microgrid	[redacted]															
Microgrid	[redacted]															
Microgrid	[redacted]															
Microgrid	[redacted]															
New Wind	[redacted]															
New Wind	[redacted]															
New Wind	[redacted]															
New Wind	[redacted]															
New Wind	[redacted]															
New Wind	[redacted]															
New Wind	[redacted]															
New Wind	[redacted]															
New Wind	[redacted]															
New Wind	[redacted]															
New Solar	[redacted]															
New Solar	[redacted]															
New Solar	[redacted]															
New Solar	[redacted]															
New Solar	[redacted]															
New Solar	[redacted]															
New Solar	[redacted]															
New Solar	[redacted]															

ATTACHMENT D.1(A)(7): DEMAND CHARGES FOR PURCHASE POWER

Demand Charges for Purchased Power - B.1(k) ($/kW-Yr)																
Contract	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
Westwing I Energy Storage	[redacted]															
Westwing II Energy Storage	[redacted]															
Scatterwash 1 & 2 Energy Storage	[redacted]															
Future Energy Storage System 1	[redacted]															
Mesquite PVS (Energy Storage)	[redacted]															
Mesquite PVS (Solar)	[redacted]															
Sunstreams 3 PVS (Energy Storage)	[redacted]															
Sunstreams 3 PVS (Solar)	[redacted]															
Sunstreams 4 PVS (Energy Storage)	[redacted]															
Sunstreams 4 PVS (Solar)	[redacted]															
Serrano PVS (Energy Storage)	[redacted]															
Serrano PVS (Solar)	[redacted]															
Yuma PVS (Energy Storage)	[redacted]															
Yuma PVS (Solar)	[redacted]															
Harquahala PVS (Energy Storage)	[redacted]															
Harquahala PVS (Solar)	[redacted]															
CO Bar C PVS (Energy Storage)	[redacted]															
CO Bar C PVS (Solar)	[redacted]															
CC Tolling # 1	[redacted]															
CC Tolling # 2	[redacted]															
CC Tolling # 3	[redacted]															
Future CC Tolling #1	[redacted]															
Future CC Tolling #2	[redacted]															
Future CC Tolling #3	[redacted]															
Future CT Tolling #1	[redacted]															
Future CT Tolling #2	[redacted]															
Future CT Tolling #3	[redacted]															
Future CT Tolling #4	[redacted]															
Future CT Tolling #5	[redacted]															
Future CT Tolling #6	[redacted]															

ATTACHMENT D.1(A)(8) – ENVIRONMENTAL IMPACTS

CO2 Emissions – B.1(p) (Metric Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Four Corners																	
Unit 4	[redacted]																
Unit 5	[redacted]																
Cholla																	
Unit 1	[redacted]																
Unit 3	[redacted]																
Ocotillo																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Unit 7 CT	[redacted]																
Saguaro																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
West Phoenix																	
Unit 1 CC	[redacted]																
Unit 2 CC	[redacted]																
Unit 3 CC	[redacted]																
Unit 4 CC	[redacted]																
Unit 5 CC	[redacted]																
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																

ATTACHMENT D.1(A)(8) – ENVIRONMENTAL IMPACTS (CONTINUED)

CO2 Emissions – B.1(p) (Metric Tons)																	
UNIT	**Rate[1] (lb/ MM Btu)**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
Redhawk																	
Unit 1 CC	[redacted]																
Unit 2 CC	[redacted]																
Sundance																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Unit 7 CT	[redacted]																
Unit 8 CT	[redacted]																
Unit 9 CT	[redacted]																
Unit 10 CT	[redacted]																
Yucca																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Douglas																	
Unit 1 CT	[redacted]																
Microgrids																	
Aligned	[redacted]																
MCASY	[redacted]																
Punkin Center	[redacted]																
Preacher	[redacted]																
Forest Lakes	[redacted]																
TSMC	[redacted]																
City of Phx	[redacted]																

ATTACHMENT D.1(A)(8) – ENVIRONMENTAL IMPACTS (CONTINUED)

CO2 Emissions – B.1(p) (Metric Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Tolling Agreements & Purchases																	
CC Tolling #1	[redacted]																
CC Tolling #2	[redacted]																
CC Tolling #3	[redacted]																
Short Term Purchase	[redacted]																
Other Purchases[2]	[redacted]																
Future Units																	
Future CC Tolling #1	[redacted]																
Future CC Tolling #2	[redacted]																
Future CC Tolling #3	[redacted]																
Future CT Tolling #1	[redacted]																
Future CT Tolling #2	[redacted]																
Future CT Tolling #3	[redacted]																
Future CT Tolling #4	[redacted]																
Future CT Tolling #5	[redacted]																
Future CT Tolling #6	[redacted]																
Future CT #1	[redacted]																
Future CT #2	[redacted]																
Future CT #3	[redacted]																
Future CT #4	[redacted]																
Future CT #5	[redacted]																
Future CT #6	[redacted]																
Future CT #7	[redacted]																
Future CT #8	[redacted]																
Future CT #9	[redacted]																
Future CT #10	[redacted]																
Future CT #11	[redacted]																
Future CT #12	[redacted]																
Future CT #13	[redacted]																
Future Microgrids	[redacted]																
TOTAL		**9,269,138**	**9,995,292**	**9,333,136**	**9,264,452**	**9,720,751**	**10,076,763**	**10,741,569**	**9,606,822**	**8,091,363**	**5,599,247**	**5,992,489**	**6,318,392**	**6,461,851**	**6,422,540**	**6,450,278**	**6,709,760**

Notes:
(1) Emissions rates are based on 2023 estimates.
(2) Includes economic purchases from the market.

ATTACHMENT D.1(A)(8) – ENVIRONMENTAL IMPACTS (CONTINUED)

CO Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Four Corners																	
Unit 4	[redacted]																
Unit 5	[redacted]																
Cholla																	
Unit 1	[redacted]																
Unit 3	[redacted]																
Ocotillo																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Unit 7 CT	[redacted]																
Saguaro																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
West Phoenix																	
Unit 1 CC	[redacted]																
Unit 2 CC	[redacted]																
Unit 3 CC	[redacted]																
Unit 4 CC	[redacted]																
Unit 5 CC	[redacted]																
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																

ATTACHMENT D.1(A)(8) – ENVIRONMENTAL IMPACTS (CONTINUED)

CO Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Redhawk																	
Unit 1 CC	[redacted]																
Unit 2 CC	[redacted]																
Sundance																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Unit 7 CT	[redacted]																
Unit 8 CT	[redacted]																
Unit 9 CT	[redacted]																
Unit 10 CT	[redacted]																
Yucca																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Douglas																	
Unit 1 CT	[redacted]																
Microgrids																	
Aligned	[redacted]																
MCASY	[redacted]																
Punkin Center	[redacted]																
Preacher	[redacted]																
Forest Lakes	[redacted]																
TSMC	[redacted]																
City of Phx	[redacted]																

ATTACHMENT D.1(A)(8) – ENVIRONMENTAL IMPACTS (CONTINUED)

CO Emissions – B.1(p) (Tons)																	
UNIT	**Rate[1] (lb/ MM Btu)**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
Tolling Agreements & Purchases																	
CC Tolling #1																	
CC Tolling #2																	
CC Tolling #3																	
Short Term Purchase																	
Other Purchases[2]																	
Future Units																	
Future CC Tolling #1																	
Future CC Tolling #2																	
Future CC Tolling #3																	
Future CT Tolling #1																	
Future CT Tolling #2																	
Future CT Tolling #3																	
Future CT Tolling #4																	
Future CT Tolling #5																	
Future CT Tolling #6																	
Future CT #1																	
Future CT #2																	
Future CT #3																	
Future CT #4																	
Future CT #5																	
Future CT #6																	
Future CT #7																	
Future CT #8																	
Future CT #9																	
Future CT #10																	
Future CT #11																	
Future CT #12																	
Future CT #13																	
Future Microgrids																	
TOTAL		**1,196**	**1,284**	**1,133**	**1,065**	**1,095**	**1,116**	**1,170**	**1,037**	**693**	**409**	**446**	**465**	**481**	**469**	**470**	**486**

Notes:
(1) Emissions rates are based on 2023 estimates.
(2) Includes economic purchases from the market.

ATTACHMENT D.1(A)(8) – ENVIRONMENTAL IMPACTS (CONTINUED)

VOC Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Four Corners																	
Unit 4	[redacted]																
Unit 5	[redacted]																
Cholla																	
Unit 1	[redacted]																
Unit 3	[redacted]																
Ocotillo																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Unit 7 CT	[redacted]																
Saguaro																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
West Phoenix																	
Unit 1 CC	[redacted]																
Unit 2 CC	[redacted]																
Unit 3 CC	[redacted]																
Unit 4 CC	[redacted]																
Unit 5 CC	[redacted]																
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																

ATTACHMENT D.1(A)(8) – ENVIRONMENTAL IMPACTS (CONTINUED)

VOC Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Redhawk																	
Unit 1 CC	[redacted]																
Unit 2 CC	[redacted]																
Sundance																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Unit 7 CT	[redacted]																
Unit 8 CT	[redacted]																
Unit 9 CT	[redacted]																
Unit 10 CT	[redacted]																
Yucca																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Douglas																	
Unit 1 CT	[redacted]																
Microgrids																	
Aligned	[redacted]																
MCASY	[redacted]																
Punkin Center	[redacted]																
Preacher	[redacted]																
Forest Lakes	[redacted]																
TSMC	[redacted]																
City of Phx	[redacted]																

ATTACHMENT D.1(A)(8) – ENVIRONMENTAL IMPACTS (CONTINUED)

VOC Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Tolling Agreements & Purchases																	
CC Tolling #1	[redacted]																
CC Tolling #2																	
CC Tolling #3																	
Short Term Purchase																	
Other Purchases[2]																	
Future Units																	
Future CC Tolling #1	[redacted]																
Future CC Tolling #2																	
Future CC Tolling #3																	
Future CT Tolling #1																	
Future CT Tolling #2																	
Future CT Tolling #3																	
Future CT Tolling #4																	
Future CT Tolling #5																	
Future CT Tolling #6																	
Future CT #1																	
Future CT #2																	
Future CT #3																	
Future CT #4																	
Future CT #5																	
Future CT #6																	
Future CT #7																	
Future CT #8																	
Future CT #9																	
Future CT #10																	
Future CT #11																	
Future CT #12																	
Future CT #13																	
Future Microgrids																	
TOTAL		**43**	**47**	**47**	**52**	**58**	**65**	**73**	**66**	**87**	**74**	**77**	**83**	**84**	**86**	**86**	**89**

Notes:
(1) Emissions rates are based on 2023 estimates.
(2) Includes economic purchases from the market.

ATTACHMENT D.1(A)(8) – ENVIRONMENTAL IMPACTS (CONTINUED)

NOX Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Four Corners																	
Unit 4	[redacted]																
Unit 5	[redacted]																
Cholla																	
Unit 1	[redacted]																
Unit 3	[redacted]																
Ocotillo																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Unit 7 CT	[redacted]																
Saguaro																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
West Phoenix																	
Unit 1 CC	[redacted]																
Unit 2 CC	[redacted]																
Unit 3 CC	[redacted]																
Unit 4 CC	[redacted]																
Unit 5 CC	[redacted]																
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																

ATTACHMENT D.1(A)(8) – ENVIRONMENTAL IMPACTS (CONTINUED)

NOX Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Redhawk																	
Unit 1 CC	[redacted]																
Unit 2 CC	[redacted]																
Sundance																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Unit 7 CT	[redacted]																
Unit 8 CT	[redacted]																
Unit 9 CT	[redacted]																
Unit 10 CT	[redacted]																
Yucca																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Douglas																	
Unit 1 CT	[redacted]																
Microgrids																	
Aligned	[redacted]																
MCASY	[redacted]																
Punkin Center	[redacted]																
Preacher	[redacted]																
Forest Lakes	[redacted]																
TSMC	[redacted]																
City of Phx	[redacted]																

ATTACHMENT D.1(A)(8) – ENVIRONMENTAL IMPACTS (CONTINUED)

NOX Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Tolling Agreements & Purchases																	
CC Tolling #1	[redacted]																
CC Tolling #2	[redacted]																
CC Tolling #3	[redacted]																
Short Term Purchase	[redacted]																
Other Purchases[2]	[redacted]																
Future Units																	
Future CC Tolling #1	[redacted]																
Future CC Tolling #2	[redacted]																
Future CC Tolling #3	[redacted]																
Future CT Tolling #1	[redacted]																
Future CT Tolling #2	[redacted]																
Future CT Tolling #3	[redacted]																
Future CT Tolling #4	[redacted]																
Future CT Tolling #5	[redacted]																
Future CT Tolling #6	[redacted]																
Future CT #1	[redacted]																
Future CT #2	[redacted]																
Future CT #3	[redacted]																
Future CT #4	[redacted]																
Future CT #5	[redacted]																
Future CT #6	[redacted]																
Future CT #7	[redacted]																
Future CT #8	[redacted]																
Future CT #9	[redacted]																
Future CT #10	[redacted]																
Future CT #11	[redacted]																
Future CT #12	[redacted]																
Future CT #13	[redacted]																
Future Microgrids	[redacted]																
TOTAL		**3,430**	**3,554**	**2,667**	**2,223**	**2,311**	**2,576**	**2,719**	**2,456**	**2,251**	**991**	**943**	**1,064**	**1,046**	**1,105**	**1,151**	**1,332**

Notes:
(1) Emissions rates are based on 2023 estimates.
(2) Includes economic purchases from the market.

ATTACHMENT D.1(A)(8) – ENVIRONMENTAL IMPACTS (CONTINUED)

SO2 Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Four Corners																	
Unit 4	[redacted]																
Unit 5	[redacted]																
Cholla																	
Unit 1	[redacted]																
Unit 3	[redacted]																
Ocotillo																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Unit 7 CT	[redacted]																
Saguaro																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
West Phoenix																	
Unit 1 CC	[redacted]																
Unit 2 CC	[redacted]																
Unit 3 CC	[redacted]																
Unit 4 CC	[redacted]																
Unit 5 CC	[redacted]																
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																

ATTACHMENT D.1(A)(8) – ENVIRONMENTAL IMPACTS (CONTINUED)

SO2 Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Redhawk																	
Unit 1 CC	[redacted]																
Unit 2 CC	[redacted]																
Sundance																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Unit 7 CT	[redacted]																
Unit 8 CT	[redacted]																
Unit 9 CT	[redacted]																
Unit 10 CT	[redacted]																
Yucca																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Douglas																	
Unit 1 CT	[redacted]																
Microgrids																	
Aligned	[redacted]																
MCASY	[redacted]																
Punkin Center	[redacted]																
Preacher	[redacted]																
Forest Lakes	[redacted]																
TSMC	[redacted]																
City of Phx	[redacted]																

ATTACHMENT D.1(A)(8) – ENVIRONMENTAL IMPACTS (CONTINUED)

SO2 Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Tolling Agreements & Purchases																	
CC Tolling #1																	
CC Tolling #2																	
CC Tolling #3																	
Short Term Purchase																	
Other Purchases[2]																	
Future Units																	
Future CC Tolling #1																	
Future CC Tolling #2																	
Future CC Tolling #3																	
Future CT Tolling #1																	
Future CT Tolling #2																	
Future CT Tolling #3																	
Future CT Tolling #4																	
Future CT Tolling #5																	
Future CT Tolling #6																	
Future CT #1																	
Future CT #2																	
Future CT #3																	
Future CT #4																	
Future CT #5																	
Future CT #6																	
Future CT #7																	
Future CT #8																	
Future CT #9																	
Future CT #10																	
Future CT #11																	
Future CT #12																	
Future CT #13																	
Future Microgrids																	
TOTAL		**1,866**	**2,006**	**1,573**	**1,350**	**1,333**	**1,301**	**1,322**	**1,162**	**487**	**35**	**36**	**38**	**39**	**44**	**46**	**56**

Notes:
(1) Emissions rates are based on 2023 estimates.
(2) Includes economic purchases from the market.

ATTACHMENT D.1(A)(8) – ENVIRONMENTAL IMPACTS (CONTINUED)

HG Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Four Corners																	
Unit 4																	
Unit 5																	
Cholla																	
Unit 1																	
Unit 3																	
Ocotillo																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Unit 7 CT																	
Saguaro																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
West Phoenix																	
Unit 1 CC																	
Unit 2 CC																	
Unit 3 CC																	
Unit 4 CC																	
Unit 5 CC																	
Unit 1 CT																	
Unit 2 CT																	

ATTACHMENT D.1(A)(8) – ENVIRONMENTAL IMPACTS (CONTINUED)

HG Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Redhawk																	
Unit 1 CC	[redacted]																
Unit 2 CC	[redacted]																
Sundance																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Unit 7 CT	[redacted]																
Unit 8 CT	[redacted]																
Unit 9 CT	[redacted]																
Unit 10 CT	[redacted]																
Yucca																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Douglas																	
Unit 1 CT	[redacted]																
Microgrids																	
Aligned	[redacted]																
MCASY	[redacted]																
Punkin Center	[redacted]																
Preacher	[redacted]																
Forest Lakes	[redacted]																
TSMC	[redacted]																
City of Phx	[redacted]																

ATTACHMENT D.1(A)(8) – ENVIRONMENTAL IMPACTS (CONTINUED)

HG Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Tolling Agreements & Purchases																	
CC Tolling #1																	
CC Tolling #2																	
CC Tolling #3																	
Short Term Purchase																	
Other Purchases[2]																	
Future Units																	
Future CC Tolling #1																	
Future CC Tolling #2																	
Future CC Tolling #3																	
Future CT Tolling #1																	
Future CT Tolling #2																	
Future CT Tolling #3																	
Future CT Tolling #4																	
Future CT Tolling #5																	
Future CT Tolling #6																	
Future CT #1																	
Future CT #2																	
Future CT #3																	
Future CT #4																	
Future CT #5																	
Future CT #6																	
Future CT #7																	
Future CT #8																	
Future CT #9																	
Future CT #10																	
Future CT #11																	
Future CT #12																	
Future CT #13																	
Future Microgrids																	
TOTAL		**0.020**	**0.021**	**0.018**	**0.017**	**0.018**	**0.019**	**0.020**	**0.018**	**0.018**	**0.013**	**0.014**	**0.015**	**0.015**	**0.015**	**0.015**	**0.016**

Notes:
(1) Emissions rates are based on 2023 estimates.
(2) Includes economic purchases from the market.

ATTACHMENT D.1(A)(8) – ENVIRONMENTAL IMPACTS (CONTINUED)

PM10 Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Four Corners																	
Unit 4	[redacted]																
Unit 5	[redacted]																
Cholla																	
Unit 1	[redacted]																
Unit 3	[redacted]																
Ocotillo																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Unit 7 CT	[redacted]																
Saguaro																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
West Phoenix																	
Unit 1 CC	[redacted]																
Unit 2 CC	[redacted]																
Unit 3 CC	[redacted]																
Unit 4 CC	[redacted]																
Unit 5 CC	[redacted]																
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																

ATTACHMENT D.1(A)(8) – ENVIRONMENTAL IMPACTS (CONTINUED)

PM10 Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Redhawk																	
Unit 1 CC	[redacted]																
Unit 2 CC																	
Sundance																	
Unit 1 CT	[redacted]																
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Unit 7 CT																	
Unit 8 CT																	
Unit 9 CT																	
Unit 10 CT																	
Yucca																	
Unit 1 CT	[redacted]																
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Douglas																	
Unit 1 CT	[redacted]																
Microgrids																	
Aligned	[redacted]																
MCASY																	
Punkin Center																	
Preacher																	
Forest Lakes																	
TSMC																	
City of Phx																	

ATTACHMENT D.1(A)(8) – ENVIRONMENTAL IMPACTS (CONTINUED)

PM10 Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Tolling Agreements & Purchases																	
CC Tolling #1	[redacted]																
CC Tolling #2	[redacted]																
CC Tolling #3	[redacted]																
Short Term Purchase	[redacted]																
Other Purchases[2]	[redacted]																
Future Units																	
Future CC Tolling #1	[redacted]																
Future CC Tolling #2	[redacted]																
Future CC Tolling #3	[redacted]																
Future CT Tolling #1	[redacted]																
Future CT Tolling #2	[redacted]																
Future CT Tolling #3	[redacted]																
Future CT Tolling #4	[redacted]																
Future CT Tolling #5	[redacted]																
Future CT Tolling #6	[redacted]																
Future CT #1	[redacted]																
Future CT #2	[redacted]																
Future CT #3	[redacted]																
Future CT #4	[redacted]																
Future CT #5	[redacted]																
Future CT #6	[redacted]																
Future CT #7	[redacted]																
Future CT #8	[redacted]																
Future CT #9	[redacted]																
Future CT #10	[redacted]																
Future CT #11	[redacted]																
Future CT #12	[redacted]																
Future CT #13	[redacted]																
Future Microgrids	[redacted]																
TOTAL		374	402	360	346	362	375	396	354	289	196	208	219	225	225	226	236

Notes:
(1) Emissions rates are based on 2023 estimates.
(2) Includes economic purchases from the market.

ATTACHMENT D.1(A)(8) – ENVIRONMENTAL IMPACTS (CONTINUED)

Water Consumption – B.1(q) (Acre-Feet)																	
UNIT	Rate[1] (Gal/MWh)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
PaloVerde 1,2,3	[redacted]																
Cholla 1,3	[redacted]																
Four Corners 4,5	[redacted]																
Ocotillo CTs 1-7	[redacted]																
Redhawk 1,2	[redacted]																
Saguaro CTs 1,2,3	[redacted]																
Sundance CTs 1-10	[redacted]																
West Phoenix CCs 1-5, CTs 1,2	[redacted]																
Yucca CTs 1-6	[redacted]																
Douglas	[redacted]																
Tolling Agreements & Purchases																	
CC Tolling #1	[redacted]																
CC Tolling #2	[redacted]																
CC Tolling #3	[redacted]																
	[redacted]																
Short Term Purchase	[redacted]																
	[redacted]																
Other Purchases[2]	[redacted]																
	[redacted]																
Salton Sea Geothermal	[redacted]																
Snowflake Biomass	[redacted]																
NW Regional Landfill	[redacted]																
Solana	[redacted]																

ATTACHMENT D.1(A)(8) – ENVIRONMENTAL IMPACTS (CONTINUED)

Water Consumption – B.1(q) (Acre-Feet)																	
UNIT	Rate[1] (Gal/MWh)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Future Units																	
Future CC Tolling #1	[redacted]																
Future CC Tolling #2	[redacted]																
Future CC Tolling #3	[redacted]																
Future CT Tolling #1	[redacted]																
Future CT Tolling #2	[redacted]																
Future CT Tolling #3	[redacted]																
Future CT Tolling #4	[redacted]																
Future CT Tolling #5	[redacted]																
Future CT Tolling #6	[redacted]																
Future CT #1	[redacted]																
Future CT #2	[redacted]																
Future CT #3	[redacted]																
Future CT #4	[redacted]																
Future CT #5	[redacted]																
Future CT #6	[redacted]																
Future CT #7	[redacted]																
Future CT #8	[redacted]																
Future CT #9	[redacted]																
Future CT #10	[redacted]																
Future CT #11	[redacted]																
Future CT #12	[redacted]																
Future CT #13	[redacted]																
TOTAL		**51,329**	**52,818**	**50,752**	**49,785**	**50,979**	**52,992**	**54,829**	**51,836**	**48,431**	**43,123**	**44,131**	**44,524**	**44,805**	**44,449**	**44,400**	**44,978**

Notes:
(1) Water rates are based on 2023 estimates.
[redacted]

ATTACHMENT D.1(A)(8) – ENVIRONMENTAL IMPACTS (CONTINUED)

Coal Ash Bottom Collected - B.1 (r) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Four Corners																	
Unit 4																	
Unit 5																	
Cholla																	
Unit 1																	
Unit 3																	
TOTAL		109,412	120,718	114,048	112,654	111,189	108,007	109,514	96,534	36,313	-	-	-	-	-	-	-

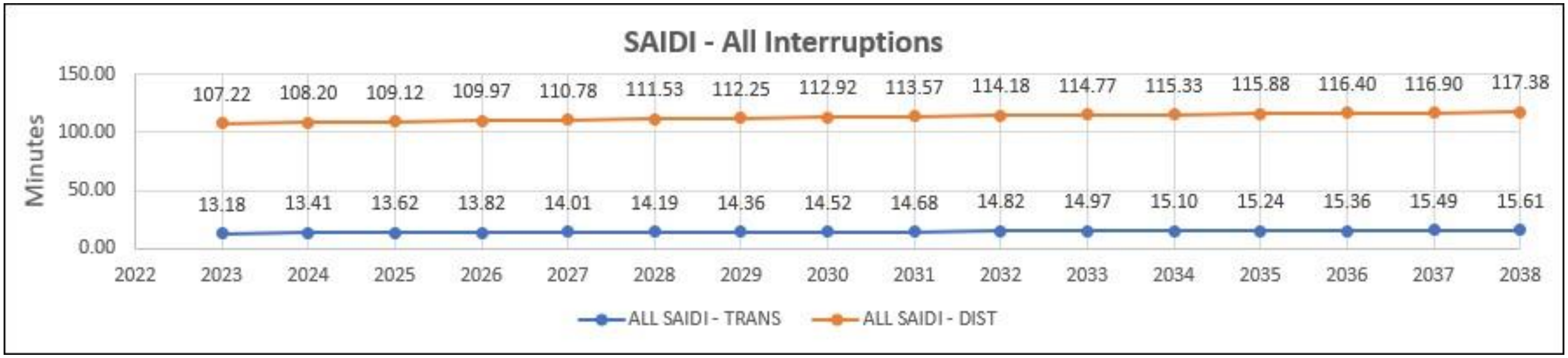
Notes:
(1) Emissions rates are based on 2023 estimates.

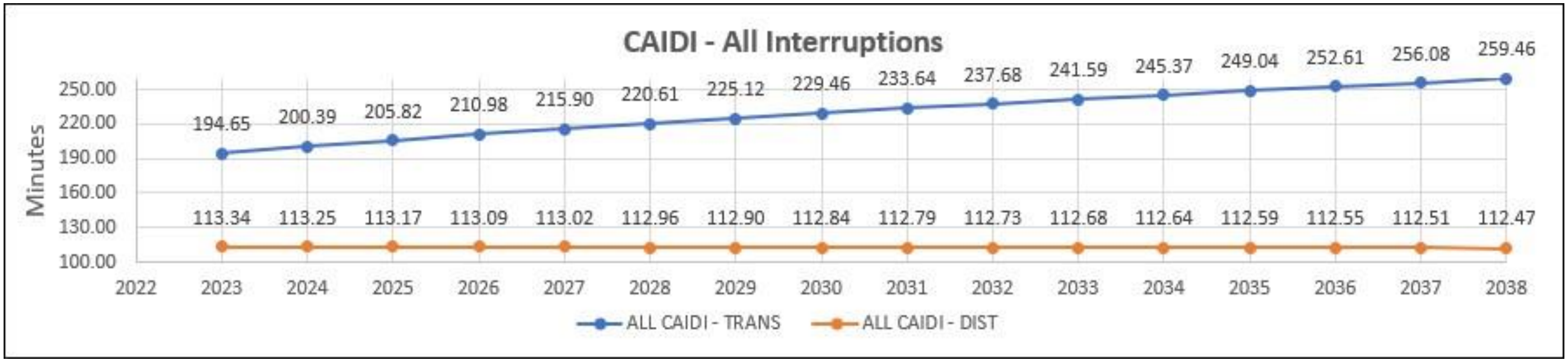
ATTACHMENT D.1(A)(8) – ENVIRONMENTAL IMPACTS (CONTINUED)

Coal Fly Ash Collected – B.1(r) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Four Corners																	
Unit 4																	
Unit 5																	
Cholla																	
Unit 1																	
Unit 3																	
TOTAL		**484,183**	**529,403**	**474,756**	**450,615**	**444,756**	**432,030**	**438,055**	**386,138**	**145,251**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

Notes:
(1) Emissions rates are based on 2023 estimates.

ATTACHMENT D.1(B): TRANSMISSION & DISTRIBUTION RELIABILITY





ATTACHMENT D.1(C): CAPITAL COST AND CONSTRUCTION SPENDING SCHEDULE

2023 Resource Plan - Capital Costs
Generation Construction Cash Flow without AFUDC
in Millions of Dollars

		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	Capital Costs through 2038 TOTAL
1 Peaking Generation																		
2	Future CT	[redacted]																
1	Future CT	[redacted]																
2	Future CT	[redacted]																
1	Future CT	[redacted]																
4	Future CT	[redacted]																
1	Future CT	[redacted]																
2	Future CT	[redacted]																
1	Solar + Storage System*ESS added to Existing	[redacted]																
1	Solar + Storage System	[redacted]																
1	Solar + Storage System	[redacted]																
1	Solar + Storage System	[redacted]																
1	Solar + Storage System	[redacted]																
	Subtotal	[redacted]																
2 Energy Storage																		
	Energy Storage System	[redacted]																
	Energy Storage System	[redacted]																
	Energy Storage System	[redacted]																
	Subtotal	[redacted]																
3 Microgrid Systems																		
	Microgrid	[redacted]																
	Microgrid	[redacted]																
	Microgrid	[redacted]																
	Microgrid	[redacted]																
	Subtotal	[redacted]																
4 Renewables																		
	New Wind	[redacted]																
	New Wind	[redacted]																
	New Wind	[redacted]																
	New Wind	[redacted]																
	New Wind	[redacted]																
	New Wind	[redacted]																
	New Wind	[redacted]																
	New Wind	[redacted]																
	New Wind	[redacted]																
	New Wind	[redacted]																

ATTACHMENT D.1(C): CAPITAL COST AND CONSTRUCTION SPENDING SCHEDULE (CONTINUED)

2023 Resource Plan - Capital Costs
Generation Construction Cash Flow without AFUDC
in Millions of Dollars

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	Capital Costs through 2038 TOTAL
4 Renewables (Continued)																	
New Solar	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
New Solar	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
New Solar	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
New Solar	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
New Solar	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
New Solar	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
New Solar	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
New Solar	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5 Grand Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6 Cumulative Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

ATTACHMENT D.1(F): TRANSMISSION PROJECTS

PROJECT DESCRIPTION	ISD	PARTICIPANTS	KV	RATING	TOTAL ESTIMATED COST ($MILLIONS)	LENGTH (MILES)	PURPOSE
McFarland Solar Project Generation Tie Project	2023	SDG&E	500	TBD	[redacted]	<1	To connect the McFarland Solar Project substation to Hoodoo Wash switchyard.
Chevelon Butte Wind Generation Tie Line	2023	APS	345	TBD	[redacted]	1	To connect the Chevelon Butte Wind Generation project to the Cholla-Preacher Canyon 345kV line.
Serrano Solar and Storage Project Generation Tie Line	2023	APS	230	TBD	[redacted]	~7	To connect the Serrano Solar and Storage Project substation to the Saguaro substation.
Contrail 230kV lines	2023	None	230	TBD	[redacted]	~7	To provide electric energy to a new high load customer in the area. In-service date is predicated on the ramp rate of customer load.
AES Energy Storage Project Interconnection at Westwing 230kV	2024	AES	230	TBD	[redacted]	<1	To connect the Battery Energy Storage Project to the Westwing 230kV substation.
Three Rivers 230kV lines	2024	None	230	TBD	[redacted]	~8	To provide electric energy to a new high load customer in the area. In-service date is predicated on ramp rate of customer load.
Parkway 230kV Lines	2024	None	230	TBD	[redacted]	<1	To provide electric energy to a new high load customer in the area. In-service date is predicated on ramp rate of customer loads.
Runway 230kV lines	2025	None	230	TBD	[redacted]	~4.5	To provide service to a new high load customer and additional redundancy to new and existing high load customers in the area. In-service date is predicated on ramp rate of customer load.
Broadway 230kV lines	2025	None	230	TBD	[redacted]	<1	To provide electric energy to a new high load customer in the area. In-service date is predicated on ramp rate of customer load.
Proving Ground Solar and Storage 500kV Interconnection	2025	Strata Clean Energy	500	TBD	[redacted]	<1	To connect the Proving Ground Solar and Battery Storage project to the Hoodoo Wash switchyard.
Hashknife Energy Center Generation Tie Line	2025	Hashknife Energy Center, LLC	500	TBD	[redacted]	<1	To connect the Hashknife Energy Center project to the Cholla substation.
TS24 230kV Lines	2026	None	230	TBD	[redacted]	<1	To provide electric energy to new high load customers in the area, as well as to continue to provide reliable service for the continued load growth in Pinal County. The TS24 Project will also fix existing paired element limitations at Casa Grande substation.
TS22 Project	2027	None	500/230	TBD	[redacted]	<1	To provide electric energy to a new high load customer in the area. In-service date is predicated on ramp rate of customer load.
Panda - Freedom 230kV Line Rebuild	2027	None	230	3000A	[redacted]	~40	To provide electric energy to a new high load customer in the area. The project will also be used to provide system reliability and serve numerous large load customers near Freedom with electric energy. This project will have double-circuit capability with one circuit in service in 2027 and the second circuit in service TBD.
Palm Valley - Parkway Switchyards	2027	None	230	TBD	[redacted]	<1	To provide electric energy to new high load customers in the area. In-service date is predicated on ramp rate of customer loads.
Sun Valley - TS23 230kV Line	2027	None	230	3000A	[redacted]	~18	To provide electric energy to growing load demands in the Wittmann area. This Project will also bring greater reliability to the Morristown and McMicken areas by adding an additional source to the 69kV system in the area.
Jojoba - Rudd 500kV Line	2028	None	500	TBD	[redacted]	~25	To provide an additional source to the west valley to strengthen the EHV sources serving the Phoenix metropolitan area, which is experiencing rapid economic development. Continued load growth, including high-load data center customers and semi-conductor manufacturing, will stress existing infrastructure, requiring a new path to bring generation into the load pocket. Additionally, this new source will provide customers in the area greater access to a diverse mix of resources from around the region.

Source: 2023-2032 Ten-Year Transmission System Plan dated January 2023.

ATTACHMENT D.3: GENERATION TECHNOLOGIES

Conventional Generation Technologies Assumptions

Plant	Location	Annual Capacity	Summer Capacity	Capital Cost ($/kW)	Book Life (Years)	Fixed O&M ($/kW-Yr)	Variable O&M ($/MWh)	Heat Rate (BTU/kWh)*	Capacity Factor %	CO2 Emmissions (lbs/mmBTU)	Water Consumption (gal/MWh)
NUCLEAR											
Advanced Nuclear	Palo Verde	2,156 MW	2,156 MW	6,790	40	165.14	3.21	10,443	94%	0	767
Small Modular Reactor (SMR)	Palo Verde	600 MW	600 MW	7,463	40	128.98	4.07	10,443	94%	0	740
NATURAL GAS											
Large Frame Combustion Turbine	Maricopa	222 MW	216 MW	900	35	24.25	5.77	9,138	10%	125	15
Aeroderivative Combustion Turbines	Maricopa	42/104 MW	41/102 MW	1,538	35	19.76	1.94/0.66	9,845/8,968	10%	122	111/141
Combined Cycle	Maricopa	547 MW	542 MW	1,042	35	31.61	2.01	7,753	50%	122	20
Combined Cycle with Carbon Capture Sequestration (CCS) 90%	Maricopa	377 MW	377 MW	2,224	35	71.28	6.79	8,724	50%	12	34
MICROGRID											
Genset	Maricopa	100 MW	100 MW	1,265	30	6.52	1.05	8,300	2%	161	0
ENERGY STORAGE											
Battery Energy Storage System (Li-ion) - 4 Hr.	Maricopa	100 MW	100 MW	1,853	20	46.32	0	*85%	15%	0	0
Battery Energy Storage System (Li-ion) - 5 Hr.	Maricopa	100 MW	100 MW	2,223	20	55.58	0	*85%	15%	0	0
Compressed Air Energy Storage (CAES)	Maricopa	100 MW	100 MW	4,176	30	22.74	2.02	*80%	15%	122	0
Pumped Storage Hydropower	Maricopa	100 MW	100 MW	3,376	30	20.16	0.58	*80%	15%	0	0

Renewable Generation Technologies Assumptions

Generation Resource Options	Summer Capacity	Capital Cost ($/kW)	Book Life (Years)	Fixed O&M ($/kW-Yr)	Variable O&M ($/MWh)	Capacity Factor %	CO2 Emmissions (lbs/mmBTU)	Water Consumption (gal/MWh)	Fuel Cost ($/MWh)
GRID-SCALE SOLAR									
Thin Film Solar - Utility Scale Single Axis Tracking	100 MW	1,721	40	20.55	0	35%	0	0	0
Thin Film Solar - Utility Scale Fixed	100 MW	1,426	40	20.55	0	25%	0	0	0
Solar PV + Battery Energy Storage System (PVS) - 4 Hr.	100 MW	3,573	40	66.87	0	34%	0	0	0
Solar PV + Battery Energy Storage System (PVS) - 5 Hr.	100 MW	3,944	40	76.14	0	34%	0	0	0
Solar Thermal Tower - Concentrating Solar Power (CSP)	130 MW	5,888	40	69.37	3.29	54%	0	134	0
Distributed Solar									
Solar - Distributed Commercial PV	150 kW	1,434	40	17.10	0	20%	0	0	0
Solar - Distributed Residential PV	5 kW	2,177	40	24.88	0	22%	0	0	0
OTHER RENEWABLE ENERGY SOURCES									
Southwest Wind	150 MW	1,760	40	46.36	0	50%	0	0	0
Geothermal	50 MW	6,226	30	154.51	0.00	80%	0	221	0
Biomass	50 MW	4,474	30	170.67	6.56	80%	0	553	68

Notes:
* Efficiency
1) Costs are in year-2025 dollars
2) Capital costs are overnight construction costs; $/kW is based on summer capacity rating
3) Capacity Factor % is an estimation based on technology type
4) In the LTCE, SMR, Advanced Nuclear are modeled as smaller traunches

ATTACHMENT D.10: 2023 RESOURCE PLAN - TOTAL REVENUE REQUIREMENTS

Total Revenue Requirements - Selected Portfolio ($Millions)																
YEAR	GENERATION						PURCHASES			SALES					TOTAL	
	Capital Rev. Req.	Fuel	Var . O&M	Fixed Fuel + O&M	New Trans-mission	Sub Total	Demand	Energy	Sub Total		Gas Transport	Imputed Debt	EMIS Costs	DE-EE Costs	$Millions	$/MWH
2023	746	508	71	369	10	1,704	118	573	691	0	84	25	0	115	2,619	79
2024	823	556	76	389	9	1,853	191	496	687	0	84	38	0	109	2,771	79
2025	839	584	72	351	9	1,855	469	496	965	0	85	93	0	113	3,110	84
2026	890	605	71	355	17	1,938	602	492	1,094	0	86	91	0	116	3,327	83
2027	1,008	649	77	390	21	2,145	648	487	1,135	0	97	88	0	120	3,584	83
2028	1,047	694	85	420	23	2,270	676	525	1,200	0	112	83	253	126	4,045	89
2029	1,103	765	92	443	26	2,428	680	477	1,157	0	120	79	277	128	4,189	89
2030	1,205	727	93	478	32	2,535	684	470	1,154	0	121	74	254	135	4,274	87
2031	1,284	738	91	492	97	2,701	688	469	1,158	0	131	69	219	141	4,419	88
2032	1,340	562	79	560	199	2,739	718	457	1,175	0	114	69	155	149	4,401	86
2033	1,339	614	96	587	203	2,838	731	457	1,188	0	117	67	170	148	4,529	87
2034	1,323	667	105	561	221	2,877	737	457	1,194	0	130	61	184	150	4,597	87
2035	1,313	711	123	577	233	2,957	761	453	1,214	0	133	60	193	155	4,713	87
2036	1,382	727	130	605	263	3,107	768	463	1,230	0	129	53	197	160	4,877	89
2037	1,602	749	135	647	297	3,431	774	440	1,214	0	125	50	202	166	5,187	93
2038	1,548	797	138	689	315	3,487	781	454	1,235	0	134	44	216	172	5,288	93
CPW@6.74%																
(2023-2038)	10,580	6,230	864	4,463	890	23,027	5,539	4,681	10,220	0	1,034	634	1,180	1,269	37,365	86

ATTACHMENT D.14(A): EE AND DR PROGRAM DESCRIPTIONS AND DEPLOYMENT

PROGRAM TYPE	NAME	DEPLOYMENT	RESIDENTIAL EE PROGRAM DESCRIPTION
Residential EE	1. Existing Homes	On-going	APS combined the Consumer Products, Existing Homes HVAC, and Home Performance with ENERGY STAR programs into one comprehensive Existing Homes program. The combined program offers a one-stop shop for APS customers and local trade allies to access all of the DSM program savings opportunities that are available for existing homes under one convenient umbrella including HVAC, Home Performance with Energy Star and smart thermostats.
Residential EE	2. New Construction	On-going	The Residential New Construction program promotes high efficiency construction practices for new homes through builder incentives. While the program emphasizes the “whole building” approach to improving EE and includes field testing of homes to ensure compliance with APS performance standards that are based off the EPA ENERGY STAR Homes program, participation in other Residential New Construction program measures including EV Pre-Wire and Smart Thermostats, EV Pre-Wire, Induction Cooking, and Connected Water Heating.
Residential EE	3. Low Income Weatherization	On-going	APS’s Energy Wise Low Income Weatherization program is designed to improve the energy efficiency, safety, and health attributes of homes occupied by customers whose income falls within 200% of the Federal Poverty Guidelines. The weatherization component of this program serves low-income customers with various home improvement measures, including cooling system repair and replacement, insulation, sunscreens, water heaters, window repairs and improvements, as well as other general household repairs. These programs are administered by various community action agencies throughout APS’s service territory. In 2020, the program partnered with local weatherization agencies and a non-profit multi-family rehabilitation project expert to encourage comprehensive retrofits of limited income multi-family properties. These projects leverage program funds with capital from building owners and other funding sources to offer added benefits for customers and extend the reach of program funds to improve cost effectiveness. In response to stakeholder input, the program also targets support to reach disadvantaged communities and provide upgrades for multifamily properties where at least 66% of residents are qualifying limited income customers, but where the program can also help other building tenants who are just above the federal income guidelines.
Residential EE	4. Conservation Behavior	On-going	The Residential Conservation Behavior program provides participating residential customers with periodic reports containing information designed to help motivate them to adopt energy conservation behaviors. The program provides direct-mailed reports to participants to show how the energy usage in their home compares with energy efficient and other similar homes. In 2020, APS expanded the use of Home Energy Reports as a tool to help limited income customers learn how their home uses energy and the best ways to save money on their home energy costs. In 2021, APS added a Rate Plan Coach element to the program to help customers reduce their on-peak energy use and save with their rate plan. In 2022, APS introduced Energy Saving Days voluntary demand response messages to the program which encourage energy savings on peak summer days.
Residential EE	5. Multi-Family Construction	On-going	The Multi-Family Energy Efficiency Program (MEEP) is a program that targets multi-family properties and dormitories with solutions designed to promote energy and demand savings, including a variety of EE new construction measures, and retrofit smart thermostats and connected water heaters/water heater controls.
Residential EE	6. Residential Battery Pilot	On-going	The Residential Battery Pilot supports the adoption of customer-sited, behind-the-meter distributed energy storage systems that can provide a wide variety of benefits to the grid. The Pilot will help APS learn about battery performance in a variety of conditions and how batteries may create value for customers through improved management of energy use at their residence while also helping reduce stress on the electric grid. The Pilot pays incentives for customers participating at either of two possible participation levels, data only or data and shared storage options.
Residential & Non-Residential EE	7. Codes & Standards	On-going	APS may count toward meeting the standard up to one third of the energy savings, resulting from energy efficiency building codes and appliance standards, that are quantified and reported through a measurement and evaluation study.

PROGRAM TYPE	NAME	DEPLOYMENT	RESIDENTIAL DR PROGRAM DESCRIPTION
Residential DR	1. TOU-E Saver Choice (4pm-7pm)	On-going	TOU-E (Saver Choice) is a seasonal energy-only rate. It has a summer period of May-October with all other months being winter. The rate features an on-peak period from 4pm-7pm for both summer and winter seasons. During the winter season this rate gains a super off-peak period from 10am-3pm.
Residential DR	2. R-2 Saver Choice Plus (4pm-7pm)	Frozen to new customers	R-2 (Saver Choice Plus) is a seasonal two-part rate that includes both demand and energy charges. It has a summer period of May-October with all other months being winter. The rate features an on-peak period from 4pm-7pm for both summer and winter seasons.
Residential DR	3. R-3 Saver Choice Max (4pm-7pm)	On-going	R-3 (Saver Choice Max) is a seasonal two-part rate that includes both demand and energy charges. It has a summer period of May-October with all other months being winter. The rate features an on-peak period from 4pm-7pm for both summer and winter seasons. The rate has a stronger demand price signal over R-2.
Residential DR	4. R-Tech Saver Choice Tech Pilot (3pm-8pm)	On-going	R-Tech (Saver Choice Tech) is a seasonal two-part rate that includes an on-peak and off-peak demand and energy charges. It has a summer period of May-October with all other months being winter. The rate features - an on-peak period from 3pm-8pm for both summer and winter seasons. The rate features a stronger demand - price signal over R-3 and a demand charge for off peak kW greater than 5 kW. This rate is only available to customers that have newly installed primary technologies such as solar, battery storage, or an electric vehicle, or two secondary technologies such as a variable speed HVAC, grid-interactive water heater, smart thermostat, or an automated load controller. This rate plan has an initial cap of 10,000 customers.
Residential DR	5. ET-1 Time Advantage (9am-9pm)	Frozen to new customers	ET-1 (Time Advantage) has an energy-only rate with an on-peak period from 9am-9pm. The program has been in place since 1982. In a previous rate case approved under A.C.C. Decision No. 71448, APS closed the series ET-1 rate to new customers. This rate is frozen and limited to only existing customers on the rate with distributed generation effective August 2017 in ACC Decision No. 76295.
Residential DR	6. ECT-1R Combined Advantage (9am-9pm)	Frozen to new customers	ECT-1R (Combined Advantage) includes both demand and energy charges. Similar to the ET-1 rate schedule, the peak hours are from 9am-9pm. APS anticipates closing the rate to all customers within the next three years and transitioning any remaining customers to the ET-2 or ECT-2 rates. This rate is frozen and limited to only existing customers on the rate with distributed generation effective August 2017 in ACC Decision No. 76295.
Residential DR	7. ET-2 Time Advantage (Noon – 7pm)	Frozen to new customers	ET-2 (Time Advantage) has an energy-only rate with an on-peak period from Noon- 7:00pm. This rate is frozen and limited to only existing customers on the rate with distributed generation effective August 2017 in ACC Decision No. 76295.

ATTACHMENT D.14(A): EE AND DR PROGRAM DESCRIPTIONS AND DEPLOYMENT (CONTINUED)

PROGRAM TYPE	NAME	DEPLOYMENT	RESIDENTIAL DR PROGRAM DESCRIPTION
Residential DR	8. ECT-2 Combined Advantage (Noon – 7pm)	Frozen to new customers	ECT-2 (Combined Advantage) includes demand and energy charges with a peak period of Noon – 7:00pm. This rate is frozen and limited to only existing customers on the rate with distributed generation effective August 2017 in ACC Decision No. 76295.
Residential DR	9. Peak Event Pricing (also referred to as Critical Peak Pricing)	On-going	Provides a high price signal over a small number of core summer peak days and hours. The program can be called on when the Company is experiencing extreme temperatures, very high electrical demand, high market electric costs, or is experiencing a major generation or transmission disturbance. The critical peak price signal is "dynamic" in that it is callable by APS for up to 18 days and 90 hours per year, weekdays during the months June through September. APS declares a "critical event" day and notifies participants by 4:00 p.m. the prior day. During the event the customer is charged an additional $0.25 per kWh for consumption during the hours 3pm to 8pm. The customer also receives a discount of approximately $0.012143 per kWh for all consumption during the June through September billing cycles. The prices are designed so that the monthly discounts equal the critical peak charges for the typical customer. Therefore, to save money, the customer must be able to reduce usage during critical hours.
Residential & Non-Residential DR	10. Energy & Demand Management Education	Ongoing	This program focuses on energy information tools, including web based energy and demand analyzers, personalized videos to guide customers through targeted savings opportunities that match their usage profiles, and enhance mobile phone apps that can provide near real time feedback on a home's demand and energy use. A key objective of the program is to help educate customers on ways to save energy and reduce their bills while we measure the EE savings resulting from behavioral changes in energy use that occur when the customer receives the enhanced energy information.
Residential & Non-Residential DR	11. EV Managed Charging Pilot	Ongoing	In the 2020 DSM Plan, APS received Commission approval for the EV Load Management Pilot which is designed to manage the peak demand impacts of the emerging electric vehicle market and help encourage beneficial charging behavior. The pilot currently includes the Smart Charge data share element to help gather better load research on EV charging behaviors, as well as offering incentives for residential customers to encourage them to adopt ENERGY STAR rated level two connected EV chargers. In the 2023 DSM Plan, APS is proposing two new program elements to encourage off peak charging and to conduct demand response with EV charging stations.
Residential Shade Trees	12. Shade Trees Program	Ongoing	APS reintroduced the Shade Tree program that was suspended in Decision No. 75323. The updated version of the program has been streamlined to improve cost-effectiveness based on input from residential customers, community groups and stakeholders. APS is working with local retail nurseries to implement the program so that participating customers will plant trees in locations that maximize the value of shade for EE and provide information online about proper tree planting and maintenance, as well as typical size of trees and availability. Incentives will be provided on a sliding scale between 25% to 75% of tree costs depending on the targeted areas with higher incentives being paid for trees planted in disadvantaged community neighborhoods, limited to two discounted trees per household.
Residential and Non Residential Tribal Communities	13. Tribal Communities Program	Ongoing	Tribal Community program incentive funding for EE projects will be split equally between residential and non-residential customers. Along with EE projects that serve individual homes, business and community solar, storage, electrification and EE projects designed to benefit tribal communities as a whole will also qualify.
Residential & Non-Residential DR	14. Demand Response, Energy Storage and Load Management Program	On-going	In 2016, APS filed for the Residential Demand Response, Energy Storage and Load Management (DRESLM) program which is deploying commercially available load management and load shifting technologies. The program is designed to support the deployment of residential load management, demand response and energy storage technologies that help APS residential customers shift energy use and manage peak demand while also providing system peak reduction and other grid operational benefits. The program includes three elements: battery storage with residential and commercial batteries, thermal storage with residential connected water heaters, and demand response with over 75,000 participating residential smart thermostats.

PROGRAM TYPE	NAME	DEPLOYMENT	NON-RESIDENTIAL EE PROGRAM DESCRIPTION
Non-Residential EE	1. Existing Facilities	On-going	The Existing Facilities program is targeted at customers for EE improvements in HVAC, motors, building envelope, and refrigeration measures. The program includes Large Existing facilities and Small Business. In 2020, APS added five new electrification pilot measures within the Non-Residential Existing Facilities and New Construction program including: Standby truck refrigeration, Electric forklifts, Airplane tugs, Airport luggage carts, and Airport luggage conveyors. APS is also proposing new EE measures designed for data centers. Incentives are also provided to customers who conduct qualifying energy studies. Custom incentives are also provided for EE measures not covered by the prescriptive incentives.
Non-Residential EE	2. New Construction	On-going	The Non-Residential New Construction program includes three components: (1) design assistance; (2) prescriptive measures; and (3) custom efficiency measures. Design assistance involves efforts to integrate EE into a customer's design process to influence equipment/system selection early in the process. Prescriptive incentives are available for EE improvements in measures such as HVAC, motors, building envelope, and refrigeration applications. Whole Building Design is a component within the New Construction custom efficiency measures that influences customers, developers, and design professionals to design, build, and invest in higher performing building through a stepped performance incentive structure with the financial incentives increasing as the building performance improves.
Non-Residential EE	3. Schools	On-going	The Schools program is designed to set aside funding for K-12 public, private, and charter school buildings. Schools can receive up to a maximum of $100,000 in incentives per year. EE incentives for Schools are the same as in the Existing Facilities (for existing school facilities) and New Construction (for new school construction and major renovation projects) programs. In addition, any size school may receive Direct Install measure incentives and is eligible to receive APS-arranged program financing for their EE projects.
Non-Residential EE	4. Energy Information Systems	On-going	The Energy Information Systems program is a subscription service for software that provides 15-minute interval electric usage data to large non-residential customers through a web-based energy information tool. This tool provides users with information that can be used to improve or monitor energy usage patterns, reduce energy use, reduce demands during on-peak periods, and to better manage overall energy operations.
Non-Residential EE	5. Advanced Rooftop Controls Pilot	On-going	The Advanced Rooftop Controls (ARC) pilot offers K-12 Schools and qualifying non-profit customers incentives for improving the efficiency of their HVAC system and indoor air quality by installing qualifying equipment including advanced rooftop controls with VSD, and an outdoor air economizer and energy management system. Prescriptive incentives are also available for DSM improvements in HVAC systems.

ATTACHMENT D.14(A): EE AND DR PROGRAM DESCRIPTIONS AND DEPLOYMENT (CONTINUED)

PROGRAM TYPE	NAME	DEPLOYMENT	NON-RESIDENTIAL DR PROGRAM DESCRIPTION
Non-Residential DR	1. E-20	On-going	Intended for houses of worship, E-20 was implemented in 1996. On-peak and off-peak charges are included for both energy and demand.
Non-Residential DR	2. E-221-8T	On-going	Designed for water pumping customers, the E-221-8T rate was implemented in 1986. On-peak and off-peak charges are included for both energy and demand.
Non-Residential DR	3. E-221 AG TOU	On-going	Designed for agricultural water pumping customers, the E-221 AG TOU rate was implemented in 2021. It includes three time periods On-peak (3pm-8pm M-F), Super Off-peak (10am-3pm)and off-peak charges are included for both energy and demand.
Non-Residential DR	4. E-32 XS TOU	On-going	For business customers, the E-32 TOU rates (which include extra small, small, medium, and large customers) were implemented in 2005 and are available for customers with less than 3 MW of monthly peak demand. On-peak and off-peak charges are included for both energy and demand.
Non-Residential DR	5. E-32 S TOU		
Non-Residential DR	6. E-32 M TOU		
Non-Residential DR	7. E-32 L TOU		
Non-Residential DR	8. E-32 L Storage Pilot	On-going	E-32 L SP is a time of use rate specialized for customers with onsite chemical, mechanical, or thermal energy storage systems. The rate has both energy and demand charges for On and Off peak with seasonal differentiation. The summer season is May through October and winter is November through April. The on peak period is 4pm to 9pm daily.
Non-Residential DR	9. E-35	On-going	E-35 was implemented in 1988 for extra large business customers exceeding 3 MW of monthly peak demand. On-peak and off-peak charges are included for both energy and demand.
Non-Residential DR	10. GS-Schools M	On-going	Designed for public and private schools providing primarily on-site K-12 education, the GS-Schools TOU rates were implemented in 2010 and are available to schools with less than 3 MW of monthly peak demand. The rates contain varied energy charges by seasons including summer (May-October) and winter (November through April). The demand charge is computed based on the monthly maximum demand.
Non-Residential DR	11. GS-Schools L		
Non-Residential DR	12. CPP-Critical Peak Pricing	On-going	Provides a high price signal over a small number of core summer peak days and hours. The program can be called on when the Company is experiencing extreme temperatures, very high electrical demand, high market electric costs, or is experiencing a major generation or transmission disturbance. The critical peak price signal is “dynamic” in that it is callable by APS for up to 18 days and 90 hours per year, weekdays during the months June through September. APS declares a “critical event” day and notifies participants by 4:00 p.m. the prior day. During the event the customer is charged an additional $0.25 per kWh for consumption during the hours 3pm to 8pm. The customer also receives a discount per kWh (amount varies by parent rate schedule) for all consumption during the June through September billing cycles. The prices are designed so that the monthly discounts equal the critical peak charges for the typical customer. Therefore, to save money, the customer must be able to reduce usage during critical hours.
Non-Residential DR	13. IRR-Interruptible Rate	On-going	The rate rider IRR was approved for July 1st 2012. IRR provides interruptible service for extra-large general service customers who can interrupt at least 500 kW of load when requested by the Company. Under this service, the customer can choose between two curtailment options, two notification options, and a one-year or five-year agreement. The customer receives capacity and energy payments for the interruptible load based on these options. The customer may also incur a penalty for failing to curtail when requested.
Non-Residential DR	14. Peak Solutions	On-going	APS Peak Solutions is a DR program approved in ACC Decision 71104 that offers financial incentives to eligible commercial and industrial customers to reduce their electricity usage on up to 18 DR events during APS's summer peak periods (June through September). Load reductions are created through customer adjustments to HVAC systems, lighting, refrigeration, and industrial processes.

1 Details on the Builder Option Packages can be found in Decision No. 72060 (Docket No. E-01345A-10-0219).
2 APS Peak Solutions Application filed, 11/6/2008, Docket E-01345A-08-0569.

ATTACHMENT D.14(B): EE PROGRAM PARTICIPATION[1]

RESIDENTIAL PROGRAM NAME	MEASURE OR UNIT	ACTUAL PARTICIPATION IN 2022
Existing Homes	Giveaway LEDs	29,493
	Marketplace LEDs	72,752
	Home Energy Analyzer	23,829
	Smart Thermostats	13,813
	Water Heater Timers	11
	AC with Quality Installation	8,963
	Audits	884
	Western Cool Control	3
	Duct Repair	965
	Direct install LED	4,420
	Insulation	684
	Low Flow Shower Heads	884
Residential New Construction	APS ENERGY STAR® Homes V3.0	9,663
	Ducts in Conditioned Space	2,063
	Connected Water Heaters	1
	Smart Thermostats	13,434
	EV - Prewire	263
Behavioral	Email Reports Generated	2,526,316
	Printed Reports Generated	1,947,260
	TOU with Demand Plan Coach emails	2,323,447
	Fixed Charge Plan Coach emails	3,821,631
	Behavioral DR Welcome Letters	330,000
	Behavioral DR Welcome emails	3,296,487
Multi-Family	Connected Water Heaters	0
	Connected Water Heater Controls	406
	Direct Install LEDs	22,866
	Smart Thermostats	52
	HVAC Quality Install	0
	NC Builder Package	2,782
	Common Area Measures	139,673
Low Income Weatherization	Weatherization	638
Residential Battery Pilot	Battery Systems - Data Only	179
	Battery Systems - Data plus Management	72
Tribal Communities	Tribal Communities - Residential	116
NON-RESIDENTIAL PROGRAM NAME	**MEASURE OR UNIT**	**ACTUAL PARTICIPATION IN 2022**
Existing Facilities	No. of Applications Paid	556
New Construction	No. of Applications Paid	131
Schools	No. of Applications Paid	61
Energy Information Systems	No. of Meters	87
Advanced Rooftop Controls Pilot	No. of Applications Paid	22
Tribal Communities	Tribal Communities - Non Residential	215
DSM INITIATIVES	**MEASURE OR UNIT**	**ACTUAL PARTICIPATION IN 2022**
EV Managed Charging	EV owners enrolled in data sharing	494
	Marketplace - level two smart EV chargers	543
DRESLM / Rewards	Cool Rewards - Smart Thermostats DR	73,868
	Storage Rewards - Residential Batteries	39
	C&I Demand Response	75

[1] Additional details pertaining to EE programs were provided in the 2022 APS Annual DSM Progress Report filed with the ACC on March 1, 2023.

ATTACHMENT D.16: GAS TRANSPORT ANALYSIS

YEAR	2023		2024		2025		2026		2027	
Season	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
Peak burn day (mmbtu/day)	**531,396**	**375,117**	**562,788**	**303,150**	**646,224**	**351,061**	**662,403**	**352,233**	**718,331**	**396,210**
Current firm fuel contracts										
El Paso - FT3HX000	99,994	36,888	99,994	36,888						
El Paso - FT39D000	100,742	56,145	108,266	56,145						
El Paso - FT39E000	24,375	11,250	33,473	11,250						
El Paso - FT39H000	31,500	19,000	31,500	19,000						
El Paso - H822E000	30,500	25,500								
El Paso - 613904	4,751		1,078		1,078		1,078		1,078	
El Paso - 617999	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000
El Paso - 611222[1]	30,759		30,759		30,759		30,759			
El Paso - 613881[2]	31,200		31,200		31,200		31,200		31,200	
El Paso - 613878[2]	40,200		40,200		40,200		40,200		40,200	
Transwestern - 102446	220,000	140,000	220,000	140,000	220,000	140,000	220,000	140,000	220,000	140,000
Transwestern - 104819[1]	53,900		53,900		65,600		65,600			
North Baja - A027F1 (Yuma Only)	11,000	11,000	11,000	11,000						
North Baja - YA027F1 (Yuma Only)	62,750	62,750	62,750	62,750						
Total Current firm contracts[3]	**682,921**	**303,783**	**665,370**	**278,283**	**403,837**	**155,000**	**403,837**	**155,000**	**307,478**	**155,000**

Rollover ROFR firm fuel contracts										
El Paso - FT3HX000					99,994	36,888	99,994	36,888	99,994	36,888
El Paso - FT39D000					108,266	56,145	108,266	56,145	108,266	36,795
El Paso - FT39E000					24,375	5,638	33,473	11,250	33,473	5,638
El Paso - FT39H000					31,500	19,000	31,500	19,000	31,500	19,000
El Paso - H822E000			30,500	25,500	30,500	25,500	30,500	25,500	30,500	25,500
El Paso - 613904										
El Paso - 617999										
El Paso - 611222[1]									30,759	
El Paso - 613881[2]										
El Paso - 613878[2]										
Transwestern - 102446										
Transwestern - 104819[1]									65,600	
North Baja - A027F1 (Yuma Only)					11,000	11,000	11,000	11,000	11,000	11,000
North Baja - YA027F1 (Yuma Only)					62,750	62,750	62,750	62,750	62,750	62,750
Total ROFR firm contracts[3]	**0**	**0**	**30,500**	**25,500**	**294,635**	**143,171**	**303,733**	**148,783**	**400,092**	**123,821**

Future fuel contracts[4]										
Long Term Seasonal Firm Purchases										
Short Term Purchases[5]	0	76,277	691	66,680	118,057	87,187	77,357	32,741	121,037	64,953
Total future contracts	0	76,277	691	66,680	118,057	87,187	77,357	32,741	121,037	64,953
Total contract rights	682,921	380,060	696,561	370,463	816,529	385,358	784,927	336,524	828,607	343,774
LONG/(SHORT) CONTRACT RIGHTS	**151,525**	**4,943**	**133,773**	**67,313**	**170,305**	**34,297**	**122,524**	**(15,709)**	**110,276**	**(52,437)**

[1]Contract serves Griffith PPA.
[2]Contract serves South Point PPA.
[3]North Baja capacity serving only Yuma is not included in total current firm contracts.
[4]Based upon hourly optimization analysis.
[5]Short Term Purchases include future potential gas transportation contracts and delivered gas products to cover shortfall in transportation.

ATTACHMENT D.16: GAS TRANSPORT ANALYSIS (CONTINUED)

Year	2028		2029		2030		2031		2032	
Season	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
Peak burn day (mmbtu/day)	**751,841**	**431,108**	**738,060**	**467,854**	**747,867**	**488,121**	**815,780**	**512,792**	**769,361**	**584,491**
Current firm fuel contracts										
El Paso - FT3HX000										
El Paso - FT39D000										
El Paso - FT39E000										
El Paso - FT39H000										
El Paso - H822E000										
El Paso - 613904										
El Paso - 617999	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000
El Paso - 611222[1]										
El Paso - 613881[2]										
El Paso - 613878[2]										
Transwestern - 102446	220,000	140,000								
Transwestern - 104819[1]										
North Baja - A027F1 (Yuma Only)										
North Baja - YA027F1 (Yuma Only)										
Total Current firm contracts[3]	**235,000**	**155,000**	**15,000**	**15,000**	**15,000**	**15,000**	**15,000**	**15,000**	**15,000**	**15,000**
Rollover ROFR firm fuel contracts										
El Paso - FT3HX000	99,994	36,888	99,994	36,888	99,994	36,888	86,509	36,888	99,994	36,888
El Paso - FT39D000	108,266	36,795	108,266	36,795	108,266	36,795	95,926	36,795	108,266	36,795
El Paso - FT39E000	33,473	5,638	33,473	5,638	33,473	5,638	18,676	5,638	33,473	5,638
El Paso - FT39H000	31,500	19,000	31,500	19,000	31,500	19,000	31,500	19,000	31,500	19,000
El Paso - H822E000	30,500	25,500	30,500	25,500	30,500	25,500	30,500	25,500	30,500	25,500
El Paso - 613904	4,751		4,751		4,751		12,751		4,751	
El Paso - 617999										
El Paso - 611222[1]	30,759		30,759		30,759		30,759		30,759	
El Paso - 613881[2]	31,200		31,200		31,200		31,200		31,200	
El Paso - 613878[2]	40,200		40,200		40,200		40,200		40,200	
Transwestern - 102446			220,000	140,000	220,000	100,000	200,000	140,000	195,000	100,000
Transwestern - 104819[1]	65,600		65,600		65,600		65,600		65,600	
North Baja - A027F1 (Yuma Only)	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000
North Baja - YA027F1 (Yuma Only)	62,750	62,750	62,750	62,750	62,750	62,750	62,750	62,750	62,750	62,750
Total ROFR firm contracts[3]	476,243	123,821	696,243	263,821	696,243	223,821	643,621	263,821	671,243	223,821
Future fuel contracts[4]										
Long Term Seasonal Firm Purchases										
Short Term Purchases[5]	148,708	89,849	199,212	59,524	233,115	93,848	215,415	150,217	282,630	121,469
Total future contracts	**148,708**	**89,849**	**199,212**	**59,524**	**233,115**	**93,848**	**215,415**	**150,217**	**282,630**	**121,469**
Total contract rights	**859,951**	**368,670**	**910,455**	**338,345**	**944,358**	**332,669**	**874,036**	**429,038**	**968,873**	**360,290**
Long/(Short) contract rights	**108,110**	**(62,438)**	**172,395**	**(129,509)**	**196,491**	**(155,452)**	**58,256**	**(83,754)**	**199,512**	**(224,201)**

[1]Contract serves Griffith PPA.
[2]Contract serves South Point PPA.
[3]North Baja capacity serving only Yuma is not included in total current firm contracts.
[4]Based upon hourly optimization analysis.
[5]Short Term Purchases include future potential gas transportation contracts and delivered gas products to cover shortfall in transportation.

ATTACHMENT D.16: GAS TRANSPORT ANALYSIS (CONTINUED)

Year	2033		2034		2035	
Season	Summer	Winter	Summer	Winter	Summer	Winter
Peak burn day (mmbtu/day)	**804,989**	**653,018**	**780,649**	**639,137**	**793,877**	**606,544**
Current firm fuel contracts						
El Paso - FT3HX000						
El Paso - FT39D000						
El Paso - FT39E000						
El Paso - FT39H000						
El Paso - H822E000						
El Paso - 613904						
El Paso - 617999	15,000	15,000	15,000	15,000	15,000	15,000
El Paso - 611222[1]						
El Paso - 613881[2]						
El Paso - 613878[2]						
Transwestern - 102446						
Transwestern - 104819[1]						
North Baja - A027F1 (Yuma Only)						
North Baja - YA027F1 (Yuma Only)						
Total Current firm contracts[3]	**15,000**	**15,000**	**15,000**	**15,000**	**15,000**	**15,000**
Rollover ROFR firm fuel contracts						
El Paso - FT3HX000	86,509	36,888	99,994	36,888	99,994	36,888
El Paso - FT39D000	95,926	52,026	78,550	56,145	108,266	64,839
El Paso - FT39E000	18,676	10,597	15,395	11,250	33,473	14,747
El Paso - FT39H000	31,500	19,000	27,000	19,000	31,500	23,000
El Paso - H822E000	30,500	25,500	30,500	25,500	30,500	25,500
El Paso - 613904	12,751		19,494		1,078	
El Paso - 617999						
El Paso - 611222[1]	30,759		30,759		30,759	
El Paso - 613881[2]	31,200		31,200		31,200	
El Paso - 613878[2]	40,200		40,200		40,200	
Transwestern - 102446	200,000	140,000	195,000	140,000	220,000	100,000
Transwestern - 104819[1]	65,600		65,600		65,600	
North Baja - A027F1 (Yuma Only)	11,000	11,000	11,000	11,000	11,000	11,000
North Baja - YA027F1 (Yuma Only)	62,750	62,750	62,750	62,750	62,750	62,750
Total ROFR firm contracts[3]	643,621	284,011	633,692	288,783	692,570	264,974
Future fuel contracts[4]						
Long Term Seasonal Firm Purchases						
Short Term Purchases[5]	244,694	122,869	223,375	141,641	191,737	143,865
Total future contracts	**244,694**	**122,869**	**223,375**	**141,641**	**191,737**	**143,865**
Total contract rights	**903,315**	**421,880**	**872,067**	**445,424**	**899,307**	**423,839**
Long/(Short) contract rights	**98,326**	**(231,138)**	**91,418**	**(193,713)**	**105,429**	**(182,705)**

[1]Contract serves Griffith PPA.
[2]Contract serves South Point PPA.
[3]North Baja capacity serving only Yuma is not included in total current firm contracts.
[4]Based upon hourly optimization analysis.
[5]Short Term Purchases include future potential gas transportation contracts and delivered gas products to cover shortfall in transportation.

ATTACHMENT D.16: GAS TRANSPORT ANALYSIS (CONTINUED)

Year	2036		2037		2038	
Season	Summer	Winter	Summer	Winter	Summer	Winter
Peak burn day (mmbtu/day)	**758,396**	**619,044**	**770,424**	**606,576**	**757,023**	**623,131**
Current firm fuel contracts						
El Paso - FT3HX000						
El Paso - FT39D000						
El Paso - FT39E000						
El Paso - FT39H000						
El Paso - H822E000						
El Paso - 613904						
El Paso - 617999	15,000	15,000	15,000	15,000	15,000	15,000
El Paso - 611222[1]						
El Paso - 613881[2]						
El Paso - 613878[2]						
Transwestern - 102446						
Transwestern - 104819[1]						
North Baja - A027F1 (Yuma Only)						
North Baja - YA027F1 (Yuma Only)						
Total Current firm contracts[3]	**15,000**	**15,000**	**15,000**	**15,000**	**15,000**	**15,000**
Rollover ROFR firm fuel contracts						
El Paso - FT3HX000	99,994	36,888	99,994	36,888	99,994	36,888
El Paso - FT39D000	108,266	64,839	108,266	64,839	108,266	56,145
El Paso - FT39E000	33,473	14,747	33,473	14,747	33,473	11,250
El Paso - FT39H000	31,500	23,000	31,500	23,000	31,500	19,000
El Paso - H822E000	30,500	25,500	30,500	25,500	30,500	25,500
El Paso - 613904	1,078		1,078		1,078	
El Paso - 617999						
El Paso - 611222[1]	30,759		30,759		30,759	
El Paso - 613881[2]	31,200		31,200		31,200	
El Paso - 613878[2]	40,200		40,200		40,200	
Transwestern - 102446	220,000	100,000	220,000	100,000	220,000	140,000
Transwestern - 104819[1]	65,600		65,600		65,600	
North Baja - A027F1 (Yuma Only)	11,000	11,000	11,000	11,000	11,000	11,000
North Baja - YA027F1 (Yuma Only)	62,750	62,750	62,750	62,750	62,750	62,750
Total ROFR firm contracts[3]	692,570	264,974	692,570	264,974	692,570	288,783
Future fuel contracts[4]						
Long Term Seasonal Firm Purchases						
Short Term Purchases[5]	203,842	134,620	189,005	123,742	191,781	139,782
Total future contracts	**203,842**	**134,620**	**189,005**	**123,742**	**191,781**	**139,782**
Total contract rights	**911,412**	**414,594**	**896,575**	**403,716**	**899,351**	**443,565**
Long/(Short) contract rights	**153,015**	**(204,450)**	**126,150**	**(202,860)**	**142,328**	**(179,566)**

[1]Contract serves Griffith PPA.
[2]Contract serves South Point PPA.
[3]North Baja capacity serving only Yuma is not included in total current firm contracts.
[4]Based upon hourly optimization analysis.
[5]Short Term Purchases include future potential gas transportation contracts and delivered gas products to cover shortfall in transportation.

ATTACHMENT F.1(A)(1): REFERENCE L&R AND ENERGY MIX

	Reference - Loads & Resources - MW Energy Contribution at Peak																
		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
1	**Load Requirements**																
2	APS Peak Demand	8,184	8,594	9,012	9,525	10,020	10,427	10,805	11,127	11,398	11,646	11,903	12,146	12,386	12,634	12,877	13,119
3	Reserve Requirements	1,201	1,247	1,304	1,349	1,330	1,124	1,122	1,142	1,413	1,450	1,165	1,295	1,254	1,605	1,685	1,703
4	**Total Load Requirements**	9,385	9,841	10,316	10,874	11,350	11,551	11,927	12,269	12,811	13,096	13,068	13,442	13,641	14,240	14,562	14,823
5	**Existing Resources**																
6	Nuclear	1,146	1,146	1,146	978	978	978	978	978	978	978	978	978	978	978	978	978
7	Coal	1,347	1,347	970	828	828	828	828	828	0	0	0	0	0	0	0	0
8	Natural Gas	5,832	5,489	5,320	4,577	4,581	4,583	4,492	4,401	4,311	3,799	3,351	3,354	2,869	2,873	2,874	2,875
9	Combined Cycle	1,844	1,997	1,997	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661
10	Combustion / Steam Turbines	1,503	1,520	1,520	1,363	1,363	1,363	1,270	1,176	1,082	1,082	1,082	1,082	1,082	1,082	1,082	1,082
11	Tolling Agreements	1,598	1,598	1,660	1,446	1,446	1,446	1,446	1,446	1,446	934	486	486	0	0	0	0
12	Market / Call Options / Hedges /AG-X	887	374	142	106	110	112	115	118	121	122	122	125	126	130	131	131
13	Renewable Energy	475	476	463	440	444	444	449	443	448	446	441	435	434	442	404	403
14	Distributed Energy	6	6	6	14	14	14	14	14	14	14	13	14	13	14	10	9
15	PURPA QF	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16	Solar	356	343	328	296	296	294	295	295	296	293	291	293	291	294	291	290
17	Wind	87	100	103	106	111	113	117	120	124	125	125	128	130	135	103	104
18	Geothermal	10	10	10	9	9	9	9	0	0	0	0	0	0	0	0	0
19	Biomass/Biogas	16	16	16	15	15	15	15	15	15	15	12	0	0	0	0	0
20	Energy Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21	Microgrid	35	35	35	30	30	30	30	30	30	30	30	30	30	30	30	30
22	**Total Existing Resources**	8,835	8,492	7,934	6,852	6,860	6,862	6,777	6,679	5,766	5,252	4,800	4,796	4,310	4,322	4,285	4,285
23	**Customer Resources**																
24	Future Energy Efficiency	132	234	319	327	404	489	581	687	780	852	931	1,035	1,127	1,244	1,322	1,412
25	Future Distributed Energy	11	27	48	288	358	412	469	513	559	582	605	653	674	733	751	777
26	Demand Response (Future & Existing)	90	95	144	145	145	195	192	240	275	320	310	300	305	310	315	320
27	**Total Customer Resources**	232	355	512	760	906	1,095	1,242	1,439	1,613	1,754	1,845	1,987	2,105	2,286	2,388	2,509
28	**Future Resources**																
29	Nuclear (SMR)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	Natural Gas	0	199	0	171	264	319	359	439	1,501	2,013	2,461	2,461	2,948	3,153	3,153	3,153
31	Combined Cycle	0	0	0	0	0	0	0	0	0	512	960	960	1,446	1,446	1,446	1,446
32	Combustion Turbines	0	0	0	80	199	319	359	439	1,501	1,501	1,501	1,501	1,501	1,707	1,707	1,707
33	Short-Term Purchases/Summer Contracts	0	199	0	91	64	0	0	0	0	0	0	0	0	0	0	0
34	Renewable Energy	62	115	101	271	307	305	328	447	462	719	743	732	775	953	1,053	1,043
35	Wind	62	115	101	271	268	274	292	318	329	545	547	567	574	746	828	832
36	Solar	0	0	0	0	40	31	36	128	133	174	195	165	202	206	224	211
37	Bio/Geothermal/CSP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
38	PVS (PV + BESS)	240	525	1,531	1,691	1,877	1,871	2,152	2,206	2,217	2,234	2,258	2,228	2,271	2,268	2,402	2,331
39	Energy Storage	24	97	338	585	591	603	628	642	661	660	661	680	682	706	748	958
40	Microgrid	8	58	58	544	544	544	544	544	742	742	742	742	742	742	767	767
41	**Total Future Resources**	333	993	2,028	3,262	3,584	3,643	4,011	4,278	5,583	6,369	6,865	6,843	7,418	7,822	8,123	8,252
42	**TOTAL RESOURCES**	**9,400**	**9,841**	**10,474**	**10,874**	**11,350**	**11,600**	**12,030**	**12,397**	**12,962**	**13,375**	**13,510**	**13,626**	**13,833**	**14,431**	**14,795**	**15,047**

ATTACHMENT F.1(A)(1): REFERENCE L&R AND ENERGY MIX (CONTINUED)

Energy Mix - Reference

ENERGY (GWH)							
	Nuclear	Coal	Gas	Renew	DSM	Purchase	TOT
2023	9,243	6,456	8,528	6,975	7,858	5,074	44,136
2024	9,314	7,033	9,178	8,625	8,172	4,618	46,940
2025	9,290	6,145	9,798	11,709	8,498	4,608	50,047
2026	9,291	5,702	10,722	15,149	8,831	4,217	53,912
2027	9,296	5,634	12,451	16,867	9,173	4,343	57,763
2028	9,308	5,400	13,547	17,441	9,523	5,536	60,755
2029	9,280	5,416	13,722	19,565	9,879	5,629	63,491
2030	9,296	4,593	13,453	22,839	10,242	5,316	65,738
2031	9,281	1,574	17,428	23,158	10,609	5,486	67,535
2032	9,300	0	15,878	27,355	10,978	5,656	69,167
2033	9,296	0	16,632	27,848	11,349	5,627	70,753
2034	9,281	0	16,796	28,874	11,723	5,611	72,285
2035	9,280	0	17,544	29,155	12,100	5,619	73,699
2036	9,314	0	16,286	31,663	12,480	5,532	75,275
2037	9,290	0	15,804	33,414	12,862	5,468	76,837
2038	9,289	0	16,420	33,971	13,246	5,512	78,439

ENERGY MIX %							
	Nuclear	Coal	Gas	Renew	DSM	Purchase	TOT
2023	20.9%	14.6%	19.3%	15.8%	17.8%	11.5%	100.0%
2024	19.8%	15.0%	19.6%	18.4%	17.4%	9.8%	100.0%
2025	18.6%	12.3%	19.6%	23.4%	17.0%	9.2%	100.0%
2026	17.2%	10.6%	19.9%	28.1%	16.4%	7.8%	100.0%
2027	16.1%	9.8%	21.6%	29.2%	15.9%	7.5%	100.0%
2028	15.3%	8.9%	22.3%	28.7%	15.7%	9.1%	100.0%
2029	14.6%	8.5%	21.6%	30.8%	15.6%	8.9%	100.0%
2030	14.1%	7.0%	20.5%	34.7%	15.6%	8.1%	100.0%
2031	13.7%	2.3%	25.8%	34.3%	15.7%	8.1%	100.0%
2032	13.4%	0.0%	23.0%	39.5%	15.9%	8.2%	100.0%
2033	13.1%	0.0%	23.5%	39.4%	16.0%	8.0%	100.0%
2034	12.8%	0.0%	23.2%	39.9%	16.2%	7.8%	100.0%
2035	12.6%	0.0%	23.8%	39.6%	16.4%	7.6%	100.0%
2036	12.4%	0.0%	21.6%	42.1%	16.6%	7.3%	100.0%
2037	12.1%	0.0%	20.6%	43.5%	16.7%	7.1%	100.0%
2038	11.8%	0.0%	20.9%	43.3%	16.9%	7.0%	100.0%

1) Renew includes DE installed since 2008. EE includes energy beginning in 2005.

2) Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts

3) Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

ATTACHMENT F.1(A)(2): FOUR CORNERS COAL EXIT 2027 L&R AND ENERGY MIX

	Four Corners Coal Exit 2027 - Loads & Resources - MW Energy Contribution at Peak																
		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
1	**Load Requirements**																
2	APS Peak Demand	8,184	8,594	9,012	9,525	10,020	10,427	10,805	11,127	11,398	11,646	11,903	12,146	12,386	12,634	12,877	13,119
3	Reserve Requirements	1,201	1,247	1,304	1,349	1,330	1,124	1,122	1,142	1,413	1,450	1,165	1,295	1,254	1,605	1,685	1,703
4	**Total Load Requirements**	9,385	9,841	10,316	10,874	11,350	11,551	11,927	12,269	12,811	13,096	13,068	13,442	13,641	14,240	14,562	14,823
5	**Existing Resources**																
6	Nuclear	1,146	1,146	1,146	978	978	978	978	978	978	978	978	978	978	978	978	978
7	Coal	1,347	1,347	970	828	828	0	0	0	0	0	0	0	0	0	0	0
8	Natural Gas	5,832	5,489	5,320	4,577	4,581	4,583	4,492	4,401	4,311	3,799	3,351	3,354	2,869	2,873	2,874	2,875
9	Combined Cycle	1,844	1,997	1,997	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661
10	Combustion / Steam Turbines	1,503	1,520	1,520	1,363	1,363	1,363	1,270	1,176	1,082	1,082	1,082	1,082	1,082	1,082	1,082	1,082
11	Tolling Agreements	1,598	1,598	1,660	1,446	1,446	1,446	1,446	1,446	1,446	934	486	486	0	0	0	0
12	Market / Call Options / Hedges /AG-X	887	374	142	106	110	112	115	118	121	122	122	125	126	130	131	131
13	Renewable Energy	475	476	463	440	444	444	449	443	448	446	441	435	434	442	404	403
14	Distributed Energy	6	6	6	14	14	14	14	14	14	14	13	14	13	14	10	9
15	PURPA QF	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16	Solar	356	343	328	296	296	294	295	295	296	293	291	293	291	294	291	290
17	Wind	87	100	103	106	111	113	117	120	124	125	125	128	130	135	103	104
18	Geothermal	10	10	10	9	9	9	9	0	0	0	0	0	0	0	0	0
19	Biomass/Biogas	16	16	16	15	15	15	15	15	15	15	12	0	0	0	0	0
20	Energy Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21	Microgrid	35	35	35	30	30	30	30	30	30	30	30	30	30	30	30	30
22	**Total Existing Resources**	8,835	8,492	7,934	6,852	6,860	6,034	5,949	5,851	5,766	5,252	4,800	4,796	4,310	4,322	4,285	4,285
23	**Customer Resources**																
24	Future Energy Efficiency	132	234	319	327	404	489	581	687	780	852	931	1,035	1,127	1,244	1,322	1,412
25	Future Distributed Energy	11	27	48	288	358	412	469	513	559	582	605	653	674	733	751	777
26	Demand Response (Future & Existing)	90	95	144	145	145	195	192	240	275	320	310	300	305	310	315	320
27	**Total Customer Resources**	232	355	512	760	906	1,095	1,242	1,439	1,613	1,754	1,845	1,987	2,105	2,286	2,388	2,509
28	**Future Resources**																
29	Nuclear (SMR)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	Natural Gas	0	199	0	199	263	1,046	1,291	1,411	1,491	2,003	2,451	2,451	3,143	3,143	3,143	3,143
31	Combined Cycle	0	0	0	0	0	0	0	0	0	512	960	960	1,446	1,446	1,446	1,446
32	Combustion Turbines	0	0	0	80	199	1,046	1,291	1,411	1,491	1,491	1,491	1,491	1,697	1,697	1,697	1,697
33	Short-Term Purchases/Summer Contracts	0	199	0	119	64	0	0	0	0	0	0	0	0	0	0	0
34	Renewable Energy	62	115	101	244	308	389	404	469	502	760	780	760	809	918	1,093	1,081
35	Wind	62	115	101	231	268	282	295	319	329	545	546	566	572	711	832	835
36	Solar	0	0	0	12	40	107	109	151	172	215	234	194	237	207	261	246
37	Bio/Geothermal/CSP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
38	PVS (PV + BESS)	240	525	1,531	1,691	1,877	1,881	1,918	1,924	1,932	1,938	1,945	1,936	1,948	1,939	2,089	2,055
39	Energy Storage	24	97	338	585	591	603	834	869	907	915	928	940	966	976	980	1,161
40	Microgrid	8	58	58	544	544	544	544	544	742	742	742	742	742	742	767	767
41	**Total Future Resources**	333	993	2,028	3,262	3,584	4,463	4,992	5,218	5,574	6,358	6,846	6,829	7,609	7,718	8,072	8,207
42	**TOTAL RESOURCES**	**9,400**	**9,841**	**10,474**	**10,874**	**11,350**	**11,592**	**12,183**	**12,508**	**12,952**	**13,364**	**13,491**	**13,612**	**14,024**	**14,327**	**14,744**	**15,001**

ATTACHMENT F.1(A)(2): FOUR CORNERS COAL EXIT 2027 L&R AND ENERGY MIX (CONTINUED)

Energy Mix - Four Corners Coal Exit 2027

ENERGY (GWH)							
	Nuclear	Coal	Gas	Renew	DSM	Purchase	TOT
2023	9,243	6,464	8,529	6,975	7,858	5,066	44,136
2024	9,314	7,031	9,191	8,625	8,172	4,607	46,941
2025	9,290	6,143	9,802	11,709	8,498	4,606	50,048
2026	9,291	5,701	10,725	15,149	8,831	4,215	53,912
2027	9,296	5,619	12,465	16,865	9,173	4,345	57,763
2028	9,308	0	16,192	20,326	9,523	5,441	60,790
2029	9,280	0	17,705	20,929	9,879	5,707	63,501
2030	9,296	0	17,750	22,860	10,242	5,582	65,729
2031	9,281	0	18,882	23,169	10,609	5,591	67,531
2032	9,300	0	15,873	27,363	10,978	5,655	69,170
2033	9,296	0	16,889	27,564	11,349	5,657	70,754
2034	9,281	0	17,029	28,608	11,723	5,642	72,283
2035	9,280	0	17,776	28,885	12,100	5,652	73,693
2036	9,314	0	16,975	30,922	12,480	5,579	75,270
2037	9,290	0	15,869	33,333	12,862	5,456	76,809
2038	9,289	0	16,469	33,900	13,246	5,507	78,411

ENERGY MIX %							
	Nuclear	Coal	Gas	Renew	DSM	Purchase	TOT
2023	20.9%	14.6%	19.3%	15.8%	17.8%	11.5%	100.0%
2024	19.8%	15.0%	19.6%	18.4%	17.4%	9.8%	100.0%
2025	18.6%	12.3%	19.6%	23.4%	17.0%	9.2%	100.0%
2026	17.2%	10.6%	19.9%	28.1%	16.4%	7.8%	100.0%
2027	16.1%	9.7%	21.6%	29.2%	15.9%	7.5%	100.0%
2028	15.3%	0.0%	26.6%	33.4%	15.7%	9.0%	100.0%
2029	14.6%	0.0%	27.9%	33.0%	15.6%	9.0%	100.0%
2030	14.1%	0.0%	27.0%	34.8%	15.6%	8.5%	100.0%
2031	13.7%	0.0%	28.0%	34.3%	15.7%	8.3%	100.0%
2032	13.4%	0.0%	22.9%	39.6%	15.9%	8.2%	100.0%
2033	13.1%	0.0%	23.9%	39.0%	16.0%	8.0%	100.0%
2034	12.8%	0.0%	23.6%	39.6%	16.2%	7.8%	100.0%
2035	12.6%	0.0%	24.1%	39.2%	16.4%	7.7%	100.0%
2036	12.4%	0.0%	22.6%	41.1%	16.6%	7.4%	100.0%
2037	12.1%	0.0%	20.7%	43.4%	16.7%	7.1%	100.0%
2038	11.8%	0.0%	21.0%	43.2%	16.9%	7.0%	100.0%

1) Renew includes DE installed since 2008. EE includes energy beginning in 2005.
2) Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts
3) Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

ATTACHMENT F.1(A)(3): FOUR CORNERS COAL EXIT 2028 L&R AND ENERGY MIX

	Four Corners Coal Exit 2028 - Loads & Resources - MW Energy Contribution at Peak																
		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
1	**Load Requirements**																
2	APS Peak Demand	8,184	8,594	9,012	9,525	10,020	10,427	10,805	11,127	11,398	11,646	11,903	12,146	12,386	12,634	12,877	13,119
3	Reserve Requirements	1,201	1,247	1,304	1,349	1,330	1,124	1,122	1,142	1,413	1,450	1,165	1,295	1,254	1,605	1,685	1,703
4	**Total Load Requirements**	9,385	9,841	10,316	10,874	11,350	11,551	11,927	12,269	12,811	13,096	13,068	13,442	13,641	14,240	14,562	14,823
5	**Existing Resources**																
6	Nuclear	1,146	1,146	1,146	978	978	978	978	978	978	978	978	978	978	978	978	978
7	Coal	1,347	1,347	970	828	828	828	0	0	0	0	0	0	0	0	0	0
8	Natural Gas	5,832	5,489	5,320	4,577	4,581	4,583	4,492	4,401	4,311	3,799	3,351	3,354	2,869	2,873	2,874	2,875
9	Combined Cycle	1,844	1,997	1,997	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661
10	Combustion / Steam Turbines	1,503	1,520	1,520	1,363	1,363	1,363	1,270	1,176	1,082	1,082	1,082	1,082	1,082	1,082	1,082	1,082
11	Tolling Agreements	1,598	1,598	1,660	1,446	1,446	1,446	1,446	1,446	1,446	934	486	486	0	0	0	0
12	Market / Call Options / Hedges /AG-X	887	374	142	106	110	112	115	118	121	122	122	125	126	130	131	131
13	Renewable Energy	475	476	463	440	444	444	449	443	448	446	441	435	434	442	404	403
14	Distributed Energy	6	6	6	14	14	14	14	14	14	14	13	14	13	14	10	9
15	PURPA QF	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16	Solar	356	343	328	296	296	294	295	295	296	293	291	293	291	294	291	290
17	Wind	87	100	103	106	111	113	117	120	124	125	125	128	130	135	103	104
18	Geothermal	10	10	10	9	9	9	9	0	0	0	0	0	0	0	0	0
19	Biomass/Biogas	16	16	16	15	15	15	15	15	15	15	12	0	0	0	0	0
20	Energy Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21	Microgrid	35	35	35	30	30	30	30	30	30	30	30	30	30	30	30	30
22	**Total Existing Resources**	8,835	8,492	7,934	6,852	6,860	6,862	5,949	5,851	5,766	5,252	4,800	4,796	4,310	4,322	4,285	4,285
23	**Customer Resources**																
24	Future Energy Efficiency	132	234	319	327	404	489	581	687	780	852	931	1,035	1,127	1,244	1,322	1,412
25	Future Distributed Energy	11	27	48	288	358	412	469	513	559	582	605	653	674	733	751	777
26	Demand Response (Future & Existing)	90	95	144	145	145	195	192	240	275	320	310	300	305	310	315	320
27	**Total Customer Resources**	232	355	512	760	906	1,095	1,242	1,439	1,613	1,754	1,845	1,987	2,105	2,286	2,388	2,509
28	**Future Resources**																
29	Nuclear (SMR)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	Natural Gas	0	199	0	199	263	319	1,262	1,422	1,501	2,013	2,461	2,461	2,948	3,153	3,153	3,153
31	Combined Cycle	0	0	0	0	0	0	0	0	0	512	960	960	1,446	1,446	1,446	1,446
32	Combustion Turbines	0	0	0	80	199	319	1,262	1,422	1,501	1,501	1,501	1,501	1,501	1,707	1,707	1,707
33	Short-Term Purchases/Summer Contracts	0	199	0	119	64	0	0	0	0	0	0	0	0	0	0	0
34	Renewable Energy	62	115	101	239	308	305	397	447	449	741	738	758	750	878	1,038	1,058
35	Wind	62	115	101	239	268	274	297	318	329	546	546	568	574	705	832	838
36	Solar	0	0	0	0	40	31	100	128	120	195	192	190	176	174	205	220
37	Bio/Geothermal/CSP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
38	PVS (PV + BESS)	240	525	1,531	1,691	1,877	1,871	2,189	2,206	2,195	2,257	2,257	2,251	2,247	2,242	2,294	2,254
39	Energy Storage	24	97	338	589	591	603	628	642	661	660	661	680	682	706	777	989
40	Microgrid	8	58	58	544	544	544	544	544	742	742	742	742	742	742	767	767
41	**Total Future Resources**	333	993	2,028	3,262	3,584	3,643	5,020	5,260	5,548	6,414	6,860	6,892	7,369	7,722	8,029	8,222
42	**TOTAL RESOURCES**	**9,400**	**9,841**	**10,474**	**10,874**	**11,350**	**11,600**	**12,211**	**12,551**	**12,927**	**13,420**	**13,505**	**13,675**	**13,785**	**14,331**	**14,702**	**15,016**

ATTACHMENT F.1(A)(3): FOUR CORNERS COAL EXIT 2028 L&R AND ENERGY MIX (CONTINUED)

Energy Mix - Four Corners Coal Exit 2028

ENERGY (GWH)							
	Nuclear	Coal	Gas	Renew	DSM	Purchase	TOT
2023	9,243	6,457	8,542	6,975	7,858	5,060	44,136
2024	9,314	7,033	9,182	8,625	8,172	4,615	46,940
2025	9,290	6,145	9,795	11,709	8,498	4,612	50,048
2026	9,291	5,702	10,734	15,149	8,831	4,206	53,913
2027	9,296	5,628	12,463	16,865	9,173	4,339	57,763
2028	9,308	5,458	13,496	17,441	9,523	5,531	60,756
2029	9,280	0	17,141	21,583	9,879	5,627	63,510
2030	9,296	0	17,781	22,834	10,242	5,575	65,727
2031	9,281	0	18,910	23,158	10,609	5,573	67,531
2032	9,300	0	15,773	27,474	10,978	5,643	69,168
2033	9,296	0	16,785	27,677	11,349	5,644	70,751
2034	9,281	0	16,727	28,946	11,723	5,609	72,286
2035	9,280	0	17,477	29,228	12,100	5,613	73,699
2036	9,314	0	16,817	31,104	12,480	5,558	75,272
2037	9,290	0	15,895	33,300	12,862	5,466	76,812
2038	9,289	0	16,505	33,857	13,246	5,517	78,414

ENERGY MIX %							
	Nuclear	Coal	Gas	Renew	DSM	Purchase	TOT
2023	20.9%	14.6%	19.4%	15.8%	17.8%	11.5%	100.0%
2024	19.8%	15.0%	19.6%	18.4%	17.4%	9.8%	100.0%
2025	18.6%	12.3%	19.6%	23.4%	17.0%	9.2%	100.0%
2026	17.2%	10.6%	19.9%	28.1%	16.4%	7.8%	100.0%
2027	16.1%	9.7%	21.6%	29.2%	15.9%	7.5%	100.0%
2028	15.3%	9.0%	22.2%	28.7%	15.7%	9.1%	100.0%
2029	14.6%	0.0%	27.0%	34.0%	15.6%	8.9%	100.0%
2030	14.1%	0.0%	27.1%	34.7%	15.6%	8.5%	100.0%
2031	13.7%	0.0%	28.0%	34.3%	15.7%	8.3%	100.0%
2032	13.4%	0.0%	22.8%	39.7%	15.9%	8.2%	100.0%
2033	13.1%	0.0%	23.7%	39.1%	16.0%	8.0%	100.0%
2034	12.8%	0.0%	23.1%	40.0%	16.2%	7.8%	100.0%
2035	12.6%	0.0%	23.7%	39.7%	16.4%	7.6%	100.0%
2036	12.4%	0.0%	22.3%	41.3%	16.6%	7.4%	100.0%
2037	12.1%	0.0%	20.7%	43.4%	16.7%	7.1%	100.0%
2038	11.8%	0.0%	21.0%	43.2%	16.9%	7.0%	100.0%

1) Renew includes DE installed since 2008. EE includes energy beginning in 2005.
2) Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts
3) Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

ATTACHMENT F.1(A)(4): FOUR CORNERS COAL EXIT 2029 L&R AND ENERGY MIX

	Four Corners Coal Exit 2029 - Loads & Resources - MW Energy Contribution at Peak																
		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
1	**Load Requirements**																
2	APS Peak Demand	8,184	8,594	9,012	9,525	10,020	10,427	10,805	11,127	11,398	11,646	11,903	12,146	12,386	12,634	12,877	13,119
3	Reserve Requirements	1,201	1,247	1,304	1,349	1,330	1,124	1,122	1,142	1,413	1,450	1,165	1,295	1,254	1,605	1,685	1,703
4	**Total Load Requirements**	9,385	9,841	10,316	10,874	11,350	11,551	11,927	12,269	12,811	13,096	13,068	13,442	13,641	14,240	14,562	14,823
5	**Existing Resources**																
6	Nuclear	1,146	1,146	1,146	978	978	978	978	978	978	978	978	978	978	978	978	978
7	Coal	1,347	1,347	970	828	828	828	828	0	0	0	0	0	0	0	0	0
8	Natural Gas	5,832	5,489	5,320	4,577	4,581	4,583	4,492	4,401	4,311	3,799	3,351	3,354	2,869	2,873	2,874	2,875
9	Combined Cycle	1,844	1,997	1,997	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661
10	Combustion / Steam Turbines	1,503	1,520	1,520	1,363	1,363	1,363	1,270	1,176	1,082	1,082	1,082	1,082	1,082	1,082	1,082	1,082
11	Tolling Agreements	1,598	1,598	1,660	1,446	1,446	1,446	1,446	1,446	1,446	934	486	486	0	0	0	0
12	Market / Call Options / Hedges /AG-X	887	374	142	106	110	112	115	118	121	122	122	125	126	130	131	131
13	Renewable Energy	475	476	463	440	444	444	449	443	448	446	441	435	434	442	404	403
14	Distributed Energy	6	6	6	14	14	14	14	14	14	14	13	14	13	14	10	9
15	PURPA QF	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16	Solar	356	343	328	296	296	294	295	295	296	293	291	293	291	294	291	290
17	Wind	87	100	103	106	111	113	117	120	124	125	125	128	130	135	103	104
18	Geothermal	10	10	10	9	9	9	9	0	0	0	0	0	0	0	0	0
19	Biomass/Biogas	16	16	16	15	15	15	15	15	15	15	12	0	0	0	0	0
20	Energy Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21	Microgrid	35	35	35	30	30	30	30	30	30	30	30	30	30	30	30	30
22	**Total Existing Resources**	8,835	8,492	7,934	6,852	6,860	6,862	6,777	5,851	5,766	5,252	4,800	4,796	4,310	4,322	4,285	4,285
23	**Customer Resources**																
24	Future Energy Efficiency	132	234	319	327	404	489	581	687	780	852	931	1,035	1,127	1,244	1,322	1,412
25	Future Distributed Energy	11	27	48	288	358	412	469	513	559	582	605	653	674	733	751	777
26	Demand Response (Future & Existing)	90	95	144	145	145	195	192	240	275	320	310	300	305	310	315	320
27	**Total Customer Resources**	232	355	512	760	906	1,095	1,242	1,439	1,613	1,754	1,845	1,987	2,105	2,286	2,388	2,509
28	**Future Resources**																
29	Nuclear (SMR)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	Natural Gas	0	199	0	199	263	319	359	1,342	1,501	2,013	2,461	2,461	2,948	3,153	3,153	3,153
31	Combined Cycle	0	0	0	0	0	0	0	0	0	512	960	960	1,446	1,446	1,446	1,446
32	Combustion Turbines	0	0	0	80	199	319	359	1,342	1,501	1,501	1,501	1,501	1,501	1,707	1,707	1,707
33	Short-Term Purchases/Summer Contracts	0	199	0	119	64	0	0	0	0	0	0	0	0	0	0	0
34	Renewable Energy	62	115	101	244	308	320	335	447	449	726	743	758	777	885	1,059	1,049
35	Wind	62	115	101	231	268	274	292	318	329	547	547	568	575	686	837	840
36	Solar	0	0	0	12	40	46	43	128	120	179	195	190	202	198	222	209
37	Bio/Geothermal/CSP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
38	PVS (PV + BESS)	240	525	1,531	1,691	1,877	1,881	2,178	2,206	2,195	2,235	2,258	2,252	2,271	2,266	2,417	2,340
39	Energy Storage	24	97	338	585	591	603	628	642	661	660	661	680	682	706	706	927
40	Microgrid	8	58	58	544	544	544	544	544	742	742	742	742	742	742	767	767
41	**Total Future Resources**	333	993	2,028	3,262	3,584	3,667	4,044	5,181	5,548	6,377	6,865	6,893	7,419	7,752	8,103	8,236
42	**TOTAL RESOURCES**	**9,400**	**9,841**	**10,474**	**10,874**	**11,350**	**11,623**	**12,063**	**12,471**	**12,927**	**13,383**	**13,510**	**13,676**	**13,834**	**14,361**	**14,776**	**15,031**

ATTACHMENT F.1(A)(4): FOUR CORNERS COAL EXIT 2029 L&R AND ENERGY MIX (CONTINUED)

Energy Mix - Four Corners Coal Exit 2029																
ENERGY (GWH)									ENERGY MIX %							
	Nuclear	Coal	Gas	Renew	DSM	Purchase	TOT			Nuclear	Coal	Gas	Renew	DSM	Purchase	TOT
2023	9,243	6,456	8,535	6,975	7,858	5,068	44,136		**2023**	20.9%	14.6%	19.3%	15.8%	17.8%	11.5%	100.0%
2024	9,314	7,033	9,188	8,625	8,172	4,608	46,940		**2024**	19.8%	15.0%	19.6%	18.4%	17.4%	9.8%	100.0%
2025	9,290	6,145	9,788	11,709	8,498	4,618	50,048		**2025**	18.6%	12.3%	19.6%	23.4%	17.0%	9.2%	100.0%
2026	9,291	5,702	10,734	15,149	8,831	4,206	53,913		**2026**	17.2%	10.6%	19.9%	28.1%	16.4%	7.8%	100.0%
2027	9,296	5,630	12,454	16,865	9,173	4,345	57,762		**2027**	16.1%	9.7%	21.6%	29.2%	15.9%	7.5%	100.0%
2028	9,308	5,458	13,495	17,441	9,523	5,531	60,756		**2028**	15.3%	9.0%	22.2%	28.7%	15.7%	9.1%	100.0%
2029	9,280	5,399	13,737	19,568	9,879	5,628	63,491		**2029**	14.6%	8.5%	21.6%	30.8%	15.6%	8.9%	100.0%
2030	9,296	0	17,775	22,836	10,242	5,578	65,726		**2030**	14.1%	0.0%	27.0%	34.7%	15.6%	8.5%	100.0%
2031	9,281	0	18,910	23,158	10,609	5,573	67,531		**2031**	13.7%	0.0%	28.0%	34.3%	15.7%	8.3%	100.0%
2032	9,300	0	15,630	27,631	10,978	5,630	69,168		**2032**	13.4%	0.0%	22.6%	39.9%	15.9%	8.1%	100.0%
2033	9,296	0	16,649	27,837	11,349	5,622	70,752		**2033**	13.1%	0.0%	23.5%	39.3%	16.0%	7.9%	100.0%
2034	9,281	0	16,669	29,009	11,723	5,604	72,287		**2034**	12.8%	0.0%	23.1%	40.1%	16.2%	7.8%	100.0%
2035	9,280	0	17,424	29,291	12,100	5,603	73,699		**2035**	12.6%	0.0%	23.6%	39.7%	16.4%	7.6%	100.0%
2036	9,314	0	17,036	30,879	12,480	5,564	75,272		**2036**	12.4%	0.0%	22.6%	41.0%	16.6%	7.4%	100.0%
2037	9,290	0	15,618	33,606	12,862	5,445	76,820		**2037**	12.1%	0.0%	20.3%	43.7%	16.7%	7.1%	100.0%
2038	9,289	0	16,207	34,194	13,246	5,486	78,423		**2038**	11.8%	0.0%	20.7%	43.6%	16.9%	7.0%	100.0%

1) Renew includes DE installed since 2008. EE includes energy beginning in 2005.
2) Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts
3) Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

ATTACHMENT F.1(A)(5): FOUR CORNERS COAL EXIT 2030 L&R AND ENERGY MIX

	Four Corners Coal Exit 2030 - Loads & Resources - MW Energy Contribution at Peak																
		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
1	**Load Requirements**																
2	APS Peak Demand	8,184	8,594	9,012	9,525	10,020	10,427	10,805	11,127	11,398	11,646	11,903	12,146	12,386	12,634	12,877	13,119
3	Reserve Requirements	1,201	1,247	1,304	1,349	1,330	1,124	1,122	1,142	1,413	1,450	1,165	1,295	1,254	1,605	1,685	1,703
4	**Total Load Requirements**	9,385	9,841	10,316	10,874	11,350	11,551	11,927	12,269	12,811	13,096	13,068	13,442	13,641	14,240	14,562	14,823
5	**Existing Resources**																
6	Nuclear	1,146	1,146	1,146	978	978	978	978	978	978	978	978	978	978	978	978	978
7	Coal	1,347	1,347	970	828	828	828	828	828	0	0	0	0	0	0	0	0
8	Natural Gas	5,832	5,489	5,320	4,577	4,581	4,583	4,492	4,401	4,311	3,799	3,351	3,354	2,869	2,873	2,874	2,875
9	Combined Cycle	1,844	1,997	1,997	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661
10	Combustion / Steam Turbines	1,503	1,520	1,520	1,363	1,363	1,363	1,270	1,176	1,082	1,082	1,082	1,082	1,082	1,082	1,082	1,082
11	Tolling Agreements	1,598	1,598	1,660	1,446	1,446	1,446	1,446	1,446	1,446	934	486	486	0	0	0	0
12	Market / Call Options / Hedges /AG-X	887	374	142	106	110	112	115	118	121	122	122	125	126	130	131	131
13	Renewable Energy	475	476	463	440	444	444	449	443	448	446	441	435	434	442	404	403
14	Distributed Energy	6	6	6	14	14	14	14	14	14	14	13	14	13	14	10	9
15	PURPA QF	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16	Solar	356	343	328	296	296	294	295	295	296	293	291	293	291	294	291	290
17	Wind	87	100	103	106	111	113	117	120	124	125	125	128	130	135	103	104
18	Geothermal	10	10	10	9	9	9	9	0	0	0	0	0	0	0	0	0
19	Biomass/Biogas	16	16	16	15	15	15	15	15	15	15	12	0	0	0	0	0
20	Energy Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21	Microgrid	35	35	35	30	30	30	30	30	30	30	30	30	30	30	30	30
22	**Total Existing Resources**	8,835	8,492	7,934	6,852	6,860	6,862	6,777	6,679	5,766	5,252	4,800	4,796	4,310	4,322	4,285	4,285
23	**Customer Resources**																
24	Future Energy Efficiency	132	234	319	327	404	489	581	687	780	852	931	1,035	1,127	1,244	1,322	1,412
25	Future Distributed Energy	11	27	48	288	358	412	469	513	559	582	605	653	674	733	751	777
26	Demand Response (Future & Existing)	90	95	144	145	145	195	192	240	275	320	310	300	305	310	315	320
27	**Total Customer Resources**	232	355	512	760	906	1,095	1,242	1,439	1,613	1,754	1,845	1,987	2,105	2,286	2,388	2,509
28	**Future Resources**																
29	Nuclear (SMR)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	Natural Gas	0	199	0	199	336	319	359	439	1,491	2,003	2,451	2,548	3,035	3,035	3,074	3,074
31	Combined Cycle	0	0	0	0	0	0	0	0	0	512	960	960	1,446	1,446	1,446	1,446
32	Combustion Turbines	0	0	0	80	199	319	359	439	1,491	1,491	1,491	1,588	1,588	1,588	1,628	1,628
33	Short-Term Purchases/Summer Contracts	0	199	0	119	137	0	0	0	0	0	0	0	0	0	0	0
34	Renewable Energy	62	115	101	244	246	305	335	447	450	743	740	749	771	936	1,052	1,072
35	Wind	62	115	101	244	268	274	292	318	329	546	547	564	571	755	833	838
36	Solar	0	0	0	0	(22)	31	43	128	121	197	193	185	199	181	219	233
37	Bio/Geothermal/CSP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
38	PVS (PV + BESS)	240	525	1,531	1,691	1,866	1,871	2,178	2,206	2,195	2,258	2,257	2,248	2,269	2,243	2,448	2,397
39	Energy Storage	24	97	338	585	591	603	628	642	661	660	661	680	682	706	706	931
40	Microgrid	8	58	58	544	544	544	544	544	742	742	742	742	742	742	767	767
41	**Total Future Resources**	333	993	2,028	3,262	3,584	3,643	4,044	4,278	5,539	6,406	6,852	6,967	7,498	7,661	8,048	8,241
42	**TOTAL RESOURCES**	**9,400**	**9,841**	**10,474**	**10,874**	**11,350**	**11,600**	**12,063**	**12,397**	**12,918**	**13,412**	**13,497**	**13,751**	**13,913**	**14,269**	**14,721**	**15,035**

ATTACHMENT F.1(A)(5): FOUR CORNERS COAL EXIT 2030 L&R AND ENERGY MIX (CONTINUED)

Energy Mix - Four Corners Coal Exit 2030

ENERGY (GWH)	Nuclear	Coal	Gas	Renew	DSM	Purchase	TOT
2023	9,243	6,456	8,532	6,975	7,858	5,071	44,136
2024	9,314	7,033	9,195	8,625	8,172	4,602	46,940
2025	9,290	6,145	9,799	11,709	8,498	4,608	50,048
2026	9,291	5,702	10,725	15,149	8,831	4,215	53,913
2027	9,296	5,632	12,454	16,865	9,173	4,343	57,763
2028	9,308	5,471	13,487	17,441	9,523	5,524	60,754
2029	9,280	5,404	13,733	19,568	9,879	5,626	63,490
2030	9,296	4,601	13,441	22,838	10,242	5,320	65,738
2031	9,281	0	18,871	23,177	10,609	5,594	67,530
2032	9,300	0	15,711	27,535	10,978	5,643	69,168
2033	9,296	0	16,724	27,740	11,349	5,643	70,751
2034	9,281	0	17,305	28,301	11,723	5,671	72,282
2035	9,280	0	17,891	28,752	12,100	5,668	73,691
2036	9,314	0	16,417	31,500	12,480	5,560	75,271
2037	9,290	0	15,643	33,595	12,862	5,449	76,837
2038	9,289	0	16,234	34,171	13,246	5,499	78,439

ENERGY MIX %	Nuclear	Coal	Gas	Renew	DSM	Purchase	TOT
2023	20.9%	14.6%	19.3%	15.8%	17.8%	11.5%	100.0%
2024	19.8%	15.0%	19.6%	18.4%	17.4%	9.8%	100.0%
2025	18.6%	12.3%	19.6%	23.4%	17.0%	9.2%	100.0%
2026	17.2%	10.6%	19.9%	28.1%	16.4%	7.8%	100.0%
2027	16.1%	9.8%	21.6%	29.2%	15.9%	7.5%	100.0%
2028	15.3%	9.0%	22.2%	28.7%	15.7%	9.1%	100.0%
2029	14.6%	8.5%	21.6%	30.8%	15.6%	8.9%	100.0%
2030	14.1%	7.0%	20.4%	34.7%	15.6%	8.1%	100.0%
2031	13.7%	0.0%	27.9%	34.3%	15.7%	8.3%	100.0%
2032	13.4%	0.0%	22.7%	39.8%	15.9%	8.2%	100.0%
2033	13.1%	0.0%	23.6%	39.2%	16.0%	8.0%	100.0%
2034	12.8%	0.0%	23.9%	39.2%	16.2%	7.8%	100.0%
2035	12.6%	0.0%	24.3%	39.0%	16.4%	7.7%	100.0%
2036	12.4%	0.0%	21.8%	41.8%	16.6%	7.4%	100.0%
2037	12.1%	0.0%	20.4%	43.7%	16.7%	7.1%	100.0%
2038	11.8%	0.0%	20.7%	43.6%	16.9%	7.0%	100.0%

1) Renew includes DE installed since 2008. EE includes energy beginning in 2005.
2) Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts
3) Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

ATTACHMENT F.1(A)(6): TECHNOLOGY NEUTRAL L&R AND ENERGY MIX

	Technology Neutral - Loads & Resources - MW Energy Contribution at Peak																
		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
1	**Load Requirements**																
2	APS Peak Demand	8,184	8,594	9,012	9,525	10,020	10,427	10,805	11,127	11,398	11,646	11,903	12,146	12,386	12,634	12,877	13,119
3	Reserve Requirements	1,201	1,247	1,304	1,349	1,330	1,124	1,122	1,142	1,413	1,450	1,165	1,295	1,254	1,605	1,685	1,703
4	**Total Load Requirements**	9,385	9,841	10,316	10,874	11,350	11,551	11,927	12,269	12,811	13,096	13,068	13,442	13,641	14,240	14,562	14,823
5	**Existing Resources**																
6	Nuclear	1,146	1,146	1,146	978	978	978	978	978	978	978	978	978	978	978	978	978
7	Coal	1,347	1,347	970	828	828	828	828	828	0	0	0	0	0	0	0	0
8	Natural Gas	5,832	5,489	5,320	4,577	4,581	4,583	4,492	4,401	4,311	3,799	3,351	3,354	2,869	2,873	2,874	2,875
9	Combined Cycle	1,844	1,997	1,997	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661
10	Combustion / Steam Turbines	1,503	1,520	1,520	1,363	1,363	1,363	1,270	1,176	1,082	1,082	1,082	1,082	1,082	1,082	1,082	1,082
11	Tolling Agreements	1,598	1,598	1,660	1,446	1,446	1,446	1,446	1,446	1,446	934	486	486	0	0	0	0
12	Market / Call Options / Hedges /AG-X	887	374	142	106	110	112	115	118	121	122	122	125	126	130	131	131
13	Renewable Energy	475	476	463	440	444	444	449	443	448	446	441	435	434	442	404	403
14	Distributed Energy	6	6	6	14	14	14	14	14	14	14	13	14	13	14	10	9
15	PURPA QF	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16	Solar	356	343	328	296	296	294	295	295	296	293	291	293	291	294	291	290
17	Wind	87	100	103	106	111	113	117	120	124	125	125	128	130	135	103	104
18	Geothermal	10	10	10	9	9	9	9	0	0	0	0	0	0	0	0	0
19	Biomass/Biogas	16	16	16	15	15	15	15	15	15	15	12	0	0	0	0	0
20	Energy Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21	Microgrid	35	35	35	30	30	30	30	30	30	30	30	30	30	30	30	30
22	**Total Existing Resources**	8,835	8,492	7,934	6,852	6,860	6,862	6,777	6,679	5,766	5,252	4,800	4,796	4,310	4,322	4,285	4,285
23	**Customer Resources**																
24	Future Energy Efficiency	132	234	319	327	404	489	581	687	780	852	931	1,035	1,127	1,244	1,322	1,412
25	Future Distributed Energy	11	27	48	288	358	412	469	513	559	582	605	653	674	733	751	777
26	Demand Response (Future & Existing)	90	95	144	145	145	195	192	240	275	320	310	300	305	310	315	320
27	**Total Customer Resources**	232	355	512	760	906	1,095	1,242	1,439	1,613	1,754	1,845	1,987	2,105	2,286	2,388	2,509
28	**Future Resources**																
29	Nuclear (SMR)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	Natural Gas	0	199	0	126	325	319	359	439	1,302	1,814	2,262	2,262	2,748	2,954	2,954	2,954
31	Combined Cycle	0	0	0	0	0	0	0	0	0	512	960	960	1,446	1,446	1,446	1,446
32	Combustion Turbines	0	0	0	80	199	319	359	439	1,302	1,302	1,302	1,302	1,302	1,508	1,508	1,508
33	Short-Term Purchases/Summer Contracts	0	199	0	47	126	0	0	0	0	0	0	0	0	0	0	0
34	Renewable Energy	62	115	101	252	253	269	269	401	746	1,032	1,012	1,061	1,118	1,130	1,225	1,251
35	Wind	62	115	101	252	253	269	269	307	623	765	763	818	832	868	928	936
36	Solar	0	0	0	0	0	0	0	94	124	266	249	244	285	262	297	315
37	Bio/Geothermal/CSP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
38	PVS (PV + BESS)	240	525	1,531	1,691	1,825	1,829	1,835	1,835	1,834	1,836	1,837	1,836	1,838	1,836	2,069	2,056
39	Energy Storage	24	97	338	648	637	669	933	967	993	1,066	1,048	1,063	1,101	1,112	1,116	1,288
40	Microgrid	8	58	58	544	544	544	544	544	619	619	619	619	619	643	693	693
41	**Total Future Resources**	333	993	2,028	3,262	3,584	3,630	3,940	4,187	5,493	6,367	6,779	6,842	7,423	7,675	8,057	8,242
42	**TOTAL RESOURCES**	**9,400**	**9,841**	**10,474**	**10,874**	**11,350**	**11,587**	**11,959**	**12,305**	**12,872**	**13,373**	**13,424**	**13,625**	**13,838**	**14,283**	**14,730**	**15,036**

ATTACHMENT F.1(A)(6): TECHNOLOGY NEUTRAL L&R AND ENERGY MIX (CONTINUED)

Energy Mix - Technology Neutral

ENERGY (GWH)							
	Nuclear	Coal	Gas	Renew	DSM	Purchase	TOT
2023	9,243	6,463	8,541	6,975	7,858	5,055	44,136
2024	9,314	7,033	9,188	8,625	8,172	4,609	46,941
2025	9,290	6,145	9,799	11,709	8,498	4,608	50,048
2026	9,291	5,701	10,693	15,185	8,831	4,225	53,926
2027	9,296	5,640	13,312	15,818	9,173	4,516	57,753
2028	9,308	5,548	14,510	16,203	9,523	5,647	60,738
2029	9,280	5,556	16,453	16,454	9,879	5,785	63,407
2030	9,296	5,545	16,268	18,500	10,242	5,832	65,683
2031	9,281	1,815	16,005	23,973	10,609	5,778	67,460
2032	9,300	0	13,823	29,514	10,978	5,572	69,187
2033	9,296	0	14,846	29,726	11,349	5,562	70,778
2034	9,281	0	15,094	30,619	11,723	5,584	72,300
2035	9,280	0	15,770	30,915	12,100	5,650	73,715
2036	9,314	0	16,076	31,803	12,480	5,619	75,293
2037	9,290	0	15,461	33,716	12,862	5,545	76,874
2038	9,289	0	16,172	34,175	13,246	5,580	78,462

ENERGY MIX %							
	Nuclear	Coal	Gas	Renew	DSM	Purchase	TOT
2023	20.9%	14.6%	19.4%	15.8%	17.8%	11.5%	100.0%
2024	19.8%	15.0%	19.6%	18.4%	17.4%	9.8%	100.0%
2025	18.6%	12.3%	19.6%	23.4%	17.0%	9.2%	100.0%
2026	17.2%	10.6%	19.8%	28.2%	16.4%	7.8%	100.0%
2027	16.1%	9.8%	23.0%	27.4%	15.9%	7.8%	100.0%
2028	15.3%	9.1%	23.9%	26.7%	15.7%	9.3%	100.0%
2029	14.6%	8.8%	25.9%	26.0%	15.6%	9.1%	100.0%
2030	14.2%	8.4%	24.8%	28.2%	15.6%	8.9%	100.0%
2031	13.8%	2.7%	23.7%	35.5%	15.7%	8.6%	100.0%
2032	13.4%	0.0%	20.0%	42.7%	15.9%	8.1%	100.0%
2033	13.1%	0.0%	21.0%	42.0%	16.0%	7.9%	100.0%
2034	12.8%	0.0%	20.9%	42.3%	16.2%	7.7%	100.0%
2035	12.6%	0.0%	21.4%	41.9%	16.4%	7.7%	100.0%
2036	12.4%	0.0%	21.4%	42.2%	16.6%	7.5%	100.0%
2037	12.1%	0.0%	20.1%	43.9%	16.7%	7.2%	100.0%
2038	11.8%	0.0%	20.6%	43.6%	16.9%	7.1%	100.0%

1) Renew includes DE installed since 2008. EE includes energy beginning in 2005.
2) Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts
3) Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

ATTACHMENT F.1(A)(7): HIGH GAS PRICE L&R AND ENERGY MIX

	High Gas Price - Loads & Resources - MW Energy Contribution at Peak																
		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
1	**Load Requirements**																
2	APS Peak Demand	8,184	8,594	9,012	9,525	10,020	10,427	10,805	11,127	11,398	11,646	11,903	12,146	12,386	12,634	12,877	13,119
3	Reserve Requirements	1,201	1,247	1,304	1,349	1,330	1,124	1,122	1,142	1,413	1,450	1,165	1,295	1,254	1,605	1,685	1,703
4	**Total Load Requirements**	9,385	9,841	10,316	10,874	11,350	11,551	11,927	12,269	12,811	13,096	13,068	13,442	13,641	14,240	14,562	14,823
5	**Existing Resources**																
6	Nuclear	1,146	1,146	1,146	978	978	978	978	978	978	978	978	978	978	978	978	978
7	Coal	1,347	1,347	970	828	828	828	828	828	0	0	0	0	0	0	0	0
8	Natural Gas	5,832	5,489	5,320	4,577	4,581	4,583	4,492	4,401	4,311	3,799	3,351	3,354	2,869	2,873	2,874	2,875
9	Combined Cycle	1,844	1,997	1,997	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661
10	Combustion / Steam Turbines	1,503	1,520	1,520	1,363	1,363	1,363	1,270	1,176	1,082	1,082	1,082	1,082	1,082	1,082	1,082	1,082
11	Tolling Agreements	1,598	1,598	1,660	1,446	1,446	1,446	1,446	1,446	1,446	934	486	486	0	0	0	0
12	Market / Call Options / Hedges /AG-X	887	374	142	106	110	112	115	118	121	122	122	125	126	130	131	131
13	Renewable Energy	475	476	463	440	444	444	449	443	448	446	441	435	434	442	404	403
14	Distributed Energy	6	6	6	14	14	14	14	14	14	14	13	14	13	14	10	9
15	PURPA QF	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16	Solar	356	343	328	296	296	294	295	295	296	293	291	293	291	294	291	290
17	Wind	87	100	103	106	111	113	117	120	124	125	125	128	130	135	103	104
18	Geothermal	10	10	10	9	9	9	9	0	0	0	0	0	0	0	0	0
19	Biomass/Biogas	16	16	16	15	15	15	15	15	15	15	12	0	0	0	0	0
20	Energy Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21	Microgrid	35	35	35	30	30	30	30	30	30	30	30	30	30	30	30	30
22	**Total Existing Resources**	8,835	8,492	7,934	6,852	6,860	6,862	6,777	6,679	5,766	5,252	4,800	4,796	4,310	4,322	4,285	4,285
23	**Customer Resources**																
24	Future Energy Efficiency	132	234	319	327	404	489	581	687	780	852	931	1,035	1,127	1,244	1,322	1,412
25	Future Distributed Energy	11	27	48	288	358	412	469	513	559	582	605	653	674	733	751	777
26	Demand Response (Future & Existing)	90	95	144	145	145	195	192	240	275	320	310	300	305	310	315	320
27	**Total Customer Resources**	232	355	512	760	906	1,095	1,242	1,439	1,613	1,754	1,845	1,987	2,105	2,286	2,388	2,509
28	**Future Resources**																
29	Nuclear (SMR)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	Natural Gas	0	199	0	159	209	319	359	439	1,439	1,951	2,399	2,399	2,886	2,886	2,926	2,926
31	Combined Cycle	0	0	0	0	0	0	0	0	0	512	960	960	1,446	1,446	1,446	1,446
32	Combustion Turbines	0	0	0	80	199	319	359	439	1,439	1,439	1,439	1,439	1,439	1,439	1,479	1,479
33	Short-Term Purchases/Summer Contracts	0	199	0	79	10	0	0	0	0	0	0	0	0	0	0	0
34	Renewable Energy	62	115	101	269	336	374	420	515	531	795	791	826	816	1,071	1,130	1,150
35	Wind	62	115	101	269	273	288	306	318	329	546	547	570	576	816	849	854
36	Solar	0	0	0	0	64	86	114	154	159	206	202	213	198	212	239	253
37	Bio/Geothermal/CSP	0	0	0	0	0	0	0	43	43	43	43	43	43	43	43	43
38	PVS (PV + BESS)	240	525	1,531	1,691	1,890	1,902	2,012	2,022	2,027	2,037	2,037	2,045	2,044	2,042	2,242	2,205
39	Energy Storage	24	97	338	599	604	617	792	820	844	852	852	888	889	912	914	1,127
40	Microgrid	8	58	58	544	544	544	544	544	742	742	742	742	742	767	767	767
41	**Total Future Resources**	333	993	2,028	3,262	3,584	3,757	4,127	4,340	5,583	6,378	6,823	6,901	7,377	7,678	7,979	8,174
42	**TOTAL RESOURCES**	**9,400**	**9,841**	**10,474**	**10,874**	**11,350**	**11,714**	**12,146**	**12,458**	**12,962**	**13,383**	**13,468**	**13,684**	**13,792**	**14,287**	**14,652**	**14,969**

ATTACHMENT F.1(A)(7): HIGH GAS PRICE L&R AND ENERGY MIX (CONTINUED)

Energy Mix - High Gas Price

ENERGY (GWH)							
	Nuclear	Coal	Gas	Renew	DSM	Purchase	TOT
2023	9,243	6,465	8,527	6,975	7,858	5,067	44,136
2024	9,314	7,078	9,240	8,626	8,172	4,511	46,941
2025	9,290	6,322	9,836	11,709	8,498	4,393	50,047
2026	9,291	5,925	10,444	15,505	8,831	3,922	53,918
2027	9,296	5,886	11,145	18,522	9,173	3,772	57,793
2028	9,308	5,714	11,584	19,965	9,523	4,712	60,805
2029	9,280	5,736	12,592	20,957	9,879	5,079	63,523
2030	9,296	5,535	12,758	22,911	10,242	5,009	65,751
2031	9,281	2,186	16,823	23,318	10,609	5,329	67,546
2032	9,300	0	15,767	27,729	10,978	5,408	69,182
2033	9,296	0	16,781	27,925	11,349	5,417	70,767
2034	9,281	0	16,491	29,399	11,723	5,407	72,301
2035	9,280	0	17,175	29,684	12,100	5,473	73,712
2036	9,314	0	14,896	33,269	12,480	5,329	75,288
2037	9,290	0	14,406	35,105	12,862	5,193	76,856
2038	9,289	0	14,831	35,843	13,246	5,256	78,464

ENERGY MIX %							
	Nuclear	Coal	Gas	Renew	DSM	Purchase	TOT
2023	20.9%	14.6%	19.3%	15.8%	17.8%	11.5%	100.0%
2024	19.8%	15.1%	19.7%	18.4%	17.4%	9.6%	100.0%
2025	18.6%	12.6%	19.7%	23.4%	17.0%	8.8%	100.0%
2026	17.2%	11.0%	19.4%	28.8%	16.4%	7.3%	100.0%
2027	16.1%	10.2%	19.3%	32.0%	15.9%	6.5%	100.0%
2028	15.3%	9.4%	19.1%	32.8%	15.7%	7.7%	100.0%
2029	14.6%	9.0%	19.8%	33.0%	15.6%	8.0%	100.0%
2030	14.1%	8.4%	19.4%	34.8%	15.6%	7.6%	100.0%
2031	13.7%	3.2%	24.9%	34.5%	15.7%	7.9%	100.0%
2032	13.4%	0.0%	22.8%	40.1%	15.9%	7.8%	100.0%
2033	13.1%	0.0%	23.7%	39.5%	16.0%	7.7%	100.0%
2034	12.8%	0.0%	22.8%	40.7%	16.2%	7.5%	100.0%
2035	12.6%	0.0%	23.3%	40.3%	16.4%	7.4%	100.0%
2036	12.4%	0.0%	19.8%	44.2%	16.6%	7.1%	100.0%
2037	12.1%	0.0%	18.7%	45.7%	16.7%	6.8%	100.0%
2038	11.8%	0.0%	18.9%	45.7%	16.9%	6.7%	100.0%

1) Renew includes DE installed since 2008. EE includes energy beginning in 2005.
2) Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts
3) Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

ATTACHMENT F.1(A)(8): LOW RENEWABLE TECHNOLOGY COST L&R AND ENERGY MIX

	Low Renewable Technology Cost - Loads & Resources - MW Energy Contribution at Peak																
		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
1	**Load Requirements**																
2	APS Peak Demand	8,184	8,594	9,012	9,525	10,020	10,427	10,805	11,127	11,398	11,646	11,903	12,146	12,386	12,634	12,877	13,119
3	Reserve Requirements	1,201	1,247	1,304	1,349	1,330	1,124	1,122	1,142	1,413	1,450	1,165	1,295	1,254	1,605	1,685	1,703
4	**Total Load Requirements**	9,385	9,841	10,316	10,874	11,350	11,551	11,927	12,269	12,811	13,096	13,068	13,442	13,641	14,240	14,562	14,823
5	**Existing Resources**																
6	Nuclear	1,146	1,146	1,146	978	978	978	978	978	978	978	978	978	978	978	978	978
7	Coal	1,347	1,347	970	828	828	828	828	828	0	0	0	0	0	0	0	0
8	Natural Gas	5,832	5,489	5,320	4,577	4,581	4,583	4,492	4,401	4,311	3,799	3,351	3,354	2,869	2,873	2,874	2,875
9	Combined Cycle	1,844	1,997	1,997	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661
10	Combustion / Steam Turbines	1,503	1,520	1,520	1,363	1,363	1,363	1,270	1,176	1,082	1,082	1,082	1,082	1,082	1,082	1,082	1,082
11	Tolling Agreements	1,598	1,598	1,660	1,446	1,446	1,446	1,446	1,446	1,446	934	486	486	0	0	0	0
12	Market / Call Options / Hedges /AG-X	887	374	142	106	110	112	115	118	121	122	122	125	126	130	131	131
13	Renewable Energy	475	476	463	440	444	444	449	443	448	446	441	435	434	442	404	403
14	Distributed Energy	6	6	6	14	14	14	14	14	14	14	13	14	13	14	10	9
15	PURPA QF	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16	Solar	356	343	328	296	296	294	295	295	296	293	291	293	291	294	291	290
17	Wind	87	100	103	106	111	113	117	120	124	125	125	128	130	135	103	104
18	Geothermal	10	10	10	9	9	9	9	0	0	0	0	0	0	0	0	0
19	Biomass/Biogas	16	16	16	15	15	15	15	15	15	15	12	0	0	0	0	0
20	Energy Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21	Microgrid	35	35	35	30	30	30	30	30	30	30	30	30	30	30	30	30
22	**Total Existing Resources**	8,835	8,492	7,934	6,852	6,860	6,862	6,777	6,679	5,766	5,252	4,800	4,796	4,310	4,322	4,285	4,285
23	**Customer Resources**																
24	Future Energy Efficiency	132	234	319	327	404	489	581	687	780	852	931	1,035	1,127	1,244	1,322	1,412
25	Future Distributed Energy	11	27	48	288	358	412	469	513	559	582	605	653	674	733	751	777
26	Demand Response (Future & Existing)	90	95	144	145	145	195	192	240	275	320	310	300	305	310	315	320
27	**Total Customer Resources**	232	355	512	760	906	1,095	1,242	1,439	1,613	1,754	1,845	1,987	2,105	2,286	2,388	2,509
28	**Future Resources**																
29	Nuclear (SMR)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	Natural Gas	0	199	0	167	287	319	359	439	1,491	2,003	2,451	2,451	2,937	2,937	3,017	3,017
31	Combined Cycle	0	0	0	0	0	0	0	0	0	512	960	960	1,446	1,446	1,446	1,446
32	Combustion Turbines	0	0	0	80	199	319	359	439	1,491	1,491	1,491	1,491	1,491	1,491	1,570	1,570
33	Short-Term Purchases/Summer Contracts	0	199	0	88	88	0	0	0	0	0	0	0	0	0	0	0
34	Renewable Energy	62	115	101	275	291	308	336	432	460	723	719	758	750	989	1,033	1,082
35	Wind	62	115	101	275	267	274	296	316	327	545	546	568	574	802	840	848
36	Solar	0	0	0	0	23	34	40	116	133	178	174	190	176	187	192	234
37	Bio/Geothermal/CSP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
38	PVS (PV + BESS)	240	525	1,531	1,691	1,870	1,877	2,187	2,192	2,225	2,243	2,243	2,261	2,256	2,254	2,424	2,397
39	Energy Storage	24	97	338	585	591	603	628	642	661	660	661	680	682	706	706	939
40	Microgrid	8	58	58	544	544	544	544	544	742	742	742	742	742	767	767	767
41	**Total Future Resources**	333	993	2,028	3,262	3,584	3,652	4,054	4,250	5,579	6,371	6,816	6,891	7,367	7,653	7,946	8,201
42	**TOTAL RESOURCES**	**9,400**	**9,841**	**10,474**	**10,874**	**11,350**	**11,608**	**12,073**	**12,368**	**12,958**	**13,377**	**13,461**	**13,674**	**13,782**	**14,262**	**14,619**	**14,995**

ATTACHMENT F.1(A)(8): LOW RENEWABLE TECHNOLOGY COST L&R AND ENERGY MIX (CONTINUED)

Energy Mix - Low Renewable Technology Cost

ENERGY (GWH)

	Nuclear	Coal	Gas	Renew	DSM	Purchase	TOT
2023	9,243	6,457	8,547	6,975	7,858	5,055	44,136
2024	9,314	7,032	9,189	8,625	8,172	4,608	46,940
2025	9,290	6,145	9,802	11,709	8,498	4,604	50,048
2026	9,291	5,701	10,689	15,192	8,831	4,208	53,912
2027	9,296	5,634	12,523	16,780	9,173	4,357	57,763
2028	9,308	5,374	13,456	17,583	9,523	5,516	60,759
2029	9,280	5,430	13,714	19,560	9,879	5,628	63,491
2030	9,296	4,569	13,475	22,844	10,242	5,317	65,742
2031	9,281	1,615	17,380	23,165	10,609	5,488	67,538
2032	9,300	0	15,653	27,607	10,978	5,635	69,172
2033	9,296	0	16,662	27,813	11,349	5,637	70,756
2034	9,281	0	16,505	29,197	11,723	5,585	72,291
2035	9,280	0	17,256	29,479	12,100	5,588	73,703
2036	9,314	0	15,185	32,838	12,480	5,465	75,282
2037	9,290	0	14,877	34,436	12,862	5,382	76,845
2038	9,289	0	15,382	35,115	13,246	5,419	78,452

ENERGY MIX %

	Nuclear	Coal	Gas	Renew	DSM	Purchase	TOT
2023	20.9%	14.6%	19.4%	15.8%	17.8%	11.5%	100.0%
2024	19.8%	15.0%	19.6%	18.4%	17.4%	9.8%	100.0%
2025	18.6%	12.3%	19.6%	23.4%	17.0%	9.2%	100.0%
2026	17.2%	10.6%	19.8%	28.2%	16.4%	7.8%	100.0%
2027	16.1%	9.8%	21.7%	29.0%	15.9%	7.5%	100.0%
2028	15.3%	8.8%	22.1%	28.9%	15.7%	9.1%	100.0%
2029	14.6%	8.6%	21.6%	30.8%	15.6%	8.9%	100.0%
2030	14.1%	7.0%	20.5%	34.7%	15.6%	8.1%	100.0%
2031	13.7%	2.4%	25.7%	34.3%	15.7%	8.1%	100.0%
2032	13.4%	0.0%	22.6%	39.9%	15.9%	8.1%	100.0%
2033	13.1%	0.0%	23.5%	39.3%	16.0%	8.0%	100.0%
2034	12.8%	0.0%	22.8%	40.4%	16.2%	7.7%	100.0%
2035	12.6%	0.0%	23.4%	40.0%	16.4%	7.6%	100.0%
2036	12.4%	0.0%	20.2%	43.6%	16.6%	7.3%	100.0%
2037	12.1%	0.0%	19.4%	44.8%	16.7%	7.0%	100.0%
2038	11.8%	0.0%	19.6%	44.8%	16.9%	6.9%	100.0%

1) Renew includes DE installed since 2008. EE includes energy beginning in 2005.
2) Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts
3) Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

ATTACHMENT F.1(A)(9): PREFERRED (SELECTED) L&R AND ENERGY MIX

	Preferred (Selected) - Loads & Resources - MW Energy Contribution at Peak																
		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
1	**Load Requirements**																
2	APS Peak Demand	8,184	8,594	9,012	9,525	10,020	10,427	10,805	11,127	11,398	11,646	11,903	12,146	12,386	12,634	12,877	13,119
3	Reserve Requirements	1,201	1,247	1,304	1,349	1,330	1,124	1,122	1,142	1,413	1,450	1,165	1,295	1,254	1,605	1,685	1,703
4	**Total Load Requirements**	9,385	9,841	10,316	10,874	11,350	11,551	11,927	12,269	12,811	13,096	13,068	13,442	13,641	14,240	14,562	14,823
5	**Existing Resources**																
6	Nuclear	1,146	1,146	1,146	978	978	978	978	978	978	978	978	978	978	978	978	978
7	Coal	1,347	1,347	970	828	828	828	828	828	0	0	0	0	0	0	0	0
8	Natural Gas	5,832	5,489	5,320	4,577	4,581	4,583	4,492	4,401	4,311	3,799	3,351	3,354	2,869	2,873	2,874	2,875
9	Combined Cycle	1,844	1,997	1,997	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661
10	Combustion / Steam Turbines	1,503	1,520	1,520	1,363	1,363	1,363	1,270	1,176	1,082	1,082	1,082	1,082	1,082	1,082	1,082	1,082
11	Tolling Agreements	1,598	1,598	1,660	1,446	1,446	1,446	1,446	1,446	1,446	934	486	486	0	0	0	0
12	Market / Call Options / Hedges /AG-X	887	374	142	106	110	112	115	118	121	122	122	125	126	130	131	131
13	Renewable Energy	475	476	463	440	444	444	449	443	448	446	441	435	434	442	404	403
14	Distributed Energy	6	6	6	14	14	14	14	14	14	14	13	14	13	14	10	9
15	PURPA QF	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16	Solar	356	343	328	296	296	294	295	295	296	293	291	293	291	294	291	290
17	Wind	87	100	103	106	111	113	117	120	124	125	125	128	130	135	103	104
18	Geothermal	10	10	10	9	9	9	9	0	0	0	0	0	0	0	0	0
19	Biomass/Biogas	16	16	16	15	15	15	15	15	15	15	12	0	0	0	0	0
20	Energy Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21	Microgrid	35	35	35	30	30	30	30	30	30	30	30	30	30	30	30	30
22	**Total Existing Resources**	8,835	8,492	7,934	6,852	6,860	6,862	6,777	6,679	5,766	5,252	4,800	4,796	4,310	4,322	4,285	4,285
23	**Customer Resources**																
24	Future Energy Efficiency	132	234	319	327	404	489	581	687	780	852	931	1,035	1,127	1,244	1,322	1,412
25	Future Distributed Energy	11	27	48	288	358	412	469	513	559	582	605	653	674	733	751	777
26	Demand Response (Future & Existing)	90	95	144	145	145	195	192	240	275	320	310	300	305	310	315	320
27	**Total Customer Resources**	232	355	512	760	906	1,095	1,242	1,439	1,613	1,754	1,845	1,987	2,105	2,286	2,388	2,509
28	**Future Resources**																
29	Nuclear (SMR)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	Natural Gas	0	199	0	122	201	319	359	439	1,302	1,814	2,262	2,262	2,748	2,954	3,034	3,034
31	Combined Cycle	0	0	0	0	0	0	0	0	0	512	960	960	1,446	1,446	1,446	1,446
32	Combustion Turbines	0	0	0	80	199	319	359	439	1,302	1,302	1,302	1,302	1,302	1,508	1,587	1,587
33	Short-Term Purchases/Summer Contracts	0	199	0	43	1	0	0	0	0	0	0	0	0	0	0	0
34	Renewable Energy	62	115	101	248	310	317	335	487	675	913	934	948	981	1,013	1,004	1,025
35	Wind	62	115	101	248	270	276	288	319	494	684	688	709	720	764	784	789
36	Solar	0	0	0	0	40	41	47	168	182	228	246	239	261	249	220	236
37	Bio/Geothermal/CSP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
38	PVS (PV + BESS)	240	525	1,531	1,691	1,885	1,890	1,945	1,958	1,958	1,971	1,979	1,975	1,982	1,978	2,180	2,156
39	Energy Storage	24	97	338	657	644	656	835	906	923	936	950	968	986	1,020	991	1,174
40	Microgrid	8	58	58	544	544	544	544	544	742	742	742	742	742	742	767	767
41	**Total Future Resources**	333	993	2,028	3,262	3,584	3,727	4,019	4,334	5,602	6,376	6,867	6,895	7,440	7,708	7,976	8,155
42	**TOTAL RESOURCES**	**9,400**	**9,841**	**10,474**	**10,874**	**11,350**	**11,683**	**12,038**	**12,452**	**12,980**	**13,381**	**13,512**	**13,678**	**13,855**	**14,316**	**14,649**	**14,950**

ATTACHMENT F.1(A)(9): PREFERRED (SELECTED) L&R AND ENERGY MIX (CONTINUED)

Energy Mix - Preferred (Selected)

ENERGY (GWH)							
	Nuclear	Coal	Gas	Renew	DSM	Purchase	TOT
2023	9,243	6,461	8,533	6,975	7,858	5,066	44,136
2024	9,314	7,034	9,190	8,625	8,172	4,606	46,941
2025	9,290	6,145	9,802	11,709	8,498	4,604	50,048
2026	9,291	5,701	10,736	15,141	8,831	4,229	53,929
2027	9,296	5,627	11,998	17,393	9,173	4,314	57,800
2028	9,308	5,466	13,185	17,804	9,523	5,503	60,789
2029	9,280	5,542	14,689	18,364	9,879	5,724	63,480
2030	9,296	4,886	13,230	22,695	10,242	5,418	65,766
2031	9,281	1,838	15,929	24,187	10,609	5,727	67,571
2032	9,300	0	14,122	29,213	10,978	5,580	69,193
2033	9,296	0	15,122	29,431	11,349	5,583	70,781
2034	9,281	0	15,837	29,822	11,723	5,651	72,313
2035	9,280	0	16,214	30,484	12,100	5,649	73,728
2036	9,314	0	16,065	31,876	12,480	5,570	75,305
2037	9,290	0	16,126	33,102	12,862	5,504	76,883
2038	9,289	0	16,747	33,642	13,246	5,558	78,482

ENERGY MIX %							
	Nuclear	Coal	Gas	Renew	DSM	Purchase	TOT
2023	20.9%	14.6%	19.3%	15.8%	17.8%	11.5%	100.0%
2024	19.8%	15.0%	19.6%	18.4%	17.4%	9.8%	100.0%
2025	18.6%	12.3%	19.6%	23.4%	17.0%	9.2%	100.0%
2026	17.2%	10.6%	19.9%	28.1%	16.4%	7.8%	100.0%
2027	16.1%	9.7%	20.8%	30.1%	15.9%	7.5%	100.0%
2028	15.3%	9.0%	21.7%	29.3%	15.7%	9.1%	100.0%
2029	14.6%	8.7%	23.1%	28.9%	15.6%	9.0%	100.0%
2030	14.1%	7.4%	20.1%	34.5%	15.6%	8.2%	100.0%
2031	13.7%	2.7%	23.6%	35.8%	15.7%	8.5%	100.0%
2032	13.4%	0.0%	20.4%	42.2%	15.9%	8.1%	100.0%
2033	13.1%	0.0%	21.4%	41.6%	16.0%	7.9%	100.0%
2034	12.8%	0.0%	21.9%	41.2%	16.2%	7.8%	100.0%
2035	12.6%	0.0%	22.0%	41.3%	16.4%	7.7%	100.0%
2036	12.4%	0.0%	21.3%	42.3%	16.6%	7.4%	100.0%
2037	12.1%	0.0%	21.0%	43.1%	16.7%	7.2%	100.0%
2038	11.8%	0.0%	21.3%	42.9%	16.9%	7.1%	100.0%

1) Renew includes DE installed since 2008. EE includes energy beginning in 2005.
2) Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts
3) Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

ATTACHMENT F.1(A)(10): HIGH RENEWABLE TECHNOLOGY COST L&R AND ENERGY MIX

	High Renewable Technology Cost - Loads & Resources - MW Energy Contribution at Peak																
		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
1	**Load Requirements**																
2	APS Peak Demand	8,184	8,594	9,012	9,525	10,020	10,427	10,805	11,127	11,398	11,646	11,903	12,146	12,386	12,634	12,877	13,119
3	Reserve Requirements	1,201	1,247	1,304	1,349	1,330	1,124	1,122	1,142	1,413	1,450	1,165	1,295	1,254	1,605	1,685	1,703
4	**Total Load Requirements**	9,385	9,841	10,316	10,874	11,350	11,551	11,927	12,269	12,811	13,096	13,068	13,442	13,641	14,240	14,562	14,823
5	**Existing Resources**																
6	Nuclear	1,146	1,146	1,146	978	978	978	978	978	978	978	978	978	978	978	978	978
7	Coal	1,347	1,347	970	828	828	828	828	828	0	0	0	0	0	0	0	0
8	Natural Gas	5,832	5,489	5,320	4,577	4,581	4,583	4,492	4,401	4,311	3,799	3,351	3,354	2,869	2,873	2,874	2,875
9	Combined Cycle	1,844	1,997	1,997	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661
10	Combustion / Steam Turbines	1,503	1,520	1,520	1,363	1,363	1,363	1,270	1,176	1,082	1,082	1,082	1,082	1,082	1,082	1,082	1,082
11	Tolling Agreements	1,598	1,598	1,660	1,446	1,446	1,446	1,446	1,446	1,446	934	486	486	0	0	0	0
12	Market / Call Options / Hedges /AG-X	887	374	142	106	110	112	115	118	121	122	122	125	126	130	131	131
13	Renewable Energy	475	476	463	440	444	444	449	443	448	446	441	435	434	442	404	403
14	Distributed Energy	6	6	6	14	14	14	14	14	14	14	13	14	13	14	10	9
15	PURPA QF	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16	Solar	356	343	328	296	296	294	295	295	296	293	291	293	291	294	291	290
17	Wind	87	100	103	106	111	113	117	120	124	125	125	128	130	135	103	104
18	Geothermal	10	10	10	9	9	9	9	0	0	0	0	0	0	0	0	0
19	Biomass/Biogas	16	16	16	15	15	15	15	15	15	15	12	0	0	0	0	0
20	Energy Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21	Microgrid	35	35	35	30	30	30	30	30	30	30	30	30	30	30	30	30
22	**Total Existing Resources**	8,835	8,492	7,934	6,852	6,860	6,862	6,777	6,679	5,766	5,252	4,800	4,796	4,310	4,322	4,285	4,285
23	**Customer Resources**																
24	Future Energy Efficiency	132	234	319	327	404	489	581	687	780	852	931	1,035	1,127	1,244	1,322	1,412
25	Future Distributed Energy	11	27	48	288	358	412	469	513	559	582	605	653	674	733	751	777
26	Demand Response (Future & Existing)	90	95	144	145	145	195	192	240	275	320	310	300	305	310	315	320
27	**Total Customer Resources**	232	355	512	760	906	1,095	1,242	1,439	1,613	1,754	1,845	1,987	2,105	2,286	2,388	2,509
28	**Future Resources**																
29	Nuclear (SMR)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	Natural Gas	0	199	0	132	294	319	359	439	1,588	2,100	2,548	2,754	3,240	3,240	3,338	3,338
31	Combined Cycle	0	0	0	0	0	0	0	0	0	512	960	960	1,446	1,446	1,446	1,446
32	Combustion Turbines	0	0	0	80	199	319	359	439	1,588	1,588	1,588	1,794	1,794	1,794	1,892	1,892
33	Short-Term Purchases/Summer Contracts	0	199	0	52	95	0	0	0	0	0	0	0	0	0	0	0
34	Renewable Energy	62	115	101	310	285	325	355	459	497	770	750	750	772	1,013	1,074	1,069
35	Wind	62	115	101	270	267	274	291	318	363	572	573	588	595	817	846	850
36	Solar	0	0	0	41	18	51	65	141	134	198	177	162	177	195	228	219
37	Bio/Geothermal/CSP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
38	PVS (PV + BESS)	240	525	1,531	1,691	1,860	1,874	2,016	2,047	2,037	2,079	2,063	2,050	2,067	2,062	2,262	2,197
39	Energy Storage	24	97	338	585	601	617	636	653	671	672	672	690	693	717	717	943
40	Microgrid	8	58	58	544	544	544	544	569	742	742	742	742	742	742	767	767
41	**Total Future Resources**	333	993	2,028	3,262	3,584	3,680	3,911	4,166	5,536	6,363	6,775	6,987	7,515	7,774	8,159	8,315
42	**TOTAL RESOURCES**	**9,400**	**9,841**	**10,474**	**10,874**	**11,350**	**11,637**	**11,930**	**12,285**	**12,915**	**13,369**	**13,421**	**13,770**	**13,930**	**14,382**	**14,831**	**15,109**

ATTACHMENT F.1(A)(10): HIGH RENEWABLE TECHNOLOGY COST L&R AND ENERGY MIX (CONTINUED)

Energy Mix - High Renewable Technology Cost

ENERGY (GWH)							
	Nuclear	Coal	Gas	Renew	DSM	Purchase	TOT
2023	9,243	6,459	8,537	6,975	7,858	5,063	44,136
2024	9,314	7,034	9,191	8,625	8,172	4,604	46,940
2025	9,290	6,144	9,807	11,709	8,498	4,599	50,047
2026	9,291	5,697	10,255	15,747	8,831	4,093	53,915
2027	9,296	5,633	12,729	16,531	9,173	4,395	57,757
2028	9,308	5,369	13,460	17,591	9,523	5,508	60,759
2029	9,280	5,295	13,809	19,560	9,879	5,611	63,433
2030	9,296	4,434	13,576	22,916	10,242	5,207	65,670
2031	9,281	1,544	16,889	23,611	10,609	5,537	67,471
2032	9,300	0	16,035	27,134	10,978	5,647	69,094
2033	9,296	0	17,042	27,333	11,349	5,659	70,679
2034	9,281	0	18,018	27,440	11,723	5,739	72,201
2035	9,280	0	18,773	27,699	12,100	5,749	73,602
2036	9,314	0	16,464	31,350	12,480	5,586	75,194
2037	9,290	0	16,707	32,350	12,862	5,539	76,746
2038	9,289	0	17,357	32,847	13,246	5,599	78,338

ENERGY MIX %							
	Nuclear	Coal	Gas	Renew	DSM	Purchase	TOT
2023	20.9%	14.6%	19.3%	15.8%	17.8%	11.5%	100.0%
2024	19.8%	15.0%	19.6%	18.4%	17.4%	9.8%	100.0%
2025	18.6%	12.3%	19.6%	23.4%	17.0%	9.2%	100.0%
2026	17.2%	10.6%	19.0%	29.2%	16.4%	7.6%	100.0%
2027	16.1%	9.8%	22.0%	28.6%	15.9%	7.6%	100.0%
2028	15.3%	8.8%	22.2%	29.0%	15.7%	9.1%	100.0%
2029	14.6%	8.3%	21.8%	30.8%	15.6%	8.8%	100.0%
2030	14.2%	6.8%	20.7%	34.9%	15.6%	7.9%	100.0%
2031	13.8%	2.3%	25.0%	35.0%	15.7%	8.2%	100.0%
2032	13.5%	0.0%	23.2%	39.3%	15.9%	8.2%	100.0%
2033	13.2%	0.0%	24.1%	38.7%	16.1%	8.0%	100.0%
2034	12.9%	0.0%	25.0%	38.0%	16.2%	7.9%	100.0%
2035	12.6%	0.0%	25.5%	37.6%	16.4%	7.8%	100.0%
2036	12.4%	0.0%	21.9%	41.7%	16.6%	7.4%	100.0%
2037	12.1%	0.0%	21.8%	42.2%	16.8%	7.2%	100.0%
2038	11.9%	0.0%	22.2%	41.9%	16.9%	7.1%	100.0%

1) Renew includes DE installed since 2008. EE includes energy beginning in 2005.
2) Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts
3) Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

ATTACHMENT F.1(A)(11): HIGH DEMAND SIDE TECHNOLOGY L&R AND ENERGY MIX

	High Demand Side Technology - Loads & Resources - MW Energy Contribution at Peak																
		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
1	**Load Requirements**																
2	APS Peak Demand	8,184	8,594	9,012	9,525	10,020	10,427	10,805	11,127	11,398	11,646	11,903	12,146	12,386	12,634	12,877	13,119
3	Reserve Requirements	1,195	1,231	1,279	1,357	1,341	1,137	1,135	1,156	1,430	1,464	1,175	1,303	1,254	1,597	1,666	1,672
4	**Total Load Requirements**	9,378	9,825	10,291	10,882	11,361	11,564	11,940	12,283	12,828	13,111	13,078	13,449	13,640	14,231	14,543	14,792
5	**Existing Resources**																
6	Nuclear	1,146	1,146	1,146	978	978	978	978	978	978	978	978	978	978	978	978	978
7	Coal	1,347	1,347	970	828	828	828	828	828	0	0	0	0	0	0	0	0
8	Natural Gas	5,832	5,489	5,320	4,575	4,578	4,579	4,488	4,395	4,303	3,790	3,342	3,342	2,857	2,857	2,858	2,858
9	Combined Cycle	1,844	1,997	1,997	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661
10	Combustion / Steam Turbines	1,503	1,520	1,520	1,363	1,363	1,363	1,270	1,176	1,082	1,082	1,082	1,082	1,082	1,082	1,082	1,082
11	Tolling Agreements	1,598	1,598	1,660	1,446	1,446	1,446	1,446	1,446	1,446	934	486	486	0	0	0	0
12	Market / Call Options / Hedges /AG-X	887	374	142	104	107	108	110	112	113	112	112	112	113	114	115	115
13	Renewable Energy	475	475	461	436	438	436	440	432	433	429	424	412	411	412	378	377
14	Distributed Energy	6	6	6	14	14	13	13	13	13	13	12	12	12	12	8	8
15	PURPA QF	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16	Solar	356	343	326	295	293	291	292	291	290	286	285	284	283	283	280	279
17	Wind	87	100	103	104	107	109	112	114	115	115	115	115	117	117	90	90
18	Geothermal	10	10	10	9	9	9	9	0	0	0	0	0	0	0	0	0
19	Biomass/Biogas	16	16	16	15	15	15	15	15	15	15	12	0	0	0	0	0
20	Energy Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21	Microgrid	35	35	35	30	30	30	30	30	30	30	30	30	30	30	30	30
22	**Total Existing Resources**	8,835	8,492	7,932	6,846	6,850	6,850	6,763	6,663	5,743	5,226	4,772	4,760	4,275	4,276	4,244	4,242
23	**Customer Resources**																
24	Future Energy Efficiency	173	339	487	491	617	750	916	1,088	1,225	1,349	1,535	1,711	1,893	2,013	2,161	2,267
25	Future Distributed Energy	11	27	48	281	347	396	449	487	519	535	554	583	601	632	648	665
26	Demand Response (Future & Existing)	72	120	175	254	313	355	367	392	390	399	394	391	408	419	436	455
27	**Total Customer Resources**	256	486	711	1,026	1,278	1,502	1,732	1,967	2,133	2,282	2,483	2,685	2,902	3,064	3,244	3,387
28	**Future Resources**																
29	Nuclear (SMR)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	Natural Gas	0	58	0	169	225	319	359	439	970	1,482	1,930	1,930	2,416	2,622	2,622	2,622
31	Combined Cycle	0	0	0	0	0	0	0	0	0	512	960	960	1,446	1,446	1,446	1,446
32	Combustion Turbines	0	0	0	80	199	319	359	439	970	970	970	970	970	1,176	1,176	1,176
33	Short-Term Purchases/Summer Contracts	0	58	0	90	26	0	0	0	0	0	0	0	0	0	0	0
34	Renewable Energy	61	113	99	201	256	252	284	391	521	730	725	721	718	703	728	743
35	Wind	61	113	99	201	196	200	211	235	350	523	522	535	541	545	562	563
36	Solar	0	0	0	0	59	53	73	156	171	207	203	186	177	158	165	181
37	Bio/Geothermal/CSP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
38	PVS (PV + BESS)	239	523	1,528	1,656	1,777	1,782	1,986	2,019	2,027	2,039	2,033	2,031	2,030	2,024	2,199	2,167
39	Energy Storage	23	96	348	712	702	702	715	751	762	762	760	760	763	766	762	940
40	Microgrid	8	58	58	272	272	272	272	272	718	718	718	718	718	792	792	792
41	**Total Future Resources**	331	847	2,033	3,011	3,233	3,327	3,616	3,873	4,998	5,730	6,165	6,159	6,646	6,907	7,103	7,264
42	**TOTAL RESOURCES**	**9,421**	**9,825**	**10,675**	**10,882**	**11,361**	**11,679**	**12,111**	**12,503**	**12,874**	**13,238**	**13,420**	**13,605**	**13,823**	**14,247**	**14,590**	**14,892**

ATTACHMENT F.1(A)(11): HIGH DEMAND SIDE TECHNOLOGY L&R AND ENERGY MIX (CONTINUED)

Energy Mix - High Demand Side Technology																
ENERGY (GWH)									ENERGY MIX %							
	Nuclear	Coal	Gas	Renew	DSM	Purchase	TOT			Nuclear	Coal	Gas	Renew	DSM	Purchase	TOT
2023	9,243	6,438	8,449	6,920	7,978	5,052	44,080		**2023**	21.0%	14.6%	19.2%	15.7%	18.1%	11.5%	100.0%
2024	9,314	7,023	8,931	8,569	8,485	4,562	46,884		**2024**	19.9%	15.0%	19.0%	18.3%	18.1%	9.7%	100.0%
2025	9,290	6,120	9,361	11,653	9,027	4,541	49,991		**2025**	18.6%	12.2%	18.7%	23.3%	18.1%	9.1%	100.0%
2026	9,291	5,704	10,395	14,628	9,595	4,281	53,893		**2026**	17.2%	10.6%	19.3%	27.1%	17.8%	7.9%	100.0%
2027	9,296	5,632	11,818	16,406	10,272	4,330	57,754		**2027**	16.1%	9.8%	20.5%	28.4%	17.8%	7.5%	100.0%
2028	9,308	5,336	12,390	17,266	10,981	5,467	60,749		**2028**	15.3%	8.8%	20.4%	28.4%	18.1%	9.0%	100.0%
2029	9,280	5,171	12,279	19,520	11,713	5,483	63,447		**2029**	14.6%	8.2%	19.4%	30.8%	18.5%	8.6%	100.0%
2030	9,296	4,008	12,039	22,856	12,470	5,019	65,688		**2030**	14.2%	6.1%	18.3%	34.8%	19.0%	7.6%	100.0%
2031	9,281	1,309	13,611	24,555	13,254	5,485	67,494		**2031**	13.8%	1.9%	20.2%	36.4%	19.6%	8.1%	100.0%
2032	9,300	0	12,617	27,651	14,052	5,493	69,114		**2032**	13.5%	0.0%	18.3%	40.0%	20.3%	7.9%	100.0%
2033	9,296	0	13,274	27,817	14,855	5,456	70,698		**2033**	13.1%	0.0%	18.8%	39.3%	21.0%	7.7%	100.0%
2034	9,281	0	13,677	28,100	15,654	5,513	72,226		**2034**	12.8%	0.0%	18.9%	38.9%	21.7%	7.6%	100.0%
2035	9,280	0	14,081	28,308	16,440	5,532	73,641		**2035**	12.6%	0.0%	19.1%	38.4%	22.3%	7.5%	100.0%
2036	9,314	0	14,602	28,554	17,193	5,548	75,210		**2036**	12.4%	0.0%	19.4%	38.0%	22.9%	7.4%	100.0%
2037	9,290	0	14,256	29,893	17,896	5,448	76,783		**2037**	12.1%	0.0%	18.6%	38.9%	23.3%	7.1%	100.0%
2038	9,289	0	14,600	30,456	18,545	5,506	78,396		**2038**	11.8%	0.0%	18.6%	38.8%	23.7%	7.0%	100.0%

1) Renew includes DE installed since 2008. EE includes energy beginning in 2005.
2) Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts
3) Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

ATTACHMENT F.1(A)(12): NO LOAD GROWTH L&R AND ENERGY MIX

	No Load Growth - Loads & Resources - MW Energy Contribution at Peak																
		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
1	**Load Requirements**																
2	APS Peak Demand	8,184	8,442	8,649	8,928	9,077	9,212	9,409	9,497	9,592	9,738	9,850	9,971	10,206	10,192	10,331	10,372
3	Reserve Requirements	1,201	1,208	1,226	1,264	1,267	1,084	1,074	1,081	1,322	1,337	1,040	1,145	1,125	1,392	1,425	1,401
4	**Total Load Requirements**	9,385	9,650	9,875	10,192	10,343	10,296	10,482	10,579	10,914	11,075	10,890	11,116	11,331	11,584	11,755	11,773
5	**Existing Resources**																
6	Nuclear	1,146	1,146	1,146	978	978	978	978	978	978	978	978	978	978	978	978	978
7	Coal	1,347	1,347	970	828	828	828	828	828	0	0	0	0	0	0	0	0
8	Natural Gas	5,832	5,489	5,320	4,569	4,569	4,567	4,474	4,379	4,286	3,774	3,324	3,325	2,839	2,839	2,839	2,837
9	Combined Cycle	1,844	1,997	1,997	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661
10	Combustion / Steam Turbines	1,503	1,520	1,520	1,363	1,363	1,363	1,270	1,176	1,082	1,082	1,082	1,082	1,082	1,082	1,082	1,082
11	Tolling Agreements	1,598	1,598	1,660	1,446	1,446	1,446	1,446	1,446	1,446	934	486	486	0	0	0	0
12	Market / Call Options / Hedges /AG-X	887	374	142	98	98	96	97	96	97	96	94	95	96	96	96	94
13	Renewable Energy	475	470	455	421	416	411	410	397	397	395	386	374	376	375	345	343
14	Distributed Energy	6	6	6	13	12	11	11	10	10	10	9	9	9	9	6	6
15	PURPA QF	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16	Solar	356	338	319	287	282	279	276	273	272	270	267	266	266	265	263	262
17	Wind	87	100	104	99	99	98	99	99	100	100	98	99	100	101	76	75
18	Geothermal	10	10	10	9	9	9	9	0	0	0	0	0	0	0	0	0
19	Biomass/Biogas	16	16	16	15	15	15	15	15	15	15	12	0	0	0	0	0
20	Energy Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21	Microgrid	35	35	35	30	30	30	30	30	30	30	30	30	30	30	30	30
22	**Total Existing Resources**	8,835	8,487	7,925	6,825	6,820	6,813	6,719	6,611	5,691	5,176	4,717	4,706	4,222	4,222	4,191	4,187
23	**Customer Resources**																
24	Future Energy Efficiency	132	342	475	447	534	627	728	834	926	1,003	1,067	1,165	1,267	1,362	1,447	1,549
25	Future Distributed Energy	11	38	70	337	398	450	497	523	564	587	589	613	646	665	667	681
26	Demand Response (Future & Existing)	90	95	144	145	145	195	192	240	275	320	310	300	305	310	315	320
27	**Total Customer Resources**	232	475	689	928	1,077	1,271	1,417	1,596	1,764	1,910	1,965	2,078	2,218	2,337	2,429	2,550
28	**Future Resources**																
29	Nuclear (SMR)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	Natural Gas	0	0	0	125	199	319	359	439	479	991	1,439	1,439	1,925	1,925	1,925	1,925
31	Combined Cycle	0	0	0	0	0	0	0	0	0	512	960	960	1,446	1,446	1,446	1,446
32	Combustion Turbines	0	0	0	80	199	319	359	439	479	479	479	479	479	479	479	479
33	Short-Term Purchases/Summer Contracts	0	0	0	45	0	0	0	0	0	0	0	0	0	0	0	0
34	Renewable Energy	62	112	97	117	140	127	118	129	387	466	478	473	480	515	627	622
35	Wind	62	112	97	113	114	112	114	114	357	427	419	423	429	460	544	539
36	Solar	0	0	0	4	26	15	4	15	30	39	59	50	51	55	83	83
37	Bio/Geothermal/CSP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
38	PVS (PV + BESS)	240	524	1,513	1,602	1,684	1,646	1,637	1,622	1,645	1,637	1,616	1,611	1,637	1,641	1,619	1,595
39	Energy Storage	24	97	340	545	529	526	532	527	536	534	520	525	535	538	619	783
40	Microgrid	8	58	58	49	49	49	49	49	421	421	421	421	421	421	421	421
41	**Total Future Resources**	333	791	2,008	2,439	2,602	2,668	2,696	2,766	3,467	4,049	4,473	4,469	4,998	5,039	5,211	5,346
42	**TOTAL RESOURCES**	**9,400**	**9,753**	**10,623**	**10,192**	**10,498**	**10,752**	**10,832**	**10,973**	**10,922**	**11,134**	**11,155**	**11,253**	**11,438**	**11,597**	**11,830**	**12,083**

ATTACHMENT F.1(A)(12): NO LOAD GROWTH L&R AND ENERGY MIX (CONTINUED)

Energy Mix - No Load Growth

ENERGY (GWH)							
	Nuclear	Coal	Gas	Renew	DSM	Purchase	TOT
2023	9,243	6,461	8,539	6,975	7,858	5,059	44,136
2024	9,314	6,789	7,508	8,859	8,510	4,237	45,218
2025	9,290	5,502	6,960	12,077	9,015	3,910	46,754
2026	9,291	5,405	6,183	14,832	9,533	3,369	48,612
2027	9,296	5,520	6,203	15,544	10,064	3,178	49,805
2028	9,308	3,934	6,240	16,137	10,607	4,645	50,871
2029	9,280	3,940	6,349	16,486	11,161	4,817	52,032
2030	9,296	3,481	6,733	16,816	11,725	4,836	52,887
2031	9,281	503	5,897	21,016	12,295	4,725	53,718
2032	9,300	0	5,757	22,209	12,869	4,558	54,693
2033	9,296	0	5,696	22,348	13,446	4,532	55,318
2034	9,281	0	5,794	22,409	14,028	4,595	56,108
2035	9,280	0	6,089	22,674	14,615	4,751	57,408
2036	9,314	0	5,545	23,068	15,205	4,554	57,686
2037	9,290	0	4,871	24,398	15,798	4,145	58,501
2038	9,289	0	4,466	24,855	16,396	4,093	59,099

ENERGY MIX %							
	Nuclear	Coal	Gas	Renew	DSM	Purchase	TOT
2023	20.9%	14.6%	19.3%	15.8%	17.8%	11.5%	100.0%
2024	20.6%	15.0%	16.6%	19.6%	18.8%	9.4%	100.0%
2025	19.9%	11.8%	14.9%	25.8%	19.3%	8.4%	100.0%
2026	19.1%	11.1%	12.7%	30.5%	19.6%	6.9%	100.0%
2027	18.7%	11.1%	12.5%	31.2%	20.2%	6.4%	100.0%
2028	18.3%	7.7%	12.3%	31.7%	20.9%	9.1%	100.0%
2029	17.8%	7.6%	12.2%	31.7%	21.5%	9.3%	100.0%
2030	17.6%	6.6%	12.7%	31.8%	22.2%	9.1%	100.0%
2031	17.3%	0.9%	11.0%	39.1%	22.9%	8.8%	100.0%
2032	17.0%	0.0%	10.5%	40.6%	23.5%	8.3%	100.0%
2033	16.8%	0.0%	10.3%	40.4%	24.3%	8.2%	100.0%
2034	16.5%	0.0%	10.3%	39.9%	25.0%	8.2%	100.0%
2035	16.2%	0.0%	10.6%	39.5%	25.5%	8.3%	100.0%
2036	16.1%	0.0%	9.6%	40.0%	26.4%	7.9%	100.0%
2037	15.9%	0.0%	8.3%	41.7%	27.0%	7.1%	100.0%
2038	15.7%	0.0%	7.6%	42.1%	27.7%	6.9%	100.0%

1) Renew includes DE installed since 2008. EE includes energy beginning in 2005.
2) Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts
3) Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

ATTACHMENT F.1(A)(13): LOW LOAD GROWTH L&R AND ENERGY MIX

	Low Load Growth - Loads & Resources - MW Energy Contribution at Peak																
		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
1	**Load Requirements**																
2	APS Peak Demand	8,184	8,514	8,793	9,146	9,348	9,556	9,805	9,989	10,163	10,387	10,542	10,742	11,068	11,155	11,360	11,493
3	Reserve Requirements	1,201	1,219	1,248	1,365	1,357	1,179	1,193	1,187	1,418	1,427	1,151	1,245	1,251	1,502	1,549	1,531
4	**Total Load Requirements**	9,385	9,733	10,041	10,511	10,705	10,735	10,997	11,176	11,581	11,814	11,694	11,987	12,319	12,658	12,908	13,024
5	**Existing Resources**																
6	Nuclear	1,146	1,146	1,146	978	978	978	978	978	978	978	978	978	978	978	978	978
7	Coal	1,347	1,347	970	828	828	828	828	828	0	0	0	0	0	0	0	0
8	Natural Gas	5,832	5,489	5,320	4,571	4,571	4,571	4,479	4,385	4,293	3,780	3,332	3,333	2,849	2,850	2,849	2,849
9	Combined Cycle	1,844	1,997	1,997	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661
10	Combustion / Steam Turbines	1,503	1,520	1,520	1,363	1,363	1,363	1,270	1,176	1,082	1,082	1,082	1,082	1,082	1,082	1,082	1,082
11	Tolling Agreements	1,598	1,598	1,660	1,446	1,446	1,446	1,446	1,446	1,446	934	486	486	0	0	0	0
12	Market / Call Options / Hedges /AG-X	887	374	142	100	100	100	102	102	103	103	102	103	106	107	106	105
13	Renewable Energy	475	470	454	425	421	417	418	407	408	406	400	388	392	392	360	358
14	Distributed Energy	6	6	6	13	12	12	11	11	11	10	10	10	10	10	7	7
15	PURPA QF	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16	Solar	356	338	317	288	284	281	279	277	276	274	272	271	272	271	268	267
17	Wind	87	100	105	101	101	102	104	105	107	106	106	108	110	111	85	84
18	Geothermal	10	10	10	9	9	9	9	0	0	0	0	0	0	0	0	0
19	Biomass/Biogas	16	16	16	15	15	15	15	15	15	15	12	0	0	0	0	0
20	Energy Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21	Microgrid	35	35	35	30	30	30	30	30	30	30	30	30	30	30	30	30
22	**Total Existing Resources**	8,835	8,487	7,924	6,831	6,827	6,823	6,732	6,627	5,708	5,193	4,738	4,728	4,248	4,249	4,216	4,214
23	**Customer Resources**																
24	Future Energy Efficiency	132	342	475	456	547	650	762	884	984	1,068	1,156	1,266	1,376	1,479	1,572	1,683
25	Future Distributed Energy	11	38	70	344	407	467	521	554	599	625	638	666	711	736	742	762
26	Demand Response (Future & Existing)	90	95	144	145	145	195	192	240	275	320	310	300	305	310	315	320
27	**Total Customer Resources**	232	475	689	945	1,099	1,311	1,475	1,678	1,858	2,013	2,104	2,231	2,392	2,525	2,629	2,764
28	**Future Resources**																
29	Nuclear (SMR)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	Natural Gas	0	0	0	80	199	319	359	439	890	1,402	1,850	1,850	2,337	2,542	2,542	2,542
31	Combined Cycle	0	0	0	0	0	0	0	0	0	512	960	960	1,446	1,446	1,446	1,446
32	Combustion Turbines	0	0	0	80	199	319	359	439	890	890	890	890	890	1,096	1,096	1,096
33	Short-Term Purchases/Summer Contracts	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
34	Renewable Energy	62	112	98	261	264	239	246	334	627	722	747	796	798	809	874	844
35	Wind	62	112	98	261	264	239	246	274	526	617	624	664	679	689	713	707
36	Solar	0	0	0	0	0	0	0	60	101	104	123	133	119	119	161	137
37	Bio/Geothermal/CSP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
38	PVS (PV + BESS)	240	522	1,493	1,594	1,655	1,651	1,673	1,662	1,688	1,676	1,653	1,666	1,713	1,725	1,706	1,703
39	Energy Storage	24	97	338	556	542	545	558	559	570	569	564	571	589	595	678	769
40	Microgrid	8	58	58	247	247	247	247	247	247	247	247	247	247	247	272	272
41	**Total Future Resources**	333	789	1,988	2,738	2,908	3,003	3,083	3,241	4,022	4,617	5,061	5,131	5,684	5,919	6,073	6,131
42	**TOTAL RESOURCES**	**9,400**	**9,751**	**10,600**	**10,514**	**10,834**	**11,137**	**11,290**	**11,545**	**11,589**	**11,822**	**11,903**	**12,090**	**12,323**	**12,693**	**12,917**	**13,109**

ATTACHMENT F.1(A)(13): LOW LOAD GROWTH L&R AND ENERGY MIX (CONTINUED)

Energy Mix - Low Load Growth

ENERGY (GWH)	Nuclear	Coal	Gas	Renew	DSM	Purchase	TOT
2023	9,243	6,465	8,543	6,975	7,858	5,052	44,136
2024	9,314	6,930	8,484	8,863	8,510	4,491	46,592
2025	9,290	5,932	8,460	12,093	9,015	4,326	49,116
2026	9,291	5,676	8,078	15,940	9,533	3,776	52,295
2027	9,296	5,604	9,252	16,777	10,064	3,885	54,878
2028	9,308	5,088	9,454	17,374	10,607	5,173	57,005
2029	9,280	5,043	10,326	17,780	11,161	5,421	59,010
2030	9,296	4,149	10,210	20,044	11,725	5,184	60,607
2031	9,281	1,102	9,692	24,305	12,295	5,266	61,941
2032	9,300	0	9,345	26,592	12,869	5,257	63,363
2033	9,296	0	9,652	26,758	13,446	5,285	64,437
2034	9,281	0	9,533	27,584	14,028	5,236	65,661
2035	9,280	0	10,041	28,063	14,615	5,326	67,325
2036	9,314	0	9,985	28,270	15,205	5,320	68,094
2037	9,290	0	10,128	28,822	15,798	5,283	69,320
2038	9,289	0	10,113	29,197	16,396	5,298	70,293

ENERGY MIX %	Nuclear	Coal	Gas	Renew	DSM	Purchase	TOT
2023	20.9%	14.6%	19.4%	15.8%	17.8%	11.4%	100.0%
2024	20.0%	14.9%	18.2%	19.0%	18.3%	9.6%	100.0%
2025	18.9%	12.1%	17.2%	24.6%	18.4%	8.8%	100.0%
2026	17.8%	10.9%	15.4%	30.5%	18.2%	7.2%	100.0%
2027	16.9%	10.2%	16.9%	30.6%	18.3%	7.1%	100.0%
2028	16.3%	8.9%	16.6%	30.5%	18.6%	9.1%	100.0%
2029	15.7%	8.5%	17.5%	30.1%	18.9%	9.2%	100.0%
2030	15.3%	6.8%	16.8%	33.1%	19.3%	8.6%	100.0%
2031	15.0%	1.8%	15.6%	39.2%	19.8%	8.5%	100.0%
2032	14.7%	0.0%	14.7%	42.0%	20.3%	8.3%	100.0%
2033	14.4%	0.0%	15.0%	41.5%	20.9%	8.2%	100.0%
2034	14.1%	0.0%	14.5%	42.0%	21.4%	8.0%	100.0%
2035	13.8%	0.0%	14.9%	41.7%	21.7%	7.9%	100.0%
2036	13.7%	0.0%	14.7%	41.5%	22.3%	7.8%	100.0%
2037	13.4%	0.0%	14.6%	41.6%	22.8%	7.6%	100.0%
2038	13.2%	0.0%	14.4%	41.5%	23.3%	7.5%	100.0%

1) Renew includes DE installed since 2008. EE includes energy beginning in 2005.
2) Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts
3) Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

ATTACHMENT F.1(A)(14): HIGH LOAD GROWTH L&R AND ENERGY MIX

	High Load Growth - Loads & Resources - MW Energy Contribution at Peak																
		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
1	**Load Requirements**																
2	APS Peak Demand	8,217	8,592	9,035	9,613	10,183	10,715	11,220	11,627	11,917	12,107	12,275	12,434	12,592	12,752	12,897	13,050
3	Reserve Requirements	1,206	1,247	1,308	1,411	1,423	1,260	1,274	1,288	1,552	1,588	1,295	1,443	1,395	1,745	1,818	1,840
4	**Total Load Requirements**	9,424	9,839	10,343	11,023	11,607	11,976	12,495	12,915	13,469	13,696	13,570	13,876	13,987	14,497	14,715	14,890
5	**Existing Resources**																
6	Nuclear	1,146	1,146	1,146	978	978	978	978	978	978	978	978	978	978	978	978	978
7	Coal	1,347	1,347	970	828	828	828	828	828	0	0	0	0	0	0	0	0
8	Natural Gas	5,832	5,489	5,320	4,578	4,583	4,586	4,497	4,407	4,317	3,805	3,356	3,358	2,872	2,876	2,875	2,875
9	Combined Cycle	1,844	1,997	1,997	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661
10	Combustion / Steam Turbines	1,503	1,520	1,520	1,363	1,363	1,363	1,270	1,176	1,082	1,082	1,082	1,082	1,082	1,082	1,082	1,082
11	Tolling Agreements	1,598	1,598	1,660	1,446	1,446	1,446	1,446	1,446	1,446	934	486	486	0	0	0	0
12	Market / Call Options / Hedges /AG-X	887	374	142	107	112	115	120	124	127	127	127	129	129	132	132	132
13	Renewable Energy	476	477	464	443	448	451	458	456	460	456	451	440	440	445	404	402
14	Distributed Energy	6	6	6	15	15	14	15	15	15	14	14	14	14	14	9	9
15	PURPA QF	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16	Solar	358	344	328	298	298	297	298	300	300	296	295	293	293	294	290	288
17	Wind	86	100	104	107	112	116	122	126	131	131	130	133	134	138	105	105
18	Geothermal	10	10	10	9	9	9	9	0	0	0	0	0	0	0	0	0
19	Biomass/Biogas	16	16	16	15	15	15	15	15	15	15	12	0	0	0	0	0
20	Energy Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21	Microgrid	35	35	35	30	30	30	30	30	30	30	30	30	30	30	30	30
22	**Total Existing Resources**	8,836	8,494	7,934	6,856	6,866	6,872	6,790	6,698	5,784	5,267	4,814	4,805	4,320	4,328	4,287	4,284
23	**Customer Resources**																
24	Future Energy Efficiency	132	233	318	331	411	503	606	723	819	890	968	1,069	1,158	1,268	1,337	1,418
25	Future Distributed Energy	8	24	44	283	356	414	477	542	599	630	665	698	738	788	803	826
26	Demand Response (Future & Existing)	90	95	144	145	145	195	192	240	275	320	310	300	305	310	315	320
27	**Total Customer Resources**	229	351	507	759	911	1,112	1,275	1,504	1,693	1,839	1,942	2,066	2,200	2,366	2,455	2,564
28	**Future Resources**																
29	Nuclear (SMR)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	Natural Gas	27	204	0	375	635	776	975	1,254	1,884	2,396	2,844	2,844	3,330	3,330	3,330	3,330
31	Combined Cycle	0	0	0	0	0	0	0	0	0	512	960	960	1,446	1,446	1,446	1,446
32	Combustion Turbines	0	0	0	337	616	776	975	1,254	1,884	1,884	1,884	1,884	1,884	1,884	1,884	1,884
33	Short-Term Purchases/Summer Contracts	27	204	0	38	19	0	0	0	0	0	0	0	0	0	0	0
34	Renewable Energy	61	113	99	271	296	416	542	810	972	1,072	1,035	1,175	1,179	1,402	1,447	1,330
35	Wind	61	113	99	267	285	312	362	364	496	568	560	676	678	882	914	857
36	Solar	0	0	0	4	12	62	138	104	134	163	134	158	159	179	192	132
37	Bio/Geothermal/CSP	0	0	0	0	0	43	43	341	341	341	341	341	341	341	341	341
38	PVS (PV + BESS)	239	523	1,527	1,701	1,827	1,833	1,832	1,831	1,831	1,834	1,835	1,836	1,836	1,836	1,838	2,348
39	Energy Storage	23	96	339	591	601	621	648	672	690	686	689	695	703	719	715	715
40	Microgrid	8	58	58	470	470	470	470	470	742	742	742	742	742	742	742	742
41	**Total Future Resources**	359	994	2,023	3,409	3,830	4,116	4,468	5,037	6,120	6,731	7,146	7,293	7,790	8,029	8,073	8,466
42	**TOTAL RESOURCES**	**9,424**	**9,839**	**10,463**	**11,023**	**11,607**	**12,099**	**12,534**	**13,239**	**13,598**	**13,837**	**13,903**	**14,164**	**14,310**	**14,723**	**14,815**	**15,314**

ATTACHMENT F.1(A)(14): HIGH LOAD GROWTH L&R AND ENERGY MIX (CONTINUED)

Energy Mix - High Load Growth

ENERGY (GWH)							
	Nuclear	Coal	Gas	Renew	DSM	Purchase	TOT
2023	9,243	6,523	8,770	6,920	7,858	5,084	44,399
2024	9,314	7,041	9,334	8,566	8,172	4,664	47,091
2025	9,290	6,178	10,184	11,653	8,498	4,661	50,463
2026	9,291	5,708	11,317	15,514	8,831	4,297	54,958
2027	9,296	5,657	14,314	16,388	9,173	4,662	59,490
2028	9,308	5,489	15,360	18,284	9,523	5,658	63,621
2029	9,280	5,354	16,172	21,159	9,879	5,597	67,440
2030	9,296	4,958	17,382	23,065	10,242	5,596	70,539
2031	9,281	1,937	20,104	25,042	10,609	5,743	72,715
2032	9,300	0	20,556	27,483	10,978	5,819	74,136
2033	9,296	0	21,021	27,719	11,349	5,766	75,151
2034	9,281	0	20,224	29,105	11,723	5,782	76,115
2035	9,280	0	20,506	29,339	12,100	5,781	77,006
2036	9,314	0	18,340	32,314	12,480	5,618	78,066
2037	9,290	0	18,668	32,528	12,862	5,565	78,912
2038	9,289	0	17,255	34,800	13,246	5,463	80,053

ENERGY MIX %							
	Nuclear	Coal	Gas	Renew	DSM	Purchase	TOT
2023	20.8%	14.7%	19.8%	15.6%	17.7%	11.5%	100.0%
2024	19.8%	15.0%	19.8%	18.2%	17.4%	9.9%	100.0%
2025	18.4%	12.2%	20.2%	23.1%	16.8%	9.2%	100.0%
2026	16.9%	10.4%	20.6%	28.2%	16.1%	7.8%	100.0%
2027	15.6%	9.5%	24.1%	27.5%	15.4%	7.8%	100.0%
2028	14.6%	8.6%	24.1%	28.7%	15.0%	8.9%	100.0%
2029	13.8%	7.9%	24.0%	31.4%	14.6%	8.3%	100.0%
2030	13.2%	7.0%	24.6%	32.7%	14.5%	7.9%	100.0%
2031	12.8%	2.7%	27.6%	34.4%	14.6%	7.9%	100.0%
2032	12.5%	0.0%	27.7%	37.1%	14.8%	7.8%	100.0%
2033	12.4%	0.0%	28.0%	36.9%	15.1%	7.7%	100.0%
2034	12.2%	0.0%	26.6%	38.2%	15.4%	7.6%	100.0%
2035	12.1%	0.0%	26.6%	38.1%	15.7%	7.5%	100.0%
2036	11.9%	0.0%	23.5%	41.4%	16.0%	7.2%	100.0%
2037	11.8%	0.0%	23.7%	41.2%	16.3%	7.1%	100.0%
2038	11.6%	0.0%	21.6%	43.5%	16.5%	6.8%	100.0%

1) Renew includes DE installed since 2008. EE includes energy beginning in 2005.
2) Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts
3) Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

ATTACHMENT F.1(B)(1): REVENUE REQUIREMENTS FOR ALL PORTFOLIOS

Total Revenue Requirements ($Millions)					
	REFERENCE	FOUR CORNERS COAL EXIT 2027	FOUR CORNERS COAL EXIT 2028	FOUR CORNERS COAL EXIT 2029	FOUR CORNERS COAL EXIT 2030
2023	2,619	2,619	2,619	2,619	2,619
2024	2,771	2,768	2,768	2,768	2,768
2025	3,110	3,228	3,117	3,113	3,113
2026	3,317	3,316	3,315	3,316	3,316
2027	3,565	3,579	3,559	3,558	3,562
2028	4,012	3,907	4,023	4,009	4,008
2029	4,130	4,151	4,061	4,134	4,120
2030	4,265	4,302	4,316	4,255	4,277
2031	4,484	4,422	4,411	4,427	4,416
2032	4,449	4,416	4,404	4,411	4,450
2033	4,612	4,571	4,558	4,568	4,591
2034	4,683	4,675	4,658	4,668	4,698
2035	4,835	4,851	4,816	4,822	4,839
2036	5,014	5,047	5,030	5,051	4,985
2037	5,403	5,371	5,366	5,388	5,386
2038	5,611	5,682	5,572	5,597	5,621
CPW@6.74%					
(2023-2038)	37,722	37,748	37,583	37,631	37,665

ATTACHMENT F.1(B)(1): REVENUE REQUIREMENTS FOR ALL PORTFOLIOS (CONTINUED)

Total Revenue Requirements ($Millions)					
	TECHNOLOGY NEUTRAL	HIGH GAS PRICE	LOW RENEWABLE TECHNOLOGY COST	PREFERRED PORTFOLIO (SELECTED)	HIGH RENEWABLE TECHNOLOGY COST
2023	2,619	2,619	2,619	2,619	2,619
2024	2,771	2,830	2,771	2,771	2,771
2025	3,110	3,232	3,110	3,110	3,110
2026	3,325	3,509	3,306	3,327	3,323
2027	3,589	3,825	3,542	3,584	3,611
2028	4,031	4,363	3,975	4,045	4,052
2029	4,214	4,548	4,076	4,189	4,181
2030	4,348	4,726	4,176	4,274	4,378
2031	4,369	5,030	4,411	4,419	4,631
2032	4,416	4,963	4,337	4,401	4,619
2033	4,599	5,145	4,484	4,529	4,765
2034	4,652	5,204	4,531	4,597	4,859
2035	4,762	5,377	4,681	4,713	5,013
2036	5,028	5,591	5,000	4,877	5,376
2037	5,284	6,038	5,364	5,187	5,802
2038	5,436	6,234	5,510	5,288	6,023
CPW@6.74%					
(2023-2038)	37,626	40,978	37,233	37,365	38,727

ATTACHMENT F.1(B)(1): REVENUE REQUIREMENTS FOR ALL PORTFOLIOS (CONTINUED)

Total Revenue Requirements ($Millions)				
	HIGH DEMAND SIDE TECHNOLOGY	NO LOAD GROWTH	LOW LOAD GROWTH	HIGH LOAD GROWTH
2023	2,723	2,619	2,619	2,626
2024	2,889	2,725	2,764	2,776
2025	3,254	3,016	3,089	3,125
2026	3,496	3,122	3,237	3,393
2027	3,860	3,224	3,413	3,717
2028	4,308	3,471	3,744	4,277
2029	4,415	3,460	3,773	4,430
2030	4,572	3,497	3,824	4,747
2031	4,678	3,377	3,761	4,946
2032	4,789	3,414	3,817	4,963
2033	4,977	3,468	3,892	5,118
2034	5,090	3,456	3,904	5,079
2035	5,249	3,542	4,016	5,191
2036	5,415	3,710	4,263	5,296
2037	5,606	3,906	4,464	5,491
2038	5,682	3,939	4,472	5,591
CPW@6.74%				
(2023-2038)	40,043	31,461	34,013	39,813

ATTACHMENT F.1(B)(1): REVENUE REQUIREMENTS FOR ALL PORTFOLIOS (CONTINUED)

Total Revenue Requirements - Reference ($Millions)																
YEAR	GENERATION						PURCHASES			SALES					TOTAL	
	Capital Rev. Req.	Fuel	Var . O&M	Fixed Fuel + O&M	New Trans-mission	Sub Total	Demand	Energy	Sub Total		Gas Transport	Imputed Debt	EMIS Costs	DE-EE Costs	$Millions	$/MWH
2023	746	508	71	369	10	1,705	118	572	691	0	84	25	0	115	2,619	79
2024	823	555	75	389	9	1,852	191	497	687	0	84	38	0	109	2,771	79
2025	839	583	72	351	9	1,855	469	496	965	0	85	93	0	113	3,110	84
2026	878	605	71	352	17	1,924	606	493	1,099	0	86	91	0	116	3,317	83
2027	973	664	78	382	20	2,117	654	487	1,141	0	100	88	0	120	3,565	83
2028	1,008	705	86	410	22	2,231	676	526	1,202	0	114	83	256	126	4,012	89
2029	1,101	732	90	440	25	2,387	680	477	1,157	0	115	79	264	128	4,130	87
2030	1,194	733	94	475	30	2,527	684	473	1,157	0	122	74	249	135	4,265	87
2031	1,305	843	92	477	37	2,755	688	474	1,162	0	124	69	234	141	4,484	90
2032	1,355	635	89	525	158	2,761	718	457	1,175	0	118	69	177	149	4,449	87
2033	1,376	681	104	557	173	2,892	731	459	1,190	0	125	67	190	148	4,612	89
2034	1,384	722	114	536	197	2,953	737	458	1,195	0	125	61	199	150	4,683	88
2035	1,382	784	132	552	209	3,059	761	452	1,214	0	135	60	212	155	4,835	90
2036	1,447	740	126	590	339	3,241	768	461	1,229	0	129	53	201	160	5,014	91
2037	1,592	737	124	645	550	3,648	774	439	1,213	0	126	50	200	166	5,403	97
2038	1,525	782	126	689	682	3,805	781	453	1,234	0	143	44	213	172	5,611	99
CPW@6.74%																
(2023-2038)	10,621	6,411	873	4,374	1,052	23,331	5,546	4,687	10,234	0	1,039	634	1,215	1,269	37,722	87

ATTACHMENT F.1(B)(1): REVENUE REQUIREMENTS FOR ALL PORTFOLIOS (CONTINUED)

Total Revenue Requirements - Four Corners Exit 2027 ($Millions)																
YEAR	GENERATION						PURCHASES			SALES					TOTAL	
	Capital Rev. Req.	Fuel	Var . O&M	Fixed Fuel + O&M	New Trans-mission	Sub Total	Demand	Energy	Sub Total		Gas Transport	Imputed Debt	EMIS Costs	DE-EE Costs	$Millions	$/MWH
2023	746	508	71	369	10	1,704	118	573	691	0	84	25	0	115	2,619	79
2024	820	555	76	389	9	1,850	191	496	687	0	84	38	0	109	2,768	79
2025	836	705	72	351	9	1,973	469	496	965	0	85	93	0	113	3,228	87
2026	874	605	71	353	17	1,921	609	493	1,101	0	86	91	0	116	3,316	83
2027	964	679	78	391	20	2,132	654	487	1,141	0	100	88	0	120	3,579	83
2028	1,132	597	69	377	29	2,204	676	540	1,216	0	113	83	164	126	3,907	86
2029	1,254	695	75	413	35	2,471	680	489	1,169	0	118	79	185	128	4,151	88
2030	1,347	726	82	414	39	2,608	684	480	1,164	0	128	74	192	135	4,302	88
2031	1,343	821	88	434	41	2,727	688	475	1,164	0	107	69	214	141	4,422	88
2032	1,364	635	89	483	158	2,729	718	457	1,175	0	117	69	177	149	4,416	86
2033	1,359	691	104	518	172	2,845	731	459	1,190	0	127	67	193	148	4,571	88
2034	1,367	732	114	531	196	2,940	737	458	1,195	0	127	61	201	150	4,675	88
2035	1,385	795	132	552	207	3,070	761	453	1,214	0	137	60	215	155	4,851	90
2036	1,439	773	129	584	335	3,261	768	461	1,229	0	134	53	210	160	5,047	92
2037	1,566	741	125	636	547	3,615	774	439	1,213	0	126	50	201	166	5,371	96
2038	1,599	785	128	684	679	3,875	781	452	1,233	0	144	44	214	172	5,682	100
CPW@6.74%																
(2023-2038)	10,902	6,439	845	4,233	1,064	23,482	5,548	4,710	10,258	0	1,038	634	1,066	1,269	37,748	87

ATTACHMENT F.1(B)(1): REVENUE REQUIREMENTS FOR ALL PORTFOLIOS (CONTINUED)

Total Revenue Requirements - Four Corners Exit 2028 ($Millions)																
YEAR	GENERATION						PURCHASES			SALES					TOTAL	
	Capital Rev. Req.	Fuel	Var . O&M	Fixed Fuel + O&M	New Trans-mission	Sub Total	Demand	Energy	Sub Total		Gas Transport	Imputed Debt	EMIS Costs	DE-EE Costs	$Millions	$/MWH
2023	746	509	71	369	10	1,705	118	572	690	0	84	25	0	115	2,619	79
2024	820	555	76	389	9	1,850	191	496	687	0	84	38	0	109	2,768	79
2025	836	594	72	351	9	1,862	469	496	965	0	85	93	0	113	3,117	84
2026	874	606	71	352	17	1,921	609	492	1,101	0	86	91	0	116	3,315	83
2027	967	664	79	383	20	2,112	654	487	1,140	0	100	88	0	120	3,559	83
2028	1,002	712	86	420	22	2,242	676	526	1,201	0	114	83	256	126	4,023	89
2029	1,205	669	74	409	34	2,390	680	489	1,168	0	117	79	179	128	4,061	86
2030	1,326	727	81	450	38	2,622	684	480	1,164	0	128	74	193	135	4,316	88
2031	1,329	823	88	436	41	2,716	688	476	1,164	0	107	69	214	141	4,411	88
2032	1,356	631	88	485	158	2,718	718	457	1,175	0	117	69	176	149	4,404	86
2033	1,351	687	104	520	172	2,834	731	459	1,190	0	126	67	192	148	4,558	87
2034	1,364	719	114	535	196	2,928	737	458	1,195	0	126	61	198	150	4,658	88
2035	1,368	780	132	553	208	3,041	761	452	1,214	0	135	60	211	155	4,816	89
2036	1,427	766	130	585	338	3,247	768	461	1,229	0	132	53	208	160	5,030	92
2037	1,556	742	124	638	549	3,609	774	439	1,213	0	127	50	201	166	5,366	96
2038	1,484	786	127	685	681	3,763	781	453	1,234	0	144	44	214	172	5,572	98
CPW@6.74%																
(2023-2038)	10,698	6,383	855	4,280	1,061	23,276	5,548	4,699	10,248	0	1,035	634	1,121	1,269	37,583	87

ATTACHMENT F.1(B)(1): REVENUE REQUIREMENTS FOR ALL PORTFOLIOS (CONTINUED)

Total Revenue Requirements - Four Corners Exit 2029 ($Millions)																
YEAR	GENERATION						PURCHASES			SALES					TOTAL	
	Capital Rev. Req.	Fuel	Var . O&M	Fixed Fuel + O&M	New Trans-mission	Sub Total	Demand	Energy	Sub Total		Gas Transport	Imputed Debt	EMIS Costs	DE-EE Costs	$Millions	$/MWH
2023	746	509	71	369	10	1,705	118	572	690	0	84	25	0	115	2,619	79
2024	820	555	76	389	9	1,850	191	496	687	0	84	38	0	109	2,768	79
2025	836	590	72	351	9	1,858	469	496	966	0	85	93	0	113	3,113	84
2026	874	606	71	352	17	1,921	609	492	1,101	0	86	91	0	116	3,316	83
2027	967	664	79	382	20	2,111	654	487	1,141	0	100	88	0	120	3,558	83
2028	1,004	705	86	411	22	2,228	676	526	1,201	0	114	83	256	126	4,009	88
2029	1,087	739	90	450	25	2,391	680	477	1,157	0	116	79	264	128	4,134	87
2030	1,276	727	81	441	37	2,562	684	480	1,164	0	127	74	193	135	4,255	87
2031	1,313	823	88	469	40	2,732	688	476	1,164	0	107	69	214	141	4,427	88
2032	1,368	626	88	486	159	2,728	718	457	1,175	0	116	69	174	149	4,411	86
2033	1,367	682	104	521	173	2,848	731	459	1,190	0	125	67	190	148	4,568	88
2034	1,376	716	114	536	197	2,939	737	458	1,195	0	125	61	197	150	4,668	88
2035	1,376	778	132	553	209	3,049	761	452	1,213	0	134	60	210	155	4,822	89
2036	1,433	778	131	583	339	3,264	768	461	1,229	0	133	53	211	160	5,051	92
2037	1,575	730	124	639	569	3,637	774	439	1,213	0	124	50	198	166	5,388	97
2038	1,510	773	126	690	694	3,795	781	452	1,233	0	142	44	210	172	5,597	99
CPW@6.74%																
(2023-2038)	10,630	6,407	866	4,315	1,068	23,286	5,548	4,692	10,240	0	1,031	634	1,171	1,269	37,631	87

ATTACHMENT F.1(B)(1): REVENUE REQUIREMENTS FOR ALL PORTFOLIOS (CONTINUED)

Total Revenue Requirements - Four Corners Exit 2030 ($Millions)																
YEAR	GENERATION						PURCHASES			SALES					TOTAL	
	Capital Rev. Req.	Fuel	Var . O&M	Fixed Fuel + O&M	New Trans-mission	Sub Total	Demand	Energy	Sub Total		Gas Transport	Imputed Debt	EMIS Costs	DE-EE Costs	$Millions	$/MWH
2023	746	508	71	369	10	1,704	118	573	691	0	84	25	0	115	2,619	79
2024	820	556	76	389	9	1,850	191	496	687	0	84	38	0	109	2,768	79
2025	836	590	72	351	9	1,857	469	496	965	0	85	93	0	113	3,113	84
2026	874	606	71	352	17	1,921	609	493	1,101	0	86	91	0	116	3,316	83
2027	967	664	78	382	20	2,111	660	487	1,147	0	97	88	0	120	3,562	83
2028	1,004	705	86	410	22	2,228	676	525	1,201	0	114	83	257	126	4,008	88
2029	1,090	732	90	441	25	2,378	680	476	1,156	0	115	79	264	128	4,120	87
2030	1,191	740	94	484	30	2,539	684	473	1,157	0	122	74	249	135	4,277	88
2031	1,307	821	89	467	39	2,721	688	476	1,164	0	107	69	214	141	4,416	88
2032	1,372	629	89	519	156	2,766	718	457	1,175	0	117	69	175	149	4,450	87
2033	1,389	685	105	520	171	2,869	731	459	1,190	0	125	67	191	148	4,591	88
2034	1,393	745	114	530	176	2,958	737	458	1,195	0	128	61	204	150	4,698	89
2035	1,400	802	132	547	176	3,056	761	453	1,214	0	138	60	216	155	4,839	90
2036	1,454	745	125	583	301	3,209	768	462	1,229	0	131	53	202	160	4,985	91
2037	1,607	731	125	640	533	3,635	774	439	1,213	0	125	50	198	166	5,386	97
2038	1,551	774	127	687	679	3,819	781	453	1,234	0	142	44	210	172	5,621	99
CPW@6.74%																
(2023-2038)	10,643	6,422	872	4,343	1,004	23,284	5,553	4,688	10,241	0	1,029	634	1,207	1,269	37,665	87

ATTACHMENT F.1(B)(1): REVENUE REQUIREMENTS FOR ALL PORTFOLIOS (CONTINUED)

Total Revenue Requirements - Technology Neutral ($Millions)																
YEAR	GENERATION						PURCHASES			SALES					TOTAL	
	Capital Rev. Req.	Fuel	Var . O&M	Fixed Fuel + O&M	New Trans-mission	Sub Total	Demand	Energy	Sub Total		Gas Transport	Imputed Debt	EMIS Costs	DE-EE Costs	$Millions	$/MWH
2023	746	509	71	369	10	1,705	118	572	690	0	84	25	0	115	2,619	79
2024	823	555	76	389	9	1,852	191	496	687	0	84	38	0	109	2,771	79
2025	839	583	72	351	9	1,855	469	496	965	0	85	93	0	113	3,110	84
2026	889	604	71	355	17	1,936	602	493	1,095	0	86	91	0	116	3,325	83
2027	962	692	81	378	19	2,132	659	489	1,148	0	102	88	0	120	3,589	83
2028	982	739	89	400	20	2,230	676	528	1,204	0	119	83	269	126	4,031	89
2029	1,051	828	97	424	23	2,423	680	479	1,159	0	129	79	296	128	4,214	89
2030	1,131	839	101	452	27	2,550	684	471	1,155	0	131	74	302	135	4,348	89
2031	1,256	735	78	490	111	2,670	688	464	1,152	0	117	69	219	141	4,369	87
2032	1,344	550	71	570	227	2,762	718	453	1,171	0	113	69	153	149	4,416	86
2033	1,367	603	84	603	256	2,912	731	456	1,187	0	116	67	168	148	4,599	88
2034	1,347	637	88	582	288	2,943	737	454	1,191	0	130	61	176	150	4,652	88
2035	1,328	692	104	600	286	3,010	761	453	1,214	0	135	60	188	155	4,762	88
2036	1,385	726	110	623	410	3,254	768	463	1,230	0	132	53	197	160	5,028	92
2037	1,524	716	112	667	513	3,532	774	440	1,214	0	128	50	194	166	5,284	95
2038	1,466	766	114	713	574	3,634	781	453	1,234	0	142	44	209	172	5,436	96
CPW@6.74%																
(2023-2038)	10,386	6,338	819	4,468	1,215	23,225	5,547	4,681	10,228	0	1,051	634	1,218	1,269	37,626	87

ATTACHMENT F.1(B)(1): REVENUE REQUIREMENTS FOR ALL PORTFOLIOS (CONTINUED)

Total Revenue Requirements - High Gas Price ($Millions)																
YEAR	GENERATION						PURCHASES			SALES					TOTAL	
	Capital Rev. Req.	Fuel	Var . O&M	Fixed Fuel + O&M	New Trans-mission	Sub Total	Demand	Energy	Sub Total		Gas Transport	Imputed Debt	EMIS Costs	DE-EE Costs	$Millions	$/MWH
2023	746	509	71	369	10	1,705	118	573	691	0	84	25	0	115	2,619	79
2024	823	601	77	389	9	1,899	191	508	699	0	84	38	0	109	2,830	81
2025	839	683	76	351	9	1,958	469	514	984	0	85	93	0	113	3,232	87
2026	889	753	76	357	18	2,092	605	519	1,124	0	86	91	0	116	3,509	88
2027	1,017	839	84	393	22	2,356	649	518	1,167	0	94	88	0	120	3,825	89
2028	1,079	924	91	430	26	2,551	676	583	1,259	0	100	83	243	126	4,363	96
2029	1,152	1,011	96	459	30	2,749	680	544	1,224	0	109	79	260	128	4,548	96
2030	1,238	1,039	105	493	33	2,908	684	542	1,226	0	119	74	264	135	4,726	97
2031	1,326	1,242	100	489	56	3,213	688	555	1,244	0	123	69	240	141	5,030	100
2032	1,379	1,023	100	539	170	3,210	718	529	1,247	0	114	69	174	149	4,963	97
2033	1,395	1,094	125	570	177	3,361	731	523	1,254	0	124	67	190	148	5,145	99
2034	1,414	1,115	138	551	197	3,415	737	525	1,262	0	124	61	193	150	5,204	98
2035	1,418	1,192	155	570	210	3,544	761	521	1,282	0	130	60	205	155	5,377	100
2036	1,487	1,071	142	616	464	3,780	768	529	1,297	0	119	53	182	160	5,591	102
2037	1,707	1,064	151	678	652	4,251	774	504	1,278	0	113	50	181	166	6,038	108
2038	1,685	1,095	150	725	740	4,396	781	519	1,300	0	132	44	191	172	6,234	110
CPW@6.74%																
(2023-2038)	10,946	8,625	965	4,493	1,189	26,218	5,542	5,127	10,669	0	1,001	634	1,186	1,269	40,978	94

ATTACHMENT F.1(B)(1): REVENUE REQUIREMENTS FOR ALL PORTFOLIOS (CONTINUED)

Total Revenue Requirements - Low Renewable Technology Cost ($Millions)

YEAR	GENERATION						PURCHASES			SALES					TOTAL	
	Capital Rev. Req.	Fuel	Var . O&M	Fixed Fuel + O&M	New Trans-mission	Sub Total	Demand	Energy	Sub Total		Gas Transport	Imputed Debt	EMIS Costs	DE-EE Costs	$Millions	$/MWH
2023	746	509	71	369	10	1,705	118	572	690	0	84	25	0	115	2,619	79
2024	823	556	76	389	9	1,852	191	496	687	0	84	38	0	109	2,771	79
2025	839	583	72	351	9	1,855	469	496	965	0	85	93	0	113	3,110	84
2026	869	604	71	352	17	1,914	606	493	1,099	0	86	91	0	116	3,306	83
2027	948	666	79	380	20	2,092	656	487	1,143	0	100	88	0	120	3,542	82
2028	978	702	86	409	22	2,197	676	526	1,201	0	114	83	254	126	3,975	88
2029	1,050	732	90	436	25	2,333	680	477	1,156	0	115	79	264	128	4,076	86
2030	1,112	734	94	469	30	2,439	684	472	1,156	0	122	74	249	135	4,176	85
2031	1,225	841	93	469	53	2,681	688	474	1,162	0	124	69	234	141	4,411	88
2032	1,252	627	89	518	167	2,653	718	457	1,175	0	116	69	174	149	4,337	85
2033	1,253	682	105	549	174	2,763	731	459	1,190	0	125	67	190	148	4,484	86
2034	1,258	709	115	529	195	2,805	737	458	1,195	0	125	61	195	150	4,531	85
2035	1,256	769	133	547	207	2,912	761	452	1,213	0	133	60	208	155	4,681	87
2036	1,288	693	121	590	558	3,249	768	461	1,229	0	122	53	187	160	5,000	91
2037	1,407	699	125	645	751	3,628	774	439	1,213	0	120	50	188	166	5,364	96
2038	1,335	738	127	685	839	3,724	781	452	1,233	0	136	44	199	172	5,510	97
CPW@6.74%																
(2023-2038)	10,025	6,345	874	4,347	1,283	22,874	5,548	4,686	10,234	0	1,028	634	1,195	1,269	37,233	86

ATTACHMENT F.1(B)(1): REVENUE REQUIREMENTS FOR ALL PORTFOLIOS (CONTINUED)

Total Revenue Requirements - Preferred Portfolio (Selected) ($Millions)															
YEAR	GENERATION					PURCHASES			SALES					TOTAL	
	Capital Rev. Req.	Fuel	Var . O&M	Fixed Fuel + O&M	New Trans-mission	Sub Total	Demand	Energy	Sub Total		Gas Transport	Imputed Debt	EMIS Costs	DE-EE Costs	$Millions	$/MWH
2023	746	508	71	369	10	1,704	118	573	691	0	84	25	0	115	2,619	79
2024	823	556	76	389	9	1,853	191	496	687	0	84	38	0	109	2,771	79
2025	839	584	72	351	9	1,855	469	496	965	0	85	93	0	113	3,110	84
2026	890	605	71	355	17	1,938	602	492	1,094	0	86	91	0	116	3,327	83
2027	1,008	649	77	390	21	2,145	648	487	1,135	0	97	88	0	120	3,584	83
2028	1,047	694	85	420	23	2,270	676	525	1,200	0	112	83	253	126	4,045	89
2029	1,103	765	92	443	26	2,428	680	477	1,157	0	120	79	277	128	4,189	89
2030	1,205	727	93	478	32	2,535	684	470	1,154	0	121	74	254	135	4,274	87
2031	1,284	738	91	492	97	2,701	688	469	1,158	0	131	69	219	141	4,419	88
2032	1,340	562	79	560	199	2,739	718	457	1,175	0	114	69	155	149	4,401	86
2033	1,339	614	96	587	203	2,838	731	457	1,188	0	117	67	170	148	4,529	87
2034	1,323	667	105	561	221	2,877	737	457	1,194	0	130	61	184	150	4,597	87
2035	1,313	711	123	577	233	2,957	761	453	1,214	0	133	60	193	155	4,713	87
2036	1,382	727	130	605	263	3,107	768	463	1,230	0	129	53	197	160	4,877	89
2037	1,602	749	135	647	297	3,431	774	440	1,214	0	125	50	202	166	5,187	93
2038	1,548	797	138	689	315	3,487	781	454	1,235	0	134	44	216	172	5,288	93
CPW@6.74%															
(2023-2038)	10,580	6,230	864	4,463	890	23,027	5,539	4,681	10,220	0	1,034	634	1,180	1,269	37,365	86

ATTACHMENT F.1(B)(1): REVENUE REQUIREMENTS FOR ALL PORTFOLIOS (CONTINUED)

Total Revenue Requirements - High Renewable Technology Cost ($Millions)															
YEAR	GENERATION						PURCHASES			SALES					TOTAL	
	Capital Rev. Req.	Fuel	Var . O&M	Fixed Fuel + O&M	New Trans-mission	Sub Total	Demand	Energy	Sub Total		Gas Transport	Imputed Debt	EMIS Costs	DE-EE Costs	$Millions	$/MWH
2023	746	509	71	369	10	1,705	118	572	690	0	84	25	0	115	2,619	79
2024	823	556	76	389	9	1,853	191	496	687	0	84	38	0	109	2,771	79
2025	839	584	72	351	9	1,855	469	495	965	0	85	93	0	113	3,110	84
2026	900	590	70	358	18	1,936	603	491	1,094	0	86	91	0	116	3,323	83
2027	1,000	673	79	387	20	2,159	656	487	1,144	0	101	88	0	120	3,611	84
2028	1,050	702	86	414	22	2,274	676	525	1,201	0	113	83	254	126	4,052	89
2029	1,145	735	92	439	25	2,436	680	479	1,159	0	117	79	262	128	4,181	88
2030	1,304	739	97	471	31	2,641	684	475	1,159	0	121	74	248	135	4,378	90
2031	1,480	807	94	478	48	2,907	688	472	1,160	0	127	69	226	141	4,631	92
2032	1,524	640	90	525	150	2,929	718	457	1,175	0	119	69	179	149	4,619	90
2033	1,531	696	106	551	153	3,037	731	459	1,190	0	127	67	195	148	4,765	91
2034	1,522	781	114	526	172	3,115	737	459	1,196	0	123	61	213	150	4,859	92
2035	1,518	858	131	540	184	3,231	761	454	1,216	0	123	60	228	155	5,013	93
2036	1,607	746	120	584	539	3,596	768	462	1,230	0	133	53	203	160	5,376	98
2037	1,763	777	126	640	725	4,031	774	439	1,213	0	130	50	212	166	5,802	104
2038	1,766	833	128	689	793	4,210	781	454	1,235	0	136	44	226	172	6,023	106
CPW@6.74%																
(2023-2038)	11,375	6,494	876	4,366	1,208	24,319	5,546	4,688	10,234	0	1,036	634	1,235	1,269	38,727	89

ATTACHMENT F.1(B)(1): REVENUE REQUIREMENTS FOR ALL PORTFOLIOS (CONTINUED)

Total Revenue Requirements - High Demand Side Technology ($Millions)																
YEAR	GENERATION						PURCHASES			SALES					TOTAL	
	Capital Rev. Req.	Fuel	Var . O&M	Fixed Fuel + O&M	New Trans-mission	Sub Total	Demand	Energy	Sub Total		Gas Transport	Imputed Debt	EMIS Costs	DE-EE Costs	$Millions	$/MWH
2023	746	506	71	369	10	1,702	118	572	690	0	84	25	0	222	2,723	83
2024	823	548	75	389	9	1,845	179	495	674	0	84	38	0	248	2,889	83
2025	839	569	70	351	9	1,839	469	494	963	0	85	93	0	275	3,254	89
2026	883	594	70	353	17	1,918	606	492	1,098	0	86	91	0	303	3,496	89
2027	975	644	77	379	21	2,095	650	485	1,135	0	93	88	0	449	3,860	92
2028	1,012	667	82	406	23	2,191	676	522	1,198	0	104	83	242	490	4,308	98
2029	1,082	682	86	432	26	2,307	680	473	1,153	0	102	79	243	531	4,415	97
2030	1,169	682	89	464	32	2,436	684	471	1,155	0	102	74	220	585	4,572	98
2031	1,243	647	79	472	77	2,518	688	464	1,152	0	105	69	180	654	4,678	99
2032	1,266	514	74	520	171	2,545	718	453	1,171	0	98	69	138	768	4,789	100
2033	1,264	552	86	545	173	2,621	731	454	1,185	0	96	67	149	859	4,977	102
2034	1,246	589	93	517	179	2,625	737	453	1,190	0	103	61	158	952	5,090	104
2035	1,236	628	108	530	178	2,681	761	448	1,210	0	107	60	166	1,024	5,249	106
2036	1,276	668	113	546	198	2,802	768	458	1,226	0	111	53	177	1,046	5,415	108
2037	1,446	671	117	581	232	3,048	774	435	1,209	0	101	50	177	1,021	5,606	110
2038	1,410	703	117	622	252	3,104	781	449	1,230	0	116	44	186	1,002	5,682	111
CPW@6.74%																
(2023-2038)	10,178	5,836	806	4,265	734	21,819	5,534	4,657	10,191	0	923	634	1,040	5,437	40,043	97

ATTACHMENT F.1(B)(1): REVENUE REQUIREMENTS FOR ALL PORTFOLIOS (CONTINUED)

Total Revenue Requirements - No Load Growth ($Millions)																
YEAR	GENERATION						PURCHASES			SALES					TOTAL	
	Capital Rev. Req.	Fuel	Var . O&M	Fixed Fuel + O&M	New Trans-mission	Sub Total	Demand	Energy	Sub Total		Gas Transport	Imputed Debt	EMIS Costs	DE-EE Costs	$Millions	$/MWH
2023	746	509	71	369	10	1,705	118	572	690	0	84	25	0	115	2,619	79
2024	823	506	69	389	9	1,797	175	487	662	0	84	38	0	145	2,725	83
2025	839	484	59	351	9	1,743	469	476	945	0	85	93	0	150	3,016	92
2026	858	456	57	343	10	1,723	602	466	1,068	0	85	91	0	156	3,122	93
2027	911	459	59	356	11	1,797	648	446	1,094	0	85	88	0	161	3,224	96
2028	927	451	51	377	12	1,819	676	490	1,166	0	85	83	148	170	3,471	104
2029	927	469	54	384	12	1,845	680	444	1,124	0	85	79	153	174	3,460	103
2030	937	487	54	389	12	1,879	684	442	1,126	0	85	74	150	183	3,497	105
2031	965	356	30	395	101	1,848	688	423	1,112	0	85	69	73	190	3,377	101
2032	987	269	31	443	140	1,870	718	407	1,125	0	85	69	61	205	3,414	102
2033	995	276	33	456	143	1,903	731	415	1,146	0	85	67	62	205	3,468	105
2034	992	290	35	425	143	1,884	737	415	1,152	0	85	61	64	209	3,456	104
2035	994	314	45	433	143	1,929	761	421	1,182	0	85	60	70	216	3,542	106
2036	1,028	302	43	449	270	2,091	768	425	1,193	0	85	53	65	224	3,710	112
2037	1,127	283	38	485	389	2,322	774	386	1,161	0	85	50	58	231	3,906	119
2038	1,088	272	34	531	420	2,345	781	390	1,171	0	85	44	54	240	3,939	121
CPW@6.74%																
(2023-2038)	8,834	3,955	491	3,829	793	17,901	5,525	4,384	9,909	0	811	634	515	1,690	31,461	99

ATTACHMENT F.1(B)(1): REVENUE REQUIREMENTS FOR ALL PORTFOLIOS (CONTINUED)

Total Revenue Requirements - Low Load Growth ($Millions)															
YEAR	GENERATION					PURCHASES			SALES					TOTAL	
	Capital Rev. Req.	Fuel	Var . O&M	Fixed Fuel + O&M	New Trans-mission	Sub Total	Demand	Energy	Sub Total		Gas Transport	Imputed Debt	EMIS Costs	DE-EE Costs	$Millions	$/MWH
2023	746	509	71	369	10	1,705	118	572	690	0	84	25	0	115	2,619	79
2024	823	535	73	389	9	1,829	175	494	668	0	84	38	0	145	2,764	81
2025	839	538	67	351	9	1,804	469	488	957	0	85	93	0	150	3,089	88
2026	873	518	63	355	18	1,827	598	480	1,079	0	85	91	0	156	3,237	87
2027	935	558	69	378	20	1,959	648	468	1,116	0	88	88	0	161	3,413	88
2028	951	565	69	400	21	2,005	676	510	1,185	0	94	83	206	170	3,744	95
2029	948	611	75	407	21	2,062	680	464	1,144	0	96	79	219	174	3,773	93
2030	988	614	77	421	23	2,123	684	460	1,144	0	97	74	203	183	3,824	93
2031	1,055	492	54	442	105	2,149	688	450	1,138	0	85	69	129	190	3,761	90
2032	1,077	393	52	499	177	2,198	718	439	1,157	0	89	69	101	205	3,817	91
2033	1,078	416	60	519	180	2,252	731	444	1,175	0	85	67	107	205	3,892	92
2034	1,073	427	62	496	205	2,262	737	440	1,177	0	86	61	108	209	3,904	92
2035	1,070	465	76	513	210	2,333	761	440	1,201	0	89	60	117	216	4,016	92
2036	1,141	475	77	531	335	2,558	768	449	1,217	0	91	53	119	224	4,263	98
2037	1,223	492	79	556	418	2,769	774	427	1,201	0	89	50	124	231	4,464	102
2038	1,135	503	79	585	447	2,750	781	440	1,221	0	91	44	127	240	4,472	102
CPW@6.74%															
(2023-2038)	9,228	4,951	660	4,134	965	19,937	5,522	4,570	10,093	0	847	634	813	1,690	34,013	90

ATTACHMENT F.1(B)(1): REVENUE REQUIREMENTS FOR ALL PORTFOLIOS (CONTINUED)

Total Revenue Requirements - High Load Growth ($Millions)															
YEAR	GENERATION					PURCHASES			SALES					TOTAL	
	Capital Rev. Req.	Fuel	Var . O&M	Fixed Fuel + O&M	New Trans-mission	Sub Total	Demand	Energy	Sub Total		Gas Transport	Imputed Debt	EMIS Costs	DE-EE Costs	$Millions	$/MWH
2023	746	514	72	369	10	1,712	120	572	692	0	84	25	0	113	2,626	79
2024	823	559	76	389	9	1,857	191	498	689	0	84	38	0	108	2,776	79
2025	839	596	73	351	9	1,869	469	497	967	0	85	93	0	112	3,125	83
2026	923	626	74	360	18	2,000	602	497	1,099	0	87	91	0	116	3,393	82
2027	1,028	728	86	388	20	2,249	650	498	1,147	0	113	88	0	119	3,717	83
2028	1,118	789	96	427	23	2,453	676	536	1,212	0	125	83	277	126	4,277	89
2029	1,192	849	110	454	27	2,631	680	488	1,168	0	132	79	292	128	4,430	86
2030	1,306	980	120	487	29	2,922	684	490	1,174	0	136	74	305	135	4,747	88
2031	1,384	1,122	115	480	66	3,167	688	491	1,179	0	110	69	279	141	4,946	89
2032	1,459	992	122	519	109	3,202	718	474	1,191	0	111	69	240	150	4,963	89
2033	1,475	1,051	137	536	123	3,322	731	477	1,208	0	120	67	252	149	5,118	91
2034	1,465	1,001	140	519	170	3,294	737	471	1,207	0	119	61	246	151	5,079	89
2035	1,453	1,051	157	540	170	3,371	761	467	1,228	0	121	60	255	156	5,191	91
2036	1,518	901	146	578	325	3,469	768	471	1,239	0	144	53	229	161	5,296	92
2037	1,559	944	154	613	408	3,678	774	447	1,221	0	134	50	240	167	5,491	95
2038	1,607	869	148	666	478	3,768	781	459	1,240	0	139	44	226	173	5,591	96
CPW@6.74%															
(2023-2038)	11,152	7,707	1,013	4,363	859	25,095	5,542	4,773	10,315	0	1,061	634	1,440	1,268	39,813	87

ATTACHMENT F.1(B)(2): ANNUAL AVERAGE SYSTEM COST

Annual Average System Cost ($/MWh)					
	REFERENCE	FOUR CORNERS COAL EXIT 2027	FOUR CORNERS COAL EXIT 2028	FOUR CORNERS COAL EXIT 2029	FOUR CORNERS COAL EXIT 2030
2023	79.3	79.3	79.3	79.3	79.3
2024	79.2	79.1	79.1	79.1	79.1
2025	83.8	87.0	84.0	83.9	83.9
2026	82.8	82.8	82.8	82.8	82.8
2027	82.8	83.2	82.7	82.7	82.8
2028	88.5	86.2	88.8	88.5	88.4
2029	87.4	87.8	85.9	87.5	87.2
2030	87.3	88.1	88.4	87.1	87.6
2031	89.6	88.3	88.1	88.4	88.2
2032	87.1	86.5	86.2	86.4	87.1
2033	88.5	87.8	87.5	87.7	88.1
2034	88.3	88.1	87.8	88.0	88.6
2035	89.7	90.0	89.4	89.5	89.8
2036	91.3	92.0	91.6	92.0	90.8
2037	96.8	96.3	96.2	96.6	96.5
2038	99.0	100.2	98.3	98.7	99.1

ATTACHMENT F.1(B)(2): ANNUAL AVERAGE SYSTEM COST (CONTINUED)

Annual Average System Cost ($/MWh)					
	TECHNOLOGY NEUTRAL	HIGH GAS PRICE	LOW RENEWABLE TECHNOLOGY COST	PREFERRED PORTFOLIO (SELECTED)	HIGH RENEWABLE TECHNOLOGY COST
2023	79.3	79.3	79.3	79.3	79.3
2024	79.2	80.9	79.2	79.2	79.2
2025	83.8	87.1	83.8	83.8	83.8
2026	83.0	87.6	82.5	83.1	83.0
2027	83.4	88.9	82.3	83.3	83.9
2028	88.9	96.3	87.7	89.3	89.4
2029	89.2	96.2	86.2	88.6	88.5
2030	89.0	96.8	85.5	87.5	89.6
2031	87.3	100.5	88.1	88.3	92.5
2032	86.5	97.2	84.9	86.2	90.4
2033	88.3	98.8	86.1	87.0	91.5
2034	87.7	98.1	85.4	86.7	91.6
2035	88.4	99.8	86.9	87.5	93.0
2036	91.6	101.9	91.1	88.9	97.9
2037	94.7	108.2	96.1	93.0	104.0
2038	95.9	110.0	97.2	93.3	106.2

ATTACHMENT F.1(B)(2): ANNUAL AVERAGE SYSTEM COST (CONTINUED)

Annual Average System Cost ($/MWh)				
	HIGH DEMAND SIDE TECHNOLOGY	NO LOAD GROWTH	LOW LOAD GROWTH	HIGH LOAD GROWTH
2023	82.8	79.3	79.3	78.8
2024	83.3	83.4	81.2	78.9
2025	89.0	91.7	87.6	83.2
2026	89.0	93.4	87.1	82.4
2027	92.0	96.4	88.5	82.9
2028	98.2	103.8	94.5	88.6
2029	97.2	103.1	93.0	86.2
2030	98.1	104.6	92.9	88.2
2031	98.7	101.3	90.4	89.4
2032	99.8	102.2	90.7	88.5
2033	102.4	104.6	92.0	90.7
2034	103.6	104.5	91.5	89.4
2035	105.9	105.6	92.4	90.9
2036	107.9	112.5	98.2	92.1
2037	110.4	118.6	102.0	95.1
2038	110.5	121.0	102.0	96.3

ATTACHMENT F.1(B)(3): ANNUAL NATURAL GAS BURNS

Annual Natural Gas Burns (BCF)					
	REFERENCE	FOUR CORNERS COAL EXIT 2027	FOUR CORNERS COAL EXIT 2028	FOUR CORNERS COAL EXIT 2029	FOUR CORNERS COAL EXIT 2030
2023	61.17	61.20	61.27	61.24	61.20
2024	64.04	64.14	64.02	64.09	64.18
2025	69.32	69.35	69.29	69.25	69.34
2026	76.25	76.18	76.28	76.28	76.21
2027	89.40	89.50	89.49	89.44	89.21
2028	98.29	120.14	97.92	97.92	97.88
2029	99.49	129.51	125.99	99.59	99.57
2030	98.44	129.97	130.16	130.14	98.33
2031	126.92	137.14	137.33	137.31	137.07
2032	117.42	117.36	116.66	115.64	116.24
2033	123.11	124.86	124.19	123.23	123.72
2034	124.89	126.36	124.41	124.03	128.09
2035	129.76	131.11	129.32	129.00	131.79
2036	120.84	125.64	124.59	126.09	121.76
2037	117.34	117.93	118.14	116.12	116.20
2038	121.83	122.30	122.56	120.43	120.50

ATTACHMENT F.1(B)(3): ANNUAL NATURAL GAS BURNS (CONTINUED)

Annual Natural Gas Burns (BCF)					
	TECHNOLOGY NEUTRAL	HIGH GAS PRICE	LOW RENEWABLE TECHNOLOGY COST	PREFERRED PORTFOLIO (SELECTED)	HIGH RENEWABLE TECHNOLOGY COST
2023	61.29	61.19	61.36	61.24	61.25
2024	64.07	64.46	64.16	64.10	64.11
2025	69.32	69.46	69.35	69.36	69.41
2026	76.08	74.10	75.98	76.38	72.92
2027	95.50	79.83	89.83	86.19	91.35
2028	105.54	83.70	97.62	95.50	97.65
2029	119.92	90.93	99.40	106.57	100.43
2030	118.70	92.87	98.59	96.50	99.85
2031	117.86	122.44	126.53	118.25	124.25
2032	101.58	116.02	115.77	103.69	118.76
2033	109.20	123.47	123.26	111.07	126.24
2034	111.70	122.22	122.87	117.07	132.66
2035	116.61	126.81	127.92	119.76	136.41
2036	118.80	110.14	112.89	118.71	122.25
2037	114.33	106.74	110.76	119.11	123.93
2038	119.59	109.83	114.44	123.43	127.75

ATTACHMENT F.1(B)(3): ANNUAL NATURAL GAS BURNS (CONTINUED)

Annual Natural Gas Burns (BCF)				
	HIGH DEMAND SIDE TECHNOLOGY	NO LOAD GROWTH	LOW LOAD GROWTH	HIGH LOAD GROWTH
2023	60.55	61.24	61.30	62.91
2024	62.71	52.56	59.65	65.15
2025	66.02	48.53	59.37	72.20
2026	73.55	43.29	56.88	80.78
2027	84.51	43.50	65.41	103.95
2028	89.14	43.70	66.92	112.97
2029	88.41	44.54	73.31	120.09
2030	87.61	47.24	72.95	129.18
2031	100.96	41.72	70.06	140.71
2032	92.26	40.68	67.22	145.77
2033	96.99	40.22	69.43	147.64
2034	100.31	40.97	68.72	144.93
2035	102.95	43.11	72.45	145.71
2036	106.76	39.18	72.12	134.70
2037	104.25	34.32	73.13	136.95
2038	106.48	31.32	72.84	128.73

ATTACHMENT F.1(B)(4): ANNUAL CO_2 EMISSIONS

Annual CO2 Emissions (Metric Tons)					
	REFERENCE	FOUR CORNERS COAL EXIT 2027	FOUR CORNERS COAL EXIT 2028	FOUR CORNERS COAL EXIT 2029	FOUR CORNERS COAL EXIT 2030
2023	9,260,898	9,269,572	9,267,138	9,265,434	9,262,499
2024	9,991,807	9,994,951	9,993,643	9,995,167	9,998,576
2025	9,330,227	9,329,900	9,328,353	9,326,471	9,331,375
2026	9,264,716	9,263,381	9,269,741	9,269,741	9,266,367
2027	9,914,773	9,906,851	9,913,584	9,911,593	9,917,335
2028	10,168,208	6,538,585	10,200,069	10,200,017	10,209,593
2029	10,247,045	7,172,464	6,939,501	10,236,607	10,240,121
2030	9,448,099	7,287,309	7,306,475	7,304,476	9,449,438
2031	8,631,550	7,899,546	7,920,872	7,919,541	7,895,041
2032	6,382,977	6,375,418	6,340,503	6,283,577	6,313,038
2033	6,687,905	6,786,249	6,750,873	6,694,148	6,719,411
2034	6,812,490	6,900,922	6,782,203	6,760,740	7,013,654
2035	7,097,763	7,189,650	7,068,440	7,047,117	7,237,768
2036	6,563,609	6,849,754	6,790,730	6,888,402	6,609,757
2037	6,373,748	6,403,318	6,418,056	6,303,632	6,302,189
2038	6,624,857	6,645,898	6,665,193	6,544,344	6,541,067

ATTACHMENT F.1(B)(4): ANNUAL CO_2 EMISSIONS (CONTINUED)

Annual CO2 Emissions (Metric Tons)					
	TECHNOLOGY NEUTRAL	HIGH GAS PRICE	LOW RENEWABLE TECHNOLOGY COST	PREFERRED PORTFOLIO (SELECTED)	HIGH RENEWABLE TECHNOLOGY COST
2023	9,273,945	9,270,524	9,272,666	9,269,138	9,269,033
2024	9,994,607	10,042,259	9,996,220	9,995,292	9,996,433
2025	9,329,833	9,509,638	9,331,796	9,333,136	9,334,476
2026	9,248,210	9,344,252	9,249,380	9,264,452	9,075,364
2027	10,265,199	9,611,845	9,943,536	9,720,751	10,023,798
2028	10,692,911	9,666,244	10,108,265	10,076,764	10,105,337
2029	11,483,276	10,074,894	10,254,003	10,741,569	10,188,553
2030	11,425,544	9,997,589	9,434,809	9,606,822	9,381,053
2031	8,097,421	8,881,661	8,641,950	8,091,363	8,363,249
2032	5,501,392	6,279,582	6,287,157	5,599,247	6,451,279
2033	5,908,056	6,683,525	6,693,108	5,992,489	6,855,845
2034	6,042,282	6,620,665	6,687,221	6,318,392	7,326,107
2035	6,309,095	6,876,837	6,972,032	6,461,851	7,632,971
2036	6,452,593	5,938,988	6,109,635	6,422,540	6,642,294
2037	6,198,512	5,756,126	5,997,055	6,450,278	6,748,404
2038	6,494,806	5,927,070	6,201,343	6,709,760	7,023,704

ATTACHMENT F.1(B)(4): ANNUAL CO_2 EMISSIONS (CONTINUED)

Annual CO2 Emissions (Metric Tons)				
	HIGH DEMAND SIDE TECHNOLOGY	NO LOAD GROWTH	LOW LOAD GROWTH	HIGH LOAD GROWTH
2023	9,211,827	9,269,593	9,276,162	9,421,680
2024	9,873,735	9,098,884	9,608,909	10,060,991
2025	9,128,449	7,621,210	8,597,626	9,516,015
2026	9,118,450	7,212,138	8,184,783	9,508,598
2027	9,639,693	7,323,166	8,579,909	10,709,567
2028	9,617,272	5,903,745	8,196,422	11,041,503
2029	9,428,541	5,954,826	8,499,719	11,325,895
2030	8,337,487	5,687,326	7,674,143	11,570,399
2031	6,660,587	2,704,265	4,777,537	10,311,640
2032	4,991,578	2,194,884	3,631,295	8,649,596
2033	5,242,000	2,171,051	3,749,672	8,850,587
2034	5,422,185	2,212,082	3,711,450	8,448,779
2035	5,565,458	2,329,526	3,912,027	8,525,708
2036	5,789,181	2,117,532	3,896,824	7,497,100
2037	5,656,197	1,855,700	3,951,495	7,662,586
2038	5,786,210	1,689,438	3,934,591	7,015,800

ATTACHMENT F.1(B)(5): ANNUAL WATER USE

Annual Water Use (Acre-Feet)					
	REFERENCE	FOUR CORNERS COAL EXIT 2027	FOUR CORNERS COAL EXIT 2028	FOUR CORNERS COAL EXIT 2029	FOUR CORNERS COAL EXIT 2030
2023	51,329	51,338	51,330	51,328	51,326
2024	52,811	52,814	52,815	52,818	52,815
2025	50,758	50,757	50,760	50,756	50,758
2026	49,755	49,769	49,758	49,758	49,753
2027	51,477	51,474	51,483	51,488	51,471
2028	53,252	44,925	53,302	53,302	53,317
2029	53,571	46,308	45,503	53,542	53,541
2030	51,438	45,664	45,455	45,411	51,448
2031	47,786	46,065	45,813	45,821	46,121
2032	44,191	44,362	44,089	43,943	44,215
2033	45,014	45,414	45,157	45,031	45,279
2034	44,697	45,092	44,638	44,543	45,375
2035	45,389	45,539	45,328	45,278	45,849
2036	44,133	44,877	44,590	44,753	44,582
2037	43,566	43,691	43,627	43,356	43,678
2038	44,133	44,292	44,199	43,890	44,245

ATTACHMENT F.1(B)(5): ANNUAL WATER USE (CONTINUED)

Annual Water Use (Acre-Feet)					
	TECHNOLOGY NEUTRAL	HIGH GAS PRICE	LOW RENEWABLE TECHNOLOGY COST	PREFERRED PORTFOLIO (SELECTED)	HIGH RENEWABLE TECHNOLOGY COST
2023	51,326	51,327	51,321	51,329	51,330
2024	52,812	52,861	52,815	52,818	52,820
2025	50,752	51,113	50,760	50,752	50,755
2026	49,734	49,633	49,711	49,785	49,163
2027	52,534	50,148	51,561	50,979	51,809
2028	54,557	51,108	53,096	52,992	53,083
2029	56,647	52,465	53,582	54,829	53,432
2030	56,337	52,602	51,415	51,836	51,167
2031	48,004	49,083	48,019	48,431	47,532
2032	42,580	44,619	44,156	43,123	44,508
2033	43,553	45,723	45,217	44,131	45,568
2034	43,418	45,088	44,568	44,524	45,784
2035	44,078	45,690	45,253	44,805	46,364
2036	44,200	43,561	43,396	44,449	44,442
2037	43,561	42,878	42,904	44,400	44,486
2038	44,175	43,336	43,392	44,978	45,037

ATTACHMENT F.1(B)(5): ANNUAL WATER USE (CONTINUED)

Annual Water Use (Acre-Feet)				
	HIGH DEMAND SIDE TECHNOLOGY	NO LOAD GROWTH	LOW LOAD GROWTH	HIGH LOAD GROWTH
2023	51,191	51,332	51,336	51,705
2024	52,506	50,382	51,832	53,030
2025	50,196	45,994	48,710	51,277
2026	49,502	43,936	46,670	50,423
2027	50,855	44,007	47,819	53,691
2028	51,942	42,585	48,315	55,603
2029	51,599	42,790	49,302	56,067
2030	48,727	42,237	47,282	59,514
2031	44,893	35,967	40,923	54,743
2032	41,684	34,781	38,571	51,147
2033	42,339	34,652	38,876	51,522
2034	42,505	34,525	38,449	50,614
2035	42,850	34,949	38,988	50,833
2036	43,217	34,332	38,888	48,947
2037	42,683	33,230	38,919	49,039
2038	43,106	32,784	38,985	47,818

ATTACHMENT F.9(B)(1): 2023 RESOURCE PLAN - LOADS & RESOURCES FORECAST

	2023 Resource Plan - Loads & Resources - MW Energy Contribution at Peak																
		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
1	**Load Requirements**																
2	APS Peak Demand	8,184	8,594	9,012	9,525	10,020	10,427	10,805	11,127	11,398	11,646	11,903	12,146	12,386	12,634	12,877	13,119
3	Reserve Requirements	1,201	1,247	1,304	1,349	1,330	1,124	1,122	1,142	1,413	1,450	1,165	1,295	1,254	1,605	1,685	1,703
4	**Total Load Requirements**	9,385	9,841	10,316	10,874	11,350	11,551	11,927	12,269	12,811	13,096	13,068	13,442	13,641	14,240	14,562	14,823
5	**Existing Resources**																
6	Nuclear	1,146	1,146	1,146	978	978	978	978	978	978	978	978	978	978	978	978	978
7	Coal	1,347	1,347	970	828	828	828	828	828	0	0	0	0	0	0	0	0
8	Natural Gas	5,832	5,489	5,320	4,577	4,581	4,583	4,492	4,401	4,311	3,799	3,351	3,354	2,869	2,873	2,874	2,875
9	Combined Cycle	1,844	1,997	1,997	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661	1,661
10	Combustion / Steam Turbines	1,503	1,520	1,520	1,363	1,363	1,363	1,270	1,176	1,082	1,082	1,082	1,082	1,082	1,082	1,082	1,082
11	Tolling Agreements	1,598	1,598	1,660	1,446	1,446	1,446	1,446	1,446	1,446	934	486	486	0	0	0	0
12	Market / Call Options / Hedges /AG-X	887	374	142	106	110	112	115	118	121	122	122	125	126	130	131	131
13	Renewable Energy	475	476	463	440	444	444	449	443	448	446	441	435	434	442	404	403
14	Distributed Energy	6	6	6	14	14	14	14	14	14	14	13	14	13	14	10	9
15	PURPA QF	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16	Solar	356	343	328	296	296	294	295	295	296	293	291	293	291	294	291	290
17	Wind	87	100	103	106	111	113	117	120	124	125	125	128	130	135	103	104
18	Geothermal	10	10	10	9	9	9	9	0	0	0	0	0	0	0	0	0
19	Biomass/Biogas	16	16	16	15	15	15	15	15	15	15	12	0	0	0	0	0
20	Energy Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21	Microgrid	35	35	35	30	30	30	30	30	30	30	30	30	30	30	30	30
22	**Total Existing Resources**	8,835	8,492	7,934	6,852	6,860	6,862	6,777	6,679	5,766	5,252	4,800	4,796	4,310	4,322	4,285	4,285
23	**Customer Resources**																
24	Future Energy Efficiency	132	234	319	327	404	489	581	687	780	852	931	1,035	1,127	1,244	1,322	1,412
25	Future Distributed Energy	11	27	48	288	358	412	469	513	559	582	605	653	674	733	751	777
26	Demand Response (Future & Existing)	90	95	144	145	145	195	192	240	275	320	310	300	305	310	315	320
27	**Total Customer Resources**	232	355	512	760	906	1,095	1,242	1,439	1,613	1,754	1,845	1,987	2,105	2,286	2,388	2,509
28	**Future Resources**																
29	Nuclear (SMR)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	Natural Gas	0	199	0	122	201	319	359	439	1,302	1,814	2,262	2,262	2,748	2,954	3,034	3,034
31	Combined Cycle	0	0	0	0	0	0	0	0	0	512	960	960	1,446	1,446	1,446	1,446
32	Combustion Turbines	0	0	0	80	199	319	359	439	1,302	1,302	1,302	1,302	1,302	1,508	1,587	1,587
33	Short-Term Purchases/Summer Contracts	0	199	0	43	1	0	0	0	0	0	0	0	0	0	0	0
34	Renewable Energy	62	115	101	248	310	317	335	487	675	913	934	948	981	1,013	1,004	1,025
35	Wind	62	115	101	248	270	276	288	319	494	684	688	709	720	764	784	789
36	Solar	0	0	0	0	40	41	47	168	182	228	246	239	261	249	220	236
37	Bio/Geothermal/CSP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
38	PVS (PV + BESS)	240	525	1,531	1,691	1,885	1,890	1,945	1,958	1,958	1,971	1,979	1,975	1,982	1,978	2,180	2,156
39	Energy Storage	24	97	338	657	644	656	835	906	923	936	950	968	986	1,020	991	1,174
40	Microgrid	8	58	58	544	544	544	544	544	742	742	742	742	742	742	767	767
41	**Total Future Resources**	333	993	2,028	3,262	3,584	3,727	4,019	4,334	5,602	6,376	6,867	6,895	7,440	7,708	7,976	8,155
42	**TOTAL RESOURCES**	**9,400**	**9,841**	**10,474**	**10,874**	**11,350**	**11,683**	**12,038**	**12,452**	**12,980**	**13,381**	**13,512**	**13,678**	**13,855**	**14,316**	**14,649**	**14,950**

ACRONYMS AND GLOSSARY

4FRI	Four Forest Restoration Initiative
AC	Alternating Current
ACC	Arizona Corporation Commission
ACDC	APS Cyber Defense Center
ACE	Affordable Clean Energy
ADEQ	Arizona Department of Environmental Quality
ADMS	Advanced Distribution Management System
ADWR	Arizona Department of Water Resources
AESP	Association of Energy Services Professionals
AF	Acre Feet
AFB	Air Force Base
AFUDC	Allowance for Funds Used During Construction
AGS	Arizona Gas Storage
AMA	Active Management Area
AMI	Advanced Metering Infrastructure
APP	Aquifer Protection Permit
APS	Arizona Public Service
ASRFP	All Source Request for Proposal
ATC	Available Transfer Capability
BA	Balancing Authority
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
BCF	Billion Cubic Feet
BES	Bulk Electric System
BESS	Battery Energy Storage System
BNEF	Bloomberg New Energy Finance
BOR	Bureau of Reclamation
BTA	Biennial Transmission Assessment
BTU	British Thermal Unit
C&I	Commercial and Industrial
CAA	Clean Air Act
CAES	Compressed Air Energy Storage
CAFO	Concentrating Animal Feeding Operation
CAIDI	Customer Average Interruption Duration Index
CAISO	California Independent System Operator
CAP	Central Arizona Project
CC	Combined Cycle
CCR	Coal Combustion Residual
CCS	Carbon Capture & Sequestration/Carbon Capture & Storage
CDP	Climate Disclosure Project
CEC	Certificate of Environmental Compatibility
CERCLA	Comprehensive Environmental Response Compensation & Liability Act
CFI	Communicating Fault Indicators

CO	Carbon Monoxide
CO2	Carbon Dioxide
Commission	Arizona Corporation Commission
Committee	Arizona Power Plant and Line Siting Committee
Company	Arizona Public Service
COVID-19	Coronavirus Disease 2019
CPP	Clean Power Plan
CPP-RES	Critical Peak Pricing for Residential Customers
CSP	Concentrating Solar Power
CT	Combustion Turbine
CWA	Clean Water Act
D.C. Circuit	U.S. Court of Appeals for the District of Columbia Circuit
DA	Distribution Automation
DAM	Distribution Asset Monitoring
DC	Direct Current
DE	Distributed Energy
DER	Distributed Energy Resources
DMS	Distribution Management System
DOE	U.S. Department of Energy
DR	Demand Response
DRESLM	Demand Response, Energy Storage, Load Management program
DSCADA	Distribution Supervisory Control and Data Acquisition
DSM	Demand Side Management
E-20	Time-of-use for Religious Houses of Worship
E3	Energy and Environmental Economics, Inc.
E-32	Extra-small, Small, Medium, Large Businesses
E-35	Extra Large Time-of-use Business
EA	Environmental Assessment
EAB	Environmental Appeals Board
ECT-1R	Combined Advantage (9am-9pm)
ECT-2	Combined Advantage (Noon-7pm)
EDAM	Extended Day-Ahead Market
EE	Energy Efficiency
EES	Energy Efficiency Standard
EGU	Electric Generating Units
EIA	Energy Information Administration
EIM	Energy Imbalance Market
EIS	Environmental Impact Statement
ELG	Effluent Limitations Guidelines
ELCC	Effective Load Carrying Capability
EMS	Energy Management System
EPA	Environmental Protection Agency

EPC	Engineering, Procurement, and Construction
EPNG	El Paso Natural Gas
EPRI	Electric Power Research Institute
ESA	Endangered Species Act
ESG	Environment, Social and Governance
ESIGA	Energy System Integration Group
ESS	Energy Storage Systems
ET-1	Time Advantage (9am-9pm)
ET-2	Time Advantage (Noon-7pm)
ET-SP	Time Advantage Super Peak
EV	Electric Vehicle
FC	Four Corners Power Plant
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
FIP	Federal Implementation Plan
FONSI	Finding of No Significant Impact
Genset	Generator Set
GHG	Greenhouse Gas
GRIC	Gila River Indian Community
GS-Schools	General Service Medium and Large Time-of-use for Elementary and Secondary Schools
GUAC	Groundwater Users Advisory Council
GW	Gigawatt
GWh	Gigawatt-Hours
HAPs	Hazardous Air Pollutants
Hg	Mercury
HRSG	Heat Recovery Steam Generator
HVAC	Heating, Ventilation, and Air Conditioning
ICAP	Installed Capacity
IEA	International Energy Agency
IEEE	Institute of Electrical and Electronics Engineers
IFES	Feeder-scale battery storage
IGCC	Integrated Gasification Combined Cycle
IRA	Inflation Reduction Act
IRP	Integrated Resource Plan
ITC	Investment Tax Credit
IVVC	Integrated Volt/VAR Control
KAF	Thousand Acre Feet
KM	Kinder Morgan
KV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-Hour
LAER	Lowest Achievable Emission Rate
LCOE	Levelized Cost of Electricity
LED	Light Emitting Diode
LFP	Lithium Ion Phosphate

Li-Ion	Lithium Ion
LNB	Low Nox Burners
LOLE	Loss of Load Expectation
LOLH	Loss of Load Hours
LOLP	Loss of Load Probability
LTCE	Long term capacity expansion
MACT	Maximum Achievable Control Technology
MAIFI	Momentary Average Interruption Frequency Index
MATS	Mercury and Air Toxics Standard
MCAQD	Maricopa County Air Quality Department
MCAS	Marine Corps Air Station
MER	Measurement and Evaluation Research
MMBtu	Million British Thermal Units
MOD-29	Rated System Path Methodology
MOD-30	Flowgate Methodology
MTU	Metric Ton of Uranium
MW	Megawatt
MWh	Megawatt-Hour
N2	Nitrogen
NAAQS	National Ambient Air Quality Standards
NaS	Sodium-sulfur
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NGS	Navajo Generating Station
NMC	Nickel Manganese Cobalt
NNSR	Nonattainment New Source Review
NOx	Nitrogen Oxide
NP	Network Protections
NPV	Net Present Value
NRC	Nuclear Regulatory C
NSPS	New Source Performance Standards
NSR	New Source Review
O&M	Operation & Maintenance
OASIS	Open Access Same-Time Information System
OATT	Open Access Transmission Tariff
OMP	Ocotillo Modernization Project
OMS	Outage Management System
PAC	Program Administrator Cost
PC	Participant Cost
PCM	Production Cost Model
PCAP	Perfect Capacity
PCB	Polychlorinated Biphenyls
PEV	Plug-in Electric Vehicle
PLMA	Peak Load Management Alliance

PM	Particulate Matter
PMUs	Phasor Measurement Units
PPA	Purchased Power Agreement
PPB	Parts per Billion
PPH	People Per Household
PSD	Prevention of Significant Deterioration
PSIA	Pounds Per Square Inch Absolute
PTC	Production Tax Credit
PTR	Peak Time Rebate
PURPA	Public Utility Regulatory Policies Act
PV	Photovoltaic
PVNGS	Palo Verde Nuclear Generating Station
PVS	Photovoltaic with Storage
PVWRF	Palo Verde Water Reclamation Facility
PWR	Pressurized Water Reactor
QF	Qualified Facility
R-2	Saver Choice Plus
R-3	Saver Choice Max
RC	Reliability Coordinator
RCP	Resource Comparison Proxy
RCRA	Resource Conservation & Recovery Act
RE	Renewable Energy Resource
Redox	Reduction and Oxidation
RES	Renewable Energy Standard
REST	Renewable Energy Standard Tariff
RFP	Request for Proposal
RIM	Ratepayer Impact Measure
ROP	NERC's Rules of Procedure
RPAC	Resource Planning Advisory Council
RPS	Renewable Portfolio Standard
R-TECH	Saver Choice Tech Pilot
RTOA	Regional Transmission Organization
R-TOU-E	Saver Choice
RTP	Renewable Transmission Projects
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAT	Single-Axis Tracking
SC	Societal Cost
SCE	Southern California Edison Company
SCR	Selective Catalytic Reduction
SEPA	Smart Electric Power Alliance
SERVM	Strategic Energy and Risk Evaluation Model
SF6	Sulfur Hexafluoride
SHM	Substation Health Monitoring
SIP	State Implementation Plan
SMR	Small Modular Reactor
SO2	Sulfur Dioxide
SOC	State-Of-Charge
SRP	Salt River Project Agricultural Improvement and Power District
SRSG	Southwest Reserve Sharing Group
SWAT	Southwest Area Transmission
TEP	Tucson Electric Power
TO	Transmission Owner
TOP	Transmission Operator
TOU	Time of Use
TRC	Total Resource Cost
TSCA	Toxic Substances Control Act
UCAP	Unforced Capacity
USBR	United States Bureau of Reclamation
USGS	U.S. Geological Survey
VER	Variable Energy Resources
VOC	Volatile Organic Compounds
WEC	World Energy Council
WECC	Western Electricity Coordinating Council
WEIM	Western Energy Imbalance Market
WIIN	Water Infrastructure Improvements
WMEG	Western Markets Exploratory Group
WRAP	Western Resource Adequacy Program
ZLD	Zero Liquid Discharge

2023 Resource Plan (or 2023 Integrated Resource Plan or IRP)	Represents the documented process APS undertakes to select a number of alternative energy resource portfolios for the 2023-2038 period based upon a wide range of supply- and demand-side options.
4FRI	See Four Forest Restoration Initiative
ABB (Formerly Ventyx)	The company that produces the modeling tool, Strategist, used for this IRP.
Acre-Foot	The volume of water that will cover an area of one acre to a depth of one foot. One acre foot equals approximately 325,851 gallons.
Action Plan	Material actions anticipated to occur during the Action Plan Period.
Action Plan Period	For the purposes of this filing, the timeframe of 2020-2024.
Activated Carbon Injection System (ACI)	An engineered mercury control system from which powdered activated carbon (PAC) is pneumatically injected from a storage silo into the flue gas ductwork of a coal-fired power plant or industrial boiler. The PAC adsorbs the vaporized mercury from the flue gas and is then collected with the fly ash in the facility's particulate collection device.
Aquifer Protection Permit Program in Arizona	An ADEQ program designed to protect the quality of Arizona drinking water. Includes two key requirements: (1) meet Aquifer Water Quality Standards at the Point of Compliance; and (2) demonstrate Best Available Demonstrated Control Technology.
Arizona Administrative Code (A.A.C.)	The official compilation of rules that govern the state of Arizona's agencies, boards, and commissions.
Arizona Corporation Commission (ACC or Commission)	The Arizona Corporation Commission is comprised of five publicly elected persons who have full power to make reasonable rules, regulations and orders by which public service corporations shall be governed in doing business within the state of Arizona.
Arizona Department of Environmental Quality (ADEQ)	Administers a variety of programs to improve the health and welfare of citizens and ensure the quality of Arizona's air, land, and water resources meet healthful, regulatory standards.
Aurora	Energy Exemplar's production simulation software for forecast modeling and analysis. AURORA, which is a production cost model that optimizes commitment and dispatch of resources against hourly load, has enhanced storage logic that facilitates efficient integration of energy storage on systems with large renewable penetrations.
Auxiliary Load	The load that serves the power plant itself. Under normal circumstances, the auxiliary load is served by the production at the plant. If the plant is not producing power, then it is necessary for the grid to server the auxiliary load.
Baghouse	An air pollution abatement device that traps particulates (dust) by forcing gas streams through large filter bags, usually made of fiberglass or other synthetic fabrics and coatings.
Baseload Plant	An electric generating plant devoted to the production of electricity on a relatively continuous basis. Baseload plants are typically operated for the majority of the hours during a given year and are taken off-line relatively infrequently. Baseload plants usually have a low variable production cost relative to other production facilities available to the system.
Best Available Retrofit Technology (BART)	Under the Clean Air Act, states must require the installation of the best retrofit emission controls available as part of state strategies for meeting the regional haze rule. The BART requirement applies to facilities built between 1962 and 1977 that have the potential to emit more than 250 tons a year of visibility-impairing pollution.
Biogas	A mixture of gases produced by the breakdown of organic matter in the absence of oxygen (anaerobically), primarily consisting of methane and carbon dioxide. Biogas, which can be produced from raw materials such as agricultural waste, manure, municipal waste or landfill, is used a fuel for the production of electric power.
Biomass	Organic non-fossil material of biological origin constituting a renewable energy source that can be either processed into biofuel or burned directly to produce steam or electricity.
British Thermal Unit (Btu)	Used to describe the heat content of fuel. The price of fuel is typically expressed in terms of dollars per million Btu (or $/MMBtu).
Cap-and-Trade	An approach used to control emissions by providing economic incentives for achieving reductions. A central authority (usually a government or international body) sets a limit or cap on the amount that can be emitted. Companies or other groups are issued emission permits and are required to hold an equivalent number of allowances (or credits) which represent the right to emit a specific amount. The total amount of allowances cannot exceed the cap, limiting total emissions to that level. Companies that need to increase their emission allowances must buy credits from those that emit less. The transfer of allowances is referred to as a trade. In effect, the buyer is paying a charge for emitting, while the seller is being rewarded for having reduced emissions by more than was required.

Capacity	The maximum amount of electricity produced or extracted from a resource in any given moment. Capacity is usually measured in units of megawatts. It should be noted that most resources are not operated at their maximum capacity rating during all hours. See Capacity Factor
Capacity Factor	A value used to express the average output level of a resource over a given period of time. Capacity factor is expressed as a percentage of the maximum possible output of the resource had operated at its maximum capacity rating for all hours during the period. For example, a generating facility which operates at an average of 60% of its maximum capacity over a measured period has a capacity factor of 60% for that period.
Capacity Value	A resource's ability to reliably serve load during the top 90 load hours of the year. APS calculates capacity value by dividing the average net capacity of the resource during APS's top 90 load hours by the resource's maximum hourly capacity.
Carbon Capture & Sequestration/Storage (CCS)	A technology under development to limit emissions of carbon by capturing and storing it away from the atmosphere.
Carbon Dioxide (CO2)	A naturally occurring gas, and also a by-product of burning fossil fuels and biomass, as well as land-use changes and other industrial processes. It is the principal greenhouse gas that affects the Earth's radiative balance. See Greenhouse Gas, Emissions
Carbon Intensity	The amount of carbon dioxide produced for every unit of energy. For the purposes of this IRP, carbon intensity will be measured in metric tons of carbon dioxide per megawatt-hour.
Carbon Monoxide (CO)	A colorless, odorless, toxic gas produced by the incomplete combustion of carbon-containing substances. One of the major air pollutants, it is emitted in large quantities by exhaust of gasoline-powered vehicles.
Carrying Charges (or Carrying Costs)	Annual costs associated with investment in assets including depreciation, debt interest, equity return, income taxes, and property taxes.
Class-Based Hourly Load Models	Methods for identifying the hourly pattern of electricity demand for groups of customers with similar characteristics.
Clean Air Act (CAA)	The primary federal law enacted by the U.S. Congress to govern the regulation of emissions into the atmosphere on a national level. The primary responsibility for administering the CAA was given to EPA which develops and enforces regulations to protect the general public from exposure to airborne contaminants.
Clean Energy Commitment (CEC)	APS Clean Energy Commitment 1) By 2050, APS will deliver 100 percent clean, carbon–free and affordable electricity to our customers. 2) This goal includes a nearer–term 2030 target of 65 percent clean energy, with 45 percent of our generation portfolio coming from renewable energy. 3) APS will cease all coal–fired generation by 2031.
Coal Combustion Residual (CCR)	Referred to as coal ash, CCRs are currently considered exempt wastes under the Beville amendment to the Resource Conservation and Recovery Act (RCRA). They are residues from the combustion of coal in power plants and captured by pollution control technologies, such as scrubbers.
Coincident Peak	An individual customer's peak coincides with the system peak, meaning they are contributing to that peak hour.
Combined Cycle (CC)	Twin-stage natural gas-fired power plants that deliver higher fuel efficiency. In the first stage, a gaseous fuel source (natural gas, gaseous coal, etc.) is combusted in a gas turbine. The turbine is used to drive an electric generator. In the second stage, waste heat is captured from the gas turbine's hot exhaust gases in a heat recovery steam generator (HRSG). The steam that is produced in the HRSG is used to drive a steam turbine and produce additional electricity. This beneficial use of the residual heat content in the gas turbine's exhaust stream contributes to the excellent fuel efficiency of the combined cycle power plant.
Combustion Turbines (CT)	Also referred to as a simple cycle gas turbine, these electric generators operate on a principle similar to the engines on jet airplanes. Ambient air is compressed to high pressures in the compressor section of the machine. A gaseous fuel source is added to this compressed air and combusted in the combustor section. The resulting hot gases are then expanded through a turbine section that provides the driving force for both an electric generator and the compressor section.
Commercial Operation Date (COD)	The date when an operating utility formally declares a new generation resource to be available for the regular production of electricity.
Commodity Hedging Strategies	See Hedging
Compact Fluorescent Lamp (CFL)	A type of fluorescent lamp. Compared to incandescent lamps giving the same amount of visible light, CFLs use less power and have a longer rated life.

Competitive Procurement Procedure	Any solicitation process initiated to meet APS energy requirements. The Competitive Procurement Process shall include, as appropriate, preparing and conducting the solicitation, bid evaluation and selection, and negotiating the definitive agreement(s), but shall not include management or implementation of such agreement(s) after their execution.
Concentrated Solar Power (CSP)	Technologies that concentrate solar energy to generate electricity. This class of solar technologies includes solar trough, power towers, dish stirling, and concentrating photovoltaics.
Conditional Demand Analysis (CDA)	Statistical approach that allocates total household electricity demand during a period into components associated with a particular electricity-using appliance or end-use.
Consumption (Energy Use)	The total amount of electricity consumed over a period of time, measured in megawatt-hours. Consumption varies from demand in that demand is the rate at which electricity is being used at any one given time.
Conventional Resources	Conventional generating resources include a broad class of technologies that use coal, nuclear, natural gas, or fuel oil to generate electricity. Generally, conventional resources are dispatchable.
Cooling Degree-day	A measure of how warm a location is over a period of time relative to a base temperature, most commonly specified as 65 degrees Fahrenheit. The measure is computed for each day by subtracting the base temperature (65 degrees) from the average of the day's high and low temperatures, with negative values set equal to zero. Each day's cooling degree-days are summed to create a cooling degree-day measure for a specified reference period. Cooling degree-days are used in energy analysis as an indicator of air conditioning energy requirements or use.
Critical Peak Pricing (CPP)	Time-of-use rate plan (also known as Peak Event Pricing) that provides an extremely high price signal during a limited number of hours on critical days (such as periods of high electrical demands, extreme temperatures, system outages, or other abnormal grid-related events).
Customer Average Interruption Duration Index (CAIDI)	The average outage duration for those customers experiencing an outage.
Customer Resources (or customer-sited resources)	Resource options which rely upon active participation by customers to produce either a reduction in energy consumption or peak demand. These customer-side resource programs include energy efficiency programs, demand response programs, and alternative rate schedules. Energy efficiency programs are directed at achieving reductions in customer energy consumption through more efficient equipment or improvements to a building's thermal envelope. Demand response programs generally target reductions during the highest usage periods of the year through special rate schedules (such as time-of-use prices), energy storage options, or other similar programs
Day-Ahead Trader	Trader that engages in forward markets that cover a 24-hour period in advance of a given day.
Delivered Cost	Refers to the cost of power produced by a generating unit (or a purchased power contract) where the cost of delivering the electric power from the generating source to the load center (area of customer consumption) has also been included in the cost.
Demand	The rate at which electricity is being used at any given time, measured in megawatts. Demand differs from energy use, which reflects the total amount of electricity consumed over a period of time.
Demand Response (DR)	Mechanisms designed to provide incentives to customers to reduce their load in response to high electric market prices or electric system reliability concerns. Demand response measures could include direct load control programs, such as cycling of air conditioner load, or customer-initiated load reductions. Price response programs include real-time pricing, dynamic pricing, critical peak pricing, time-of-use rates, and demand bidding or buyback programs.
Demand-Side Management (DSM)	The planning, implementation, and monitoring of utility activities designed to encourage residential and business customers to modify patterns of electricity usage, including the timing and level of electricity demand.
Discount Rate	An interest rate used to convert future cash flows to present values
Dispatchable	Generating units (or purchased power contracts) whose rate of power production can be adjusted or varied based upon economic or other considerations. Different types of generating units have varying degrees of dispatchability either for technical or economic reasons.
Distributed Energy	A term referring to a small generator, typically 10 megawatts or smaller, that is sited at or near load, and that is attached to the distribution grid or the customer's electrical system. Distributed generation can serve as a primary or backup energy source and can use various technologies, including combustion turbines, reciprocating engines, fuel cells, wind generators, and solar photovoltaics.
Distribution	The delivery of energy to retail customers.

Dry Cooling	The typical steam power plant requires cooling water to improve overall cycle efficiency by returning the exhaust steam to a liquid state that can then be returned to the boiler to produce more steam. In a dry-cooled power plant, the exhaust steam is cooled by use of air-cooled condensers thereby eliminating the use of water from this portion of the power production process; however, the air-cooled condensers are more expensive and overall plant efficiency is reduced versus water-cooled plants
DSM Implementation Plan	Annual filing required for compliance with the Arizona Corporation Commission's Electric Energy Efficiency Standards, codified at A.A.C. RI4-2-2401, which includes the implementation strategy APS will use to achieve compliance with the EE Standard.
Effluent	Wastewater, treated or untreated, that flows out of a treatment plant, sewer, or industrial outfall. Generally refers to wastes discharged into surface waters.
Electric Generating Units (EGU)	A solid fuel-fired steam generating unit that serves a generator who produces electricity for sale to the electric grid.
Emissions	Discharges into the atmosphere from stacks, other vents, and surface areas of commercial and industrial facilities; from residential chimneys; and from motor vehicle, locomotive, or aircraft exhaust.
Energy	The amount of electricity a resource outputs, or an end user consumes, in any given period of time. It is usually measured in units of kilowatt-hours, megawatt-hours, or gigawatt-hours.
Energy Efficiency	
	In the context of resource planning, energy efficiency refers to actions taken by consumers to reduce their overall consumption of electric energy. These reductions could be the result of installation of more efficient equipment, improvements to the thermal envelopes of structures, or behavioral changes. Energy efficiency improvements can be encouraged through utility-sponsored programs, mandated by building codes or other standards or simply implemented by the customer.
Energy Efficiency Standard (EES)	Requirement codified in A.A.C. R14-2-2404 to achieve an accumulated energy savings equivalent to 22% of retail sales by the year 2020.
Energy Exemplar	The company that produces the modeling tool, Aurora, used for this IRP.
Energy Mix	The percentage of each type of energy generated in a scenario or profile. Together, the percentages for each scenario add up to 100%.
Energy Savings	A reduction in the amount of electricity used by end users. In this IRP, it specifically refers to the reduction that is result of participation in energy efficiency programs and load management programs.
Environmental Protection Agency (EPA)	A governmental agency established in 1970 to research, monitor, and establish standards that protect human health and the environment. The EPA also has the authority to enforce regulations when necessary, although normally the states implement them.
Externalities	Occurs when an entity is engaged in an activity that creates harm or benefits for others as a byproduct, but that entity does not pay the costs of, or receive compensation for, the harm or benefits created. An example would be water use and water consumption.
Federal Energy Regulatory Commission (FERC)	A governmental agency that regulates the interstate transmission of natural gas, oil, and electricity and wholesale power transactions. FERC also regulates natural gas and hydropower projects.
Federal Poverty Guidelines	Issued each year in the Federal Register by the Department of Health and Human Services. The guidelines are a simplification of the poverty thresholds for use for administrative purposes — for instance, determining financial eligibility for certain federal programs.
Flexible Resource	Dispatchable generation resource capable of reaching full capacity in under an hour from cold start.
Force Majeure	Disruptions in service caused by natural disasters (earthquakes, hurricanes, floods, etc.); wars, riots, or other major upheaval; or, performance failures of parties outside the control of the contracting party.
Four Forest Restoration Initiative (4FRI)	The Arizona Four Forest Restoration Initiative focus has been to improve and sustain watershed health, improve wildlife habitat, conserve biodiversity, protect old-growth, reduce the risk of uncharacteristic wildland fire and promote the reintroduction of natural fire, and restore natural forest structure and function.
Fuel Cell	A device that converts chemical energy into electrical energy using a fuel. Fuel cells require a constant supply of fuel and oxygen for its chemical reaction unlike batteries where the chemicals react with each other to provide the electricity.
Genset	At its simplest, a generator set consists of an engine and an electric generator, which is used to produce electrical power. A diesel generation set provides fast-starting, backup power in the event of a grid disruption.

Geothermal	Energy produced below the Earth's crust in a layer of hot and molten rock called magma, heating nearby rock and water that has seeped deep into the Earth. At geothermal power plants, wells are drilled into the rock to more effectively capture the hot water and steam to be used to drive electric generators.
Greenhouse Gas (GHG)	A collection of gaseous substances, primarily consisting of carbon dioxide, methane, and nitrogen oxides, which have been shown to warm the earth's atmosphere by trapping solar radiation. Greenhouse gases also include chlorofluorocarbons, a group of chemicals used primarily in cooling systems and which are now either outlawed or severely restricted by most industrialized nations.
(Power or electric) Grid	An interconnected network of electric power transmission lines. The United States power grid, which covers most of the country as well as parts of Canada and Mexico, is made up the Eastern Interconnection, Western Interconnection, and Texas Interconnection. These networks include extra-high-voltage connections between individual utilities, which transfer electrical energy from one part of the network to another. The Interconnects distribute electricity in their respective areas via a network of smaller units that enable better management of power distribution.
Groundwater	Water that is held in soil or in rocks underground. Groundwater is distinct from surface water, which is water held in lakes and rivers.
Hazardous Air Pollutants (HAP)	Substances covered by air quality criteria, which may cause or contribute to illness or death.
Heat Rate	A measure of the amount of thermal energy required to produce a given amount of electric energy. It is usually expressed in British thermal units per kilowatt-hour (Btu/kWh). The performance of a power plant is measured by its fuel consumption rate (Btu/hr) and the corresponding amount of electric energy generated; thus, heat rate can be used to indicate the efficiency with which thermal energy is converted into electric energy.
Heating Degree-day	A measure of how cold a location is over a period of time relative to a base temperature, most commonly specified as 65 degrees Fahrenheit. The measure is computed for each day by subtracting the average of the day's high and low temperatures from the base temperature (65 degrees), with negative values set equal to zero. Each day's heating degree-days are summed to create a heating degree-day measure for a specified reference period. Heating degree-days are used in energy analysis as an indicator of space heating energy requirements or use.
Heating, Ventilating and Air Conditioning (HVAC)	Technology which provides indoor air comfort.
Hedging	The attempt to eliminate at least a portion of the risk associated with owning an asset or having an obligation by acquiring an asset or obligation with offsetting risks. For example, a company that has an obligation to purchase fuel oil in six months may want to eliminate the risk that prices will increase before that time. In this case, the company could hedge, or reduce, that risk by purchasing a futures contract that provides the right to purchase fuel oil at a fixed price. Any profit or loss on the futures contract should offset the effects of higher or lower oil prices at the time the company needs to buy oil.
Hg (Mercury)	See Mercury
Hub	In the context of the electric grid, a hub is a location on the transmission network having a high concentration of interconnected transmission lines, generating sources, and/or counterparties willing to transact power trades such that this becomes a location having a great deal of commercial activity.
Hybrid Cooling	A type of technology that utilizes a combination of water cooling and dry cooling techniques. The relative contribution from each is dependent upon the plant design, weather conditions, and water consumption policies. See also Dry Cooling.
Inflation Reduction Act (IRA)	On August 16, 2022, President Biden signed the Inflation Reduction Act (IRA) into law. The IRA includes several tax provisions such as Production Tax Credit (PTC), Investment Tax Credit (ITC), Carbon Capture and Sequestration (CCS) tax credit, and hydrogen production tax credit.
Integrated Gasification Combined Cycle (IGCC)	A power generation technology which allows a reduction of emissions by combining two technologies: (1) coal gasification, which uses coal to create a clean-burning gas; and, (2) combined cycle generation.
Intensity	Metric employed to characterize the emission of pollutants, relative to the power produced. For example, tons of CO2 emitted per MWh or gallons of water used per MWh can be used to help characterize the energy intensity of the system resources independent of load growth.
Interconnection	A connection between two electric systems permitting the transfer of electric energy in either direction. Additionally, an interconnection refers to the facilities that connect a generator to a system.

Intermediate Resource	Generation resources that usually fulfill a somewhat flexible role in the generating system. During some times of the year, these generating units will be started in the morning hours, used to meet daytime peak loads and then brought off-line in the evening. The operation may change during heavier load times of the year when these units may operate in more of a baseload manner and remain on-line for all hours of the day.
Intermittent (or Variable [Energy]) Resource	Generating resources that have some degree of variability in the production pattern, typically due to weather conditions. An example of an intermittent generating source is a wind project. The power output from the wind project is entirely dependent upon the wind conditions and will fluctuate with changes in wind conditions.
Investment Tax Credit (ITC)	Allows taxpayers to take a dollar-for-dollar reduction in the amount of federal income taxes that must be paid. Certain qualified facilities are characterized as energy property and are eligible for tax credit, depending on the technology. A taxpayer cannot take both an ITC and PTC for a facility that could qualify for both; one must elect to receive either an ITC or PTC for each project.
Kilowatt (kW)	Unit of measure for demand. One thousand Watts.
Kilowatt-Hour (kWh)	Unit of measure for energy. The equivalent of one thousand Watts used steadily for one hour.
Landfill gas	Gas that is generated by decomposition of organic material at landfill disposal sites. The methane in landfill gas may be vented, flared, combusted to generate electricity, or used as thermal energy on-site.
Light-Emitting Diode (LED)	A semiconductor light source increasingly used for lighting. LEDs present many advantages over incandescent light sources including lower energy consumption, improved robustness, smaller size, faster switching, and greater durability and reliability.
Load	The moment-to-moment measurement of the power requirement in the entire system.
Load Center	A point at which the load of a given area is assumed to be concentrated.
Load Pocket	A geographic area that has a high demand of energy constrained by transmission import limitations. For example, the metro Phoenix area is considered a load pocket.
Loads & Resources Table	Presents the annual expected resource needs and additions.
Loss of Load Probability (LOLP)	The probability that generation resources will fall short of the resource need. The LOLP is expressed as a number between 0 and 1.
Losses on Peak	Total electric energy losses during the hour of greatest energy demand. The losses consist of transmission, transformation, and distribution losses between supply sources and delivery points. Electric energy is lost primarily due to heating of transmission and distribution equipment (wire, transformers, etc.).
Low NOx Burner (LNB)	A type of burner that is typically used in utility boilers to produce steam. Air used for combustion is split into two or more parts. The initial combustion, which occurs at a high temperature, takes place in an oxygen-deficient condition to form molecular nitrogen (N2) instead of NOx. Further down the flame, additional air is added to complete the combustion after the nitrogen has been driven out of the coal as N2.
Lowest Achievable Emission Rate (LAER)	The most stringent emission limitation derived from either of the following: (a) the most stringent emission limitation contained in the implementation plan of any State for such class or category of source; or, (b) the most stringent emission limitation achieved in practice by such class or category of source. The emissions rate may result from a combination of emissions-limiting measures such as: (1) a change in the raw material processed; (2) a process modification; and, (3) add-on controls.
Major Modification	Any physical change or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Clean Air Act.
Major Sources	Term used to determine applicability of permitting regulation to stationary sources. For Title V of the Clean Air Act, refers to sources of air pollution that emit or have the potential to emit 100 tons per year or more of any criteria air pollutant.
Maximum Achievable Control Technology (MACT)	The standards which are established by EPA to require the maximum degree of emission reduction that EPA determines to be achievable for hazardous air pollutants. These standards are authorized by Section 112 of the Clean Air Act.
Megawatt (MW)	One megawatt equals one million watts. See Watt
Megawatt-Hour (MWh)	One million watt-hours See Watt-Hour
Mercury	A naturally-occurring element that is found in air, water and soil. Coal contains mercury and when coal is burned, mercury is released into the environment.
Must Take Generation	Electricity production that must be taken when it is produced by the utility. Generally refers to qualifying facilities under the Public Utility Regulatory Policies Act (PURPA).

Nameplate Rating (or Nameplate Capacity or Nameplate)	A rating for each resource that specifies the maximum expected output of the resource.
National Ambient Air Quality Standards (NAAQS)	The standards established by EPA under authority of the Clean Air Act that apply to outdoor air throughout the country. Primary standards are designed to protect human health, with an adequate margin of safety.
National Environmental Policy Act (NEPA)	Establishes a process by which federal agencies must study the environmental effects of their actions, so these effects can be taken into consideration during federal decision-making.
Net Present Value (NPV)	Method for evaluating the cost or profitability of an investment. Individual future cash amounts are discounted back to their present values and then summed.
New Source Performance Standards (NSPS)	Pollution control standards issued by the Environmental Protection Agency.
New Source Review (NSR)	A permitting program that was established by Congress as part of the 1977 Clean Air Act Amendments. NSR is a preconstruction permitting program to ensure air quality is not significantly degraded from the addition of new and modified factories, boilers, and power plants and that advances in pollution control occur with industrial expansion.
Nitrogen Oxide (NOx)	Compounds of nitrogen and oxygen formed by combustion under high temperature and high pressure and a major contributor to the formation of ozone.
Non-Spinning Reserves	A generating reserve not connected to the system but capable of serving demand within a specified time, usually ten minutes.
North American Electric Reliability Corporation (NERC)	NERC is a non-government organization which has statutory responsibility to regulate bulk power system users, owners, and operators through the adoption and enforcement of standards for fair, ethical, and efficient practices.
Nuclear Fuel	Fissionable materials of such composition and enrichment that when placed in a nuclear reactor will support a self-sustaining fission chain reaction and produce heat in a controlled manner for process use.
Nuclear Regulatory Commission (NRC)	The federal agency responsible for the regulation and inspection of nuclear power plants to assure safety.
Off-Peak	Period of relatively low system demand. These periods often occur in daily, weekly, and seasonal patterns.
On-Peak	Periods of relatively high system demand. These periods often occur in daily, weekly, and seasonal patterns.
Operating Reserves (or reserves or Contingency Reserves)	A combination of spinning and non-spinning reserves. Operating reserve is the portion of all reserves APS is required to carry over and above firm system demand to provide for regulation, load-forecasting error, equipment forced and scheduled outages and local area protection. APS will increase its planning reserve to 20.2% in 2026 to account for changing conditions.
Operation & Maintenance (O&M)	Actions taken after construction to ensure that facilities constructed will maintain performance by being properly operated and maintained to achieve normative efficiency levels in an optimum manner.
Ozone	Ozone, the triatomic form of oxygen (O3), is a gaseous atmospheric constituent. In the troposphere, it is created both naturally and by photochemical reactions involving gases resulting from human activities (photochemical smog). The layer of ozone that begins approximately 15 km above Earth and thins to an almost negligible amount at about 50 km, shields the Earth from harmful ultraviolet radiation from the sun.
Palo Verde Hub	An energy hub (see Hub) in the area of PVNGS located west of Phoenix, Arizona, where numerous regional counterparties engage in power transactions which form the basis for various indices. For example, the Dow Jones Palo Verde Electricity Price Indexes are volume-weighted averages of specifically-defined bilateral, wholesale, and physical transactions in the hub quoted in either $/MWh or $/MW.
Particulate Matter	Particle pollution in the air that includes a mixture of solid particles and liquid droplets.
Peak Demand (or Peak Load or Peak)	The greatest demand that occurred or is expected to occur during a prescribed time period.
Peaking Resources	Technologies used to respond to high customer demands during the hot summer afternoons. These could include combustion turbines and DR measures and may include short-term market purchases.
Peaking Units	These generation units usually see relatively infrequent service during the non-summer months. During the summer, peaking units are used during the hot summer afternoons in response to high customer demands. It is not unusual for peaking units to operate less than 10% of the hours during the year.

PM10	Particles with diameters that are 10 micrometers or smaller. Sources of particles include combustion, crushing or grinding operations, and dust from paved or unpaved roads.
Power Tower	Flat, sun-tracking mirrors, known as heliostats, focus sunlight onto a receiver located at the top of a tall tower. A heat-transfer fluid is used to heat a working fluid, which, in turn, produces electricity in a conventional turbine generator. Working fluids have high heat capacity, which can be used to store the energy (to generate power after the sun sets) before using it to boil water to drive turbines.
Preference Power	Federal hydropower and resources from the Colorado River system.
Prevention of Significant Deterioration (PSD)	EPA program in which state and/or federal permits are required in order to restrict emissions from new or modified sources in places where air quality already meets or exceeds primary and secondary ambient air quality standards.
Production Tax Credit (PTC)	Allows a tax credit for the amount of energy produced for electricity generated at qualified facilities. The PTC amounts, credit periods, and definitions of qualified facilities are technology-specific. A taxpayer cannot take both an ITC and a PTC for a facility that could qualify for both – one must elect to receive either an ITC or PTC for each project.
Public Utility Regulatory Policies Act (PURPA)	In response to the 1973 energy crisis, PURPA was enacted to promote 1) energy conservation (reduce demand), 2) greater use of domestic energy, and 3) renewable energy (increase supply).
Purchased Power Agreement (PPA)	A contractual agreement between two entities for the sale of electric energy and capacity from a specific generating unit, utility system, or unspecified wholesale market sources.
Real-Time Operations	Operational activity which manages the economic commitment of APS's generation resources to match the system load on a real-time basis. Requires making decisions to optimize system operation to provide lowest cost, reliable power to APS customers.
Real-Time Traders	Individuals involved solely in commodity trading of power, specifically electricity.
Regional Haze Rule	Requirements established by EPA to address source-by-source visibility impairment.
Regression Models	A statistical technique used to find relationships between variables for the purpose of predicting future values.
Renewable Energy	An energy resource that is replaced rapidly by a natural, ongoing process and that is not nuclear or fossil fuel.
Renewable Energy Standard (RES)	Requirement codified at A.A.C. R14-2-1804 which requires regulated electric utilities within Arizona to generate 15 percent of their energy from renewable resources by 2025.
Renewable Energy Standard Implementation Plan	Requirement for Arizona's regulated utility companies to file annual implementation plans describing how they will comply with the Renewable Energy Standard rules.
Request for Proposal (RFP)	A competitive solicitation for suppliers, often through a bidding process, to submit a proposal on a specific commodity or service.
Residential Direct Load Control	Demand response programs where the utility or a third-party contractor can remotely control customer-specific loads and reduce or cycle the energy consumption for a specified period of time.
Resource Conservation and Recovery Act (RCRA)	Gives EPA the authority to control hazardous waste from the "cradle-to-grave." This includes the generation, transportation, treatment, storage, and disposal of hazardous waste. RCRA also set forth a framework for the management of non-hazardous solid wastes.
Resource Planning Rules	Codified at A.A.C. R14-2-703, the Resource Planning Rules require regulated electric utilities to file a plan for future generation needs.
Revenue Requirements	Annual revenue level required to supply customers energy needs, including: (1) carrying charges on existing and future generation, future transmission over and above APS Ten Year Transmission Plan, and capital expenditures on existing generation; (2) fuel costs; (3) purchase power costs; (4) operating and maintenance costs for existing and future generation; (5) energy efficiency program and incentive costs; (6) distributed energy program and incentive costs; and, (7) power plant emissions costs including CO_2. Revenue requirements as used in the IRP do not include costs associated with existing transmission, existing and future distribution, or sales tax on retail electric sales.
Scenario Analysis	Refers to the grouping together of a set of assumptions of key uncertain variables that could potentially all occur in tandem. The goal of scenario analysis is to illustrate the impact to the portfolios of multiple key variables being stressed in a plausible manner. Results of these studies provide information on diversity, cost, environmental impacts, robustness and overall risk to assist in the selection of a resource plan.
Selective Catalytic Reduction (SCR) Controls	A post-combustion pollution control technology that removes NO_x emissions from an air stream. Ammonia (NH_3) is injected into the flue gas downstream from the combustion process and upstream from a catalyst bed. The NH_3 reacts with the NO_x on the catalyst surface to form nitrogen (N_2) and water vapor (H_2O).
(Retail) Service Territory	The area where a utility provides power.

Simple Cycle	See Combustion Turbine
Societal Cost Test (SCT)	A variant of the Total Resource Cost Test. It measures the impacts of DSM on society as a whole by including externality costs of power generation not captured by the market.
Solar Photovoltaic (PV, or Solar PV)	A method of generating electrical power by converting solar radiation directly into electricity.
Solar Thermal	A method for harnessing solar energy for thermal energy.
Southern California Edison (SCE)	One of the largest electric utilities in California, serving more than 14 million people in a 50,000 square-mile area of central, coastal and Southern California, excluding the City of Los Angeles and certain other cities.
Southwest Reserve Sharing Group (SRSG)	A NERC-registered entity. SRSG participants share contingency reserves to maximize generator dispatch efficiency and contribute to electric reliability in the Western Interconnection.
Spinning Reserves	Available generating capacity that is synchronously connected to the electric grid and capable of automatically responding to frequency deviations on the system.
Spot Market	A commodities or securities market in which goods are sold for cash and delivered immediately.
Standby Generation	Customer-owned generation resources, typically diesel- or gas-fired, that provide customers with a guaranteed source of power in the event that either power quality or reliability issues occur with their local utility.
Startup Costs	The costs associated with starting a power plant. These costs have become more of a consideration as more variable energy resources have been added to the electricity system and start-ups have become more frequent for some types of generation.
State Implementation Plan (SIP)	Plans developed by state and local air quality management agencies and submitted for approval to EPA to comply with the federal Clean Air Act.
Strategist	An ABB company resource expansion plan optimizing software model.
Sulfur Dioxide (SO2)	A colorless gas of compounds of sulfur and oxygen that is produced primarily by the combustion of fossil fuel.
Summer Peak	See Peak Demand
System Average Interruption Duration Index (SAIDI)	Used as a reliability indicator by electric power utilities. SAIDI is the average annual outage duration experienced by the average customer.
System Average Interruption Frequency Index (SAIFI)	Used as a reliability indicator by electric power utilities. SAIFI is the average annual outage frequency experienced by the average customer.
Thermal Energy Storage (TES) Cooling Programs	Systems that utilize a storage medium, such as chilled water or ice, which is “charged” during off-peak hours and then used as the cooling energy source during on-peak hours, offsetting the need to operate high-demand refrigeration equipment.
Total Own Load Peak	The greatest demand for energy during a specified time period by customers that APS has a requirement to serve.
Total Resource Cost Test (TRCT)	Measures the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participants' and the utility's.
Transmission	The transportation of bulk energy along a network or grid of power lines. It is often intended to refer specifically to high-voltage (69,000 volts or higher) electricity of the type bought and sold on the wholesale market. An additional stage of service, referred to as distribution, is required to actually deliver usable low-voltage energy to an end-use customer.
Utility-Scale	A resource that is sized to provide power to a utility and not directly to an on-site customer.
Volatile Organic Compounds (VOC)	Types of organic compounds which have significant vapor pressures (evaporate easily, forming a gas) and which can affect the environment and human health.
Water Intensity	The amount of water needed to produce a unit of electricity. In general, this document will give water intensity as acre-feet per megawatt-hour.
Watt-Hour	The total amount of energy used in one hour by a device that requires one watt of power for continuous operation. Electric energy sold to retail customers is commonly measured in kilowatt-hours.
Watt	The electrical unit of real power or rate of doing work; specifically, the rate of energy transfer equivalent to one ampere flowing due to an electrical pressure of one volt at unity power factor.
WestConnect	WestConnect is composed of utility companies providing electric transmission in the U.S. Members work collaboratively to assess stakeholder and market needs and develop cost-effective enhancements to Western wholesale electricity markets.

Western Electricity Coordinating Council (WECC)	The regional entity responsible for coordinating and promoting bulk electric system reliability in the Western Interconnection.
Western Interconnection	The interconnected electrical systems that encompass the region of the Western Electricity Coordinating Council of the North American Electric Reliability Council. The region extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia, the northern portion of Baja California (Mexico), and all or portions of the 14 western states in between, including Arizona.
Western Interstate Energy Board (WIEB)	Organization of 11 western states and three western Canadian provinces. Board Members are appointed by state governors. The Board provides the instruments and framework for cooperative state efforts to “enhance the economy of the West and contribute to the well-being of the region’s people.”
Wholesale Customer	Any party who purchases electricity in bulk for resale to end-use customers. Wholesale customers may include marketers, utilities and distribution companies, co-ops, and any other entity engaged in energy resale.
Zero Liquid Discharge (ZLD)	A treatment process designed to remove all the liquid waste from a system. The focus of ZLD is to reduce wastewater economically and produce clean water that is suitable for reuse (e.g. irrigation), thereby saving money and being beneficial to the environment. ZLD systems employ advanced wastewater treatment technologies to purify and recycle virtually all of the wastewater produced.

APPENDIX A

REGIONAL MARKET REPORT

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June 1, 2023

Docket Control
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Re: Arizona Public Service Company (APS or Company)
Resource Planning and Procurement in 2021, 2022, and 2023
Docket No. E-99999A-22-0046

Resource Planning and Procurement in 2019, 2020, and 2021
Docket No. E-00000V-19-0034

Pursuant to Decision No. 78499 (March 2, 2022), APS, Tucson Electric Power Company (TEP), and UNS Electric, Inc. (UNSE) are each required to file by June 1, 2023, in the 2023 Resource Planning and Procurement docket:

> …a Market Report on the status of their engagement in regional market development forums including, but not limited to, the Energy Imbalance Market, the Western Market Exploratory Group, the Enhanced Day Ahead Market of the California Independent System Operator, and the Western Resource Adequacy Program.

Attached is the Company's Market Report, which is being filed concurrently in Docket No. E-00000V-19-0034 for compliance purposes.

The Decision also required APS, TEP, and UNSE to host a stakeholder workshop on the content and findings of their respective Market Reports as part of the resource planning process. The joint Market Report workshop was held virtually via Microsoft Teams on May 4, 2023, and was attended by more than 40 participants including stakeholders and Arizona Corporation Commission Staff. A workshop summary is included in the Market Report Appendix.

Please let me know if you have any questions.

Sincerely,

/s/ Rachael Leonard

Rachael Leonard

RJR/awf
Attachment

MARKET REPORT

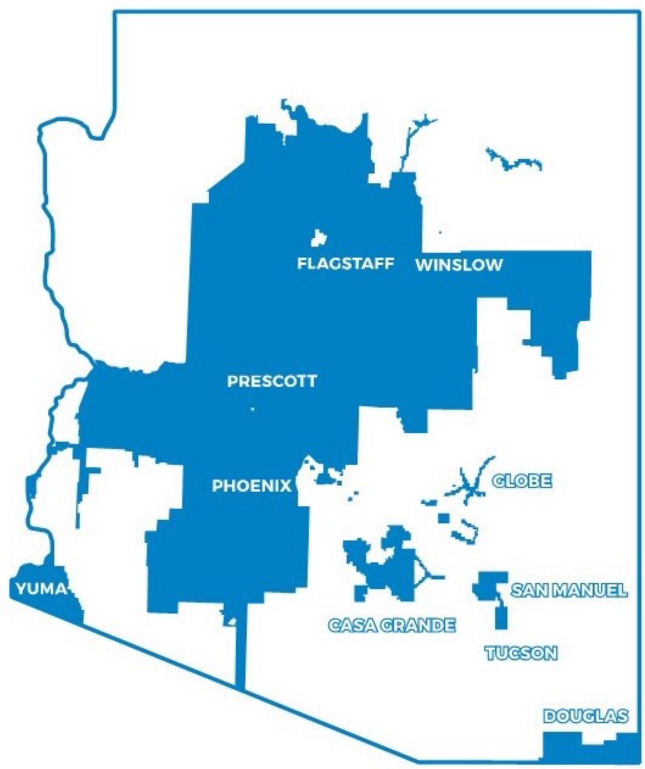
JUNE 1, 2023

FILED IN ACCORDANCE WITH DECISION NO. 78499 (MARCH 2, 2022)

aps

INTRODUCTION

Arizona Public Service's (APS or Company) market activities are characterized by a commitment to achieve higher levels of reliable operation, customer cost savings, and clean energy integration for the near- and long-term. This year, the National Renewable Energy Laboratory offered a report to aggregate a slew of Western-specific studies and demonstrated that challenges associated with achieving such benefits can be overcome with greater collaboration and coordination across broader balancing authority (BA) footprints.[1]



APS is Arizona's largest utility, serving more than 1.3 million customers across 34,646 square miles.

Since APS's entrance into the Energy Imbalance Market (EIM or WEIM) in 2016, the Company has maintained activities to ensure that potential paths to expand wholesale market participation are desirable and fair to entities in the Southwest. APS is currently engaged in the development of two day-ahead market options: the California Independent System Operator's (CAISO) Extended Day-Ahead Market (EDAM) and Southwest Power Pool's (SPP) Markets+. In 2022, APS announced a commitment to participate in the Western Resource Adequacy Program (WRAP) administered by Western Power Pool (WPP). Finally, APS is collaborating with regional load-serving entities as part of the Western Markets Exploratory Group

[1] David Hurlburt, *et al*., National Renewable Energy Laboratory, The Impacts on California of Expanded Regional Cooperation to Operate the Western Grid (Final Report) (2023), https://www.nrel.gov/docs/fy23osti/84848.pdf.

(WMEG) to explore pathway scenarios to Western organized market participation up to and including a Regional Transmission Organization (RTO).

APS's market participation over the past few years and the anticipated trajectory and assessment of existing market offerings are summarized below. The Company also explains how its transition from a Contract Path operation to Flow Based functionality will allow better utilization of transmission system capability.

In addition to ordering the Market Report, Decision No. 78449 also required APS, Tucson Electric Power Company, and UNS Electric, Inc. to host a stakeholder workshop on the content and findings of their respective Market Reports as part of the resource planning process. The joint Market Report workshop was held virtually via Microsoft Teams on May 4, 2023, and was attended by more than 40 stakeholders. A workshop summary is included in the Appendix.

DAY-AHEAD MARKETS

Day-ahead markets for Western entities are targeted to commence in the next few years. APS is involved in developing two day-ahead market opportunities, focusing on ensuring programs will operate with a governance structure and market design, that promote fairness and opportunities to access market benefits.

With both CAISO and SPP targeting tariff filings this year for their respective day-ahead market programs, APS is evaluating a commitment to join a day-ahead market. In addition to governance and market design, the preferences of other Western entities will also factor into APS's decision since broad market participation offers the best opportunity to take advantage of differing load shapes and resource diversity.

In the areas of transmission planning, coordination, tariff consolidation, cost-allocation, and utilization arrangements, it is important to note that neither CAISO nor SPP is targeting a full RTO with their day-ahead offering. Traditionally these areas are covered with a full RTO offering, but with a day-ahead market offering, there may still be coordination and information sharing that is performed between the market operators and those who retain these functions. When coordination is required in these areas, it would appear in the form of seams agreements. Importantly, APS will be evaluating both the CAISO and SPP market opportunities on present day benefits and on the potential for future expansion, including full RTO development.

California Independent System Operator (CAISO)

CAISO is a single-state ISO formed under California state law. It operates the EIM, a real-time wholesale energy market in which APS became an early participant. The EIM finds the least-cost solution across the market's footprint for each 15- and 5-minute interval. CAISO reporting shows, since joining the EIM, APS has saved customers nearly $337 million in fuel and purchased power costs as of the end of the first quarter of 2023.

CAISO provides EDAM as its day-ahead market offering for transactions across the footprint on a 12- to 24-hour forward basis. At the beginning of the year, the CAISO governing bodies approved the EDAM proposal, and CAISO is progressing through the detailed business practices and final stages of EDAM tariff development, targeting a June 2023 filing to FERC.

The governance structure of EDAM has been a focal point for APS throughout the program's development. APS continues to champion a governance structure that promotes independent and unbiased decision making to achieve balanced outcomes for all market participants. APS endorsed a fully independent governance structure to ensure adequate representation of market participants external to California. While the final EDAM proposal does not include an independent governance structure, EDAM has adopted a method of joint authority between the WEIM Governing Body and the CAISO Board in response to concerns about adequate representation in market decisions. Approval by both bodies will be required to enact EDAM initiative changes once the program is live.

A path for the adoption of an independent governance structure is possible but changes are likely multiple years away. A change in the CAISO structure requires California state legislative action. Assembly Bill 538,[2] submitted during the 2023 legislative session, would enable CAISO to transition to a regional transmission operator with a fully independent governance. The bill is pending with the Appropriations Committee. APS is proactively collaborating with other entities, including California load-serving entities, to propose an independent governance structure for CAISO should the legislation pass.

EDAM Program Timeline – Upcoming Dates

June 2023	Target tariff filing at FERC
2025	Target program commencement

Southwest Power Pool (SPP)

SPP is an RTO overseeing the operation of the bulk power system in 14 states in the central U.S. SPP offers two market participation opportunities for entities who are not members of their RTO: (1) the Western Energy Imbalance Service (WEIS) as a real-time energy market that began in 2021, and (2) Markets+ as a pending day-ahead market.

In March of this year, APS executed a funding agreement to participate in Phase I of Markets+ development. APS will help develop market protocols, tariff design, and governing documents for Markets+.

Prior to the start of Phase I and following feedback from stakeholders, including APS, SPP proposed an independent governance structure for its day-ahead market offering. The Markets+ Independent Panel (MIP), composed of an SPP independent director and four independent, industry professionals with senior management level

[2] A.B. 538, 2023-24 Reg. Sess. (Ca. 2023), https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=202320240AB538.

expertise, will have the highest level of authority for decisions related to Markets+. The SPP board of directors will provide oversight of SPP's administration of Markets+ subject to FERC regulatory jurisdiction.

Governance for Markets+ began operating with Phase I's commencement. APS personnel have assumed roles in various positions. APS and other Phase I funders make up the Markets+ Participants Executive Committee (MPEC). Brian Cole, Senior Director Western Market Evolution, was chosen as Vice Chair of the MPEC and APS has staffed a representative in each Markets+ working group and task force. These groups will embark on the Markets+ tariff development considering broad stakeholder input. The effort is expected to continue through the end of 2023 and conclude with a filing of the tariff at FERC by the first quarter of 2024.

Markets+ Program Timeline – Upcoming Dates

2023 Q1	Phase I went live APS joined Phase I
2023 Q4 or 2024 Q1	Target tariff filing at FERC
Early 2025	Target Phase II commencement
2026	Target program commencement

RESOURCE ADEQUACY

Resource Adequacy (RA) programs and well-designed organized markets complement each other. A common and well-functioning RA standard is a large contributor to an organized market's success, providing reliability and equitability among participants. APS prefers a Federal Energy Regulatory Commission (FERC) approved common resource adequacy standard as a basis for an organized market over a resource sufficiency test like that employed by the WEIM.

Western Resource Adequacy Program (WRAP)

WRAP is Western Power Pool's pioneering program to bring regional entities together in collaboration and ensure reliability within the participating footprint. Essential to WRAP's operation is the assurance that committed physical resources are deliverable to participants' load, particularly during critical system conditions. FERC approved the WRAP tariff on February 10, 2023.

APS is one of 22 entities to-date to participate in WRAP. Currently, all WRAP entities are participating in a transitional period that involves non-binding operations within the program. This will transition to a binding period between 2025 and 2028. Once all entities are binding, a long-term benefit of participation will be the ability for entities to reduce the resources necessary to maintain reliability.

WRAP Program Timeline – Upcoming Dates

Winter 2023-2024	Non-binding forward showing program Non-binding operations program
Summer 2025-Winter 2028	Transition seasons for operations and forward showing programs
Summer 2026	Target commencement of APS binding participation
Summer 2028	Binding program established without transitions going forward

FURTHER EXPLORATION

Western Markets Exploratory Group (WMEG)

A coalition of 25 Western load-serving entities, including APS, convened WMEG to evaluate regional energy markets and services. WMEG is evaluating new market services and possible market footprints, including the CAISO and SPP offerings under development, and other power supply and grid solutions that remain consistent with various state regulations and policies.

The WMEG effort will culminate in the creation of a roadmap that conveys optional approaches for energy markets up to and including an RTO functioning in the West. As one data point, the effort will include a financial analysis from a cost-benefit study. Once members review and validate the study's results, members will provide a public release of the study to all interested parties. APS expects these activities to occur this summer.

TRANSMISSION SYSTEM OPERATION TRANSITION

In early 2023, APS transitioned operation of its transmission system from a Contract Path operation, which is a path that can be designated to form a single continuous electrical path between the parties to an agreement, to a Flow Based operation, after several years of planning and coordination with neighboring transmission system operators. APS is the first WECC balancing authority outside of the CAISO to move to Flow Based operation. The Flow Based operation, often referred to as Flow Gate or Mod-30, will allow the transmission system to be utilized in a more efficient manner and allow for higher power flows under most conditions. By improving utilization of the transmission system, more remote resources can be delivered to load centers without the need for costly upgrades. It is envisioned that, as APS explores new broader wholesale market opportunities, a transition to a Flow Based operation will be necessary for efficiency reasons.

CONCLUSION

APS is one of Arizona's three largest-serving electric utilities engaging in the development and exploration of expanded wholesale market participation. APS routinely collaborates with Tucson Electric Power (TEP) and Salt River Project Agriculture Improvement and Power District (SRP) to ensure the developing programs appropriately consider issues inherent to the Southwest and such programs will have the capacity to offer benefits to the region. The coordination among Arizona's utilities offers an opportunity to incrementally influence program development and garner the ability to determine a best fit for the region's eventual participation.

This year, or early 2024 will likely see the filing of tariffs for both CAISO's and SPP's day-ahead market programs. Once FERC approves these tariffs, APS anticipates an ability to commit to a day-ahead program soon thereafter, with expanded wholesale market operations beginning in late 2025 or early 2026.

Appendix

Joint Market Report Workshop
Hosted by Arizona Public Service, Tucson Electric Power and Unisource Energy
May 4, 2023

Meeting date and time

Thursday, May 4, 2023, at 10:00 a.m.
This meeting was held virtually via Microsoft Teams.

Agenda

Welcome	Michael Eugenis, Manager, Resource Planning and Analysis, APS
TEP/UNSE Market Update	Sam Rugel, Director, System Control, TEP
APS Market Update	Brian Cole, General Manager, Western Market Affairs, APS
Discussion/Q&A	Aly Koslow, Director, Federal Regulatory Affairs and Compliance, APS

Stakeholders in attendance

Steve Jennings, AARP Arizona
Brian Turner, Advanced Energy United
Michael Barrio, Advanced Energy United
Josh Alpert, Joshua Alpert Strategies
Amanda Ormond, ASU Just Energy Transition Center
Autumn Johnson, AriSEIA
John Mitman, AriSEIA
Jeffrey Cebrik, Avangrid
Shay Glackin-Coley, Avangrid
Doug Patterson, Black Forest Partners
Caleb Franzmann, Clearway Energy
Thomas Hungerford, Clearway Energy
Charles Banke, ConnectGEN
Phoebe Autio, Copia Power
Cathy Kim, Copia Power
Ian Calkins, Copper State Consulting Group
Jack Wadleigh, EDP Renewables
Poonum Agrawal, Enel North America
Pete Ewen, Freeport McMoRan
Patrick Black, Fennemore
Allison Moore, Fresh from Mexico
Brendon Baatz, Gabel Associates
Rob Lamb, GLHN Architects & Engineers
Michelle Brandt King, Holland & Hart
Austin Jensen, Holland & Hart
Sarita Morales, IBEW 1116
Emily Martinez, Innovant Public Relations
Sam Johnston, Interwest Energy Alliance
Ric Fanyo, RLFanyo Law
Yves Khawam, Pima County
Court Rich, Rose Law Group
Akshay Shivaram, RWE Clean Energy

Sandy Bahr, Sierra Club
Agnes Lut, SRP
Marcie L Martin, SRP
Stephen Cassidy, U.S. Air Force – Davis-Monthan Air Force Base
Claire Michael, Wildfire
Murphy Bannerman, Western Resource Advocates
Sydney Welter, Western Resource Advocates
Lakshmi Alagappan, E3

ACC Staff in attendance
Chaunce De Roos
Luke Hutchison

Arizona Public Service Staff in attendance
Omaya Ahmad
Tara Beske
Brian Cole
Sage Dillon
Michael Eugenis
Ardyn Feken
Brent Goodrich
Todd Komaromy
Aly Koslow
Rachael Leonard
Akhil Mandadi
Tyler Moore
Nicole Rodriguez

Tucson Electric Power | Unisource Energy Staff in attendance
Victory Aguirre
Erik Bakken
Joe Barrios
Rhonda Bodfield
Jenny Crusenberry
Nonso Emordi
Megan Garvey
Megan Hill
Jake Jones
Karen Kansfield
Bonnie Medler
Alexander Moe
Isle Morales Duarte
Blake Pederson
Sam Rugel
Joe Salkowski
Mike Sheehan
Alex Tai

JOINT MARKET REPORT WORKSHOP

May 4, 2023

UNS
UNS Energy Corporation
A Fortis Company

aps®

WELCOME

Michael Eugenis

Manager, Resource Planning and Analysis
Arizona Public Service

Market Workshop

Arizona Public Service

Brian Cole
General Manager
Western Market Affairs

May 4, 2023

Goals of Western Market Efforts

- **Reliability**
  - Maintain or improve
  - Will be challenged with changing resources
- **Customer cost savings**
  - Via utilization of both load and resource diversity
  - Needed to offset increases in costs
- **Integration of clean energy**
  - Cannot meet clean energy goals without it

Background & Drivers

- Previous efforts
  - RTO discussions have occurred intermittently for over 20 years
- Current effort
  - It's different this time
  - Needed for clean energy integration
- ACC Docket tracking market efforts

Recall APS goals

1. Reliability
2. Customer Savings
3. Clean energy integration

Ongoing Engagement

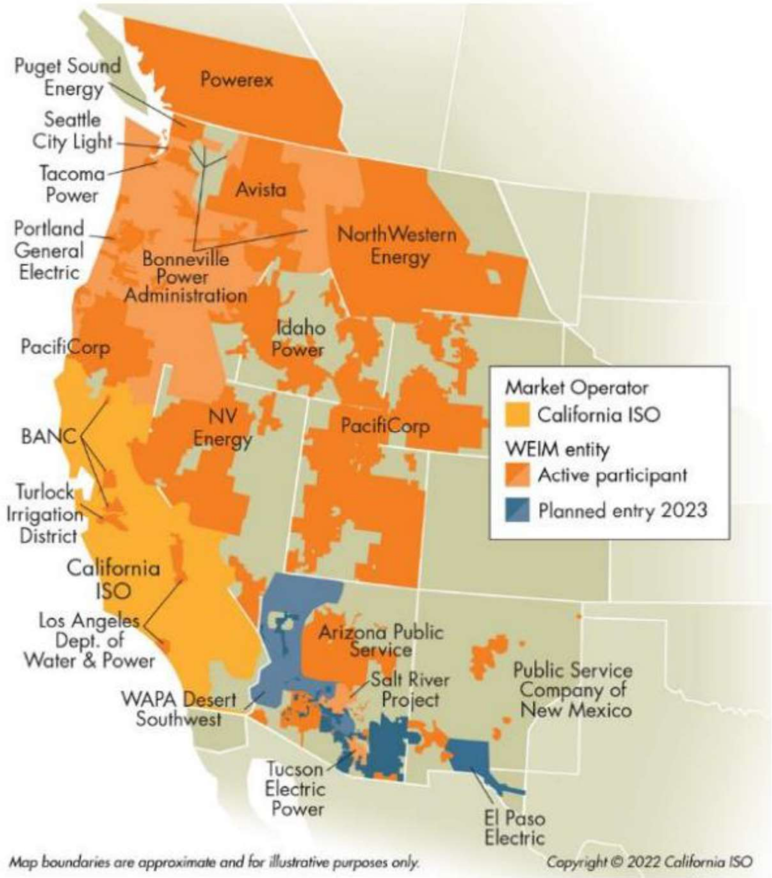
- Western Resource Adequacy Program **(WRAP)**
- CAISO Extended Day Ahead Market **(EDAM)**
- Southwest Power Pool **(SPP)** Markets+ Day Ahead Market
- Western Market Exploratory Group **(WMEG)**

Western Resource Adequacy Program (WRAP)

1. Arizona Public Service
2. Avista
3. Bonneville Power Administration
4. Calpine
5. Chelan County PUD
6. Clatskanie PUD
7. Eugene Water & Electric Board
8. Grant PUD
9. Idaho Power
10. NorthWestern Energy
11. NV Energy
12. PacifiCorp
13. Portland General Electric
14. Powerex
15. Public Service Company of New Mexico
16. Puget Sound Energy
17. Salt River Project
18. Seattle City Light
19. Shell Energy
20. Snohomish PUD
21. Tacoma Power
22. The Energy Authority

CAISO

Western Energy Imbalance Market (WEIM)



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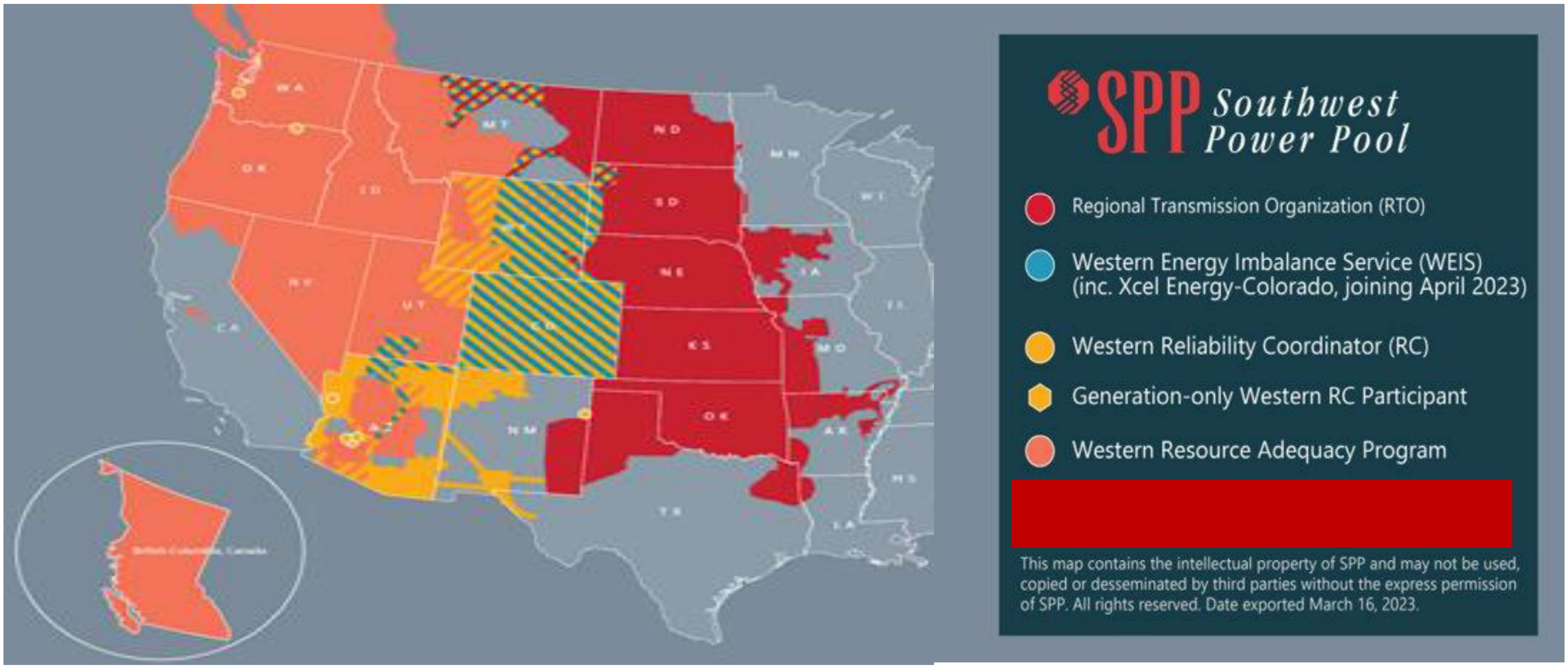
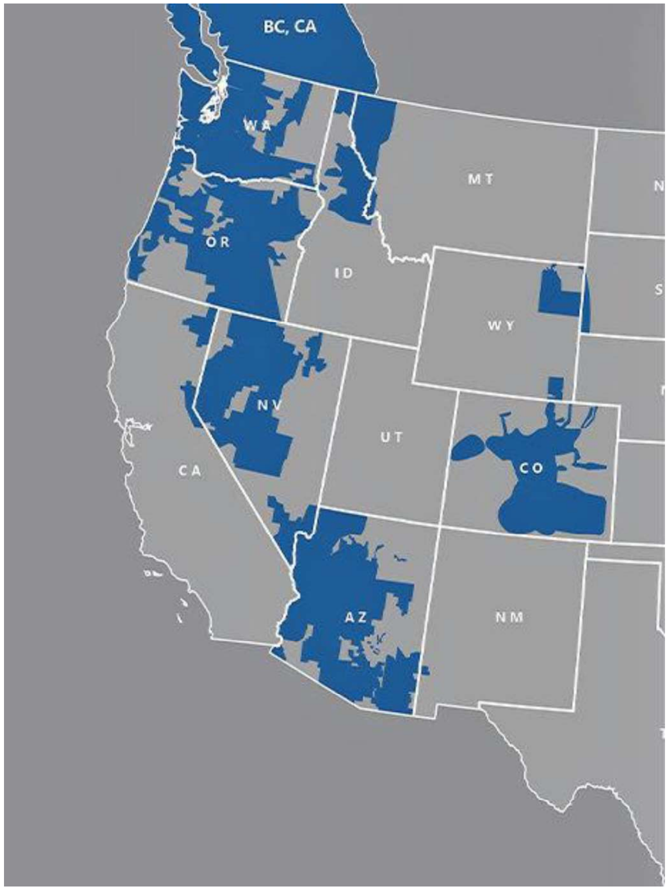
Southwest Power Pool (SPP) in the West

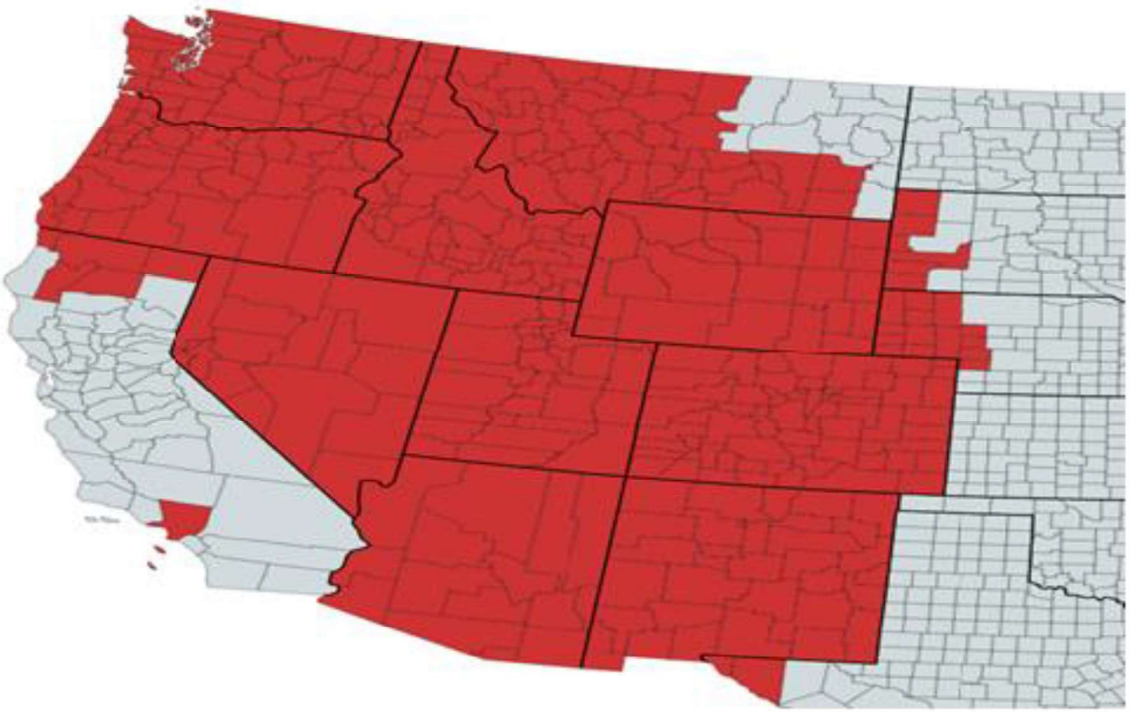


SPP Markets+ Phase 1

1. American Clean Power Association
2. Arizona Electric Power Cooperative
3. Arizona Public Service
4. Black Hills Colorado Electric & Black Hills Power, Inc.
5. Bonneville Power Administration
6. Chelan (PUD No. 1 of Chelan County)
7. Cheyenne Light, Fuel & Power Co.
8. Clean Energy Buyers Association
9. Interwest Energy Alliance
10. Liberty Utilities (Calpeco Electric)
11. Municipal Energy Agency of Nebraska
12. National Resource Defense Council
13. Northwest & Intermountain Power Producers Coalition
14. NV Energy
15. Pattern Energy
16. Powerex Corp.
17. Public Generating Pool
18. Public Power Council
19. Public Service Company of Colorado
20. PUD No. 2 of Grant County, Washington
21. Puget Sound Energy
22. Renewable Northwest
23. Salt River Project
24. Snohomish Public Utility
25. Tacoma Power
26. The Energy Authority
27. Tri-State
28. Tucson Electric Power
29. Western Energy Freedom Action
30. Western Power Trading Forum
31. Western Resource Advocates



Western Market Exploratory Group (WMEG)



1. APS
2. SRP
3. TEP
4. PNM
5. Black Hills
6. LDWP
7. Portland General
8. Seattle City & Light
9. Platte River
10. NV Energy
11. PacifiCorp
12. Idaho
13. Puget Sound
14. Xcel Energy
15. Arizona Electric Power Co-Op
16. Avista
17. BANC
18. BPA
19. Chelan County PUD
20. El Paso Electric
21. Grant County PUD
22. NorthWestern Energy
23. Tacoma Power
24. Tri-State
25. WAPA

Target Milestones

- WRAP began transition period on January 1, 2023
  – Binding participation will transition between 2025 and 2028
- Day-Ahead market option work and commitments – 2023/2024
  – Includes participation in Tariff and Business Practices for each option (CAISO/SPP)
- Day-Ahead market operation – Late 2025/Early 2026
- Future market steps “up to and including RTO” – 2026-2030 and beyond

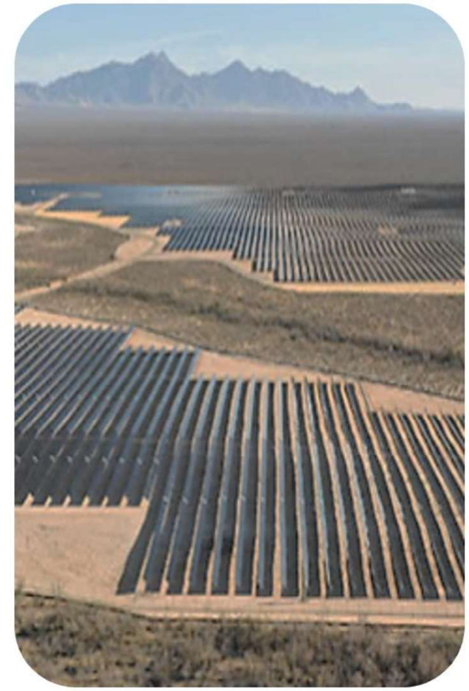
UNS Energy Corporation
A Fortis Company

Western Market Exploration

Sam Rugel

Director, System Control

May 4, 2023



Energy Markets 101

Energy Markets 101

Markets for delivering power to consumers in the United States are split into two systems: traditionally regulated bilateral markets, and those run by RTO/ISOs

Traditional wholesale electricity markets exist primarily in the Southeast U.S. and the West outside of California

- Utilities are responsible for system operations and for providing power to retail consumers

Two-thirds of the population of the United States is served by electricity markets run by Regional Transmission Organizations or Independent System Operators (RTO/ISOs or organized markets)

RTO/ISO markets optimize electricity through structured market design/mechanisms

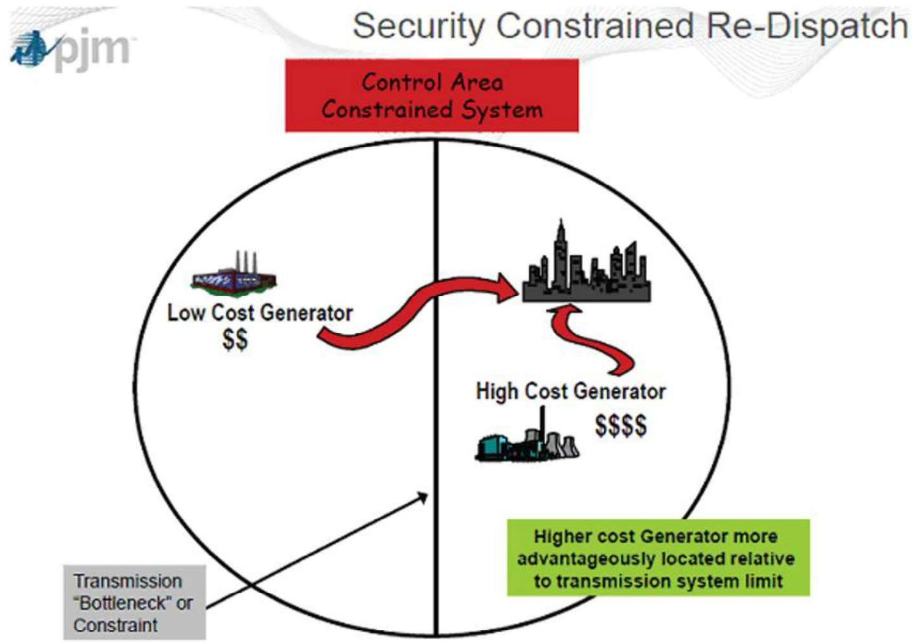
Day Ahead & Real Time Optimization

Day Ahead: Run Generation Optimization for next 7 days	Create Day Ahead Plan and submit to the market • Generation Base Schedules, Intertie Base Schedules, & Ancillary Services Create Bids and submit to the market Input all Generation & Transmission Outage Day Ahead: Run Generation Optimization for next 7 days
Real Time: Run Generation Optimization for next open hour through balance of day	Ensure generation follows real-time (5 minute) Dispatch Instructions from market Manage Unit Startup/Shutdown Monitor load and renewable forecasts & update Generation/Transmission Outages Congestion management via Security-Constrained Economic Dispatch (SCED)

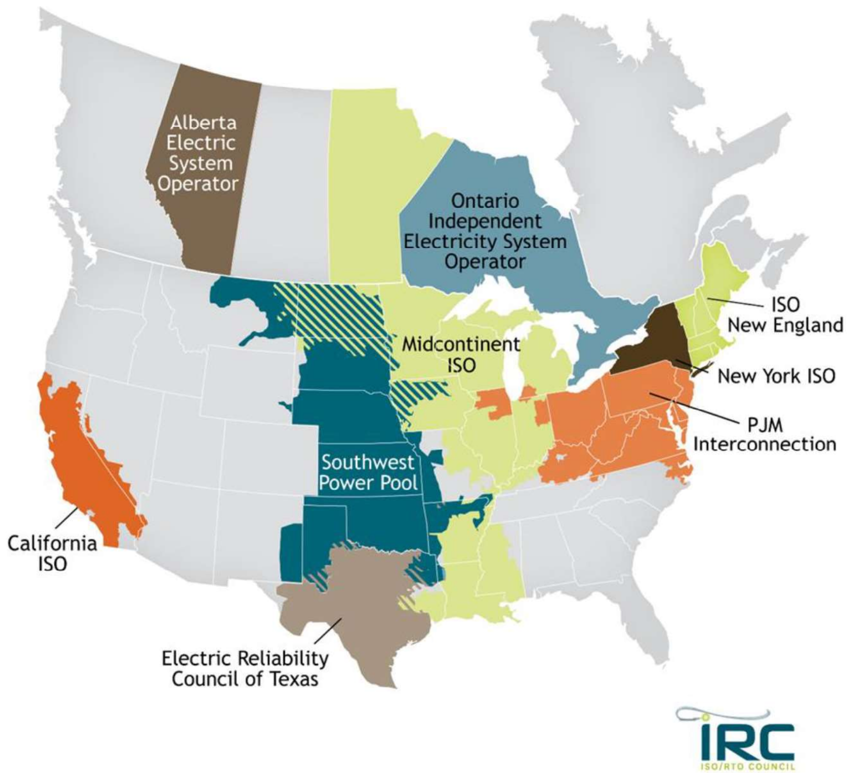
Security-Constrained Economic Dispatch (SCED)

- Optimizes generation to the extent the transmission system can support it
- Identifies and encourages addition of transmission investments needed to alleviate congestion

Security Constrained Re-Dispatch



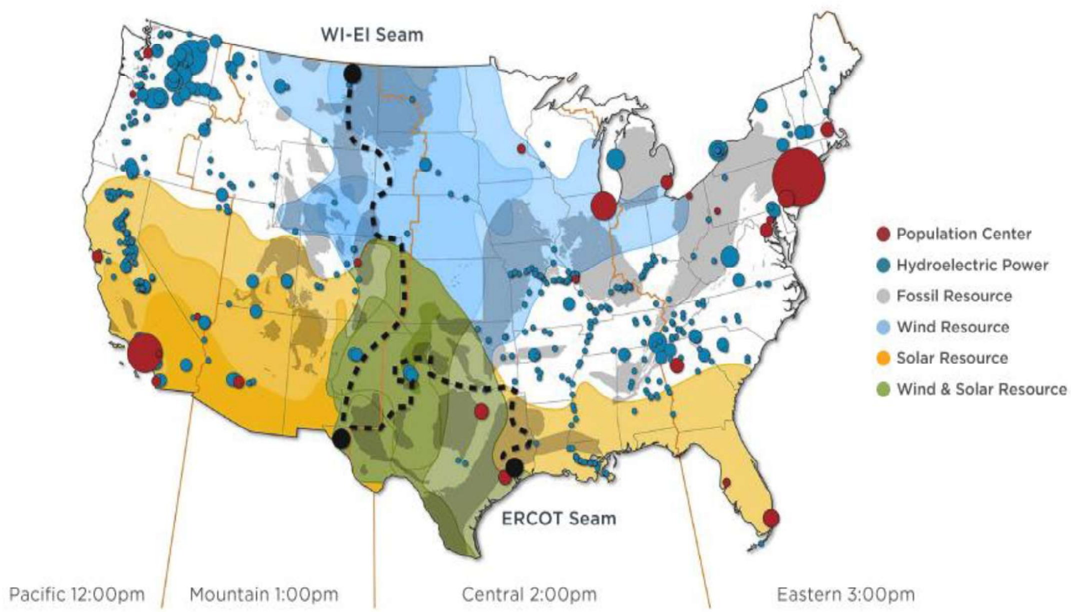
Existing Structured Markets



Current organized markets in North America

Market Evolution

Drivers: Geographic Diversity



Resource Diversity

- Southwest utilities have access to northwest hydro capacity in summer
- Northwest utilities have access to southwest gas and renewable capacity in winter

Peak Diversity

- Utilities peak at different times of day and year
- Allows for resource optimization, especially renewables

Drivers: Resource Adequacy

Members must ensure their own resource adequacy

- Supports reliability of entire region

Resource optimization/efficient dispatch

- Carried out across entire footprint instead of individual utilities

Liquid Market

- Improves reliability
- Efficient, low-cost transactions

Benefits

Reliability

- Resource adequacy requirements ensure reasonable reserve margins
- Compensates owners to add resources to support load growth
- Compensates owners to add transmission to alleviate congestion

Customer value

- Economic dispatch of all resources across the market footprint results in savings for the customer

Renewable Integration

- System-wide resources used to support intermittency
- Results in fewer renewable curtailments

Stakeholder Collaboration

- Members have a voice in market rules
- Effective resolutions achieved between differing parties

Market Evolution

Most organized markets in North America evolved by forming collective reliability organizations responsible for different aspects of operations:

Transmission Operations	Generation Dispatch	Reliability Coordinator

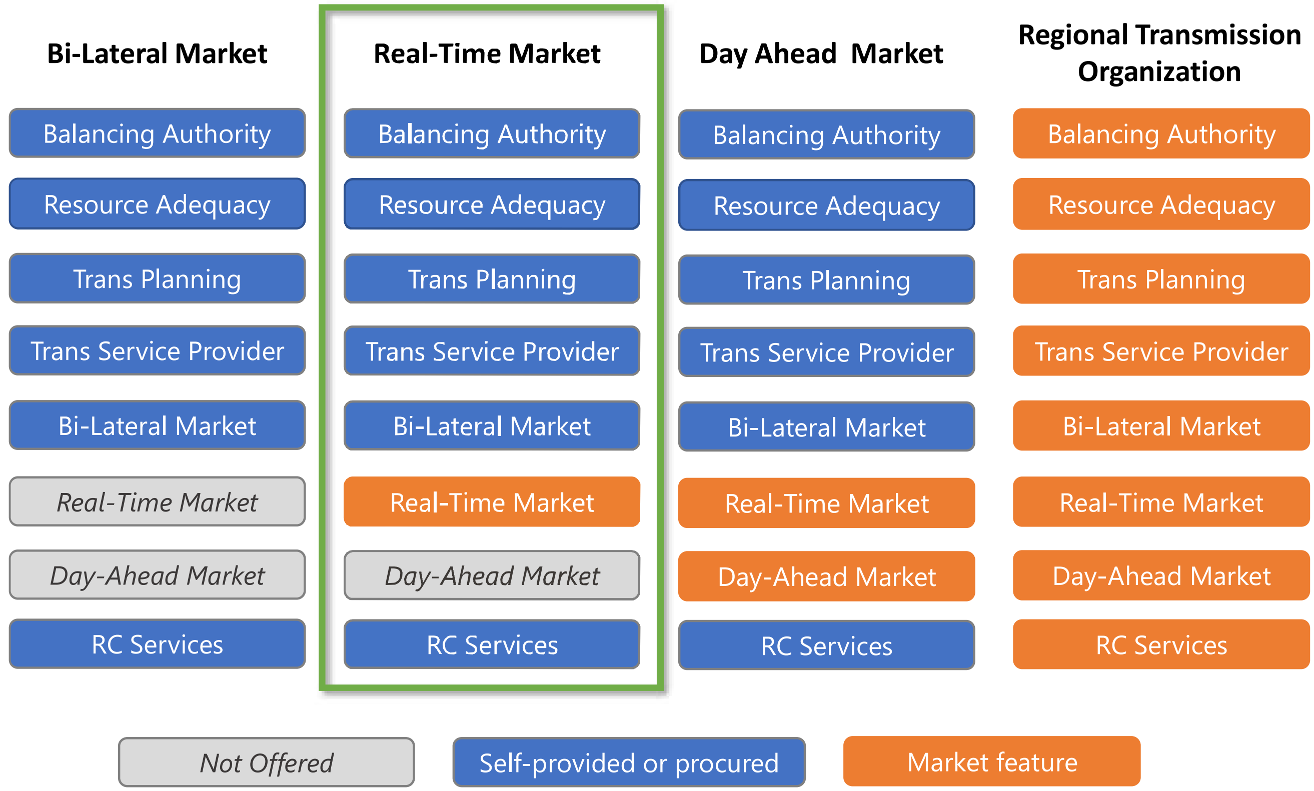
Over time, they added additional functions:

Tariff consolidation	Transmission Planning	Imbalance Markets

Until they eventually launched full markets for participants

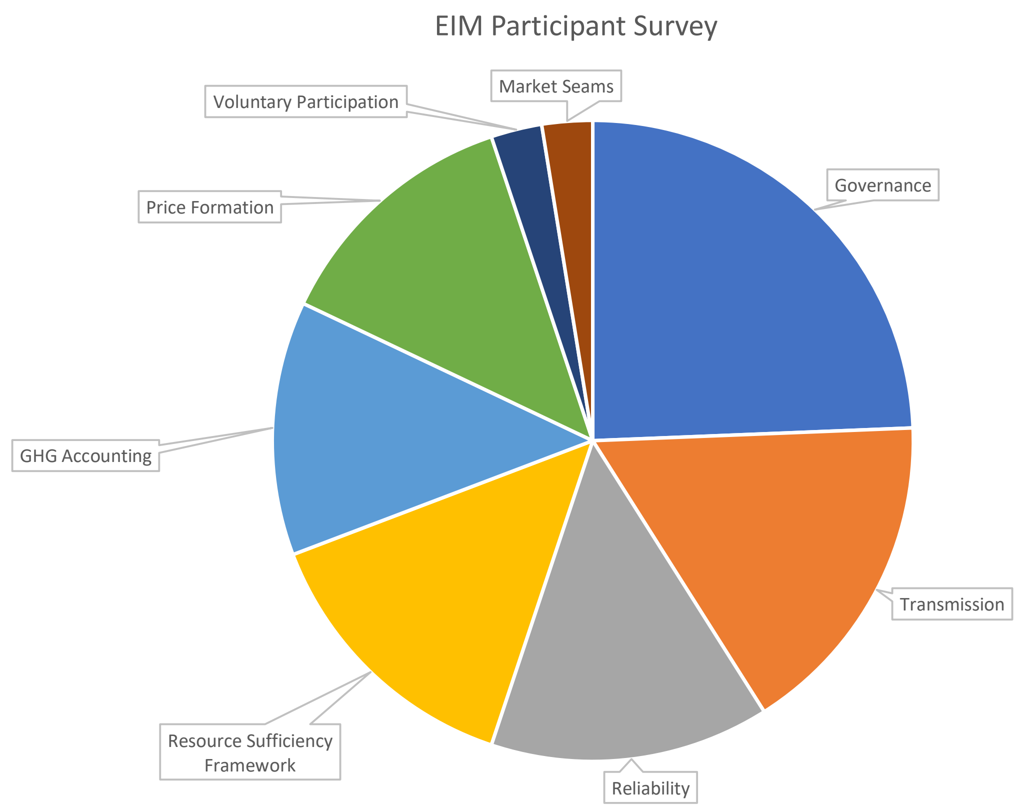
Most began organizing shortly after FERC Order 888 (1998)

Market Features



Day Ahead Market Priorities

- Governance
- Transmission
- Reliability
- Resource Adequacy Framework
- GHG Accounting
- Price Formation
- Voluntary Participation
- Market Seams



Western Market Efforts

EDAM	Develop an approach to extend participation in the day-ahead market to the Western Energy Imbalance Market (EIM) entities in a framework like the existing EIM approach for the real-time market, rather than requiring full integration into the California ISO balancing area. A bill is moving through the CA legislator, AB 538, that potentially creates a pathway for CAISO to form an RTO with entities outside of the state.
SPP Markets+	It's a conceptual bundle of services proposed by SPP that would centralize day-ahead and real-time unit commitment and dispatch, provide service across its footprint and pave the way for the reliable integration of a rapidly growing fleet of renewable generation.
WMEG	Utility executives are exploring the potential for a staged approach to new market services, including day-ahead energy sales, transmission system expansion, and other power supply and grid solutions consistent with existing state regulations.

APPENDIX B

WMEG: WESTERN DAY AHEAD MARKET PRODUCTION COST IMPACT STUDY

ORIGINAL

E000031018

Rachael Leonard
Manager
State Regulatory Affairs

Mail Station 9774
PO Box 53999
Phoenix, Arizona 85072-3999
Tel 602-250-2404
Rachael.Leonard@aps.com

September 28, 2023

Docket Control
ARIZONA CORPORATION COMMISSION
1200 W. Washington Street
Phoenix, AZ 85007

RE: Arizona Public Service Company (APS or Company)
Resource Planning and Procurement in 2021, 2022, and 2023
Docket No. E-99999A-22-0046

APS was one of 25 utilities and public power entities participating in the Western Markets Exploratory Group (WMEG). The group's efforts to examine the economic impacts of various day-ahead and differing levels of market participation scenarios concluded in Summer 2023. Attached is WMEG's Western Day Ahead Market Production Cost Impact Study, which includes public results in aggregate for all participating entities.

In addition to the public results, each participating entity holds confidential access to their individual cost benefit results for the studied scenarios. Also attached is a public summary of APS's results to specifically illuminate estimated impacts to APS customers. These documents are best reviewed together to understand the aggregate results versus APS-specific results.

Please let me know if you have questions.

Sincerely,

/s/ Rachael Leonard

Rachael Leonard

RL/ac
Attachments

cc: Ranelle Paladino

Western Markets Exploratory Group
Western Day Ahead Market Production Cost Impact Study

Western Markets Exploratory Group: Western Day Ahead Market Production Cost Impact Study

Prepared by Energy and Environmental Economics (E3)

June 2023

Energy+Environmental Economics

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1 Study Context and Key Questions

The Western Markets Exploratory Group (WMEG) is a group of 25 utilities and public power entities across the Western Interconnection. The WMEG is examining ways to develop more integrated electric power markets in the West, including emerging day-ahead market opportunities, and ways to further integrate markets services over the long term, up to and including a regional transmission organization (RTO).

The West is at a critical juncture of regionalization within the power industry, as it seeks to extend regional markets from real-time operations to the day-ahead level. Organized electricity markets have long been shown to provide various benefits to participant members including a more optimal system dispatch. The Western Energy Imbalance Market (EIM or WEIM) is the first organized market outside of the California ISO (CAISO) to bring these benefits to multiple Balancing Authority Areas (BAAs) in the Western Interconnection. The WEIM is a real-time wholesale energy market with participants across the WECC footprint. Over the past decade, it has provided millions of dollars of annual savings for members. In 2021, SPP launched a similar real-time imbalance market in the West: the Western Energy Imbalance Services (WEIS).

Recently, California ISO (CAISO) proposed plans to form a day-ahead market option for the West titled the **Extended Day- Ahead Market** (EDAM). The Southwest Power Pool (SPP) released a separate plan to offer Western entities a day-ahead market service titled **Markets+**. Both market options will augment existing functionality for real-time markets in different parts of the Western Interconnection through CAISO's Western Energy Imbalance Market (WEIM or EIM) and SPP's Western Energy Imbalance Service (WEIS or EIS) offering.

Colorado[1] and Nevada[2] have passed laws that require transmission utilities to join RTOs by 2030. PacifiCorp recently announced it will join EDAM[3] and Powerex Corp. has announced it will join Markets+[4]. Amid the rollout of these new markets and moves towards regionalization, it is important for Western utilities to understand the impacts of these markets to help make informed decisions on their next steps.

The WMEG, through its consultant Utilicast, engaged Energy & Environmental Economics, Inc. (E3) to perform a Cost Benefit Study ("CBS" or "the study") examining the economic impact that joining either the EDAM or the Markets+ option would have for each WMEG entity and for the WECC overall. The study explores the impact that each market could have along two dimensions: (1) based on different **footprints** of which entities join either market, and (2) on the currently proposed design **features** of each market. In the CBS, E3 studies a Business as Usual (BAU) Case and three different market footprint options each comprised of different Western entities joining EDAM or Markets+ respectively by the 2026 study year.

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[1] Colorado SB21-072, https://leg.colorado.gov/sites/default/files/2021a_072_signed.pdf

[2] Nevada SB 448, https://www.leg.state.nv.us/App/NELIS/REL/81st2021/Bill/8201/Text#

[3] PacifiCorp, "PacifiCorp to build on success of real-time energy market innovation as first to sign on to new Western day-ahead market", https://www.pacificorp.com/about/newsroom/news-releases/EDAM-innovative-efforts.html

[4] Powerex, "Powerex Commits to Markets+", https://Powerex.com/sites/default/files/2022-11/Powerex%20Commits%20to%20Markets%2B.pdf

Additionally, for the 2030 and 2035 study years, the CBS also examines the impact that increasing levels of market integration over a longer-term period could have for WMEG members.

Study impact focus: The WMEG guided E3 to focus the CBS only on the impact to variable generation and power purchase costs for each entity – that is, changes to the costs each entity incurs for fuel, variable O&M, and startup costs to generate electric power, as well the cost and/or revenue from power market purchases and sales. The E3 study does not estimate the cost of joining either market in terms of labor, software, or participation fees; savings in this study can be seen as gross of the cost of participation.

Additionally, this study does not consider a range of other benefits generally found to result from formation of a regional market, such as:

a) generation investment savings due to programmatic sharing of load and resource diversity for participating entities – for example, through the proposed Western Resource Adequacy Program (WRAP),
b) procurement savings by market enabling entities to contract with resources from across a larger market footprint (supported by a transparent locational market price and frictionless transmission access) rather than restrictions to procuring resources in one's own local area or with direct transmission schedules to reserve transfer capability to a local area,
c) coordinated regional transmission planning and investment, or
d) reliability improvement during extreme weather or challenging operational conditions.

The WMEG chose to focus the CBS on variable generation and purchase cost impacts as a directly quantifiable outcome of market formation but recognizes that these other benefit components may provide significant additional long-term savings. For example, the State Led Study Market Studies found that a two-market day-ahead option relative to a BAU case with only real-time markets could yield $85 million in adjusted production cost savings and $416 million in capacity savings.[5] Also, the 2016 Senate Bill 350 Study on the impact to California of a regional CAISO-led Western power market identified $104 to $523 million in adjusted production cost savings, $680 to $800 million in annual capital cost investment savings related to renewable procurement, and $120 million in annual capacity savings due to load diversity.[6] Additionally, for an example in the Eastern Interconnection, MISO's 2022 Value proposition estimates that the MISO market facilitates $890 to $923 million in Energy and Ancillary Services savings, $1,942 to $2,866 million in Resource Capacity Sharing, and $409 to $479 million in Renewable Resource Optimization, which is procurement related.[7] It is important to recognize that the savings estimates calculated in this study are conservative because they do not include these other types of potential savings.

[5] https://www.energystrat.com/s/Final-Roadmap-Technical-Report-210730.pdf
[6] https://www.caiso.com/documents/sb350study_aggregatedreport.pdf
[7] https://cdn.misoenergy.org/2022%20Value%20Proposition%20Annual%20View%20-%20Detailed%20Report628393.pdf

2 Study Approach

Study methodology overview: To conduct this study, E3 created a multi-stage simulation of the Western Interconnection using the PLEXOS production cost model developed by Energy Exemplar. Energy Exemplar worked closely with E3 to enhance E3's efficiency running over 4,000 cases in a Cloud-based environment, as well as customizing PLEXOS to directly address WMEG questions and represent the EDAM and Markets+ offerings in detail. In PLEXOS, E3 modeled the dispatch of all major power plants in the Western Interconnection on an hourly basis for each study year and study scenario.

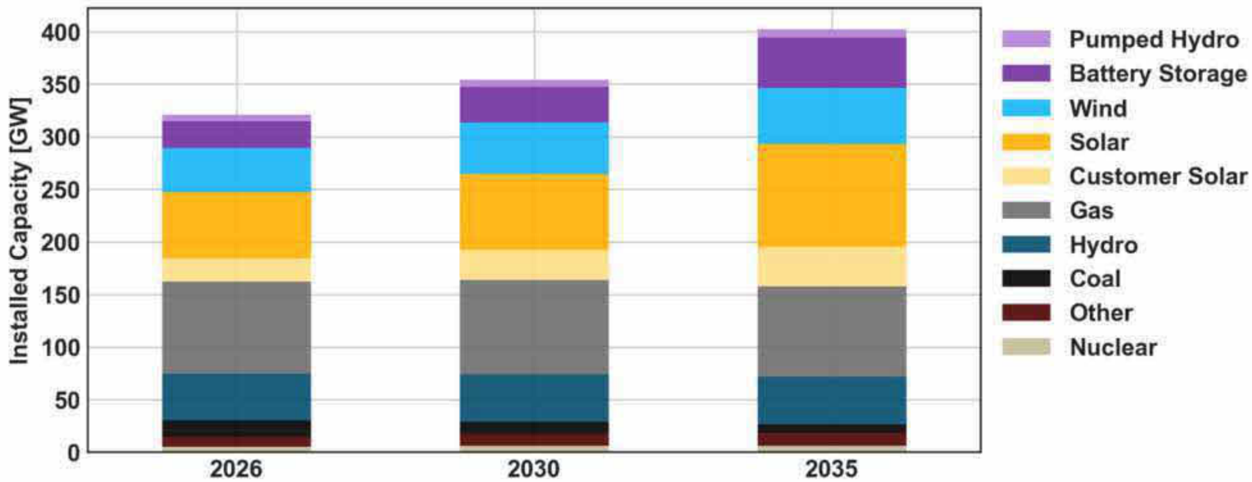
E3 modeled each of these cases first on a day ahead (DA) stage to identify commitment of long-start generation and calculate day ahead transactions, and then on a Real Time (RT) stage for actual dispatch in the operating day. E3 modeled the DA stage with load, wind, and solar forecast error in DA relative to the actual load, wind, and solar values that occur in the RT stage. To manage this forecast error, the model held flexibility on generators in the form of DA forecast error reserves to respond to changes in load or variable energy resources (VERs) between the DA and RT stages.

This section provides a summary of the study data and key assumptions. Appendix A to this report contains more extensive detail on each of these assumptions.

Study data: The starting database for the study was the 2032 Anchor Data Set (ADS) created by the Western Electric Coordinating Council (WECC) with subsequent modifications for both WMEG member areas and non-WMEG areas.[8] The CBS benefited significantly from contributions by staff from each WMEG member in providing input data – including load growth projections, updated generator additions and retirement information, as well as generator operational parameters, costs, and percentage shares that are owned and or contracted to different WMEG entities, which is necessary for calculating the adjusted production cost impact of different market participation plans for each entity. The 2026 study cases and those for subsequent years include significant generation additions, particularly of solar, wind, and storage resources based on the data developed by WECC and updated by WMEG members. The regionwide resource mix for each year is summarized in the table below.

[8] The 25 WMEG members represented are AEPCO, APS, Avista, Balancing Authority of Northern California (BANC), Black Hills Energy, BPA, Chelan County PUD, El Paso Electric (EPE), Grant County PUD, Idaho Power Company, Los Angeles Department of Water & Power (LADWP), NorthWestern Energy, NV Energy, PacifiCorp, Portland General Electric, Public Service of new Mexico (PNM), Platte River power Authority, Public Service of Colorado (PSCO), Puget Sound Energy (PSE), Seattle City Light (SCL), Salt River Project (SRP), Tacoma Power, Tucson Electric Power (TEP), Tri-State Generation and Transmission Authority (TSGT), and Western Area Power Administration (WAPA), which was modeled in 5 separate areas (SNR, CRCM, LAP, WALC/DSW, and WAUW). The rest of the WECC was represented as non-WMEG.

Figure 2-1 Total U.S. WECC Installed Capacity[9]



The CBS uses a zonal transmission topology based on Total Transfer Capability (TTC) between entities. The zonal option enables the study to avoid the additional complexity and significant run-time considerations of modeling a nodal topology, allowing both more cases to be run and more accurate modeling of ancillary services as well as the specific proposed market features of EDAM and Markets+. To ensure accurate modeling of transmission limitations, the study model incorporated a number of market trading hubs (or "tie zones") that connect multiple entities in today's actual operations. E3 developed the topology for these tie zones with the support of the WMEG transmission task force and staff at many WMEG entities. E3 also worked with WMEG Task Force members to develop assumptions for gas price forecasts, as well as greenhouse gas (GHG) prices, which were applied on in-state generation as well as imports into California, Washington, and Colorado. For non-WMEG areas, E3 supplemented data in the WECC ADS case with additional information gathered on resources and transmission.

Study Scenarios: The table below shows four scenarios with alternative market participation footprints that WMEG directed E3 to model for the 2026 study year.[10] In the BAU case, E3 models wheeling and trading friction at the border of individual BAAs. Within each market footprint (EDAM or Markets+), transactions do not face wheeling or frictional costs, but these charges are applied to trades on the border or seams between markets. Additionally, the market footprint determines the region over which DA forecast error reserves can be held on resources.

These cases were developed by the WMEG using a collaborative process intended to explore key impacts of (a) having a single market spanning all of the US WECC (in the EDAM Bookend case) versus (b) having two Western markets, with separate market footprints that reflect intentions already announced by

[9] Total WECC capacity does not include AESO resources as this was implemented as a price stream within the CBS. BC resources and loads (as well as trades with Alberta) were modeled as an integrated pumped hydro facility based on the anticipated quantity of energy to be imported from or exported to the US, based on data provided by Powerex. This BC capacity is included with pumped storage in the chart.

[10] For a subset of WMEG members who requested further exploration, E3 modeled four other alternative market footprints in 2026.

certain entities to join the EDAM or Markets+ as well as one potential set of assumed participation choices by the remaining Western entities that have not yet announced market decisions (in Main Split and Markets+ Bookend). These footprints do not represent the only potential maps for two Western Markets, as there are a wide range of potential combinations that could lead to different market footprints. A subset of WMEG members chose to fund additional footprint sensitivity cases, which are provided separately from this report.

The detailed participation of each entity in different markets for these scenarios is provided in Appendix B to this report.

Figure 2-2 2026 Core Study Cases

Note: The Markets+ Bookend footprint matches that of the Main Split Case, except for WAPA SNR region which was represented in Markets+ in the Markets+ Bookend and in EDAM in the Main Split Case

- The **2026 BAU Case** models a day-ahead (DA) stage with bilateral trading but no organized market. In the real-time (RT) stage, the BAU case represents wheeling and friction-free trading within the existing WEIM and WEIS footprints.
- The **EDAM Bookend** case models a single DA and RT market that covers the entire U.S. portion of the Western Interconnection, excluding Alberta, British Columbia (BC), and CFE in Baja Mexico. Trades inside the Market reflect the currently proposed EDAM design and are simulated with no wheeling costs or transactional friction.
- The **Main Split** case models two separate DA and RT footprints: (a) an EDAM comprised of PacifiCorp, and the state of California (CAISO, LADWP, BANC, LADWP, TIDC, and IID), and (b) a Markets+ region consisting of the rest of the US WECC, plus BC which is modeled as a pumped hydro generator with net purchases and sales at the US-Canadian border.. Alberta and CFE are modeled as external zones not participating in either the EDAM or Markets+.
- Finally, the **Markets+ Bookend** case models market footprints similar to the Main Split, except that WAPA Sierra Nevada Region (SNR), a sub-BA of the Balancing Authority of Northern California (BANC) is modeled in Markets+ rather than EDAM.

For the 2030 and 2035 study years, the Core CBS simulates additional cases shown in the figure below. WMEG selected these cases to explore ways in which the WECC region could pursue additional integration beyond a day-ahead and real-time energy market. Each case adds an extra feature of further integration to the previous simulation. Additional detail to these scenarios is provided in Appendix B to this report.

Figure 2-3 2030 and 2035 Core Study Cases

- E3 modeled **2030 & 2035 Main Split** cases with the same market footprint as the 2026 Main Split case, but with load growth, generation retirement additions, and updated fuel and GHG prices reflected.
- The **2030 and 2035 Market to Market (M2M) Coordination** cases use the 2030 and 2035 Main Split footprint for EDAM and Markets+ but reduces the hurdle rates that are charged on trades over the seams between the two markets footprints to represent transactional friction.
- The **2030 and 2035 M2M plus Consolidated Balancing Authority (M2M + CBA)** cases reflect the Main Split footprint with M2M coordination, but also add a market for co-optimized ancillary services (AS) procurement across sub-regions of each Market footprint.
- The **2035 RTO Case** models the Main Split footprint with M2M and CBA and adds significant transmission to evaluate each market's performance with additional transmission from coordinated planning, enabling greater trading across the footprint.

Market Features: the most distinct modeling difference between the EDAM and Markets+ footprints was that E3 represented **Fast Start Pricing (FSP)** in the Markets+ portion of the WECC footprint, but not in zones that are placed in EDAM. FSP is an adjustment to settlements currently used in the SPP market in the Eastern Interconnection and proposed for Markets+. Typically, generators provide multi-part bids including (a) start costs and costs to run at minimum output, and (b) the incremental cost to dispatch at a higher level. However, the locational marginal prices (LMPs) calculated by PLEXOS and used to settle energy transactions for all loads and generators do not include the start costs. Historically in LMP-based markets, an ex-post calculation determined whether generator start costs were fully recovered through infra-marginal rents during hours when the generator operated. Any start costs that were not fully recovered were charged to all loads via an "uplift" charge. Recently, certain North American markets have incorporated FSP, which converts generator start cost and minimum load costs into a marginal cost adder and then reruns the market process to generate new, higher market clearing prices. This higher price is then used to settle generator awards and load payments.

For this study, E3 created a custom modeling process in the PLEXOS simulation to follow the same approach used by SPP for FSP and applied the resulting prices to Day-Ahead transactions in areas within the Markets+ footprint of each scenario. This resulted in higher prices in some hours in the Markets+ zones (by up to $10/MWh in a limited number of hours and approximately $1/MWh on average). Notably, however, the FSP price adders may not propagate to the entire market footprint when transmission congestion occurs. For example, if there is congestion between the Pacific Northwest and

Desert Southwest during a time when fast-starting pricing is triggered in the Desert Southwest, the price increases from fast start pricing do not apply to zones in the Pacific Northwest. This dynamic is observed in many hours of the simulations.

The other major market feature modeled differently between the markets was GHG revenue allocation for the EDAM Market.[11] The current EDAM market design proposal includes a mechanism to allocate revenue associated with imports into GHG regulated zones (California and Washington for the study; this approach was not applied for Colorado) from other EDAM locations that do not have GHG pricing. E3 created a separate "GHG Reference Case" run in PLEXOS that excluded any imports into the GHG regulated zones and then used a detailed post-processing approach to identify EDAM member zones that send incremental energy to the GHG regulated areas (when compared to the GHG Reference Case), and then to identify generators that produce incremental energy. In situations in which the identified generator with incremental dispatch to California has a lower GHG emission factor than the market clearing emissions rate, E3's modeling allocates net revenue to the generator reflecting additional margin beyond the cost the generator would face for GHG permits on the imported energy. The Markets+ design proposal does not currently have a defined GHG allocation approach so costs for GHG are assumed to be returned to the regulating state. The state regulatory agencies can then determine whether to allocate a portion of this revenue among energy entities (or to allocate this revenue elsewhere). For this modeling study, we do not allocate GHG revenue for markets where the mechanism for allocation has not been defined at the time of this study. More detail on GHG modeling is described in Appendix A to this report, and more detail on allocation of GHG revenue is provided in Appendix C.

Individual WMEG Entity Benefit Calculations: E3 developed a comprehensive settlement process code that takes in output data from the various market model runs and generates ex-post settlement details down to the generator level for each WMEG entity over the study year. The code then aggregates these results to an entity level for each WMEG member. For each entity and each scenario, E3 calculate an entity-specific "**Net Variable Cost**" using the following formula:

Net Variable Cost = Load Cost + Generation Cost + Reserve Cost – Reserve Revenue – Generation Revenue – Wheeling Revenue – Congestion Revenue – Wheeling Revenue

Each of these components is discussed below.

- **Load Cost:** Entities incur a cost to serve load based on (a) the hourly quantity of load (in MWh) that the entity is obligated to serve in each zone of the model times (b) the hourly zonal energy price.
- **Generation Cost:** The model reports variable production costs for each generating unit as the sum of fuel costs, startup costs, and variable O&M cost for that resource. Generation Costs are attributed to each entity as (a) the total variable production cost of the unit times (b) the percentage share of that unit that is owned or contracted to the entity.

[11] For a subset of WMEG members who requested further exploration, E3 modeled additional market scenarios for 2026 in which transmission capability in the EDAM footprint and on market seams (as well as in the BAU) was reduced by 10%. Markets+ transmission capability was maintained at the same full TTC level to represent the potential impact of Markets+ utilizing a Mod 30 transmission rating approach.

- **Reserve Cost & Reserve Revenue:** In the BAU Case, E3 enforces ancillary service reserve requirements at the BAA level but does not settle these products at a market clearing price. For all the market cases, day ahead forecast error reserves are enforced at the level of a subregion within each market (e.g. the Northwest portion of Markets+), and each entity is assigned a Reserve Cost responsibility based on of (a) the hourly quantity of reserves that entity needs times (b) the hourly market price for reserves within that market sub-region. ; each entity is also awarded Reserve Revenue from the market based on (a) the quantity of reserves that are contributed by generators owned or contracted by the entity times (b) the hourly market price for reserves within that market subregion. In the 2030 and 2035 CBA cases, Reserve Costs and Reserve Revenues are calculated separately for each reserve product (spinning reserves, non-spinning reserves, and regulating reserves, as well as day ahead forecast error reserves).
- **Generation Revenue:** Generation Revenue is first calculated for each resource based on (a) the hourly energy produced by the generator, times (b) the hourly price at the generator's zone. This Generation Revenue is then attributed to each entity based on the percentage share of each resource that is owned or contracted to the entity.
- **Wheeling Revenue:** Wheeling revenue is revenue that transmission providers earn by selling transmission service. In the BAU Case, total Wheeling Revenue is calculated in the model for each entity based on the product of (a) the amount of energy exported over transmission lines connected to that entity, times (b) the OATT rate or market wheeling rate applicable that BAA or transmission entity, plus an additional $/MWh charge for bilateral day ahead market friction. In the RT stage of the BAU Case, wheeling is not charged for transactions between entities in the WEIM or WEIS market. In the DA markets cases, total wheeling revenue is first determined at a market-footprint level based on the (a) amount of energy flowing exported over transmission lines connected to each market footprint times (b) the load-weighted average of OATT rates of zones participating in that market, plus an additional $/MWh charge for transactional friction on seams between the markets. This total market wheeling revenue is then distributed among market participants based on each participant's percentage share of total load in the market (load-ratio share basis).[12]
- **Congestion Revenue:** Price differentials between zones due to transmission constraints creates congestion between entities, resulting in loads paying higher prices than remote generators receive on the other side of congested interface. The value of this difference is assigned back to the entities in the BAU case and for lines within each market footprint. Congestion on the border of each market is allocated among all participants in that market on a load ratio share basis.
- **GHG Revenue:** For established GHG revenue allocation methodologies (CAISO/EDAM) individual generators are awarded GHG revenues per the applicable allocation methodology. However, for Markets+, which does not have an established allocation methodology fully defined yet so in the model GHG revenue on imports are assigned the regulating states, which would have

[12] Separate proposals for market elements in EDAM and Markets+ that seek to provide some compensation to entities that lose current short-term firm or non-firm point to point revenues were not represented in this analysis due to the definitions of those mechanisms not being fully defined at the time when study assumptions for this analysis were finalized. Revenue from such mechanisms (or charges to derive this revenue) would be additional to any individual benefits represented in this study.

responsibility for determining any allocations of this revenue under currently proposed Markets+ rules.

For each entity, E3 then calculated the **Net Variable Cost Savings** from market participation (or the **Net Variable Cost Increase** due to market participation) as the difference between the Net Variable Costs for that entity in a market case (e.g., EDAM Bookend) compared to that entity's Net Variable Cost in the BAU case.

The sum of Net Variable Cost for all entities in the region (including WMEG members and non-WMEG entities) is equal to the regionwide Adjusted Production Cost. Therefore, the sum of Net Variable Cost Savings (or Net Variable Cost Increases) compared to the BAU for all entities in the region equals the total regionwide Adjusted Production Cost savings (or Adjusted Production Cost Increase).[13]

E3's settlement process is performed for both the Day-Ahead and Real-time market. Real-Time market settlement is typically performed as incremental to the Day-Ahead settlements – for example incremental Real-time generation dispatched at a level higher than the Day-Ahead schedule from the DA run will be valued based on RT stage prices and used for RT settlements. Similar approaches are used for Load costs and other individual benefit components. All pricing for the Day-Ahead settlement includes Fast Start Pricing for any zones included in the Markets+ footprint.

[13] This regionwide equation is due to the fact that most of the components of Net Variable Cost represent "transfers" or payments from one entity in the region to another entity in the region, which leads the net effect of revenues and costs from these transfers to cancel or offset each other at the regionwide level. The exception to this (components that are net transfers) are (a) Generator Costs, which are payments for fuel, operations, and maintenance for the generators, (b) revenues for sales or cost for purchases from entities outside the region (in Alberta or the Eastern Interconnection), and (c) GHG compliance costs that are paid to the GHG regulating states (if GHG revenue for imports are in excess of the GHG compliance cost, then those are captured as transfers to the exporting entity as well).

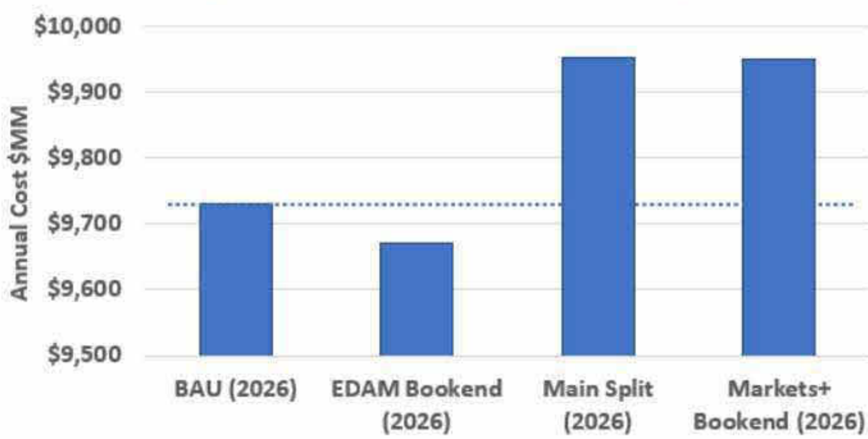
3 Study Results and Key Findings

The simulation cases that E3 modeled each produced hourly dispatch and dispatch cost for each generator, hourly reserves held on each unit, as well as hourly zonal transmission flows, and market prices. E3 used these outputs to create a set of adjusted production costs for each case on a regionwide basis, as well as a summary of the Net Variable Cost impact for each WMEG member (as well as for the non-WMEG entities, comprised of and for the rest of WECC loads and resources not associated with any WMEG member). Each case produced many results, so it is valuable to look across cases to highlight their important impacts and to explore their implications for the WMEG members and the Western Interconnection more broadly. This section describes the results of these cases, as well as key implications of their results.

3.1 Regionwide Impact

Under the BAU Case, the regionwide Adjusted production Cost is $9,732 million in 2026. Compared to BAU case, the regionwide Adjusted Production Cost is $60 million lower in the EDAM Bookend Case, $221 million higher in the Main Split Case, and $218 million higher in the Markets+ Bookend. As the next section describes, the impact for individual entities varies widely for each case, and the majority of the increase in Adjusted production Cost in the Main Split and Markets+ Bookend accrues as a Net Variable Cost increase for non-WMEG members.

Figure 3-1 Annual Regionwide Adjusted Production Cost by 2026 Study Case



Note: Y-axis in chart does not start at $0.

The magnitude of the regionwide impact for market cases ranges from 0.6% to -2.3% as a percentage of BAU case costs. This impact is small relative to total production costs because the BAU Case includes existing real-time markets (the WEIM and WEIS), and the market cases change the footprint of these real-time markets while also adding day-ahead markets. In addition, compared to today's system, the 2026 study year has fewer long-start resources (due to retirement of existing coal generators) and more flexible storage and quick-start thermal resources. These changes in the regional resource mix enable greater optimization in the real-time stage of operations (modeled here as hourly) relative to today's system.

The increase in regionwide production costs in the cases with two markets (Markets+ Bookend and Main Split) is due to reducing the size of the WEIM's geographic footprint. The increase in production costs due to a smaller WEIM footprint outweighs the savings that accrue from the addition of two day-ahead markets for the EDAM and Markets+ footprints.

In addition to the cases above, E3 modeled a separate BAU sensitivity case that assumed less optimized WEIM and WEIS markets. The purpose of this sensitivity is to recognize the uncertainty around how efficient and flexible RT markets (alone) could become by 2026, and to develop a bookend value that represents an optimistic case for the additional value created by DA markets. This sensitivity case constrains RT flows over each line between zones to the day ahead scheduled flow ± 15% of the line's total transfer capability. For example, if a 1000 MW line had 500 MW scheduled to flow in the DA stage for a given hour, the RT stage flows were constrained to range between 350 MW and 650 MW for that hour (500 ± 15% x 1000). This case results in regionwide annual production costs that are $70 million higher than the BAU case for this study. Comparing the DA market cases to this BAU sensitivity results in regionwide production cost savings in the EDAM Bookend growing from $60 million to $130 million, and the regionwide Adjusted Production Cost increases in the Main Split case shrinking from $221 million to $151 million.

Implication of small regionwide energy cost impact: It is important to carefully assess the other sources of potential impact of a DA market or greater integration, such as compatibility with a resource adequacy market that can enable generation investment savings, coordinated transmission planning, reduced curtailment of energy production that meets state clean and renewable energy standards, and more optimal resource procurement over a geographic wider area. Because dispatch-related benefits are relatively modest, it is more likely that other benefit types are key determinants in whether one or the other market options available to WMEG members is more beneficial overall.

Analyzing these other sources of benefits was not in the scope of this CBS, but other regional market studies have shown these benefits sources to be considerable – ranging from two to ten times the DA energy cost impact from DA trading alone.[14] Because this study has shown that DA energy benefits are likely relatively small, it is even more likely that other benefit types are key determinants in whether one or the other market options available to WMEG members is more beneficial overall.

3.2 Net Cost Impact for individual entities

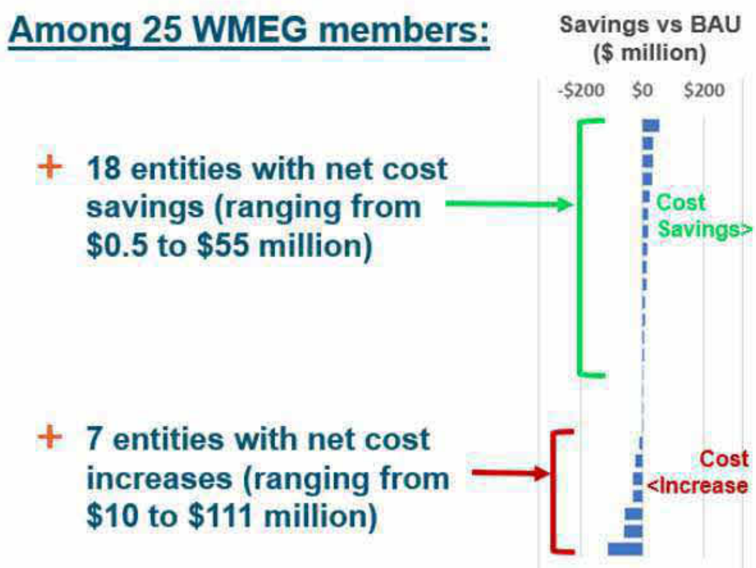
The Net Cost Impact for each individual entity was provided confidentially to each WMEG member funding this study, and the WMEG members chose to keep those results confidential. While Net Variable Cost for individual entities are not included in this summary report, this section discusses the key dynamics observed in results across different entities. The impacts on individual entities vary widely depending on the scenario.

[14] See discussion of other studies in Section **Error! Reference source not found.**.

3.2.1 EDAM Bookend Case Individual Results

In the figure below, each blue bar represents the Net Variable Cost savings or increases in the EDAM Bookend versus the 2026 BAU for one of the 25 WMEG member entities.[15]

Figure 3-2 EDAM Bookend Case – Net Cost Impacts among WMEG members



Overall, in the EDAM Bookend case compared to the BAU, the majority of WMEG members experience Net Variable Cost savings, ranging from \$0.5 to \$55 million per year. Other WMEG members, however, show increases in Net Variable Cost, ranging from \$10 million up to \$111 million, in the EDAM Bookend case. **For all 25 WMEG members summed together, Net Variable Cost increases by \$20 million in the EDAM Bookend**. Higher Net Variable Cost for individual entities is largely due to two factors:

1. Reduced wheeling revenue compared to the BAU case since wheeling is not collected in intra-market transactions and the EDAM spans nearly the full West in this scenario. There is notable variation in wheeling revenues among study participants. The study approach did not attempt to capture existing transmission contracts in the BAU case, which may impact how these revenues would actually be distributed. Some entities may choose to discount the impact of wheeling revenues when analyzing their individual results. To facilitate this, wheeling revenues have been segregated from other benefit streams when requested. <u>If the reduced wheeling revenue were omitted from Net Variable Costs, WMEG members would together see savings of \$369 million in the EDAM Bookend case</u> compared to the BAU; and
2. An increase in the price of market purchases for certain entities: in the BAU case, some entities purchase energy from their immediate neighbors at a low price because those neighbors would have faced pancaked wheeling charges to sell their energy to entities farther away, but the

[15] The impact for five WAPA regions is represented as a single total bar for WAPA as a one WMEG member, though individual results were provided to WAPA by sub-region. These individual impacts include reduced wheeling costs which have a significant impact on Net Variable Costs for members.

EDAM Bookend reduces the cost to transact throughout the wider EDAM footprint, which increases competition for purchases and increases market prices in in some instances.

Non-WMEG entities experience a Net Variable Cost savings of **$80 million versus the BAU case**. Non-WMEG entities include loads in the Western Interconnection that are not represented by the WMEG members as well as resources not owned or contracted to WMEG members. A significant majority of non-WMEG entities, representing 73% of non-WMEG load and 66% of non-WMEG generation capacity in the model, is based in California.[16]

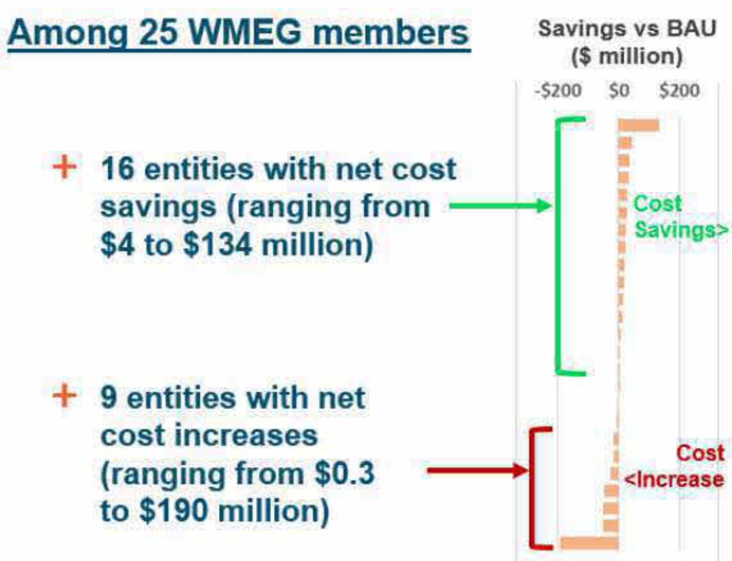
The production cost savings and individual member impacts in the EDAM Bookend relative to the BAU case are due to the day-ahead optimization over a large market footprint.

The market features simulated here for EDAM are largely similar to that of Markets+, with the exception of Fast Start Pricing (FSP) and allocation of GHG revenue for imports, which affect allocation of benefits but not regionwide savings. Therefore, if footprint identical to the EDAM Bookend market had been represented in a Markets+ scenario, the model would have produced similar regionwide result as for the EDAM Bookend, though with some differences in the allocation of participant-specific benefits.

3.2.2 Main Split & Markets+ Bookend Case Individual Results

In the figure below, each orange bar represents the net savings (or net cost increase) in the Main Split Case versus the 2026 BAU for an individual WMEG member.

Figure 3-3: 2026 Main Split Case – Individual Net Cost Impact among WMEG members



[16] California based non-WMEG entities include loads and resources in CAISO, IID, and Turlock Irrigation District. Non-WMEG entities outside California include CFE, BC, Douglas PUD, Grid Force, Avangrid, and Basin Electric, as well as generation in the model that was located throughout the WECC but not identified as being owned or contracted to WMEG entities so treated as merchant generation for the purposes of summarizing cost impacts.

Similar to the EDAM bookend, the majority of WMEG members experience net cost savings in the Main Split Case though some of the members experience cost increases. **For all 25 WMEG members summed together, Total Net Costs decline by $26 million**. The size of this cost decline reflects the net impact of reduced wheeling revenues modeled for WMEG entities compared to the BAU case. As previously noted, wheeling revenues vary significantly among study participants, and this study did not attempt to capture the impact of existing transmission contracts on wheeling revenue distribution. <u>If the impact on the model of reduced wheeling revenue were omitted from Net Variable Costs, WMEG members would together have a $266 million Net Variable Cost reduction in the Main Split case compared to the BAU.</u> Individual WMEG entities that experience lower net Variable Net Costs in the EDAM Bookend do not all experience lower Total Net Variable Costs in the Main Split Case.

The **Main Split case also showed a $247 million Total Net Cost increase for the non-WMEG entities**. The driver of this cost increase for non-WMEG members is that the Main Split Case introduces a larger cost of wheeling over the market seams.

The Non-WMEG entities, who are primarily located in California and are part of the EDAM in this case, import significant amounts of energy in the BAU case, though these entities also have significant net sales (exports) in other hours, primarily solar heavy periods.

In the Main Split case, many of the entities that export power to serve non-WMEG loads join Markets+, which causes those exports to EDAM to face a significant wheeling cost and market friction. To reduce exposure to these higher import costs, the non-WMEG entities increase dispatch of local gas generation – with a 6.7 TWh increase in non-WMEG gas dispatch overall compared to the BAU case.

Many gas units have higher fuel costs in the non-WMEG areas (compared to WMEG areas) due to pipeline transportation costs. Additionally, the implied heat rates of gas units in non-WMEG zones are also elevated during early evening ramping hours. Together, these factors result in a higher cost for the incremental local gas generation dispatched in the Main Split Case compared to the cost of market purchases in the BAU Case.

Moreover, the non-WMEG areas also face a higher cost for exporting generation, so the non-WMEG entities must curtail more solar generation when prices outside the EDAM are not high enough to justify the export cost. Batteries and pumped storage are also run more heavily in the non-WMEG areas, incurring round trip efficiency losses.

Regionwide GHG total emissions change moderately in this case, but the location of their source shifts – with California and other GHG-regulated areas facing more GHG emissions from local generation in non-WMEG areas, rather than from imports. It is possible that this local gas generation impact may have different impacts on local air quality, but E3 did not explore these changes in this study. Additionally, more gas dispatch in California could potentially have an impact on local gas prices due to higher in-state fuel use in certain hours compared to a BAU case, though these impacts were not considered in the current study.

Among WMEG entities, the impact of the Main Split Case varies widely due to three separate factors:

First, these entities overall **reduce local gas dispatch** (due to lower exports to non-WMEG areas), **resulting in lower Generator Costs but also less Generation Revenue**.

Additionally, many WMEG entities in the Main Split Case **lose wheeling revenue compared to the BAU** Case since wheeling revenue **(based on the transmission tariff and buy-sell spreads from transactional friction)** is not collected in intra-market transactions in this case. Some entities in Markets+ footprint, however, **receive increased Wheeling Revenue** due to the allocated share of wheeling charges applied on transactions over market seams when selling to the EDAM footprint. The EDAM participants also receive a share of Wheeling Revenue from EDAM exports to the Markets+ footprint.

Finally, **the market footprint (and cost to transact over market seams) greatly impacts day-ahead market prices, which have a significant effect on the Load Cost and Generation Revenue for many individual WMEG entities.** Fewer exports to the EDAM area (comprised of primarily non-WMEG members) result in lower prices in the Main Split Case for the Markets+ footprint in some hours. WMEG entities that are net purchasers of energy during these hours make their purchases at a lower price than in the BAU Case (or in the EDAM case) resulting in savings. The converse is also true –net sellers in the BAU Case tend to have more negative results in the Main Split Case when prices are lower.

Fewer exports from the EDAM area during heavy solar, low load periods do lead to higher prices in the Markets+ region at certain times. The impact of these lower solar-hour prices varies, however, by entity, as some Southwest entities with significant local solar generation received more revenue for the solar generation they own or have contracted; additionally, the load levels in these hours tend to be smaller so price reductions are less impactful on total net costs.

In the Desert Southwest, there are hours with Fast Start Pricing (FSP) applied in the Main Split Case, which boosts Markets+ prices during those hours, partially offsetting the downward price impact from fewer exports to the EDAM region. Fast start pricing, however, has less of an impact in the Pacific Northwest portion of the Markets+ footprint, due to transmission constraints getting from the Northwest to the Southwest or Rockies area while avoiding transmission through the EDAM (California and PacifiCorp). The next section discusses these effects in more detail.

The table below summarizes the net cost to WMEG and non-WMEG members across different cases for 2026, highlighting the greater variation in results for non-WMEG entities vs. the sum of impact for WMEG members across cases.

Figure 3-4: Sum of Total Net Variable Cost for WMEG Members and Non-WMEG Entities

Note: Y-axis in chart does not start at $0.

Implication of wide variation in individual entity benefits: The individual entity results discussed here have two key implications:

- Among WMEG entities: it is important to closely consider the individual entity impact. These impacts do not always have the same sign as regionwide production cost impacts, nor the sum of Total Net Costs to all WMEG members. Overall, the two factors that most affect individual entity Total Net Costs are (a) whether the entity is a net purchaser or seller and whether the market footprint increases or decreases market prices, and (b) the allocation of wheeling and congestion revenues—particularly on market seams. The market rules for these allocations are still being defined but could affect the individual benefits of many entities in the West.
- For non-WMEG entities: it is important to consider that non-WMEG entities likely receive a sizable amount of the Net Variable Cost reduction in a single market footprint (as reflected in the EDAM footprint). They would also accrue a significant share of the cost increase that results from dividing the Western interconnection into two separate market footprints. While individual WMEG entity impacts vary, the sum of changes in the Total Net Cost to all WMEG members together remains relatively stable over the cases. Non-WMEG results, by contrast, show wider differences between different market cases or different footprints. Recognizing this difference in impact, it may be useful for non-WMEG members to seek other attributes of a single market (outside of Net Variable Cost) that could provide additional encouragement for wider participation. Alternatively, it may be useful to seek opportunities for improving market-to-market coordination (discussed later in this report) that could lead to results that are more like those of a single market.

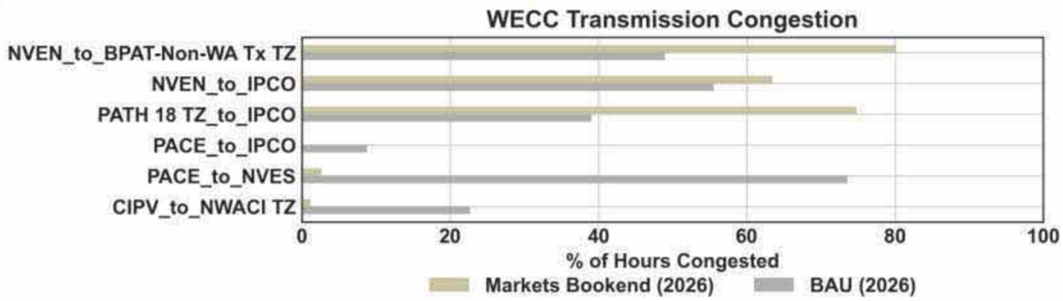
3.3 Importance of Transmission between Pacific Northwest and Desert Southwest

In the Main Split and Markets+ Bookend Case, transactions within the Markets+ Footprint between the Pacific Northwest and Desert Southwest (as well as to the Rockies) depend heavily on key paths through the states of Idaho, Nevada, and Montana. These transmission ties, which are already frequently utilized in the BAU Case, increase in importance in the Main Split Case because California and PacifiCorp are represented in a separate market (EDAM). Sending power from one part of the Markets+ footprint to California areas or PacifiCorp incurs significant wheeling charges and transactional friction on the market seam. Moreover, passing through the EDAM footprint to get to another sub-region of the Markets+ footprint would require also incurring wheeling costs a second time to get out of the EDAM, resulting in an additional "pancaked" transmission cost.[17]

[17] Powerex, which was represented in Markets+ for all scenarios, identified additional transmission contracts it holds on paths connecting the Northwest to the Southwest. This contracted transmission is modeled as part of the Markets+ region to facilitate more trades between the Northwest and Southwest. The total demand for Northwest to Southwest transactions, however, was still greater than the transmission available when transactions over paths connecting through zones participating in EDAM are subject to wheeling charges and friction on market seams.

As a result, in the Main Split case, the model indicates a large shift of transmission flow. There is a reduction of flow and congestion on paths that cross the market seams, including the Northwest AC Intertie (NWACI) to the PG&E Valley zone in Northern California (CIPV), as well as on lines between PacifiCorp East (PACE) and NV Energy (NVES). Instead, transmission flows in this case shift to lines that connect the Northwest to other portions of the Markets+, including from BPA to Nevada, BPA to Idaho Power, and Idaho Power to Montana (via Path 18). The chart below identifies the percentage of hours in which these links are congested in the model in the BAU case as well as the Main Split case which results in a significant increase in intra-Markets+ flow.

Figure 3-5: Frequency of Transmission Congestion on Key Northwest-Southwest Paths

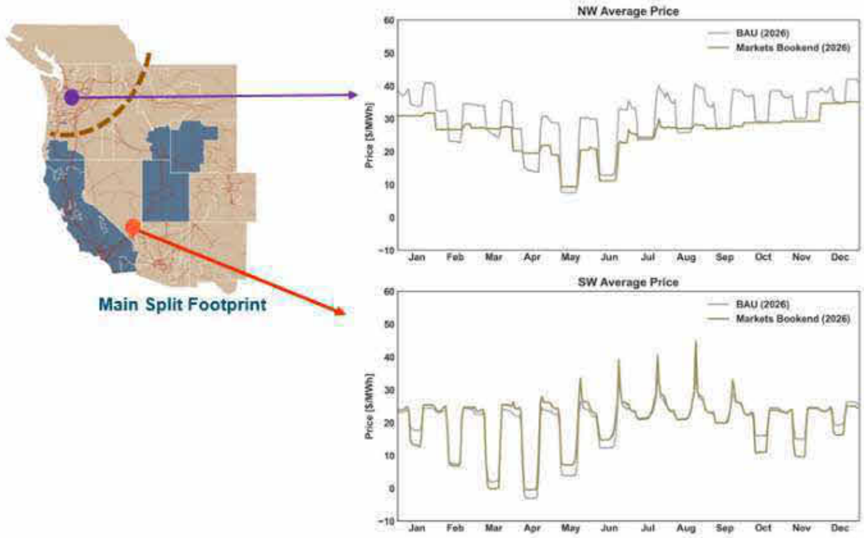


The congestion on these lines has a significant impact on market pricing in the sub-regions of the Markets+ footprint. The figure below compares Pacific Northwest (NW) and Desert Southwest (SW) prices in the BAU case versus the Markets+ bookend on a month-hour basis. For example, the average price for all January days at 1:00 AM is shown as the first data point in each table. The Northwest prices are higher on average due to GHG pricing applied in the State of Washington, but in the BAU Case the patterns of prices between the Northwest zones are quite similar to the pattern of the Southwest, because the BAU case does not have a high cost market seam (as there is in the Main Split Case) that limits the economic transmission flow through California zones or the PacifiCorp system.

In the Markets Bookend Case, however, as well as in the Main Split Case, prices in the Northwest become much flatter than in the Southwest. The Northwest has significant quantities of flexible hydro generation that can be used to balance local loads and renewables. This flexibility is also used to make hourly exports to other zones outside of the Northwest. With the significant hurdle rate and wheeling cost now imposed on transmission to California (or through PacifiCorp), there are many evening hours with higher market prices in the Southwest. In these hours, the Northwest cannot get as much of its flexible generation directly over to the Southwest due to transmission congestion. As a result, Southwest prices spike upward (and even more so due to fast-start pricing) but Northwest prices stay flat as there is sufficient local hydro to balance out and meet local demand across most days.

In the Southwest, there are hours with Fast Start Pricing (FSP) applied in the Main Split Case, which boosts Markets+ prices during those hours, but fast start pricing has less of an impact in the Pacific Northwest portion of the Markets+ footprint, due to the transmission constraints between the Northwest and Southwest.

Figure 3-6: Month-Hour Average Market Prices in Northwest versus Southwest



Implication of Northwest-Southwest transmission congestion within Markets+ zones: These congested lines indicate that there is value from Northwest hydro flexibility that is not being fully utilized for maximizing efficiency across the Markets+ zone. This results in higher dispatch costs and higher load prices for Southwest entities in Markets+ compared to a situation in which these lines were not congested. This dynamic also reduces revenue for Northwest entities that could export more energy at high value times if there were more transmission available within the Markets+ region.

This result implies that if the Western U.S. ends up forming two separate markets with a footprint similar to Main Split or Markets+ Bookend, it will be valuable to explore opportunities to contract for or potentially construct additional transmission to more robustly connect the Northwest and Southwest portions of Markets+.

3.4 Impact of Market-to-Market Coordination

For both 2030 and 2035, the study also modeled a Main Split with improved Market to Market (M2M) Coordination. This case was implemented by reducing the assumed cost of transactional friction in both directions on market seams between the Markets+ and EDAM footprints. For 2030, this reduction in market seams friction reduces regionwide Adjusted Production Cost by $162 million compared to the 2030 Main Split case with no M2M coordination, and in 2035, the reduction in seams friction created a $206 million reduction in Adjusted Production Cost compared to the 2035 Main Split Case with no M2M coordination. These results are highlighted in the figure below together with a map illustrating the approximate vicinity of the market seams between cases. The largest portion of this reduction in cost due to M2M coordination accrued as Net Variable Cost reduction for non-WMEG entities.

Figure 3-7: Regionwide Adjusted Production Cost Impact due to Improved Market to Market Coordination

Market to Market coordination could benefit WMEG members in Markets+ (reducing the Net Variable Cost for many WMEG members) by facilitating more sales to the EDAM footprint, as well as purchases from EDAM when those transactions are economic in a scenario with Market to Market Coordination but may not be economic in the absence of M2M coordination due to the high cost of transactional friction on market seams. M2M could also create opportunities to transact more between different portions of the Markets+ footprint if transactions through EDAM transmission (which may otherwise be underutilized) can be used for Markets+ to EDAM to other Markets+ areas as a result of potentially lower seams cost in M2M cases in certain period.

For EDAM participants, the Net Variable Cost savings that accrue from improved M2M coordination could also be significant. EDAM participants benefit from an improved opportunity to purchase economic imports from the Markets+ footprint at costs lower than that of local generation, as well as the opportunity to export more solar generation (with lower seams cost) during midday hours.

Key implications of M2M results: In practice, M2M coordination can involve a wide range of different processes. A separate report for WMEG, led by Utilicast, summarized existing M2M practices and experiences from other jurisdictions, highlighting some of the more valuable opportunities.

There is a large degree of uncertainty regarding the transactional friction that might occur between the EDAM and Markets+ footprints, because they are each new instances of day-ahead markets options that are not full RTOs, and because the experiences of market-to-market transactions depends significantly on details of the resources and practices of neighboring regions.

Therefore, the magnitude of transaction friction modeled on market seams the 2030 Main Split Case ($10/MWh in Day ahead and Real time) and the reduced level in the M2M case ($6/MWh in Day ahead and $3/MWh in real time) carry some degree of uncertainty.[18] Nevertheless, the results provide a strong indication of the positive directional impact on potential savings that pursuing M2M coordination could

[18] Additional detail on hurdle rates in each scenario are provided in Appendix A to this report.

carry. The results of these cases highlight the value of prioritizing further exploration of improving M2M coordination through the process of designing either market.

When exploring M2M coordination, this study points toward the particular value of coordination in real time or near real time. Coordination during the RT stage may be more challenging than day ahead due to faster speed at which RT transactions need to be executed, but if there are two separate Western markets with both DA and RT stages, it may be useful to explore mechanisms for facilitating more liquid transactions between the markets after the DA stage but ahead of the RT stage. For example, at a period of three to four hours ahead of the operation hour (either through market mechanisms or in an improved bilateral trading format), the level of certainty for wind, solar, and load has greatly improved compared to the prior day, and there may still be time to bring additional thermal generation online if economic to do so. Therefore, better coordination in this period a few hours before real-time (either through the markets or in an improved bilateral format) is worth exploring for its potential to obtain a portion of the savings and efficiency of a single market.

3.5 Impact of Consolidated Balancing Areas

For the 2030 and 2035 simulation years, the study also modeled Consolidated Balancing Areas (CBAs) for zones within each market footprint, with footprints consistent with the Main Split Case. The model represented a CBA by aggregating the Spinning Reserve, Non-Spinning Reserve, and Regulating Reserve requirements for each BAA to a level of a sub-region of each market footprint allowing zones to purchase reserves from their neighboring zones in the same market.

The CBA case does not reduce the total quantity of reserve requirements needed within each sub-region. By setting the Spinning and Non-Spinning Reserves requirements in the BAU Case each at 3% of zonal load, the BAU case already reflects savings enabled from existing contingency reserve sharing pools in the West. It is possible that the quantity of Regulating Reserves could be reduced through BA consolidation but calculating potential changes in these needs would require intensive sub-hourly data analysis. Since this study focused on an hourly time step, Regulating Reserves quantities were not changed in this case, so potential quantity reductions represent an additional potential opportunity for savings not examined here. The CBA case also did not model any potential increase in path ratings due to BA consolidation, which if feasible would represent additional potential benefits beyond the savings included here.

This change resulted in a $10 million annual reduction in regionwide Adjusted Production Cost compared to the Main Split M2M case for both the 2030 and 2035 study years. The size of this incremental savings change is modest, which is likely driven by the fact that the model already has significant flexible storage resources making it relatively easy to meet operational reserve requirements in most hours of the year. Since the overall cost of carrying operational reserve requirements is relatively low during these future years, the savings are also relatively small from carrying them in a more geographically flexible manner in the CBA scenarios.

It is important to note that the study covers only the operational-related cost savings from a CBA – which is largely related to more efficient commitment of less or less expensive thermal generation. The study did not seek to account for potential capacity-related savings that a CBA might provide if it enabled fewer or more optimal investments in new resources for serving load and meeting reserve needs. Investment savings, if any, would be additional to those modeled in this study.

3.6 Impact of RTO

The 2035 Main Split RTO case modifies the 2035 M2M+CBA Case, by adding significant additional transmission facilities throughout the region to reflect coordinated transmission planning for an RTO. Additional detail on the transmission additions in Appendix B to this report. The 2035 main Split RTO case produced a $387 million reduction in incremental regionwide Adjusted Production Cost compared to the 2035 Main Split M2M + CBA case. These savings accrued in similar levels between the non-WMEG entities and the WMEG members, though the impact to individual WMEG members varies based both on how the new lines affect market prices and on each WMEG members' net positions as sellers or purchasers.

This case was particularly important in creating more integrated pricing between the Northwest and Southwest regions by reducing transmission congestion on paths connecting these areas relative to the other cases that did not add transmission capability in those corridors. This result indicates that more transmission capability would provide value in either market footprint for improving dispatch efficiency and reducing Adjusted Production Costs on a regionwide basis, as well as improving the Net Variable costs to individual entities.

For the Core CBS Study, the RTO Case is only modeled for the Main Split Scenario, though a sub-set of WMEG members also funded additional footprint sensitivities cases for the RTO case. The CBS did not model a WECC-wide RTO scenario, but similar levels of regionwide Adjusted production Costs savings would likely accrue in a WECC-wide RTO footprint, which may not require as much additional transmission to realize these savings due to the absence of market seams.

The results of the RTO case reflect do not reflect the capital cost of constructing new transmission, nor any generation investment savings due to programmatic sharing of load and resource diversity for participating entities, or from more optimized regional resource procurement. Therefore, these results indicate that more transmission capability would provide value in either market footprint for improving dispatch efficiency and reducing Net Variable Cost, but do not represent a full assessment of benefits of any individual line to compare to the line's full costs.

3.7 Summary of key results and implications

The table below summarizes the key results of this study, along with the drivers that lead to these results, and the implication of these results for further market development and actions.

Table 3-1: Summary of Key Study Results, Drivers, and Implications

Key Result	Key Drivers of Results	Implication of Results
1. Market Cases have a relatively small impact on regionwide variable cost	The BAU case includes WEIM and WEIS real-time markets, which already provide significant savings, leaving less room for improvement.	Other benefit categories (such as generation investment savings for serving peak load, and optimized procurement over the market footprint,

(0.6 to 2.3% change vs. total BAU costs).		and coordinated transmission) may have a larger impact than Adjusted production Cost at a regionwide level or individual entity net variable costs, and therefore are important for further assessment.
2. Impacts on individual WMEG members vary widely within market cases.	(a) Entities that are net purchasers benefit from reduced prices in market cases, while sellers see lower sales revenues. (b) Additionally, some entities receive less wheeling revenue from exports or wheel-through transactions in the market cases than in the BAU case because the market cases do not charge wheeling on intra-market transactions.	When an entity evaluating the Net Variable Cost impact of different market options, it is important to consider: (a) the entity's anticipated net sales position and also how wheeling revenues on market seams are allocated in final design, and (b) how much wheeling revenue the entity would receive in a BAU (no market) scenario, and whether the entity expects transmission customers will continue contracting for transmission in a market scenario (e.g., for greater certainty or to receive congestion revenue) or will reduce payments for transmission contracts
3. Significant savings in EDAM Bookend accrues to non-WMEG members (primarily California) while the Main Split and Markets+ Bookend Cases create cost increases primarily in non-WMEG areas (again – primarily in California).	In the non-WMEG areas, gas generation goes down in EDAM Bookend but up significantly in the Main Split Case because higher costs of wheeling friction over market seams prevent optimal trading.	Non-WMEG members should recognize the variable cost savings that accrue to them in a situation with one Western market versus two markets and look for ways that other benefit categories may help encourage this direction.
4. If there are two Western markets (such as in the Main Split Case), transmission between the Northwest and Southwest is important for Markets+ transactions.	Results in the Main Split case show a significant amount of flexibility in the Northwest with limited transmission to reach the Southwest via Idaho and Nevada as well as through Montana to the Rockies.	If pursuing two markets in the West, it is important to seek options to contract for or build additional transmission capability in Markets+ between the Northwest and Southwest.
5. If there are two Western markets, Market to Market coordination can be valuable for achieving improved efficiency.	Market to market coordination in the 2030 M2M case reduced regionwide costs by over $150 million due to the reduction in the transactional friction applied on market seams.	Market to Market coordination may be challenging to implement but important to investigate, particularly in the real-time market stage. Potentially, improved trading in hours leading up to real-time could help facilitate improved efficiency.

Appendix A. CBS Modeling Approach

A.1. Modeling Framework and Assumptions

The modeling framework behind the analysis focused on the key differences between the proposed EDAM and Markets+ products and how those would translate to different costs or benefits relative to one another. The study was done using Energy Exemplar's PLEXOS production simulation model, and E3's machine learning-based RESERVE tool provided reserve requirements based on load and renewable forecast error. E3 also developed renewable generation forecasts at the plant level and load forecasts for WMEG members. Lastly, E3 developed a settlements algorithm using Python that conducted hourly settlement of both EDAM and Markets+ across market participants to provide entity-specific system costs for any scenario.

EDAM and Markets+ Features

E3 incorporated differences and similarities between EDAM and Markets+ in the production cost modeling and settlement calculations. E3 used industry knowledge, conducted research, and worked extensively with Utilicast and WMEG members through multiple task forces to identify important market features including:

- Fast Start Pricing
- Transmission Availability
- GHG Revenue Allocation
- Market Seams
- Imbalance Reserves
- Transmission Congestion Rent
- Wheeling Revenue
- Resource Sufficiency Test
- 3rd Party Transmission revenue

E3 then worked with Utilicast and WMEG task forces to understand the key differences and similarities between EDAM and Markets+. For this study, a resource sufficiency test was discussed with the WMEG but was not included in the modeling. Thus, these results assume that all market participants are considered resource sufficient for each hour, but the model did not explicitly assess this compliance. Any potential resource insufficiency penalties should be assessed by the individual WMEG members. Third Party transmission revenue was not calculated within this analysis as this revenue may change in the future. E3 instead provided full transmission congestion and wheeling revenue on each line to members who could allocate a portion to 3rd parties as a post-processing step outside of the core analysis. E3, Utilicast, and WMEG discussed the remaining market features extensively and developed the key aspects of remaining contrast and comparability.

Given that some EDAM and Markets+ rules have not been fully developed, it was challenging to know if there were indeed similarities or differences in some of the market features. For the purposes of this study, it was assumed that if a market feature has not been distinctly defined for Markets+ or EDAM, then it was treated similarly to the other market that had defined this area. This treatment is consistent with the observation that in the long run, mature markets tend to be aligned and resemble one another. The table below identifies how E3 modeled the key market features for EDAM and Markets+ within the analysis with particular attention to Fast Start Pricing and GHG revenue allocation. Transmission availability appeared to differ between the two markets, however the differences were not clear enough to be considered part of the core study and were instead changed as part of a sensitivity study (APP #3).

Table A-1 Market Feature Comparison in EDAM vs. Markets+

Feature	EDAM	Markets+
Features modeled in different ways for each market*:		
Fast Start Pricing	No	Yes
GHG Revenue Allocation	GHG Revenue allocated to out of state generators in EDAM sending incremental power to CA & WA (compared to a "GHG Reference Case")	Distribution of revenue for GHG imports not yet specified in market design; assumed to be determined by the states; for this study was not explicitly allocated to electric power entities represented in the study
Transmission Availability	Modeled based on Zone-to-zone Total Transfer Capability (TTC) with tie zones. **Sensitivity case (APP3)**: Reduce transmission availability in EDAM relative to M+ capability based on flow based.	
Features modeled similarly for each market:		
Market Seams	Model market footprint-wide $/MWh export charged to exports from EDAM footprint or from M+ footprint	
Imbalance Reserves	Model as Ancillary services product needed in each zone (or sub-region) calculated based on percentile of each zone's DA forecast net load forecast error (reduced for EDAM or M+ footprint diversity)	
Transmissions Congestion Rents	Congestion rent allocation based on ownership share of lines/paths between zones (Markets+ allocation design not yet fully defined so assumed to follow same format as EDAM)	

This Appendix section contains additional details on each of these market features as well as other modeling assumptions detail.

While not a direct feature of the market per se, Powerex provided guidance to model its system and transactions with the U.S. A consistent assumption across all modelling scenarios is that Powerex is participating in Markets+. Powerex has publicly committed to joining Markets+ and is working with SPP to enable implementation of Markets+ real-time in 2024. The full Markets+ Day Ahead /Real-time platform is expected to go live in 2026.

For each WMEG scenario, Powerex provided information about its projected market activity in two key categories:

1. The portion of its market activity that is likely to occur in fixed 24/16/8-hour blocks; and
2. The portion of its market activity that is likely to occur on an hourly optimized basis.

Under the modelling scenarios in which BPA and other NW entities join EDAM, Powerex expects that its most attractive market opportunities would be forward sales in 24/16/8-hour blocks to utilities and large commercial and industrial customers seeking reliable firm capacity for resource adequacy purposes and/or deliveries of carbon-free energy (often on a 24/7 basis).

To supplement these block transactions, Powerex also expects that it would generally make approximately 1,000 MW of hourly flexibility available for hourly optimized transactions in Markets+, including enabling intertie bidding at the BC/US Border for transactions to and from the EDAM footprint. These assumptions are generally consistent with the present, in which Powerex's WEIM activity has been limited (to much less than 1,000MW on average), as a result of:

1. Powerex viewing price formation in the bilateral markets as more attractive; and
2. Powerex choosing not to make sales of carbon-free energy in the WEIM, due to its concerns about the CAISO's GHG algorithm inaccurately deeming Powerex's carbon-free supply as being delivered to California, with an assumed simultaneous backfilling of unspecified energy to BC.

Under the modelling scenarios in which BPA and other NW entities join Markets+ (enabling strong transmission connectivity within the NW), Powerex expects that its most attractive market opportunities will be hourly optimized transactions through Markets+ (instead of continuing to make forward transactions in fixed blocks for resource adequacy and carbon-free supply purposes).

Accordingly, Powerex indicated that it expects to make its full hourly flexibility available to a well-connected Markets+ footprint (limited only by minimum and maximum generation and transmission limits). Consequently, the modelling scenarios in which BPA (and other NW entities) join Markets+ have much more Powerex hourly flexibility available for dispatch. E3 estimates that the incremental regionwide cost reduction attributable to Powerex's increased hourly flexibility in these scenarios is approximately $7 million.

A.2. Market Modeling

The analysis uses Energy Exemplar's PLEXOS production cost simulation software to model the current Business-as-Usual (BAU) WECC market interactions as well as the proposed EDAM and Markets+ markets.

E3 used CAISO's modified 2032 Anchor Data Set WECC-wide model as the base model for this study, which includes CAISO's resource updates for California.

Model Topology

E3 worked with WMEG members and Utilicast to develop an updated model topology that reflects the geographical locations of BAAs while also capturing key transmission constraints and trading hubs throughout the West. The topology goes a level deeper than the usual hub and spoke representation of WECC.

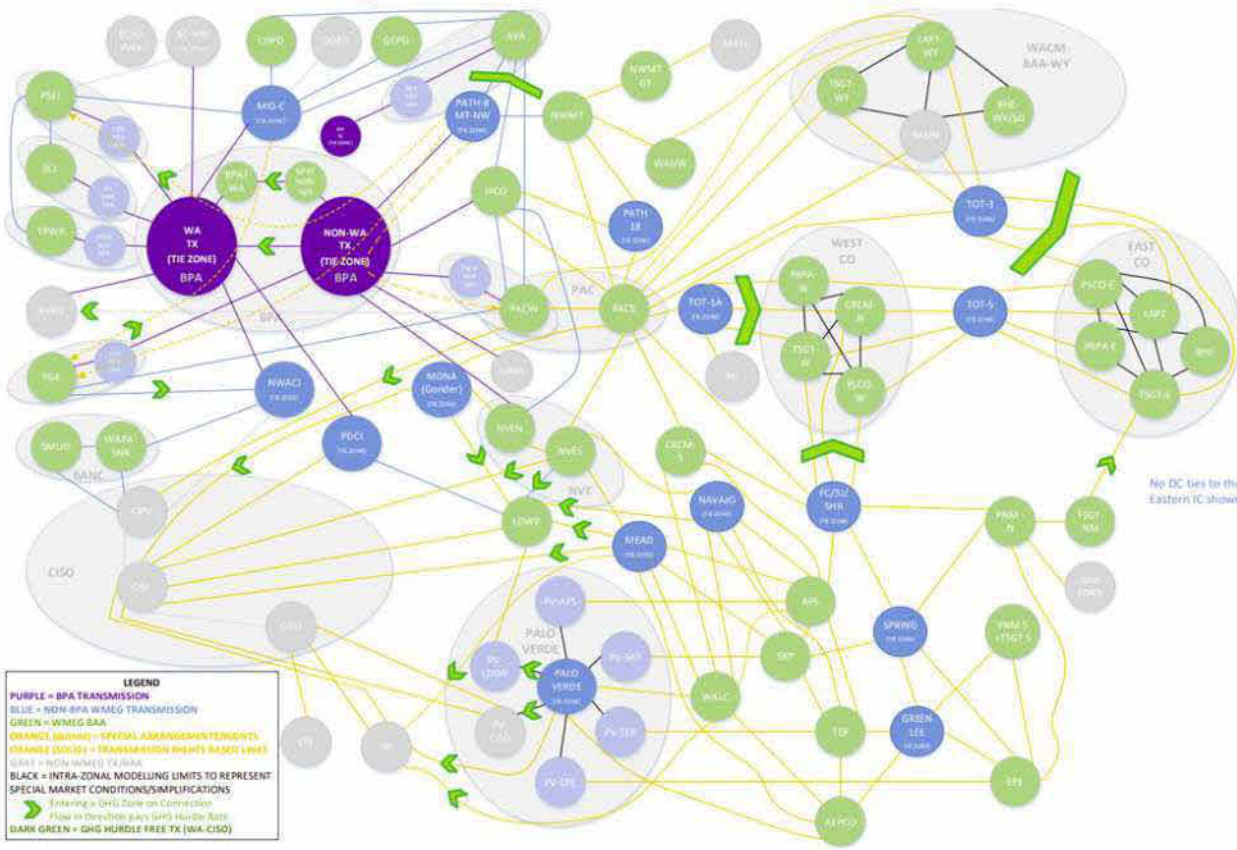
In addition to incorporating major trading hubs in the West such as Mid-C, Palo Verde, and Mead, E3 models other areas where multiple entities can transact with one another. These junctions are defined as "Tie Zones" within the model and allow transmission paths to be broken out and allocated among WECC entities to track transactions into and out of individual zones. This is particularly an issue in the Southwest where entities can transact with each other at multiple seams across the region, and the Northwest where most entities use BPA transmission to some extent. This level of granularity allows individual members to highlight transmission constraints either within their BAA or within their region while also maintaining a more detailed accounting of transmission capacity, wheeling, and congestion revenues.

The Tie zones in the model are shown in the figure below and include the following locations:

- In the Pacific Northwest: Washington Transmission (WA TX) Tie Zone and Non-WA Transmission Tie zone in BPA, Mid-C, Path-8 (Montana-Northwest), and Path 18, as well as the NWACI, PDCI, and Mona connections to California
- In the Rockies region: Tot-3 Tot-1A, and Tot-5, and
- In the Desert Southwest: Palo Verde, Mead, Navajo, Four Corners/San Juan/Shiprock, Springerville, and Greenlee tie zones.

Each of these zones connects multiple entities that can transact with each other up to a given level of transmission capability to the tie zone and/or downstream from the tie zone to another entity.

Figure A-1 Modified Zonal Model Topology



As shown by the green chevrons in Figure A-1, E3 included a greenhouse gas (GHG) import hurdle rate on lines that flow into Washington, California, and Colorado. These are used to help calculate GHG revenue across different scenarios. The WECC system is also connected to the Eastern Interconnect via multiple DC tie lines, which are not shown on Figure A-1. The Eastern Interconnect is defined by an hourly price stream based on historical data for SPP North and South hubs and adjusted for projected future changes to gas prices for 2026, 2030, and 2035.

Canada was modeled differently from the rest of the Western interconnection. With the help and guidance of Powerex, the BC Hydro system load and generation was simplified to be represented as a single integrated pumped hydro facility. Separately, Alberta was modeled as an external market with a fixed hourly price to which the WECC could make sales or purchases.

Model Input Assumptions

E3 worked with WMEG members and Utilicast to update and add data to the base model. The model simulates all major WECC generators (except for Canadian resources, as discussed above) and optimizes a full year of operations at an hourly granularity. Based on member feedback, E3 added new and subtracted resources from the base model for the CBS study years 2026, 2030, and 2035, and modified detailed generator operational data.

The base model used 2018 weather year data for hourly renewable profiles. E3 used the large library of existing solar and wind profiles within the database as the profiles in the CBS. WMEG members provided data to E3 to help update load forecasts at the BAA level for 2026, 2030, and 2035. To model coincident weather-driven load and renewable conditions, E3 and WMEG members matched future load profiles to 2018 weather/load conditions on a daily basis. Hydro data was collected from all members that wanted to provide updated data. Though 2018 was the selected weather year for the study, members could also provide updated hydro data to reflect future weather conditions. E3 used ADS fuel prices that were either sourced from the CEC's IEPR forecasts or EIA data.

Given the modified zonal model topology, members provided Total Transfer Capability (TTC) values for each line in the forward and backward direction for 2026 and provided any TTC changes in 2030 and 2035.

All members also provided long term point-to-point Open Access Transmission Tariff (OATT) rates which were converted to $/MWh in the day-ahead stage Business as Usual (DA BAU) case, these wheeling rates for each BAA were added to $2/MWh of assumed friction-based hurdle rate to represent the total wheeling or "hurdle rates" applied. In the real-time (RT BAU) case, these values were set to zero within the WEIM and WEIS footprint but are still used on market seams for exports from each real-time market footprint.

The OATT-based wheeling rates for each entity were also used to develop EDAM and Markets+ wheeling rates for transactions on market seams (for exports that are delivered outside of each market footprint). The exit rate of each market was assumed to be calculated as the load-weighted average of the wheeling rate of the entities participating in that market, together with additional frictional wheeling charges discussed by scenario the table below.

Table A-2 Hurdle Rate Assumptions

BAU Hurdle Rate	Market Hurdle Rate
OATT Rate + Friction on exports from zone or collection of zones that represent one entity	**Weighted Average OATT Rate of Market + Friction + Congestion Risk** for exports from a zone that is in Market A to a zone that is in Market B

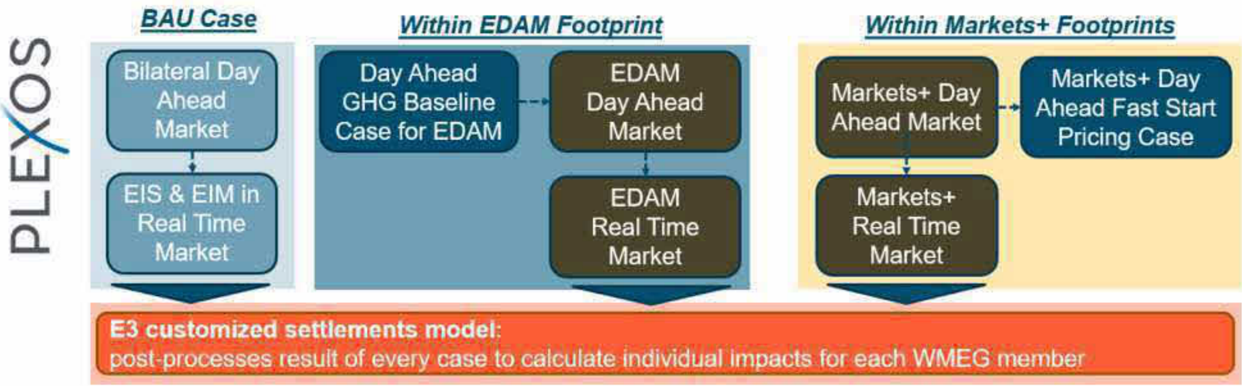
All CBS assumptions on hurdle rates are discussed in more detail later in Appendix A.

PLEXOS Model Structure

The PLEXOS model uses a multi-stage process to capture Day-Ahead and Real-Time market transactions as well as other unique market characteristics. For the BAU case, the Day-Ahead stage is a bilateral market run that creates an optimal dispatch subject to transmission based on BAA load forecasts and renewable forecasts. In this bilateral trading stage, long-start unit commitment decisions (gas and coal steam, combined cycle) are made in the context of economic dispatch. These commitment decisions are held through the Real-Time stage. In the Real-Time stage, WEIM and WEIS participants can trade with each other at no cost while non-market participants can transact bilaterally subject to OATT rates.

The market cases (representing both EDAM and Markets+) use the same two stage process as the BAU, however, the Day-Ahead stage now represents an EDAM or Markets+ footprint. Similar to the BAU cases, for the market cases during the Real-time modeling stage, commitment of longer start units are held fixed or "locked in" to their DA schedule. In the market cases, there are additional dispatch runs to capture unique characteristics of each of the various markets: (a) a GHG Baseline run and (b) a Fast Start pricing run.

Figure A-2: PLEXOS case structure and E3 settlements model



Note: The Main Split & M+ Bookend cases modeled both EDAM and Markets+ simultaneously in different portions of the WECC Footprint

Day Ahead Dispatch Period

The WMEG members determined which units are available for the model to use in the day ahead dispatch period. Each of the economic dispatch solutions honor availability and generator restrictions leading into the DA run and carry these restrictions (and day-ahead commitment for longer-start units) forward into the RT dispatch period.

The CBS does not reflect Virtual Bids or Offers in any market footprint – CAISO, EDAM or Markets+. While these products may be in all the Market designs by 2026, at the time of the CBS, WMEG does not yet have a basis for how these Virtual Transaction might be strategically used by financial participants. To the extent that WMEG wants to account for some effect, it would be more practical to assume some percentage of the benefits accrue to financial players.

There is no Residual Unit Commitment (RUC) represented process in the PLEXOS model for the CBS. It is assumed that reliability has been checked via resource adequacy programs or reserve requirements that have been calculated as inputs to the DA dispatch run.

Real-Time Market Period

The Real-Time Market for this simulation is run at an hourly granularity. This simplifying assumption may understate the benefits of the WEIM, which solves at 15-minute granularity for unit commitments and then optimizes the dispatch at 5-minute intervals and WEIS market which optimizes the dispatch at 5-minute intervals, but these real-time subhourly benefits may be similar in the BAU case and market Cases due to the presence of RT markets in the BAU.

The PLEXOS Real-Time Market stage does allow additional resource commitments of certain units. The CAISO WEIM market has a Short-Term Unit Commitment (STUC) and Real-Time Unit Commitment (RTUC) process. For the CBS, CT resources are allowed to re-commit for the RT Market.
The WEIS Market does not currently have a RT Resource commitment process, but for the CBS, CT resources in that footprint were allowed to re-commit. SPP's Integrated Marketplace does have a Real-Time RUC process which commits additional resources as necessary every few hours.

GHG Baseline stage overview

The GHG Baseline run is used to mimic the GHG revenue allocation methodology in EDAM and potentially Markets+. This dispatch run is optimized by assuming no imports into the Washington and California areas[19] to provide a reference dispatch against which the actual EDAM and Markets+ dispatches will be compared. In the EDAM and Markets+ Day Ahead runs these import constraints are lifted, which enables quantification of GHG imports and associated GHG revenue. As part of the EDAM benefit calculation, the settlement calculations award GHG revenue to resources. Since Markets+ GHG accounting rules have not been finalized, GHG revenue was not calculated by resource for any of the California- or Washington-based zones that are represented in Markets+ for a particular case. Instead imports into those Markets+ GHG regulated zones are represented as a total dollar amount that could be assigned to the state for determination of how to allocate. Additional detail on GHG modeling is provided later in this appendix.

Fast Start Pricing stage overview

Costs incurred as a function of generator commitment, such as start and no-load costs, have traditionally been recovered via uplift charges because these costs are not included in the marginal price of energy. As part of Markets+, units that can start quickly ("fast start" units) can potentially recover some of these costs by increasing energy prices during intervals in which they have started. To do so, first a Day-Ahead economic dispatch run is performed to establish the unit commitment of all units. Subsequently, a Fast Start Pricing run is performed, which holds unit commitment decisions constant from the initial Markets+ Day-Ahead run but adds an incremental fast start cost ($/MWh) to units that can start quickly. This cost is added only to intervals in which the units started in the initial Day-Ahead run. Markets+ defines the fast start adder as the sum of no-load cost and start cost amortized over the minimum run time of the unit. This fast start pricing run re-optimizes the economic dispatch of the system, producing the final market clearing prices within the Markets+ footprint. Additional detail on modeling of Fast Start Pricing is provided in the next section of this Appendix.

[19] The WMEG group also considered Colorado a GHG area in this study that was subject to carbon prices, however, unlike CA and WA, the WMEG group recommended that GHG revenue not be explicitly allocated to generators exporting to Colorado; instead GHG revenue associated with wheeling energy into Colorado was tracked as a total dollar figure that would then be allocated by the state. This is the same procedure that was used for addressing GHG revenue in Markets+.

A.3. Fast Start Pricing Detail

Fast Start Pricing is a market feature exclusively for Markets+. The SPP Integrated Marketplace has updated the approach to LMP determination to include an adjustment for Fast Start Resources (FSRs). This is described in the Protocols Section 3.1.1. In essence, for FSRs, the scheduling run performs normally according to the three-part offers (startup, no-load and incremental energy). When an FSR is committed in the scheduling run, SPP will "amortize" the startup and no-load costs over the Resource max and the minimum market run time based on the relevant market interval definition (rounded up). These additional costs are then added to the energy offer to create a "composite" offer for the pricing run (subject to mitigation). It appears that this could significantly increase the market clearing price when FSRs are committed. The approach applies in both DA and RT in Integrated Marketplace. It is not known whether this will be included in Markets+.
SPP defines an FSR for Marketplace as a Resource which offers in DA or RT: a Start-Up Time of 10 min or less and Minimum Run Time offer of 60 minutes or less.

Based on discussions with SPP, E3 developed a Day-Ahead Fast Start Pricing run to mimic Markets+ operations. The Day-Ahead run produces market outputs and generator schedules based on marginal cost offers. The Fast Start Pricing run fixes unit commitments from the Day-Ahead market schedule. All CTs and ICE resources are assumed to be fast start eligible and are taken as FSRs in the Past Start Pricing run. In the pricing run, FSRs are allowed to dispatch down to 0MW and have "fast start adder" on their marginal cost bid that represented the addition costs to make the composite offer discussed above. The CBS production cost model did not incorporate no-load costs for resources therefore in this study only the start-up cost is assumed to be included in the Fast Start price offer.

The Fast Start Pricing run is then run again to generate updated Markets+ prices within its footprint which are subsequently used within the settlement calculation process. The Fast Start Pricing run was only implemented as part of the Day-Ahead market run and not the Real-Time market run. The assumption here is that most transactions occur in the Day-Ahead stage so having Fast Start Pricing in that run would capture almost all of its effect.

A.4. Wheeling Rates & Transactional Friction in Model

The following assumptions are used to model interactions between footprints of a given Market Operator by model Stage.

DA BAU enables bilateral trading between WECC entities and does not assume any market operator except the existing CAISO. In DA BAU, apart from CAISO, all BAAs will charge a hurdle rate exiting their area equivalent to their long-term point-to-point OATT rate in Q4 of 2022. CAISO has no wheeling between zones in its footprint as it is an organized market. In DA stages that include EDAM or Markets+, once EDAM is modeled in a scenario it becomes part of CAISO by removing any hurdle rate between EDAM zones and CAISO zones and they are treated as one larger market footprint. The same applies to Markets+ zones, hurdle rates between participants in DA are reduced to $0/MWh.

Between EDAM and Markets+ footprints the hurdle rate will be large to mimic reluctance to trade across different DA markets. The assumption for these rates contains three major pieces. The first is the load weighted average of the long-term point-to-point OATT rates of the entities within the EDAM or Markets+

footprint to mimic an access charge much like CAISO has today. The second is an assumed market friction adder in DA that quantifies the opportunity cost of trading across markets. The third is a congestion risk adder.

The market wheeling rates and hurdle rates adders for each scenario included in the CBS are summarized in the table below. Appendix B provides additional detail describing each Scenario including market participation of each entity.

Table A-3 Market Wheeling rates and Sub

	2026	2030	2035
BAU	OATT Rate + $2 Marketing Friction on exports from zone or collection of zones that represent one entity. If an entity has a split zone, there is no hurdle between their zones.		
EDAM & Markets+ [without M2M Coordination]	**Within Market Footprint:** $0	**Within Market: $0**	**Within Market: $0**
	Seam: Weighted Avg OATT Rate of Market* + $2 Friction + $8 Congestion Risk for exports from a Zone that is in Market A to a Zone that is in Market B	**Seam: Weighted Avg OATT Rate of Markets+ $2 Friction + $8 Congestion Risk** for exports from a Zone that is in Market A to a Zone that is in Market B	**Seam: Weighted Avg OATT Rate of Markets+ $2 Friction + $8 Congestion Risk** for exports from a Zone that is in Market A to a Zone that is in Market B
M2M Coordination		**Within Market:** $0	**Within Market:** $0
		Seam: Weighted Avg OATT Rate of Market + $2 Friction + $4 DA Congestion Risk (or $1 RT Congestion Risk) for exports from Market A to a Zone that is in Market B	**Seam: Weighted Avg OATT Rate of Market + $2 Friction + $4 DA Congestion Risk (or $1 RT Congestion Risk)** for exports from Market A to a Zone that is in Market B
M2M Coordination + CBA and AS Market		Within Market: $0	Within Market: $0
		Seam: Weighted Avg OATT Rate of Market + $2 Friction + $4 DA Congestion Risk (or $1 RT Congestion Risk) for exports from Market A to a Zone that is in Market B	**Seam: Weighted Avg OATT Rate of Market + $2 Friction + $4 DA Congestion Risk (or $1 RT Congestion Risk)** for exports from Market A to a Zone that is in Market B

RTO			Within Market: $0 Full RTO / Enhanced Transmission Portfolio – Same hurdle rates as CBA+ASM and M2M case; key difference in the RTO case is different transmission buildout

The weighted-average market wheeling rates for each footprint are represented in the table below for each market scenario and each study year.

Table A-4 Market Wheeling Rates

Weighted Average OATT of Market* ($/MWh)

** Friction, congestion risk, and GHG adders not included in the values below*

Main Split Scenario

Market	EDAM	Markets+
2026	$ 9.53	$ 4.21
2030	$ 9.56	$ 4.22
2035	$ 9.57	$ 4.25

EDAM Bookend Scenario

Market	EDAM	Markets+
2026	$ 6.43	$ 7.76
2030	$ 6.45	$ 7.76
2035	$ 6.50	$ 7.76

Markets+ Bookend Scenario

Market	EDAM	Markets+
2026	$ 9.66	$ 4.19
2030	$ 9.68	$ 4.20
2035	$ 9.69	$ 4.23

In RT BAU, entities that are not part of WEIM or WEIS may continue to bilaterally trade close to real-time for any last-minute balancing subject to BAA wheeling rates. There is a Market Operator assumption for entities in WEIM or WEIS in the BAU scenario that brings the hurdle rate to $0/MWh between zones within the same market footprint. This also applies to all other RT market scenarios for EDAM and Markets+.

For 2030 and 2035 scenarios, cross market hurdle rates are reduced in the market-to-market (M2M) change cases. The DA case will reduce its congestion risk hurdle adder from $8/MWh to $4/MWh. In RT the congestion risk adder will reduce further from $4/MWh in DA to $1/MWh. These reductions in hurdle rates between markets represent increased coordination between markets and reduced barriers to cross-market trading that may occur with market maturity.

A.5. Reserve Modeling & Forecasting

E3 developed Day-Ahead load and renewable forecasts that are used in the Day-Ahead market stage. E3 also developed Real-Time load profiles for the study years with input from WMEG members. E3 used these forecasts as well as additional assumptions to create reserve requirements across all cases in the CBS.

Load and Renewable Forecasting

Day-Ahead forecasts for load and renewables were developed as part of the multi-stage market analysis. Decisions in the Day-Ahead market stage and market schedule outcomes are based off these forecasts.

E3 worked with WMEG members to develop real-time future year load profiles either using member specific forecasts or E3's forecast methodology. E3 wanted to maintain load and renewable correlation by modeling the same weather year within the CBS. The PLEXOS model was pre-seeded with WECC Anchor Data Set (ADS) profiles based on a 2018 weather year. Those were kept in the CBS model as the real-time renewable resource profiles. Each member forecast load for the RT stage followed observed 2018 weather patterns to ensure that weather-dependent load is realistically correlated across the study region, and overall load levels were scaled to approximate a median or 1-in-2 forecast level. E3 worked with WMEG members to obtain the real-time load profiles for the 2026, 2030, and 2035 study years.

For the Day-ahead stage, E3 then perturbed those profiles using historical day-ahead forecast error data to create load profiles that represent day-ahead forecasts of the future year profile. E3 developed a computable methodology to generate hundreds of renewable forecast profiles. These day-ahead renewable forecasts were developed by E3 based on a weighted combination of the actual real-time for matching hours from the prior day, together with month-hour average values. E3 then blended these values with the actual real-time to match data E3 previously obtained for day ahead forecast error mean average percentage error (MAPE) statistics to more accurately account for relative forecast quality. The advantage of this relatively simple forecast methodology is that unlike forecasts developed using randomized forecast error for each resource, it produces an error that captures correct correlations of errors across different projects locations. This feature allows the forecast to account correctly for geographic diversity both within individual BAAs, as well as when the forecast errors for multiple BAAs are combined into a broader market region.

Creation of load profiles directly involved WMEG members as part of a load forecasting task force. WMEG members provided hourly demand projections for E3 to use in the CBS study. Demand profiles for 2026, 2030, and 2035 were provided based on each WMEG member's latest or most applicable demand forecasts. E3 used a day matching approach to synchronize the member-submitted load forecasts with the 2018 weather year of the wind and solar profiles. The rank order of days within seasonal windows were calculated for both the member-submitted forecasts and a reference load forecast from the ADS that was based on 2018 weather conditions. Each day from the member-submitted forecast was re-arranged to correspond to the rank order of daily load values in the reference ADS load forecast. Member-submitted forecasts were used in the real-time model stage.

To develop day-ahead load forecasts consistent with member-submitted load profiles, E3 developed an hourly time series of forecast error percentage using historical data. To do so, day-ahead forecast and real-time demand data for each balancing area in WECC was collected from the Energy Information Administration's Hourly Electric Grid Monitor. The percentage difference between the day-ahead and real-time demand was calculated for each hour of a single year (either 2018 or 2019, depending on balancing area). Forecast error percentages were capped at 30% in any single hour to address data quality issues and were adjusted upward or downward to set the annual mean forecast error to zero. The resulting hourly time series of percentage error values were multiplied by the member-submitted forecasts, resulting in a synthetic day-ahead load forecast for each balancing authority area (BAA).

Reserves overview

Five ancillary service products are represented in the production cost model: Spinning Reserves, Non-Spinning Reserves, Regulation Up, Regulation Down, and Imbalance Up. Except for Imbalance Up reserves, the reserve requirements are calculated as a percentage of load: Spinning (3%), Non-Spinning (3%), Regulation Up (1%), and Regulation Down (1%).

Imbalance reserve requirements ensure system reliability by reserving capacity to account for forecast error associated with renewables and load. Imbalance reserves are part of proposed EDAM and Markets+ Day-Ahead market designs. For the CBS, imbalance reserve requirements were calculated using E3's in-house RESERVE model, which calculates imbalance reserve requirements given forecast errors of load, wind, and solar. Imbalance Up reserve requirements were created using RESERVE's prediction of the 97.5th percentile of net load forecast error, and as such the Day-Ahead production cost model stage is prepared to address all but 2.5th percentile of net load under-forecast events. Imbalance Down reserves were not modeled in the CBS due to the expected abundance of resources that could provide this product in the day-ahead timeframe, including the ability to de-commit thermal units, charge storage resources, or curtail renewable generators.

Depending on the CBS scenario, reserve requirements were either modeled as BA-specific or pooled as part of a market at a regional level via the subregion breakout in Figure A-3. Pooling reserve requirements across a larger area provides diversity benefits compared to a BA-specific requirement and is one of the numerous benefits of an organized wholesale market. Specifically, the imbalance or day ahead forecast error reserves were calculated in pooled cases based on the aggregated net load forecast error of sub-regions of each market footprint (for example the Pacific Northwest sub-area of Markets+). The aggregation of net load across multiple zones results in a lower reserve level needed to cover the 97.5th percentile of forecast error, so these pooled cases enable cost savings and reduced reserve needs due to geographic diversity.

Figure A-3 Market Reserve Subregions[20]

Table A-5 Categorization of Western Zones for Reserve Subgroups

California	Northwest	Southwest	Rockies
CAISO	PacifiCorp	NVE	BH
BANC	ID	AEPCO	PRPA
LADWP	NWMT	APS	PSCo
Turlock	Avangrid	EPE	TSGT
IID	Avista	PNM	BASIN
WAPA SNR	BPA	SRP	WAPA CRSP
	Chelan	TEP	WAPA LAP
	Douglas	WAPA DSW	
	Grant		
	PGE		
	PSE		
	SCL		
	Tacoma		
	WAPA UGP		
	BC/Powerex		

E3's RESERVE tool was used to provide both BA-specific and regional imbalance reserve requirements that were used for different scenarios within the CBS. The details of E3's RESERVE tool and its application to the CBS are discussed in more detail in the next section. **Error! Reference source not found.** includes more d etails on how each reserve was modeled. CBS modeling does not include capacity held and subsequently released in real-time via flexible ramping product (for the WEIM) or a similar reserve in the WEIS market.

Currently most WECC BAAs self-provide ancillary services. There are a few sales here and there, especially as it relates to some entities which do not have the ability to really provide these services reliably on their own (e.g., Avangrid, NaturEner), but there are not large volumes of transactions. As part of this study,

[20] NERC, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/EPA_Scenario_Final_v2.pdf

ancillary service requirements were set for each BAA in the BAU case and then at the subregional level within the market scenarios with ancillary service markets. For most of the market scenarios, the Spinning, Non-Spinning and Regulating reserve requirements were maintained at the individual BAA level with values that were the same as in the BAU Case. In the 2030 and 2035 M2M+CBA scenarios however, these reserve requirements were pooled within each market on a sub-regional basis. The same quantity of total reserves in these categories, however, is maintained, such that the CBA market cases' total reserves for each sub-region are equal to sum of the individual BAA level requirements from the BAU case for the zones in that sub-region. By contrast, Imbalance Up reserve requirements were calculated at the BAA level for the BAU case and at the subregional level in all market cases. E3 used its RESERVE tool, described in the next section of appendix, to calculate hourly requirements for Imbalance Up reserves.

Imbalance reserves are held to prepare for forecast errors between day-ahead and real-time market timeframes. Because the timeframe of required response is relatively long for imbalance reserves, thermal resources that can start quickly are able to provide the required response, even when offline. As a result, combustion turbines and reciprocating engines were modeled as contributing to Imbalance Up reserves when offline. These resources were also modeled as contributing to Imbalance Up reserves when online. Longer-start thermal resources such as gas and coal steam turbines and gas combined cycles are modeled as only contributing to Imbalance Up reserves when online because these resources may not be able to start up in time to correct for forecast errors between day-ahead and real-time markets.

We ensured that system operators would be prepared for contingency events by requiring contingency reserve headroom to be held in both the Day-Ahead and Real-Time stages. However, the model did not change the schedule of generator outages between the Day-Ahead and Real-Time, and as a result we did not model contingency reserve deployment in Real-Time.

Dispatchable hydro, thermal, and storage resources were modeled as able to contribute to all reserve products. The contribution of these resources to each reserve was limited via their ramp rates (**Error! Reference source not found.**). To address state of charge concerns, storage resources were required to keep an adequate amount of energy in storage to be able to provide the required service for one hour continuously. For upward reserves, this means that providing reserves requires energy to be stored in the battery; for downward reserves this requires the battery to have a state of charge that is less than full.

We do not model wind and solar resources as contributing to reserves in the CBS, though the exclusion of Imbalance Down reserves from the modeling is in part because renewable resources could supply downward imbalance reserve capacity by turning down (curtailing) output in real-time. Storage, online thermal, and dispatchable hydro resources are also expected to provide ample Imbalance Down capacity, thereby minimizing the impact that including this reserve would have on modeling results.

As is standard in production cost modeling, the CBS model's co-optimization of energy and reserves results in resources providing reserves at their opportunity cost; no additional cost or bid to provide reserves was added above a resource's opportunity cost when determining reserve commitments.

Table A-6 Reserve products modeled in the CBS

	Imbalance Up	Spinning	Non-Spinning	Regulation Up	Regulation Down
Purpose	Prepare for forecast errors between day-ahead and real-time market timeframes	Quickly replace capacity lost from a contingency event	Replace spinning reserve capacity	BAA ACE management outside of market signals	BAA ACE management outside of market signals
Direction	Headroom	Headroom	Headroom	Headroom	Footroom
How is the requirement calculated?	97.5% percentile of day ahead forecast error, as calculated by E3's RESERVE model	3% of load	3% of load	1% of load	1% of load
Held in Day-Ahead Stage?	Yes	Yes	Yes	Yes	Yes
Held in Real-Time Stage?	No (capacity released for dispatch)	Yes	Yes	Yes	Yes
Offline quick-start thermal capacity can contribute?	Yes	No	Yes	No	No
Timeframe (limits online resource contribution via ramp rates)	10 minutes	15 minutes	30 minutes	10 minutes	10 minutes

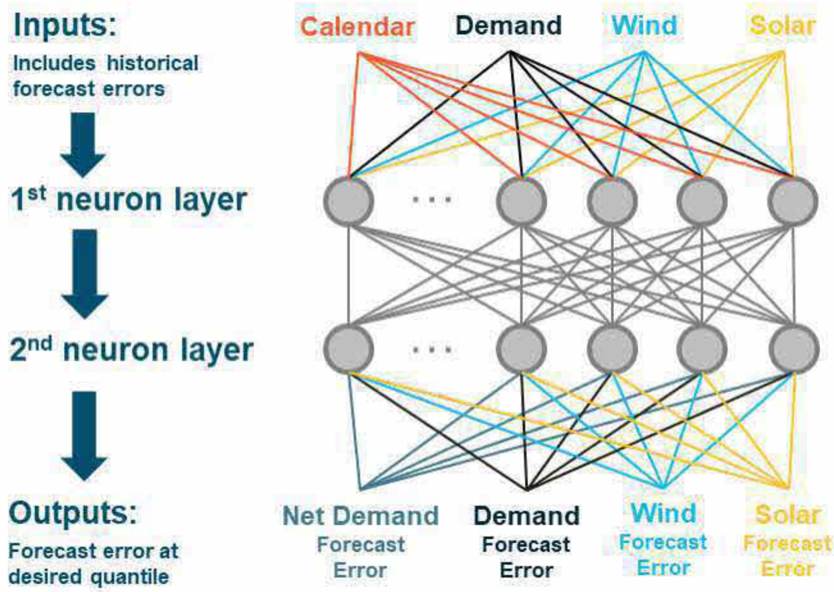
A.6. E3 RESERVE Tool Description

We use the RESERVE model[21] to quantify the likelihood of extreme forecast error events. Extreme forecast error events are inherently infrequent and can therefore be challenging to quantify in a statistically rigorous manner. Furthermore, forecast errors can be driven not only by weather conditions themselves, but also by non-linearities in the response of load, wind output, and solar output to changes in weather conditions. As an example, the relationship between cloudiness and solar output is non-linear. With no clouds or fully overcast sky, the variability of solar output stays minimal as the solar output stays minimal, whereas in partly overcast weather we see the highest amount of uncertainty.

[21] See Sun, Yuchi, James H. Nelson, John C. Stevens, Adrian H. Au, Vignesh Venugopal, Charles Gulian, Saamrat Kasina, Patrick O'Neill, Mengyao Yuan, and Arne Olson. "Machine learning derived dynamic operating reserve requirements in high-renewable power systems." Journal of Renewable and Sustainable Energy 14, no. 3 (2022): 036303. https://doi.org/10.1063/5.0087144

The RESERVE model employs the multi-layer perceptron method (MLP), commonly known as artificial neural network (ANN). ANNs can model highly non-linear relationships between inputs and outputs by choosing a non-linear activation for each neuron and allowing the neurons to interact and superimpose their non-linearity. RESERVE employs a pinball loss function.

Figure A-4 Illustrative diagram of the RESERVE neural network



One of the primary data sources that RESERVE uses to make forecast error predictions is renewable and load forecast and actual (real-time) data. RESERVE combines this forecast error data with calendar data such as the earth's revolution and rotation angle, as well as the solar azimuth and elevation angle. The calendar data allows the model to capture dynamics that depend on the hour of day, time of year, or position of the sun in the sky. RESERVE's neural network uses the input data to make forecast error predictions that are individually tailored to each hour of the year.

RESERVE can simultaneously produce multiple probabilistic outputs, including predictions of net load forecast error as well as the forecast error of individual net load components (load, wind, and solar). In this study we focused on net load forecast error as it directly sets the imbalance reserve requirements. The individual net load component forecast errors were used in the quality control process.

The RESERVE model can characterize reserve requirements for any user-defined percentile of forecast error. Following the EDAM Final Proposal,[22] in this study RESERVE was used to calculate an Imbalance Up reserve requirement that is set at the 97.5% percentile of net load forecast error in each hour. Put another way, the day ahead net load forecast plus the imbalance reserve requirement will be higher than the realized real-time net load in all but 2.5% of hours.

[22] http://www.caiso.com/InitiativeDocuments/FinalProposal-Day-AheadMarketEnhancements.pdf, p.28-29

A.7. Non-WMEG Entity Modeling

There are 14 Balancing Areas in the WECC which are not participants of WMEG. Error! Reference source not found. contains the modeling assumptions for these entities.

Figure A-5 Non-WMEG Modeling Assumptions

BAA	Description	Type	Approach
CISO	California ISO	CAISO	EDAM Transactions as CAISO
AESO	Alberta	Non-US	Assumed to be independently optimized relative to their own unique organized market. Modeled as a price stream within the WMEG model
BCHA	BC Hydro	Non-US	Described in detail below
CFE	Mexico	Non-US	Bilateral Only
SPP	SPP Marketplace	Non-WECC	Assumed to be independently optimized relative to their own unique organized market. Modeled as a price stream within the WMEG model
DEAA	Arlington Valley	IPP	Bilateral or as Contracted to WMEG; Assumed it a market in market scenarios
GRIF	Griffith	IPP	Bilateral or as Contracted to WMEG; Assumed it a market in market scenarios
GWA	NaturEner Glacier	IPP	Bilateral or as Contracted to WMEG; Assumed it a market in market scenarios
HGMA	Harquahala	IPP	Bilateral or as Contracted to WMEG; Assumed in a market in market scenarios
WWA	NaturEner Wind Watch	IPP	Bilateral or as Contracted to WMEG; Assumed it a market in market scenarios
DOPD	Douglas PUD	Muni	Bilateral or as Contracted to WMEG; Assumed it a market in market scenarios
IID	Imperial Irrigation District	Muni	Bilateral or as Contracted to WMEG; Assumed it a market in market scenarios
TID	Turlock Irrigation District	Muni	Bilateral or as Contracted to WMEG; Assumed it a market in market scenarios; WEIM in BAU
GRID	Grid Force	Multiple Clients	Bilateral or as Contracted to WMEG; Assumed it a market in market scenarios

BC Hydro was modeled uniquely with guidance from Powerex. The BC Hydro system was aggregated as a pumped-storage unit. The unit was given maximum and minimum daily energy budgets which were shaped to the WECC net load profile from the CBS study. As Powerex has committed itself to Markets+ the units flexibility was dependent on the footprint and the neighboring entities. In a single EDAM market case, Powerex is only allowed to trade in blocks and will withhold some of its generation from the market for other internal system usages. If other WECC entities are part of Markets+, BC Hydro will make its total capacity fully available and fully flexible for Markets+ interaction. The BC Hydro system can import and export to the rest of the West via its transmission into the Northwest and elsewhere.

A.8. Fuel, and Electric Market Price Modeling

Fuel Price Forecast

Fuel prices use forecasts are based on data from the CEC 2021 Integrated Energy Policy Report (IEPR) and the Energy Information Agency's (EIA) 2022 Annual Energy Outlook (AEO). The CEC IEPR forecasts originate from the North American Market Gas-trade (NAMGas) Model which considers some degree of natural gas pipeline capacity via a nodal model. All fuel prices, except natural gas, are constant over the year. Natural gas prices are developed on a monthly granularity. For 2026 and 2035, the data directly uses the forecast for Western hub locations from the CEC IEPR. That CEC forecast is based on projected Henry Hub prices of $2.98/MMBtu on average for 2026 and $3.26/MMBtu for 2030 (in 2022$). For 2035, the IEPR does not have a gas projection so the monthly CEC basis differentials from 2030 are added to the EIA AEO data for Henry Hub in 2035 ($3.74/MMBtu).

Gas prices do not vary between DA and RT stages as this may cause results to be skewed if different members provide individual views on gas price deviations at hubs or generators across WECC. The table below shows the resulting annual average of gas prices at selected Western Hub locations. Each price shown varies monthly.

Table A-7 Annual Average Gas Price for Selected Western Locations ($/MMBtu)

Study Year	SoCal Citigate	Sumas (Northwest)	Waha (West Texas)
2026	$4.68	$3.17	$2.72
2030	$5.12	$3.48	$3.06
2035	$5.60	$3.96	$3.55

Electric Market Price Forecasts (External regions)

E3 develops in-house price forecasts for locations across North America including the West, Canada, and SPP. For the CBS, E3 developed market prices for Alberta and SPP where WECC entities could interact with the separate organized markets. Within this model, SPP is represented via two different price streams - SPP North and SPP South - that vary between 2026, 2030, and 2035. Alberta is represented as a single price stream that connects to the model's Montana-Alberta Tie Line (MATL) zone. Hourly historical prices for SPP and AESO were selected in a year weather synchronized with WECC load and renewable data; E3 then scaled these prices to be consistent with gas price increases that E3 used for the projected study year of 2026, 2030 and 2035.

Market participants provided OATT based wheeling charge to be applied for imports and exports with Alberta (including MATL charges) and the Eastern Interconnection DC ties which.

A.9. Hydro Modeling

Several WMEG members have hydro fleets with sufficient storage to meaningfully shift generation between hours of the day, days of the week or, sometimes, on a seasonal basis. This ability to shift generation impacts the opportunity cost which will drive the Resource offer in the Day-Ahead and Real-Time Markets. These Resources also often have reservoir restrictions which do not match the generator characteristics (e.g., minimum elevation, maximum elevation, minimum flow, maximum draft).

Hydro resources are modeling two distinct ways within the production cost model:

1. Fixed Dispatch
2. Dispatchable

As a default assumption, the CBS uses 2018 hydro year, because it is representative for typical or average hydro conditions for many Western locations, and because it aligns with the wind and solar shapes used for the study; in particular cases, however, WMEG members provided alternative values if they believed that another year for their system was more representative of typical conditions than 2018.

Fixed Dispatch: resources were model with a fixed 8760 profile that was either provided by a WMEG member based on their hydro year or the original. These units were held at their fixed output with a $0/MWh generation cost.

Dispatchable: for these resources, WMEG members shaped their hydro based on their chosen hydro year into daily hydro budgets reflective of any inherent flow restrictions or minimum flow requirements. PLEXOS optimized the hydro dispatch over each day and does not consider longer hydro budget usage. For this, members provided daily energy budgets that were shaped based on a weekend/weekday schedule. The energy budgets were considered hard constraints by the model which meant that the entirety of the budget was to be utilized by the model over the day and PLEXOS would shift hydro generation around within the day to minimize system-wide production cost. Hydro dispatch was also restricted to member-defined hourly (8760) maximum MW output and Minimum MW output profiles. This enabled members to represent minimum flow requirements or any other unique flow requirements for individual hydro units. Much like the fixed dispatch hydro, dispatchable hydro units were dispatched without a marginal cost (at $0/MWh); the value of the energy and flexibility of dispatchable hydro is determined by the opportunity cost of the production simulation. Dispatchable units were able to contribute to all ancillary services, subject to the limits defined above.

Pumped storage represents an additional resource type that was modelled somewhat differently than hydro resources. Pumped storage units were modeled using head and tail reservoir volumes and pumping efficiencies from the WECC ADS. This was altered if members provided different data. Like other hydro units there was no offer cost. The marginal cost of these units ranged from $0 to $3/MWh to reflect variable O&M on certain units, in addition to pumping efficiency losses. Pumped storage units were modeled as able to provide reserves. WMEG members selectively updated pumped storage generator properties including pmax, pmin, max pump load, and pumping efficiency for certain units.

As part of the CBS, pumped storage and dispatchable hydro units were scheduled in the Day-Ahead market and were able to be re-optimized again in the Real-Time market. This may provide some additional flexibility in the model that may not be reflective of reality. Fixed profile resource outputs remained the same in Day-Ahead and Real-Time. Furthermore, hydro units within the production cost model were only allowed to bid their marginal cost, which is assumed to be $0/MWh. There were no offer prices included in any resources as this would indicate some sort of trading strategy among participants in the West. The purpose of this modeling was to estimate costs and benefits in a market where there are not additional bidding strategies other than bidding at cost. Market power mitigation assumptions are also discussed later.

A.10. Green House Gas Modeling

E3 worked with the Green House Gas Task Force to develop the modeling assumptions for GHG in the CBS. Based on discussion within the task force, a Clean Energy Policy matrix was developed that identifies state and corporate clean energy targets, the model created three GHG areas to effectively represent the overlap of these different policies as part of one regionwide production cost model. The GHG areas are California, Washington, and Colorado.

The GHG market feature has been developed in detail for EDAM, however Markets+ had not established a GHG methodology at the time of developing assumptions for the CBS. GHG prices were based on the California Energy Commission (CEC) 2021 IEPR mid forecast. In this analysis there was no distinction between specified and unspecified imports. All imports into GHG areas were subject to the same hurdle rate that is defined by a GHG price, which was set based on the default rate used for unspecified imports into California. These values are summarized in **Error! Reference source not found.**.

Table A-8 Carbon Price GHG Hurdle Rate for Imports to CA, WA, and CO

Study Year	Carbon Price ($/metric tonne)	Unspecified Rate on Imports (tonnes/MWh)	Implied GHG Hurdle Price ($/MWh)
2026	$39.33	0.437	$17.19
2030	$62.05	0.437	$27.12
2035	$109.74	0.437	$47.96

EDAM Approach

The CBS uses the following steps to represent EDAM's GHG approach in the model:

- Establish a GHG Baseline dispatch which would exist for each BAA. This is done with no transfers and all GHG bids being set to zero be not allowing any imports into GHG areas in the GHG Baseline run.
- Using E3's settlement script, generators are rewarded GHG revenue based on GHG price less compliance cost of each resource. GHG revenue allocation is described in more detail in Appendix C to this report.
- Each external resource "bids" a GHG price and MW based on compliance cost and emissions rate which is calculated on an annual basis from the Day-Ahead run (Total Emissions/Total Generation)
- Calculate the cost-based Bid for each Resource and eligible MW per Resource as the DA Award – Reference Run Award
- Calculate the BAA eligible GHG award per hour based on net exports in that hour.
- Calculate the Resource stack per BAA capped by the BAA net exports.
- Create the market resource stack based on each BAA's capped Resource stack.
- Determine the cleared resources up to the CA and WA imports.
- Calculate the potential margin per cleared Resource.
- Allocate the GHG revenue based on each unit's bid cost.

- A similar process is done for Real-Time except using the Day-Ahead Award as the baseline and the Real-Time dispatch would be incremental or decremental to that.

Markets+ Approach

For the purposes of the CBS, Markets+ uses a zonal approach for GHG with the following key steps:

- Each Resource has a GHG cost. There are three general types of resources. In-Zone, External-Specified and External-Unspecified. The Unspecified resources are assigned a proxy GHG cost.
- The market minimizes the combined cost of Energy and GHG.
- When there are imports to the GHG Zone, there is a shadow price for the marginal cost of GHG. The LMP reflects only the Energy Cost (and congestion and loss).
- Resources within the GHG zone have a compliance obligation. They receive GHG revenues in settlements. Like the EDAM approach, if the GHG shadow price is above their compliance cost, they will receive net payments.
- Specified External Resources have a compliance obligation. They receive GHG revenues in settlements. Like the EDAM approach, if the GHG shadow price is above their compliance cost, they will receive net payments.
- Unspecified External Resources do not have a compliance cost. The market operator collects that money and returns it to the state of the compliance region for further allocation, but this process has yet to be defined at the time of this study.

As part of the CBS, it is assumed that all external resources are unspecified and do not have a compliance cost and the money associated with imports into GHG areas is collected by the Markets+ operator and returned to the compliance entity, in this case the GHG area. The lump sum is provided to participants in a Markets+ in the CBS and at that point it is up to the GHG area to decide how that will be allocated among participants.

Additional Washington State Detail

For the purposes of the CBS, the California and Washington GHG market is considered linked for all cases. As a result, the study applies a GHG price at the generator level for each state but did not charge a separate GHG cost for energy that is wheeled between zones in these states.

Washington's Clean Energy Transformation Act's "No-Coal" provision excludes power purchases with a term of one-month or less.[23] The CBS has an hourly or daily transaction profile so there is no need to explicitly address this clause.

[23] See RCW 19.405.030.

A.11. Transmission Availability

E3 utilizes a hybrid nodal and zonal model that typically represents BAAs as individual zones. The model divides certain BAAs into more than one zone when needed to reflect impactful internal transmission constraints for WMEG members, or to represent cases where multiple different WMEG members operate as separate sub-BAAs or are otherwise important to distinguish in market operations. Some of these sub-zones are already reflected in the areas defined in the WECC Anchor Data set, and the CBS models a few additional sub-divisions. The CBS model typically does not charge wheeling or hurdle rates in the BAU case on transactions within each BAAs when a single entity responsible for most of the load and owning of the generation in both of the BAAs. With this approach, the CBS accurately represents the WECC system without utilizing a larger nodal model, which would have required significantly longer run time for each case, as well as additional decisions on the placement of new generators whose intended nodal points of injection have not yet been decided.

In addition to the tie-zones previously discussed, the BAAs that are modeled as more than one zone in the study include:

- California ISO, which the model divides into PG&E Bay Area (represented as CIPB in the model), PG&E Central Valley Area (CIPV), Southern California Edison (CISC) and San Diego Gas & Electric (CISC) to reflect internal transmission constraints.
- NV Energy, which the model divides into separate Northern (NVEN) and Southern (NVES) zones to reflect internal transmission constraints.
- PNM, which model divides into separate PNM North (PNM-N) and PNM South including Tri-State South (PNM-S + TSGT-S) and Tri-State Northern New Mexico (TSGT-NM) zones to reflect internal transmission constraints as well as distinct Tri-state operations.
- BPA, which the model divides into Washington (BPAT WA) and Non-Washington (BPAT Non-WA) zones to enable the Washington area to be represented with GHG pricing applied.
- NorthWestern Energy, which the model divides into the NorthWestern – Great Falls Area (NWMT-GF) and all other NorthWestern territory (NWMT) to reflect internal transmission constraints. The NWMT GF zone connects directly to the MATL line for transactions with Alberta.
- The PSCO BAA, which the model divides into separate PSCO-West (PSCO-W), PSCO-East (PSCO-E) and Black Hills Energy of Colorado (BHE) zones to reflect transmission path constraints, and distinct entity operations.
- The WAPA - Lower Colorado Region, for which the model represents distinct operations for the AEPCO sub-BAA and leaves the remainder of loads and resources WALC sub-zone.
- The WAPA – Colorado-Missouri Region (WACM), which the model divides into 12 separate zones to reflect transmission path constraints, distinct entity operations, and GHG regulations applicable in Colorado. These 12 zones are CRCM-North (CRCM-N), CRCM-South (CRCM-S), Loveland Area Project (LAPT), Loveland Area Project – Wyoming (LAPT-WY), Platte River Power Authority – West (PRPA-W), Platte River Power Authority – East (PRPA-W), Tri-State G&T – West (TSGT-W), Tri-State G&T – East (TSGT-E), Tri-State G&T – Wyoming (TSGT-WY), Black Hills Energy in Wyoming & South Dakota (BHE-WY/SD), Basin Electric (Basin), and Flaming Gorge (FG).
- The WAPA Sierra Nevada Region (SNR) is a member of the BANC BAA. However, for the CBS WAPA SNR requested to be studied independently from BANC for certain scenarios. BANC members other than SNR are modeled in EDAM for all scenarios. WAPA SNR, by contrast is modeled in Markets+ region the Markets+ Bookend Case (and EDAM for the EDAM Bookend

and Main Split Case). To implement this distinction, WAPA SNR is broken out of the BANC zone and assigned its own load and transmission connections to CAISO, SMUD, and the Northwest.

- Finally, for a number of entities, sub-zones were created to represent, remote generation located at a tie zone that is owned or contracted to a receiving entity who typically takes that output (e.g. over a dynamic schedule or pseudo-tie) and does not typically face incremental transmission charges or transactional friction for bringing the output of the generation into their area, but may face limits to the transmission capability that can constrain the sum of energy brought to load from energy produced by the generator and energy purchased at the tie zone.

Transmission availability was reflected within the model as total transmission capacity (TTC) between BAs and across any relevant WECC paths.

E3, Utilicast, and WMEG developed an added layer of transmission availability to the model which created the ability to define multi-party transfer limits. This concept was labeled by the group as "Seams" or "Tie-Zones" and is depicted in **Error! Reference source not found.**. Limits in and out of these l ocations are defined for multiple parties and enable multiple transactions to and from multiple entities across one path. Having Tie-Zone representations also allows for more accurate settlement calculations, particularly for wheeling and congestion, as all transactions can be tracked by individual entities. This concept was mainly for the Southwest and to some degree, the Northwest. For other regions, the Tie-Zone was used to represent entity-specific breakouts of WECC paths to again, keep track of individual wheeling and congestion.

Figure A-6 Tie-Zone Representation in Southwest

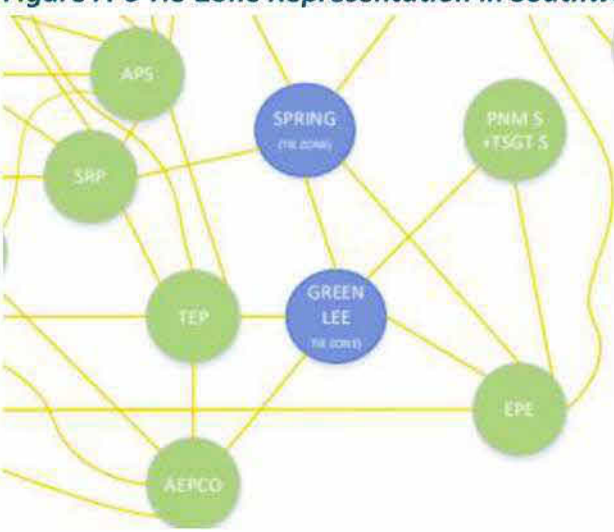
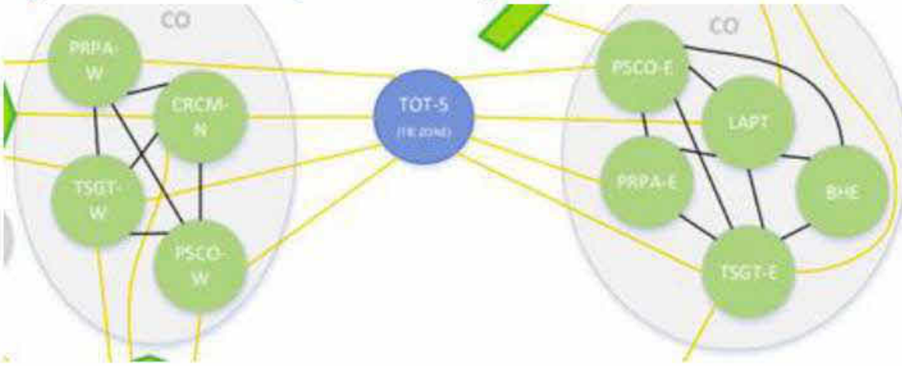


Figure A-7 Tie-Zone representation of WECC Path in Colorado



E3 incorporated an additional layer of transmission availability that included special transmission rights and special transfer obligations for WMEG members.

In the BAU case, 100% of transmission is made available for bilateral transactions within the Day-Ahead market. The Real-Time market also enables use of the full TTC which might be seen as being more flexible than reality.

To test the impact of this assumption, E3 modeled a separate BAU sensitivity case that assumed more limited efficiency in RT markets, to explore the uncertainty around how efficient and flexible RT markets (alone) could become by 2026. This sensitivity case constrained RT flows over each line between zones to the day ahead scheduled flow +/- 15% of the line's total transfer capability. For example, if a 1000 MW line had 500 MW scheduled to flow in the DA stage for a given hour, the RT stage flows were constrained to range between 350 MW and 650 MW for that hour. This case resulted in regionwide annual production costs that were $70 million higher than the BAU case for this study. If this BAU sensitivity were instead used as a point of comparison to the DA Market Cases, the resulting impact of forming a DA market would improve by $70 million for each of these cases, resulting in regionwide savings in the EDAM Bookend growing to $130 million, and the regionwide net cost increase in the Main Split case instead changing to $151 million.

According to the two different markets, there are slight differences in how they consider transmission. Though Markets+ claims to use a different transmission capacity within its market, in discussion with the WMEG it seemed like this market feature was not fully established and raised more questions than answers namely: how would each entity estimate their transmission capacity if all transactions today are done based on path ratings? Based on this, the transmission availability was not altered between an EDAM and Markets+ market. Within the CBS model each market used the available TTC between different zones.

A.12. Load Participation

The model cleared 100% of forecasted demand in the Day-Ahead run, which included day-ahead forecast error of load, wind and solar for each zone. The Real-Time run represented load and renewable "actual values", which differ from the Day-Ahead forecast values based on a simulated forecast error between the day-ahead and real-time timeframes. E3 did not model virtual bidding or other bidding behavior that would reflect less than 100% of forecasted Day-Ahead being cleared. E3 adopted this assumption for three main reasons:

Clearing less than 100% of forecasted load in the Day-Ahead regionwide model would have resulted in resource shortages in real-time dispatch because the day-ahead timeframe will be the last commitment timeframe for longer-start units. Without an adequate amount of capacity committed from longer start units, the headroom available on committed units and the fast start capacity available in real time would have likely been insufficient to meet load on certain days, especially days with very high loads or with large forecast error events. In actual practice, the residual unit commitment process can typically provide access to enough capacity to operate reliably on these days, however it is likely that both economic and reliability concerns would result in most demand being cleared day-ahead instead.

To give the CBS model the opportunity to clear less than 100% of forecasted demand, additional data would have been required to develop pricing for the opportunity to clear different levels of demand in the day-ahead timeframe. This pricing information would have required modeling tradeoffs not ideal for this study and would have been speculative to determine for the future study years.

This CBS sought to reflect the benefits for participants assuming no other bidding strategies were utilized other than bidding at cost, to minimize system cost while reliability serving hourly load. Holding a portion of generation back from the DA stage could have artificially depressed Day-Ahead prices and increased real-time prices, thereby potentially skewing benefits.

A.13. Market Power Mitigation

Market power mitigation was addressed in discussion with the WMEG; however, the model does not address MPM as the model inherently assumes all generators are bidding in a competitive manner. A central aspect of this modeling effort is to provide an estimate of benefits among all participating WMEG members in a market where participants are all acting within power market rules to minimize cost. Introducing uncompetitive bids into the analysis may skew results.

Exploration of non-cost-based bidding strategies in a future WECC power system with higher levels of renewables and storage is not feasible within the proposed timeline of the CBS.

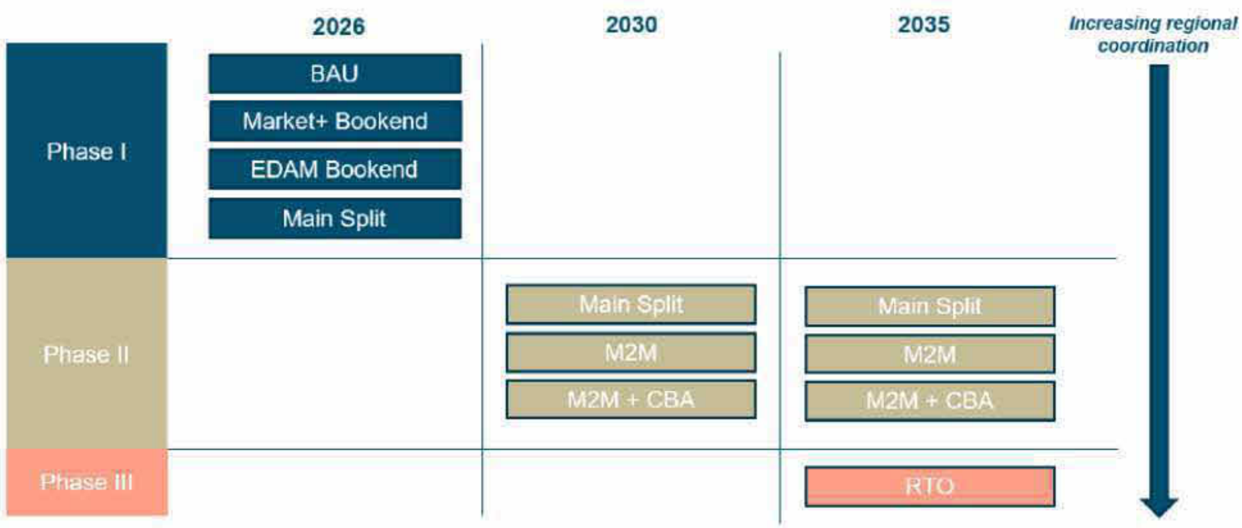
A.14. Resource Sufficiency Tests

Based on discussion with the broader WMEG members and Utilicast, E3 established that creating an additional resource sufficiency test as part of this study would require significant time to implement. Therefore, the resource sufficiency test was not conducted as part of the study, and it is assumed that all entities that participate in EDAM or Markets+ are resource sufficient in each interval of the production cost simulation as is often the case for the current WEIM.

Appendix B. Scenario Design

The scenarios within this study help address key questions surrounding the EDAM and Markets+ markets and how the different characteristics and footprints change production cost benefits. The core study has three phases of scenarios that build on one another from a BAU case to an RTO case by adding increasing regional coordination across case scenarios to provide insight to benefits of moving from a separate Day-Ahead and Real-Time market to a fully integrated RTO. Figure B-1 shows the various scenarios included in the core study and the subsequent sections of the report describe the scenarios in more detail.

Figure B-1 Study Scenario Summary



B.1. Phase I

Phase I looks at the 2026 timeframe and measures the effects of a Day-Ahead market relative to BAU.

2026 Business-as-Usual (BAU)

The BAU case sets a baseline to compare the subsequent 2026 market cases analyzed in the CBS. In the BAU case, there is no active Day-Ahead market outside of CAISO. Instead, there are scheduled bilateral transactions between zones and are subject to member long-term point-to-point OATT rate assumptions.

In the Real Time stage, the WEIM and WEIS markets are both active and additional transactions occur within their respective market footprints. WEIM and WEIS transactions are not subject to OATT rates.

Table B-1 WMEG Member Market Participation in BAU Scenario

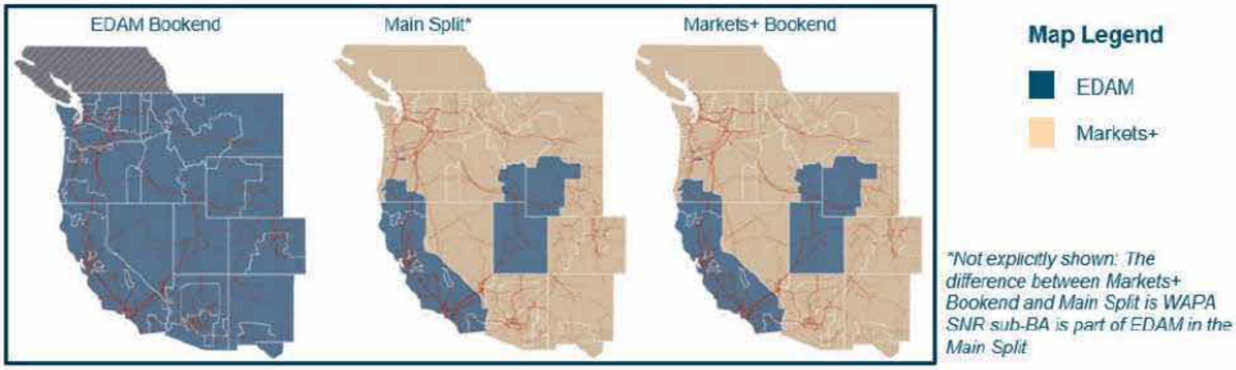
WMEG Member	Day-Ahead Market	WEIM	WEIS
AEPCO	✗	✓	✗

APS	✗	✓	✗
Avista	✗	✓	✗
BANC	✗	✓	✗
Black Hills	✗	✗	✓
BPA	✗	✓	✗
CHPD	✗	✗	✗
EPE	✗	✓	✗
GCPD	✗	✗	✗
IDP	✗	✓	✗
LADWP	✗	✓	✗
NWMT	✗	✓	✗
NVE	✗	✓	✗
PAC	✗	✓	✗
PGE	✗	✓	✗
PNM	✗	✓	✗
PRPA	✗	✗	✓
PSCo	✗	✗	✓
PSE	✗	✓	✗
SCL	✗	✓	✗
SRP	✗	✓	✗
Tacoma	✗	✓	✗
TEP	✗	✓	✗
TSGT	✗	✗	✓
WACM	✗	✗	✓
WALC	✗	✓	✗
WAUW	✗	✗	✓
WAPA SNR	✗	✓	✗

2026 Market Cases

Three different market footprints were analyzed as part of Phase I of the core CBS study: an EDAM Bookend, a Markets+ Bookend, and a Main Split. These are shown geographically in Figure B-2 2026 Market Scenario Footprints Within the different footprints, each WMEG member is considered part of either EDAM or Markets+ and is assumed to also be part of the corresponding Real-Time WEIM or WEIS market respectively.

Figure B-2 2026 Market Scenario Footprints



Since some WECC entities have already announced their intentions of joining either EDAM or Markets+, these were not changed across any footprints. There was also an additional assumption that all California Entities will remain in the EDAM across all cases except for WAPA Sierra Nevada Region (WAPA SNR), a BANC sub-BA.

Table B-2 Static WECC Market Participation Assumptions

	EDAM	Markets+
WECC Members	CAISO, BANC, TIDC, IID, LADWP, PAC	BC Hydro/Powerex

The rest of the WMEG members, including WAPA SNR, were put in EDAM in the EDAM Bookend, Markets+ in the Markets+ Bookend, and agreed on where to be placed in the Main Split scenario.

Table B-3 WMEG Member Market Assumptions for 2026 Market Scenarios

	EDAM Bookend		Markets+ Bookend		Main Split	
WMEG Member	**EDAM**	**Markets+**	**EDAM**	**Markets+**	**EDAM**	**Markets+**
AEPCO	✓	✗	✗	✓	✗	✓
APS	✓	✗	✗	✓	✗	✓
Avista	✓	✗	✗	✓	✗	✓
BANC	✓	✗	✓	✗	✓	✗
Black Hills	✓	✗	✗	✓	✗	✓
BPA	✓	✗	✗	✓	✗	✓
CHPD	✓	✗	✗	✓	✗	✓
EPE	✓	✗	✗	✓	✗	✓
GCPD	✓	✗	✗	✓	✗	✓
IDP	✓	✗	✗	✓	✗	✓
LADWP	✓	✗	✓	✗	✓	✗
NWMT	✓	✗	✗	✓	✗	✓
NVE	✓	✗	✗	✓	✗	✓
PAC	✓	✗	✓	✗	✓	✗
PGE	✓	✗	✗	✓	✗	✓

PNM	✓	✗	✗	✓	✗	✓
PRPA	✓	✗	✗	✓	✗	✓
PSCo	✓	✗	✗	✓	✗	✓
PSE	✓	✗	✗	✓	✗	✓
SCL	✓	✗	✗	✓	✗	✓
SRP	✓	✗	✗	✓	✗	✓
Tacoma	✓	✗	✗	✓	✗	✓
TEP	✓	✗	✗	✓	✗	✓
TSGT	✓	✗	✗	✓	✗	✓
WACM	✓	✗	✗	✓	✗	✓
WALC	✓	✗	✗	✓	✗	✓
WAUW	✓	✗	✗	✓	✗	✓
WAPA SNR	✓	✗	✗	✓	✓	✗

As part of the market scenario set up, Imbalance reserve requirements were calculated for WECC subregions. Aggregate reserve requirements across subregions in WECC create a noticeable diversity benefit relative to a BAU framework. For the Main Split Case, diversity-related reduction in imbalance reserve requirements range from 16% in the Rockies subregion to 43% in the Southwest sub-region with California and the Northwest in between these two values.

Table B-4: Subregional Imbalance Reserve* Diversity Benefit

Subregion**	California	Northwest	Northwest	Rockies	Southwest
Market	EDAM	EDAM	Markets+	Markets+	Markets+
Mean Reserve Requirement* (MW)	2,472	634	759	414	1,180
Sum of Mean Individual Entity BAU Reserves in Subregion (MW)	3,562	770	1,161	493	2,062
Diversity Benefit Reduction	31%	18%	35%	16%	43%

*Hourly Imbalance Reserve Requirements for each subregion in the market cases were calculated as percentile of the day ahead forecast error for load, wind, and solar for that sub-regional grouping of zones and reflects diversity in forecast error among the zones in each group. The mean reserve requirement takes the average of all hourly requirements across the year. More detail on reserve requirement calculations is provided in Appendix A.

**The zones comprising each subregions listed here are listed in Table A-5 of Appendix A.

B.2. Phase II

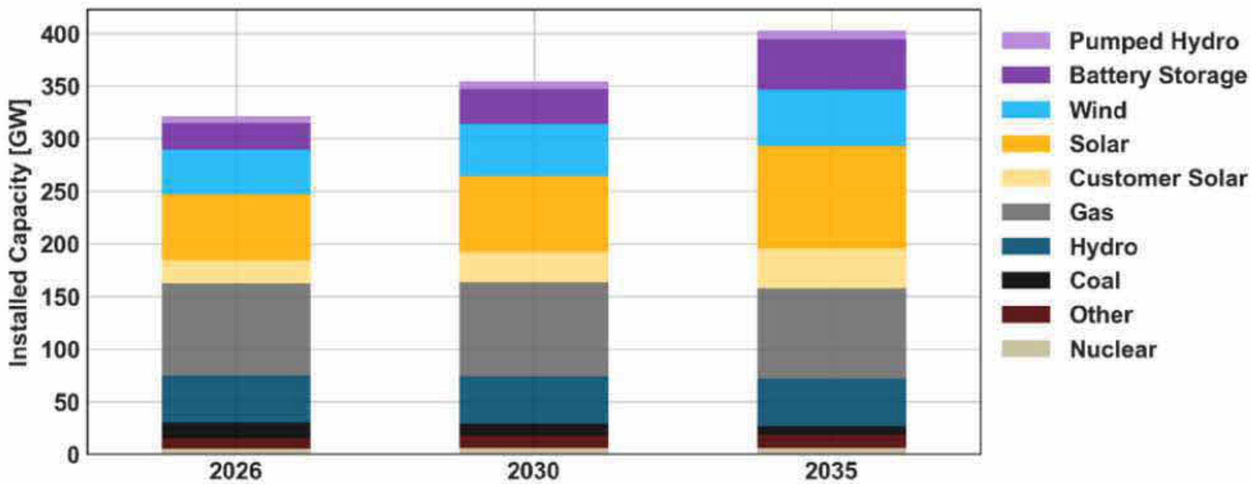
Phase II scenarios for the core CBS study involve analyzing the Main Split case for 2030 and 2035 under increasing intra- and inter-market coordination.

Main Split

The 2030 and 2035 Main Split cases account for increases in generation capacity across WECC according to WMEG member input data as well as some transmission upgrades that were considered important for individual entities. The remaining scenarios in Phase II build off each other starting with the 2030 and

2035 Main Split cases. WMEG members provided input into the resource additions and retirements for the 2030 and 2035 years. Total resource capacity across WECC shows a reduction in coal and gas capacity through 2035 while solar, wind, and storage see noticeable increases across that same timeframe.

Figure B-3 Total U.S. WECC Installed Capacity[24]



Market to Market (M2M) Coordination

The first sensitivity involves increased market-to-market (M2M) coordination. In the future, once EDAM and Markets+ have established themselves as functional Day-Ahead markets in the West, they will continue to mature and refine market rules to enhance liquidity and lower prices. Moreover, even without production cost savings, this kind of coordination could aid reliability if market to market trading opportunities can be an option near real-time. Either EDAM or Markets+ may look to enhance the efficiency of external transactions by developing clear cross-border trading procedures and minimizing the cost associated with this type of scheduling. This type of improved market to market coordination could result in a more liquid and robust trading between markets which may provide more cost-effective than strictly trading internally within either market separately.

Table B-5: 2030 & 2035 Main Split M2M Hurdle Rate Component Breakout

	Non-M2M Coordination Hurdle Rate	M2M Coordination Hurdle Rate
Within Market	$0	$0
Market Seam	Weighted Average OATT Rate of Market	Weighted Average OATT Rate of Market

[24] Total WECC capacity does not include AESO resources as this was implemented as a price stream within the CBS. BC resources and loads (as well as trades with Alberta) were modeled as an integrated pumped hydro facility based on the anticipated quantity of energy to be sent to the US for on an hourly or block schedule basis. This capacity is included with pumped storage in the chart.

	+ **$2 Friction** + **$8 Congestion Risk** for exports from a Zone that is in Market A to a Zone that is in Market B	+ **$2 Friction** + **$4 DA Congestion Risk (or $1 RT Congestion Risk)** for exports from Market A to a Zone that is in Market B

Market to Market & Consolidated Balancing Area (M2M + CBA)

The M2M + CBA case represents a future where not only have markets been able to encourage better inter-market trading, but they have also developed into a more consolidated balancing area. This includes optimal dispatch within the market footprint in addition to ancillary services markets within the footprint. Beyond an imbalance reserve sharing between entities in a Day-Ahead market construct, the consolidated balancing area would expand reserve sharing by including Spinning, Non-Spinning, and Regulation reserve market products. These reserve groupings are aggregated on a sub-regional basis within each market, instead of for the full market footprint, to account for transmission constraints within the West that may prevent reserves from being fully sourced from across the entire market footprint.

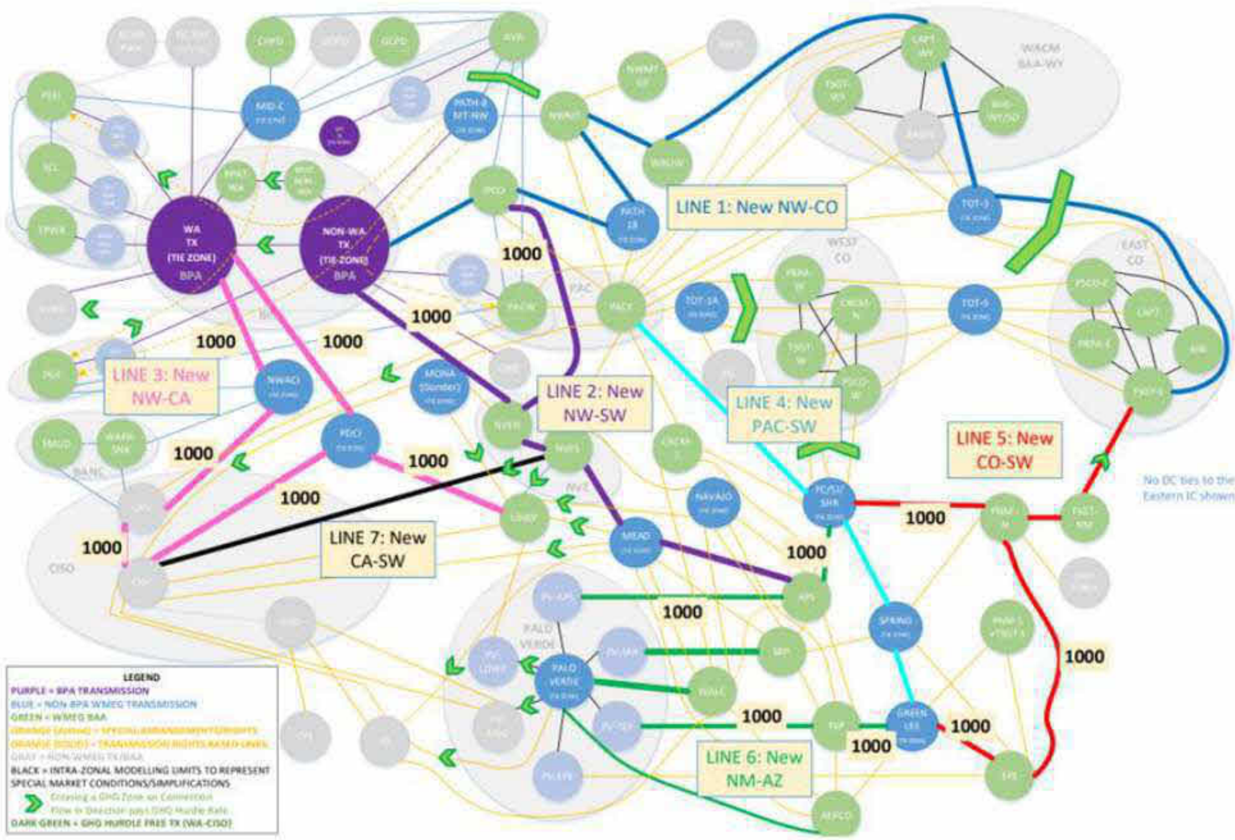
B.3. Phase III

2035 RTO Scenario

The 2035 RTO case uses the M2M + CBA case as the starting point and adds additional transmission capacity along seven major paths within the existing model topology as a representation of increased coordination of transmission development that may be facilitated through an RTO. The WMEG did not analyze individual transmission addition scenarios to determine the net cost or benefit of any individual line, nor were these linked to specific projects under development; rather, the scenario explores the aggregate impact that significant transmission additions could have for enhancing market benefits.

The map below indicates the major transmission upgrades highlighted in thicker bold coloring for the 2035 RTO Scenario, augmenting transmission links already in the existing case. The highlighted links in the figure that are marked with "1000" have added 1000 MW to the transmission capability between the linked zones compared to the transmission in the base model for 2035. The highlighted links without a number shown have added 2000 MW to transmission in the base model.

Figure B-4 RTO Case Transmission Capacity Additions



Appendix C. Settlement

E3 developed a comprehensive and detailed settlement process that takes output data from the various market model runs and generates ex-post settlement details down to the generator level for each WMEG entity over the study year. The components of settlement include the components listed below in this section.

The total **Net Variable Costs** for each entity are based on the sum of each of these components where costs are positive values and revenues are treated as negative (offsetting costs). For each entity, E3 then calculated the Net Variable Cost savings (or increase) from market participation as the difference between the Net Variable Costs for that entity from a market case (e.g., EDAM Bookend) compared to the net costs in the BAU case.

All pricing for the Day-ahead settlement includes Fast Start Pricing for any zones included in the Markets+ footprint. E3's settlement process conducts both a day-ahead market and a real-time market settlement down to the generator unit level across WECC.

C.1. Generation Cost

Generation cost for each member is the sum-product of each generator's production cost and the member's generator ownership share factor. Depending on the generator technology, its production cost could include fuel, VO&M, start/shutdown, and emission cost components (i.e., VO&M is the only relevant component for batteries). Generation costs are only incurred in real-time.

C.2. Generation Revenue

Generation revenue for each member is the sum-product of each generator's net-revenue and the member's generator ownership share factor. The net-revenue for each generator is the product of the nodal price and generation (net of any pump or charging load). DA generation revenue is calculated using DA prices and volumes, and then summed with the RT incremental volume (RT-DA) valued at the RT price. Finally, members that are off-taking hydro power from other members have those obligations (valued at the DA price at a supplying member node) added to their generation revenue (while the supplying member has it subtracted).

C.3. Loads Cost

Load cost for each member is the sum-product of nodal price, native-load,[25] and member load-ownership factor. The member load-ownership factors allocate balancing area load into member service load. DA load cost is calculated using DA prices and volumes, and then summed with RT incremental volume (RT-DA) valued at the RT price. RT native-load can be different from DA native-load due to load forecast error.

[25] Native load is the raw input load and does not include generator pumping/charging load that is accounted for in generation revenue.

C.4. Reserve Cost & Reserve Revenue

Reserve cost only includes the explicit costs for procuring market reserve products; non-market reserve cost can be considered embedded in generator net-revenues as opportunity cost. Reserve cost for each member is the sum-product of reserve price, reserve requirement, region-BAA requirement factors, native-load ratio factor, and member load-ownership factor. In cases that have region reserve markets for ancillaries, the region-BA requirement factors decompose the region-wide reserve requirement to balancing areas (defined by BA reserve requirements from the BAU 2026 case). The native-load ratio factors allocate the BA requirements to model nodes (which each represent BA or sub-BA) based on native-load. Finally, the load-ownership factors allocate cost to members. DA reserve cost is calculated using DA prices and volumes, and then summed with RT incremental volume (RT-DA) valued at the RT price. RT reserve requirement can be different from DA due to load forecast error.

Market reserve revenue for each member is the sum-product of generator reserve provision, reserve price, and generator ownership factor. Like reserve cost, DA and RT components were included.

C.5. GHG Revenue

Generator revenue for each member is the sum-product of generator GHG award, emission intensity factor and GHG price. GHG revenue can be allocated to generators outside of states with GHG programs (CA, WA, CO) when they help serve load in these localities. The hourly GHG demand is determined using the change in net imports over eligible lines[26] relative to a reference phase.[27] Generator supply caps vary for dispatchable vs non-dispatchable resources but are broadly based on differences between changes in generation and headroom between phases. After determination of the GHG demand and generator available supply caps, hourly GHG awards are allocated to generators in emission intensity merit-order. Only generators that are in BA's that are net-exporters are considered candidate resources for awards, and if there is not enough GHG supply to meet demand the remainder is allocated to a shortage resource (not owned by any member). The price that a generator receives for its GHG awards is a fraction of the GHG price proportional to its emission intensity relative to a cut-off emission intensity of 0.437 Tons/MWh. Consequently, zero-emission resources receive the full GHG price at the cut-off emissions intensity.

C.6. Wheeling Revenue

Transmission wheeling revenue is the product of line flow and the hurdle rate (constituted of OATT rate, market hurdle adder and friction adder). Broadly, when a market region is exporting power from a transmission line that crosses a market seam, the wheeling revenue is allocated to all the balancing on a native-load ratio share basis and then to members on a load-ownership share basis. Incremental RT revenue is included. The exact methodology for allocating wheeling revenue to members depends on

[26] GHG eligible lines are transmission connection connecting a non-GHG area to a GHG area. All flow entering the GHG area is subject to the designated GHG price and is represented as an additional hurdle rate.

[27] The reference phase for DA is the GHG phase (which prevented flow over GHG lines); for RT, the DA phase is used as a reference. RT demand for GHG is only considered when incrementally greater net-imports were made into GHG areas in RT than DA.

whether the line connects (1) two different markets (market-to-market), (2) a market region to a non-market region (market-to-nonmarket), or (3) an intra-market or intra-nonmarket line (non-market seam).

Wheeling revenue is distributed among entities in the BAU case based on to the amount of energy exported over transmission lines connected to their zones and their OATT rate or market wheeling rate; in the markets cases, wheeling revenue is determined based on the amount of energy flowing exported over transmission lines connected to each market footprint and then is distributed among market participants based on each participant's percentage share of total load in the market (load-ratio share basis).[28]

C.7. Congestion Revenue

Transmission congestion revenue is only incurred when (1) a line hits its flow limit, (2) the flow is in the direction of the price premium and (3) the premium exceeds any hurdle rate applicable to the line. Like wheeling revenue, the congestion revenue methodology depends on whether the line is (1) a market-to-market line, (2) a market-to-non-market line, or (3) a non-market seam line. Like wheeling revenue, when a market region is exporting power to a zone that is outside the market footprint, any congestion on the market seam is allocated to all members of that market on a load-ratio share basis. However, for other types of lines the BA exporting on the congested line is allocated all the congestion revenue and to members by load-ownership share. When the exporting node is a tie-zone, the BAAs or zones (connected via other lines) that are receiving energy from tie-zone serve the congested region divide the congestion revenue equally. This revenue would subsequently be allocated by each WMEG member to each of its transmission customers via load ratio share. RT congestion revenue is only included when the line is congested in RT and was not DA stage.

[28] Separate proposals for market elements in EDAM and Markets+ that seek to provide some compensation to entities that lose current short-term firm or non-firm point to point revenues were not represented in this analysis due to the definitions of those mechanisms not being fully defined at the time when study assumptions for this analysis were finalized. Revenue from such mechanisms (or charges to derive this revenue) would be additional to any individual benefits represented in this study.

APS Western Markets Exploratory Group
Study Results Summary

Western Market Exploratory Group (WMEG)

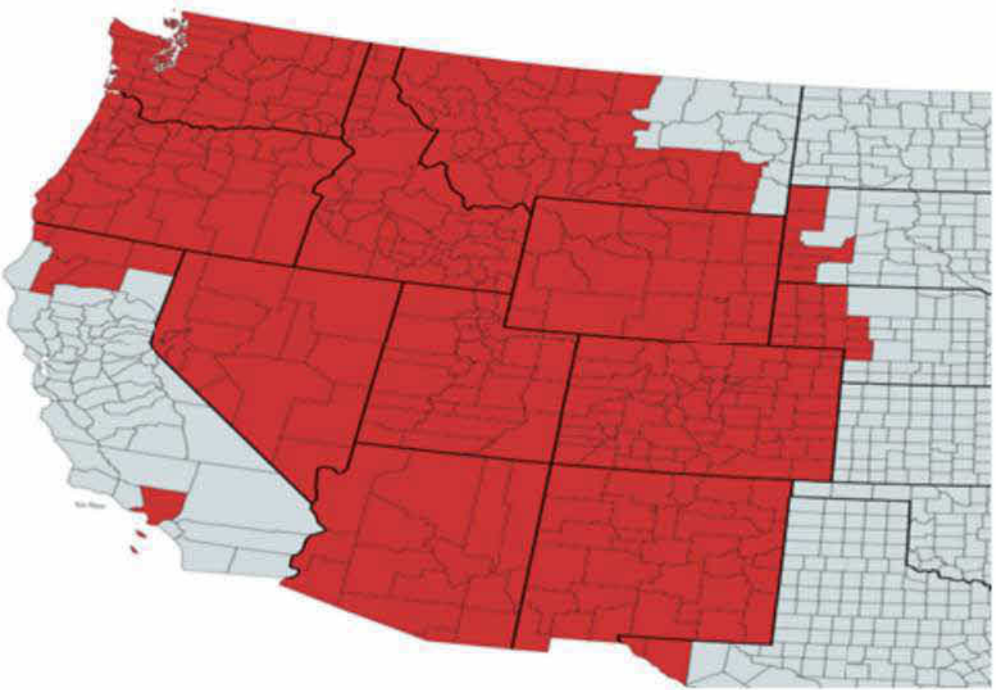
Production Cost Study Results Summary

September 2023

Goals of Market Participation

- Reliability
- Customer Cost Savings
- Clean Energy Integration

WMEG Participation



Note: Map boundaries are approximate and for illustrative purposes only

- APS
- SRP
- TEP
- AEPCO
- PNM
- Black Hills
- LADWP
- Portland
- Seattle
- Platte River
- NV Energy
- PacifiCorp
- Idaho
- Puget Sound
- Xcel
- Avista
- BANC
- BPA
- Chelan
- El Paso
- Grant
- Northwestern
- Tacoma
- Tri-State
- WAPA

Overall Take-Away from Study Results

APS, SRP, and TEP are assessing both the California Independent System Operator (CAISO) and Southwest Power Pool (SPP) market options. This WMEG cost benefit study (CBS) suggests that SPP is a viable and potentially superior option from a cost production standpoint. As a result, we will continue to pursue the build-out of the SPP market option to ensure the best outcome for our market goals.

- Overall, production cost differences between footprints are modest.
- APS, SRP, and TEP showed slightly greater cost savings in SPP Markets+ footprints than in CASIO EDAM footprints.

Purpose of Study

This study assessed production costs only (generation dispatch) in various market footprints and scenarios.

- The main report is limited to WECC-wide results and does not include individual company results.
- Each entity has individual results.

Significance

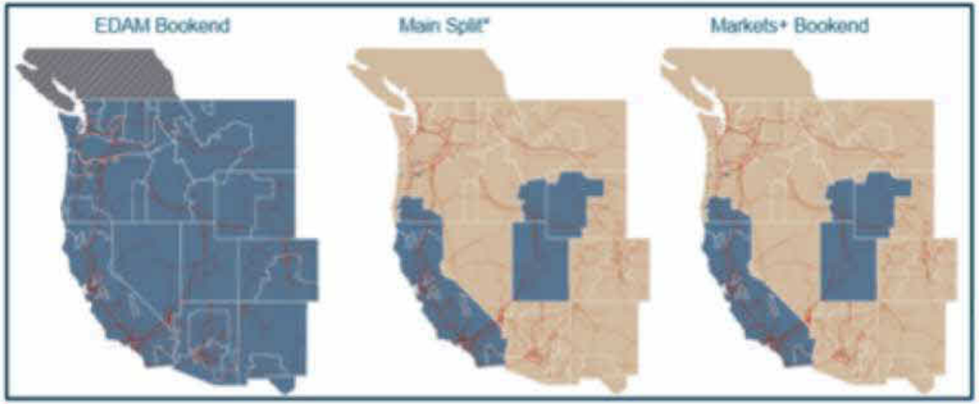
- The results demonstrate the potential production cost savings for different market scenarios and footprints.
- These production cost results are one part of our overall assessment of market participation. The results indicate only a portion of the overall savings expected of a combined resource adequacy and day-ahead market scenario.

Footprints Studied

Market Footprints and Seam Treatment

CBS looked at various footprints as part of the **Core CBS Study**.

The Main Split footprint is uses as the base footprint in all Core Study modeling.

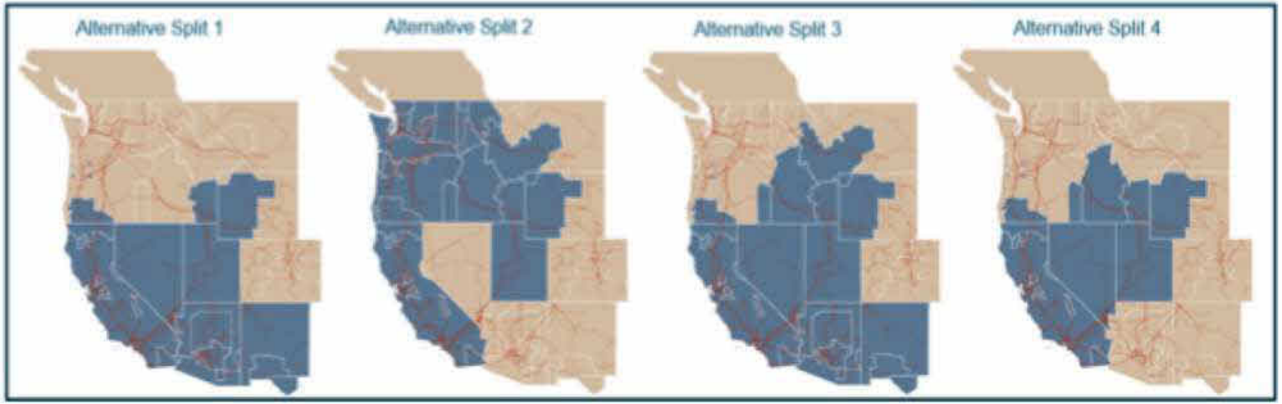


Map Legend

- EDAM
- Markets+

**Not explicitly shown: The difference between Markets+ Bookend and Main Split is WAPA SNR sub-BA is part of EDAM in the Main Split*

A subset of members opted for modeling extra market cases of **additional footprints**



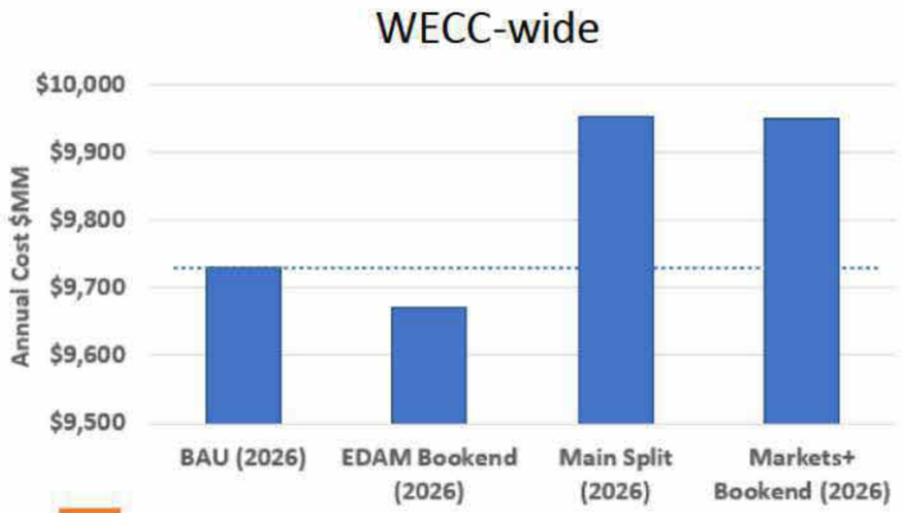
Figures provided by Greg MacDonald from PSE

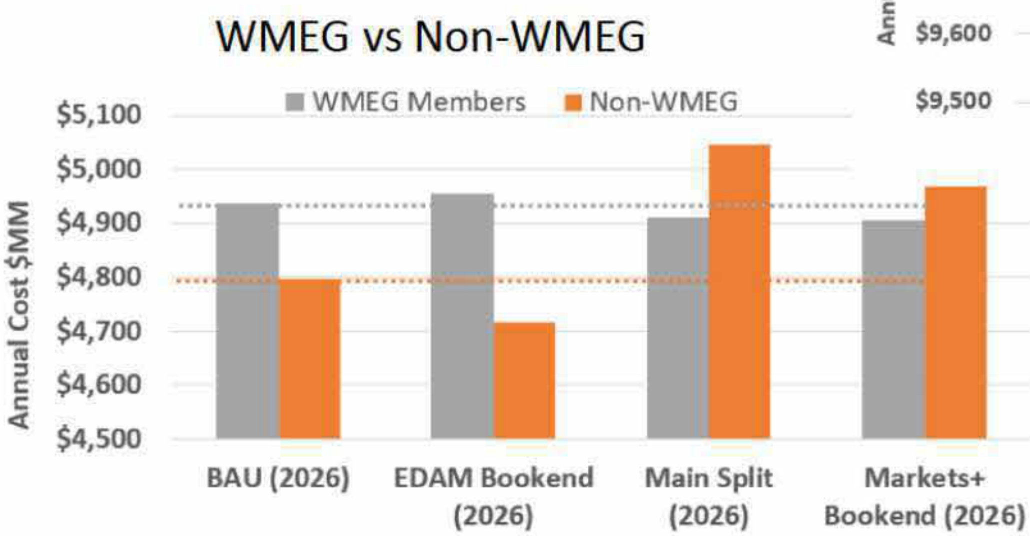
Main Study Results (WECC-wide)

1. Results with a CAISO WECC-wide footprint (compared to BAU* case):
   - WMEG entities show an overall cost increase of $20M.
   - Non-WMEG (mainly CA) entities show an overall cost decrease of $80M.
   - There is a WECC-wide overall cost decrease of $60M (0.6%).
2. Results with split footprints (compared to BAU case):
   - WMEG entities show a cost decrease of $26M.
   - Non-WMEG (mainly CA) entities show a cost increase of $247M.
   - There is a WECC-wide overall cost increase of $220M (2.3%).

*BAU means current participation in real-time markets in both CAISO and SPP. The WECC total production costs are projected to be $9.732B in 2026 in BAU case.

Main Study Results



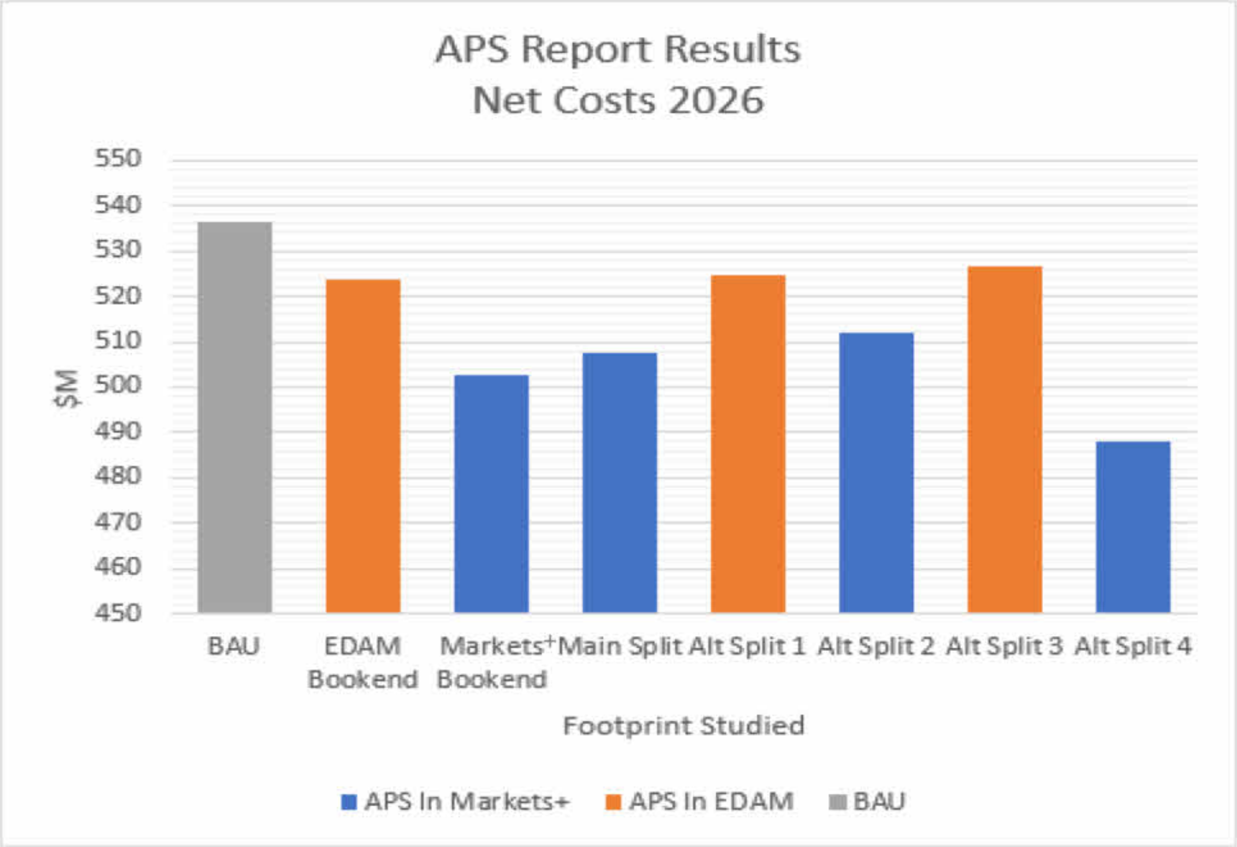


APS Study Results

Case	Net Cost ($Millions)	% Savings
BAU (2026)	536.3	N/A
EDAM Bookend (2026)	523.5	2.4%
Main Split (2026)	507.5	5.7%
Markets+ Bookend (2026)	502.9	6.6%
Alt Split 1 (2026)	524.9	2.2%
Alt Split 2 (2026)	512.1	4.7%
Alt Split 3 (2026)	526.8	1.8%
Alt Split 4 (2026)	488.2	9.9%

- All day-ahead cases result in additional cost savings over current market participation (BAU).
- Cases with a split footprint and where APS is in SPP M+ have greater savings than cases where APS is in CAISO EDAM.

APS Study Results



Take-Aways for Arizona Entities

- Arizona entities see benefits in day-ahead market participation from a production cost standpoint.
  - This holds true in single market and multiple footprint (market) scenarios.
  - It is important for Arizona entities to be aligned in our decision to maximize benefits.
  - There is a risk in not joining a day-ahead market if others do.
- Northwest – Southwest diversity is important and is an important factor in footprint selection.
  - Arizona entities see greater benefit when in the same market as NW entities.
  - Arizona entities also see greater benefit when in the same market as NW entities and are in a separate market from CA.

Summary

- APS, SRP, and TEP are assessing both CAISO and SPP market options. This study suggests that SPP is a viable and potentially superior option from a cost production standpoint. As a result, we will continue to pursue the build-out of the SPP market option to ensure the best outcome for our market goals.
- From a production cost study standpoint, APS, SRP, and TEP benefit most in a market footprint that includes the NW and SW but excludes CA due to load and resource diversity and the sharing of such. In addition, overall production cost savings are relatively modest as compared to the BAU case (real-time market operations).
- Market to market coordination (seams) is important for overall market efficiency. The CBS results showed that by adding better market to market coordination, WECC-wide costs could be reduced by $150M (~1.5%) in a 2030 case. It indicates that since most of the savings can be realized by non-WMEG members (mostly CA), CA should have an incentive to negotiate those market to market agreements.
- Production cost results are one part of the decision-making process of joining a market. The next focus of analysis will be around realizing the potential market benefits via transmission deliverability, assessing future long-term regional opportunities, and finalization of market tariffs and critical business practices.

APPENDIX C

APS EE-DR POTENTIAL STUDY REPORT

Guidehouse
Outwit Complexity

TIERRA™

2023 Energy Efficiency and Demand Response Potential Study

Prepared for:

aps®

Arizona Public Service

Submitted by:

Guidehouse Inc.
1375 Walnut Street, Suite 100
Boulder, CO 80302
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Reference No.: 218384
October 25, 2023

guidehouse.com

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Executive Summary

Arizona Public Service (APS) retained Guidehouse to develop an estimate of the potential for electric energy efficiency (EE) and demand response (DR) in APS service territory over a 20-year forecast period from 2023-2043[1]. Guidehouse worked with the APS Customer to Grid Solutions (C2GS) and Resource Planning teams to characterize measures, forecast loads, and estimate market conditions to inform the study. Guidehouse modeled the technical, economic and achievable potential for EE and DR using the proprietary DSMSim™ and DRSim models, respectively.

This EE and DR potential analysis will inform APS Resource Planning in 2023, long-term planning and load growth, DSM program planning, regulatory compliance, as well as other efforts related to cost management, EE and DR program performance evaluation, grid stability and reliability. Throughout this study, Guidehouse sought regular input and feedback from both internal and external stakeholders, who provided important market knowledge and industry expertise for producing a robust final analysis. This report details the approach used to estimate future EE and DR potential and develop scenarios to meet compliance requirements.

In Arizona Corporation Commission (ACC) Decision No. 78499, issued under Docket Number E-00000V-19-0034, APS is required to model different IRP cases that achieve varying degrees of demand-side resource annual energy savings. Specifically, it requires the following:[2]

i. *IT IS FURTHER ORDERED that Arizona Public Service Company shall in future Integrated Resource Plans include one or more portfolios which achieve an annual minimum of 1.5 percent energy savings as a percent of retail sales from a broad portfolio of EE measures (consistent with 15 percent cumulative savings over 10 years).*

ii. IT IS FURTHER ORDERED that Arizona Public Service Company shall demonstrate 1.3 percent annual EE measured by megawatt-hour savings over its next three-year planning period and shall report its annual EE savings in its 2023 Integrated Resource Plan.

iii. *IT IS FURTHER ORDERED that by January 1, 2030, Arizona Public Service Company's resource portfolio shall include a demand-side resource capacity equal to at least 35 percent of Arizona Public Service Company's 2020 peak demand. The portfolio of demand-side management measures shall include rate-enabled, load-shifting technologies, including, but not limited to, demand response, energy storage, and smart thermostats, that provide customer bill savings and clean energy benefits.*

It is important to note that the first order listed above requires APS to model a planned portfolio scenario that achieves a 1.5% target – but does not require actual achievement of that level of savings. Compliance with the 1.3% target in the second order above requires demonstrated actual savings. For simplicity, in this report we refer to both the 1.3% and 1.5% as "targets" even

[1] The time horizon for the EE study is 16 years (2023-2039), and the timeline for the DR study is 20 years (2023-2043)
[2] Arizona Corporation Commission Docket Number E-00000V-19-0034 Decision No. 78499. https://docket.images.azcc.gov/0000206081.pdf?i=1691608400140

though they are functionally different (the former needs to be demonstrated, while the latter needs to be planned in at least one scenario). Throughout this report, we show both of these targets as a percent of the prior year forecast retail savings without codes and standards (C&S) – as these codes and standards savings are already included in the load forecast, we do not double count them as program savings[3]. However, the codes and standards savings do count toward compliance goals so it is important to adjust the targets accordingly when identifying whether a portfolio meets the goal. The Guidehouse analysis team developed the following scenarios of EE potential, capturing different approaches for estimating potential in the forecast period:

1. **Business-as-Usual (BAU) Scenario**: Aligning with prior load forecasts derived from the 2022 Demand-Side Management (DSM) Implementation Plan (IP),
2. **High Scenario:** Reflecting the maximum realistically achievable potential using current program structures and regulatory precedent (i.e., incentives capped at 75% of incremental measure cost and a minimum benefit-cost ratio of 1.0).
3. **Target 1.5% Scenario:** An aggressive scenario that, as a percentage of retail sales, achieves 1.5% energy savings over a 10-year period, which fulfills the ACC portfolio requirement detailed above.

For the DR potential analysis, Guidehouse customized the proprietary DRSim model to represent the APS customer base and energy usage characteristics—considering a broad range of DR options that could apply to different market segments, including the ones that APS currently offers. The DR potential analysis estimated "achievable" demand reduction assumptions for the following DR options:

- Smart Devices and Direct Load Control (DLC)[4]
- Commercial and Industrial (C&I) Curtailment[5]
- C&I Load Shift to Backup Generators (BUGs)[5]
- Dynamic Pricing
- Behind the Meter (BTM) Battery Dispatch
- Electric Vehicle (EV) Managed Charging
- EV Behavioral
- EV Vehicle-to-Grid (V2G)
- Behavioral DR

[3] This adjustment also accounts for integrated demand side management (iDSM) measure savings, APS system savings, and other small measures (<10% of overall savings) that were not modeled in this study but do count toward achieving target goals.

[4] For the purposes of this potential assessment, the Smart Devices and DLC Option represents both switch-based control programs and technology-enabled control programs such as smart thermostat control or smart water heating control.

[5] Both C&I Curtailment and C&I Load Shift to BUGs represent potential associated with the Peak Solutions program.

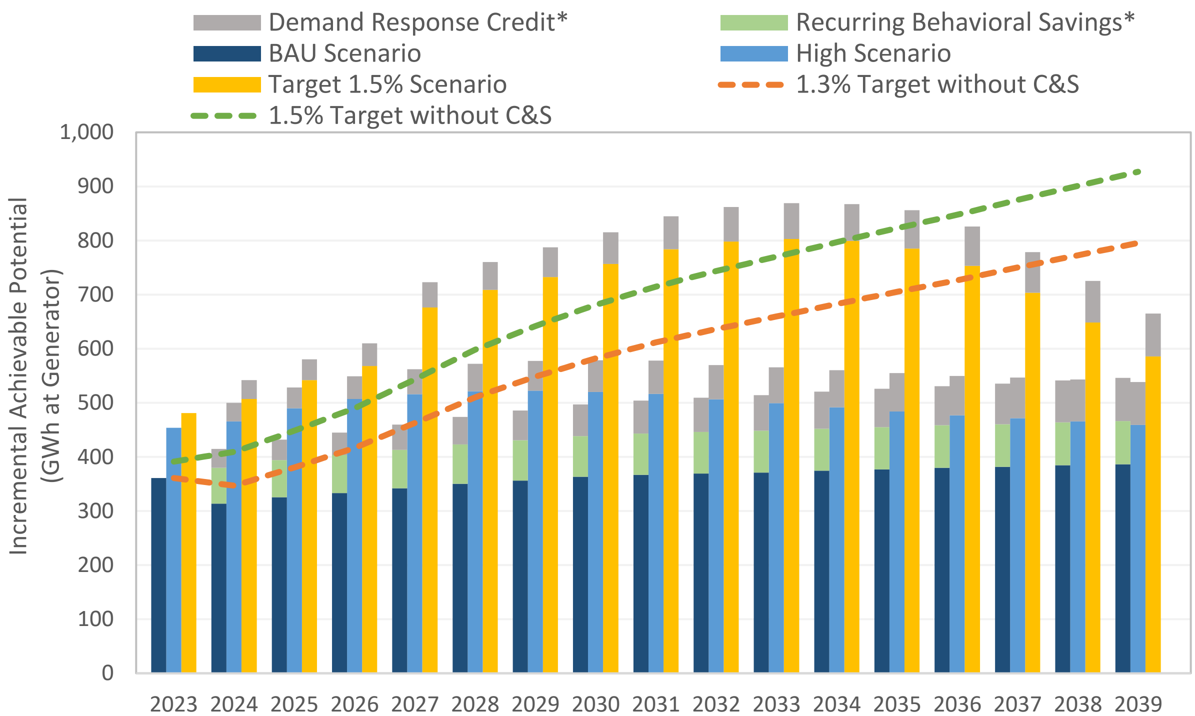
EE Findings

Figure 1 shows the incremental achievable potential in GWh at generator (including line losses) for three scenarios modeled in this study. Achievable savings from the BAU scenario meet the 1.3% target until 2026. Recurring Behavioral Savings[6] and Demand Response Credit add savings that count toward the 1.3% target, but these savings are not modeled in the IRP. The High Scenario—which represents maximum incentives from APS to customers under currently acceptable industry practice—shows earlier adoption of EE relative to the BAU scenario, which significantly increases potential from 2023-2033. This scenario will meet the 1.3% target through 2029. Meeting the target beyond 2030 is only achievable with the aggressive Target 1.5% scenario. This scenario covers the entire incremental cost of EE with incentives. Additionally, this scenario includes more measures in the market by relaxing the cost-effectiveness (CE) benefit-to-cost ratio inclusion threshold from the current 1.0 to 0.45 starting in 2027.

Note that throughout this report in all graphs of Incremental Achievable Potential or energy efficiency from 2023-2039 the bars on the bottom of each stack represent what was modeled in the IRP for each scenario, while the stacked bar or bars on top of each bottom bar represent additional credits and savings that count toward compliance with ACC targets but were not modeled in the IRP.

[6] Behavioral savings are embedded in year 1 of the BAU modeled in the IRP, but are additional to what was modeled in the IRP in years 2024 and beyond for the BAU scenario. The High and Target 1.5% Scenarios modeled in the IRP include behavioral savings for all years.

Figure 1. Incremental Achievable Potential by Scenario Compared to Load Forecast Targets



Source: Guidehouse
***** *Demand response credit and recurring behavioral savings are not modeled in the IRP*

BAU Scenario	High Scenario	Target 1.5% Scenario
Meets 1.3% target until **2026**[7]	Meets 1.3% target until **2029**	Meets 1.3% target until **2037**
		Meets 1.5% target until **2035**

Source: Guidehouse

The EE study informed these key insights:

- While the EE analysis forecasts significant growth in savings potential in the early years of the forecast period, this growth slows down in the later years as the measures in the current and forecasted portfolio of APS programs saturate the market and new loads being added to the APS system offer less EE savings potential.
- EE program budgets will need to increase significantly in order to meet savings targets beyond 2026. The BAU scenario, which represents the current state of APS programs, meets the 1.3% target until 2026. Increasing incentives to the maximum allowable under current framework (to 75% of incremental cost—as represented in the High scenario)

[7] Even though it appears that the BAU + credits achieves the target in 2027, it is 3 GWh short of the target.

results in more than a 2x increase in budget. The Target 1.5% scenario developed would require a further 6x increase in budget over the BAU scenario.

It is important to consider the following points regarding the 1.3% target relative to the BAU Scenario:

- Increased load from growth in the EV segment and the extra-high load factor (XHLF) segment (data centers, large industrial, semiconductor manufacturing) make it harder to achieve the 1.3% target. For instance, the XHLF segment causes the EE savings target to increase by approximately 35% in 2030. Additionally, while both XHLF and EV loads provide opportunities for load management and demand response, customer research indicates that there are minimal EE savings opportunities.

- All scenarios modeled in the IRP do not factor in the conversion of any MWs of peak demand savings from Demand Response programs into MWh equivalence to achieve EE savings goals. In accordance with R14-2-2404[8], these MWhs can account for the achievement of up to 10% of annual EE goals and can be an important component to help reach compliance with EE savings targets within a cost-effective, peak focused DSM portfolio. Figure 1 shows these savings as Demand Response Credit.

- The BAU modeled in the IRP did not accumulate annual savings from Behavioral Savings over time for long term participants. It only considered incremental EE savings from new customers joining the program. However, recurring participants can account for significant MWh savings to help reach compliance. Figure 1 shows these recurring customer savings as Recurring Behavioral Savings.

- This analysis represents a current snapshot of forecasted future potential. It was beyond the scope and timeframe of this study to consider all new emerging technology applications in the analysis of future EE potential, particularly in growing subsegments like XHLF loads which may offer additional savings opportunities in the future. APS intends to continue to work with customers and trade allies to pursue cost effective EE projects in these segments, research emerging EE opportunities, and provide updated EE/DR potential forecasts in subsequent Integrated Resource Plans.

DR Findings

The DR Potential assessment produced the supply curve shown in Figure 2, which stacks up the DR options in order of increasing levelized cost relative to total potential at the end of the study period in 2043.

The cost-effective DR options are Smart Devices and DLC, BTM Battery Dispatch, C&I Curtailment & Load-shift, Dynamic Pricing, and EV Behavioral. The total potential for cost-effective DR programs is projected to grow from **185 megawatts (MW) in 2023** to **851 MW in 2030**—or 8.8% of summer system net[9] peak load. Smart Devices and DLC and C&I Curtailment

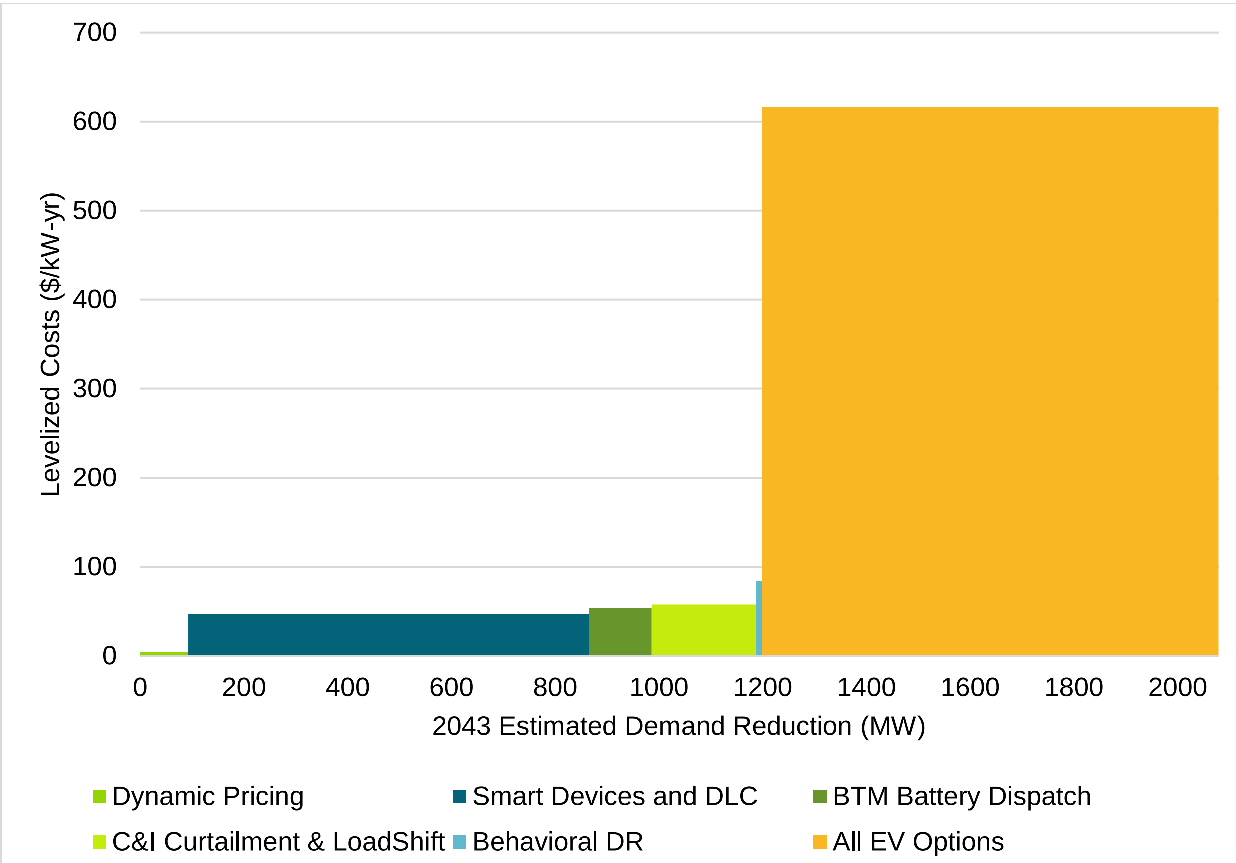
[8] AZ Admin Code R 14-2-2404

[9] Net of Distributed Generation (DG) and Energy Efficiency (EE).

& Load-shift both have significant potential for demand reduction and near-term growth given existing APS programs.

When considering additional DR measures that are **not currently cost-effective** (Behavioral DR, EV Managed Charging, and EV V2G), DR potential could grow to 910 MW in 2030 (9.4% of summer system net peak) and 2,080 MW in 2043 (19.3% of summer system net peak). Contributions from non-cost-effective options could significantly increase MW potential in the long term, but with a significant increase in program cost and impact to overall portfolio cost-effectiveness.

Figure 2. Supply Curve for DR Options



Source: Guidehouse

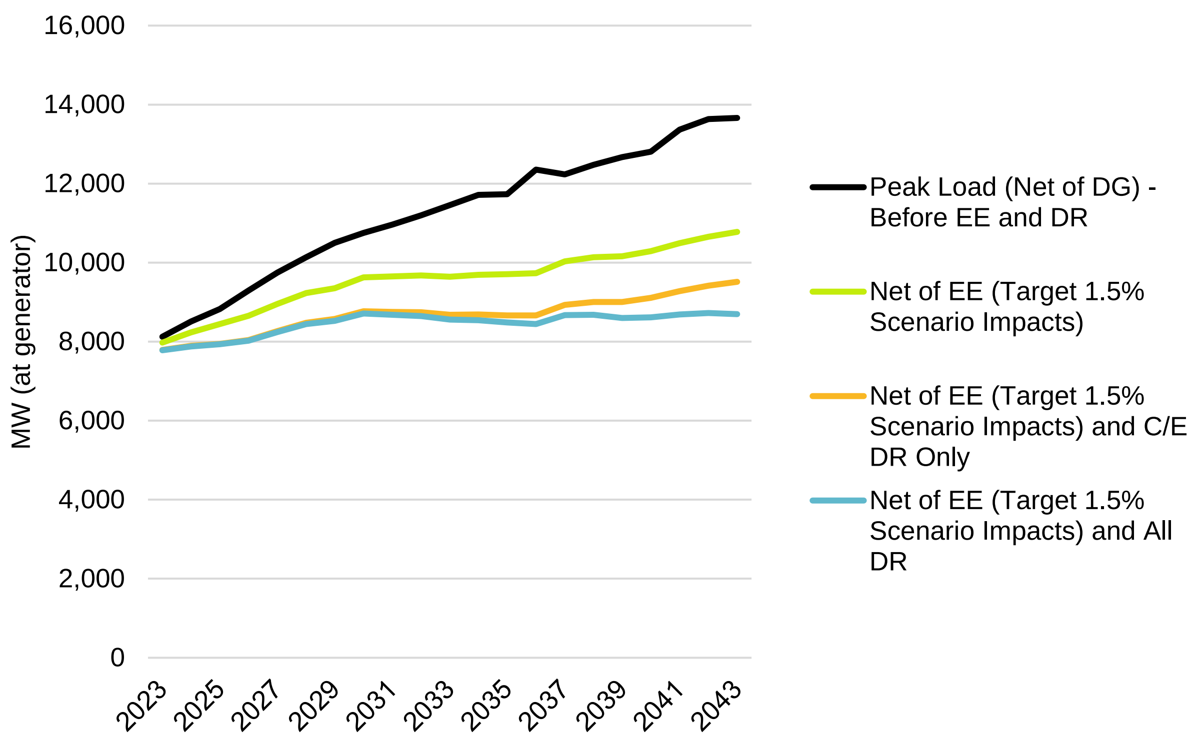
Near-term potential primarily comes from **Residential Smart Devices and DLC** and **C&I Peak Solutions** (both curtailment and load-shift). For residential customers, continuing to scale up the Cool Rewards program to a participation level of 30% of eligible customers could help realize significant cost-effective peak demand savings. Among C&I customers, curtailment opportunities are largely concentrated among a few top segments such as manufacturing/industrial, miscellaneous building type, government, and retail. For commercial customers, Auto-DR enabled curtailment opportunities could grow steadily over the years with increasing adoption of EE control technologies such as energy management systems (EMS). Additionally, including load shift to qualified backup generators at C&I customer facilities will help grow the Peak Solutions program by providing customers with additional opportunities to shift their load during demand response events.

Behavioral DR, EV Managed Charging, and EV V2G considered in the analysis are not currently cost-effective when considered as stand-alone programs from a summer net peak demand reduction perspective only. However, Behavioral DR is currently being offered in combination with the EE Behavioral program to help drive incremental program savings and it is cost-effective as currently implemented from a joint EE-DR perspective. For EVs, the benefits assessment from EV options should begin to consider additional value streams that these options could provide beyond peak demand reduction (e.g., daily load shifting, ancillary services, addressing local congestion). Additionally, these technologies are maturing rapidly and their costs are expected to reduce relatively rapidly in the coming years, which would make these options cost-effective. Given these expected trends and the anticipated potential of EV load management in the future, the implementation of APS's proposed DR and load shifting program offerings in the Managed EV Charging pilot will provide valuable real-world data to better inform the value of potential benefits and program costs.

Combined DSM Impacts on Net Peak Demand

Figure 3 represents the potential combined cumulative impacts from both EE and DR on APS's forecasted single-hour system peak demand.

Figure 3. Combined EE and DR Impacts on System Peak Demand – Single Hour Peak



Source: Guidehouse

The system net peak demand forecast with incremental demand savings from EE (second line from the top) is substantially lower than the system peak demand projections without incremental EE impacts. The energy savings considered here are based on the EE Target 1.5% scenario. With DR, the peak demand could be further lowered as represented in the figure (which shows DR impacts both with the entire DR portfolio and with cost-effective DR options only).

1. Introduction

This section provides an overview of the potential study, including background and study goals, a discussion of the report's organization, and key caveats and limitations of the potential study. Guidehouse Inc. (Guidehouse) uses best-in-class modeling tools to ensure the rigor, validity, and sensibility required of the Demand Side Management (DSM) Potential Study results. Guidehouse's potential study models have been validated in numerous US states, and the team's DSM potential studies and models have been quoted by the American Council for an Energy-Efficient Economy as being "robust and transparent… [and] their methodology for forecasting participation is industry standard best-practice."[10]

As is typical in the development of such studies, Guidehouse worked collaboratively with Arizona Public Service (APS) and its stakeholders to ensure the study, to the fullest extent, best reflects current Arizona market conditions. Guidehouse received considerable guidance and feedback from APS staff, particularly in the development of global input assumptions, measure characterizations, and calibration with historical portfolio performance. The Guidehouse team also carefully considered, and as appropriate, were responsive to stakeholders' input, incorporating their feedback into the analysis approach. It is essential to note that while potential studies focus on the measure mix and potential forecasts from a technology and customer adoption standpoint, it is difficult to account for all possible future circumstances including but not limited to, delays to regulatory approval of annual plans and budgets, policy changes, and broad shifts in the energy markets—all of which can greatly affect the actual realization of these forecasts.

1.1 Motivation for the Study

APS retained Guidehouse to develop an estimate of the potential for electric energy efficiency (EE) and demand response (DR) in APS service territory. Table 1 summarizes the project scope.

Table 1. Summary of Project Scope

Element	Dimensions
Forms of Energy	Electricity
Type of Potential	EE and DR Technical, Economic, Achievable
Sectors	Residential, Commercial, and Industrial (C&I)
Climate	Desert and Mountain
Time Horizon	EE - 2023-2039 (16 years) DR – 2023-2043 (20 years)

Source: Guidehouse

The following topics motivated the study.

[10] American Council for an Energy-Efficient Economy, "Cracking the TEAPOT: Technical, Economic, and Achievable Energy Efficiency Potential Studies," August 2014.

1.1.1 Regulatory Requirements

In Arizona, utilities such as APS have been required to achieve certain EE targets to comply with regulatory mandates. Accurate forecasting helps APS assess whether it is on track to meet these targets and take corrective actions if necessary. Recent Arizona Corporation Commission (ACC) Decisions provide the following guidance on APS's energy saving goal (GWh):[11]

> *IT IS FURTHER ORDERED that Arizona Public Service Company shall in future Integrated Resource Plans include one or more portfolios which achieve an annual minimum of 1.5 percent energy savings as a percent of retail sales from a broad portfolio of EE measures (consistent with 15 percent cumulative savings over 10 years).*
>
> *IT IS FURTHER ORDERED that Arizona Public Service Company shall demonstrate 1.3 percent annual EE measured by megawatt-hour savings over its next three-year planning period and shall report its annual EE savings in its 2023 Integrated Resource Plan.*

IT IS FURTHER ORDERED that by January 1, 2030, Arizona Public Service Company's resource portfolio shall include a demand-side resource capacity equal to at least 35 percent of Arizona Public Service Company's 2020 peak demand. The portfolio of demand-side management measures shall include rate-enabled, load-shifting technologies, including, but not limited to, demand response, energy storage, and smart thermostats, that provide customer bill savings and clean energy benefits.

Due to these regulatory requirements, this report contextualizes overall EE savings results in terms of 1.5% and 1.3% of retail sales. The ACC does not currently provide specific guidance on a separate DR capacity savings goal.

1.1.2 Resource Planning

APS needs to plan for future energy needs and ensure a reliable supply of electricity to its customers. By forecasting EE and DR potential, APS can estimate the reduction in electricity demand resulting from these initiatives. This information helps APS determine how much additional capacity it needs to invest in to meet future demand without any supply shortages.

As APS resource planners developed a new Integrated Resource Plan (IRP) in 2023, they sought to obtain the most up-to-date and accurate EE and DR potential forecasts. Guidehouse conducted the most recent EE potential study for APS in 2019. To determine updated EE potential for the 2023 IRP, Guidehouse leveraged the 2019 research as a starting point and refreshed the data and assumptions using the same model as the 2019 DSM Opportunity Study.

Specifically, the 2023 IRP model required the following scenarios:

1. A base Business-as-Usual (BAU) forecast aligning with prior load forecasts derived from the 2022 Implementation Plan (IP); referred to herein as the BAU scenario.

[11] Arizona Corporation Commission Decision No. 78499.
https://docket.images.azcc.gov/0000206081.pdf?i=1691608400140

2. A high scenario reflecting the maximum realistically achievable potential using current program structures and regulatory precedent (i.e., incentives capped at 75% of incremental measure cost and a minimum benefit-cost ratio of 1.0).

3. An aggressive scenario demonstrating savings that align with the ACC 1.5% savings target through 2034 per the ACC order described in Section 1.1.1.

1.1.3 Long-Term Planning and Specialized Load Growth

EE forecasting aids in APS's long-term planning and decision-making processes. It provides insights into the expected trajectory of energy consumption and helps APS adapt its strategies to changing energy demands and technological advancements. In particular, APS is forecasting significant load growth in the next 2-10 years from data centers and semiconductor manufacturing plants planning to interconnect to the APS system. These customers are known to have an extra high load factor (XHLF)—meaning that they consume a large amount of energy, and the use of that energy is roughly consistent across the 24 hours in the day.

Furthermore, APS is expecting to add significant electric vehicle (EV) load as the market for EVs continues to expand in the Phoenix metro area and beyond. EVs will increase overall system load and offer an opportunity for DR potential.

Both these sources of load growth must be considered in the context of the ACC Decision which requires an IRP scenario that achieves 1.5% of retail sales from EE savings over a 10-year period. EVs and XHLF loads are significant sources of load growth, without significant current opportunities for EE. As that load comes onto the system, APS must achieve even more efficiency from other commercial and residential sector loads outside of these categories. And APS should continue to work with these new customers to identify emerging opportunities for cost effective EE savings as they become available.

1.1.4 Other Objectives

While the above topics are the primary drivers for the study, this project also assists APS with the following work:

- **Cost Management:** Accurate forecasting of potential EE and DR savings allows APS to budget and allocate resources more effectively. When APS can estimate the potential reduction in energy consumption, it can also assess the financial benefits of implementing EE programs. This helps in making informed decisions about where to invest in EE measures to maximize savings and minimize costs. The costs of EE and DR are important when considered as a resource in the IRP against other supply-side resources.

- **Environmental Impact Tracking:** Accurate forecasting of EE and DR savings enables APS to assess the potential environmental benefits of reduced energy consumption and peak demand. This information can be used to track progress toward sustainability goals and highlight the positive impact on greenhouse gas emissions and air quality.

- **Performance Evaluation:** Forecasting allows APS to measure the effectiveness of its EE and DR programs over time. By comparing forecast savings with actual results, APS can identify successful initiatives and areas for improvement. This feedback loop helps APS to continuously refine and optimize its EE and DR strategies and program offerings.

- **Grid Stability and Reliability:** Peak focused EE and DR plays a critical role in maintaining grid stability and reliability, especially during peak demand periods. By accurately forecasting the potential for EE and DR, APS can identify the available resources to reduce electricity consumption when demand is high. This helps to balance supply and demand, preventing overloads on the grid and avoiding potential blackouts or brownouts.

- **Emergency Preparedness:** During emergencies or unexpected events that strain the grid, DR can be a valuable tool to manage electricity demand. Forecasting DR potential helps APS be prepared for such situations and enhances the utility's ability to respond effectively to emergencies. APS provides a critically life-sustaining service during days of extreme summer heat.

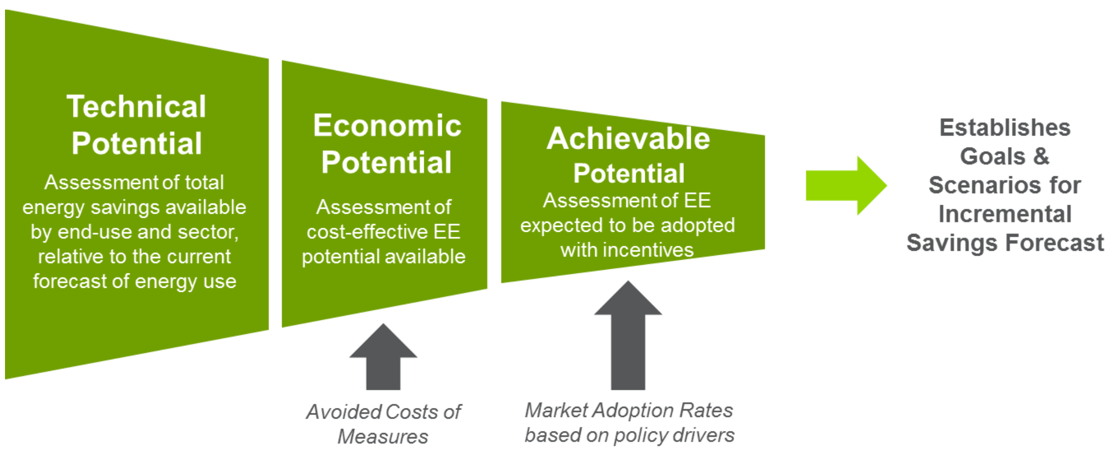
In summary, forecasting EE and DR savings is crucial for APS to make informed planning decisions about resource planning, meet regulatory requirements, and manage costs. These forecasts are an integral part of APS's efforts to deliver reliable, affordable, and clean energy to its customers and the communities it serves.

2. EE Potential

This section details Guidehouse's approach for calculating potential and provides insights into the DSMSim model employed. This section also highlights key inputs and assumptions applied during the study, accompanied by results and key takeaways.

Guidehouse employed its proprietary DSMSim potential model to estimate the technical, economic, and achievable savings potential for electric energy across APS service territory. DSMSim is a bottom-up technology diffusion and stock tracking model implemented using a System Dynamics[12] framework. The DSMSim model explicitly accounts for different types of efficient measures such as RET (Retrofit or Early Retirement), ROB (Replace on Burnout), and NEW (New Construction), and the effects these measures have on savings potential. The model then reports the technical, economic, and achievable potential savings in aggregate for the service territory, sector, customer segment, end-use category, and highest impact measures. Figure 4 provides an overview of potential calculation methodology used in the model.

Figure 4. Potential Calculation Methodology



Source: Guidehouse

Guidehouse leveraged the most recent prior EE potential study conducted for APS in 2019 for its methodology and data inputs, ("2019 DSM Opportunity Study"). Guidehouse updated the study by calibrating the model with savings and spending data from the latest implementation plans, refreshed other key inputs that changed since 2019 such as avoided costs, and included some significant additional measures that have been added to APS's programs since 2019.

2.1 Methodology

This section describes the methods behind developing key inputs, calibrating the model, and developing each scenario. Note that the methodology differs by scenario as detailed in Section 2.1.6.

[12] See Sterman, John D. *Business Dynamics: Systems Thinking and Modeling for a Complex World*. Irwin McGraw-Hill. 2000 for detail on System Dynamics modeling. Also, see http://en.wikipedia.org/wiki/System_dynamics for a high-level overview.

2.1.1 Types of Potential

The potential study forecasts potential at three levels:

- **Technical potential:** This study defines technical potential as the total energy savings available assuming that all applicable installed baseline measures can immediately be replaced with the efficient measure/technology—wherever technically feasible—regardless of the cost, market acceptance, or whether a measure has failed and must be replaced. Technical potential also accounts for measure competition, recognizing that some efficient technologies will compete in the calculation of potential for a given stock unit. For instance, a consumer has the choice to install an efficient storage water heater, a tankless water heater, or a heat pump water heater, but not all three. These efficient measures compete for the same installation, and only the measure with the highest savings is included in the summation of technical potential.

- **Economic potential:** Economic potential is a subset of technical potential, using the same assumptions regarding immediate replacement as technical potential but only including those measures that have passed the benefit-cost test chosen for measure screening. The cost-effectiveness (CE) ratio for each measure is calculated each year and compared against the measure-level CE screening threshold defined for each scenario. A measure with a CE ratio greater than or equal to 1.0 is a measure that provides monetary benefits greater than or equal to its costs. If a measure's CE ratio meets or exceeds the defined threshold, it is included in the economic potential. This benefit-cost metric measures the net benefits of EE measures from the combined stakeholder viewpoint of the program administrator and its customers according to the Societal Cost Test (SCT) used by the ACC. The benefit-cost ratio is calculated in the model using Equation 1. Guidehouse calculated CE ratios for each measure based on the present value of benefits and costs (as defined above) over each measure's life. Like technical potential, only one economic measure from each competition group is included in the summation of economic potential across measures.

Equation 1. Benefit-Cost Ratio

$$ACC\ SCT = \frac{PV(Avoided\ Costs)}{PV(Technology\ Cost + Admin\ Costs)}$$

Where:

- *PV( )* is the present value calculation that discounts cost streams over time.
- *Avoided Costs* are the monetary benefits resulting from electric energy and capacity savings—e.g., avoided costs of infrastructure investments and avoided long-run marginal cost (commodity costs) due to electric energy conserved by efficient measures.
- *Technology Cost* is the incremental equipment cost to the customer.
- *Admin Costs* are the administrative costs incurred by the utility or program administrator.

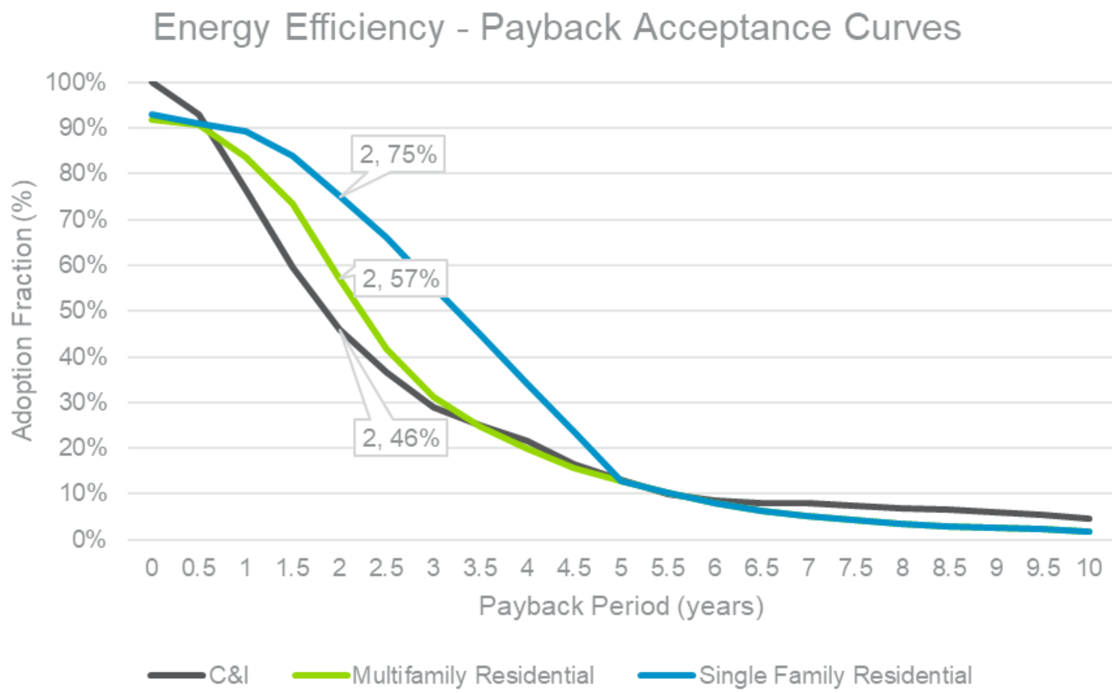
- **Achievable potential:** The output of the potential study is an achievable potential analysis, which calculates the potential that could be expected in response to specific levels of incentives and assumptions about existing policies and market influences. Future policy changes and market influences that are unknown at this time could greatly influence future potential that can realistically achieved. Achievable potential is a subset of economic potential. Achievable potential allows any measure that is cost-effective to be adopted within a group of competing measures. The model estimates awareness level of each measure in the eligible population and the willingness to adopt each measure that passes the cost-effectiveness screen based on payback acceptance. The model employs the Bass diffusion approach to simulate adoption.

2.1.2 Payback Acceptance

Payback acceptance is a way to consider costs and adoption from the customer perspective. A certain percentage of the aware and technically suitable customers are considered to “accept” (or adopt) a technology at a given payback period (in years). For example, 75% of customers in residential single-family homes will adopt a technology if the payback period is 2 years, and 46% of C&I customers would adopt a technology at the same payback period. The curves shown in Figure 5 are compiled from interviews with APS customers and building managers—cross-checked against Guidehouse’s internal database of payback acceptance data from potential studies conducted around North America.

As incentives increase, the payback period of measures decreases, and a greater percentage of the eligible and aware customers will generally adopt the technology. As adoption increases, awareness increases (via word of mouth) which also increases the eligible portion of customers. This dynamic leads to diffusion of a technology across the APS customer base. Payback acceptance is why APS is able to influence the market with different incentive levels, and why the high and mid scenarios produce more potential than the BAU scenario by using greater incentives.

Figure 5. EE Payback Acceptance Curves



The acceptance of payback periods can differ between residential and commercial investments due to various factors. Here are some key differences to consider:

- **Investment Objectives:** Residential investments are typically made for personal use or long-term rental income, whereas commercial investments are made with the primary objective of generating profit through business operations.

- **Timeframes:** Residential investments generally have longer payback periods compared to commercial investments. Residential properties are often held for several years or even decades, allowing investors to recover their initial investment over a more extended period. In contrast, commercial investments typically have shorter payback periods, as businesses aim to achieve profitability and generate returns within a relatively shorter timeframe.

- **Cash flow considerations:** Commercial properties, such as office buildings or retail spaces, generate rental income from tenants. In these cases, the payback period may be closely tied to the lease terms and the ability to attract and retain tenants. Residential investments may rely more on property appreciation over time rather than immediate cash flow, which can affect the investor's acceptance of the payback period.

- **Financing options:** Commercial investments often require substantial financing and may involve more complex loan structures, such as commercial mortgages. Lenders for commercial properties may have stricter requirements for payback periods to ensure the investment is financially viable. Residential investments can also be financed, but there may be more flexibility in terms of financing options and acceptance of longer payback periods.

2.1.3 Approach

Guidehouse updated key data and assumptions using the same base model as the 2019 DSM Opportunity Study. The EE measure list was revised to align with the latest APS Implementation Plan (IP), and measures were re-characterized as necessary including updates to savings, costs, baselines and other technology assumptions. To further enhance the reliability of the model, it was calibrated with savings and spending data from the latest implementation plans. This calibration process helps to fine-tune the model's parameters, making the results more representative of real-world scenarios.

Figure 6 provides a succinct overview of the step-by-step methodology adopted for this updated potential study, and the sections below describe these in greater detail.

Figure 6. EE Potential Study Methodology

Step 1: Measure Identification and Characterization	• Develop/update list of measures • Screen/modify list based on stakeholder feedback • Characterize measures (e.g., savings, cost, loadshapes, etc.)
Step 2: Develop Technical Potential	• Account for new vs existing building stock, equipment densities, initial saturation levels of efficient equipment • Calculate per-unit savings from every measure, and competition groups
Step 3: Develop Economic Potential	• Update avoided costs and discount rates • Only measures that exceed defined B/C ratio are included
Step 4: Develop Achievable Potential	• Account for market acceptance dynamics based on data and program-level guidance • Calibrate potential to program/implementation plan data available
Step 5: Develop Scenarios	• Develop scenarios to support IRP requirements, and meet ACC order to demonstrate 1.3 % savings over next three-year plan, and 1.5% savings over 10 years

Source: Guidehouse

2.1.4 Key Inputs

To ensure an accurate and relevant analysis, Guidehouse updated key inputs and assumptions wherever applicable based on updated implementation plan data or data received from APS.

2.1.4.1 Global Input Updates

MWh Sales

The team updated the MWh sales forecast based on the latest load forecast data received from APS.

Avoided Costs

Guidehouse updated avoided costs to reflect current 2023 avoided cost values.

Non-Incentive Program Costs

Sector level non-incentive costs—represented by $/kWh value—were updated based on program spending and kWh savings from the 2020-2022 implementation plans. These prior year costs were adjusted to expected future costs according to aggressiveness of future EE scenarios.

Table 2. Non-Incentive Costs 2020-2022

Non-Incentives $/kWh	Residential	Commercial
2020	$0.06	$0.07
2021	$0.05	$0.03
2022	$0.05	$0.05

Source: Guidehouse (Derived from APS Annual Progress Reports)

Discount Rate

The study used an updated discount rate of 6.3%, based on the Weighted Average Cost of Capital (WACC) used by APS at the time of performing the study.

The study used other global inputs retained from the 2019 DSM Opportunity Study. The building stock was not updated with this refresh because of lack of updated information in the required format (1,000 sq. ft of floor space for commercial and industrial [C&I] stock). Guidehouse extrapolated stock data used in the 2019 study for the forecast period. Other economic inputs such as retail rates, line losses, reserve margin and inflation rates were also not updated for this study.

Customer and Industry Perspectives

Additionally, as a component of the potential study effort, the Guidehouse-Tierra team conducted customer surveys and interviews to assess participation likelihood in different types of DR program offerings and load curtailment/shift estimates from these programs (included current DR programs offered by APS and potential new program offers). The customer survey and interview approach and the findings from these activities are described in detail in Appendix A. The analysis team suggests a similar interview approach be conducted to determine opportunities for EE and DR savings potential in the XHLF segment.

2.1.4.2 Measure Characterization Updates

This section provides an overview of the measure selection and update process performed for this analysis. The measure selection process for this study used the 2019 DSM Opportunity

Study's measure list as a starting point. The Guidehouse team retained and updated many technologies from the previous study but refreshed the list by adding some new measures, based upon the updated measure list included in the 2023 IP.

The updated measure list covers current APS offerings, and the savings, costs and load shapes developed for each measure through measurement, evaluation, and research (MER) served as inputs to the model. Table 3 details the measure list used in the 2019 DSM opportunity study. For the 2023 study, characterization for these measures was updated based on latest MER data, with a few exceptions for measures that did not have any significant changes. Table 4 identifies new measures added to the measure list.

Table 3. 2019 DSM Opportunity Study Measure List

End-Use Category	Residential Sector Measures	Commercial and Industrial Sector Measures
Whole Home/Building	- ENERGY STAR Homes - Multifamily New Construction - Home Energy Reports	- Commercial New Construction - Energy Information Systems - Custom Retrofits
Space Heating and Cooling (including Building Envelope)	- Efficient HVAC Equipment (Air Conditioners and Heat Pumps) with Quality Installation - Duct Test & Repair - Smart Thermostats - Attic Insulation - Limited Income Weatherization - *Western Cool Controls***	- Advanced Rooftop HVAC Controls - Air- and Water-Cooled Chillers - Energy Management Systems - Packaged AC/Heat Pumps - *Duct Test & Repair***
Appliances	- Connected Pool Controls	
Water Heating	- Connected Water Heater Control - Connected Heat Pump Water Heater	
Lighting	- LED Lighting Upgrades	
Commercial Refrigeration and Food Service		- High Efficiency Evaporator Fan Motors (EC) - *Floating Head Pressure Controls*** - *Anti-Sweat Heater Controls***
Data Centers		- Data Center Computer Room AC (CRAC) Upgrades - *Data Center Uninterruptible Power Supply (UPS)***

** Indicates measures that did not have any updates from the 2019 study characterization

Source: Guidehouse

Table 4. New Measures added since 2019 DSM Opportunity Study

End-Use Category	Residential Sector Measures	Commercial and Industrial Sector Measures
Whole Home/Building	- ENERGY STAR NextGen Homes - Home Energy Analyzer	- Non-Res Energy Analyzer - Variable Speed Drives for Pumps, Fans, Motors, etc.
Space Heating and Cooling (including Building Envelope)		- High Efficiency HVAC Fan Motors
Water Heating		- Connected Water Heater Control - Connected Heat Pump Water Heater
Commercial Refrigeration and Food Service		- Efficient Refrigerated Display Cases - Combination Ovens - Steamers

Source: Guidehouse

2.1.4.3 Inflation Reduction Act Tax Credits

The Guidehouse team also incorporated potential EE measure-level tax credits under the Inflation Reduction Act (IRA), passed into US federal law in August 2022 into the analysis of future measure participation, costs and benefits for the High Scenario and Target 1.5% Scenario. IRA includes provisions for tax credits to help reduce the cost of purchasing energy efficient end-use equipment in both residential and nonresidential premises. The methodology for developing measure-specific tax credit values differs between residential and commercial sectors.

Residential Sector Characterization

For applicable residential EE measures, the following steps were taken to derive a population weighted average per-unit tax credit amount for IRA-eligible measures characterized and included in the model:

- Identify pre-adjustment tax credit amount ($/measure) using the IRA provisions.
- Account for the requirements that the measures are installed in owner-occupied single-family homes, and the functional requirement that the homeowner has sufficient tax burden to receive the value of the tax credit, by adjusting the tax credit amount with the percent of residential customers that would qualify.

Section 2.2.3 details the impact of these tax credits on potential savings.

Commercial Sector Characterization

The IRA tax credit for commercial buildings applies to HVAC, Lighting, and Water Heating measures. The tax credit within the legislation is specified as $/sq ft and is a range depending on the total reduction in baseline energy usage. Using secondary research, Guidehouse applied

Arizona-specific building-level energy and stock data, and measure density and per-measure energy savings to estimate a measure-level tax credit value ($/unit).

2.1.5 Calibration to Past Program Performance

Guidehouse took several steps to ensure that forecast model results were reasonable by comparing historic program performance and incentive spending with the modeled forecast. Guidehouse adjusted model parameters and technology diffusion coefficients—primarily marketing and word-of-mouth factors—to obtain close agreement with the kWh savings and portfolio spending data from the latest implementation plans.

This process ensures that forecast net potential is grounded against real-world results considering the many factors that come into play in determining the likely adoption of energy efficient measures. The model was calibrated to implementation plan data from 2020-2022. Calibration targets were estimated using the actual program spend, and kWh savings. Historic accomplishments were assigned to sector and end-use combinations using the closest available measures in the Study. Calibration parameters for certain measures were adjusted based on APS program manager feedback as well. Table 5 provides kWh savings data from 2020-2022 plan for both residential and commercial sectors used for model calibration.

Table 5. kWh Savings Data from 2020-2022

	2020	2021	2022
Total Residential	91,714	91,159	119,616
Total Commercial	69,397	192,269	160,593
Total Measure-Based Savings	161,111	283,428	280,208

Source: Guidehouse

2.1.6 Scenarios

The analysis team developed the High and Target 1.5% scenarios by starting with the calibration process detailed in Section 2.1.5, representing the current state of APS's EE programs. From this starting point, the team modified the model to develop the two scenarios (High and Target 1.5%) by adjusting incentive levels and the CE threshold to meet ACC savings targets and inform the 2023 IRP model. This section details the modeling approach and parameters adjusted to develop these scenarios.

2.1.6.1 Scenario Summary

Specifically, the 2023 IRP model required the following three scenarios:

1. **BAU.** A base BAU forecast aligning with prior load forecasts derived from the 2022 IP.
2. **High.** A "High" scenario reflecting the maximum realistically achievable potential using current program structures and regulatory precedent (i.e., incentives capped at 75% of incremental measure cost and a minimum benefit-cost ratio of 1.0).

3. **Target 1.5%.** An aggressive scenario demonstrating savings that align with the ACC 1.5% savings target through 2034 per the ACC order described in Section 1.1.1.

The Guidehouse team details the methodology for modeling each of these scenarios in terms of both savings and costs.

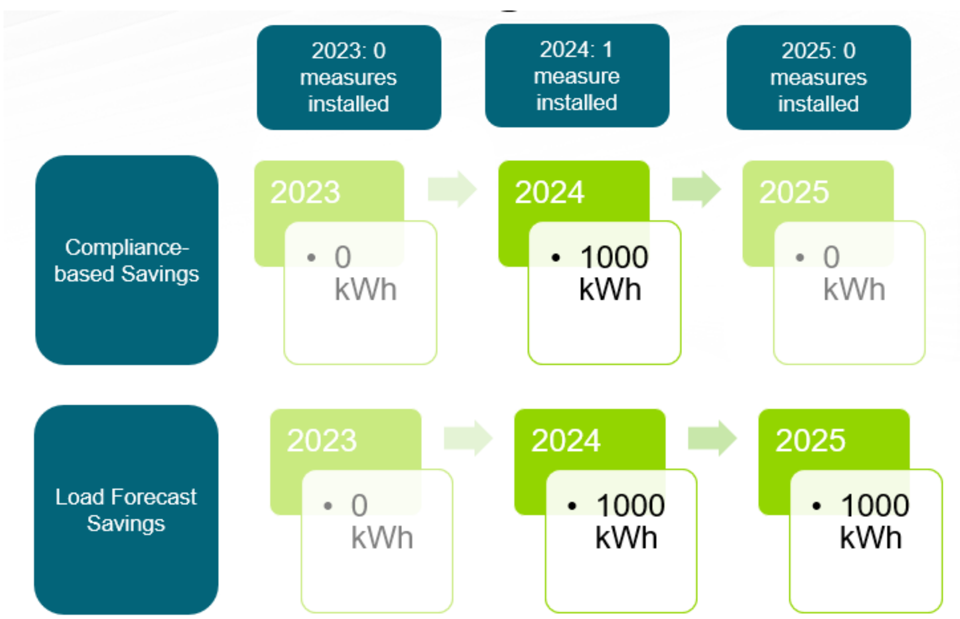
2.1.6.2 Savings Methodology: BAU Scenario

In this analysis, the BAU scenario utilized a different savings methodology than the other two scenarios. The analysis team was required to use this scenario for developing the 2023 IRP, because it aligned with past work by Guidehouse to develop an hourly net load forecast (net of EE savings in each hour). Certain portions of the IRP used this previously developed net load forecast as a basis for the modeling, so the analysis team resubmitted this work completed in September 2022 to support the 2023 IRP.

This method was first employed in Q1 2020 to estimate the hourly net load impacts using existing data. The Implementation Plan (IP) is the annual plan for how to procure savings in the coming year. This plan includes details of exactly how many participants APS program managers should target by measure, as well as program budgets. Each EE measure in the portfolio has an hourly savings shape which is used to estimate the hourly kW savings for each measure in each hour of the year.

Before detailing the method, it is important to understand the difference between compliance-based savings and load forecast savings as Figure 7 shows for the hypothetical example of one measure savings of 1,000 kWh being installed in 2024.

Figure 7. An Illustration of the Difference between Compliance and Load Forecast Savings Types for a Single 1,000 kWh Measure Installed in 2024



Source: Guidehouse

- **Compliance-based savings.** Compliance-based savings are first-year annual savings used to meet the ACC savings targets. For example, APS has a savings goal of 421 GWh in 2024. This is the total at-generator savings in that current year. The analysis does not count savings from anything installed in 2023 or before. Each measure installed in the territory only receives a one-time credit towards compliance, based on the annual energy savings in the year of installation regardless of the lifetime of the measure.

- **Load forecast savings.** Load forecast savings need to account for a measure installed in 2024 that still saves energy in each year of the measure's life. For example, a measure saves 1,000 kWh in 2024, and 1,000 kWh in 2025, therefore the total impact on the load forecast in 2025 is a reduction of 1,000 kWh from the counterfactual baseline in which this measure was never installed—even though no installation activity happened in 2025.

Furthermore, in conversations with APS Load Forecasting in 2020, the Guidehouse and APS teams agreed to treat certain types of measures differently for inclusion in or exclusion from the load forecast.

- **Cumulative savings.** Most of the measures in the APS portfolio of programs provide cumulative savings—what are typically considered as energy efficiency measures. Examples include ENERGY STAR Homes, commercial custom measures, and lighting retrofits. The team assumed that:
    - These measures have the same participation in each subsequent year as they do in the current plan year. For example, if there are 1,000 ENERGY STAR Homes in this current plan, there will be 1,000 new additional ENERGY STAR Homes in each future year.
    - These savings "persist"—meaning that at the end of a measure's life, that measure is replaced with something equally efficient.

- **Non-cumulative savings.** These are one-time measures that the team presumes will have recurring participation but the savings will not cumulatively appreciate each year. Oracle (formerly OPOWER) Home Energy Reports are the largest such measure. The analysis does assume that the same number of customers continue to participate in Home Energy Reports each year, but due to the 1-year measure life and the special circumstance that this measure is not a physically installed technology within a home or business, the savings for this measure are not cumulative year-over-year.

- **Embedded savings.** Those savings that are counted towards EE compliance, but are already be captured in the APS load forecasting model, and therefore should not be "netted out" of the load forecast due to risk of double counting. The most prominent example of these measures are system savings (APS savings on the generation side of the system) as well as codes and standards savings. The ACC allows APS to claim 33% of savings from federal, state, or local codes that impact APS customers to meet compliance goals. However, for the purposes of load forecasting, the impacts of those codes are already modeled in the base load forecast, and therefore it would be double counting to subtract 33% of the impact of codes from the base load forecast.

With the above savings types in mind, the following steps describe the BAU forecast methodology:

1. **Categorize measures**. The team reviews the IP measure-by-measure to assign each measure to one of three categories: cumulate, don't cumulate, and exclude.

2. **Normalize savings**. The team calculates EE hourly savings as a percent of the hourly forecast in the implementation plan year. The result is a percent savings from EE in each hour of the year.

3. **Scale savings.** The team applies this normalized percent from step 2 to future years of the load forecast. This means that savings increase (or decrease) in proportion to the load growth (or decrease) in each hour.

This method relies on the following key assumptions:

- **Persistence of savings**. This method assumes that these savings "persist"—meaning that at the end of a measure's life, that measure is replaced with something equally efficient. This results in significant savings in later years.

- **Recurring participation and consistent measure mix.** This method assumes that the same participation from the implementation plan recurs in each subsequent year. This estimation method therefore ignores considerations of market saturation and technology change over time. This is an effective simplifying methodology that works well over shorter planning horizons as DSM portfolios stay relatively consistent over this timeframe. The advantage of this method is that it is based on existing datasets and it is easy to develop on short notice, so it is useful for bi-annual load forecast updates. However, in reality plans can vary significantly year to year based on many factors such as market conditions, budgets, policy guidance and regulatory context as well as saturation of key measures over longer planning horizons.

2.1.6.3 Savings Methodology: All Other Scenarios

The other two scenarios (High and Target 1.5%) use the potential modeling approach described in Section 2.1.3 with inputs that vary by scenario. This section describes those inputs and the rationale for assigning these specific inputs to each scenario. The analysis team used two different parameters to model differences in savings by scenario: incentive levels and the SCT benefit-to-cost threshold ratio (a.k.a. CE threshold). Table 6 details the differences between each scenario.

Table 6. Scenario Incentive and CE Threshold Details

Scenarios	Residential Incentives	Commercial Incentives	CE Threshold
High	75%	75%	1.0
Target 1.5%	100%	100%	1.0 before 2027, 0.45 starting in 2027

Source: Guidehouse

- **High (75-75) scenario** increases incentives to 75% of incremental measure costs for both sectors, which is the maximum allowable incentive under current ACC guidance.

- **Target 1.5% (100-100) scenario** reflects an additional aggressive scenario required to comply with savings targets as 1.5% of the load forecast, which was a scenario required by ACC order. To achieve this result, the team needed to provide incentives at 100% of incremental costs—which covers the entire cost of the more efficient technology relative to the baseline. The team also needed to adjust the SCT threshold at which measures are included in economic potential, and therefore available to be achieved by APS programs, to .45 (instead of 1.0) in 2027. This threshold change is a proxy for changes in avoided costs, incremental costs, clean energy adders, and technology innovation—all of which would be necessary in some combination in order to achieve the 1.5% savings target through 2033.

2.1.6.4 Incentive Costs by Scenario

The team scaled the incentive costs for each scenario based on the savings achieved under each scenario. The model assumes that if a measure is adopted in a given year, incentives were paid to adopt that measure. The incentive costs vary by scenario due to 1) different incentive cost fractions for each scenario as detailed in Table 6 and 2) different savings in each scenario, which means more participants received an incentive in higher scenarios.

2.1.6.5 Non-Incentive Costs by Scenario

There are two steps to determining non-incentive costs—the starting value and the escalation rate.

Starting Value

The team determined a $/kWh of non-incentive program costs based on the average of historic program spending shown in Table 7 which also happens to be the actual $/kWh in 2022. The model begins with $.05/kWh in non-incentive costs in 2022 and escalates that value annually for all future years.

Table 7. Historical Non-Incentive Program Spending ($/kWh)

Non-Incentives $/kWh	Residential	Commercial
2020	$0.06	$0.07
2021	$0.05	$0.03
2022	$0.05	$0.05
Average	**$0.05**	**$0.05**

Source: Guidehouse (Derived from APS Annual Progress Reports)

Cost Escalation Rate

Non-incentive costs were further escalated to capture future scenarios and changes in EE portfolio framework. This escalation rate is intended to represent:

- Increased costs required to acquire new savings as measure saturation increases over time, and the need to target hard to reach segments.
- Any updates to codes and standards, for instance: Federal lighting standards for general service lightbulbs which are increasing minimum efficiency levels to an LED equivalent lightbulb. This increases the baseline efficiency level that utility program savings are measured against which reduces the available incremental savings that can be achieved through these programs and increases costs needed to achieve additional incremental savings over the new baseline.
- Increased focus on Limited Income and Tribal Communities EE programs that incur higher program delivery and technology costs per unit of EE savings achieved, and
- Increased reliance on complex EE technologies requiring higher levels of customer education and awareness.

The overall rationale for the increase in escalation rates by scenario is that the APS programs will need more resources to attract greater adoption of EE from the same number of customers. Put another way, as a higher percentage of customers adopt EE, it becomes increasingly more costly to develop incentives, marketing, and program design approaches to convince the remaining holdouts to adopt.

The team used the following escalation rates for each scenario shown in Table 8. The analysis team chose 2027 as the basis for determining the escalation rate, as this year is consistent with when the team re-assessed the CE threshold from 1.0 to 0.45 in the High scenario. Additionally, the non-incentive costs for High and Target 1.5% scenario were further increased by 25%.

Table 8. Scenario Non-Incentive Inputs and Rationale

Scenario	Non-incentive Cost Escalation Rate	Non-incentive Additional Cost Increase	Escalation Rate Rationale
BAU	5%	n/a	Based on inflation and historical averages
High	7.5%	25%	Based on the ratio of High to BAU 2027 GWh savings
Target 1.5%	14.9%	25%	Based on the ratio of Target 15% to BAU 2027 GWh savings

Source: Guidehouse

2.2 Results

2.2.1 GWh Savings

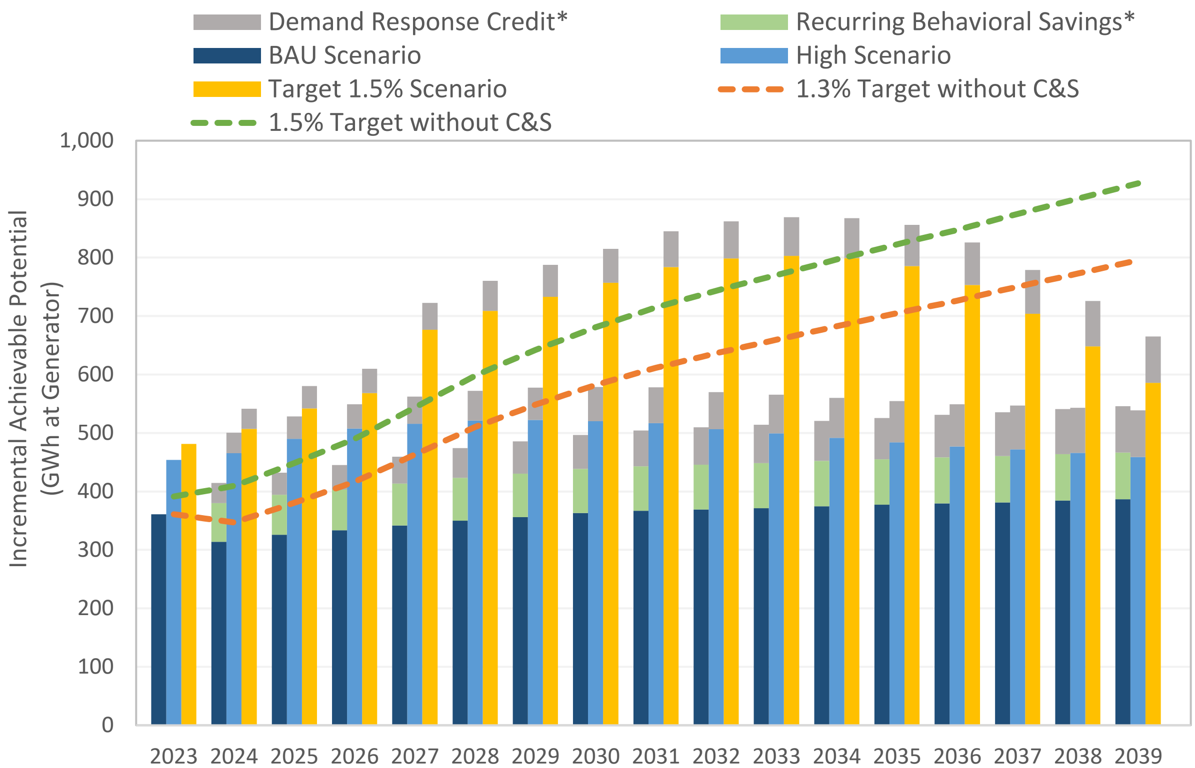
This section includes achievable potential results by scenario, comparing each scenario to the savings targets as 1.3% or 1.5% of the load forecast. The results are presented using targets from two different versions of the load forecast (with and without XHLF customers).

Throughout this report, we show both of these targets as a percent of the prior year forecast retail savings without codes and standards (C&S) – as these codes and standards savings are already included in the load forecast, we do not double count them as program savings[13]. However, the codes and standards savings do count toward compliance goals so it is important to adjust the targets accordingly when identifying whether a portfolio meets the goal.

Throughout this report in all graphs of Incremental Achievable Potential for energy efficiency from 2023-2039 the bars on the bottom of each stack represent what was modeled in the IRP for each scenario, while the stacked bar or bars on top of each bottom bar represent additional credits and savings that count toward compliance with ACC targets but were not modeled in the IRP.

[13] This adjustment also accounts for iDSM measure savings, APS system savings, and other small measures (<10% of overall savings) that were not modeled in this study but do count toward achieving target goals.

Figure 8. Incremental Achievable Potential by Scenario Compared to Load Forecast Targets



Source: Guidehouse
***** *Demand response credit and recurring behavioral savings not modeled in the IRP*

BAU Scenario	High Scenario	Target 1.5% Scenario
Meets 1.3% target until **2026**[14]	Meets 1.3% target until **2029**	Meets 1.3% target until **2037**
		Meets 1.5% target until **2035**

Source: Guidehouse

Achievable savings from the BAU scenario meet the 1.3% target until 2026. Recurring Behavioral Savings[15] and Demand Response Credit add savings that count toward the 1.3% target, but these savings are not modeled in the IRP. This section further details how a modified load forecast (excluding XHLF customers) extends the timeframe for which the BAU scenario meets the 1.3% target.

[14] Even though it appears that the BAU + credits achieves the target in 2027, it is 3 GWh short of the target.

[15] Behavioral savings are embedded in year 1 of the BAU modeled in the IRP, but are additional to what was modeled in the IRP in years 2024 and beyond for the BAU scenario. The High and Target 1.5% Scenarios modeled in the IRP include behavioral savings for all years.

The High scenario represents maximum incentives from APS to customers under currently acceptable industry practice. These incentives cause earlier adoption of EE relative to the BAU scenario, which significantly increases potential from 2023-2033. This scenario will meet the 1.3% target through 2029.

The only way to meet the 1.3% target beyond 2030 with the current load forecast is to cover the entire incremental cost of EE with incentives as in the Target 1.5% scenario. Additionally, this scenario allowed more measures to be considered in the market by relaxing the CE benefit-to-cost ratio threshold from 1.0 down to 0.45 in 2027 and beyond. This is not a realistic policy scenario, yet it does show that it is technically feasible to reach the 1.3% and 1.5% targets through 2037 and 2035 respectively.

It is important to consider the following points regarding the 1.3% target relative to the BAU Scenario:

- Increased load from growth in the EV segment and the extra-high load factor (XHLF) segment (data centers, large industrial, semiconductor manufacturing) make it harder to achieve the 1.3% target. For instance, the XHLF segment causes the EE savings target to increase by approximately 35% in 2030. Additionally, while both XHLF and EV loads provide opportunities for load management and demand response, customer research indicates that there are minimal EE savings opportunities.

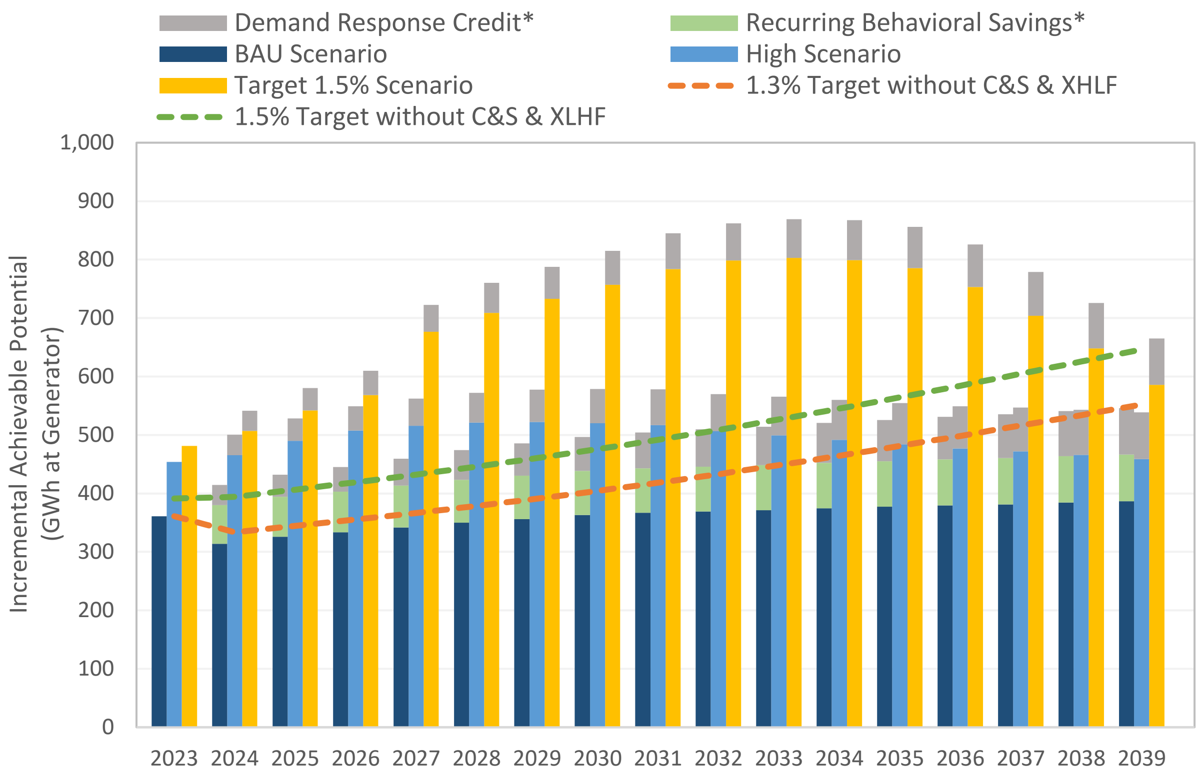
- All scenarios modeled in the IRP do not factor in the conversion of any MWs of peak demand savings from Demand Response programs into MWh equivalence to achieve EE savings goals. In accordance with R14-2-2404[16], these MWhs can account for the achievement of up to 10% of annual EE goals and can be an important component to help reach compliance with EE savings targets within a cost-effective, peak focused DSM portfolio. Figure 8 shows these savings as Demand Response Credit.

- The BAU modeled in the IRP did not accumulate annual savings from Behavioral Savings over time for long term participants. It only considered incremental EE savings from new customers joining the program. However, recurring participants can account for significant MWh savings to help reach compliance. Figure 8 shows these recurring customer savings as Recurring Behavioral Savings.

This is a current estimate of future potential, and APS intends to continue to pursue emerging cost-effective DSM opportunities, but due to the challenge of meeting these targets with currently available technology, the team found it informative to model the targets using an alternative version of the load forecast excluding customers in the extra-high load factor (XHLF) segment.

[16] AZ Admin Code R 14-2-2404

Figure 9. Incremental Achievable Potential by Scenario Compared to Load Forecast Targets excluding XHLF Customers



Source: Guidehouse

***** *Demand response credit and recurring behavioral savings not modeled in the IRP*

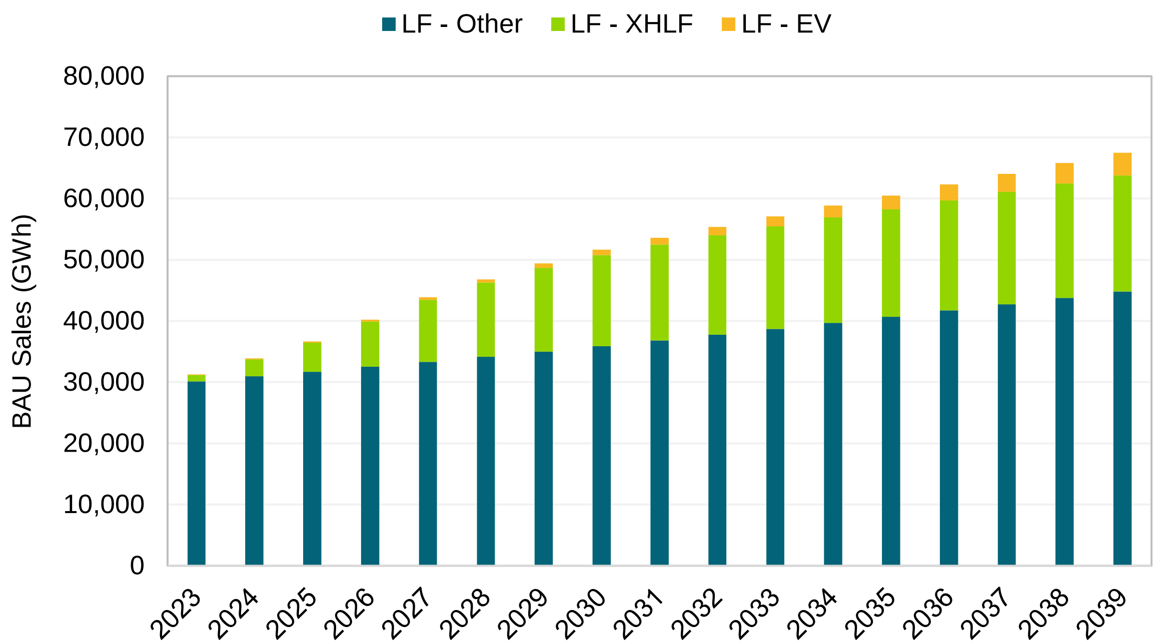
BAU Scenario	High Scenario	Target 1.5% Scenario
Meets 1.3% target until **2039**	Meets 1.3% target until **2038**	Meets 1.3% target until **2039**
		Meets 1.5% target until **2039**

Source: Guidehouse

Figure 9 clearly shows the impact of XHLF customers on the feasibility of meeting the 1.3% savings target. Excluding XHLF customers from the load forecast extends the time that the BAU scenario meets the 1.3% target by 13 years from 2026 to 2039. EE technology can change rapidly in 13 years, so it is reasonable to expect that the BAU scenario could reach the target for beyond the end of the study period due to emerging technologies that are not included in this study due to their immaturity or lack of cost effectiveness by today's standards.

The analysis team shows the targets with the XHLF customers excluded because there is currently little opportunity for EE potential within this customer segment. These customers are large data centers and semiconductor manufacturing plants which are not typical EE program participants. There is precedent for excluding such customers from regulatory compliance targets. For instance, the large mining operation owned by Freeport-McMoRan is the single largest load on the APS system with little opportunity for typical EE measures, and therefore the ACC excludes Freeport-McMoRan loads from the calculation of retail sales used to set DSM savings target. APS may have the option of excluding the XHLF loads using the same logic that justifies the exclusion of Freeport-McMoRan loads. EVs are another large and growing source of additional load that has limited opportunities for efficiency which could be considered exceptional from a compliance target-setting perspective. Figure 10 shows that by 2028 the XHLF segment adds ~10,000 GWh in retail sales which is ~23% of the total retail sales forecast for that year. During this timeframe, EVs are a relatively small contribution to load growth compared to XHLF customers.

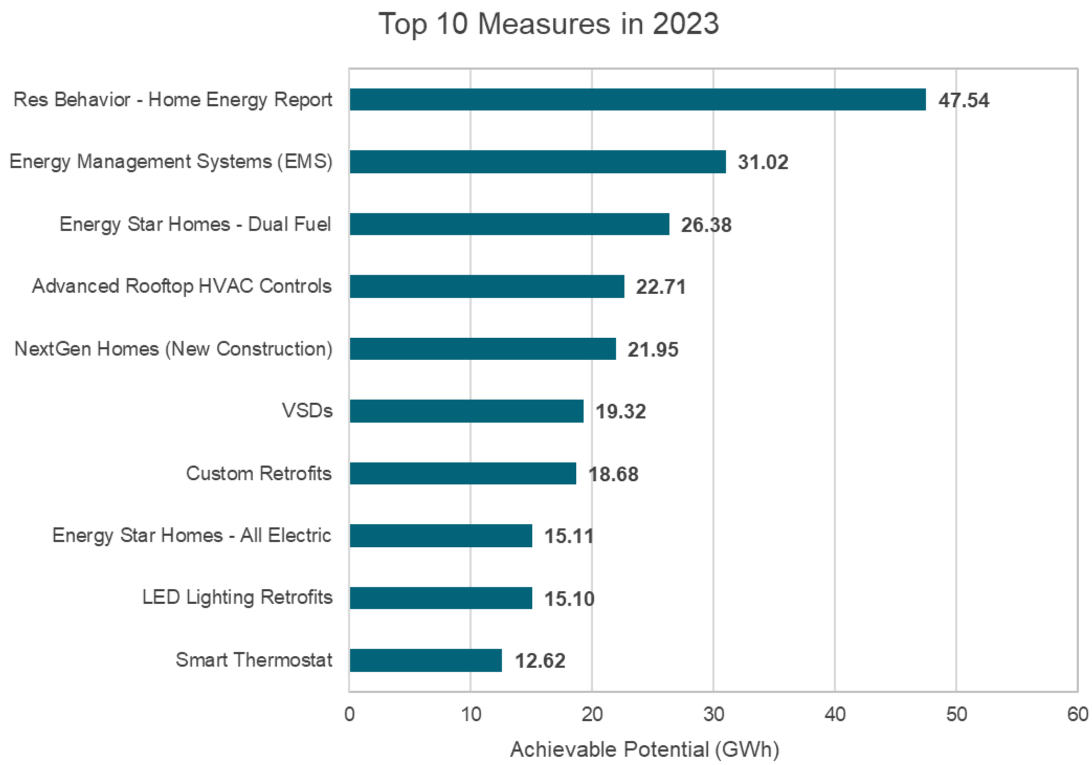
Figure 10. Comparison of Load Forecast Components



Source: Guidehouse graph of APS data

The study objectives as detailed in Section 1.1 led the team to focus on overall portfolio results rather than specific measures that hold the most potential for near-term program design. APS program managers work diligently to track the market conditions year to year and capitalize on specific measure opportunities as part of the implementation planning process which is separate from this study. Figure 11 below shows the top 10 measures in terms of achievable potential in 2023.

Figure 11. Top Ten Measures by Achievable Potential in 2023



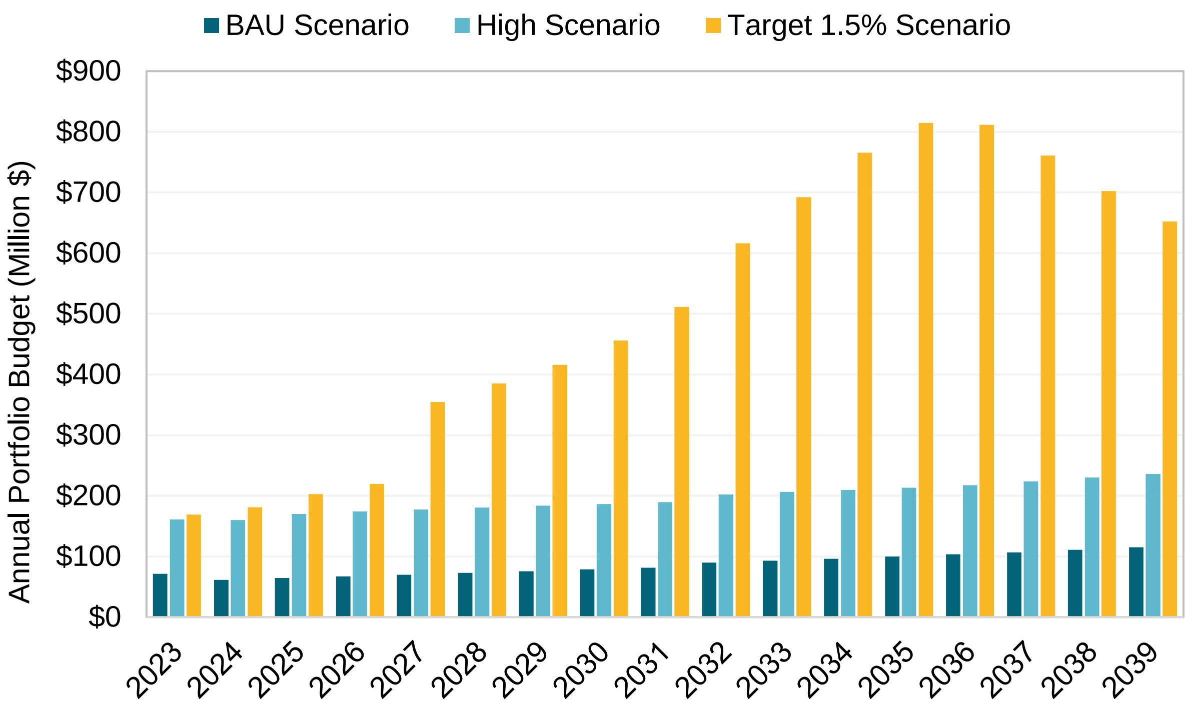
Source: Guidehouse

EE potential in the residential sector is led by the behavioral home energy report program and new home construction. Energy management systems (EMSs) and advanced rooftop HVAC controls are the leading measures in the commercial sector. Variable speed drives, Custom Retrofits, LED Lighting and Smart thermostats also have strong near-term potential.

2.2.2 Portfolio Budget

This section details the portfolio budget in terms of total budget, incentive, and non-incentive costs for achieving EE load reductions. These costs are important for Resource Planning and using EE as a resource, as APS compares the cost of these energy savings with alternative sources of energy generation when developing their IRP. Figure 12 shows the total annual budget by scenario.

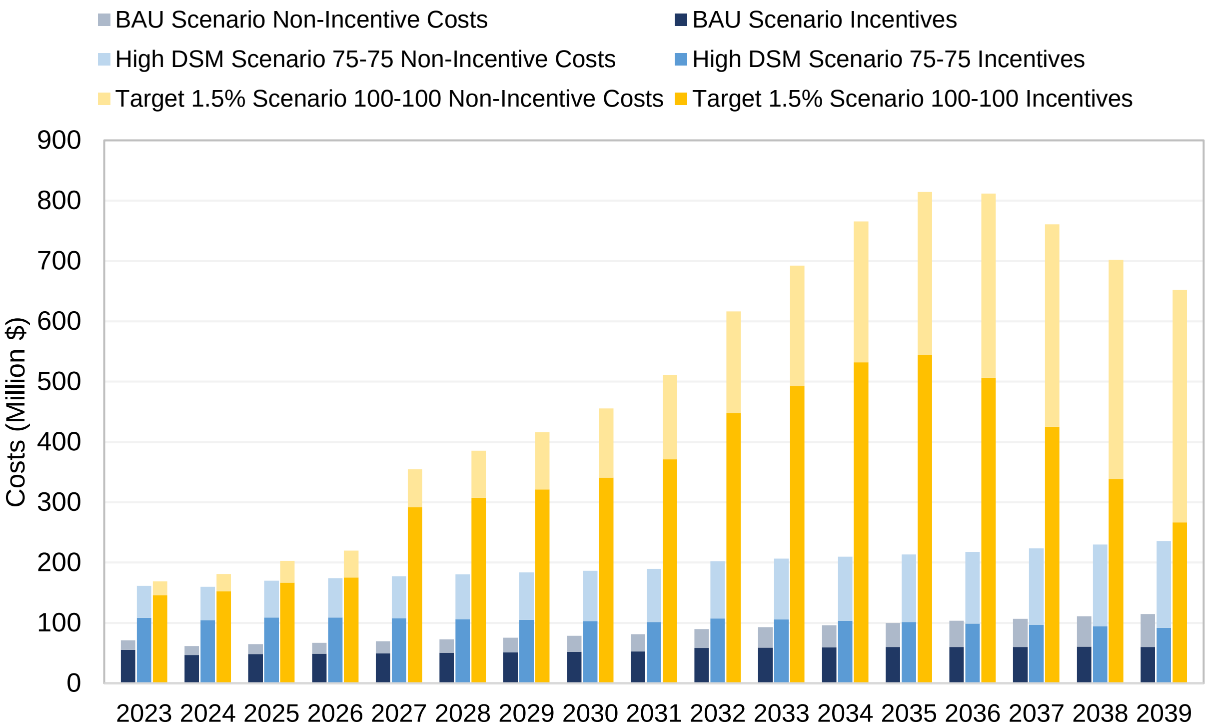
Figure 12. Annual Portfolio Budget by Scenario



Source: Guidehouse

Budgets for the BAU and High scenarios increase with achievable potential (e.g., more incentives are paid) as well as escalation of non-incentive costs due to inflation and the increased marketing required to achieve savings once technologies have saturated most of the market. The Target 1.5% scenario requires significantly more budget due to higher incentives and a higher non-incentive cost escalation rate, as well as the change of the CE benefit-to-cost ratio threshold from 1.0 to 0.45 in 2027. This change includes more technologies in the economic potential which are eligible for incentives, which increases the incentive spending as well as the Achievable Potential. Figure 13 shows the same costs by scenario differentiated by incentive and non-incentive costs.

Figure 13. Annual Portfolio Budget by Scenario and Cost Type



Source: Guidehouse

Figure 13 shows that non-incentive costs are a larger portion of the overall total costs later in the forecast period. The team began each scenario calibrating the total budget allocation between incentive and non-incentive to the average ratio of the cost types from 2020-2022 APS EE Annual Progress Reports. The incentive costs differ across scenarios based on the incentive cost fraction as well as the total units that receive incentives. The non-incentive costs of each scenario are differentiated by modifying the escalation of these costs. Section 2.1.6.5 (Non-Incentive Costs by) Scenario includes more information on the escalation rates used in each scenario.

2.2.3 IRA Impact

An important consideration for future EE potential that was of interest to APS and stakeholders, is in how the recent federal Inflation Reduction Act (IRA) legislation will impact adoption of EE technologies in APS territory. Guidehouse included IRA tax credits until 2032 for applicable measures, and characterized the tax credits to reduce overall measure incremental costs—which in turn increases adoption of these measure due to a reduction in payback periods (see Section 2.1.4 for more information). IRA impacts are included in the High and Target 1.5% scenarios. The methodology for the BAU Scenario described in Section 2.1.6.2 is not conducive to calculating IRA impacts. The top five measures impacted by the IRA are:

1. **Heating Ventilation and Air Conditioning (HVAC) Quality Installation (QI) Seasonal Energy Efficiency Ratio (SEER) 16.2—Residential**. Significant tax credits for HVAC replacements move the market toward this higher efficiency tier.

2. **HVAC QI SEER 15—Residential.** Without the tax credit, more customers choose this measure instead of the higher efficiency SEER 16 measure. Considering the impact of the tax credit actually reduces the savings attributed to this measure in favor of the higher efficiency 16 SEER replacement option.

3. **Air- and Water-Cooled Chillers—Commercial.** In the desert climate zone, the tax credit is 10% and 18% of incremental costs in the retail and lodging sectors respectively which reduces the payback time and increases adoption of this measure.

4. **Advanced Rooftop Controls—Commercial.** Similar to chillers, the payback impact and the adoption increases are greatest in the retail and lodging sectors in the desert climate zone.

5. **EMSs—Commercial.** While the tax credit is a small percentage of the incremental cost for this measure, there are many customers eligible for this measure so even a small reduction in costs yields an increase in savings.

There are two residential measures that are often highlighted in communications related to the IRA, yet the potential for these measures is limited in APS territory:

- **Residential Connected Heat Pump Water Heaters:** Only 25% of residential customers have a technically suitable location for this measure due to the need for electric water heat (instead of gas), Wi-Fi connectivity at the site of the water heater, and sufficient airspace in the installation area to allow the heat pump to function. Even with these technical characteristics, the payback for the heat pump is 8 years (6 years with BAU incentive levels) and the IRA tax credit reduces the cost by 15% when adjusted for eligibility. Due to the long payback time the tax credit does not significantly increase the adoption fraction among customers that are technically eligible to adopt.

- **Residential Attic Insulation:** For this measure to be cost-effective using the ACC SCT, the measure needed to be characterized with an R7 baseline moving to an R43 efficient case. Only 5% of the residential single-family building stock has R7 or less insulation value in the attic. Even if the home is technically eligible, the homeowner would need to be paying enough taxes in order to see some savings from the credit—which further limits eligibility.

2.3 Key Takeaways

This study's results show potential DSM opportunity through EE programs currently offered by APS. This section summarizes some of the key takeaways and unique challenges elucidated by this analysis:

- While the DSM analysis forecasts significant growth in potential in the early years of the forecast period, this growth slows down in the later years as the measures in the current and forecasted portfolio of APS programs saturate the market. It is anticipated that future emerging EE technologies may offer additional cost-effective savings opportunities that have not yet been identified at this time.

- EE program budgets will need to increase significantly in order to meet savings targets beyond 2026. This is largely due to the increase in annual retail sales anticipated over the study period, making the MWhs need to meet annual sales targets that are based on sales increase accordingly. The BAU scenario, which represents the current state of APS programs, meets the 1.3% target until 2026. Increasing incentives to maximum allowable under current framework (to 75% of incremental cost—as represented in the High scenario) results in a 2x increase in budget. The Target 1.5% scenario would require a further 6x increase in budget over the BAU scenario.

- Increased load from growth in the EV segment and the extra-high load factor (XHLF) segment (data centers, large industrial, semiconductor manufacturing) make it harder to achieve the 1.3% target. For instance, the XHLF segment causes the savings target to increase by approximately 35% in 2030. Additionally, current customer research indicates that there are minimal savings opportunities in this XHLF segment relative to the size of additional load growth this segment represents.

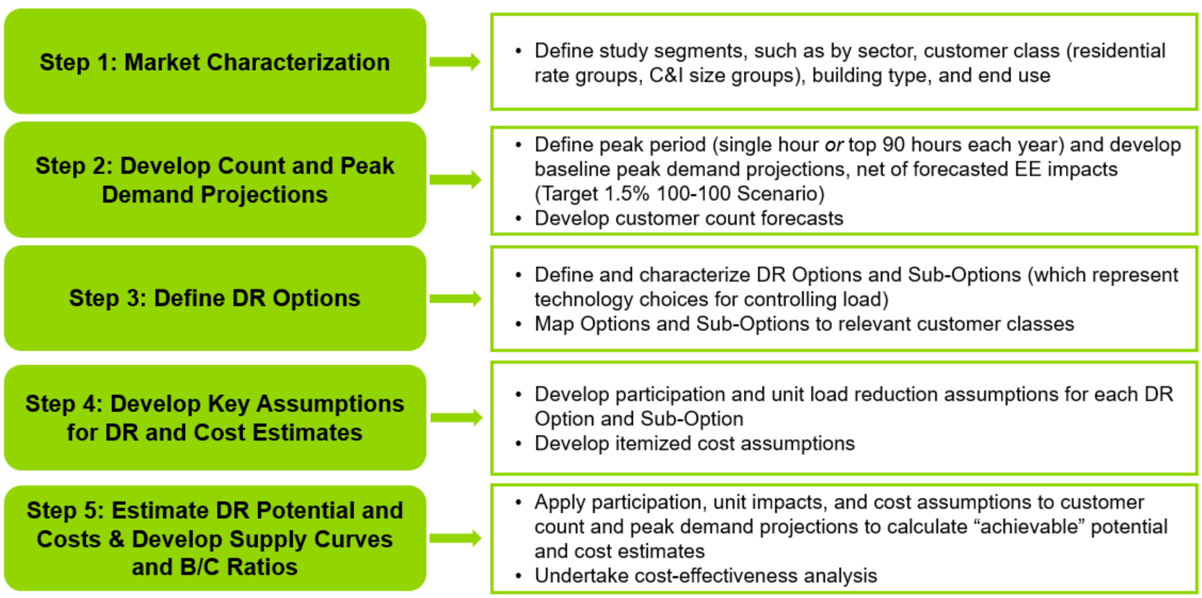
3. DR Potential

The DR potential assessment is based on a bottom-up analysis that utilizes primary data from APS and relevant secondary sources of information. The assessment was conducted using Guidehouse's DRSim model, which was customized for the analysis to represent APS's customer base and characteristics and considered a broad range of DR options that could apply to different market segments. This chapter details Guidehouse's DR potential and cost estimation methodology, key assumptions, and results.

3.1 Methodology Overview and Calculation Approach

Figure 14 summarizes the approach for the DR potential assessment at a high level. This section summarizes and discusses the overall approach with additional details in subsequent sections.

Figure 14. DR Potential Assessment Approach



Source: Guidehouse Analysis

The first step in the potential assessment is market characterization, which consists of defining study segments and developing baseline customer count and peak demand projections. These were developed based on a review of APS-provided customer and overall system data and extensive discussions with the APS team. Then, DR Options and Sub-Options are defined which represent various technology choices for controlling load, and these are each characterized with key inputs which are used to calculate potential. These represent APS's current DR program and pilot offers and new programs/rates that APS could potentially offer in the future to achieve peak demand reduction.

The key inputs for peak load reduction estimation from DR are assumptions on participation rates in DR options (either "% of eligible customers enrolled" or "% of customer peak load enrolled") and unit load reductions (per customer load reduction expressed as either "kW reduction per customer" or as "% reduction in load").

In addition to these two key inputs for peak load reduction calculations, assumptions are made on itemized program costs necessary for estimating annual program budgets and for undertaking CE assessment of individual DR options and the DR portfolio.

The characterization of DR options is primarily based on data from APS's current program and pilot offers and where applicable, data and assumptions provided in APS's IP, C&I customer survey findings (described in Appendix A), and benchmarking with similar programs and options offered by other program administrators.

Table 9 summarizes the key input variables for the estimation of peak load reduction potential and associated costs and the necessary variables for undertaking CE assessment.

Table 9. Key Variables for DR Savings and Cost Estimates

Item	Description
Participation Rates	• Percentage of eligible customers or load that enrolls in a DR Option
Unit Impacts	• kW reduction per device/customer • Reduction as % of enrolled load
Program Costs	• One-time fixed costs for program development. • One-time variable costs for customer recruitment and program marketing, equipment installation and enablement. • Recurring fixed and variable costs such as annual program admin. Costs, customer incentives, O&M, etc.
Avoided Costs	• Avoided generation capacity costs • Avoided transmission and distribution (T&D) capacity costs
Global Parameters	Program Life, Discount Rate, Inflation Rate, Line Losses, Avoided Costs

Source: Guidehouse

3.2 Market Characterization and Baseline Projections

This section details market characterization, which is the first step in the assessment of DR potential. Market characterization consists of defining study segments and then developing baseline customer count and peak demand projections for each customer segment. This characterization of the APS market forms the basis for estimates of potential from DR measures.

3.2.1 Customer Segmentation

Table 10 presents the different levels of market segmentation for the DR potential assessment. The overall segmentation approach is based on existing segmentation in APS data products and forecasts, the DR Options and Sub-Options, and discussions with APS staff. Guidehouse excluded certain segments present in APS-provided data from the potential assessment based on discussions with APS staff, including AG-X, Irrigation, Streetlighting, and Public Authority.

Table 10. Market Segmentation for DR Potential Assessment

Level	Description
Level 1: Sector	• Residential • Commercial and Industrial (C&I) • EVs

Level 2: Customer Class (Size for C&I)	• **Residential**: Standard, Demand, Time of Use
	• **C&I customers by size,** following rate schedules:
	  o Extra Small C&I: average summer peak demand up to 20 kW
	  o Small C&I: average summer peak demand up to 100 kW
	  o Medium C&I: average summer peak demand up to 400 kW
	  o Large C&I: average summer peak demand up to 3,000 kW
	  o Extra Large C&I—Excluding Mines: average summer peak demand greater than 3,000 kW
	  o Extra Large C&I—Mines: average summer peak demand greater than 3,000 kW
	  o Extra High Load Factor: average summer peak demand greater than 5,000 kW
	• **EVs**

Level 3: Building Type (within each C&I class)	• **16 C&I Building Types:** Agriculture, Communications, Data Centers, Education, Entertainment/Recreation, Food Service, Government, Grocery, Healthcare, Lodging, Manufacturing/Industrial, Miscellaneous/Other, Office, Retail, Warehouse, Wholesale Trade
Level 4: End Use (for each building type)	• **Residential:** space cooling, space heating, electric water heating, appliances, EV, battery • **C&I:** HVAC, electric water heating, lighting, refrigeration, other, total facility (where end-use breakdown does not apply) • **EVs:** charging demand

Source: Guidehouse

The first level of segmentation is by sector, which includes residential, C&I and EVs. The second level of segmentation is by customer class. Residential customers are categorized into three classes based on rate schedule. C&I customers are categorized into APS size categories according to maximum demand values. C&I customers were also split into 16 building type categories based on a combination of the premise type values present in APS data and commonly represented building types in similar potential assessments. Residential customers were not segmented by building type.

The final level of segmentation is by end use within each customer class and building type where possible using data from APS load research for residential customers and National Renewable Energy Laboratory ComStock[17] data for C&I customers. Within the C&I sector, the following six building types could not be segmented at the end-use level and thus all load was considered "total facility": Agriculture, Data Centers, Entertainment/Recreation, Manufacturing/Industrial, Miscellaneous/Other, and Wholesale Trade.

[17] National Renewable Energy Laboratory ComStock Data for Phoenix.

3.2.2 Baseline Projections

The next step after defining the customer segmentation was to develop baseline projections for the number of accounts and associated peak demand by customer class and building type over the potential analysis forecast period (FY 2023 to 2043). These estimates serve as the foundation for DR potential estimates. Figure 15 summarizes the data inputs and processing steps used to develop these customer count and peak demand projections.

Figure 15. Approach for Developing Customer Count and Peak Demand Projections

Inputs	Outputs
• **APS-Provided Data Sources** ✓ Hourly system 8760 load forecasts, 2021-2043 ✓ Customer count and annual sales forecasts by sector and class, 2023-2052 ✓ Detailed customer count and sales breakdown by class and premise type, 2021 ✓ 2021 AMI data and cross-reference files • **Guidehouse Data Sources** ✓ Forecasted energy efficiency hourly impacts, 2023-2043	• Baseline peak demand and customer count projections (by sector, customer class, and building type)

Data Processing Steps

- Defined **peak periods** in each year using system hourly load forecasts (single hour peak *or* top 90 hour peak options)
- Mapped AMI data records to study segments (customer class and building type) using demographic and cross reference files
- Used mapped AMI data to calculate average hourly coincident peak demand and **peak load factors** by customer segment
- Mapped and analyzed 2021 detailed count and sales breakdowns to determine segment splits, and used these splits to calculate **annual sales forecasts** by study segment
- Combined annual sales forecasts by study segment with AMI-derived peak load factors to calculate **coincident peak demand**
- **Calibrated** bottom-up calculated peak estimates with overall system load forecasts, accounting for hourly EE/DSM impacts and line losses

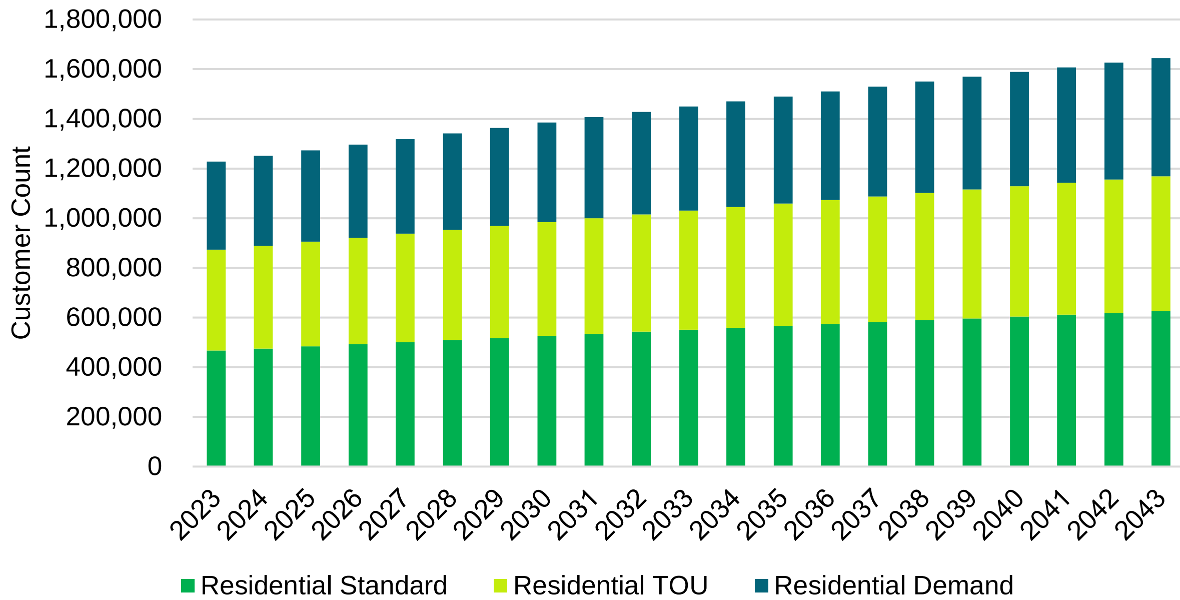
Source: Guidehouse

At a high level, the projections were developed using various data inputs provided by APS. These included forecasts of customer counts and annual sales by sector and customer class, as well as detailed segmentation breakdowns by premise type and individual customer-level Advanced Metering Infrastructure (AMI) usage data for the base year of 2021. The following sections provide additional detail on the data processing steps and show summary results for the customer count and peak demand projections.

3.2.3 Customer Count Projections

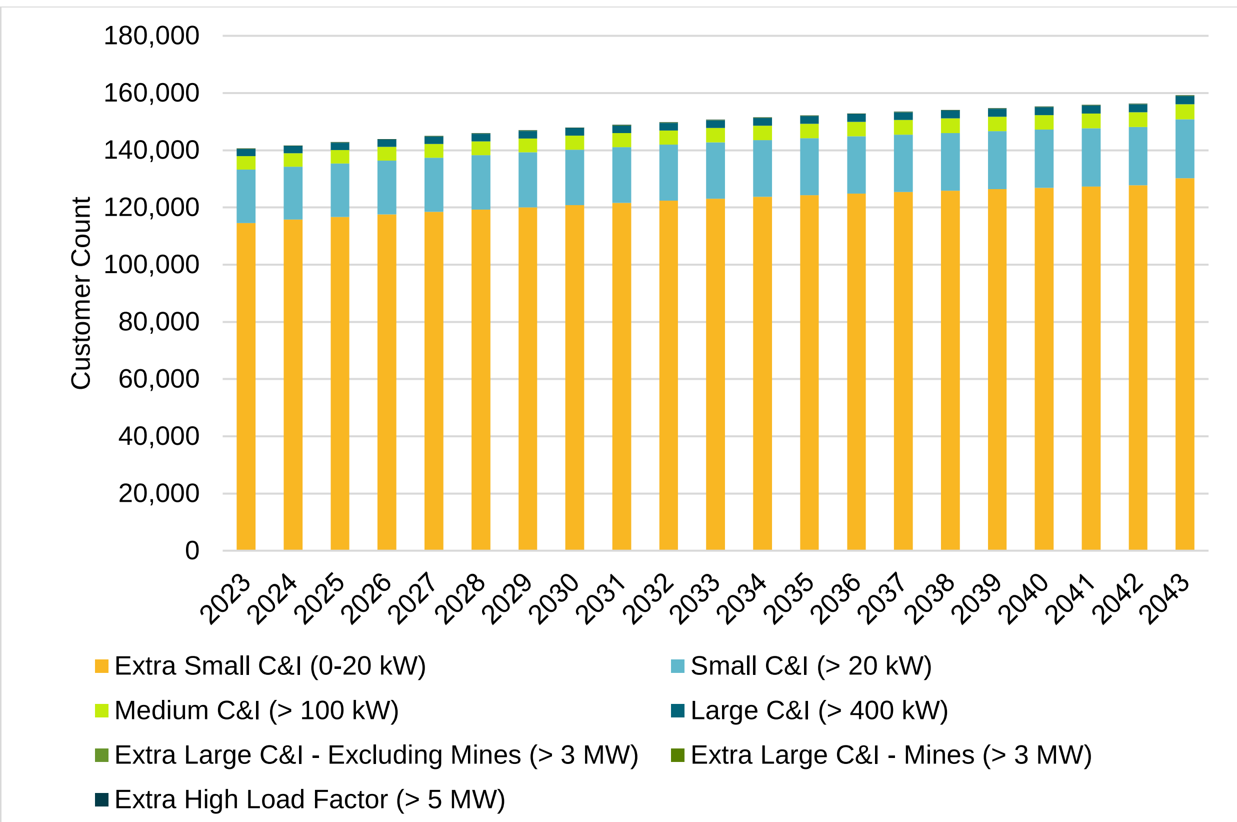
APS provided forecasts of residential accounts at the sector level and C&I accounts at the customer class level out to the end of the study period. In addition, APS provided a detailed breakdown of accounts by rate class and building type for the base year of 2021. To disaggregate customer count forecasts to the required level of granularity, Guidehouse developed factors from the 2021 data to split total residential and C&I counts into customer class and building type segments, and then applied these split factors to future projections from 2023 to 2043. Figure 16 and Figure 17 show the resulting customer count projections by customer class for the residential and C&I sectors respectively.

Figure 16. Residential Customer Count Projections by Customer Class



Source: Guidehouse

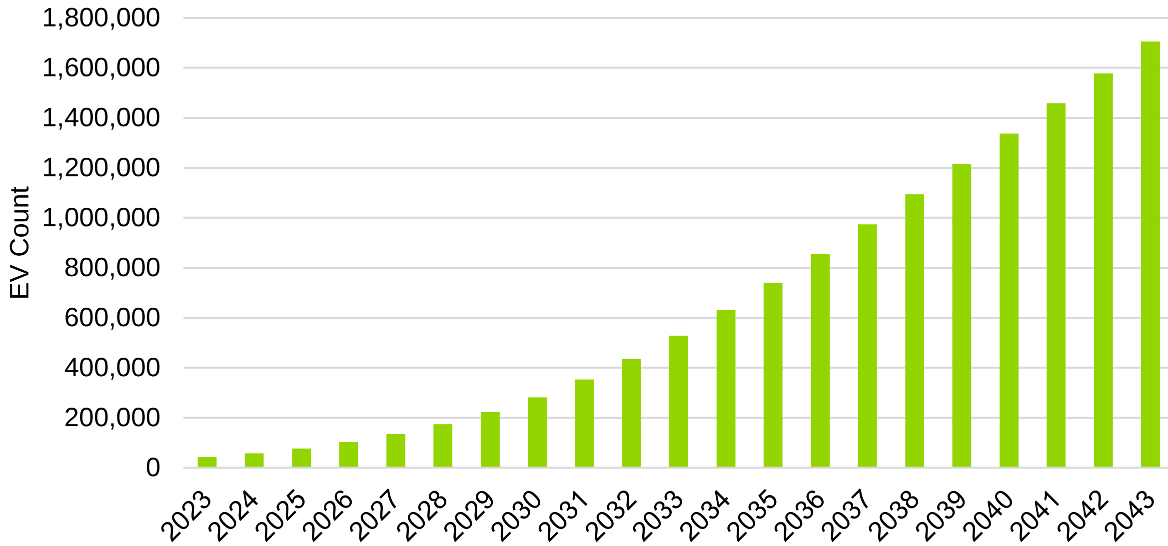
Figure 17. C&I Customer Count Projections by Customer Class



Source: Guidehouse

EV count projections were obtained in a separate data file provided by APS. There were no further subdivisions for EVs, and the projected count is shown in Figure 18.

Figure 18. EV Count Projection



Source: Guidehouse

3.2.4 Peak Demand Projections

In addition to customer counts, Guidehouse developed baseline projections of coincident peak demand for each study segment. The first step in developing peak demand projections is to define a peak period. Guidehouse considered two different peak period definitions for the overall DR Potential analysis and developed separate baseline peak demand projections using each definition:

Single Hour Peak. The peak period is defined simply as the single net system hour with the highest net load (net of distributed generation (DG) and EE) in each year. The DR potential results associated with this single hour peak definition were used by APS for IRP analysis.

Top 90 Hour Peak. The peak period is defined as the highest 90 net system load hours in each year, and the resulting peak demand for each customer segment is calculated as the average hourly demand across the top 90 net system hours in each year. This definition is consistent with APS's existing Peak Solutions program design, in which up to 18 events can be called for five hours per event in a given season.

The data sources for developing bottom-up peak demand estimates included the following APS-provided data for both the residential and C&I sectors: annual sales forecasts out to 2052 (without any embedded DSM impacts), detailed sales breakdowns by customer segment for the 2021 base year, customer-level AMI usage data for 2021 and cross-reference files, and hourly net system load forecasts from 2023 to 2043.

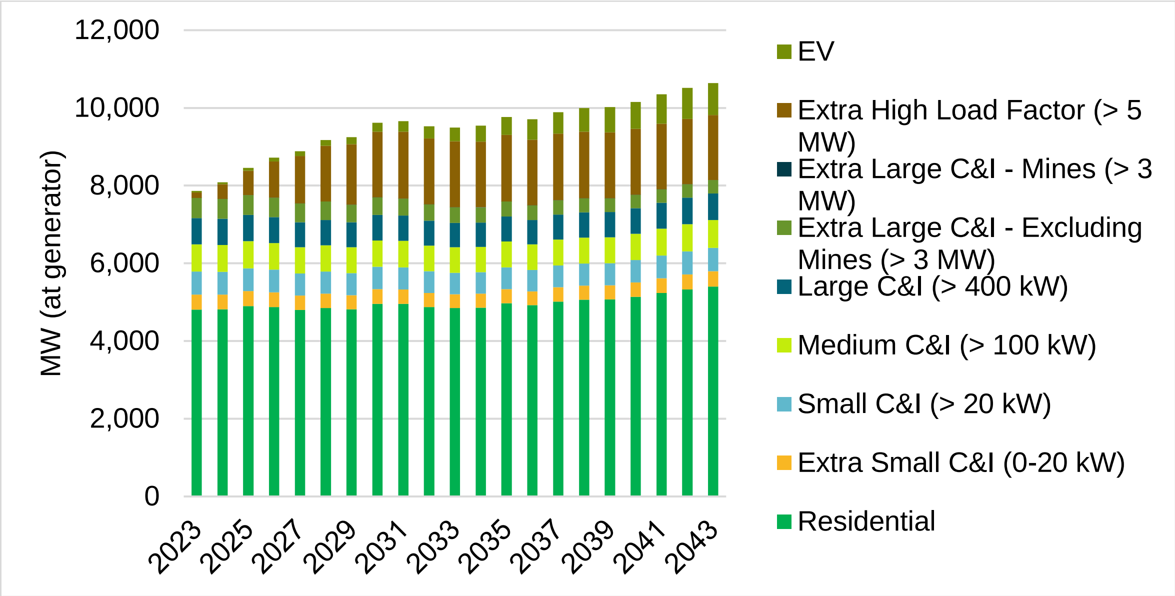
Like the customer count data, APS provided annual sales forecasts for residential at the sector level and for C&I at the customer class level. Guidehouse used the relative proportion of sales by customer class and building type within the detailed 2021 sales data to split annual sales forecasts to the required level of disaggregation.

To derive average coincident peak demand from the resulting annual sales forecasts for each customer segment, Guidehouse calculated coincident load factors using customer-level AMI data for 2021. Mathematically, the load factor for a given customer or customer group is the ratio between average hourly demand across an entire year (i.e., annual sales divided by 8,760 hours in a full year) and the average hourly demand during the peak period (i.e., the single peak hour or the average of the top 90 net system peak hours). Using demographic and other cross-reference files provided by APS, Guidehouse mapped, grouped, and aggregated individual customer records in the AMI dataset by customer class and building type segment to determine hourly load by customer segment in 2021. Using this in combination with an identification of the top single load hour or top 90 load hours for the overall system, Guidehouse calculated load factors for each customer segment. Then, applying these load factors derived from the AMI data to the annual sales forecasts for 2023-2043 yielded peak demand estimates for each customer segment.

Guidehouse then performed calibration adjustments to these “bottom-up” estimates derived from disaggregated annual sales forecasts and calculated load factors. Separate from the annual sales forecasts, APS provided hourly load forecasts at the total gross system level prior to any DSM impacts. Guidehouse adjusted this hourly gross system load forecast to account for forecast peak demand reductions associated with EE achievable potential. Specifically, Guidehouse used cumulative hourly DSM impact results from the EE potential study Target 1.5% (100-100) scenario to calculate an adjusted hourly system load value, net of both DG and EE. This was then used to identify the top single hour or top 90 net system demand hours and calculate a “top-down” system level peak demand in each forecast year. Finally, all bottom-up estimates were adjusted proportionally such that in aggregate, the total forecast peak demand across all customer segments matched the “top-down” system load forecast (gross load forecast minus EE, but with DG included, since the baseline peak demand for DR potential calculations should be net of EE only, but not net of DG).

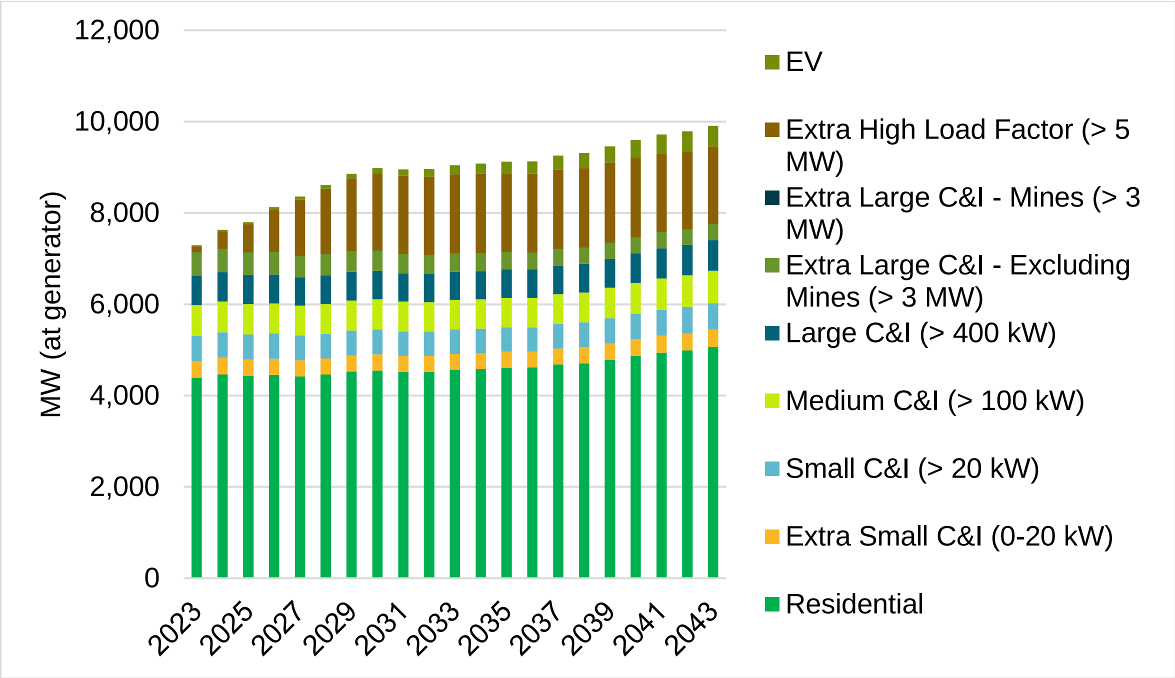
Figure 19 and Figure 20 show the resulting final baseline net peak demand projections by customer class for the single hour peak and top 90-hour peak definitions, respectively, over the study forecast period of 2023 to 2043. The projections shown in the figures are estimated at the generator (i.e., including line losses) and are net of EE impacts for the Target 1.5% (100-100) scenario, but not net of DG.

Figure 19. DR Baseline Net[18] Peak Demand Projections by Customer Class – Single Hour Peak



Source: Guidehouse

Figure 20. DR Baseline Net[19] Peak Demand Projections by Customer Class – Top 90 Hour Peak



Source: Guidehouse

[18] Net of EE, but not net of DG (EE is subtracted out, but DG is included in the peak demand).
[19] Net of EE, but not net of DG (EE is subtracted out, but DG is included in the peak demand).

3.3 Characterization of DR Options

Once the baseline net peak demand projections were developed, the next step was to characterize the different types of DR options that could be utilized to curtail summer peak demand. Table 11 below summarizes the DR options included in the analysis. These DR options represent DR programs and rates that APS currently offers, plus new programs and rates that APS could potentially offer to realize greater savings from DR. The sub-options associated with the different options specify the controlled end uses and enabling technologies.

Table 11. Summary of DR Options Included Under DR Potential Assessment

DR Option	DR Sub-Options	Eligible Customer Classes	Targeted/Controlled End Uses
Smart Devices and Direct Load Control (DLC)[20]	• CAC/Heat Pump/HVAC control via thermostats • Smart HPWH/ERWH or control via switch • Pool Pump Control • Water Heating Control	• Residential: all classes • Extra Small C&I • Small C&I	• HVAC, Water Heating, Pool Pump
C&I Curtailment[21]	• HVAC (manual and Auto-DR enabled) • Lighting (standard and advanced controls) • Water Heating Control • Refrigeration control • “Other” end-use curtailment • Total Facility (for segments that do not have end-use disaggregation)	• Small C&I • Medium C&I • Large C&I • Extra Large C&I (excluding mines) • Extra Large C&I (Mines) • Extra Large C&I (Extra High Load Factor)	• HVAC, Lighting, Water Heating, Refrigeration, Total Facility, Other
C&I Load Shift to BUGs[21]	• Load shift to Backup Generators (BUGs)	• All C&I with BUGs	• Total Facility
Dynamic Pricing	• Dynamic Pricing with enabling tech • Dynamic Pricing without enabling tech	• Residential: all classes • C&I: all classes	• Total Facility
BTM Battery Dispatch	• Res BTM Battery Dispatch • Com BTM Battery Dispatch	• Res Battery • Com Battery	• Batteries
EV Managed Charging	• EV Managed Charging	• EV	• EVs
EV Behavioral	• EV Behavioral	• EV	• EVs
EV V2G	• EV V2G	• EV	• EVs
Behavioral DR	• Behavioral DR	• Residential: all classes	• Total Facility

Source: Guidehouse

[20] For the purposes of this potential assessment, the Smart Devices and DLC Option represents both switch-based control programs and technology-enabled control programs such as smart thermostat control or smart water heating control.

[21] Both C&I Curtailment and C&I Loadshift to BUGs represent potential associated with the Peak Solutions program.

The characterization of these DR options is based on research and review of multiple documents and data sources. For the DR options that represent APS's current program offers, Guidehouse reviewed APS's current program information and evaluation, measurement, and verification (EM&V) findings to develop the eligibility, participation, unit impacts and cost inputs, and calibrated those to latest program performance data. Additionally, Guidehouse represents what is included in the latest plan for these items for programs that APS currently offers or plan to offer in the future.

In tandem with the potential study effort, the Guidehouse-Tierra team conducted customer surveys and interviews to assess participation likelihood in different types of DR program offers and load curtailment/shift estimates from these programs (included current DR programs offered by APS and potential new program offers). The customer survey and interview approach and the findings from these activities are described in detail in Appendix A. The study undertook a comprehensive review of the survey and interview findings and leaned heavily on these findings and insights to help inform participation and impact assumptions by program type and by customer class and segment. In addition, any gaps identified were supplemented with benchmarking data from similar DR programs offered by other utilities. This study also draws on data from the EE potential analysis, where applicable, for characterizing DR options. For example, the saturation of DR-enabling energy efficient technologies (e.g., smart thermostats) is informed by the adoption of these technologies in the EE potential assessment described in the previous chapter.

The key characteristics of individual DR options are further described below.

3.3.1 Smart Devices and DLC Option Characterization

Table 12 summarizes the key characteristics of the Smart Devices and Direct Load Control (DLC) option. This option includes APS's current Cool Rewards program and water heating controls as sub-options. It also includes pool pump control, which APS currently does not offer as program, but could potentially offer in the future and for which APS wanted to assess net peak demand reduction potential.

Table 12. Smart Devices and DLC Options Characteristics

Item	Description
Overview of Smart Devices and DLC Option	This includes the following sub-options: • DLC-Smart Thermostat-Central AC, which represents APS's Cool Rewards program that manages AC load using smart thermostats. It represents a Bring Your Own Thermostat delivery approach based on APS's current program offer. • Water Heating DLC, which represents management of water heating load using either a smart switch retrofitted to a water heater or a smart water heater with integrated control. • Pool pump control, using a smart switch.
Eligible Customers	• All residential customer classes with eligible end-use equipment and control • All Extra Small and Small C&I customers with eligible end-use equipment and control.
Enrollment Assumptions	• Residential steady state participation levels[22] range from 30%-40% of eligible customers depending on the sub-option and customer segment. • C&I steady state participation levels (for eligible customer classes) range from 5%-40%, depending on the sub-option and customer segment. • Residential and C&I participation ramps up to steady state participation level by 2028-2029.
Unit Impacts[23] (Single Hour Peak Demand Reduction per Device)	• Central AC control: 1.49 kW reduction per thermostat[24] • Water Heating control: 0.29 kW for electric resistance water heater[25]; 0.17 kW for heat pump water heater[26] • Pool pump control: 0.094 kW per device[27]

Participation Incentives	• Central AC control
	  ○ $50 per thermostat upfront incentive (on DR program enrollment) and $35/yr. annual incentive
	• Water Heating control
	  ○ $15 per device upfront incentive (on DR program enrollment) and $10/yr. annual incentive
	• Pool Pump control
	  ○ $10 per device upfront incentive (on DR program enrollment) and $5/yr. annual incentive

Source: Guidehouse

3.3.2 C&I Curtailment Characterization

The C&I Curtailment DR Option represents the existing APS Peak Solutions program. Table 13 summarizes the key characteristics of the C&I Curtailment Option. Overall, the characterization is based on analysis of actual 2022 Peak Solutions Performance Summary data provided by

[22] Represents participation levels in mature programs after an option is fully ramped up.
[23] All unit impacts are the highest single hour impacts during an event at the meter.
[24] From APS Cool Rewards 2022 End of Season Update.
[25] From APS Connected Water Heaters Impact Evaluation, February 2023
[26] From ProCESS 2023 Model
[27] From EE potential measure characterization information.

APS and CPower, AMI data, benchmarking with other jurisdictions, and customer survey results.

Table 13. C&I Option Characteristics

Item	Description

Sub-Options	• For C&I building types with end-use breakdown data
	  ○ Manual HVAC Control
	  ○ Auto-DR HVAC Control
	  ○ Refrigeration Control
	  ○ Standard Lighting Control
	  ○ Advanced Lighting Control
	  ○ Water Heating Control
	  ○ Other Control
	• For C&I building types without end-use breakdown data
	  ○ Total Facility Control

Eligible Customers	• All C&I building types and customer classes except Extra Small C&I
Participation Assumptions	• Current participation levels (in 2022 and 2023) were derived from summer 2022 Peak Solutions performance data and AMI data and calibrated to actual impacts • Steady state participation levels vary widely depending on sub-option, customer class and building type ○ Steady state participation assumptions are based on existing participation, benchmarking with other jurisdictions, and customer survey results • A participation ramp factor defines the growth trajectory from current (2022 and 2023) participation up to the steady state rate over a 5-year period
Unit Impacts	• Unit impacts are based on summer 2022 Peak Solutions performance data

Calibration	• Total C&I curtailment potential (estimated at the meter) is calibrated to:
	  ○ 31.2 MW in 2022 (average impact over five summer 2022 events)
	  ○ 35.0 MW in 2023 (based on ProCESS Model and input from APS staff)

Source: Guidehouse

Within the overall C&I Curtailment Option are several end-use-specific sub-options. These sub-options were used to characterize building types for which end-use load breakdown data was available.[28] For end-use-specific sub-options, the characterization also includes eligibility factors which are based on EE study adoption outputs; for example, customer eligibility for the Auto-DR HVAC control sub-option is based on the adoption of the building EMS measure in the EE potential study. For building types where end-use load breakdowns were not available,

[28] The building types with data on load breakdown by end use, and for which the end-use specific sub-options were used include Communications, Education, Food Service, Government, Grocery, Healthcare, Lodging, Office, Retail, and Warehouse.

Guidehouse used the total facility control sub-option to represent potential at the whole building level.[29]

The participation rate for each C&I segment is defined as the percent of each segment's total net peak demand that is enrolled in the program, while the unit impact factor is defined as the realized load impact as a percent of the total net peak demand for enrolled customers (also known as reference load). While participation in the Peak Solutions program involves customer nominations which are less than a customer's peak reference load, nominations are not explicitly incorporated into the calculations. Instead, the unit impact factor implicitly incorporates both the nomination as a percent of customer reference load and the realized impact as a percent of the nomination in a single factor.

To estimate existing participation rates in the Peak Solutions program, Guidehouse identified specific customer accounts participating in Peak Solutions from the 2022 end-of-season enrollment data and mapped each participating customer to the appropriate customer class and building type. The list of existing program participants was combined with AMI data to estimate the baseline net peak demand (reference load) for participating customers, which was then aggregated across each customer segment. Dividing this value by the total segment baseline net peak demand from the market characterization analysis yielded an existing 2022 participation rate. The first four columns of Table 14 show the result of these existing 2022 participation calculations at the building type level. This analysis of Peak Solutions performance data and AMI data in combination with the baseline market characterization was also used to generate unit impact values for each C&I customer segment.

[29] The following six building types could not be segmented at the end use level and thus all load reductions were represented under the "total facility" sub-option: Agriculture, Data Centers, Entertainment/Recreation, Manufacturing/Industrial, Miscellaneous/Other, and Wholesale Trade

Table 14. C&I Curtailment Participation Assumptions by Building Type, 2022

C&I Building Type	Total Segment Baseline Peak Demand (MW)	Existing Participant Peak Demand (MW)	2022 Existing Participation (% of Peak Demand)	Steady State Participation Rate (% of Peak Demand)
Agriculture	0.6	-	0%	30%
Communications	17.1	-	0%	5%
Data Centers	39.8	-	0%	5%
Education	114.8	28.9	25%	Up to 53% (varies by class)
Entertainment/ Recreation	6.5	2.5	38%	Up to 55% (varies by class)
Food Service	111.5	0.1	0%	5%
Government	160.5	16.6	10%	25%
Grocery	67.5	0.8	1%	40%
Healthcare	117.1	-	0%	5%
Lodging	71.7	1.0	1%	10%
Manufacturing/ Industrial	333.3	16.0	5%	25%
Miscellaneous/ Other	622.4	80.9	13%	25%
Office	363.4	3.0	1%	30%
Retail	302.3	61.4	20%	Up to 80% (varies by class)
Warehouse	27.1	0.2	1%	5%
Wholesale Trade	5.3	0.0	1%	5%
Total	**2,360**	**211.5**	**9%**	**-**

The full participation rate analysis was performed at both the building type and customer class level of granularity. For simplicity, this table summarizes results at the Building Type level only.

Source: Guidehouse

In addition to characterizing existing participation in 2022, Guidehouse also developed steady state participation rate assumptions, which are shown in the rightmost column of Table 14. The steady state participation rate represents the maximum proportion of net peak demand that could be expected to participate in the program. Guidehouse developed steady state participation assumptions using existing participation rates and results from the customer survey where possible. The customer survey included questions asking C&I customers about their willingness to participate in Peak Solutions; however, small response sample sizes especially at the individual segment level limited the number of segments for which the survey results could be used. As a result, Guidehouse also utilized benchmarking with other jurisdictions to develop steady state participation assumptions.

After characterizing both existing participation and steady state participation assumptions, Guidehouse calculated a participation ramp factor with a 5-year S-shaped growth curve to define the trajectory of growth from current participation levels up to the steady state rate.

As a final step in the C&I Curtailment characterization, Guidehouse calibrated achievable potential results for 2022 and 2023 to existing and expected Peak Solutions program impacts. Table 15 shows target calibration values aggregated by building type. For 2022, C&I curtailment potential was calibrated to a total of 31.2 MW across all segments, which was the average impact over the five Peak Solutions events in summer 2022. Total potential for 2023 was calibrated to 35.0 MW based on ProCESS model projections and input from APS staff.

Table 15. C&I Curtailment Achievable Potential Calibration

C&I Building Type	2022 Calibrated Achievable Potential (MW, at meter)	2023 Calibrated Achievable Potential (MW, at meter)
Agriculture	-	0
Communications	-	0
Data Centers	-	0
Education	2.4	2.7
Entertainment/Recreation	0.2	0.2
Food Service	0	0
Government	4.6	4.9
Grocery	0	0.3
Healthcare	-	0.2
Lodging	0	0
Manufacturing/Industrial	11.9	13.0
Miscellaneous/Other	6.7	7.6
Office	0.1	0.8
Retail	5.3	5.1
Warehouse	0	0
Wholesale Trade	0	0
Total	**31.2**	**35.0**

Source: Guidehouse

The full calibration analysis was performed at both the building type and customer class level of granularity. For simplicity, this table summarizes results at the Building Type level only.

3.3.3 C&I Load Shift to BUGs Characterization

The C&I Load Shift to BUGs option characterization was relatively simple. It consisted of defining the projected capacity of BUGs enrolled in the Peak Solutions program over time. These forecast capacity values are defined under a separate customer segment in the model and flow directly through as the achievable potential estimate; that is, they are not adjusted by any eligibility, participation, or unit impact factors.

The forecast BUG capacity values were informed by data provided directly from APS on existing and anticipated BUG enrollments and from the customer survey. The forecast starts with 5 MW of BUG capacity in 2023, and this increases by 10 MW every year up to a final value of 45 MW in 2027 and onward.[30]

3.3.4 Dynamic Pricing Characterization

Table 16 below summarizes the key characteristics of the Dynamic Pricing option. It represents a Critical Peak Pricing (CPP) rate offer where APS could call CPP events either on a day-ahead or day-of basis to reduce demand during net peak hours. Participants are not provided any separate incentive but get a discounted off-peak rate that is lower than their Otherwise

[30] These BUG capacity values are all at the meter.

Applicable Tariff (OAT). For residential customers, the Dynamic Pricing option included in the analysis represents APS's current CPP rate offer to these customers. For C&I customers, dynamic pricing represents a potential new CPP offer to all customer classes.

Table 16. Dynamic Pricing Option Characteristics

Item	Description
DR Option Overview	• This represents an "opt-in" CPP offer to all residential and C&I customers. • For residential customers, the Dynamic Pricing option represents APS's current CPP rate offer. • For C&I customers, the dynamic pricing represents a potentially new CPP rate offer to all C&I customer classes with a 6:1 critical peak to off-peak price ratio. • This option includes the following two sub-options: o Dynamic pricing without enabling technology: this represents customers who provide purely behavioral response to the rate without the aid of any enabling technology to reduce load during CPP events. o Dynamic pricing with enabling technology: this represents customers who could potentially provide enhanced response to the rate with the aid of enabling technology such as smart thermostats and automated DR (Auto-DR) using EMS or other types of enabling technologies. The load reduction impacts from these customers during CPP events would be higher than those from customers without any enabling technology.
Eligible Customers	• All residential customers • All C&I customers Customers who are not enrolled in the Smart Devices and DLC option are eligible to enroll in the CPP rate. Customers cannot dually enroll in both Smart Devices and DLC and CPP. This is considered in the analysis to avoid double counting of impacts from the same participants for Smart Devices and DLC and CPP.
Program Enrollment Assumptions	• 20% of eligible customers (represents steady state enrollment levels once the program matures by 2028-2029). o Residential CPP rate offer assumed to continue and reach steady state enrollment level by 2028. o C&I CPP rate offer assumed to start in 2024 and ramp up to steady state participation by 2029.
Unit impacts (Average Peak Demand Reduction per Enrolled Participant)	• For Residential: 7%-10% peak demand reduction, varies by customer class (calibrated to impacts from existing CPP rate offer). • For C&I: 6%-13% peak demand reduction, varies by customer class and by w/o and with enabling technology.
Customer Incentives	• No separate incentives offered. Customers are offered a discounted off-peak rate over their OAT and have an incentive to enroll in the CPP rate and shift their consumption out to the off-peak period from the critical peak period to realize bill savings.

Source: Guidehouse

3.3.5 Behind the Meter (BTM) Battery Dispatch Characterization

Table 17 below summarizes the key characteristics of the BTM Battery Dispatch option. This option incorporates APS's current pilot activities in the area using residential BTM batteries and assumes a future scaling up of the efforts to achieve potential from BTM battery dispatch. For C&I customers, the study assumed a potentially new offer, similar to what is considered for residential customers.

Table 17. BTM Battery Dispatch Option Characteristics

Item	Description
Overview of BTM Battery Dispatch Option	• This option assumes that APS would dispatch BTM batteries (export energy to the grid and/or offset peak customer load) to reduce demand during net peak periods. Additionally, APS could dispatch batteries during other periods (outside of the peak period) to address additional grid needs that could potentially be fulfilled by BTM battery dispatch. However, this analysis only assesses the potential for peak demand reduction (based on the peak period definition discussed earlier in this chapter).[31] • It includes two sub-options, residential BTM battery dispatch and commercial BTM battery dispatch.
Eligible Customers	• All residential and nonresidential customers with BTM batteries
Enrollment Assumptions	• Assumed 50% of BTM batteries for residential and nonresidential customers are enrolled (steady state participation level) • Enrollment ramps up and reaches steady state participation level by 2029
Unit Impacts (Average Peak Demand Reduction per Battery)	• Residential: 4.8 kW per battery single hour peak demand reduction[32] • Nonresidential: ~13% of battery capacity dispatched on an average during the peak period (assumed same impact as residential on a % of battery capacity basis)
Participation Incentives	• Residential: $1,250 per battery enrolled as upfront enrollment incentive (for customers with pre-existing batteries)[33] • Nonresidential: $120/kW of upfront enrollment incentives (same assumption as for residential on a per kW basis)

Source: Guidehouse

3.3.6 EV Managed Charging Characterization

Table 18 summarizes the key characteristics of the EV Managed Charging option. This option incorporates APS's current pilot activities in the area and assumes a future scaling up of these efforts to achieve potential from EV Managed Charging.

[31] The assessment of impact for additional grid services, beyond peak demand reduction, was outside the scope of the analysis.
[32] From APS Residential Battery Pilot 2022 Evaluation
[33] Based on 2023 Plan information.

Table 18. EV Managed Charging Option Characteristics

Item	EV Managed Charging
Option Overview	• This option represents direct control of EV charging demand during the net peak period, either through the EV supply equipment (EVSE) or through onboard telematics in the vehicle. • Additionally, APS could control EV charging demand during other periods (outside of the peak period) to address additional grid needs that could potentially be fulfilled by controlling EV charging load. However, this analysis only assesses the potential for peak demand reduction (based on the peak period definition discussed earlier in this chapter)[34] from direct control of EV charging demand.
Eligible Vehicles	• All qualified networked EVSEs and EVs with onboard telematics that are compatible with the platform controlling the charging demand.
Enrollment Assumptions	• 30% steady state participation level (as % of eligible chargers/vehicles) • Ramps up fully to steady state participation level by 2028
Unit Impacts	• 0.29 kW peak demand reduction per vehicle enrolled in the program35
Participation Incentives	• $250 upfront enrollment incentive • $240/yr. recurring participation incentive

Source: Guidehouse

3.3.7 EV Behavioral Characterization

Table 19 summarizes the key characteristics of the EV Behavioral option. This option incorporates APS's current pilot activities in the area and assumes a future scaling up of these efforts to achieve savings potential from the EV Behavioral EV option.

[34] The assessment of impact for additional grid services, beyond peak demand reduction, was outside the scope of the analysis.
[35] From APS EV Managed Charging Pilot MAS. This assumption aligns with data from other jurisdictions that offer similar EV Managed Charging pilots/programs. The unit impact represents the net effect after taking into consideration fraction of vehicles that are plugged in, opt-out of the event, and may face technical challenges. It also represents the charging demand that is coincident with the net system peak.

Table 19. EV Behavioral Option Characteristics

Item	EV Behavioral
Option Overview	• This option provides incentives to the drivers for charging their vehicles during the off-peak period. It is a purely behavioral intervention. It does not directly control the charging demand during peak periods, unlike the EV Managed Charging option. It is often referred to as "passive" control, whereas EV Managed Charging is referred to as "active" control.
Eligible Vehicles	• All EVSEs/EVs that are not enrolled in EV Managed Charging
Enrollment Assumptions	• 30% steady state participation level (as % of eligible chargers/vehicles) • Ramps up fully to steady state participation level by 2028
Unit Impacts	• 0.19 kW peak demand reduction per vehicle enrolled in the program[36]
Participation Incentives	• $60/yr. recurring participation incentive

Source: Guidehouse

3.3.8 EV V2G Characterization

Table 20 summarizes the key characteristics of the EV V2G option. This option represents a potential future V2G offer once the technology is market-ready for wider adoption than is being observed currently.

[36] From ProCESS 2023.

Table 20. EV V2G Option Characteristics

Item	EV V2G
Option Overview	• This option represents dispatch of EVs for power export to the grid during times of grid needs. This analysis assesses the net peak demand reduction potential from this option. However, the use case for this option would extend beyond peak demand reduction, addressing which is beyond the scope of the analysis being presented here. • APS could potentially offer this in the future when the technology is ready to be deployed.
Eligible Vehicles	• EVs with V2G capability; this capability is assumed to ramp up progressively from 3% of total vehicles in 2025 to 20% in 2030, 35% in 2035 and to 70% in 2040.[37]
Enrollment Assumptions	• Ramps up to 30% of eligible vehicles by 2030, starting from 2025.
Unit Impacts	• 2.2 kW per vehicle (assumed 11.2 kW average battery capacity with a 20% derating factor to account for charging profiles, connectivity, availability, etc.)[38]
Participation Incentives	• $1,250 upfront incentive (V2G charger rebate)[39] • $240/yr. recurring participation incentive (assumed to be same as that for EV Managed Charging)

Source: Guidehouse

3.3.9 Behavioral DR Characterization

Table 21 summarizes the key characteristics of the Behavioral DR (BDR) option. This option represents APS's current BDR program offer.

[37] Based on Guidehouse research for the California Energy Commission (CEC), based on comments provided by the Vehicle Grid Integration Council (VGIC).

[38] Based on data provided by VGIC as part of CEC research.

[39] Assumed V2G charger cost of $2470 based on market research. 50% incentive on that translates to $1250 per charger.

Table 21. BDR Option Characteristics

Item	BDR
Overview	• This option represents APS's current BDR program offer through Oracle. APS partners with customers on time-of-use rates and engages customers with timely reminders to reduce energy use during peak periods and shift to off-peak time periods. Customers are encouraged to engage in behavioral load shifts and do not receive any separate incentive payment.
Eligible Customers	• All residential customers.
Enrollment Assumptions	• 40%-50% of eligible customers • Ramps up to steady state participation level by 2028
Unit Impacts	• 0.02 kW peak demand reduction per participant[40]
Participation Incentives	None

Source: Guidehouse

3.4 Results

This section presents demand reduction and cost estimates from the DR options considered in the assessment and discussed in previous sections. Guidehouse estimated "achievable" demand reduction assumptions based on the assumptions described and developed levelized cost estimates for each DR option. The study assessed the CE of the DR options based on the SCT.

The beginning of this section presents CE results and levelized costs of the different DR options included in the potential assessment. It then presents annual achievable demand reduction estimates from all DR options included in the analysis, and separately calls out demand reduction estimates from cost-effective DR options only. The demand reduction results are shown by customer class and segment, which help determine the relative contributions of these customers toward the total potential. At the end, this section presents annual costs by DR option and itemized annual costs for the DR portfolio.

The results shown in this section are based on the single hour net peak definition, which aligns with the peak definition used for APS's IRP analysis. Appendix B contains additional detailed DR results, including an analogous set of results tables and figures using the alternate top 90-hour net peak definition.

3.4.1 Supply Curve and CE

As described previously in Section 3.3, the potential assessment considered these DR options: Dynamic Pricing, C&I Curtailment & Load-shift, Smart Devices and DLC, BDR, BTM Battery Dispatch, and EV options. Table 22 shows levelized costs, 2043 achievable demand reduction

[40] From APS's 2022 Behavioral Savings Workpaper

estimates, and CE from these DR options. Figure 21 presents this information in supply curves which stacks up the DR options in order of increasing levelized costs, relative to their contribution in total potential in 2043.

The cost-effective options are Dynamic Pricing, Smart Devices and DLC, BTM Battery Dispatch, C&I Curtailment & Load-shift, and EV Behavioral. Smart Devices and DLC and C&I Curtailment & Load-shift both have significant potential for demand reduction. Dynamic Pricing has the highest CE among all options but is only projected to reduce demand by 93.8 MW by 2043. The only currently cost-effective EV option is EV Behavioral, with a benefit-cost ratio of 5.99 and a levelized cost of $295.6/kW-yr. In total, stand-alone Behavioral DR and the other EV options (EV Managed Charging and EV V2G) are the least cost-effective but have the most potential for demand reduction due to the rapid growth of EVs in the future. The cost-effective options in this DR portfolio have a benefit-cost ratio of 3.72 and a levelized cost of $53.8/kW-yr. Due to the high costs but also the high potential of EV Managed Charging and EV V2G in later years, the DR portfolio with all options has a benefit-cost ratio of 1.23, which makes it cost-effective.

However, among the options that are not cost-effective, the CE assessment presented here is based on avoided generation and T&D capacity costs associated with summer net peak reduction. These two options can have a wide variety of use cases beyond summer net peak reduction, and therefore the valuation of benefits from these options should consider these additional benefits streams, which could render these options to be cost-effective. The consideration of additional benefits streams, beyond net peak demand reduction benefits, were outside the scope of this study.

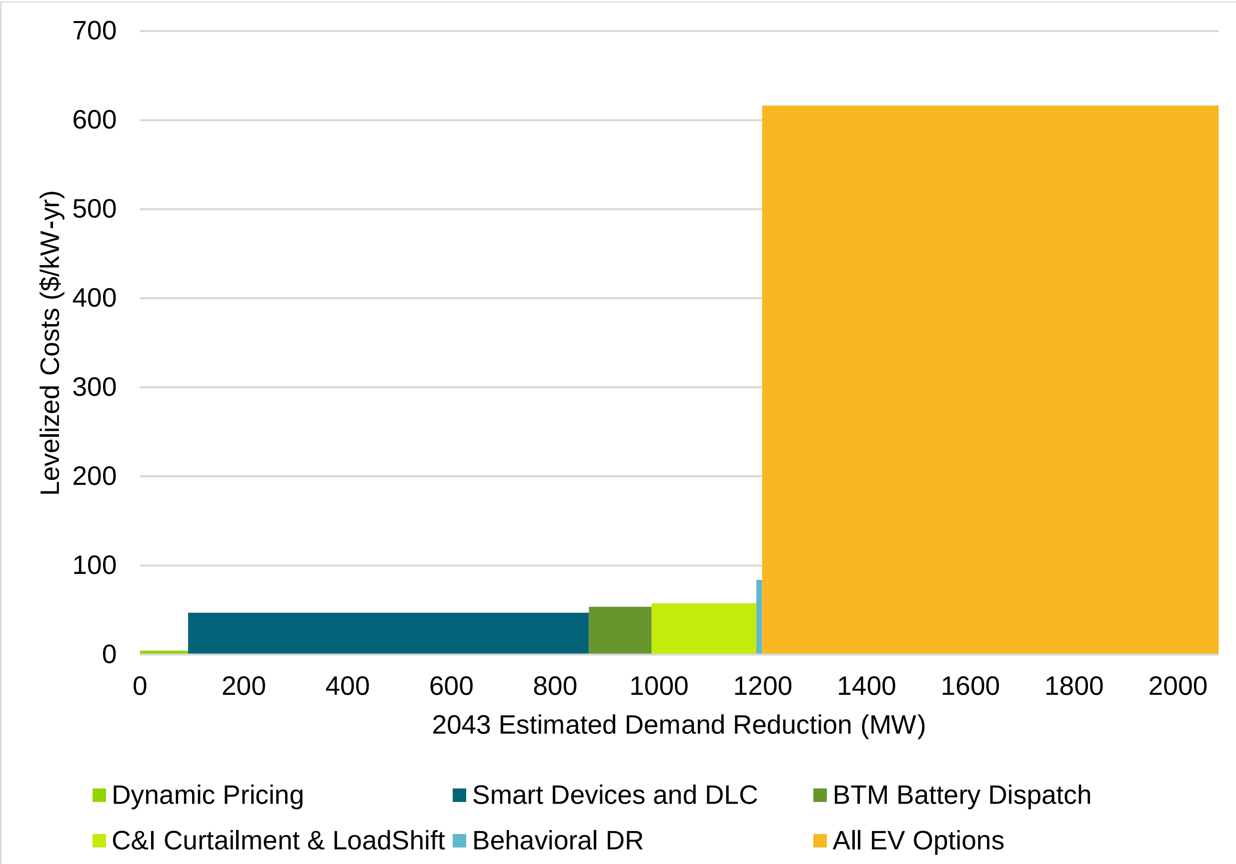
Table 22. Levelized Costs, 2043 Achievable Demand Reduction, and Benefit-Cost Ratios by DR Options – Single Hour Peak

DR Option	Levelized Cost ($/kW-yr.)	2043 Demand Reduction (MW)	B/C Ratios
Dynamic Pricing	4.4	93.8	16.12
Smart Devices and DLC	48.9	771.3	3.16
BTM Battery Dispatch	53.7	121.6	2.96
C&I Curtailment & Loadshift	57.6	201.8	4.67
EV Behavioral	295.6	75.7	5.99
C/E Options Only	**$53.8**	**1264.2**	**3.72**
Behavioral DR[41]	80.2	11.1	0.90
Other EV Options	661.1	804.3	0.32
All Options	**$820.3**	**2079.5**	**1.23**

Source: Guidehouse

[41] Behavioral DR is offered with EE and is cost-effective when both EE and DR benefits are considered.

Figure 21. Supply Curve for DR Options – Single Hour Peak



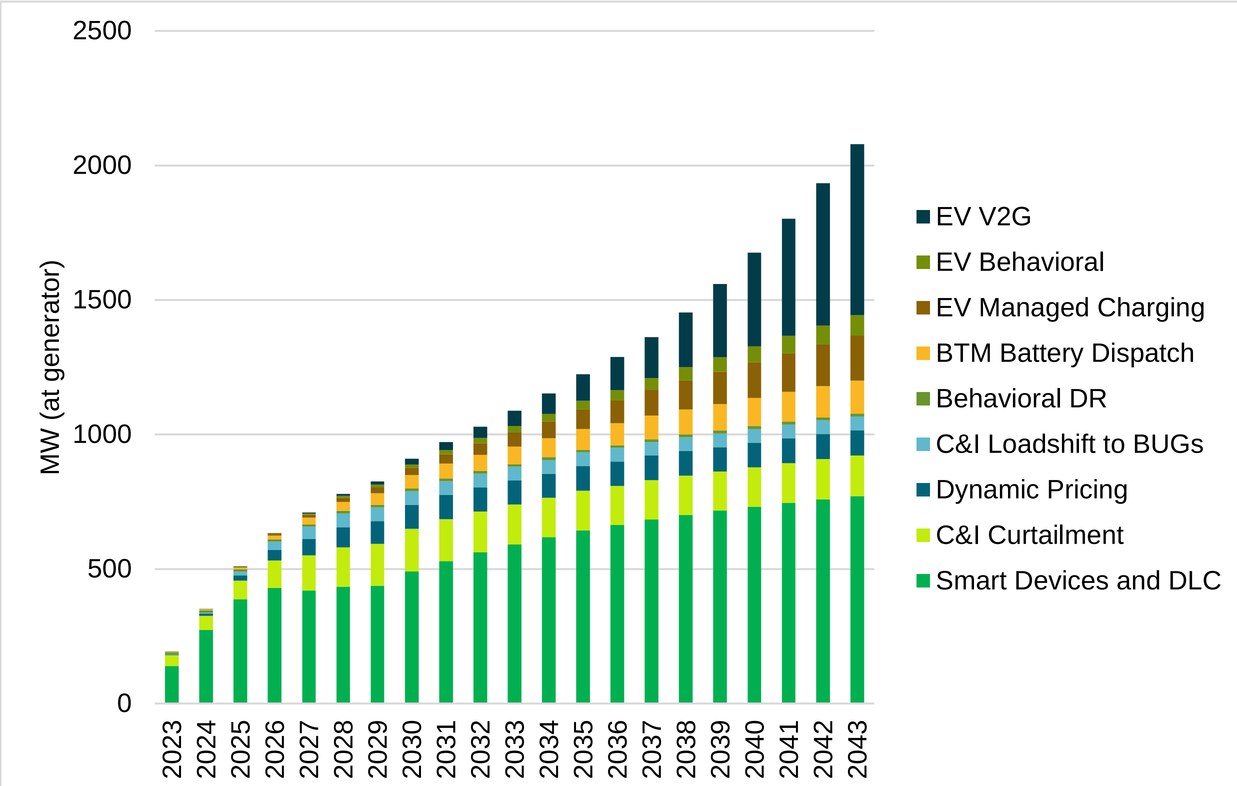
Source: Guidehouse

3.4.2 Potential from All Options

Figure 22 shows the annual demand reduction estimates from all DR options included in the analysis, which sums to 910 MW in 2030 and 2,080 MW in 2043. This translates to about 9.4% of the summer net system peak reduction in 2030 and 19.3% of the summer net system peak in 2043.[42] Smart Devices and DLC from residential customers primarily is the largest contributor to the potential in early years. However, the EV options, especially EV V2G, can potentially provide largest contribution in later years as the EV market grows significantly and vehicles progressively are equipped with V2G capabilities. C&I Curtailment and Loadshift have moderate contribution to the potential. Summer peak demand reduction potential from BDR is relatively low.

[42] The net system peak is net of both DG and EE.

Figure 22. Achievable Demand Reduction (MW at Generator) for All DR Options – Single Hour Peak

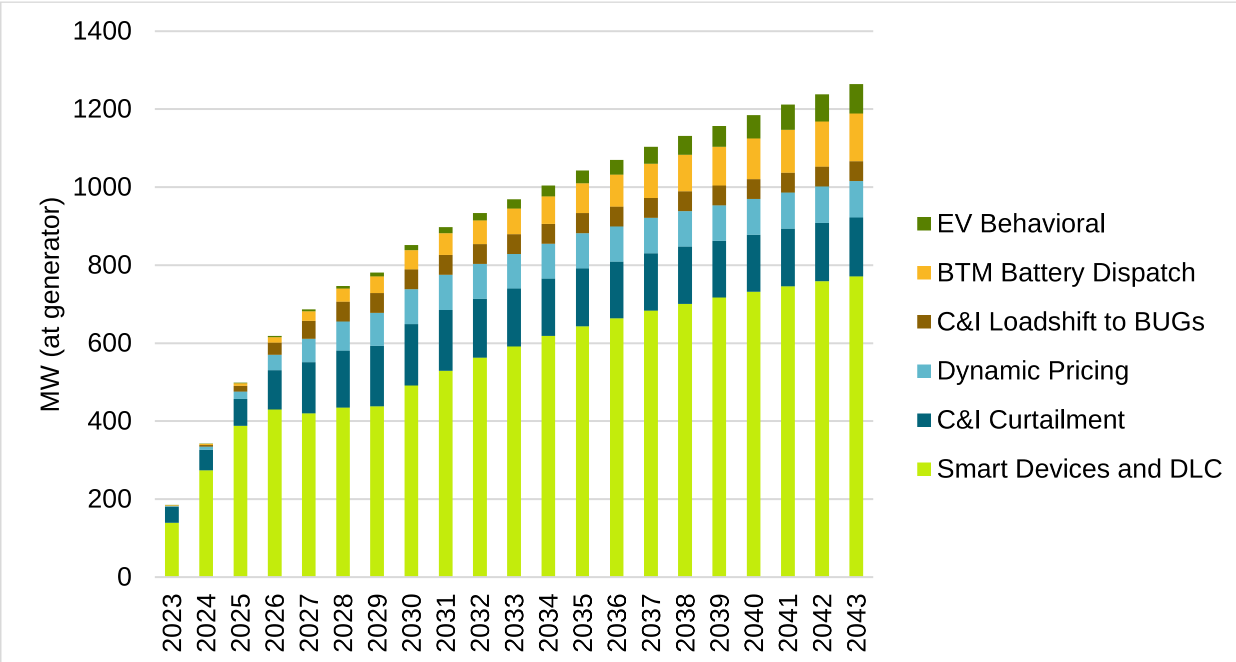


Source: Guidehouse

3.4.3 Cost-Effective DR Potential by Option

As discussed previously, Dynamic Pricing, C&I Curtailment & Loadshift, BTM Battery Dispatch, Smart Devices and DLC, and EV Behavioral options constitute the cost-effective DR portfolio over the analysis timeframe. Figure 23 shows the MW breakdown of the achievable demand reduction from cost-effective options only. The total demand reduction from the cost-effective portfolio is estimated to increase from 498 MW in 2025 to 851 MW in 2030 to 1264 MW in 2043. Smart Devices and DLC has substantially higher contribution than the other cost-effective DR options throughout the analysis timeframe.

Figure 23. Achievable Demand Reduction (MW at generator) by Cost-Effective DR Options – Single Hour Peak

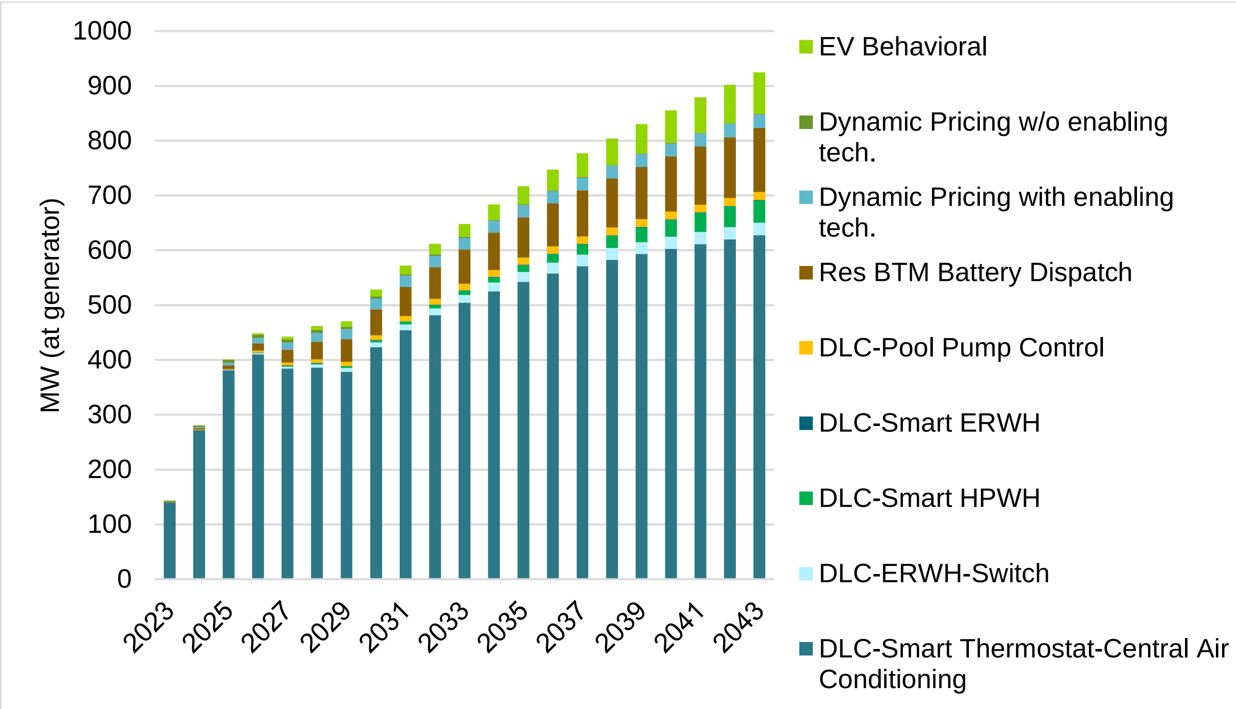


Source: Guidehouse

The following figures present a breakdown of the potential from cost-effective options by sub-option. The DR sub-options are differentiated by end-use and enabling technology combinations among the DR options. For residential Smart Devices and DLC, the sub-options represent different technologies by end uses - air-conditioning, water heating and pool pumps. The Dynamic Pricing option includes the sub-options of with and without enabling technologies. As for C&I Curtailment & Loadshift, the sub-options are divided by end use and enabling technology combinations for load curtailment and load shifting to back up generators.

Figure 24 shows the cost-effective residential sub-options within the DR options of Smart Devices and DLC and Dynamic Pricing. The total demand reduction from the residential cost-effective portfolio is estimated to increase from 401 MW in 2025 to 528 MW in 2030 to 925 MW in 2043.

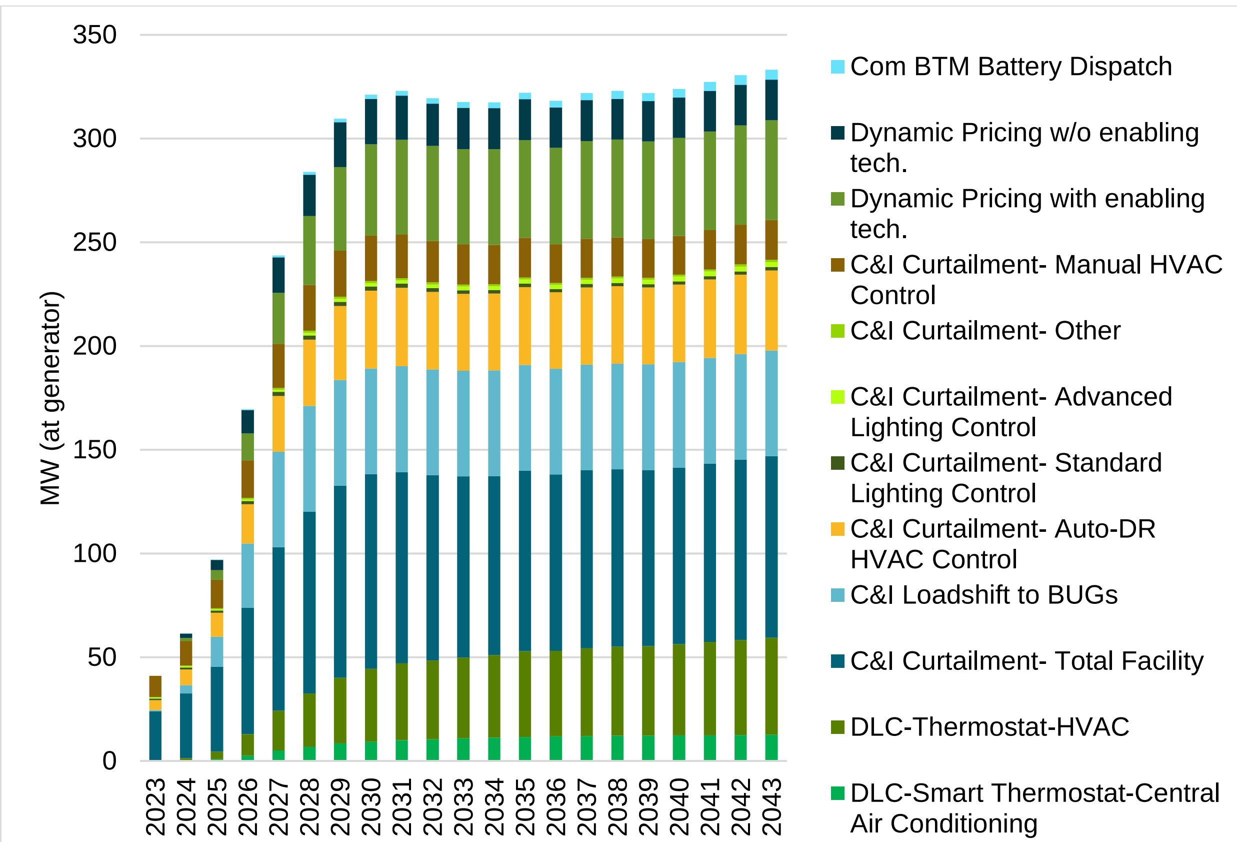
Figure 24. Achievable Demand Reduction (MW at generator) by Cost-Effective Residential DR Sub-options – Single Hour Peak



Source: Guidehouse

Figure 25 shows the cost-effective nonresidential sub-options for C&I customers, which includes the DR options of C&I Curtailment, C&I Loadshift to BUGs, Commercial Battery Dispatch, Dynamic Pricing, and DLC. The total demand reduction from the C&I cost-effective portfolio is estimated to increase from 97 MW in 2025 to 323 MW in 2030 to 339 MW in 2043. The decline after 2029 is due to reduced C&I baseline net peak demand in the future due to adoption of EE measures that reduces the overall C&I baseline net peak demand for DR. Among the C&I sub-options, largest net peak demand reduction contribution could potentially be derived from industrial customers (represented under “C&I Curtailment-Loadshift” sub-option). The loadshift potential from BUGs is estimated to grow progressively from ~1 MW in 2023 to ~45 MW by 2027 based on discussions with the APS team and insights gathered from the C&I customer survey described in Appendix A. Dynamic Pricing options provides a large group of savings, up to 68 MW in 2043. The next largest contributor to C&I potential is HVAC load curtailment at C&I customer facilities, which is represented by both manual and Auto-DR enabled curtailment. The share of Auto-DR in the total HVAC curtailment contribution could grow progressively over time with higher penetration/adoption of Auto-DR enabling technologies such as EMSs among C&I customers.

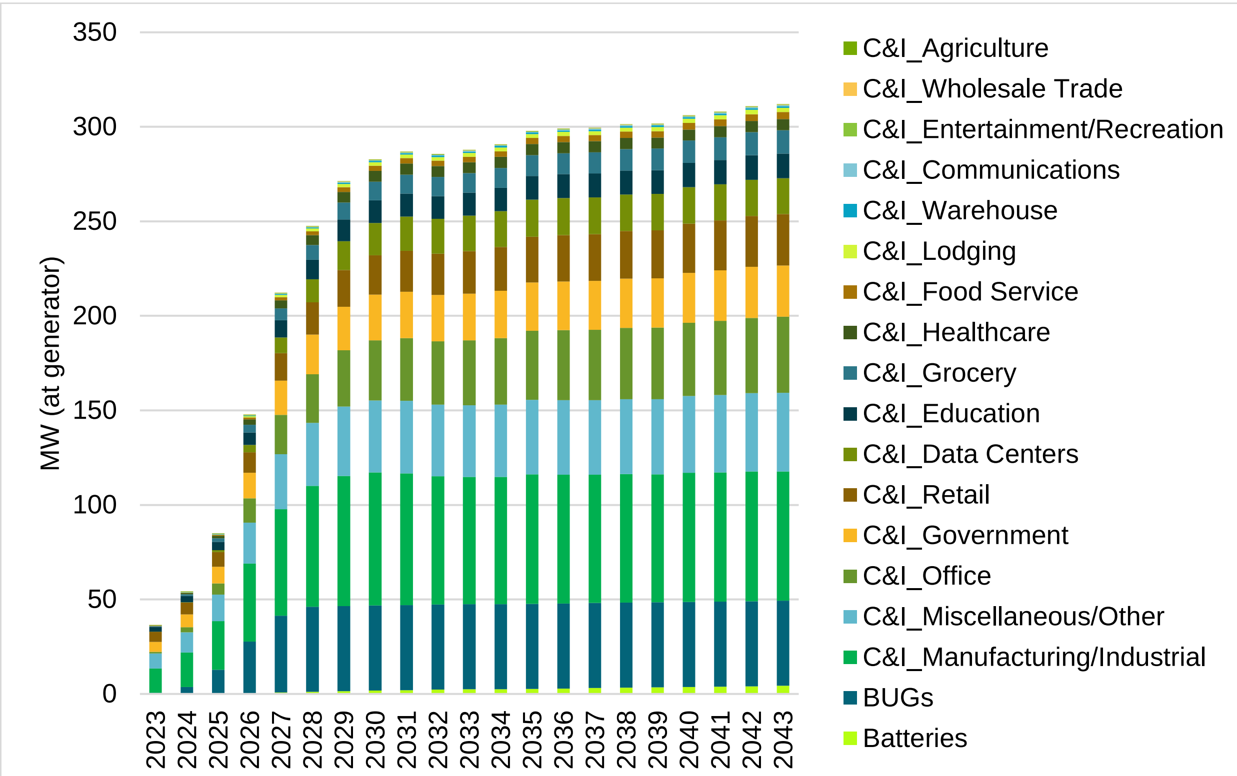
Figure 25. Achievable Demand Reduction (MW at generator) by Cost-Effective C&I DR Sub-options – Single Hour Peak



Source: Guidehouse

Figure 26 shows cost-effective C&I DR potential by C&I customer segments/building types from C&I Curtailment and Load Shift DR options. As is evident from the figure, the top five contributors to the C&I DR potential are curtailment at manufacturing/industrial facilities (extra-large and large C&I customer classes primarily), load shift at C&I facilities to BUGs, load curtailment at miscellaneous/other building types, and in government and retail facilities.

Figure 26. C&I Cost-Effective Demand Reduction (MW at generator) by C&I Segments – Single Hour Peak



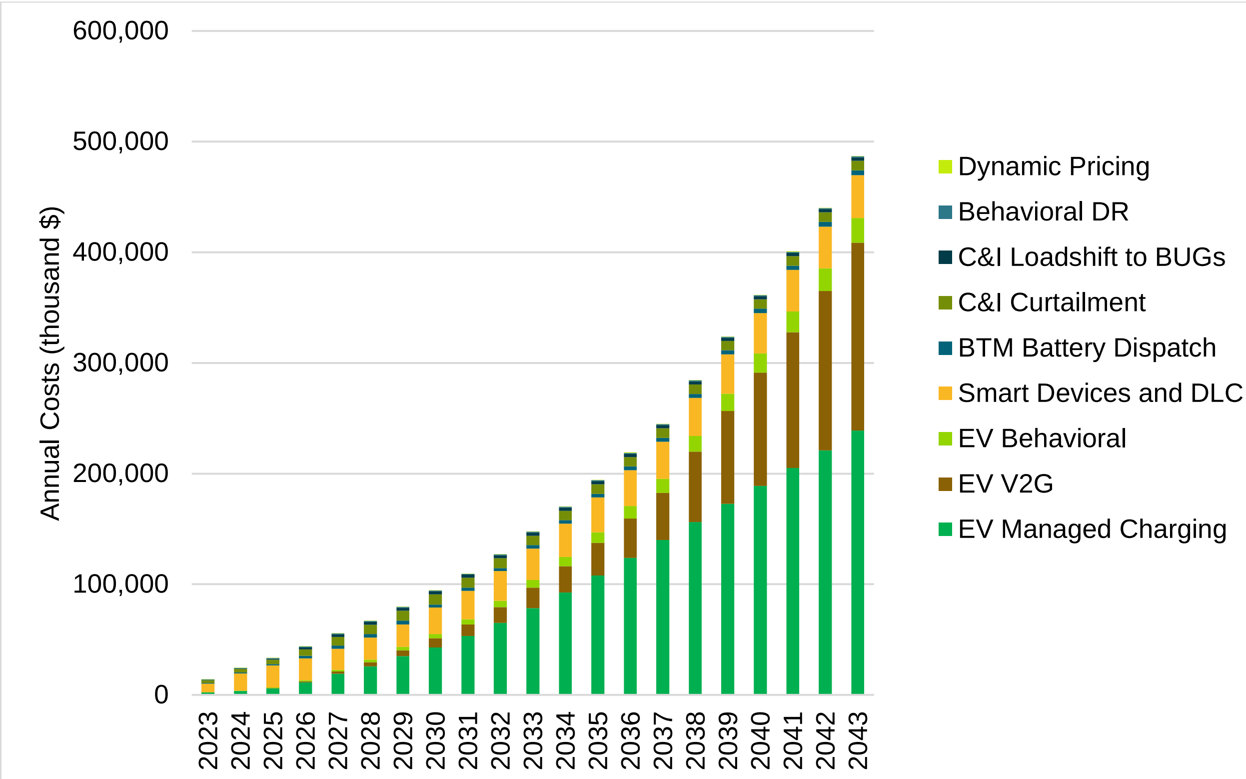
Source: Guidehouse

3.4.4 Annual Costs by Option

Figure 27 shows the annual costs associated with the entire DR portfolio and Figure 28 shows the annual costs associated with the DR options included in the cost-effective portfolio. These costs include the customer incentive costs and all other costs associated with administering the DR programs.

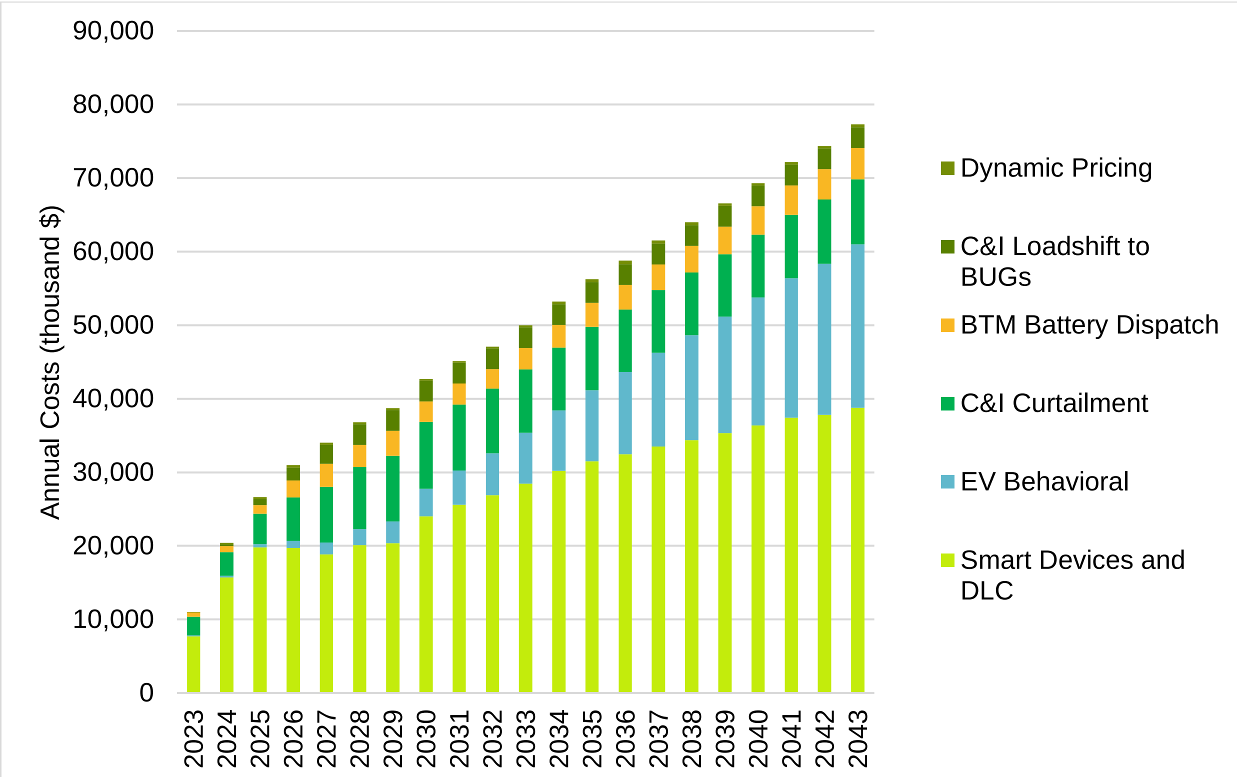
Within the entire DR portfolio, the costs for the EV options constitute ~90% of the total annual costs. However, EV Managed Charging and EV V2G are not currently cost-effective, thus dramatically decreasing the total costs in the cost-effective DR portfolio. Within the cost-effective DR portfolio, Smart Devices and DLC costs make up about 29% of total costs, EV Behavioral represents about 23% of total annual costs, and C&I Curtailment & Loadshift to BUGs make up about 12% of total annual costs. Dynamic Pricing costs have very low share in total costs as this represent a rate-based option with no separate customer incentive payment and is the least cost option.

Figure 27. Annual Costs (thousand $) for All DR Options – Single Hour Peak



Source: Guidehouse

Figure 28. Annual Costs (thousand $) for Cost-Effective DR Options – Single Hour Peak



Source: Guidehouse

3.5 Key Takeaways

As detailed above, there are many DR options with significant potential for demand reduction and multiple opportunities to decrease net system peak load. The main takeaways from the DR analysis are listed below.

- The total potential for cost-effective DR programs is projected to grow from **185 MW in 2023** to **851 MW in 2030**—or 8.8% of summer net system peak load.
- When considering additional DR options that are **not currently cost-effective** (Behavioral DR[43], EV Managed Charging, and EV V2G) DR potential could grow to:
  - 910 MW in 2030 (9.4% of summer net system peak)
  - 2080 MW in 2043 (19.3% of summer net system peak)

  Non-cost-effective options could significantly increase MW potential in long-term, primarily from the EV options, but with a significant increase in program cost and impact to overall portfolio cost-effectiveness.
- Near-term potential primarily comes from **residential Smart Devices and DLC** and **C&I Peak Solutions** (both curtailment and loadshift).

[43] Behavioral DR is cost-effective from a joint EE and DR perspective, just not as a stand-alone program offering.

  - For residential customers, scaling up of the Cool Rewards program to a modest 30% participation level (as % of eligible customers) could help realize significant peak demand savings.
  - Among C&I customers, curtailment opportunities are concentrated among a few top segments such as manufacturing/industrial, miscellaneous building type, government, and retail. For commercial customers, Auto-DR enabled curtailment opportunities could grow steadily over the years with increasing adoption of EE control technologies such as EMS. Additionally, allowing load shift to qualified backup generators at C&I customer facilities would help grow the Peak Solutions program.
- Behavioral DR (delivered as a stand-alone program), EV Managed Charging, and EV V2G considered in the analysis are not currently cost-effective from a summer peak demand reduction perspective only. However, Behavioral DR is offered in combination with the EE Behavioral program and is cost-effective from a joint EE-DR perspective. The benefits assessment from the EV options need to consider additional value streams that these options could provide beyond peak demand reduction (e.g., daily load shifting, ancillary services, address local congestion and serve as a non-wires alternative). Additionally, these technologies are maturing rapidly and their costs are expected to reduce relatively rapidly in the coming years, which would make these options cost-effective.

4. Conclusions and Recommendations for Future Studies

Guidehouse conducted this study to develop an estimate of the potential for EE and DR in APS service territory from 2023-2043. One goal of the study was to analyze the potential for EE programs to meet energy saving goals provided by the ACC. This study also forecasted EE and DR savings to inform resource planning for future energy needs.

The following items summarize the conclusions of the study, as well as recommendations for future studies.

The current portfolio of APS programs has the potential to achieve significant savings in the early years of the forecast period, achieving savings of over 1.3% of retail sales until at least 2025. However, savings in later years are lower (particularly when compared as a percentage of higher future retail sales) as the measures in the current portfolio of programs saturate the market, and the programs have diminishing returns. The team recommends that future studies consider methods to account for future technologies that have yet to emerge into the market, but that may likely emerge in the later part of the forecast period.

The analysis found that EE program budgets would need to increase significantly in order to meet the savings targets in future years. Increasing incentives to the maximum allowable under current framework (to 75% of incremental cost—as represented in the mid scenario) results in a 2x increase in budget. The High scenario developed to show compliance with the 1.5% target would require a further 6x increase in budget over the BAU scenario. Guidehouse recommends future studies continue to investigate potential opportunities to capture additional cost-effective savings.

The ACC targets are based on retail sales, with future targets calculated using estimates of load forecast growth. A large portion of the future load forecast is increased load from the XHLF segment (data centers, large industrial, semiconductor manufacturing), making it harder to meet ACC targets. For instance, the XHLF segment causes the savings target to increase by approximately 35% in 2030. Additionally, preliminary customer research indicates that there are minimal savings opportunities in this XHLF segment. Guidehouse recommends that future studies focus on exploring additional savings opportunities.

DR provides a significant opportunity to reduce demand and decrease net system peak load. A portfolio consisting only of currently cost-effective DR programs (chief among them residential Cool Rewards and C&I Peak Solutions) could decrease summer net system peak load by nearly 9.4% in 2030. Guidehouse recommends that future studies investigate opportunities to grow program participation; for example, by allowing load shift to qualified backup generators at C&I customer facilities.

Additional non-cost-effective DR measures, such as electric vehicle options and stand-alone Behavioral DR, could result in even greater reductions in peak demand, with the potential to decrease summer peak demand by 10.0% by 2030 and 20.3% by 2043. However, these options would also significantly increase program cost, which in turn would negatively impact overall portfolio cost-effectiveness. Guidehouse recommends that future studies evaluate additional value streams for these measures that could mitigate these impacts; e.g. ancillary grid services and locational benefits.

Appendix A. Customer Surveys and Interviews

To inform and help calibrate the modeling, Guidehouse conducted customer surveys and one-on-one interviews with APS commercial customers to assess interest in existing and possible new APS EE and DR programs. The email-to-web surveys were fielded in February and March of 2023 and targeted a representative mix of business types and sizes. In April and May of 2023, Guidehouse conducted one-on-one interviews with survey respondents who indicated a willingness to speak to researchers by phone. Survey invitations were sent to 362 customers who currently participate in the APS Peak Solutions DR program and 1,155 customers who have participated in the APS Solutions for Business (S4B) EE program. The surveys had a 7% response rate from both groups with 24 responses from Peak Solutions customers and 78 responses from S4B customers. Eleven S4B customers agreed to follow up one-on-one phone conversations with Guidehouse researchers to discuss their needs, thoughts, and preferences in more detail. Customer survey and interview research objectives included:

- Identifying current trends in DSM technology adoption by segment
- Exploring APS customer attitudes, as well as their knowledge of and adoption of EE and DSM technology opportunities
- Identifying customers' planned EE projects, their interest in acquiring distributed energy resources, as well as the drivers for their participation in APS clean energy programs
- Measuring customer interest in DR programs, demand-based rates, and other load management options
- Identifying barriers to participation in EE and DR programs, as well as new potential program options to better meet customer needs and drive interest in participation
- Measuring levels of customer satisfaction with the existing Peak Solutions program and identifying opportunities for program improvements.

The survey findings were used to gather inputs to the DR potential estimates. The results of the survey assessed participation likelihood, which was further analyzed and summarized by the DR segments. This information was used to inform modelling assumptions where possible. In some cases, the sample size was small and not entirely representative of its DR segment, so the Guidehouse teams leveraged their expertise and benchmarking with similar programs from other jurisdictions to develop reasonable assumptions. In addition to providing participation likelihood data, the survey also provided further details into current back-up generator capacity and capability to loadshift during DR events. This information, coupled with direct data from CPower, was used to help inform the Guidehouse team's back-up generator assumptions for model inputs.

Additionally, the survey and interview findings also help to guide APS for future modifications to program implementation approaches and to inform future EE and DR program designs to better enable APS to achieve the potential energy and demand savings identified in this study. Moreover, Guidehouse can utilize survey results to gauge customer participation based on varying program design features, such as notification time and length of events. A majority of the survey population expressed interest in DR programs, and the survey findings highlight the main customer concerns that should be considered for future program design.

Appendix B. Detailed DR Results

See accompanying Excel files for detailed DR results: one with single hour peak and one with the top 90 hours, labeled as Appendix B1 and Appendix B2 respectively.

The remainder of this Appendix shows results using the alternate top 90-hour net peak definition (instead of the single hour peak definition which is used for all results shown in Section 3.4).

Figure 29. Supply Curve for DR Options – Top 90 Hour Net Peak

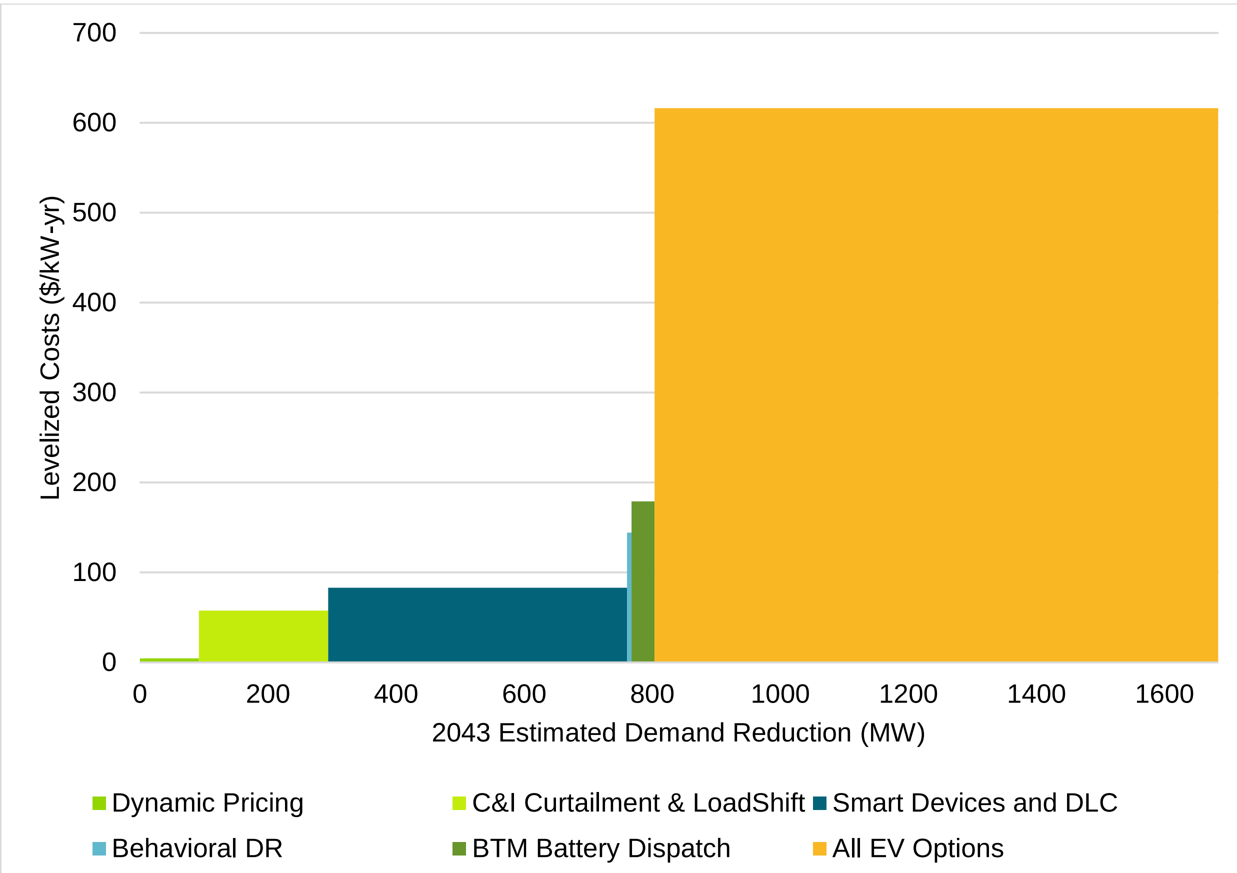


Figure 30. Achievable Demand Reduction (MW at Generator) for All DR Options – Top 90 Hour Net Peak

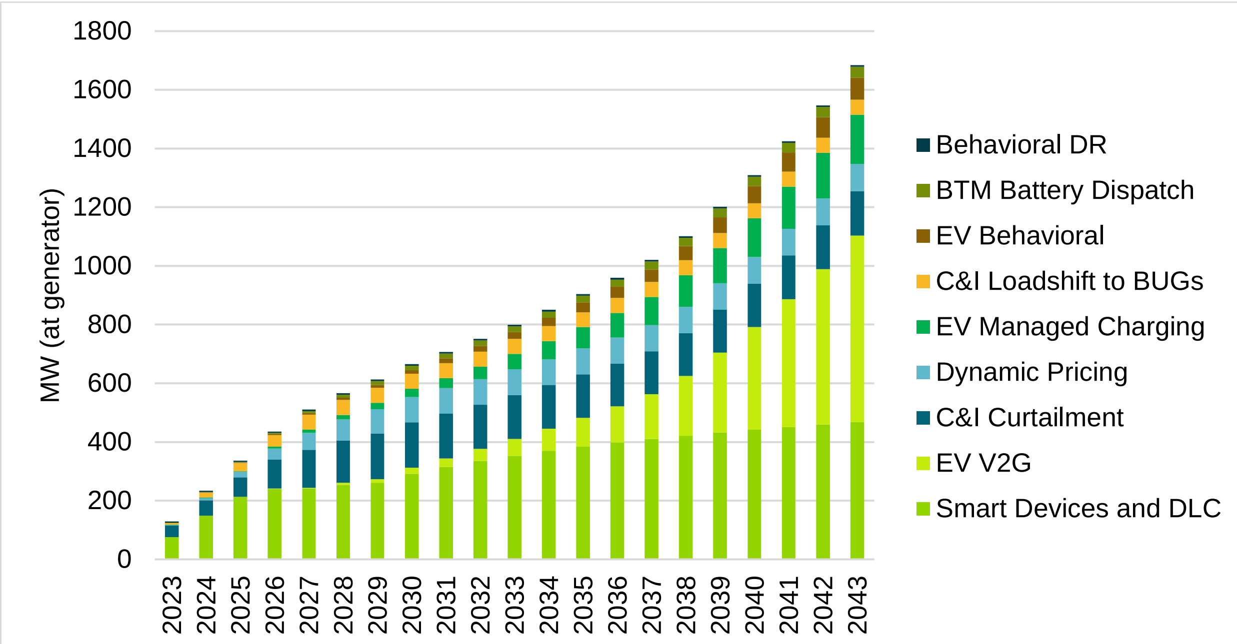


Figure 31. Achievable Demand Reduction (MW at generator) by Cost-Effective DR Options – Top 90 Hour Net Peak

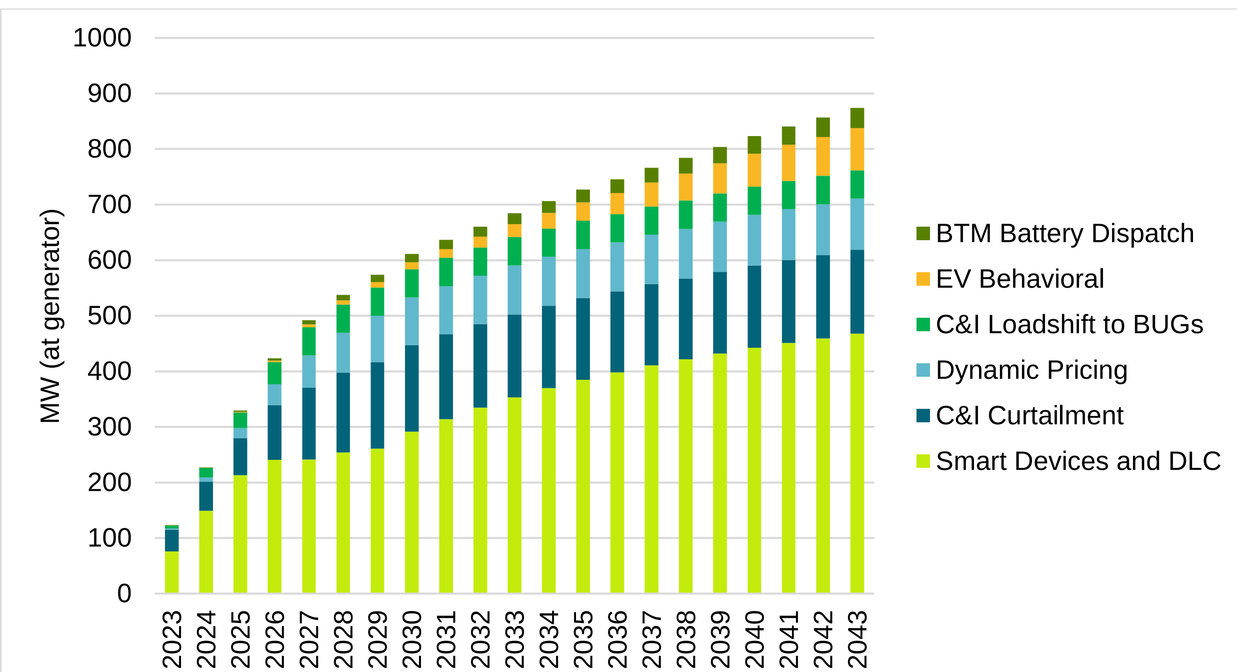


Figure 32. Achievable Demand Reduction (MW at generator) by Cost-Effective Residential DR Sub-options – Top 90 Hour Net Peak

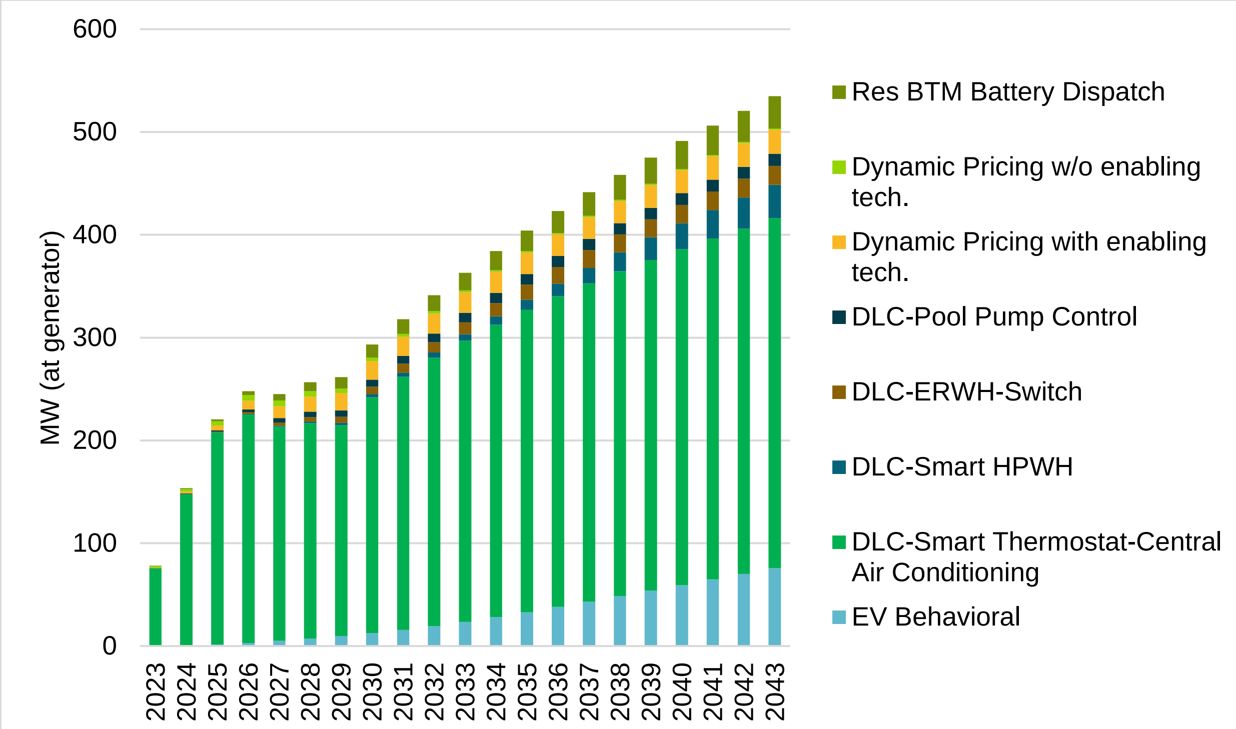


Figure 33. Achievable Demand Reduction (MW at generator) by Cost-Effective C&I DR Sub-options – Top 90 Hour Net Peak

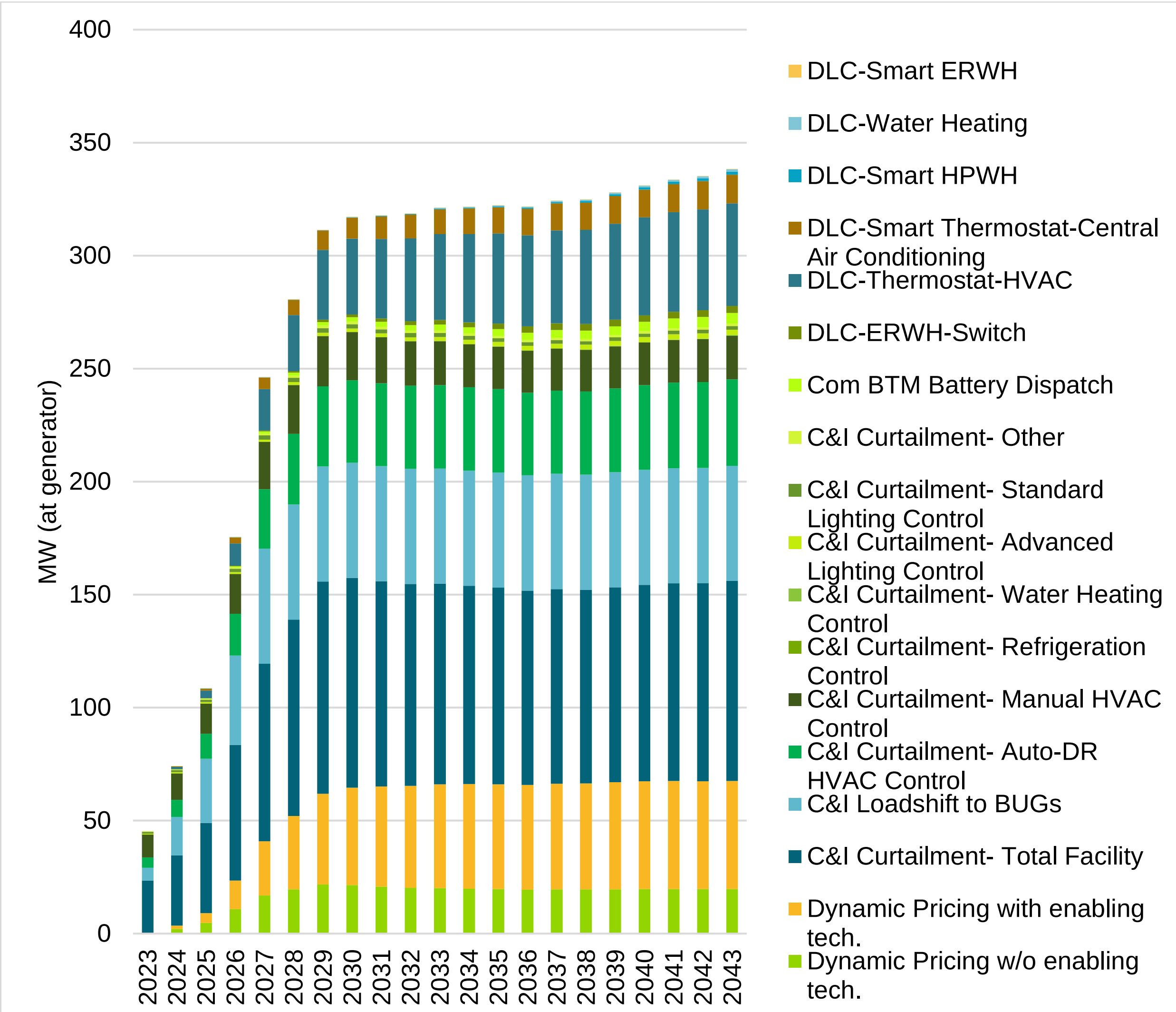
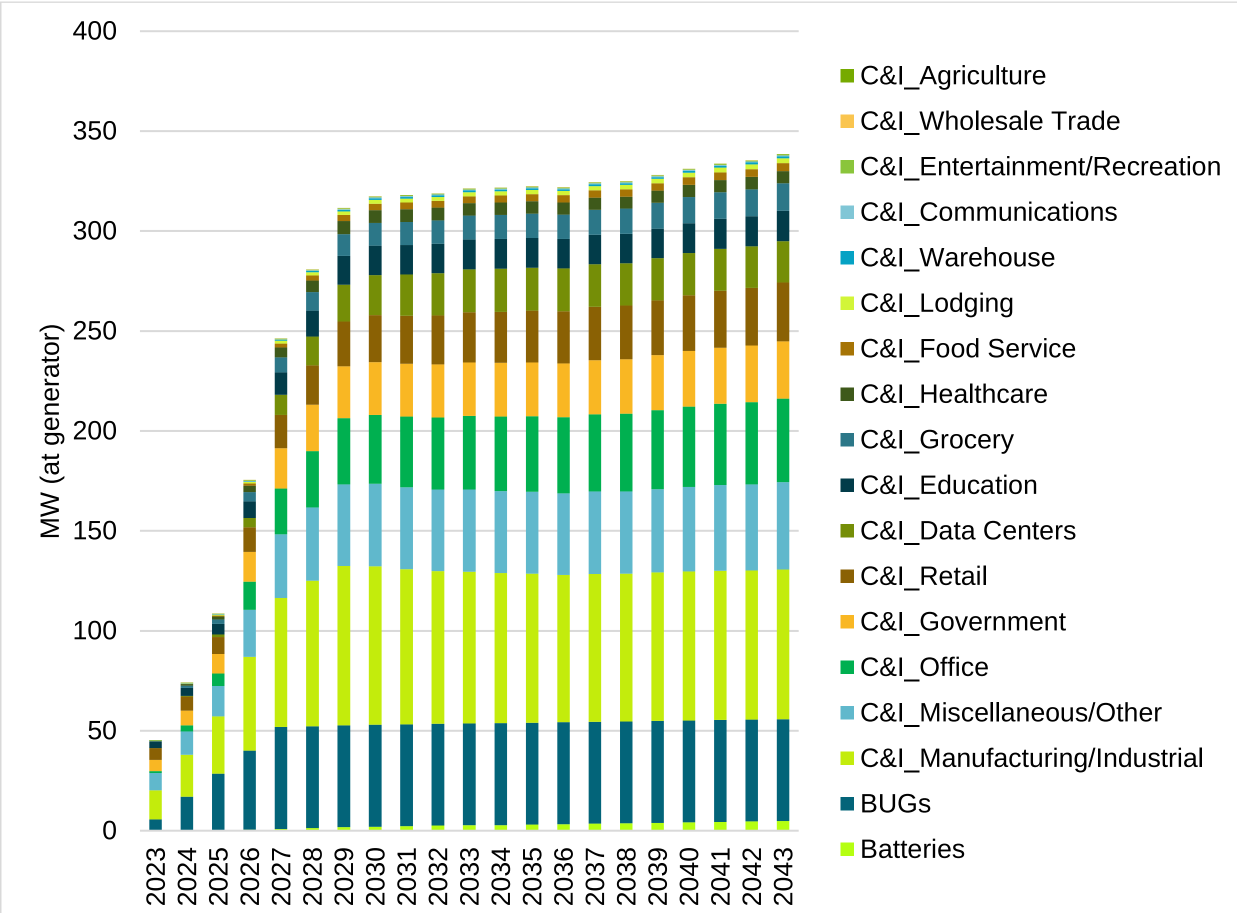


Figure 34. C&I Cost-Effective Demand Reduction (MW at generator) by C&I Segments – Top 90 Hour Net Peak



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APPENDIX D

ASTRAPE RESOURCE ADEQUACY STUDY

ASTRAPÉ CONSULTING
innovation in electric system planning

APS 2023 RESOURCE ADEQUACY STUDY

Summary

9/29/2023

PREPARED FOR

Arizona Public Service

PREPARED BY

Astrapé Consulting

SUMMARY

Astrapé Consulting has conducted a comprehensive Resource Adequacy (RA) study for Arizona Public Service Company (APS) with the objective of establishing the Planning Reserve Margin (PRM) and Effective Load Carrying Capability (ELCC) values for use in its 2023 Integrated Resource Plan (IRP). This report provides detailed insights into the following areas of the two-fold study:

- **Determination of PRM:** Multiple scenarios were evaluated by assessing the impacts of changing key parameters, such as operating conditions and resource portfolio mix.
- **Determination of Resource ELCCs**: The study established ELCC values for various resource types serving load on the APS system, by simulating hundreds of penetration levels and recording the resulting values of dependable capacity.

REFERENCE CASE PRM RESULTS

The PRM of an energy delivery system represents the amount of capacity, in excess of forecasted peak load, needed to achieve a targeted level of reliability. In this study, the PRM was calculated using three different accounting methods:

1. **ICAP Method**: Conventional/firm (conventional) resources are accredited with summer-rated Installed Capacity (ICAP) and renewable and energy-limited resources with ELCC values. Prior to its current 2023 IRP study, APS employed the ICAP methodology to determine its current PRM of 15%.
2. **UCAP Method**: Conventional resources are accredited with Unforced Capacity (UCAP) and renewable and energy-limited resources with ELCC values.
3. **PCAP Method**: All resources are accredited with ELCC values, also known as Perfect Capacity (PCAP). For a given load profile, ELCC values offset demand on a 1-for-1 megawatt (MW) basis (i.e., values represent output from a perfect generator with no outages or energy constraints).

ICAP accounting has been the traditional method of calculating PRMs for many years in the electric utility industry, as system resources have largely been conventional. However, as the penetration of renewable and energy-limited resources increase, this method becomes less effective at fully capturing relative contributions to PRM. ELCC accounting of renewable resources embeds outages and energy intermittency into its accreditation process; however, ICAP accounting of conventional resources does not. This results in an inconsistent valuation of dependable capacity. Furthermore, as the percentage of renewable and energy-limited resources accredited at ELCC increases, the ICAP reserve margin also changes. With renewable and energy-limited resources becoming a larger percentage of the resource portfolio, an ICAP reserve margin becomes a moving target.

UCAP accounting is an attempt to value the dependable capacity of renewables, energy-limited and conventional resources on the same basis, by applying the ELCC capacity accreditation method to renewables and (1-EFORd)[1] to conventional resources. However, (1-EFORd) does not fully capture the

[1] EFORd is Equivalent Forced Outage Rate on Demand.

reliability contribution of conventional resources, because it does not account for factors such as the asymmetry and variability of outages and outage correlation. Hence, UCAP accounting does not produce ELCC-equivalent dependable capacity values for conventional resources. For these reasons, UCAP accounting can fall short in an environment with increasing renewable penetrations, or environments where conventional resources are being retired and replaced with new conventional resources with lower effective forced outage rates.

PCAP accounting uses ELCC accreditation values for all resources. A PCAP PRM is based on resource capacity values that account for imperfect performance and limitations on output. Essentially, there is no distinction between resource type – all MWs are equal. A PCAP PRM does not change, as long as the load composition doesn't change. For this reason, PCAP is the recommended method of accounting in an environment with a changing resource mix.

Consistent with current industry practice, the PRM was established using a Loss of Load Expectation (LOLE) reliability target of one day in ten years (1d/10 yr), which corresponds to the one-tenth of a day per year (0.1 d/yr) threshold used in the RA study work. The performance characteristics of renewable and battery storage resources and how they impact grid reliability have sparked industry conversation on the appropriateness of continuing to use this metric, since limitations on dispatchability and energy will likely affect the magnitude and duration of loss of load events. Contrary to this thought process, results from prior work performed by Astrapé have shown that renewable and battery storage resources generally have offsetting effects on the magnitude and duration of events, and the 0.1d/yr LOLE (0.1 LOLE) standard is expected to yield a relatively consistent measure of system reliability across a range of technology resource mixes.

The PRM analysis was conducted using Astrapé's Strategic Energy and Risk Evaluation Model (SERVM). The APS system PRM is the result of an evaluation of a probabilistically weighted LOLE across 23 weather-year scenarios, five load forecast error scenarios, and hundreds of unit outage scenarios. The study commenced by examining the baseline Reference Case, which assumed the operation of APS system on an islanded basis, during the years 2026 and 2031. The remaining scenarios were exclusively studied in 2026.

Figure 1 below shows the result of the LOLE analysis for 2026. It shows LOLE as a function of the ICAP reserve margin. Assuming the 1 day in 10-year criteria, the figure shows a 0.1 LOLE intersecting the curve at a reserve margin of 18.3%.

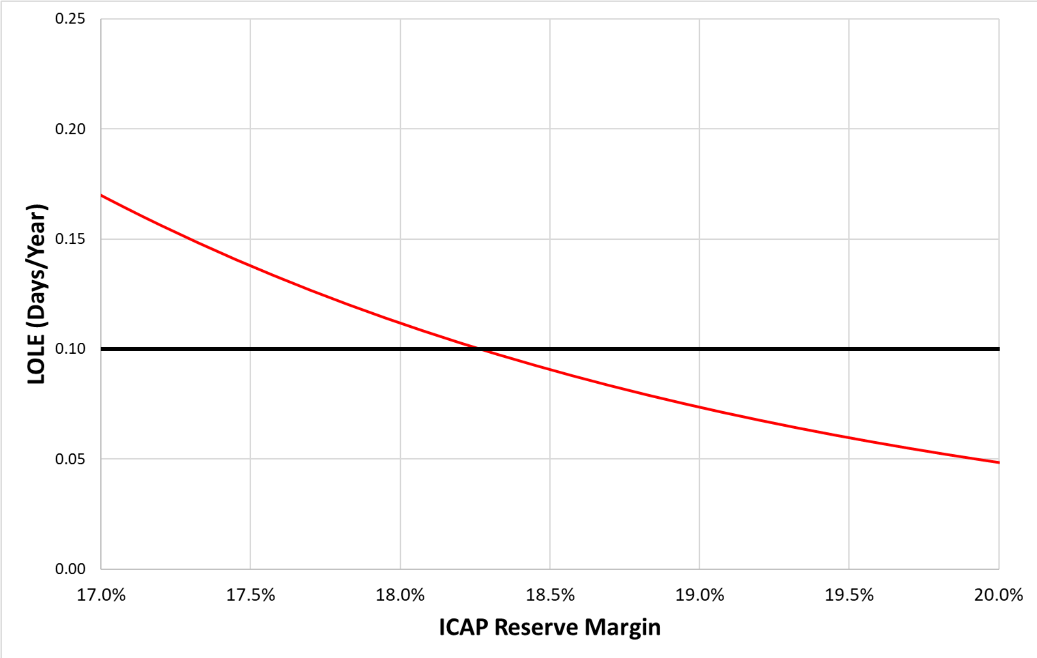

Figure 1. 2026 Reference Case LOLE Analysis

As demonstrated in this graph, LOLE decreases with increased reserve margin. As more capacity is added to the system, reliability improves. The point at which the curve crosses an LOLE of 0.1 marks the target PRM.

Table 1 below shows the ICAP accounting PRM results for the 2026 Reference Case scenario.

Table 1. 2026 Reference Case PRM - ICAP Accounting

2026 Reference Case PRM - ICAP Accounting			
Resource Type	Capacity (MW)	ELCC	Equivalent Capacity (MW)
Conventional Resources	7518		7518
ELCC Resources	6992	54.33%	3799
MW Adjustment	844		844
Total Capacity	15354		12161
Load (including adjustments)			10333
Reserves			1828
PRM[2]			18.3%

[2] Note PRM is calculated on Load (including adjustments) net of Energy Efficiency (EE) ELCC. For the 2026 study year, the ELCC of EE is 324 MW.

The MW Adjustment in Table 1 represents the amount of capacity incremental to the Reference Case assumptions needed to achieve the 0.1 LOLE reliability threshold. The ICAP PRM was calculated using a coincident peak load net of the Energy Efficiency (EE) ELCC, as follows:

$$CPL = BAU + DC\_CP + EV\_CP$$

Where,
CPL = Coincident peak load
BAU = Business as Usual load
DC_CP = contribution of data center load to the coincident peak
EV_CP = contribution of electric vehicle charging to the coincident peak

With ICAP accounting, the effects of forced outages on conventional resources are embedded in the PRM. ELCC-valued resources, however, reflect their perfect capacity equivalent. Thus, changes in system Equivalent Forced Outage Rate (EFOR), as well as changes in the penetration of renewable and energy-limited resources, can cause changes in the PRM. An alternative that attempts to stabilize the PRM by removing the effects of forced outages is the UCAP accounting method. UCAP accounting discounts the capacity of conventional resources by (1-EFORd), where EFORd is the Equivalent Forced Outage Rate on Demand of conventional resources. Table 2 shows the 2026 Reference Case PRM calculated using UCAP accounting.

Table 2. 2026 Reference Case PRM - UCAP Accounting

2026 Reference Case PRM - UCAP Accounting			
Resource Type	Capacity (MW)	ELCC	Equivalent Capacity (MW)
Conventional Resources	7518	93.54%	7032
ELCC Resources	6992	54.33%	3799
MW Adjustment	844	93.54%	789
Total Capacity	15354		11621
Load (including adjustments)			10333
Reserves			1288
PRM[3]			12.5%

[3] Note PRM is calculated on Load (including Adjustments) net of EE ELCC. For the 2026 study year, the ELCC of EE is 324 MW.

However, UCAP does not truly reflect the reliability contributions of conventional resources (i.e., it isn't a perfect capacity equivalent). Variability in outages results in some peak days having higher than average outages, resulting in a larger disparity between the true reliability contribution of the conventional fleet and the implied reliability contribution of (1-EFORd). Furthermore, it does not stabilize the PRM against changes in renewable and energy-limited resource penetration. The most stable PRM is produced using PCAP accounting, in which all resources are discounted to their perfect capacity equivalent, or ELCC equivalent. Table 3 below shows the 2026 Reference Case PCAP PRM, which is calculated based on the BAU load. BAU load was chosen for this approach to prevent distorting the PRM with the ELCC of load modifiers, such as incremental EE, data center load, or electric vehicle charging load.

Table 3. 2026 Reference Case PRM - PCAP Accounting

2026 Reference Case PRM - PCAP Accounting	
Resource Type	Equivalent Capacity (MW)
PCAP Capacity	10211
Load	9696
Reserves	515
PRM	5.3%

All three accounting methods are targeting identical reliability targets of 0.1 LOLE.

PRM SCENARIO STUDY RESULTS

The following four scenarios were studied in addition to the Reference Case, correlating the impact of changing market and operating conditions to the required PRM, with the goal of establishing the PRM that APS would adopt in its 2023 IRP and future planning activities:

1. 2031 Reference Case scenario (ICAP PRM).
2. Preserve Batteries scenario – a scenario in which battery resources were held back for reliability (i.e., were not arbitraged) (ICAP PRM).
3. Expanded Market Access scenario (ICAP PRM) – A scenario that provides an estimate of what the PRM would look like if market conditions in the Southwest change significantly and allow for APS to have a greater dependence on the market for firm resources.
4. Current Market Conditions scenario (ICAP and PCAP PRM) – A scenario that best represents the current expectation of market conditions that would exist in the Southwest in the near-term planning period.

2031 STUDY YEAR SCENARIO

This scenario evaluated an ICAP PRM assuming 2031 Reference Case assumptions rather than 2026 Reference Case assumptions. Table 4 shows the PRM results for this sensitivity.

Table 4. 2031 Reference Case PRM – ICAP Accounting

2031 Reference Case PRM - ICAP Accounting			
Resource Type	Capacity (MW)	ELCC	Equivalent Capacity (MW)
Conventional Resources	6834		6834
ELCC Resources	10574	47.57%	5030
MW Adjustment	927		927
Total Capacity	18335		12791
Load (including adjustments)			11440
Reserves			1351
PRM[4]			12.6%

The 5.7% reduction in PRM from the 2026 Reference Case is primarily the result of a greater portion of the resources being ELCC resources, when compared to the 2026 Reference Case portfolio of resources. Larger penetrations of ELCC resources means a larger percentage of the resources are being accounted for based on their perfect capacity equivalent, which drives the ICAP PRM towards the PCAP PRM.

PRESERVE BATTERIES SCENARIO

The 2026 Reference Case scenario allowed all battery resources to arbitrage daily against the load shape to shave the peak load. This creates a risk that batteries may not be available to meet reliability needs, because they were used for arbitrage purposes. The ELCC of battery resources is maximized when the batteries are held back for reliability needs (i.e., not used until needed to prevent a load shed event). Table 5 shows the results of a sensitivity that preserves all batteries for reliability purposes.

[4] Note PRM is calculated on Load (including adjustments) net of EE ELCC. For the 2031 study year, the ELCC of EE is 677 MW.

Table 5. 2026 Preserve Batteries PRM – ICAP Accounting

2026 Preserve Batteries PRM - ICAP Accounting			
Resource Type	Capacity (MW)	ELCC	Equivalent Capacity (MW)
Conventional Resources	7518		7518
ELCC Resources	6992	54.55%	3814
MW Adjustment	825		825
Total Capacity	15335		12157
Load (including adjustments)			10333
Reserves			1824
PRM[5]			18.2%

The results show no substantive difference from the 2026 Reference Case. This is because the 15 MW increase in ELCC for ELCC Resources associated with operating the batteries in the preserve reliability mode is offset by a 19 MW decrease in the required additional capacity (MW Adjustment) needed to maintain the 0.1 LOLE threshold of reliability. The preserve reliability mode of battery operation results in a greater capacity contribution (i.e., a higher ELCC) for the battery. However, it does not decrease the total amount of dependable capacity needed to maintain the 0.1 LOLE requirement. Thus, any change in battery capacity contribution is offset by an equal amount of adjusted required capacity.

EXPANDED MARKET ACCESS SCENARIO

The 2026 Reference Case model conservatively assumed system operations on an islanded basis. The resulting PRM, enabled APS to meet its load requirements without dependence on external entities. Allowing limited access to external entities, the Expanded Market Access scenario modeled APS's first-tier interconnected utilities and the following additional changes:

- Preservation of ancillary services during load shed consistent with planned Western Resource Adequacy Program (WRAP) requirements
- Pre-climate adjusted loads
- Neighboring entities' PRMs fall short of meeting a 0.1 LOLE reliability target by 3%[6]
- Batteries set to preserve reliability
- No economic load forecast error

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[5] Note PRM is calculated on Load (including adjustments) net of EE ELCC. For the 2026 study year, the ELCC of EE is 324 MW.

[6] This 3% capacity shortfall is anecdotally based on resent CAISO capacity assessments showing the potential for not having sufficient capacity to meet the 0.1 LOLE standard. For example, the 2023 report (http://www.caiso.com/Documents/2023-Summer-Loads-and-Resources-Assessment.pdf) indicated that under normal hydro conditions, CAISO would fall 1,100 MW short of meeting the 0.1 LOLE standard reliability threshold. For purposes of this sensitivity, all APS neighbors were assumed to fall short of their 0.1 LOLE requirement by 3%.

Table 6 shows the ICAP PRM results of this sensitivity.

Table 6. 2026 Expanded Market Access PRM – ICAP Accounting

2026 Expanded Market Access PRM - ICAP Accounting			
Resource Type	Capacity (MW)	ELCC	Equivalent Capacity (MW)
Conventional Resources	7518		7518
ELCC Resources	6992	49.26%	3444
MW Adjustment	839		839
Total Capacity	15349		11801
Load (including adjustments)			10292
Reserves			1509
PRM[7]			15.1%

Despite an increase in ancillary services requirements of 6% during load shed events, the Expanded Market Access PRM sensitivity resulted in a 3.2% overall decrease in reserve margin in comparison with the 2026 Reference Case. This reduction is due primarily to benefits associated with being interconnected to external entities.

CURRENT MARKET CONDITIONS SCENARIO

This scenario included all the parameters of the Expanded Market Access scenario with the following two changes:

- Used climate adjusted loads, and
- Limited the aggregate APS imports during the peak season

Tables 7 and 8 below shows the ICAP and PCAP PRM results for this scenario, respectively. Climate adjusted loads and limiting peak season imports both contributed to the 5.1% increase in PRM in comparison to the Expanded Market Access Scenario. Climate adjusted loads increased the PRM because higher temperatures raised the load in the earlier weather years, thus increasing the APS summer risk in those weather years. The limitation on APS imports during the peak season also increased APS's capacity need, thus increasing the PRM. Also, note that the Current Market Conditions Scenario ICAP PRM is about 5% higher than the current APS ICAP PRM of 15%.

[7] Note PRM is calculated on Load (including adjustments) net of EE ELCC. For the 2026 study year, the ELCC of EE is 324 MW.

Calculated for the first time in an APS IRP, Table 8 shows a PCAP PRM of 6.9% for this scenario.

Table 7. 2026 Current Market Conditions PRM - ICAP Accounting

2026 Current Market Conditions PRM - ICAP Accounting			
Resource Type	Capacity (MW)	ELCC	Equivalent Capacity (MW)
Conventional Resources	7518		7518
ELCC Resources	6992	55.23%	3861.8
MW Adjustment	973		973
Total Capacity	15483		12352.8
Load (including adjustments)			10333
Reserves			2019.8
PRM[8]			20.2%

Table 8: 2026 Current Market Conditions PRM - PCAP Accounting

2026 Current Market Conditions - PCAP Accounting	
Resource Type	Equivalent Capacity
PCAP Capacity	10369
Load	9696
Reserves	673
PRM	6.9%

[8] Note PRM is calculated on Load (including adjustments) net of EE ELCC. For the 2026 study year, the ELCC of EE is 324 MW.

ELCC RESULTS

ELCC represents the amount of dependable capacity that can be counted on to meet system load for resource adequacy purposes based on the targeted reliability level. It represents a perfect capacity equivalent. ELCC is determined by the amount of incremental load that can be reliably served once a resource is added to the system. In addition to dependable capacity, measured in MW, ELCC is also often represented as a percentage of resource nameplate capacity and is calculated by dividing the amount of incremental load by the nameplate capacity of the resource added.

ELCCs for the portfolio of solar, wind, EE measures, Battery Energy Storage Systems (BESS), the AG-X program, and demand response resources were calculated for all scenarios studied. In addition to calculating Reference Case portfolio ELCCs, average and marginal ELCCs were calculated for solar, BESS, wind, EE measures, and the AG-X program across a wide range of penetration levels for a given load. Specifically for solar, BESS and wind resources, the resulting collection of values were used to create a dense three-dimensional matrix that can be used to estimate the ELCC of any combination of these resources.

CONCLUSION

The key findings listed below not only provide a comprehensive view of the current IRP resource adequacy conditions on the APS system, but also the means to continue evaluating resource adequacy as system conditions change.

- **PRM Determination**: Through a rigorous analysis, the study showed that the Current Market Conditions scenario best accounts for APS's current operating and long-term planning system conditions. This scenario produced an ICAP PRM of 20.2%, which represents a recommended increase of about 5% from APS's current ICAP PRM of 15.0%.
- **Accounting Mechanism**: The PCAP accounting is superior to ICAP accounting (more efficient, equitable in its treatment of different resources, and unaffected by portfolio changes). Therefore, it is recommended that APS adopt the PCAP accounting methodology for its 2023 IRP. The PCAP PRM for the recommended Current Market Conditions scenario is 6.9%, which is equivalent to the 2026 Reference Case ICAP PRM of approximately 20%.
- **ELCC Assessment**: The study produced ELCC matrices for various types of current and planned APS system resources, capturing each resource's dependable capacity contribution across a wide range of penetration.

The results of this study provide valuable tools and insight that APS can leverage both now and in future Resource Planning activities, including the ability to comprehensively evaluate resource adequacy in its 2023 IRP.