



Tucson Electric Power

2026 Integrated Resource Plan



FOREWORD

A Responsible Plan for Reliable, Affordable Energy

Energy providers have a responsibility to look ahead clearly and carefully so we can deliver the safe, reliable and affordable power our communities will need. That requires balancing system reliability with evolving realities, including changing weather, affordability pressures and increasing demand across the Desert Southwest.

Tucson Electric Power's 2026 Integrated Resource Plan (IRP) outlines how we will meet our customers' energy needs over the next 15 years while staying focused on reliability, controlling costs, and making steady progress toward a cleaner energy future.

This technology-neutral base case plan emerged from a transparent evaluation of seven different portfolios, including options designed to align with goals identified by our stakeholders. After stakeholder engagement and extensive modeling, we selected a portfolio that will meet customers' energy needs at the lowest possible cost while also maintaining system reliability.

This portfolio outlines how we expect to meet our local energy needs while making progress toward our goal of achieving net-zero direct greenhouse gas emissions by 2050. While that target extends beyond the IRP's planning horizon, our objective reflects confidence that emerging technologies, such as long duration energy storage, advanced geothermal and nuclear energy will become increasingly viable in the decades ahead.

In the near term, the IRP reflects decisions already underway. In 2025, we announced plans to convert the coal-fired Units 1 and 2 at the Springerville Generating Station to natural gas. This approach is responsive to a need identified in our 2023 IRP to provide reliable generation capacity while reducing reliance on coal and mitigating future risks such as rising fuel costs, delivery challenges and changing regulations. The conversion will provide comparable capacity to the coal-fired units while costing significantly less than building new thermal or renewable resources.

That conversion also is expected to cut the carbon emissions rate from those units by about 40 percent. Overall, TEP has already reduced carbon emissions from power generation by more than 42 percent since 2019.

To maintain reliability over the next 15 years, the portfolio includes 300 MW of natural gas capacity additions and 730 MW associated with the Springerville conversion from coal to natural gas. In combination with TEP's planned exit from Four Corners in 2031, the portfolio results in net thermal additions of 190 MW, while continuing the buildout of clean energy, including 680 MW of solar and 680 MW of battery storage coming online by 2041.

Our modeling shows this approach performs better and at lower cost than alternatives relying solely on new renewables and storage, while still supporting progress toward TEP's environmental objectives.

While there is significant discussion about potential future growth, particularly from data centers and other large customers, we have developed a resource strategy based on demonstrated needs, known retirements and realistic assumptions, while preserving the flexibility to respond as conditions evolve.

That flexibility is essential. Our actual resource mix may change based on the results of competitive all-source requests for proposals, which allow developers to offer technologies that outperform current assumptions. We will file updates with the Arizona Corporation Commission to reflect new information about our plans, as necessary.

We appreciate the contributions of our Resource Planning Advisory Council, representing residential and business customers, environmental advocates, government agencies and other stakeholders. Over the course of a full year, this group engaged in a dialogue with TEP staff, providing valuable insight and gaining a deeper understanding of our industry's opportunities and challenges. Their perspectives helped ensure this IRP reflects a plan for our community, not just our company.

Our customers expect energy that is safe, reliable, affordable and responsible for future generations. This balanced, cost-effective plan puts us on a path toward meeting those expectations.

Susan Gray
Chief Executive Officer



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SECTION 1

EXECUTIVE SUMMARY

Tucson Electric Power's 2026 Integrated Resource Plan (IRP) describes how the company expects to meet customers' energy needs over the next 15 years while maintaining reliable service for customers, efficiently managing costs and continuing progress toward a cleaner energy future.

The plan reflects a rapidly changing energy landscape characterized by challenges and opportunities including growing energy demand, evolving federal policies, increasingly complex reliability challenges, new economic development opportunities and continued advances in energy technologies.

After evaluating seven portfolios representing a range of future resource, load, and policy scenarios, TEP selected a least-cost, technology-neutral portfolio with an updated resource strategy that provides the best balance of reliability and affordability while continuing to deliver meaningful environmental benefits. It protects customers from unnecessary bill impacts while supporting growth in our community.

The 2026 IRP builds on significant progress achieved since TEP's previous resource plan. Since 2023, the company continued expansion of renewable energy and battery energy storage resources, reduced carbon emissions from power generation, participated in new regional energy markets, and incorporated changing federal tax policies and resource cost forecasts into its long-term planning. At the same time, the company has seen growing interest from large energy-intensive customers, including data centers and advanced manufacturing facilities, creating new opportunities for economic development and introducing additional planning uncertainty.

Maintaining Reliability in a Changing Energy Landscape

Reliability remains the foundation of TEP's resource planning process. Customers depend on reliable electric service every hour of every day, including during extreme heat events, periods of high demand, and changing weather conditions across the Desert Southwest.

The 2026 IRP incorporates updated reliability studies and planning assumptions designed to address evolving circumstances and reliability challenges. While the expansion of battery storage and renewable resources provide substantial operational and environmental benefits, traditional peak-demand periods are expected to shift into evening and nighttime hours. Planning studies consistently show that dispatchable resources continue to play a key role in maintaining reliability during periods of low renewable output, extended weather events and other conditions that place stress on our energy grid.

The preferred portfolio includes a combination of solar generation, energy storage, firm natural gas resources and market participation rather than reliance on any single technology to maintain reliability and operational flexibility. The IRP also considers an updated Planning Reserve Margin of 18 percent, reflecting new analyses of system reliability, generator performance and resource adequacy requirements. All of the portfolios analyzed were required to meet stringent reliability standards, including resource adequacy analyses designed to ensure sufficient energy and capacity resources are available under a wide range of operating conditions.

Affordability for Customers

Customer affordability remains a critical consideration in TEP's planning decisions. Rising costs throughout the economy continue to affect households and businesses, underscoring the need to identify resources and strategies that provide reliable service at the lowest reasonable cost for customers. The preferred portfolio produced the lowest overall cost while maintaining reliability requirements and delivering significant environmental benefits, with projected customer costs about \$150 million to \$260 million lower than other portfolios analyzed under the same load growth assumptions. The company estimates that alternative portfolios requiring additional clean energy resources or emerging technologies would increase long-term costs that could be reflected in higher customer rates.

A key consideration in the 2026 IRP is anticipated economic growth. Analysis of multiple high-load-growth scenarios demonstrates that, when appropriately structured, growth can support affordability by reducing potential future bill impacts on other customers while creating opportunities for economic development throughout Southern Arizona. Large commercial and industrial customers can contribute to lower average system costs by increasing utilization of existing infrastructure and spreading fixed costs across more energy sales.

The IRP also reflects changing market realities. Since the 2023 IRP, costs for many generation technologies have evolved, federal energy tax policies have changed, and new regional power market opportunities have emerged. These developments influenced portfolio outcomes and reinforced the need for a flexible planning approach grounded in continual evaluation of market conditions and competitive resource procurement through our all-source request for proposal (ASRFP) process.

Completing the Transition Away from Coal

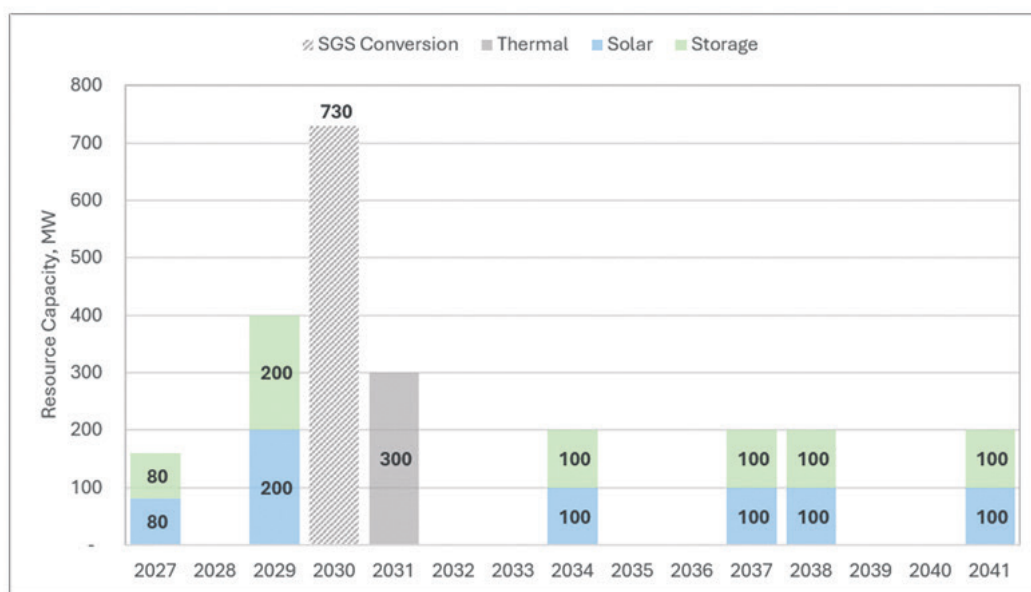
A key sustainability milestone reflected in the 2026 IRP is TEP's planned transition away from coal-fired generation.

TEP plans to convert Springerville Generating Station units 1 and 2 from coal to natural gas in 2030. This approach preserves 730 MW of critical dispatchable capacity while substantially reducing emissions, lowering environmental compliance risk and avoiding the significantly higher costs associated with alternative replacement options. The conversion is expected to reduce the carbon emissions rate from the affected units by approximately 40 percent while substantially reducing sulfur dioxide and nitrogen oxides emissions.

Additionally, TEP plans to exit its ownership share of the Four Corners Power Plant in 2031, ending the company's reliance on coal-fired generation. Together, these actions represent a major step toward achieving the company's long-term environmental goals.

The preferred portfolio continues investment in renewable generation and battery storage resources. Under the plan, TEP will add 680 MW of solar generation, 680 MW of battery storage capacity and 300 MW of new dispatchable natural gas capacity by 2041. These resources complement substantial renewable and storage investments made since the 2023 IRP and help reduce emissions, increase operational flexibility and improve the ability to shift clean, lower-cost solar energy to periods of highest customer demand.

Figure 1.1 - Preferred Portfolio Capacity Additions by Year



Despite development without specific renewable energy requirements or environmental goals, the Least-Cost, Technology Neutral portfolio includes a mix of solar, battery energy storage, and natural gas-fired resources that will bring over 50% carbon emissions reductions through 2041 relative to the 2019 baseline.

Preparing for Future Growth

Southern Arizona is experiencing increasing interest from large commercial and industrial customers including data centers, advanced manufacturing facilities and other energy-intensive industries. TEP's planning process evaluated high-load-growth scenarios to ensure the company understands the resource and infrastructure requirements necessary to support economic development opportunities that strengthen our region without shifting unnecessary costs or reliability risks to current customers.

Growth pays for growth, and new customers should appropriately support the costs associated with serving new load. The preferred portfolio provides a foundation capable of supporting future growth while preserving flexibility to respond as conditions evolve. Additional portfolios evaluated as part of the 2026 IRP demonstrate that TEP can accommodate substantially higher levels of demand growth through additional resource procurement, transmission development, and infrastructure investment.

A Balanced Path Forward

The 2026 IRP reflects a pragmatic approach to long-term planning. It preserves reliability through a diverse resource portfolio, maintains affordability through least-cost resource selection, supports continued environmental progress through the elimination of coal generation, and retains flexibility to meet future economic growth opportunities. The IRP is designed to provide flexibility that allows TEP to adapt as conditions evolve while continuing to provide safe, reliable, affordable and increasingly sustainable service.

SECTION 2

A CHANGING ENERGY LANDSCAPE

2.1. Tucson's Near-Term Economic Development Opportunities

Tucson Electric Power's (TEP's) role in supporting regional economic development will be guided by a core commitment to reliable and affordable service for existing customers, while responsibly supporting new growth. Economic expansion across Southern Arizona is being driven by accelerating trends in digitalization, electrification, decarbonization, and resilience. These trends are increasing demand for electricity while elevating expectations around grid performance, sustainability, and long-term cost certainty. TEP's ability to balance opportunity with affordability and prudent risk management will be critical to long-term success.

The Tucson metropolitan region continues to benefit from a diverse economic base that includes advanced manufacturing, aerospace and defense, natural resources, clean technologies, biosciences, and innovation anchored by the University of Arizona. Strategic logistics assets—Interstate 10, the Port of Tucson, Tucson International Airport, and intermodal rail facilities—support the region's competitiveness. As a result, economic development pipelines are expanding, with both a growing number of projects and increasing project scale.

Prospective development is increasingly larger and more energy-intensive. Large-scale projects with potential demand above 100 megawatts, such as data centers, are emerging more frequently. Many customers seek high reliability, fast delivery, long-term cost predictability, and pathways to large-scale or carbon-free energy. If realized, these projects will materially affect TEP's load forecasts, resource planning, and infrastructure investment requirements.

Capturing opportunity and supporting this growth presents significant challenges. Future development will require consensus around new and evolving generation resources, timely shared investment in major transmission and substation infrastructure, and sustained coordination across planning, permitting, and regulatory processes.

Equally important is strong alignment around regional strategic priorities and infrastructure development, including efforts by the Arizona Governor's Energy Promise Task Force, the Arizona Commerce Authority, Pima County's Economic Development Strategy, the City of Tucson's Comprehensive Economic Development Strategy, the development efforts of Marana, Oro Valley, and Sahuarita, and support from regional economic development organizations such as the Chamber of Southern Arizona. These efforts underscore the importance of coordinated decision-making among utilities, municipalities, counties, state agencies, water providers, and economic development organizations.

A foundational principle for TEP during this period is that growth will pay for growth. New customers and incremental load must appropriately support the generation, transmission, and other infrastructure required to serve them. Economic development should proceed without shifting costs or risks to existing customers, and without compromising affordability or reliability system-wide.



A foundational principle for TEP during this period is that growth will pay for growth.

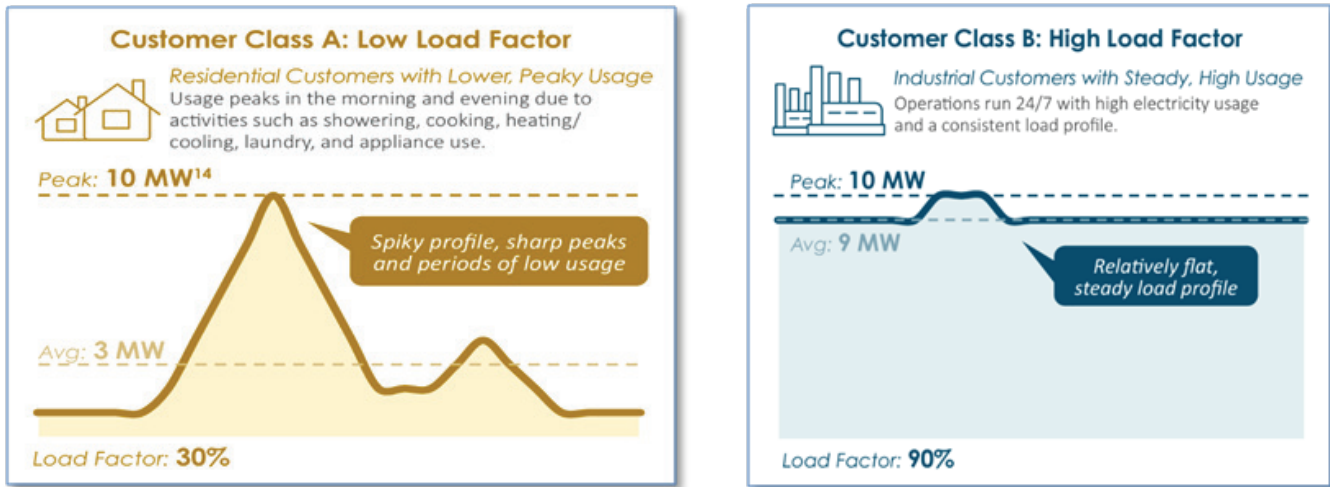
Through early engagement, disciplined evaluation of system impacts, transparent coordination, and alignment with regulatory and community expectations, TEP is positioned to support economic development that strengthens the region while protecting existing customers and advancing long-term community prosperity.

2.1.1. High Load Factor Customers

Utilities across the country have seen a proliferation in service requests by extra-high load factor (XHLF) customers. While there is no uniform industry definition for these customers, they are typically defined by the higher magnitudes of their proposed power usage and load factor.

In E3’s June 2026 report, “Beyond the Headlines: An Empirical Analysis of Data Center Grid Utilization, Cost-of-Service and Revenue Contributions,” load factor is described as “a measure of how efficiently electricity capacity is used. It is defined as the ratio of the average demand to the peak demand over a given period (e.g. a month or year). In other words, load factor indicates how steadily electricity is used relative to the customer’s max demand.”¹ **Figure 2.1** below shows a typical hourly load shape for a group of average residential customers, compared to a typical large load customer.

Figure 2.1: Residential vs. Large Load Customer Load Factor ²



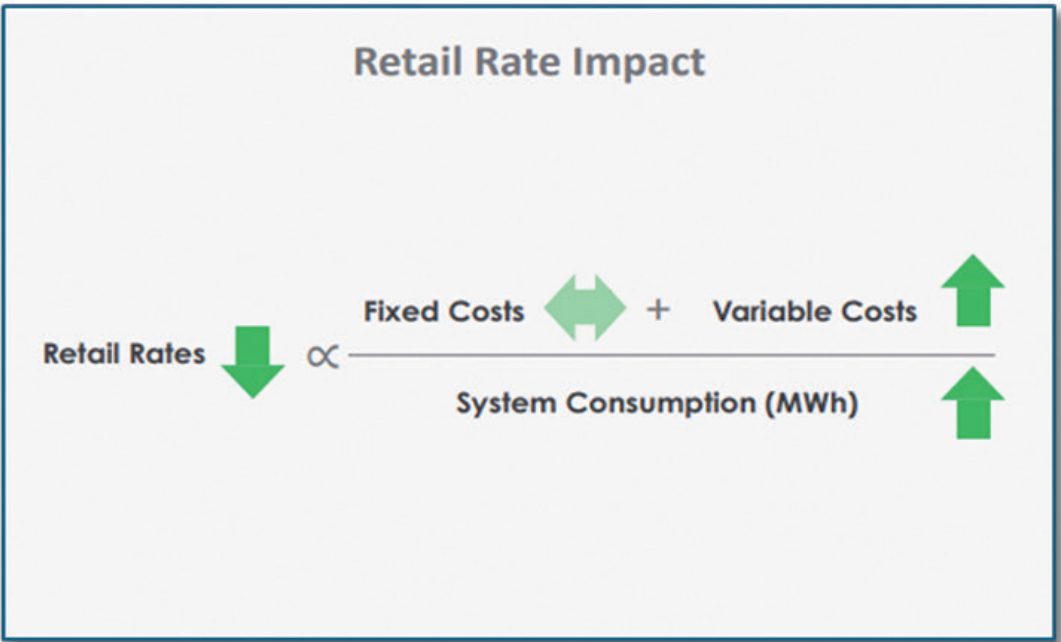
XHLF customers include many types of industrial and commercial usage, including data centers, mining facilities, and different types of manufacturing and processing plants.³ In recent years, Arizona utilities have also reported an increase in requests from XHLF customers.^{4,5} Between 2024 and 2025, TEP received inquiries from potential XHLF customers whose combined capacity needs approached 10,000MW.

¹ Energy and Environmental Economics, Inc. (E3), Beyond the Headlines: An Empirical Analysis of Data Center Grid Utilization, Cost-of-Service and Revenue Contributions (June 2026), 4, [Beyond the Headlines](#).
² E3, Beyond the Headlines, 13.

TEP requires interconnection studies before large customers may interconnect to the distribution or transmission system. Transmission interconnection studies evaluate new customers’ impacts on the local and remote transmission system, including whether new transmission facilities are needed. TEP’s resource capacity to serve the load is evaluated in concert with its ability to deliver the energy to the customer.

While there has been public concern over the effect of XHLF customers on customer rates, XHLF customers can provide system benefits by sharing existing system costs and helping to offset the costs of necessary grid upgrades.⁶ Increased power consumption spreads system costs over a larger volume of energy which drives down the average cost of energy system-wide. **Figure 2.2** illustrates this relationship.⁷

Figure 2.2 – Retail Rate Impact



³ North American Electric Reliability Corporation (NERC), Characteristics and Risks of Emerging Large Loads: Large Loads Task Force White Paper (July 2025), 8, [Characteristics and Risks of Emerging Large Loads](#).

⁴ Arizona Public Service, “APS Uses ‘Growth Pays For Growth’ Model to Develop New Natural Gas Plant” (October 30, 2025), [APS Uses ‘Growth Pays For Growth’ Model to Develop New Natural Gas Plant](#).

⁵ Salt River Project (SRP), “Data Centers and SRP” (2026), [Data Centers and SRP](#).

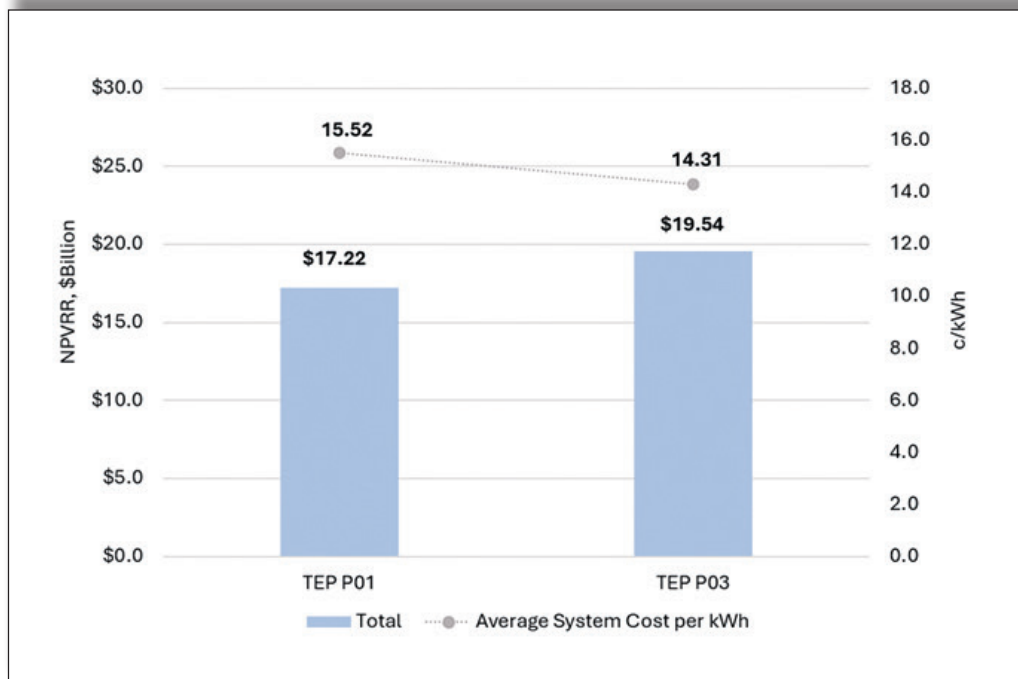
⁶ Energy and Environmental Economics, Inc. (E3), Tailored for Scale: Designing Electric Rates and Tariffs for Large Loads: A Guidebook of Industry Best Practices and Examples from Real-World Amazon Data Center Case Studies (December 2025), 7, [Ratepayer Study](#).

⁷ E3, Beyond the Headlines, 17.

This is demonstrated between TEP portfolios P01 – Least-Cost, Technology Neutral and P03 – High Load Factor Customer Growth. These two portfolios contain the same inputs, assumptions, and constraints with the exception of the load forecast. P01 assumes a typical TEP retail load increase over the fifteen-year study period plus the addition of the Humphrey’s Peak Energy Supply Agreement 1 load (see section 4.2.1 for more on TEP’s load forecast). P03 takes the P01 load forecast and adds 550 MW of generic high load factor load beginning in 2030. The P03 portfolio requires the development of additional resources to supply the additional capacity and energy needed to adequately serve the new load, but the average system cost per kWh to serve all customers across the portfolio is lower than that of P01. This demonstrates how a portfolio with a higher load forecast and higher quantity of new resources can result in lower average energy costs for all customers.

This demonstrates how a portfolio with a higher load forecast and higher quantity of new resources can result in lower average energy costs for all customers.

Figure 2.3 - Portfolio NPVRR vs Average System Cost per kWh



2.2. Resource Adequacy and Reliability

The chief purpose of the Integrated Resource Plan is to outline resource portfolios that address multiple possible futures, such as different load forecasts and different resource mixes. The characteristic that all these portfolios must have in common is resource adequacy (RA). Resource adequacy is the ability of a utility to meet system demand and required reserves under varying system conditions. Meeting RA requirements positions the utility to be able to respond to meet its customers’ needs under real-time operating conditions (see Appendix I for more information on real-time operations and reliability standards).

Until recent years, utilities could typically evaluate resource adequacy based on capacity to meet net peak demand. Resource portfolios built primarily or entirely on thermal resources that were able to provide energy on-demand meant that the ability to serve peak demand implied the ability to meet load at any other time of year or hour of the day. Since the addition of intermittent resources, such as solar and wind, as well as energy-limited resources, such as lithium-ion batteries (i.e. Battery Energy Storage Systems, or BESS), resource adequacy has become increasingly complex.

To ensure resource adequacy, power providers rely on a capacity margin, called the Planning Reserve Margin (PRM), which is the required amount of capacity above expected peak loads that will enable them to meet customers' power needs. This additional capacity is available in case the load exceeds the forecast, or there are plant or transmission outages that prevent the delivery of energy to the service territory.



A newer consideration when evaluating resources against the PRM is their accreditation value, usually called Effective Load-Carrying Capability (ELCC). Each type of resource, whether thermal, intermittent, or energy-limited, is evaluated within the system it serves and assigned a capacity value which can be applied to meet the PRM. ELCCs are dependent on a utility system's load characteristics and historical weather patterns, as well as quantities and types of generation. As variables within each utility's system change, so may the ELCCs for each resource type. This results in resource accreditation which is much more dynamic than when most resources across the grid had uniform operational characteristics.

Another aspect of resource adequacy is the loss of load expectation, or LOLE. Utilities design RA requirements and portfolios around meeting a 1-day-in-10-year LOLE. ELCC and PRM studies that model LOLE over long time frames are able to identify which hours of the day, and during which months of the year, loss of load events are most likely to occur. Utilities can then design portfolios with resources that are able to supply energy during those at-risk hours.

2.2.1. Regional Resource Adequacy Studies

In 2021, Energy & Environmental Economics, Inc (E3) conducted a study of resource adequacy in the Desert Southwest. The study was conducted with input from Arizona Public Service Company (APS), Arizona Electric Power Cooperative (AEP), El Paso Electric Company (EPE), Public Service Company of New Mexico (PNM), Salt River Project (SRP), Tucson Electric Power Company (TEP), and UNS Electric, Inc. (UNSE) and focused primarily on evaluating load growth, resource retirements in the region, and the need for aggressive resource development against reliability. It also recognized that the resource plans developed at the time by the utilities resulted in regional resource adequacy over the following decade.⁸

⁸ Energy and Environmental Economics, Inc. (E3), Resource Adequacy in the Desert Southwest: Final Report (2022), 9, [Resource Adequacy in the Desert Southwest](#).

In 2025, the same group elected to have E3 refresh the 2021 study and conduct an independent assessment of regional resource adequacy.⁹ Each utility provided updated load forecasts and resource plans to E3, who then enacted a two-pronged approach to the study:

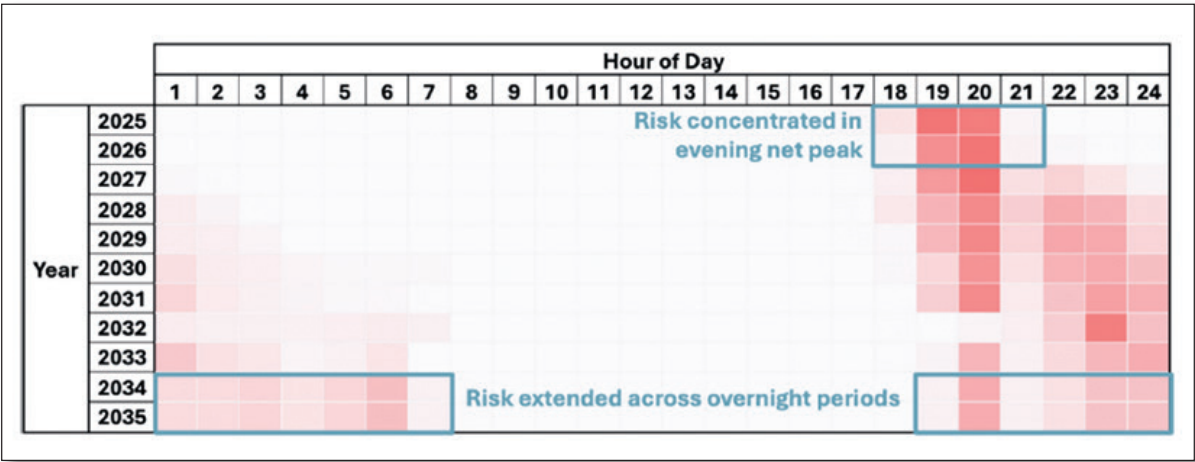
- A near-term, ten-year assessment to evaluate the loads and resources provided by participants and determine whether resource plans prove adequate, and
- A long-term, twenty-year assessment which constructed multiple future scenarios and developed multiple resource portfolios based on long-term capacity expansion (LTCE).

The near-term assessment used the criteria of the 1-day-in-10-year (0.1 days per year) LOLE and determined that utility plans result in a resource adequate system over the 2025 to 2035 study period.¹⁰ This, in concert with the original 2021 study, validates that “the utilities’ collective planning practices are effective in their identification of resource portfolios with the technical ability to maintain regional resource adequacy.”¹¹ However, the need for new resources is urgent, and the success of those resource plans is dependent on their swift implementation.

Another important result of the near-term study is the identification of shifts in reliability risks over the 10-year study period. As the Desert Southwest utilities continue to increase the amount of solar and BESS on the system, reliability challenges shift away from typical peak times, towards the evening and then into the overnight hours. This shift “increases the relative value of resources that can provide longer duration services to the grid... without limits on their use.”¹²

Figure 2.4 below from E3’s study illustrates the relative loss-of-load risk by hour of day over the 2025-2035 period.

Figure 2.4 – Relative Loss-of-Load Risk¹³



⁹ Energy and Environmental Economics, Inc. (E3), 2025 Resource Adequacy Assessment: Desert Southwest (2025), [2025 Resource Adequacy Assessment](#).
¹⁰ E3, 2025 Resource Adequacy Assessment, 12.
¹¹ E3, 2025 Resource Adequacy Assessment, 17.
¹² E3, 2025 Resource Adequacy Assessment, 13.
¹³ E3, 2025 Resource Adequacy Assessment, 13.

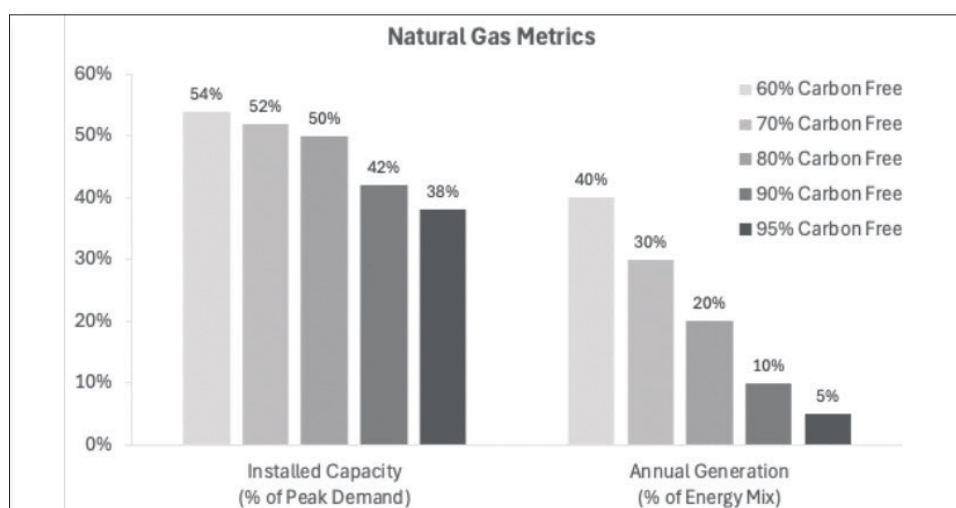
2.2.2. Resource Adequacy into the Future

The remaining key findings from the 2025 E3 study are results of the long-term analysis. For the long-term analysis, E3 developed multiple portfolios of varying levels of renewable penetration. Each portfolio was designed to meet the 1-day-in-10 LOLE requirement, and each includes some quantity of firm (gas and nuclear), renewable (wind and solar), and energy-limited (BESS) resources. Key findings include that “resource adequacy can be met with a wide range of resource mixes,”¹⁴ as portfolios between 60 to 95% carbon-free were studied and found to meet the LOLE requirement.

The long-term assessment also identified firm resources as critical to reliability, regardless of the quantity of renewable and energy-limited resources on the system. “In all long-term portfolios, nuclear and natural gas resources play a critical role in ensuring reliability when electric demand is high, renewable availability is low, and energy storage resources have been depleted...” Because gas resources are available around-the-clock and on demand, they are instrumental in providing reliability when the system experiences periods of low renewable output. The study notes that even as renewable penetration increases and the amount of energy served by natural gas resources drops, the installed capacity of gas resources needed does not decrease. In fact, even in the 95% renewable portfolio, the installed capacity of natural gas remains around 40% of the system peak to maintain resource adequacy and reliability.¹⁵

Figure 2.5 from E3’s RA study presents the key metrics for natural gas resources in the long-term adequacy assessment.

Figure 2.5 – Natural Gas Metrics¹⁶



The study finds that increasing the energy served by renewable resources drives down how often gas resources are run, but doesn’t reduce how much flexible, firm capacity is needed to maintain reliability. These results highlight that natural gas can act as a facilitator of regional plans to drive towards net-zero direct emissions.

¹⁴ E3, 2025 Resource Adequacy Assessment, 14

¹⁵ E3, 2025 Resource Adequacy Assessment, 11

¹⁶ E3, 2025 Resource Adequacy Assessment, 16

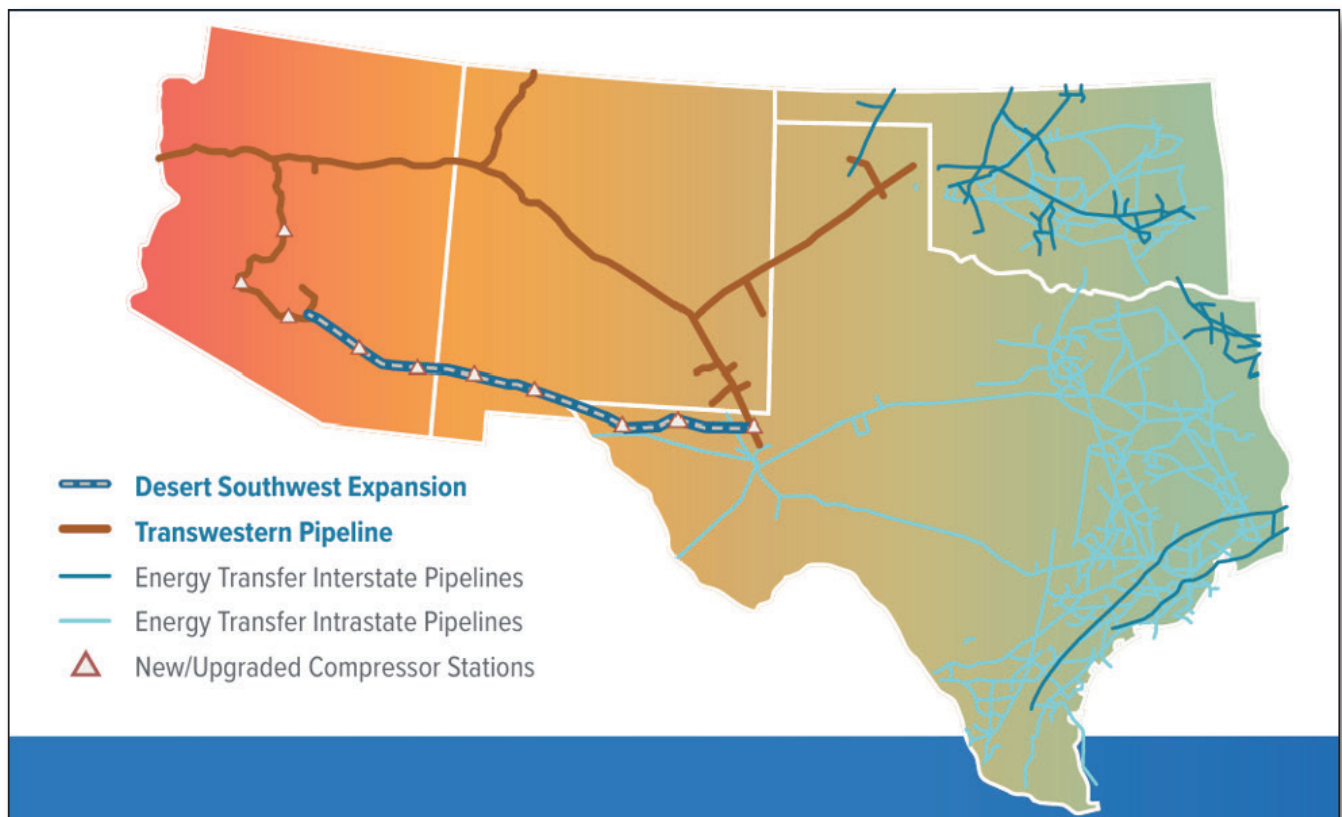
2.3. Desert Southwest Pipeline Expansion Project

Project Overview

In August 2025, Transwestern Pipeline Company announced plans to develop the Desert Southwest Pipeline Expansion project. This intrastate pipeline project is intended to increase gas delivery from the Permian Basin into Arizona and New Mexico to support growing customer demand and electric grid reliability.

The Desert Southwest Expansion is planned to originate in Winkler County, Texas, and traverse approximately 520 miles through New Mexico and Arizona to an end point in Coolidge, Arizona. The 48-inch underground pipeline will be powered by new compressor stations strategically situated along the pipeline route to deliver up to 2.3 billion cubic feet per day of natural gas to customers in Texas, New Mexico and Arizona.¹⁷ Moreover, the Desert Southwest Expansion will make Transwestern's natural gas flows on the Phoenix Lateral bi-directional, adding flexibility to move natural gas in both directions based on customer needs.

Figure 2.6 – Desert Southwest Pipeline Expansion Proposed Route



¹⁷ <https://desertsouthwest.com/>

Arizona’s Demand for New Natural Gas

Today, Arizona’s existing natural gas pipelines are fully subscribed. The Desert Southwest Pipeline Expansion project will strengthen the Southwest’s energy backbone by increasing natural gas supply and enabling Arizona electric utilities to secure natural gas transportation to fuel new and existing generation facilities, enhancing grid reliability during periods of high demand.

Arizona Governor Katie Hobbs emphasized that the project is essential for reliable, affordable energy and long-term economic growth. “The Desert Southwest Pipeline will significantly increase our state’s energy capacity and diversify our energy resources. Arizona’s all-of-the-above energy strategy is ensuring we have the energy we need to expand our economy and deliver for working people in this state.”¹⁸ The Desert Southwest Pipeline Expansion project plays a critical role in supporting the Company’s plans to supply the Gila River Generating Station and expand natural gas generation resources at the Springerville Generating Station.¹⁹

Project Timeline

The four-year project has an estimated construction start date in the second quarter of 2028, resulting in an expected in-service date of the fourth quarter of 2029.

Figure 2.7 – Desert Southwest Pipeline Expansion Project Timeline



TEP’s Need for New Natural Gas Resources

TEP’s 2023 IRP acknowledged by the Arizona Corporation Commission in October 2024 identified the Company’s need for new natural gas resources.²⁰ TEP’s 2023 Balanced Portfolio which included new natural gas resources was shown to be the most cost-effective way to maintain reliable, affordable service while reducing long-term environmental compliance risks for TEP’s customers.

While TEP’s 2023 IRP had originally identified new natural gas combustion turbines as potential resources for future generation capacity, increases in natural gas turbine acquisition costs, limited turbine availability and the elimination of tax credits for renewables led the Company to reevaluate its natural gas resource options for the 2026 IRP.

¹⁸ <https://azgovernor.gov/office-arizona-governor/news/2026/05/governor-katie-hobbs-announces-support-transwesterns-desert>

¹⁹ <https://www.tep.com/news/tep-to-convert-coal-fired-springerville-generating-station-units-to-natural-gas/>

²⁰ See ACC Decision 79589 – <https://docket.images.azcc.gov/0000212120.pdf?i=1779468799809>

2.4. Springerville Generating Station Repowering Project

As part of the 2026 IRP planning cycle, the company evaluated several new generation options to replace the Springerville Generating Station capacity upon its retirement. These analyses led to TEP's plans to repower the Springerville Generating Station with natural gas. This section provides an overview of the project along with the analysis that determined that the SGS repowering option was the lowest cost option versus a new investment in a greenfield natural gas plant, a new solar and energy storage system, or continued SGS operations on coal.

Project Overview

TEP plans to convert Units 1 and 2 at the coal-fired Springerville Generating Station to operate on natural gas by 2030. The conversion will provide comparable capacity to the existing coal-fired units while costing less than building new resources such as new natural gas combined cycle resource or solar-plus-energy storage that provide comparable capacity. The natural gas repowering option will also provide greater cost certainty and lower environmental compliance risks compared to the continued use of coal at Springerville.

Resource Scenarios Compared

The company evaluated three potential resource scenarios against continued coal operations at the Springerville Generating Station. The scenario analysis provided below highlights the cost differentials for up-front capital, net present value revenue requirements, and levelized cost of resource operations. On a stand-alone basis, this analysis provides transparency into the Company's decision to incorporate the Springerville repowering project into TEP's Long-Term Capacity Expansion (LTCE) model for evaluation in the 2026 IRP (see section 4.1.2).

Up-Front Capital

Based on up-front capital costs, repowering Springerville Units 1 and 2 would require approximately \$170 million whereas continued coal operations would require approximately \$450 million in up-front capital. In comparison, a new combined cycle unit would require approximately \$1.5 billion in up-front capital and the equivalent solar plus storage resources would require approximately \$4.5 billion in up-front capital costs. As shown below, the SGS natural gas repowering option has the lowest up-front capital investment.



Figure 2.8 – Resource Options: Up-Front Capital Investments

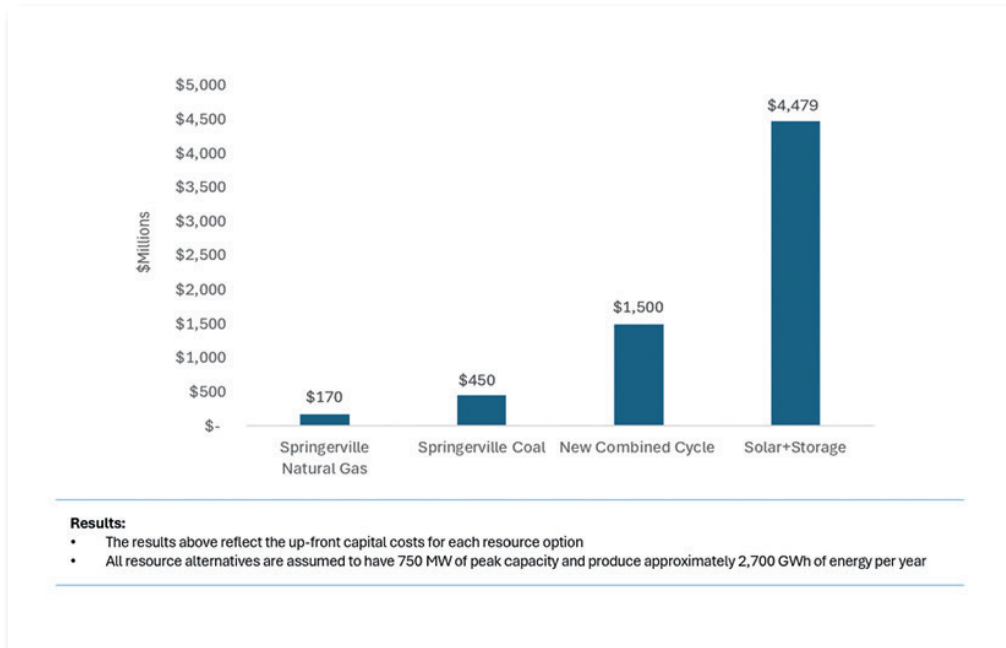


Table 2.1 - Scenario Capital Comparison

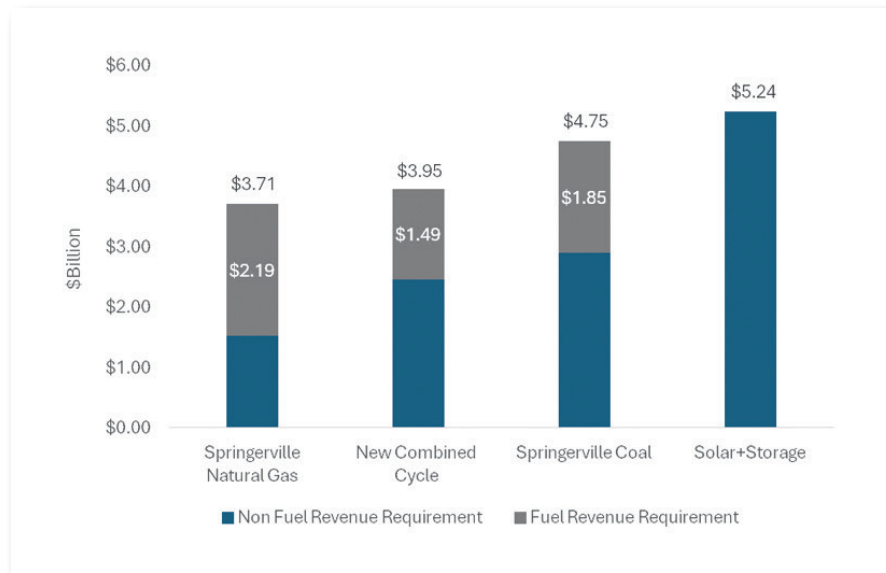
Scenarios	Scope of Capital Improvements	Upfront CapEx (\$)	Upfront CapEx (\$/kW)
Springerville Coal	New environmental upgrades	\$450 Million	\$600
Springerville Natural Gas	Boiler modifications	\$170 Million	\$227
New Combined Cycle	New greenfield project	\$1.5 Billion	\$2,000
New Solar + Storage Facilities	New greenfield project	\$4.5 Billion	\$1,828

Net Present Value Revenue Requirements

Not only does the Springerville repowering project require less up-front capital but the Net Present Value Revenue Requirement (NPVRR) of resource operations also results in the least cost option for customers over a 20-year timeframe.

Over a 20-year timeframe, the NPVRR for repowering Springerville Units 1 and 2 on natural gas would be approximately \$3.71 billion whereas the NPVRR for continued coal operations would be approximately \$4.75 billion, including both fuel and non-fuel costs. In comparison, the NPVRR for a new combined cycle unit would be approximately \$3.95 billion and the NPVRR for the equivalent solar plus storage resources would be approximately \$5.24 billion.

**Figure 2.9 – Resource Options: 20-Year
Net Present Value Revenue Requirements**



Assumptions:

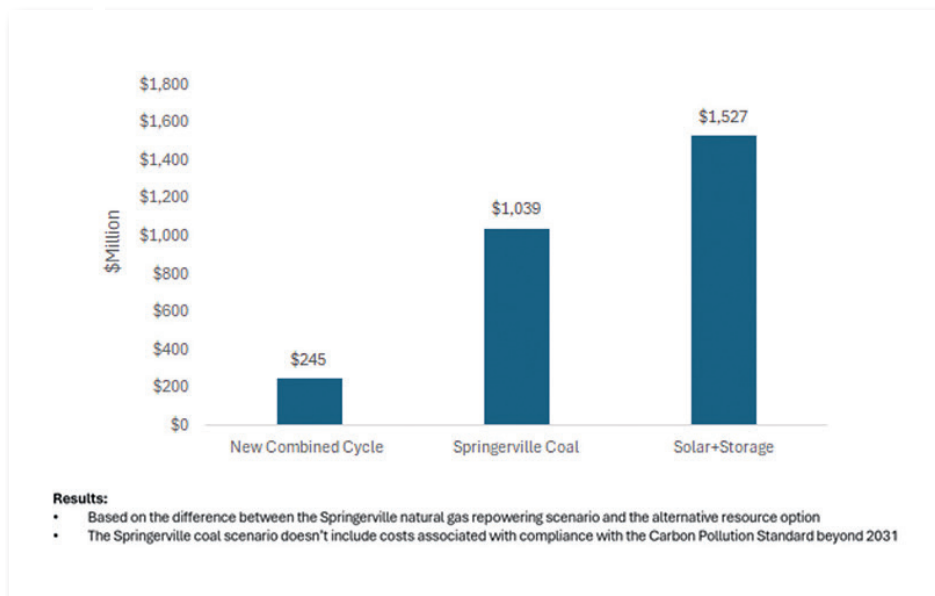
- The amounts above are based on a 20-year net present revenue requirement (NPVRR) for each resource option
- The Non-Fuel NPVRR calculation includes capex, O&M, taxes, insurance and decommissioning costs
- The Fuel NPVRR includes fuel (commodity) and transportation costs (i.e, pipeline capacity (natural gas), rail (coal))
- Solar and wind resources exclude any tax credits whereas, battery storage includes investment tax credits of 30%

Table 2.2 - Scenario NPV Comparison

Scenarios	NPV Fuel	Upfront CapEx (\$)	Upfront CapEx (\$/kW)
Springerville Coal	\$1.85	\$2.90	\$4.75
Springerville Natural Gas	\$2.19	\$1.52	\$3.71
New Combined Cycle	\$1.49	\$2.46	\$3.95
New Solar + Storage Facilities	\$0.00	\$5.24	\$5.24

Over a 20-year timeframe, the NPVRR savings for repowering Springerville Units 1 and 2 would be approximately \$245 million compared to a new combined cycle resource whereas the NPVRR savings for continued coal operations would be approximately \$1.0 billion. Finally, the NPVRR savings compared to the equivalent solar plus storage resources would be approximately \$1.5 billion.

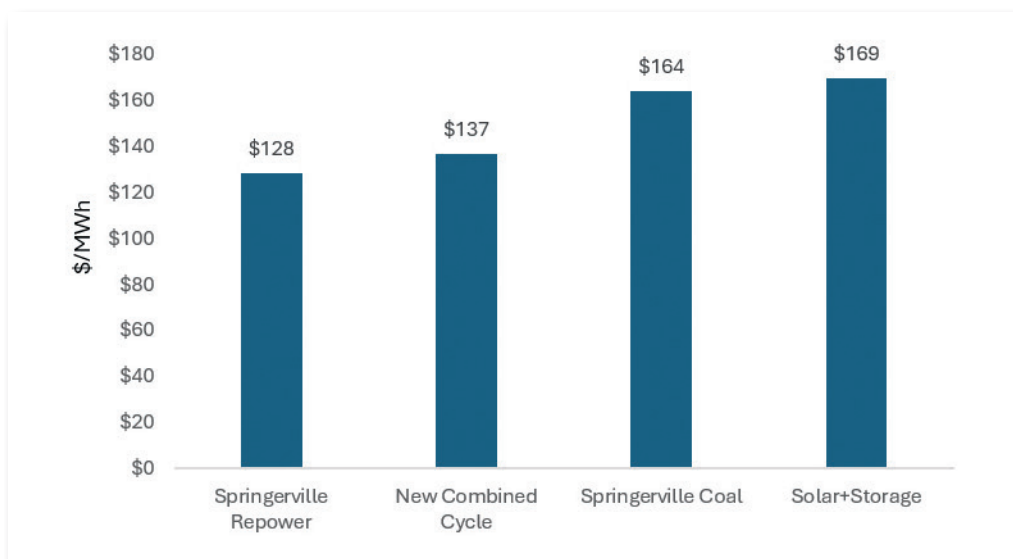
Figure 2.10 – Springerville Repowering Cost Savings versus Other Alternatives



Levelized Operating Costs

Over a 20-year timeframe, the levelized operating costs for repowering Springerville Units 1 and 2 on natural gas are lower than that of the levelized operating costs for continued coal operations, new combined cycle, and the equivalent solar plus storage (see **Figure 2.11**).

Figure 2.11 – Resource Options: Levelized Operating Costs



Lower Air Emissions

SGS’s natural gas repowering will reduce the units’ carbon emission rates by approximately 40 percent ²¹, helping TEP make progress toward our goal of net-zero direct greenhouse gas emissions by 2050. TEP already has reduced carbon emissions from power generation by 42 percent since 2019²². In addition, reductions in unit emission rates for NO_x and SO₂ are estimated to be approximately 36% and 99%, respectively, under natural gas operations at SGS when compared to average emission rates from 2020-2024. These estimated unit rate reductions are summarized in **Figure 2.12** below.

Table 2.3 – SGS Repowering Estimated Emission Rate Reductions

Air Emission Categories	NO _x	SO ₂	CO ₂
Estimated Rate Reductions	36%	99%	40%

Certificate of Environmental Compatibility

In December 2025, TEP filed an application to amend the Certificate of Environmental Compatibility (CEC) to allow the two SGS units to operate on natural gas. The Arizona Corporation Commission reviewed TEP’s request and unanimously approved the CEC amendment under Decision No. 81675 in March 2026.²³

The SGS Repowering Project Supports Arizona’s Growing Economy

Arizona Governor Katie Hobbs praised the project. “A resilient grid that’s reliable, affordable, and sustainable is core to delivering on the Arizona Promise,” Hobbs said. “The SGS repowering project will deliver cleaner air and lower costs, while strengthening communities in northeastern Arizona and building a more resilient energy future for Arizona.”

The SGS repowering project will support the continued availability of affordable, reliable power in Southern Arizona for local residents and businesses. It will also maintain jobs and tax revenues for Springerville, Eager, St. John’s, and other White Mountain communities that our SGS employees call home.



The SGS repowering project will support the continued availability of affordable reliable power in Southern Arizona for local residents and businesses.

²¹ <https://www.tep.com/sgs-repower/>
²² <https://www.tep.com/sustainability/>
²³ See ACC Decision 81675 - <https://docs.tep.com/wp-content/uploads/SGS-CEC-Amendment-No-81675.pdf>

SGS Repowering Project Selected as Part of TEP's Least-Cost, Technology Neutral Portfolio

Over the last four decades, coal-fired operations at the Springerville Generating Station have been essential in maintaining lower fuel supply costs and higher grid reliability for TEP's customers. Going forward, the SGS repowering project will enable TEP to diversify its project development and supply chain risks by utilizing an existing asset located at a strategic interconnection point on the TEP transmission network. The SGS repowering project will result in significantly lower unit emission rates while ensuring that the Company



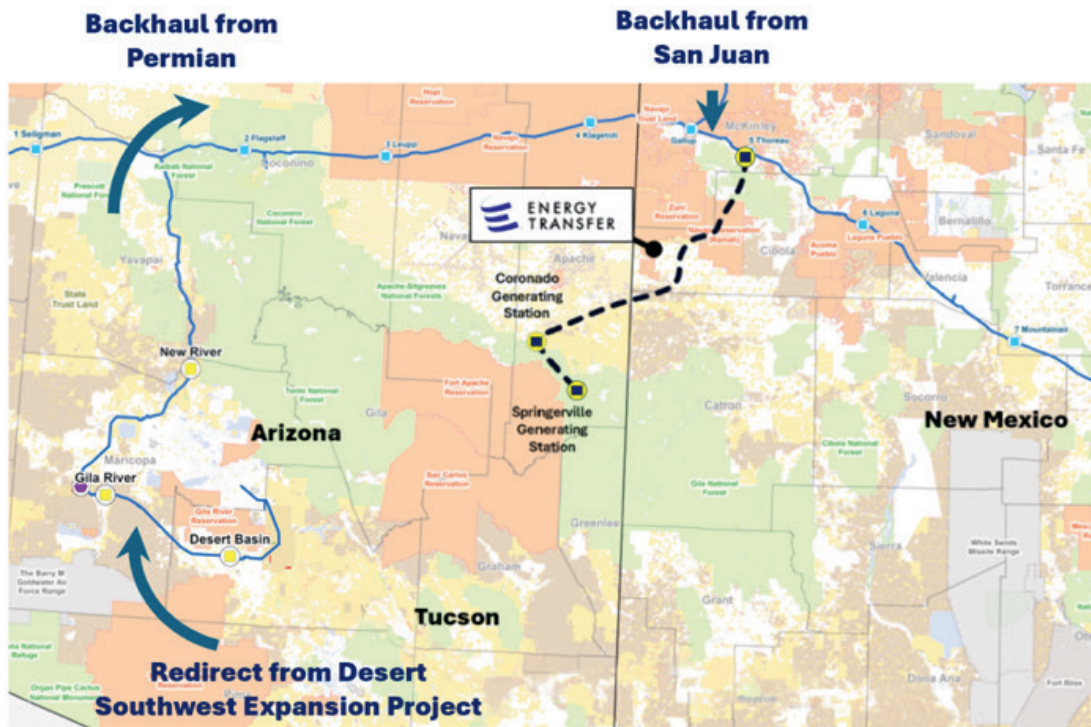
maintains its peak load-serving capabilities to meet summer demand. On a regional basis, the repowering of the Springerville Generating Station will enable 1.6 gigawatts of existing generation to remain online and available to serve Arizona's electric utility customers. As a result of the information discussed above and the assumptions used in the Company's LTCE optimization model, the SGS repowering project was selected as part of TEP's Least-Cost, Technology Neutral portfolio (P01).

2.4.1. Springerville Lateral Natural Gas Pipeline

Project Overview

In April 2026, TEP entered into a precedent agreement with Transwestern Pipeline Company to develop a new lateral pipeline to serve the Springerville Generating Station. This pipeline project will provide new natural gas service to both the Springerville and Coronado Generating Stations. The project lateral pipeline is planned to originate in Thoreau, New Mexico and traverse approximately 120 miles through New Mexico and Arizona to delivery points at the Coronado and Springerville Generating Stations. As part of the Transwestern system, the Springerville Lateral will have access to natural gas from the San Juan Basin, or from the Permian Basin via the new Desert Southwest Pipeline Expansion. The 30-inch underground pipeline will be powered by a new compressor station located along the pipeline route to deliver up to 625 million cubic feet of natural gas per day. The project has an estimated construction start date in the fourth quarter of 2028, resulting in an expected in-service date in the fourth quarter of 2029.

Figure 2.12 – Springerville-Coronado Lateral Pipeline Route



SECTION 3

THE RESOURCE PLANNING PROCESS AND CONSIDERATIONS

3.1 Overview of TEP's Planning Process

3.1.1 Reliability, Affordability, Sustainability

TEP's core planning principles are reliability, affordability, and sustainability. Each of these are guiding values, and they must be weighed against each other in any planning scenario or investment decision. In the IRP, the needs of customers and the system must be balanced in order to arrive at portfolios that achieve the required reliability metrics while keeping costs low and minimizing carbon emissions.

Reliability

A power utility's most important function is to provide power to its customers 24 hours per day without interruption. TEP's customers depend on a reliable power supply to cool their homes and run their businesses. Integrated resource planning ensures that all future scenarios the company may operate in provide this reliability. In order to do so, each resource portfolio is required to meet minimum resource adequacy metrics, as based on industry standards. The most significant of these is the Planning Reserve Margin, which is the required amount of capacity above expected peak loads that will enable them to meet customers' power needs, and is designed to meet the industry standard 1-day-in-10-year LOLE criteria (see section 2.2). Effective Load Carrying Capabilities are also applied to renewable and energy-limited resource types to ensure that the addition of these resources to the system does not result in a degradation of reliability.

The resources included in each portfolio must work in concert to serve the system's demand at any given time. Large thermal facilities tend to operate as 'base load,' where they operate at the top of their capability and are usually most efficient. Those resources may ramp up in the morning and down in the evening to accommodate afternoon peaks. Wind and solar resources are not dispatchable in this way, although weather forecasting can prepare system operators for potential changes in output. Small thermal resources, such as internal combustion turbines (ICTs) and reciprocating internal combustion engines (RICE), serve as fast-ramping resources that can respond quickly to changes in load or renewable output.

The addition of Li-ion battery resources to the TEP system, as discussed in section 3.1.2, enables the storage of excess morning solar energy for dispatch later in the day. The capture of this energy for use during peak helps achieve reliability metrics while also improving affordability and sustainability by reducing the amount of thermal generation needed to meet those peaks. While batteries do not themselves generate energy, they are an important part of a resource portfolio due to their ability to store excess or low-cost energy and provide access to that capacity on demand.

Affordability

In developing resource portfolios, TEP recognizes the broad affordability challenges that many customers face, and the need to pursue least-cost resource additions to provide power responsibly. TEP's participation in Energy Imbalance and Day-Ahead Markets (EIM and DAM, respectively) optimizes the efficient dispatch of TEP's generators, helping TEP capture the benefits of low-cost market energy and pass those savings on to customers. (see Appendix F). Energy efficiency programs enable customers to reduce their overall energy consumption and therefore costs, while demand response programs can help reduce the need for expensive peaking resources (see Appendix J).

TEP also must acquire new capacity and energy resources to satisfy retail load requirements. To ensure that TEP can acquire the most cost-effective resources, All-source Request for Proposals are issued and bids are evaluated according to cost as well as other criteria (see section 3.2.1). Factors affecting resource costs include fluctuations in federal tax incentive policies and increases in capital and operations and maintenance (O&M) costs due to inflation, supply chain delays and other market factors.

Sustainability

In 2031, TEP plans to reach a significant milestone by exiting from all coal-fired power generation. The planned conversion of Springerville Units 1 and 2 from coal to natural gas in 2030 and the planned exit from Four Corners Power Plant Units 4 and 5 in 2031 represent the Company's commitment to sustainability and a major step forward in reduction of greenhouse gas (GHG) emissions.

In 2020, TEP committed to reducing GHG emissions 80 percent below 2005 levels by 2035. In 2023, TEP committed to reducing direct GHG emissions to net-zero by 2050. Because market conditions have changed, TEP will no longer meet the 2035 carbon goal. TEP remains committed to reducing GHG emissions and providing power sustainably and responsibly and will continue to work towards the aspirational net-zero direct GHG emissions goal by 2050. Increasing reliance on renewable resources as well as exploration of new technologies are both part of that strategy. Since 2020, the Company has built or entered into PPAs for over 1,250 MW of wind, solar, and storage facilities which have displaced other thermal resources.²⁴ TEP intends to continue its pursuit of renewable resources, assessing potential investments for their contribution to system reliability and customer affordability.



²⁴ For more information on TEP's sustainability efforts, see <https://www.tep.com/sustainability/>.

3.1.2. Risk Management

Energy Resource Risk Management

Electric resource planning requires balancing cost, reliability, resilience, and environmental objectives under uncertain future conditions. Geopolitical events, shared infrastructure dependencies, cybersecurity vulnerabilities, and extreme weather events can disrupt fuel supply, generation, transmission, and distribution systems. These disruptions may result in power outages affecting homes, businesses, and essential services.

TEP manages resource risk through a diversified portfolio that includes renewable generation, energy storage, dispatchable thermal resources, demand-side resources and market participation. Resource diversification reduces reliance on any single technology, fuel source, or market mechanism while improving the system's ability to respond to changing load growth, technology developments, regulatory requirements, and market conditions.

In addition, TEP leverages regional diversity through market participation in the California Independent System Operator's Western Energy Imbalance Market (WEIM) and, in the future, Southwest Power Pool (SPP)'s Markets+, providing access to a broader pool of regional resources and market opportunities. Membership in Western Power Pool's Western Resource Adequacy Program contributes to increased reliability across the broader Western Interconnection (see Section 3.4.1). TEP also utilizes the ASRFP process to identify cost-effective resource options that support resource adequacy, resilience, environmental objectives, and customer affordability.

Fuel Price Volatility and Fuel Supply Availability Risk Management

TEP employs a diversified fuel procurement and risk management strategy to mitigate fuel price volatility and maintain reliable fuel supply for generating resources.

TEP's coal supply is secured through long-term supply agreements with fixed prices and annual inflation-based escalators. These agreements contain minimum purchase commitments, including take-or-pay provisions that help ensure fuel availability. Coal delivery could be impacted by supply chain constraints, railroad interruptions or extreme weather events. To mitigate these risks, TEP maintains a 30-to-90-day coal supply at the Springerville Generation Station. Consistent with its long-term strategy, TEP has announced plans to convert Springerville Units 1 and 2 from coal to natural gas-fired generation by 2030, and exiting the coal-fired Four Corners Units 4 and 5 by 2031.

Natural gas supply is primarily procured through short term supply agreements to manage natural gas price volatility. TEP implements a structured hedging program utilizing a rolling 36-month layered execution strategy resulting in approximately 90% of forecast natural gas requirements being hedged one month prior to delivery (primarily through fixed-for-floating financial swap transactions). TEP also maintains long-term natural gas transportation agreements with multiple pipeline providers, providing access to diverse supply basins, including the Permian and San Juan basins. While natural gas deliveries may be affected by extreme weather, pipeline outages, or changing market conditions such as liquefied natural gas export demand, supply diversity and transportation flexibility help reduce exposure to localized disruptions and support reliable fuel delivery.

Wholesale Power Market Risk Management

The Desert Southwest wholesale power market has experienced increasing price volatility and tightening resource adequacy conditions in recent years, particularly during summer peak demand periods. To mitigate exposure to wholesale market price volatility and potential capacity shortages, TEP implements a capacity hedging program designed to secure firm resource capacity in advance.

The Company procures fixed price physical power transactions and maintains a Planning Reserve Margin (PRM) target to support reliable service during peak demand periods. In 2026, TEP increased its PRM target to 18% to further strengthen resource adequacy and address evolving reliability risks. TEP utilizes a four-season laddering strategy under which approximately 25% of projected open summer-season capacity requirements are secured two years in advance, with additional purchases layered in over time as delivery approaches. This strategy reduces exposure to short-term market volatility, enhances resource adequacy, and increases certainty regarding future capacity costs.

Power System Operational Risk Management

TEP incorporates redundancy across generation, transmission, and distribution systems to ensure power reliability. The systems involve duplicating critical components, data, or functions, ensuring that if one fails, another can seamlessly take over. This redundancy minimizes disruptions, improves reliability, and enhances the ability to withstand unexpected events, such as equipment failures, natural disasters, and cyberattacks.

TEP incorporates redundancy within its Energy Management System (EMS), Outage Management System (OMS), and the communication infrastructure connecting the remote substations and generation facilities to these operational systems. Critical applications that support interconnected system operations are designed with independent primary and backup control centers to maintain operational continuity in the event of equipment or facility outages. These systems are routinely maintained, tested, and updated by the EMS personnel and system operators. In addition, both the primary and backup control centers are supported by redundant utility power feeds and backup generators to enhance system resilience during emergency conditions. Beyond internal redundancy measures, TEP's participation in the Southwest Power Pool (SPP) as its Reliability Coordinator (RC) provides an additional layer of operational reliability through regional monitoring, reliability assessments and coordination across the interconnected grid.

Demand Risk Management

Demand risk represents the uncertainty that actual electricity consumption and peak demand will differ from forecasted levels, particularly over the long-term horizon. Key sources of uncertainty include demographic and economic trends, customer behavior, technological innovations, energy efficiency, distributed energy resource adoption, electrification, and the magnitude of large load customer growth. As a result, forecasts that include large load customers inherently contain a higher degree of uncertainty than forecasts based solely on traditional retail customer growth. If demand grows more rapidly than anticipated, the utility may face reliability risks and the need for additional capacity investments or market purchases. Conversely, slower-than-expected growth may result in underutilized assets and increased costs for customers.

TEP mitigates demand forecast risk through the procurement of a diversified portfolio of energy resources, maintenance of planning reserve margins, access to wholesale markets and participation in regional real-time and day-ahead markets. Resource diversity and market access provide flexibility to respond to changes in customer demand, including uncertainty associated with large load growth. TEP's capacity hedging program and phased execution approach allow the Company to gradually secure future resource needs as the planning period shortens and forecast uncertainty declines.

3.1.3. Resource Planning Advisory Council

Stakeholder feedback is a critical input to TEP’s planning process. Since the 2020 IRP process, TEP has convened a Resource Planning Advisory Council (RPAC) intended to provide TEP with a diverse set of views from community groups. The goal is to ensure that customer and community needs are heard, understood, and reflected in long-term planning outcomes.

Through a series of regular meetings in the year leading up to the IRP’s submission to the Arizona Corporation Commission, TEP and RPAC members exchanged information on the development of the IRP. TEP representatives offered detailed insight into the TEP planning process, discussing planning objectives, methodology, internal and external considerations, and modeling outcomes. In turn, RPAC members provided critical feedback on IRP methodology and outcomes, raised questions and concerns, shared knowledge on industry best practices and key customer insights, and kept TEP informed of important events in the community that affect long-term utility planning.

Early meetings focused on utility planning basics. Several meetings also featured presentations from external industry experts on a variety of related topics. As the IRP analysis matured, the content of meetings shifted to discussion of the portfolios under review and preliminary results.

As a result of the process, RPAC members recommended the inclusion of a portfolio that would add geothermal resources to TEP’s energy mix. The interest stems from advances in geothermal technology that are expanding the possibilities of utilizing geothermal as a baseload resource to address growing demand and reliability needs. Accordingly, TEP included a geothermal portfolio as one of its seven main portfolios.

Six meetings were held between August 2025 and August 2026, as described in Table 3.1 below.

Table 3.1 – RPAC Meetings

Meeting	Topic
August 2025	RPAC Purpose & Ground Rules, Utility Basics and TEP Overview
September 2025	Technical Session: IRP Basics, Key Assumptions, and Inputs
December 2025	Technical Session: Load Forecasting and LTCE Inputs
January 2026	Focus On: Resource Adequacy and Portfolios
June 2026	IRP Base Case
August 2026	IRP Preliminary Portfolio Results Review

Membership

The RPAC included 20 members, representing a diverse set of stakeholders across a range of customer classes, advocacy groups, and community businesses.

Table 3.2 – RPAC Membership

Category	Organization
Public interest group	Chamber of Southern Arizona Tucson Young Professionals
Consumer advocacy group	AARP AZ Public Interest Resource Group
Limited-income customer advocacy group	Interfaith Community Services Wildfire
Public at-large	University of Arizona
Residential customers	AZ Residential Utility Consumer Office Tucson Unified School District
Commercial customers	City of Tucson Pima County Davis-Monthan Air Force Base Hudbay Copper World
Environmental advocate	Western Resource Advocates The Nature Conservancy Sierra Club
Renewable power representative	Arizona Solar Energy Industry Association Interwest Energy Alliance
Energy efficiency representative	Southwest Energy Efficiency Project
Regulator	Arizona Corporation Commission

Modeling Software License and Data Dashboards

In accordance with ACC Decision No. 81495, TEP offered RPAC members the option to purchase and be reimbursed for a modeling software license (Energy Exemplar's Aurora platform) in order to perform planning analysis. In lieu of the modeling software, TEP also offered RPAC members a data dashboard that included extensive modeling information. While none of the RPAC members opted for the modeling license, several selected to receive the data dashboard, which allowed them to compare long-term planning inputs and outputs of the portfolios using TEP's IRP data. The dashboard was provided subject to a TEP non-disclosure agreement.

Public Workshop

In addition to the RPAC meetings, TEP held a public workshop in October 2026, near the culmination of the 2026 IRP activities. The workshop provided a deep dive into the IRP planning process, including planning goals and objectives, methodology, selection of portfolios, and modeling outcomes. It was held virtually and provided a forum for attendees to engage with the Company regarding the 2026 IRP.

The presentations and minutes of all RPAC meetings and the public workshop are posted on TEP's RPAC webpage: <https://www.tep.com/rpac/>.



3.2. Actions Taken Since the 2023 IRP

3.2.1. All-Source Request for Proposals

TEP issues All-Source Request for Proposals (ASRFPs) to solicit bids for capacity and energy resources on an as-needed basis. ASRFPs are administered according to the requirements established in Arizona Administrative Code. The resources solicited in ASRFPs are informed by the results of Integrated Resource Planning. Although the IRP is used as a guiding document, the resources procured may not be exactly as outlined in the IRP. The timing of each ASRFP is also informed by the most recent IRP and considers the results of the previous ASRFPs.

ASRFP Process

TEP works with an Independent Monitor, which acts as an independent third-party on behalf of the Company to conduct an initial evaluation of proposals. Proposals are scored based on their cost, interconnection progression, bidder experience, and the likelihood of meeting proposed project in-service dates. Projects with the highest score are selected for a shortlist.

An evaluation of the commercial operating date is a priority for the Company in order to meet increasing summer demand and avoid unusually high summer capacity and energy prices. The timeline for executing an interconnection agreement is a critical element in the project development process, as the status of an interconnection request can significantly impact the development timeline of a project. The expectation is that proposed facilities must be constructed and interconnected to meet proposed capacity and energy deliveries by the in-service date requirements established in the ASRFP.

Deliverability is an important evaluation criterion for ranking the projects' interconnection status, regulatory status, and available transfer capability at the time and point of interconnection such that the energy and capacity will be fully available to TEP's retail customers. Projects having obtained or deemed well into the process of obtaining a Certificate of Environmental Compatibility and those which are in advanced stages of the interconnection process ranked highest. Prices are also a major factor, but the ability to bring a project into service at the time proposed is vital to maintaining reliability and avoiding potentially expensive summer purchase power.

A summary of ASRFPs conducted since the 2023 IRP is provided below.

2024 ASRFP

TEP issued an ASRFP in December 2024 to solicit bids for capacity and clean energy resources. The in-service dates preferred by TEP were indicated in the solicitation as May 1, 2026, but no later than May 1, 2027. The need for these resources was based primarily on the Company's 2023 IRP and a Needs Assessment performed in 2023 prior to the release of the ASRFP.

2026 ASRFP

TEP issued another ASRFP to solicit bids for capacity and clean energy resources in March 2026. The in-service dates preferred by TEP were indicated in the solicitation as May 1, 2028, but no later than May 1, 2029. The need for these resources was based on the 2023 IRP and the 2024 ASRFP.

For a detailed review of resource additions that have come online since the 2023 IRP, please see section 3.2.3.

3.2.2. Development Timelines

The timeline for executing an interconnection agreement is a critical element in the project development process. For purposes of an ASRFP, bidders are not necessarily required to have entered the interconnection queue process. However, the status of an interconnection request can significantly impact the development timeline of a project. Application processing time for interconnection requests vary by queue position, queue workload, and the location on the transmission network. The expectation is that proposed facilities must be constructed and interconnected to meet proposed capacity and energy deliveries by the in-service dates established in the ASRFP.

TEP studies large generator interconnection projects on an annual cluster basis. Applications for the annual cluster open on January 15th of each year, and assuming no delays occur, the study and interconnection agreement contracting process can be expected to take until April of the following year at the earliest. More information on TEP's interconnection process can be found on its Open Access Sametime Information System website (OASIS).

In addition, projects proposed in the ASRFP may require a CEC for a project to be constructed. The Arizona Power Plant and Transmission Line Siting Committee, created by the state legislature, has jurisdictional purview of proposed conventional generating plants greater than or equal to 100 megawatts and transmission lines greater than or equal to 115 kV. The Committee considers the application for a CEC through a public process relative to a series of factors specified in Section 40-360.06 of the Arizona Revised Statutes.

Upon conclusion of review, the Committee makes a recommendation to the ACC regarding the CEC. The ACC makes a final determination on the CEC application and votes in a public proceeding to accept, reject, or modify the Committee's recommendations. The ACC has 180 days after the application is filed to decide on the CEC.

The application for a CEC requires additional time for site plans and multiple environmental and archeological studies to be performed. The CEC process may run concurrently to the interconnection process, but the timeline is similar in duration – at least two years.

3.2.3. Resource Additions and Developments

Since the filing of TEP's 2023 Integrated Resource Plan, the company has continued to execute its strategy of expanding cost-effective renewable generation and energy storage resources to support reliability, reduce emissions, and accommodate native load growth. These new utility-scale battery storage resources and solar generation additions enhance TEP's ability to utilize low-cost solar energy and market purchases during peak demand periods.

Babacomari Solar (2026)

TEP's largest solar resource to date entered service in 2026 with the completion of Babacomari Solar, a 160 MW utility-scale solar facility in Cochise County Arizona. TEP contracts the output of the system through a power purchase agreement (PPA). The project includes more than 296,000 solar panels and produces enough energy annually to serve more than 40,000 homes. The facility uses single-axis tracking and bifacial solar modules, increasing energy production, particularly during afternoon hours when customer demand is higher. Babacomari Solar substantially increases TEP's renewable energy portfolio and supports the company's long-term goal of achieving net-zero direct greenhouse gas emissions by 2050.²⁵

²⁵ <https://www.tep.com/news/teps-largest-solar-array-now-online-to-serve-customers/>

Roadrunner Reserve Battery Energy Storage System (2025)

In 2025, TEP placed its largest owned battery energy storage facility into service. The Roadrunner Reserve project, located on Tucson's southeast side, provides 200 MW of battery storage capacity and can shift solar energy from periods of high production to the evening peak when customer demand is highest. With 800 MWh of storage capability, the system can provide enough energy to serve approximately 42,000 homes for up to four hours when fully charged.



Together, the two Roadrunner projects significantly expand TEP's dispatchable energy storage portfolio and enhance system reliability during summer peak periods and other high-demand conditions.²⁶



Roadrunner Reserve II (2026)

Roadrunner Reserve II, which came online in 2026, is a second 200 MW and 800 MWh owned battery energy storage system located adjacent to Roadrunner Reserve. Like Roadrunner Reserve, the facility uses lithium iron phosphate battery technology, which offers enhanced safety characteristics and longer operational life compared to earlier battery chemistries.

²⁶ <https://www.tep.com/news/tep-will-build-new-battery-system-to-support-reliability/>

Wilmot Energy Center II (2026)

In 2026, TEP also expanded its Wilmot Energy Center through the addition of 100 MW of solar generation and 100 MW of battery energy storage through a PPA. This project doubles the site's solar generating capability while significantly increasing storage capacity, creating one of TEP's most important solar-plus-storage resources. The solar array utilizes a single-axis tracking system that follows the sun throughout the day, increasing energy production and improving alignment with customer demand patterns. The resource improves TEP's ability to deliver renewable energy during evening peak hours and periods of reduced solar production.²⁷

Winchester Solar (2027)

TEP expects to further expand its renewable and energy storage portfolio through a PPA that will commence in 2027. Winchester Solar, an 80 MW solar generation facility paired with an 80 MW (320 MWh) battery energy storage system, will be located in Cochise County near Willcox, Arizona.

The solar facility is expected to generate enough electricity annually to serve approximately 11,000 homes, while the four-hour battery storage system will expand TEP's ability to store excess daytime solar production and deliver that energy during evening peak demand periods.²⁸

All Together

Investments in solar and energy storage help strengthen reliability while supporting affordability. Together, these resources provide cost-effective peak capacity, allowing utilities to manage growing demand while making greater use of lower-cost renewable energy and reducing the need for more expensive energy purchases.

These additions also represent a significant acceleration of TEP's clean energy buildout while enhancing system reliability, increasing operational flexibility, and supporting TEP's efforts to reduce dependence on fossil-fueled generation.



Collectively, resources entering service since the 2023 IRP, including announced projects currently under development, add approximately 340 MW of new solar generation and 580 MW and 2,320 MWh of energy storage capability.

²⁷ <https://www.tep.com/news/work-begins-next-year-on-teps-largest-solar-plus-battery-system/>

²⁸ <https://www.torchcleanenergy.com/press/tucson-electric-power>

3.3. Federal Tax Policy and Its Impacts

On July 4, 2025, the One Big Beautiful Bill Act (OBBBA) was signed into law, significantly accelerating the phaseout of wind and solar tax credits and reversing several clean energy incentives under the Inflation Reduction Act (IRA). New Foreign Entity of Concern restrictions also potentially limit the ability for projects to qualify.

Under OBBBA, wind and solar projects must have begun construction by July 4, 2026 to remain eligible for full tax credits. Other technology neutral resources such as battery storage, geothermal, pumped hydro storage and nuclear remain under the IRA framework and are not subject to an accelerated timeline. These technologies continue to be eligible for a 100% tax credit for projects that begin construction by 2033, with the credit phasing down to 75% in 2034, 50% in 2035, and expiring thereafter. TEP has incorporated the changes into its resource modeling. Please refer to 4.2.4 for more information.

Figures 3.1 and 3.2 show how the removal of tax incentives in the 2026 IRP affects the levelized costs of solar and wind resources relative to the 2023 IRP assumptions that included full applicable tax credits through 2036 before phasing out.

Figure 3.1 - Utility Solar Levelized Costs

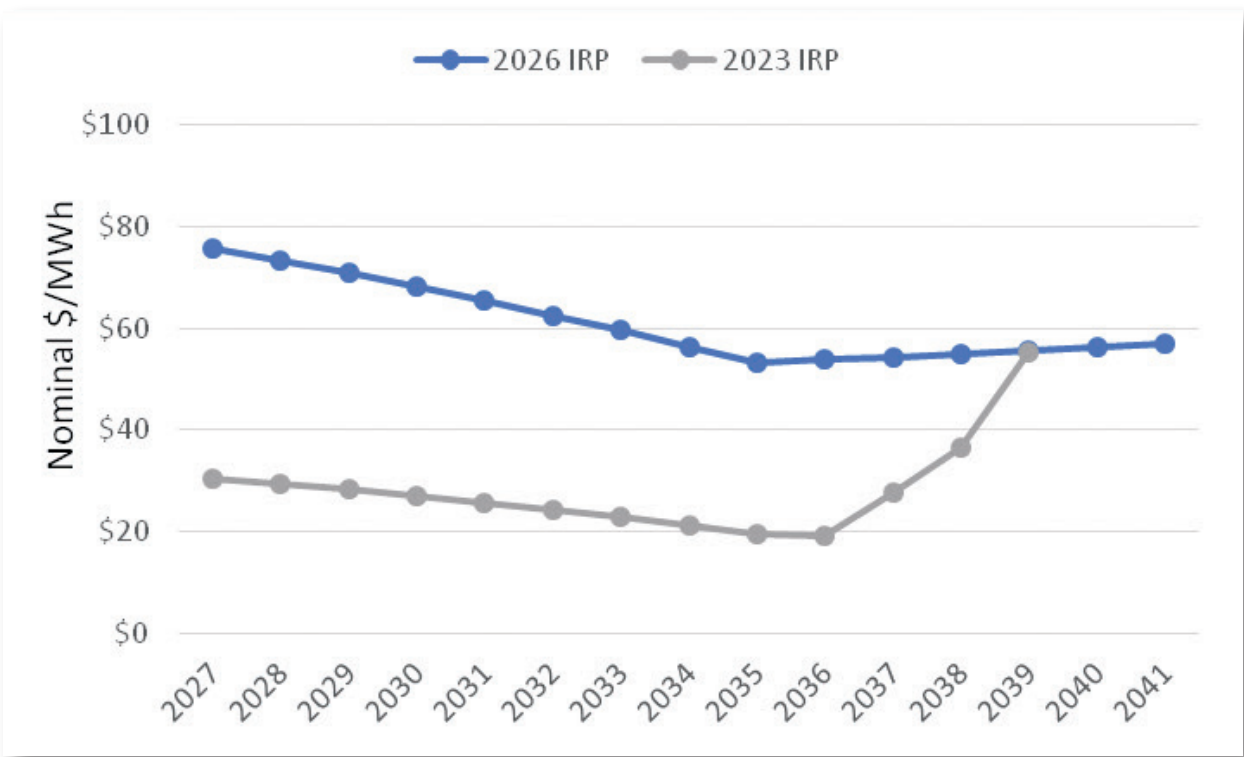
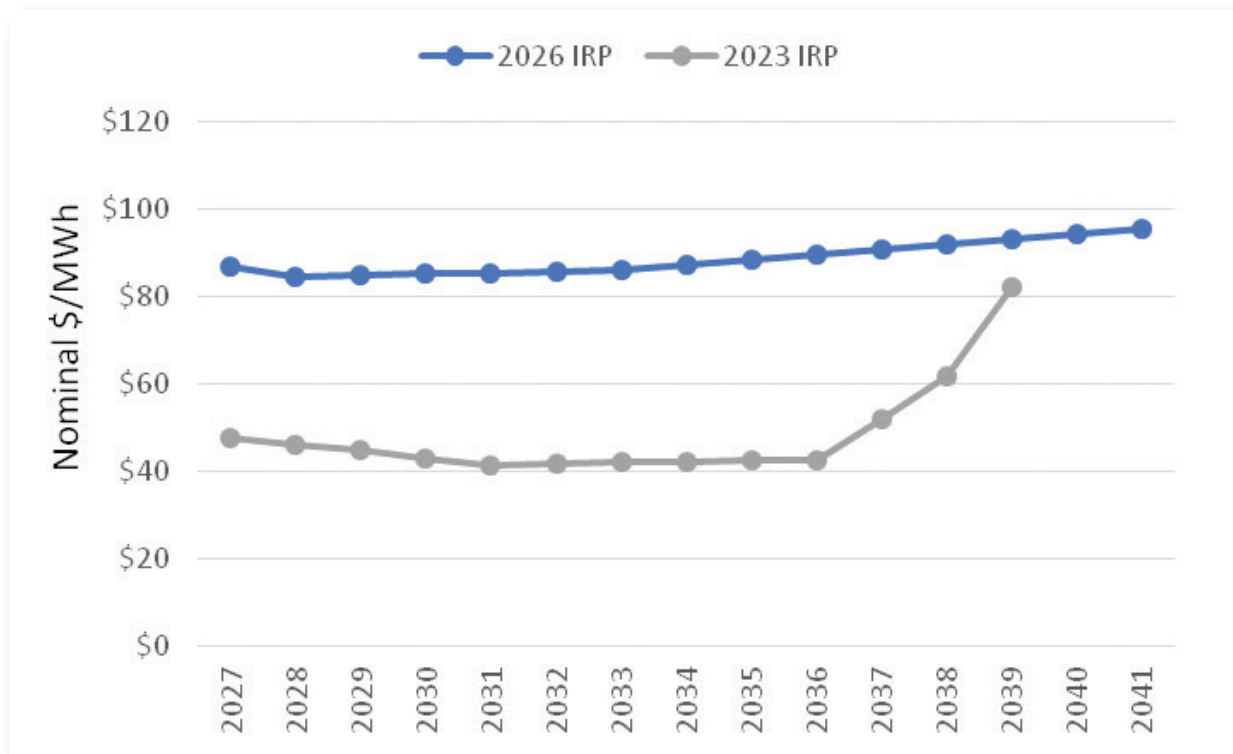


Figure 3.2 - Wind Levelized Costs



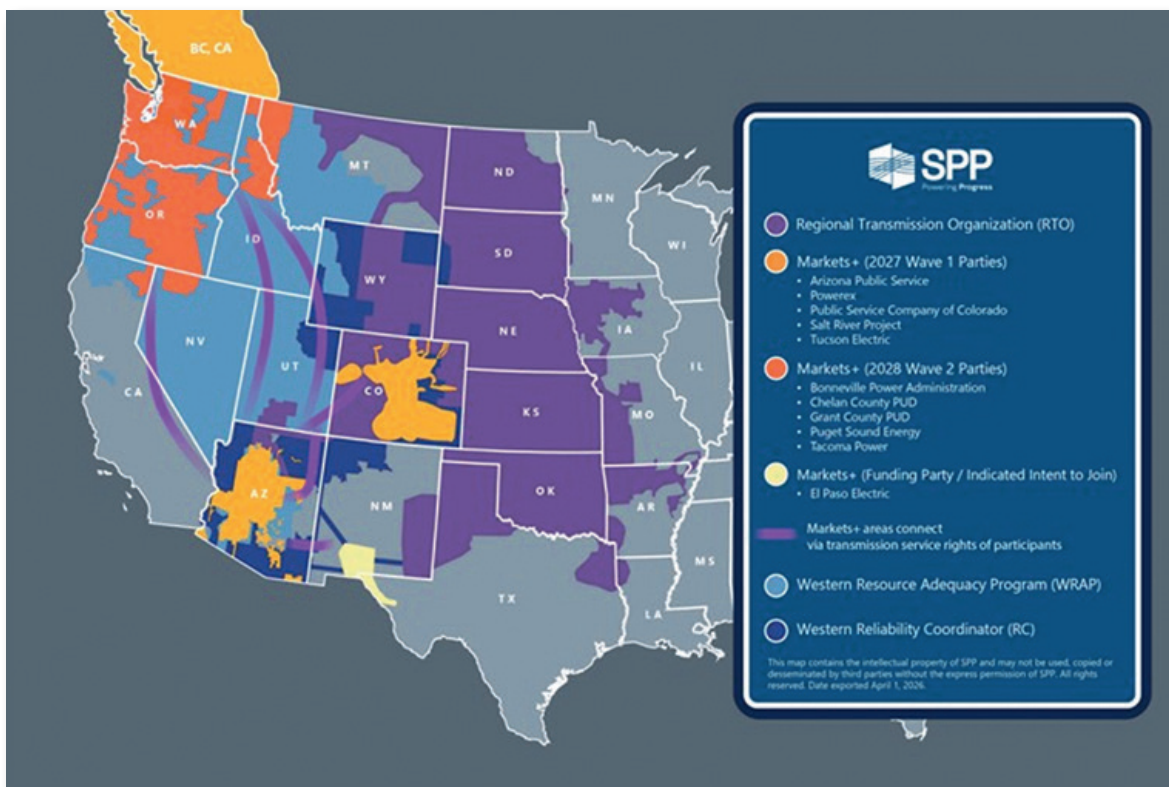
3.4. Day-Ahead Market Participation

In November 2024, TEP announced its intent to join Markets+ alongside Arizona Public Service, Salt River Project, and other western utilities when the market becomes operational in 2027. Markets+ builds on SPP's operational experience managing organized electricity markets, including the Western Energy Imbalance Service (WEIS) and SPP's Integrated Marketplace. The WEIS market currently provides real-time economic dispatch across participating western entities, while the Integrated Marketplace has demonstrated the value of coordinated day-ahead and real-time market operations through more than a decade of successful implementation.

All IRP modeling was performed according to current regulations in effect at that time. For example, portfolios were designed under existing greenhouse gas rules, published by the U.S. Environmental Protection Agency in 2024, which limit the allowable emissions of new natural gas facilities based on their thermal efficiency and capacity factor. To comply with that rule, new natural gas facilities in the portfolios were limited to 40% or less in 2032 and later. To observe the effect if these restrictions were to be lifted in the future, TEP removed those limits from the affected generators in the sensitivity modeling performed. For results of that analysis, see Section 5.3.

As of September 2026, EPA partially repealed the 2024 greenhouse gas rules, and several other regulations remain under EPA's review. TEP cannot predict the outcomes of these actions.

Figure 3.3 – SPP Markets+ Map



3.4.1. Western Resource Adequacy Program

The Western Resource Adequacy Program (WRAP) is a regional reliability planning and compliance program administered by the Western Power Pool (WPP) with program operator services provided by the Southwest Power Pool (SPP). WRAP is the designated resource adequacy program of SPP's Markets+, which TEP has joined as a Phase 2 member (see Section 3.4 and Appendix F).

WRAP is the first region-wide resource adequacy framework in the Western Interconnection and is designed to provide a coordinated approach for ensuring sufficient generation and transmission capacity to meet demand during periods of system stress. The program establishes common reliability metrics and introduces compliance obligations to ensure that participating entities contribute to regional reliability while maintaining their independent planning and operational responsibilities.²⁹

WRAP Reliability Metrics and Relationship to Planning

While TEP participates in WRAP and incorporates WRAP requirements into its compliance planning, TEP continues to use its own Integrated Resource Plan (IRP) reliability assessments and planning reserve margin targets as the primary basis for long-term resource planning. WRAP planning reserve margins are designed to demonstrate compliance within the WRAP footprint and reflect assumptions regarding regional diversity benefits, participant resource adequacy performance, transmission deliverability, and the continued availability of capacity sharing through the binding operational program. These assumptions may evolve as participation levels, accreditation methodologies, and program rules mature.

For long-term utility planning, TEP must ensure reliable service to its retail customers under a wide range of future conditions, including scenarios in which regional assistance may be constrained by transmission limitations, widespread extreme weather events, or changes in WRAP participation. TEP's IRP evaluates resource adequacy using company-specific reliability analyses and reserve margin requirements that reflect TEP's load characteristics, resource portfolio, operational experience, and planning objectives. WRAP compliance requirements are viewed as a supplemental regional reliability obligation rather than the sole determinant of TEP's capacity planning needs. As WRAP transitions to its binding phase and additional operational experience is gained, TEP will continue to assess how WRAP metrics and regional diversity benefits should be incorporated into future planning processes. For more information, refer to Appendix F.

²⁹ <https://www.westernpowerpool.org/about/programs/western-resource-adequacy-program>

3.5. Environmental Regulations and Uncertainty

Environmental policy and regulations play an important role in utility planning. TEP is tracking and complying with multiple environmental regulations implemented at the local, state, and federal levels. As detailed in Appendix G, this includes the regulation of regional haze, greenhouse gases, criteria pollutants such as ozone, coal combustion residuals, and water consumption.

All IRP modeling was performed according to current regulations in effect at that time. For example, portfolios were designed under existing greenhouse gas rules, published by the U.S. Environmental Protection Agency in 2024, which limit the allowable emissions of new natural gas facilities based on their thermal efficiency and capacity factor. To comply with that rule, new natural gas facilities in the portfolios were limited to 40% or less in 2032 and later. To observe the effect if these restrictions were to be lifted in the future, TEP removed those limits from the affected generators in the sensitivity modeling performed. For results of that analysis, see Section 5.3.

As of September 2026, EPA partially repealed the 2024 greenhouse gas rules, and several other regulations remain under EPA's review. TEP cannot predict the outcomes of these actions.



SECTION 4

PORTFOLIO DEVELOPMENT AND INPUTS

4.1. Methodology

4.1.1. Resource Adequacy Study

In 2025, TEP retained E3 to complete a new resource adequacy (RA) study (see Appendix E). The study incorporated updated TEP load forecasts, thermal generator performance assumptions, and resource plans, as well as historical weather and renewable generation profiles to perform a statistical analysis and calculate the required Planning Reserve Margin (PRM) to ensure resource adequacy. E3 evaluated system reliability using the industry standard Loss of Load Expectation (LOLE) target of 0.1 days per year and identified the PRM needed to maintain that level of reliability.

The study concluded that the TEP system will require an 18% PRM, a slight increase from the 16.5% PRM used in the 2023 IRP. The increased requirement is primarily driven by E3's enhanced modeling of thermal generator forced outages. While the thermal fleet has an average forced outage rate of approximately 5%, the analysis shows that loss of load events are most likely to occur when multiple large generating units are unavailable at the same time. During these periods, average thermal fleet availability decreases to about 85%, requiring additional reserve capacity to maintain reliability. The updated analysis also reflects higher load forecasts, greater weather variability, and updated operating reserve requirements. Based on these inputs, the modeling process iteratively adds or removes capacity until the LOLE target of 0.1 days per year is achieved. The resulting 18% PRM was applied to each TEP portfolio evaluated in the 2026 IRP.

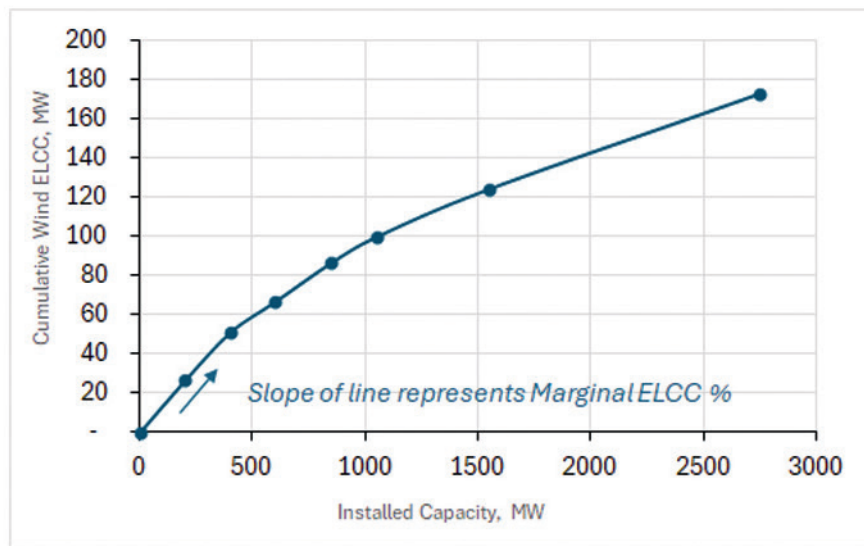
E3 also updated the Effective Load Carrying Capability (ELCC) study that was conducted for TEP in 2022. Building on the PRM study that was conducted, E3 analyzed increasing levels of wind, solar, 4-hour storage and 8-hour storage to develop updated ELCCs for TEP. ELCC represents the effective capacity that renewable and storage resources can provide toward meeting system reliability requirements such as the PRM. The updated study developed ELCC curves for individual technologies and resource combinations reflecting how the effective capacity value changes as penetration levels increase. **Figure 4.1** illustrates the diversity benefit of combining solar and 4-hour battery storage. As storage is added with increasing solar penetration, the combined ELCC increases because battery storage shifts excess daytime solar generation to high demand evening hours when solar output decreases, and reliability needs are greatest. As a result, the combined capacity value of solar and storage exceeds the sum of their individual contributions when evaluated individually.

Figure 4.1 - Portfolio ELCC Incremental Solar and Battery Storage Additions³⁰

Cumulative ELCCs (MW)		4-hour Battery Storage Capacity (MW)						
		-	200	550	800	1,300	2,300	3,300
Solar Capacity (MW)	-	-	165	368	452	554	660	725
	250	34	204	416	512	621	735	793
	500	50	231	459	564	683	800	862
	1,000	76	257	511	631	783	912	986
	1,500	87	270	544	666	844	1,011	1,097
	2,000	97	284	558	688	874	1,086	1,192
	3,000	112	301	576	718	906	1,155	1,290

The ELCC analysis confirms that the marginal capacity value of solar and wind resources declines as their proportion on the system increases. As shown in **Figure 4.2**, the marginal ELCC of wind declines as installed capacity increases, illustrating the diminishing contribution of additional wind resources at higher penetration levels. Similarly, as solar capacity is added to the system, the net system peak is pushed into the evening when solar generation is reduced or unavailable, resulting in lower marginal ELCC values. This effect, commonly referred to as resource saturation, means that while the initial additions of solar or wind provide significant reliability benefits, each subsequent addition contributes progressively less capacity.

Figure 4.2 - Cumulative ELCC for Incremental Wind Additions³¹



³⁰ Energy and Environmental Economics, Tucson Electric Power PRM and ELCC Study (2025).

³¹ Ibid

Battery Storage helps offset the resource saturation effects of solar generation by shifting excess generation to evening periods when reliability needs are greatest. While battery storage provides one of the highest marginal ELCC values among the evaluated technologies, its marginal capacity value also declines with growth. As battery storage capacity increases, reliability events tend to become longer in duration. The updated analysis indicates that 8-hour battery storage generally provides approximately 1.5 times the ELCC of comparable 4-hour storage resources. Similarly, this advantage gradually decreases as overall storage penetration increases.

Thermal resources can also be assigned Effective Load Carrying Capability (ELCC) values based on their forced outage characteristics. For this study, TEP did not develop thermal ELCC values separately. Instead, the impacts of thermal outages were incorporated directly into the Planning Reserve Margin (PRM), effectively assigning thermal resources an ELCC of 1 while increasing the PRM to account for outage risks.

The ELCC results were incorporated into the portfolio modeling process and applied consistently across all portfolios evaluated in the 2026 IRP. ELCC values are used to determine the capacity contribution when evaluating resource additions. The model increasingly selects solar and battery storage paired together to utilize the diversity benefit and, in some cases, longer-duration storage to meet the 18% PRM (see Section 5 for detailed portfolio analysis).



4.1.2. Long-Term Capacity Expansion Modeling

TEP utilizes Aurora, an energy market simulation and forecasting platform developed by Energy Exemplar, to perform its Long-Term Capacity Expansion (LTCE) modeling. The LTCE model identifies the least-cost portfolio of resource additions needed to meet future energy and capacity requirements while satisfying planning constraints for each specific portfolio. Resource expansion decisions are determined through economic optimization, allowing the model to identify the combination of resources that minimizes total system costs while maintaining reliable service.

For the 2026 IRP, TEP engaged Siemens Power Technologies International (Siemens PTI) to support the development of LTCE modeling assumptions and offer insights into industry best practices. While TEP first incorporated LTCE modeling into its 2023 IRP process, the Company sought to further strengthen its modeling approach and leverage additional modeling capabilities through collaboration with Siemens PTI.

Aurora's LTCE process uses an iterative optimization approach. Beginning with TEP's existing resource portfolio, the model evaluates system operations and determines the quantity and type of additional resources needed to satisfy planning reserve margin requirements and other planning constraints. During each iteration, candidate resources are assessed based on their costs, operating characteristics, capacity contributions, and overall value to the system. Key inputs include capital costs, fixed and variable operating costs, fuel costs, resource performance characteristics, and Effective Load Carrying Capability (ELCC) values.

Through each iteration, Aurora simulates system dispatch, calculates system economics, and evaluates the contribution of candidate resources. Based on these results, the model selects the combination of resource additions that provides the greatest overall benefit to the system while minimizing total portfolio costs. The updated portfolio is subsequently re-evaluated, and the process continues until the model reaches a stable solution and satisfies predefined convergence criteria.

The final LTCE results identify the resource additions and timing that best meet TEP's projected load growth, resource adequacy requirements, and planning objectives at the lowest overall system cost.

4.1.3. Production Cost Modeling

While Aurora's LTCE model identifies the least-cost resource portfolio that satisfies planning objectives and constraints, Aurora's Production Cost Model (PCM) provides a more detailed assessment of operational performance. Following the LTCE analysis, TEP applies its planning and operational expertise to further evaluate and refine the modeled resource additions to ensure resource adequacy requirements are met and implementation constraints are considered. The PCM then incorporates the refined resource additions and performs a chronological hourly simulation of TEP's system operations across the 15-year IRP timeframe.

The PCM economically commits and dispatches available generating resources, energy storage assets, and market purchases and sales to meet customer demand and reliability requirements at the lowest total system cost. Dispatch decisions are based on resource economics and market conditions while accounting for operational characteristics and constraints, including minimum generation levels, startup costs, ramp rates, minimum up/down times, transmission limitations, reserve requirements, and storage operating parameters.



4.2. Inputs and Assumptions

4.2.1. Load Forecast

This section summarizes TEP's customer base and load forecast methodology and subsequently details some of the major forecast components. It concludes with a summary of forecast results. Detailed forecast results can be found in Appendix C.

4.2.1.1. Service Territory and Customer Base

Figure 4.3 shows TEP's service territory, and that of its sister company, UNSE. TEP currently provides electricity to more than 459,000 customers in the Tucson metro area, located within Pima County, which has an estimated population of 1,093,000 people. The number of historic and projected residential customers is shown in **Figure 4.4**, while the current sales by customer class are shown in **Figure 4.5**.

Figure 4.3 - TEP and UNSE Service Territories

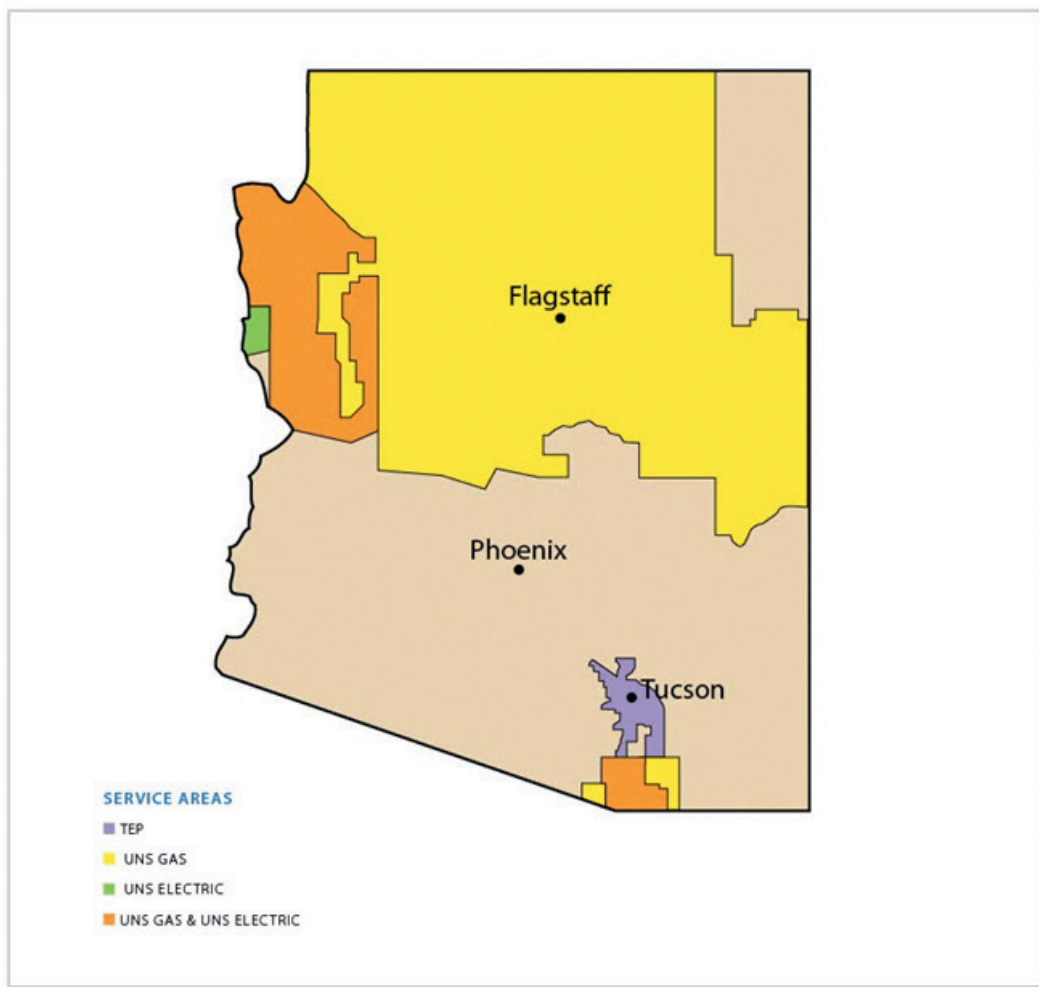


Figure 4.4 - Historic and Projected Number of Residential Customers

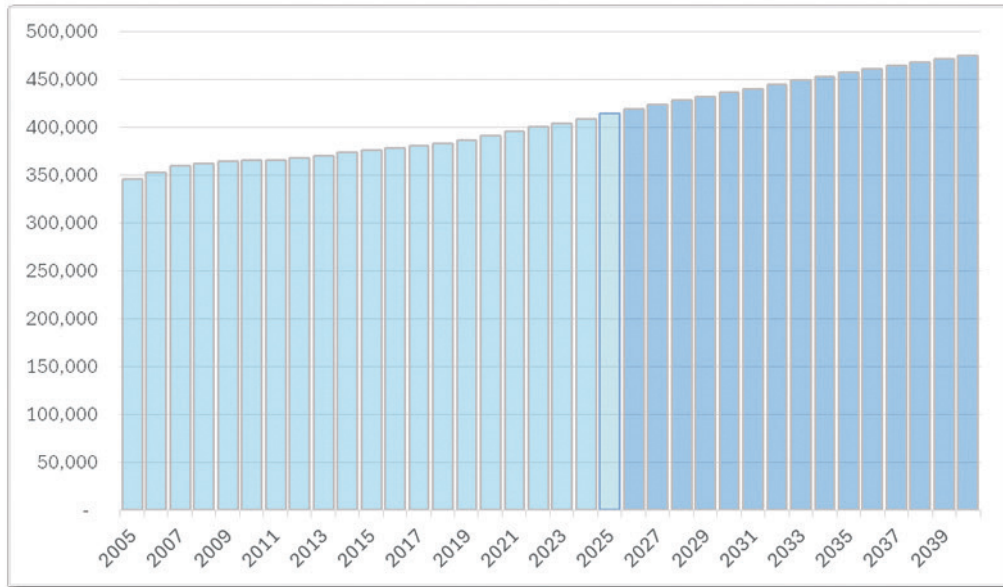
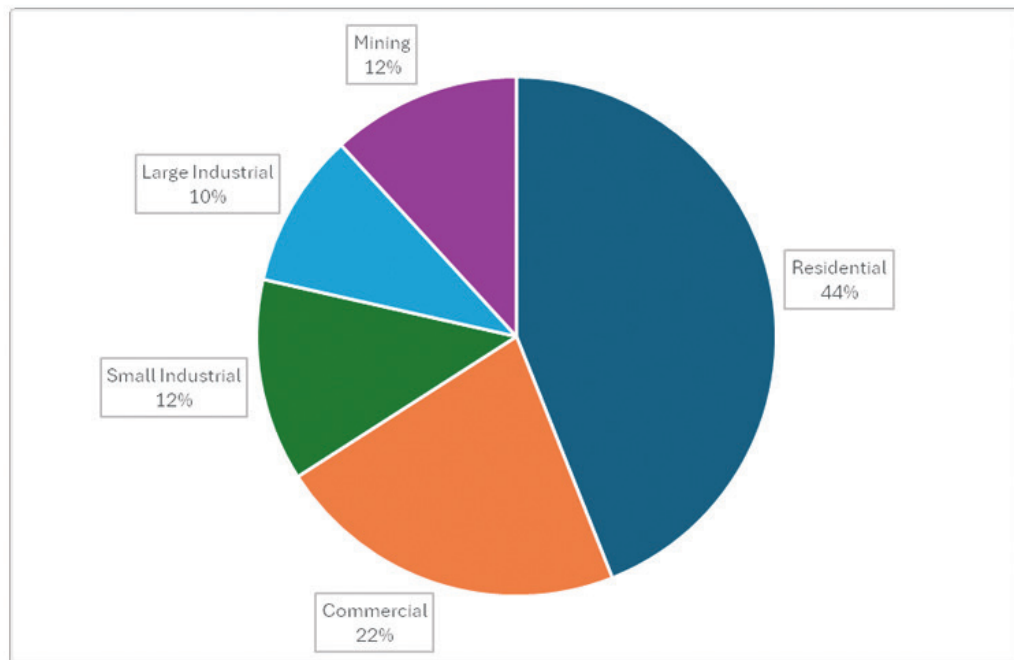


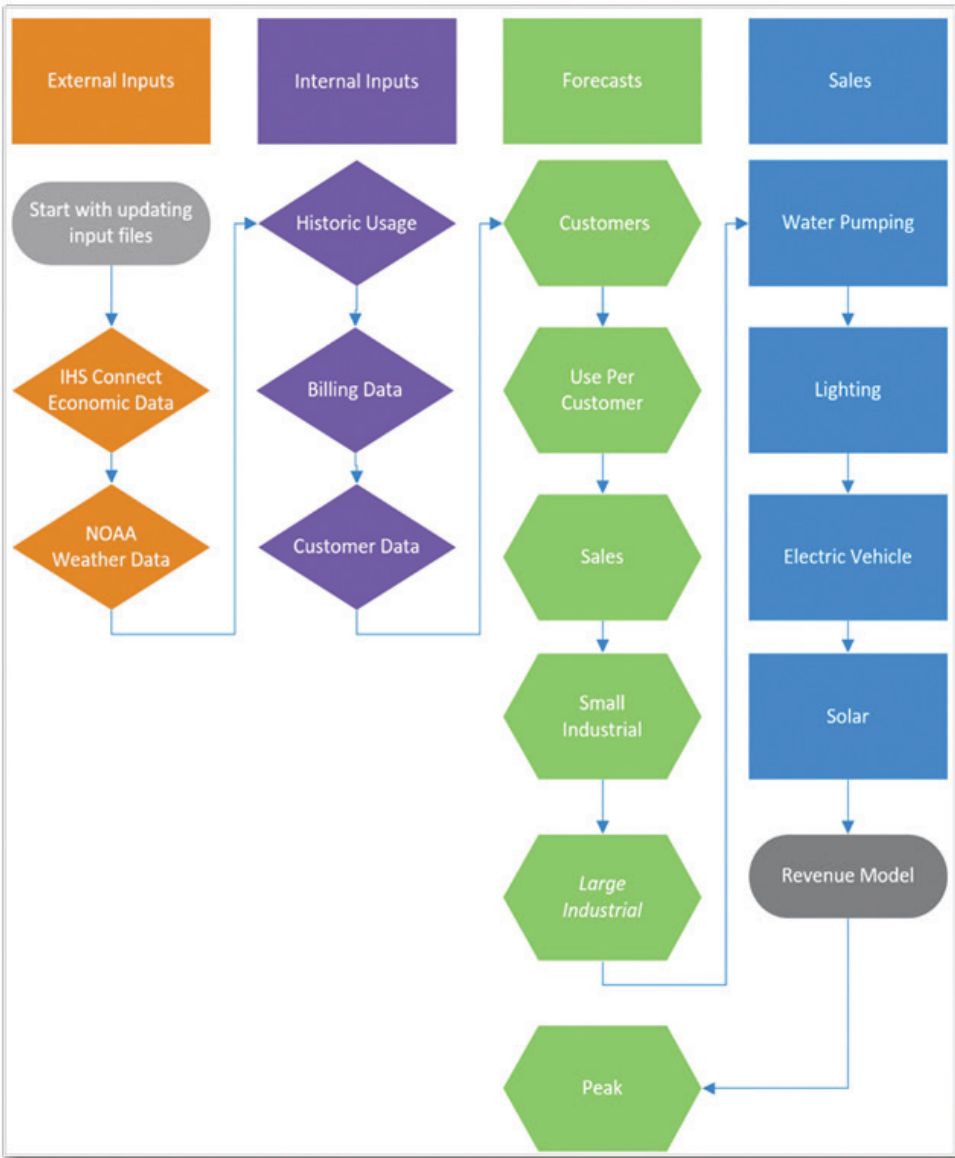
Figure 4.5 - 2025 Retail Sales by Customer Class



4.2.1.2. Methodology, Data Sources, and Uncertainties

TEP’s load forecast methodology is illustrated in **Figure 4.6**. Residential, commercial, and small industrial customer sales are forecasted monthly using statistical models based on factors such as historical usage, weather, demographic forecasts, and economic conditions. Large industrial and mining sales are likewise forecasted monthly; however, these forecasts are developed at the individual customer level, drawing on historical consumption patterns and insights from TEP’s Key Account Managers who maintain close engagement with these customers.

Figure 4.6 - Load Forecast Process



New Large Load Customers

In addition, new large load customers are incorporated into the forecast once they have either been formally contracted or have advanced to a stage at which service delivery is considered effectively certain. The timing of inclusion is determined based on the level of confidence in project execution and the anticipated realization of load. Each prospective large load addition is evaluated on an individual basis, with consideration given to its unique circumstances, contractual status, and stage of development. This case-by-case approach supports the development of forecast assumptions that are both accurate and appropriately conservative. TEP's base case balanced portfolio includes one new large load customer who is contractually committed to a peak demand of 286 MW starting in 2029.

Peak Forecast

Following the development of monthly sales forecasts by customer class, the results are aggregated and used as inputs into a separate statistical model designed to estimate retail peak demand. This peak demand model is based on historical relationships among hourly load, weather variables, calendar effects, and overall sales growth. Greater weight is given to more recent weather years to include the impact of rising temperatures.

Data Sources and Other Considerations

Data sources used in the forecast include:

- IHS Global Insights (S&P Global)
- The University of Arizona Forecasting Project
- Arizona Department of Commerce
- U.S. Census Bureau
- National Oceanic and Atmospheric Administration (NOAA)

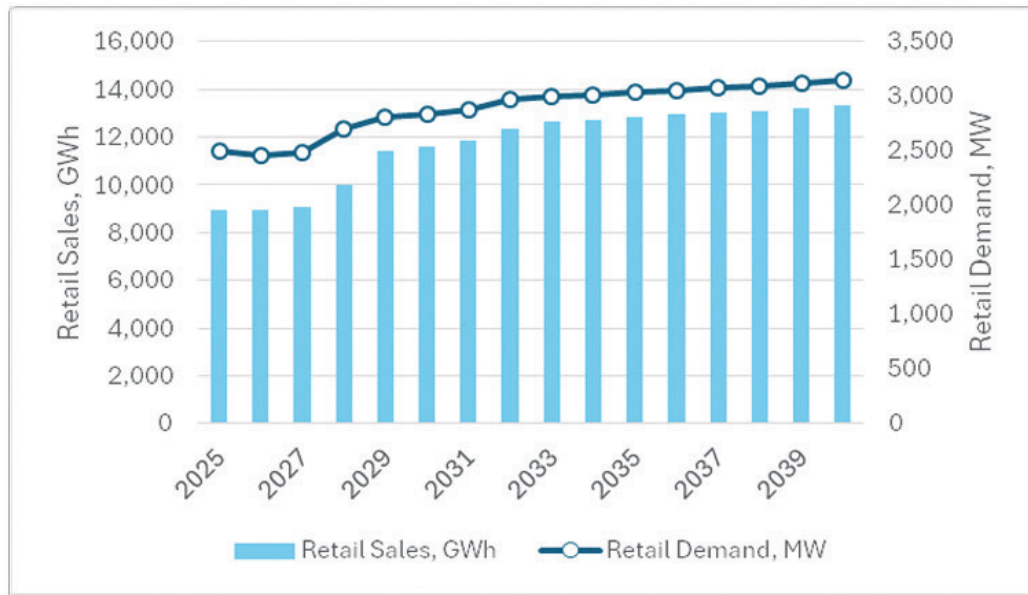
As always, projected load growth is subject to a wide range of variables and assumptions. While not all inclusive, some of the key risks to the current forecast are:

- Strength and timing of business cycle fluctuations
- Structural changes to customer behavior
- Volatility in industrial metal prices and associated shifts in mining consumption
- Efficacy of energy efficiency programs
- Technological innovations
- Volatility in demographic assumptions

4.2.1.3. Load Forecast Results

Figure 4.7 summarizes TEP’s forecasted annual retail sales and peak demand. The average annual growth rate of sales and demand over the planning period is 4.75% and 2.59% respectively. This load forecast was used to develop all portfolios. Detailed forecast results are provided in Appendix C.

Figure 4.7 - TEP Forecasted Annual Retail Sales and Peak Demand



Because of the large amount of uncertainty underlying the load forecast, it is crucial to consider the implications to resource planning if TEP experiences significantly lower or higher load growth than projected. For this reason, load growth is one of the fundamental factors considered in the risk analysis process undertaken as part of this IRP. Specifically, the performance of select potential resource portfolios is analyzed with the use of Monte Carlo load simulations. See Appendix D for Stochastic results.

4.2.2. Demand Side Management and Distributed Generation

Customer-sited resources and demand management play an increasingly important role in TEP’s resource mix, and accordingly in long-term resource planning. As part of the load forecasting methodology, all distributed generation (DG) and demand-side management (DSM) impacts present within the system are initially added back to the forecast to establish a gross load basis. Upon completion of the forecast, the embedded DG and DSM components are subsequently removed, and independent forecasts for DSM, DG, and electric vehicles (EVs) are then incorporated as layered adjustments to produce the final net load forecast. In the 2026 IRP, demand response (DR) is modeled as a dispatchable demand-side resource in the portfolio optimization process. See Appendix J – TEP Customer Programs, for more detailed information on each of these resources.

Energy Efficiency and Demand Response

TEP's demand-side management portfolio encompasses a broad range of energy efficiency and demand response programs serving residential, commercial, and industrial customers. These programs reduce system peak demand, lower customer bills, improve grid reliability and resilience, and support a cleaner energy future.

Between 2024 and 2025, TEP's energy efficiency portfolio continued delivering measurable customer and system benefits through a diverse mix of residential, commercial, and income-qualified programs. Key highlights include:

- In 2025, residential programs delivered 54,020 MWhs and commercial programs delivered 38,782 MWh of energy savings.
- Multifamily Program Relaunch – This program expanded direct install offerings, including smart thermostats and energy efficiency measures, increasing annual savings to 3,582 MWh in 2025.
- Existing Homes Program – TEP expanded residential Existing Homes offerings, including increased participation in HVAC tune-up and home efficiency measures designed to improve customer access and energy savings opportunities. The Existing Homes Program had strong customer adoption, delivering approximately 11,272 annual MWh savings in 2025.

TEP achieved cumulative annual savings equivalent to 28.5% of the retail sales in 2024 and 29.8% in 2025, exceeding Arizona's cumulative energy efficiency standard of 22%.

In July 2026, the ACC formally repealed Arizona's Electric Energy Efficiency Standard (EEES) rules. TEP's approved three-year DSM plan is still tied to the EEES requirements and will remain in effect until further order of the Commission. In the absence of new rules, future DSM program development will be at the discretion of individual utilities, subject to Commission review and approval.

TEP's demand response portfolio continues to expand through programs that leverage customer-sited resources to reduce peak demand and support grid reliability. Highlights include:

- Smart Rewards – Utilizes connected smart thermostats to reduce system peak demand. This program grew to 22,669 devices and a max first hour load shed of 38.2 MW in 2025.
- Energy Storage Rewards – Utilizes residential battery systems to reduce system peak. By late 2025, the program had 262 enrolled devices. The program has seen consistent enrollment increases and an 80% rate of high satisfaction from participants.
- Innovative Customer Solutions Framework – Launched a micro-pilot initiative focused on load optimization and reducing customer peak consumption during high demand periods. The results of this pilot are expected in early 2027.

By the end of 2025, TEP's Load Management pilots collectively reached nearly 18,000 active participants,³² reflecting growing customer adoption of connected technologies and helping establish a foundation for future virtual power plant growth. TEP is also re-vamping its commercial direct load control program to align technology offering and price structure to more closely reflect existing conditions.

³² Participants may bring more than one device to the program.

The IRP incorporates energy efficiency and demand response projections based on the results of the Demand-Side Resources Market Potential Study conducted by a third party in 2025. The study quantified the energy savings and peak demand reduction that could potentially be captured through demand-side programs over a 2026–2040 planning horizon. For the IRP, TEP utilizes the achievable potential results, assuming continuation of existing program designs, incentive structures, delivery approaches, participation trends, and budget levels. Detailed study results are available in Appendix J.

Distributed Generation

TEP offers a number of programs to support the use of customer-sited distributed generation, specifically rooftop solar and battery storage. TEP’s DG adoption trajectory reflects steady growth driven by technology advancement, electrification trends, and evolving program design, with relatively limited volatility associated with policy or economic shifts. The number of customers and total capacity deployment through 2025 is shown in **Table 4.1**.

Table 4.1 – DG Customer Adoption

DG Category	Total All-Time Customers Through 2025	Total MW
3rd Party Residential DG	54,254	378
3rd Party Non-Residential DG	1,191	203
TEP-Owned Residential Solar	464	3
GoSolar Shares	2,084	39
GoSolar Home	2,049	14
Storage Residential	2,479	27
Storage Non-Residential	10	<1

Transportation Electrification

TEP’s three-year Transportation Electrification Implementation Plan (2023–2025) increased awareness and adoption of transportation electrification, recognizing the benefits to the Company and the community of beneficial electrification. Highlights include:

- 1,398 residential EV charging ports installed
- 613 commercial EV charging ports contracted
- 11 electric school bus rebates provided in support of the state’s first bidirectional vehicle-to-grid school bus pilot, offering just under 400 kW of capacity

TEP's 2024 EV Adoption and Grid Impact Study provided a forecast of battery electric vehicle (BEV) and plug-in hybrid electric vehicle (PHEV) adoption using multiple adoption scenarios and is used to project future EV-related load growth. The forecast reflects the continued strong growth of electric vehicles in TEP's service territory.

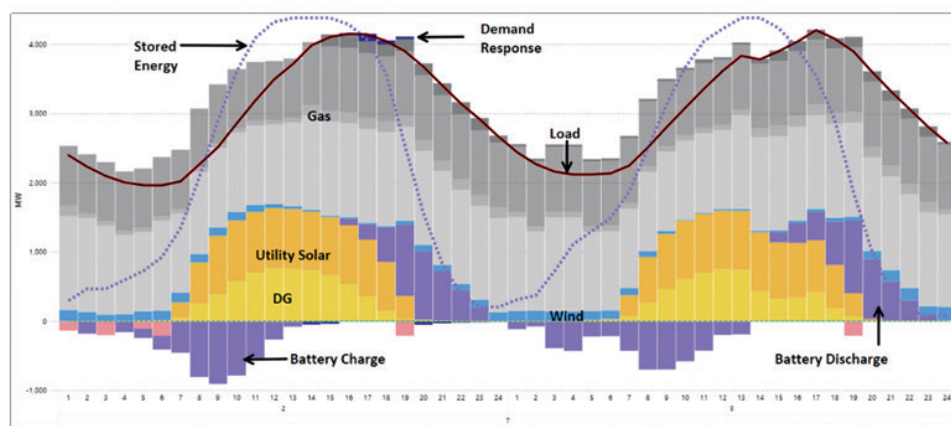
4.2.3. Resource Adequacy in the Portfolios

The Resource Adequacy (RA) of each portfolio was determined through a two-step process. First, each year was required to meet a Planning Reserve Margin (PRM) of 18%, updated from a value of 16.5% used in the prior IRP. The updated PRM was derived using a Loss of Load Probability model designed to achieve a Loss of Load Expectation (LOLE) target of 0.1 days in a given year. To determine whether the PRM is met, solar, wind, and storage resources are given a capacity value based on their Effective Load Carrying Capability (ELCC), as described in Section 4.1.1.

Second, TEP performed a "stress test" on each portfolio. Market purchases are not permitted during the study period, and TEP must meet extended hours of peak loads exclusively with its own resources. Because TEP uses Aurora as an hourly, security-constrained dispatch model, this process inherently accounts for and enforces limits on system operations. Such limits include minimum and maximum fuel restrictions, commitment decisions needed for thermal resources that are not fast-start and fast-ramping, variability of renewable resources, energy and charging limitations of storage resources, market depth and volatility, and other factors that can affect the costs and reliability on an hour-by-hour basis. Hourly results for the entire 15-year period are then examined for any shortfalls. Despite these stringent conditions evaluated through the stress test, all TEP portfolios met peak loads with their own resources and satisfied the LOLE target of 0.1 days per year.

An example of the hourly results used to verify RA is provided in **Figure 4.8**, which shows not only that each hour can be adequately served for the period illustrated, but how they are expected to be served. Load, shown in the black line, is met or exceeded each hour by a stack of resources. Generation exceeding load is used to make economy market sales or replenish energy storage resources. Total stored energy is shown in the dashed purple line. The load and resource stack shown in **Figure 4.8** are typical of summer days, and the daily charging and discharging of the storage fleet cycles as expected.

**Figure 4.8 - Example of Hourly Load and Dispatch Results
Used to Ensure Resource Adequacy (July 2-3, 2040)**



4.2.4. Resource Costs

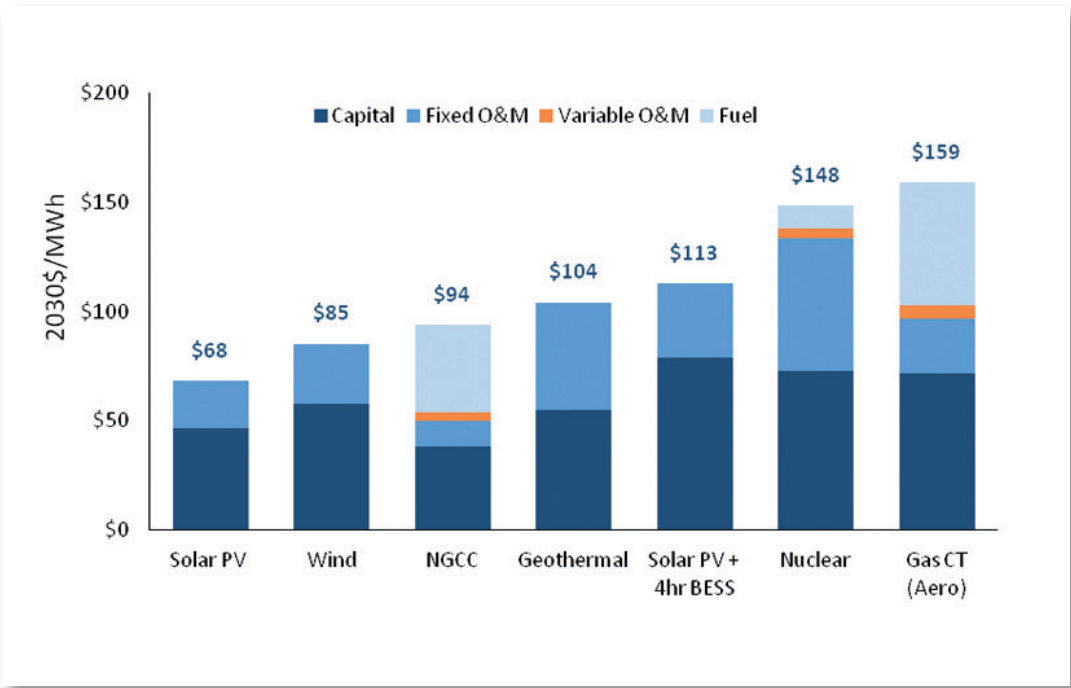
Capital cost assumptions for future resources are primarily based on Siemens PTI Spring 2025 National Forecast Model Reference Case. This outlook reflects expectations that near-term cost pressures will persist through 2030, driven by projected load growth and increasing reliability needs that are elevating demand for new generating resources. Capital costs were also benchmarked against other industry sources including the National Laboratory of the Rockies’ Annual Technology Baseline, Wood Mackenzie, the U.S. Energy Information Administration, and Lazard, as well as special project studies and TEP’s ASRFP.

In the IRP modeling, TEP assumed that solar and wind projects would not receive tax credits under the OBBBA. Resources such as storage, geothermal, pumped storage, and nuclear are assumed to meet the prevailing wage and apprenticeship requirements and qualify for the full Investment Tax Credit if the construction begins by 2033. Project construction timeframes, domestic content requirements associated with tax credit eligibility, project location and other factors are also considered. Please refer to Appendix C for more information.

Levelized Cost of Energy

The levelized cost of energy (LCOE) is commonly used to compare the cost of energy produced by different resource technologies. LCOE is calculated as the net present value of a project’s cost over its lifetime divided by the net present value of the energy produced over its lifetime (\$/MWh). Costs include construction, financing, fuel, and operation and maintenance (O&M). However, LCOE has limitations as a benchmarking metric, as it does not adequately capture key risk factors such as fuel volatility, regulatory uncertainty, and differences in system value across resources.

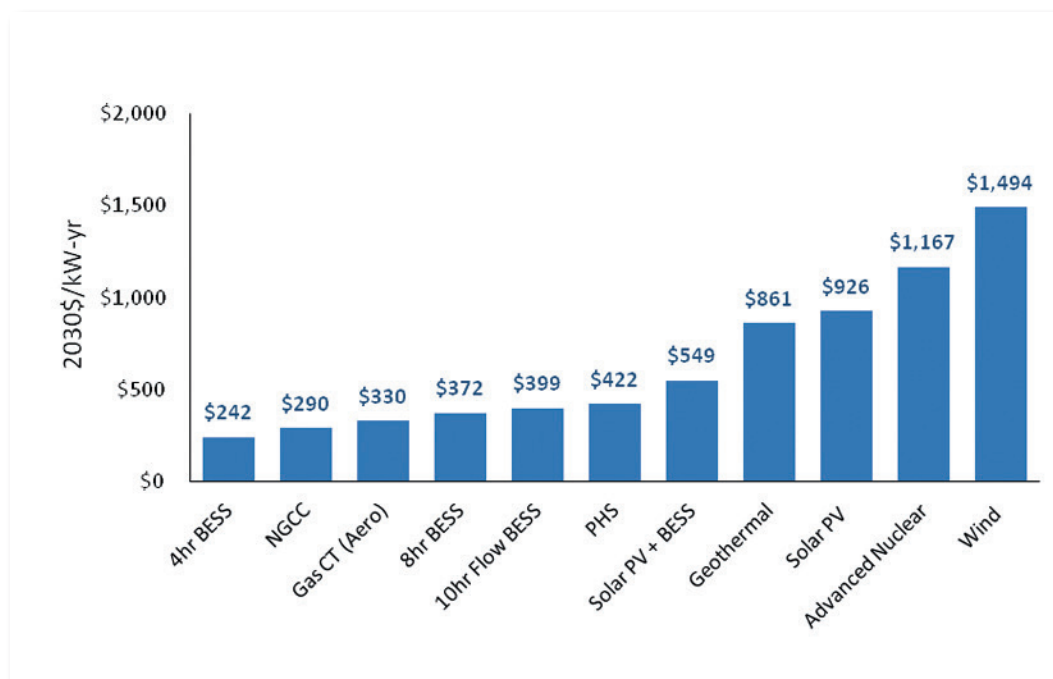
Figure 4.9 - Levelized Cost of Energy



Levelized Cost of Capacity

Another metric commonly used to compare resource costs is the levelized cost of capacity (LCOC). It measures the net present value of total cost over a project's lifetime relative to accredited capacity (\$/kW-year). LCOC generally includes capital and fixed O&M costs but excludes variable costs such as fuel and variable O&M. As a result, it does not capture fuel price risk and ignores differences in energy production across resources. However, LCOC is a useful metric for evaluating the cost of reliable capacity and aligns with planning objectives related to resource adequacy and reserve margin requirement.

Figure 4.10 - Levelized Cost of Capacity (ELCC Adjusted)



4.2.5. Market and Fuel Prices

Desert Southwest Wholesale Power Markets

Wholesale power markets in the Desert Southwest historically have provided an efficient mechanism for utilities to buy and sell power, enabling optimization of resource portfolios and reducing costs for customers. Annual trends in wholesale power prices are strongly influenced by natural gas prices, as gas-fired generation often sets the marginal cost of energy in the region. However, market prices are also impacted by increasing renewable penetration and system conditions. The extreme weather events in recent years have increased market volatility and exposed capacity shortfalls across much of the Western Interconnection. While participation in regional markets is expected to improve access to resources, utilities continue to prioritize firm resource additions to reduce exposure to higher market prices and ensure reliable service during periods of system stress.

As power demand is expected to grow at an unprecedented pace with surges in large loads, long-term wholesale power prices are projected to be volatile while trending upward. Including these dynamics in TEP’s portfolio modeling is important to account for how wholesale market opportunities are likely to affect TEP’s dispatch and operating costs.



Wholesale Power and Natural Gas Price Forecasts

TEP develops its fuel and wholesale power price forecasts using independent third-party sources to ensure alignment with current market conditions and long-term fundamentals. Near-term natural gas and wholesale power price projections are based on S&P Global Platts’ forward curves. These forward curves are derived from Intercontinental Exchange settlement data reflecting market-based pricing and current market expectations. TEP applies Platts forward natural gas and wholesale

power prices for 2027 through 2029, the first three years of the IRP study period. From 2030 through 2033, prices reflect a blend of Platts forward market data and a long-term fundamental outlook based on Wood MacKenzie’s 2025 North America Long-Term Power Market Outlook (moderate case). Beyond 2033, prices are derived entirely from the Wood Mackenzie report. This outlook assumes continued strength in natural gas supply, supported by sustained demand growth. **Figure 4.11** presents average historical and forecasted Palo Verde hub power prices, while **Figure 4.12** presents historical and forecasted Permian Basin natural gas prices.

Figure 4.11 - Palo Verde Average Wholesale Power Prices

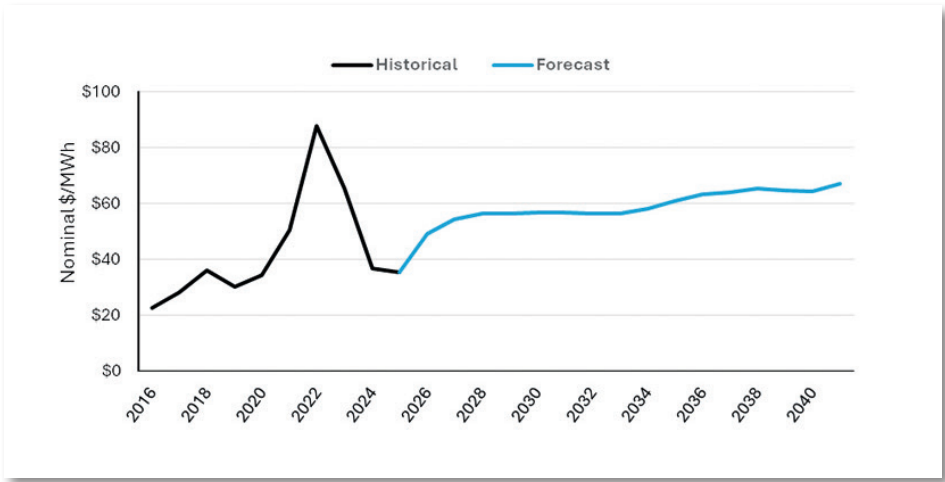
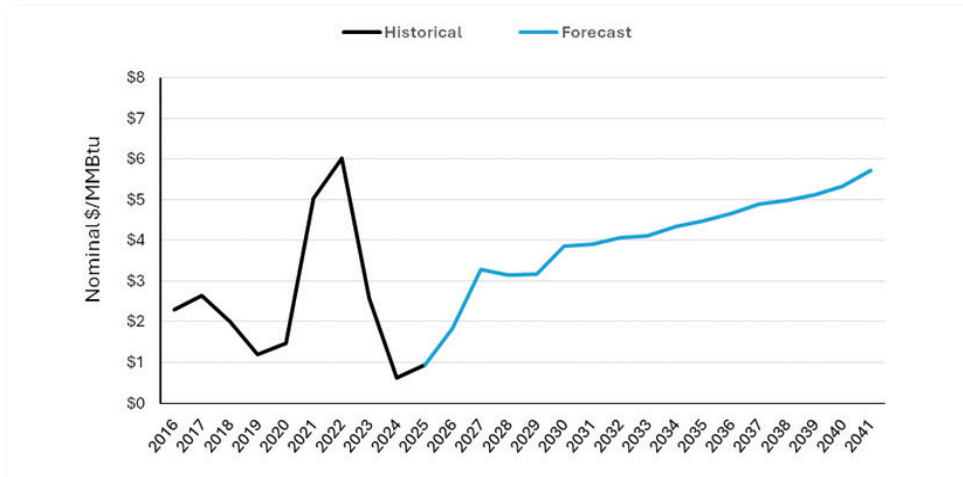


Figure 4.12 - Permian Basin Natural Gas Prices

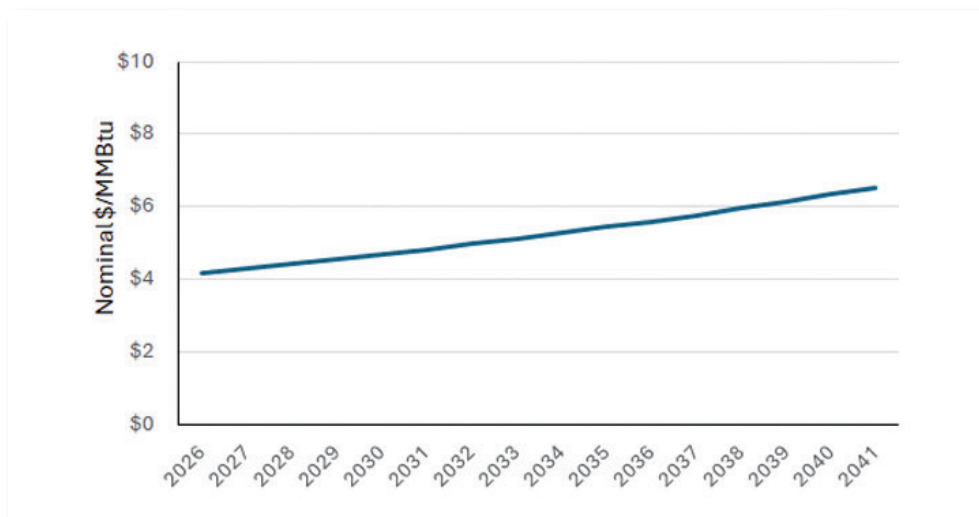


Delivered Coal Price

Figure 4.13 reflects the TEP weighted average coal pricing through the IRP study period. TEP's assumptions are based on contract indices and escalators that are part of existing coal supply agreements. TEP currently has ownership shares in two coal-fired power plants in Arizona and New Mexico. The coal supply is under long-term contracts for each.

- Springerville: The plant has access to coal from the El Segundo Lee Ranch mining complex in New Mexico via rail deliveries.
- Four Corners: The Four Corners Power plant is sourced from the Navajo Coal mine, which is a mine-mouth facility, operated by the Navajo Transitional Energy Company.

Figure 4.13 - Delivered Coal Price



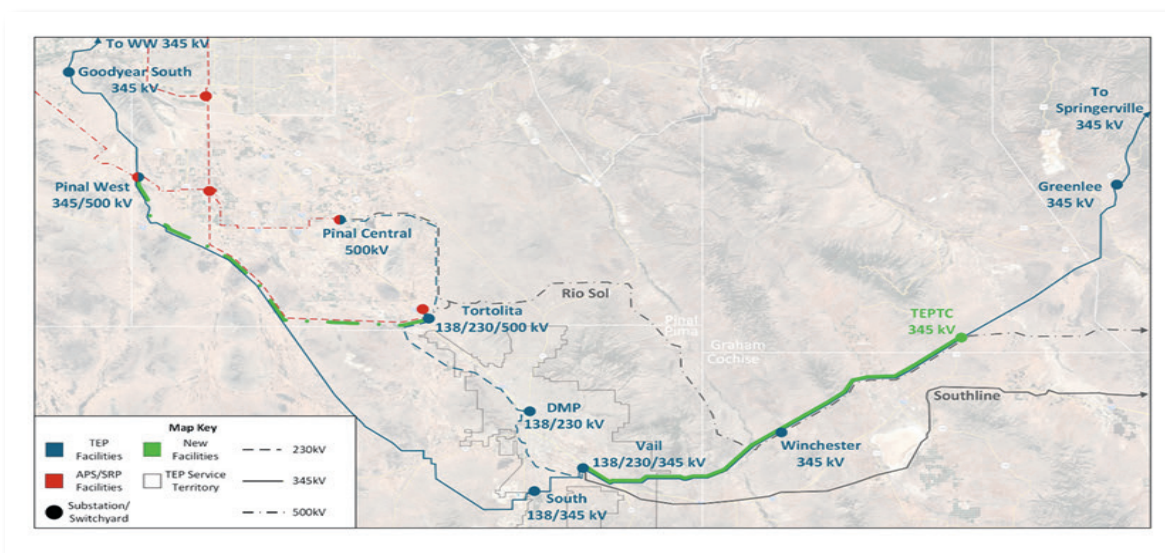
4.2.6. New Transmission Development

Tucson Electric Power serves a metropolitan load pocket that relies heavily on energy imported through a finite set of high voltage interconnections. Under the existing system configuration, the ability to import new generation is limited by the capacity of these paths. With load growth in this planning cycle driven by economic development, electrification, and large new commercial loads, these constraints increasingly restrict TEP's ability to reliably and economically deliver competitive resources to its customers. To alleviate these constraints, TEP will need to develop transmission solutions that expand import capability while creating flexibility to allow for generation selection that meets the identified needs of the Integrated Resource Plan affordably and reliably.

Vail East is a recently announced, planned 345 kV transmission line extending from TEP's Vail 345 kV substation to a planned 345 kV substation southwest of the existing Greenlee 345 kV substation. The line will follow the existing Vail to Springerville 345 kV corridor to minimize siting and land acquisition challenges. It can be phased to alleviate current congestion between the Tucson load pocket and existing solar generation and storage at the Winchester 345 kV substation, allow greater import capability for utilization of the roughly 2,240 MW of solar, storage, and natural gas generation under development in Cochise County, and, in the long-term, provide access to regional transmission projects like Southline and Rio Sol. These regional projects offer opportunities for reliability through connection of disparate parts of TEP's system and create greater access to solar, storage, wind, and natural gas generation resources in eastern Arizona and New Mexico. Vail East is targeted for service in the early 2030s.

Tortolita West is a recently announced, planned 500 kV transmission line extending from TEP's Tortolita 500 kV substation to the Pinal West 345 kV substation. The project responds to a growing set of generation opportunities being developed to the north and west of TEP's system, providing access to approximately 2,160 MW of natural gas, solar, and storage resources. In addition to improving import capability, it strengthens overall reliability by introducing an alternate path into the northern portion of TEP's transmission system. The project can be phased to reach generation as it is developed along the corridor. Tortolita West is targeted for service in the mid-2030s.

Figure 4.14 - New Transmission Development



4.2.7. Retirement Analysis

Firm and dispatchable resources play a critical role in meeting reliability in the Desert Southwest, particularly during periods of extreme weather. In considering whether generating resources should be retired, TEP looks at whether the resources still have a useful life, state and federal regulations and their associated risks, availability of fuel supply, and overall cost impacts to customers. At the same time, given the projected load growth and future capacity needs, the resources required to replace the retired capacity and maintain resource adequacy are also considered.

Luna Energy Facility and Gila River Power Blocks 2 and 3 are each natural gas combined cycle (NGCC) facilities built in 2006 and 2003, respectively. These resources are large units capable of baseload dispatch and have reasonably fast ramp rates, making these generators key components of TEP's resource adequacy. Sundt Generating Station Units 3 and 4 are both steam generators fueled by natural gas. Located in the TEP load pocket, these generators provide dispatchable capacity and contribute to TEP's resource adequacy.

Replacing these units' capacity like-for-like or with the required quantity of intermittent and energy-limited resources would result in additional capital expense, even as recovery on assets continued. Fuel transport contracts are in place, and Gila River has the capability to receive gas from both the San Juan and Permian basins, which lowers fuel risk. Given these factors and the useful life still ahead of these units, TEP does not plan to retire them within the window of this IRP.

Arizona Public Service announced on September 30, 2026 that Four Corners Power Plant would remain open until at least 2038. TEP is committed to exploring exit opportunities in light of this change, and the plan to exit Four Corners Units 4 and 5 by 2031 remains in place. The exit decision, announced in 2020, mitigates uncertainty around the cost to continue the plant's operation, including the cost of fuel and future environmental control measures.

For information on TEP's decision to convert Springerville Generating Station Units 1 and 2 from coal to natural gas in lieu of retirement, see Section 2.4.



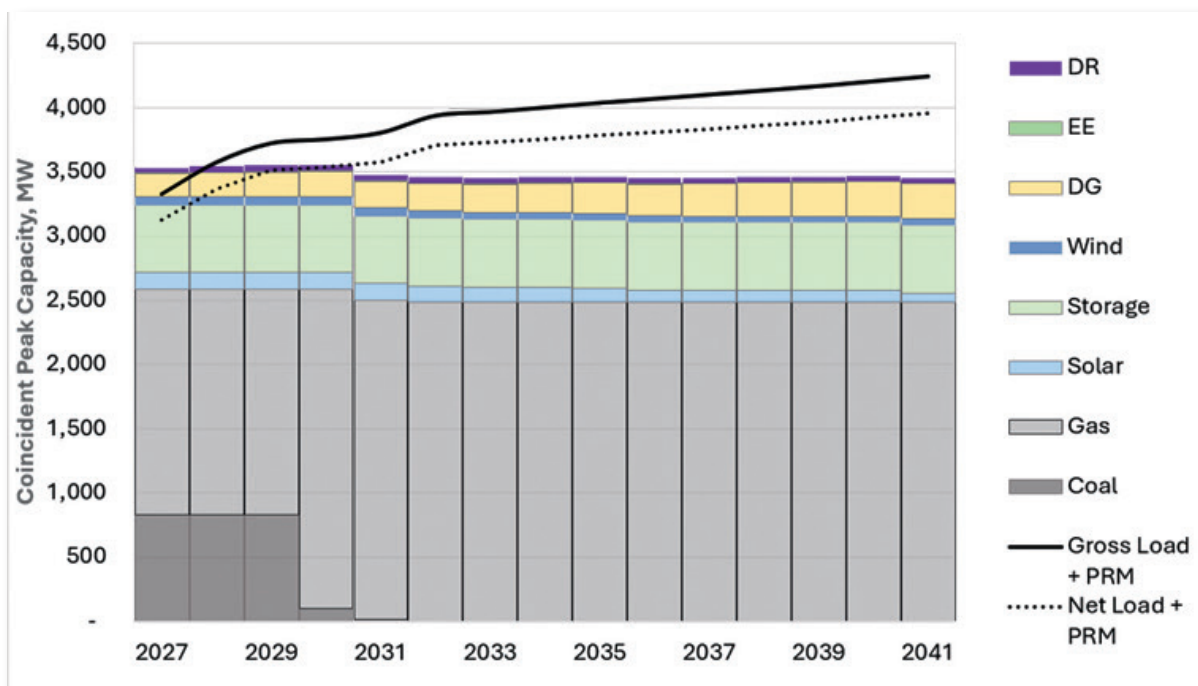
SECTION 5

PORTFOLIO RESULTS AND ANALYSIS

5.1. Existing Loads and Resources

This IRP covers the study period 2027 through 2041. **Figure 5.1** shows TEP's forecasted gross and net peak demand including the accredited capacity of existing and committed resources available to serve customer demand. Gross peak demand reflects forecasted load plus the PRM requirement. Net peak demand reflects forecasted load after the impacts of Energy Efficiency (EE) and Distributed Generation (DG), plus the PRM requirement. The coincident peak capacity for DG, utility-scale solar, wind, and storage are based on their ELCC values.

Figure 5.1 - Annual Loads and Resources with No Future Resource Additions



The resources shown in **Figure 5.1** include all existing generating resources and committed resource additions in 2027, including the Winchester facility which includes 80 MW of solar paired with 80 MW of battery storage. The study period also includes the planned conversion of the Springerville Generating Station from coal to natural gas in 2030 and the exit from the Four Corners Units 4 and 5 in 2031. No future resource additions beyond those already committed are assumed in this time frame. The gap between gross load and the top of the resource stack represents the additional capacity required over the planning horizon to meet TEP's resource adequacy requirements. The portfolio development in this IRP is informed by the timing and magnitude of the capacity needed.

5.2. Portfolio Evaluation, Results and Analysis

As summarized in Table 5.1, TEP developed a number of portfolios covering a range of future customer loads, resources, costs, and market and fuel price assumptions. This allows TEP to evaluate its adaptability to changing load and market conditions while achieving least-cost outcomes and meeting reliability objectives. These portfolios incorporate long-term capacity expansion results, two-step RA tests, and price sensitivities, and are intended to meet the requirements outlined in Appendix A.

Table 5.1 - 2026 TEP IRP Portfolios

Portfolio Number and Name	Description/Design Objectives ³³	Sensitivity Tests
P01 – Least-Cost, Technology Neutral Base Case	A least-cost, technology neutral portfolio required by the ACC. Allows the LTCE to select any resources available, including the SGS coal to gas conversion.	High/Low Market Prices Remove 40% Capacity Factor Limit on New Gas
P02 - Clean Energy Buildout	A portfolio that only allows the LTCE to choose carbon-free resources (solar, wind, storage, pumped hydro, geothermal, nuclear). The model includes the SGS coal to gas conversion.	High/Low Market Prices
P03 - High Load Factor Customer Growth (HLFCG)	A least-cost, technology neutral portfolio that adds 550 MW of high load factor customers to the base forecast beginning in 2030.	High/Low Market Prices Remove 40% Capacity Factor Limit on New Gas
P04 - High Load Factor Customer Growth (HLFCG) / Clean Energy Buildout	A portfolio that adds 550 MW of high load factor customers to the base forecast beginning in 2030 and only allows the LTCE to select carbon-free resources.	High/Low Market Prices
P05 - Pumped Hydro	A least-cost portfolio that adds 100 MW of pumped hydro storage in 2033.	High/Low Market Prices
P06 – Geothermal	A least-cost portfolio that adds 100 MW geothermal resources in 2034.	High/Low Market Prices
P07 – Nuclear	A least-cost portfolio that adds 100 MW of large nuclear resources in 2038.	High/Low Market Prices

³³ All portfolios include 730MW Springerville conversion from coal to gas

Portfolios Using the Base Forecast

TEP developed seven portfolios for the 2026 IRP in accordance with ACC Order No. 79589. The annual resource additions and retirements for each portfolio are presented in Appendix B - Portfolio Summaries.

P01 – Least-Cost, Technology Neutral serves as the least-cost, technology-neutral portfolio and TEP's reference case.³⁴ The portfolio assumes the 80 MW Winchester hybrid solar plus storage project enters into service in 2027. It also includes the Springerville coal-to-gas conversion between 2029 and 2030, TEP's exit from its 110 MW share of Four Corners coal capacity in 2031, and the retirement of several wind, solar, and storage resources over the planning horizon.

In addition, P01 adds 600 MW solar and 600 MW 4-hour energy storage resources. The LTCE model also selected 300 MW of new natural gas combined-cycle capacity in 2031. Because the portfolio was not subject to emissions reduction targets, renewable energy requirements, or other carbon-related constraints, natural gas resources remained available for selection and were identified by the model as part of the least-cost resource mix.

P02 – Clean Energy Buildout represents a variation of P01 in which the model was restricted to selecting only carbon-free resources. The resource options were comprised of solar, wind, advanced geothermal, and nuclear generation types, as well as four-, eight-, and ten-hour battery and pumped hydro storage types. This portfolio illustrates the least-cost resource plan in the absence of new gas-fired resource options. Relative to P01, the LTCE model selected an additional 600 MW of 4-hour energy storage and 500 MW of solar to replace the capacity and reliability contribution provided by the 300 MW of gas selected in the Least-Cost, Technology Neutral portfolio.

The need for approximately 1,100 MW of additional solar and storage resources to offset 300 MW of gas capacity reflects, in part, the declining Effective Load Carrying Capability (ELCC) of solar and storage resources as their penetration increases on the system in comparison to gas, consistent with the findings of E3's ELCC study (see Appendix E). In addition to declining ELCC values, resource adequacy, operational flexibility, and reserve margin requirements also influence the amount of clean energy capacity required. It is interesting to note that the LTCE did not add wind as a resource for P02 or any of the other portfolios. Increased capital cost assumptions, reduced tax credit benefits, and minimal peak credit value decreased the competitiveness of new wind resources. Solar plus storage and new natural gas resources provide a more cost-effective combination of capacity value.

In addition to the reference portfolios, TEP evaluated several emerging technologies that were of interest to both TEP and the Resource Planning Advisory Council (RPAC), including pumped hydro storage, enhanced geothermal, and advanced large nuclear resources. While these resources were available as candidate technologies in the LTCE model for both P01 and P02, none were economically selected under the modeled assumptions. To evaluate their potential impacts on future resource needs, TEP developed portfolios in which 100 MW of each technology was set in the earliest feasible in-service year, taking into consideration expected procurement, permitting, and construction timelines.

³⁴ This portfolio also meets the requirement in Decision No. 79589 to model a least cost, technology neutral portfolio.

P05 – Pumped Hydro includes 100 MW of pumped hydro storage placed in service in 2033 in addition to the assumptions in P01. Relative to P01, the resulting least-cost resource plan includes 100 MW less natural gas and 200 MW more solar capacity. Because pumped hydro provides energy shifting and capacity value but does not generate energy on a net basis, the LTCE model selected additional solar resources to provide the energy required to charge the facility while maintaining reliability and reserve margin requirements. The resulting resource mix represents the least-cost portfolio identified by the model under these revised assumptions.

P06 – Geothermal includes 100 MW of enhanced geothermal resources entering into service in 2034. Relative to P01, the addition of geothermal reduces the need for approximately 100 MW of natural gas capacity while resulting in an otherwise similar resource build. Unlike pumped hydro storage, geothermal provides both energy and capacity and can operate at high-capacity factors throughout the year. As a result, geothermal can directly offset a portion of the gas-fired capacity that would otherwise be required to maintain reliability.

P07 – Nuclear includes 100 MW of large advanced pressurized water reactor nuclear resources entering service in 2038. Relative to P01, the portfolio includes approximately 200 MW more solar capacity, 100 MW more storage capacity, and 200 MW less natural gas capacity. One of the primary drivers of this differing resource mix is the later in-service date of the nuclear resource. Because nuclear capacity is not available until 2038, the LTCE model selects additional resources earlier in the planning horizon to maintain reserve margin requirements and reliably meet projected load growth prior to the nuclear resource becoming operational.

Portfolios Using the Base Forecast Plus Additional Growth

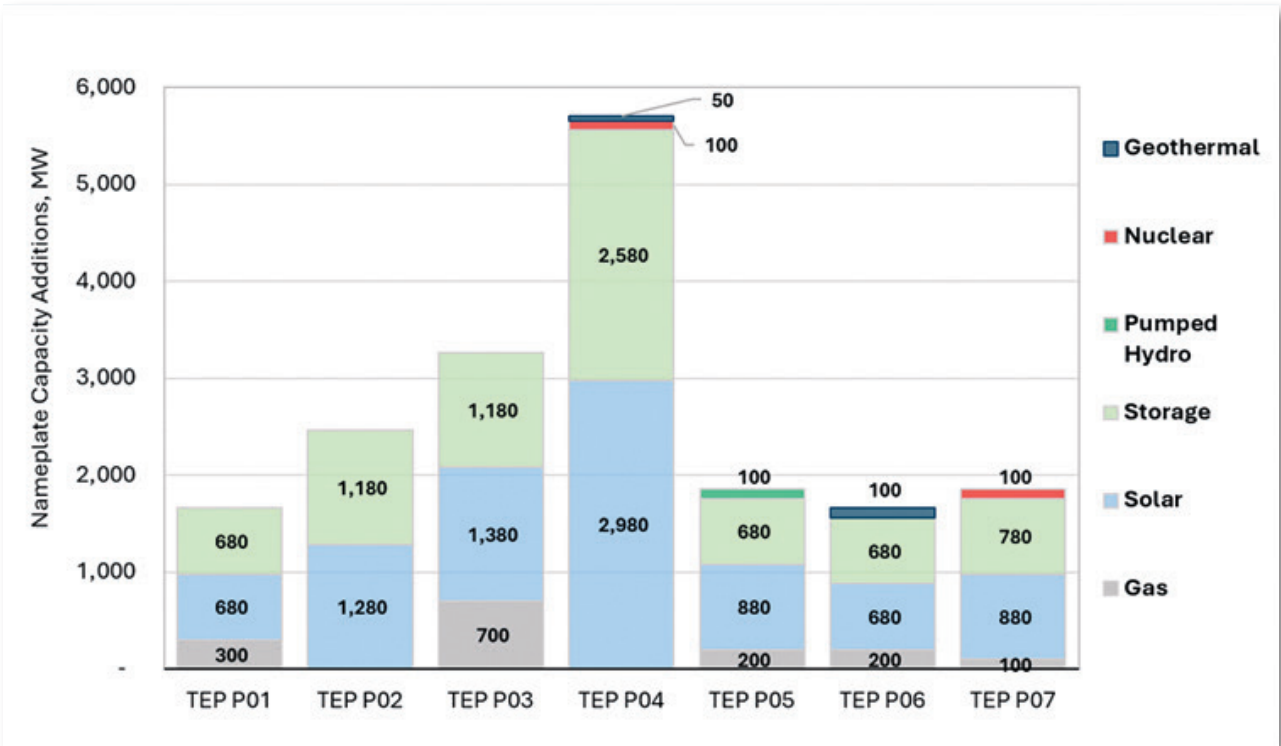
P03 – HLFCG Technology Neutral represents a variation of P01 in which TEP evaluated a High Load Factor Customer Growth (HLFCG) scenario that includes 550 MW of additional high-load-factor load. Relative to P01, the LTCE model selected an additional capacity of 400 MW of natural gas, 700 MW of solar, and 500 MW of energy storage to meet the increased demand associated with the higher load forecast (see Appendix B). Similar to P01, the model continued to select a combination of natural gas, solar, and storage resources as the least-cost portfolio under technology-neutral assumptions.

P04 – HLFCG Clean Energy represents a variation of P03 in which the same HLFCG assumptions are applied but only carbon-free resources are available for selection by the model. Relative to P03, the portfolio adds an additional 1,600 MW of solar, 1,400 MW of energy storage, including 100 MW of 10-hour duration storage, 50 MW of geothermal, and 100 MW of advanced nuclear (see Appendix B). Similar to P02, restricting the model to carbon-free resources results in substantially greater solar and storage deployment to satisfy reliability and resource adequacy requirements. The clean energy constraints, combined with the additional load requirements, also drive the selection of firm and long-duration clean energy resources, including geothermal, advanced nuclear, and long-duration storage, as part of the least-cost resource portfolio.

Portfolio Resource Buildouts

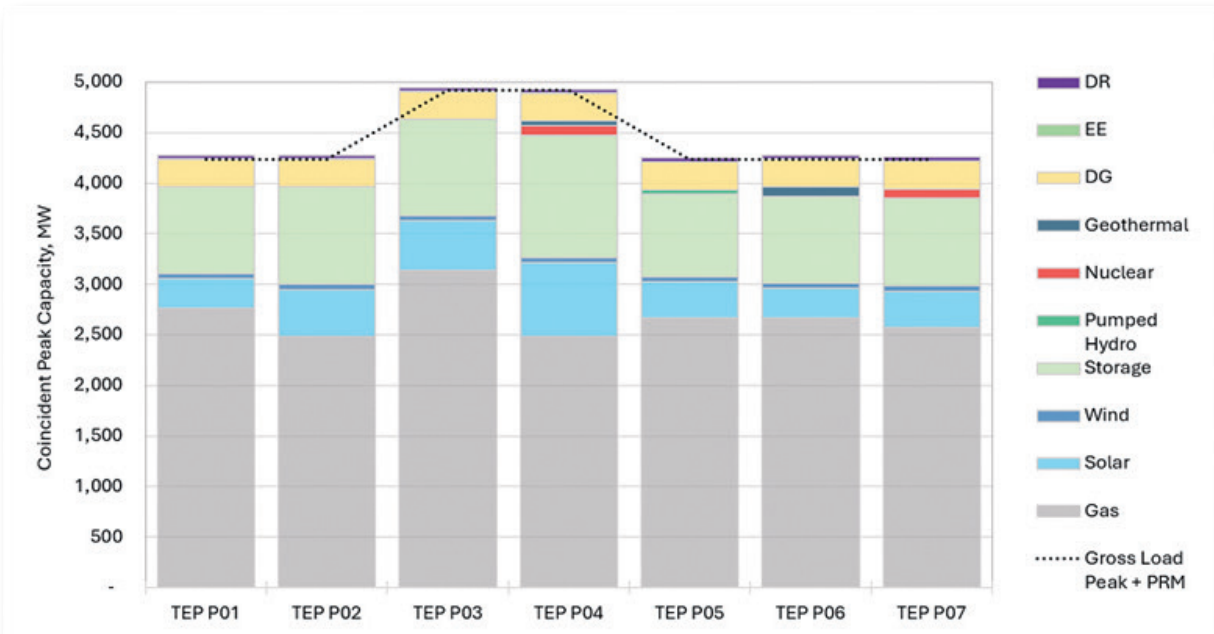
Figure 5.2 illustrates total resource additions throughout the study period by portfolio excepting the 730MW SGS coal-to-gas conversion. Portfolios P02, P03, and P04 exhibit the largest cumulative resource additions. The increased additions in P02 are driven by the carbon-free resource constraint, while P03 reflects the impact of higher load growth. Portfolio P04 combines both factors and therefore has the largest overall buildout.

Figure 5.2 – Total Resource Additions for Each Portfolio



When ELCC values are applied to determine the coincident peak contribution of all resources in service by 2041, the relative differences among portfolios narrow. As shown in Figure 5.3, the resulting coincident peak capacity across the portfolios aligns more closely with each portfolio’s gross load requirement, indicating that ELCC-adjusted capacity provides a more comparable measure of each portfolio’s contribution to reliability than installed capacity alone.

Figure 5.3 - 2041 Coincident Peak Capacity



Portfolio Costs

Figure 5.4 presents the Net Present Value of Revenue Requirements (NPVRR) and average system cost per kWh for each of the seven portfolios evaluated. Among the portfolios using the base load forecast, P02 exhibits the highest NPVRR and total system cost per retail load, while P01 represents the least-cost portfolio. **Figure 5.5** illustrates the incremental NPVRR of Portfolios under the same load assumption relative to portfolio P01.

The range of costs across these portfolios is consistent with the resource additions shown in **Figure 5.2**. Although the portfolios differ in their mix of gas, solar, storage resources, and emerging technologies, total nameplate capacity additions are generally comparable, resulting in similar levels of capital investment and fixed costs.

The most significant driver of cost variation is the scale of resource additions required to meet projected demand. As shown in **Figure 5.4**, Portfolios P03 and P04 require substantially larger resource buildouts than the other portfolios. The increased additions in P03 are driven primarily by higher load growth, while P04 reflects the combined effects of higher load growth and the clean energy resource constraint. These larger buildouts increase NPVRR through higher capital expenditures, fixed operating costs, and the additional energy production required from the expanded resource fleet. Consequently, P03 and P04 exhibit the highest overall revenue requirements among the portfolios evaluated.

Despite their higher total system costs, P03 and P04 benefit from greater energy sales associated with higher load growth. The ability to recover fixed costs over a larger sales base results in lower total system cost per kWh, with P03 having the lowest average system cost per kWh and P04 being the second lowest among the portfolios evaluated. This outcome illustrates that while higher load growth necessitates greater investment in resources and increases total revenue requirements, the resulting increase in sales volumes can offset those costs on a per-unit basis.

Figure 5.4 - NPVRR by Portfolio

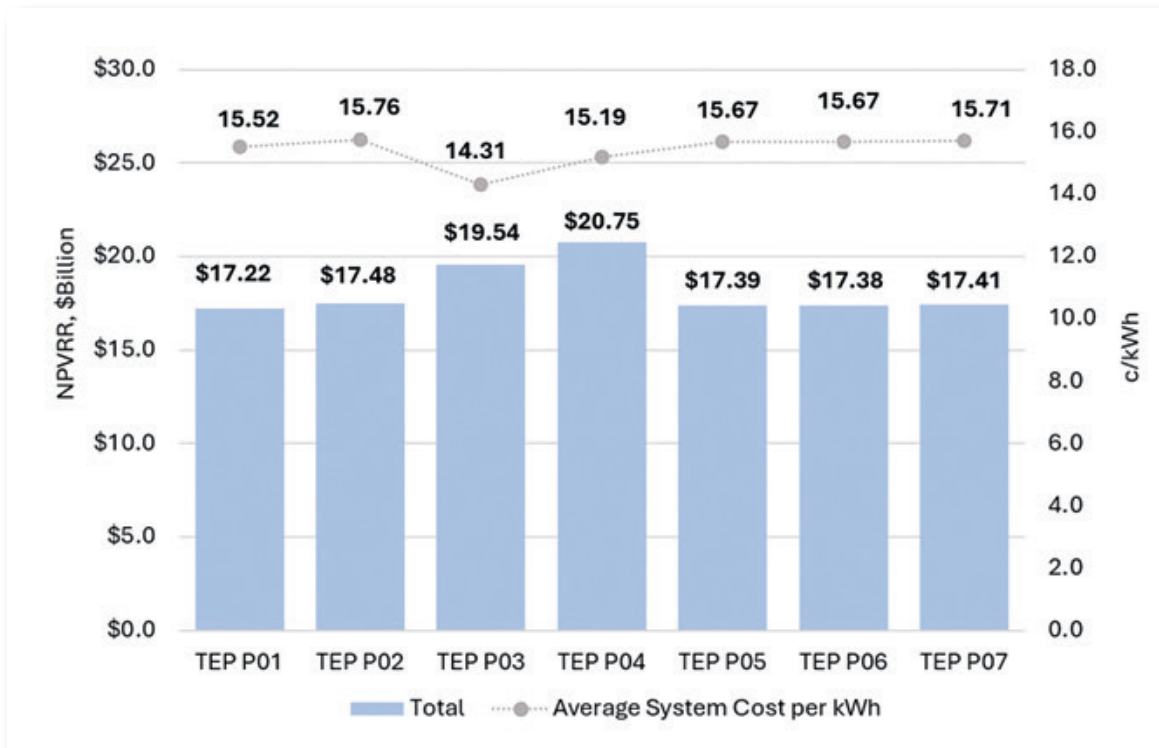
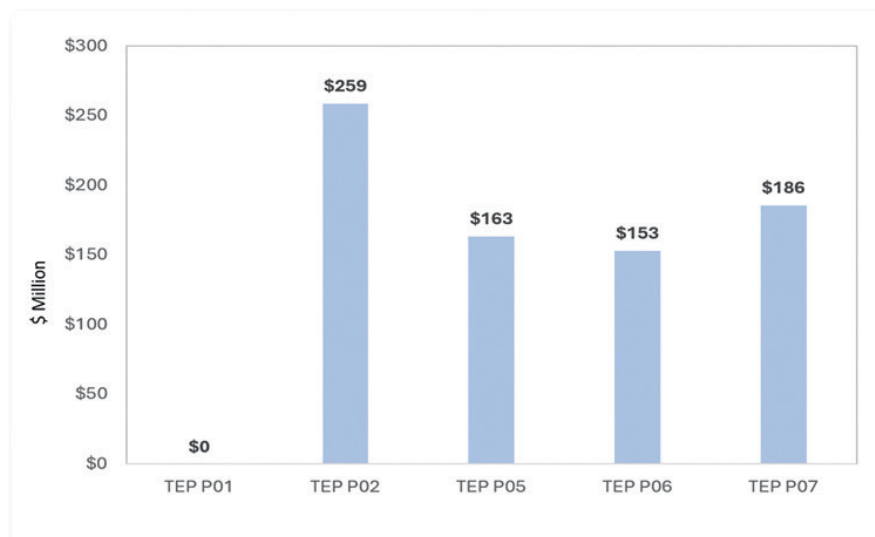


Figure 5.5 - Comparison of NPVRR Relative to P01 Tech Neutral Portfolio



Environmental Performance

Figure 5.6 through Figure 5.8 compare the environmental performance of each portfolio based on carbon dioxide (CO₂), nitrogen oxides (NO_x), and water use intensity, where intensity measures emissions or water consumption per unit of electricity generated. CO₂ and NO_x intensity decline significantly beginning in 2030, primarily due to the conversion of the Springerville Generating Station from coal to natural gas. An additional reduction occurs in 2031 following TEP's exit from the two coal-fired units at the Four Corners Power Plant. While new natural gas resources are added in most portfolios to maintain resource adequacy, the overall generation mix shifts resulting in lower emissions intensity across all portfolios.

Water intensity remains relatively consistent throughout the study period, with minimal difference among portfolios despite changes in the generation fleet. P03 and P04, which represent high load factor customer growth, exhibit lower environmental intensity towards the end of the planning period. The additional resources in these portfolios, particularly renewables, increase the total generation while reducing emissions intensity. P01 demonstrates environmental performance comparable to other evaluated portfolios.

Figure 5.6 - CO₂ Intensity

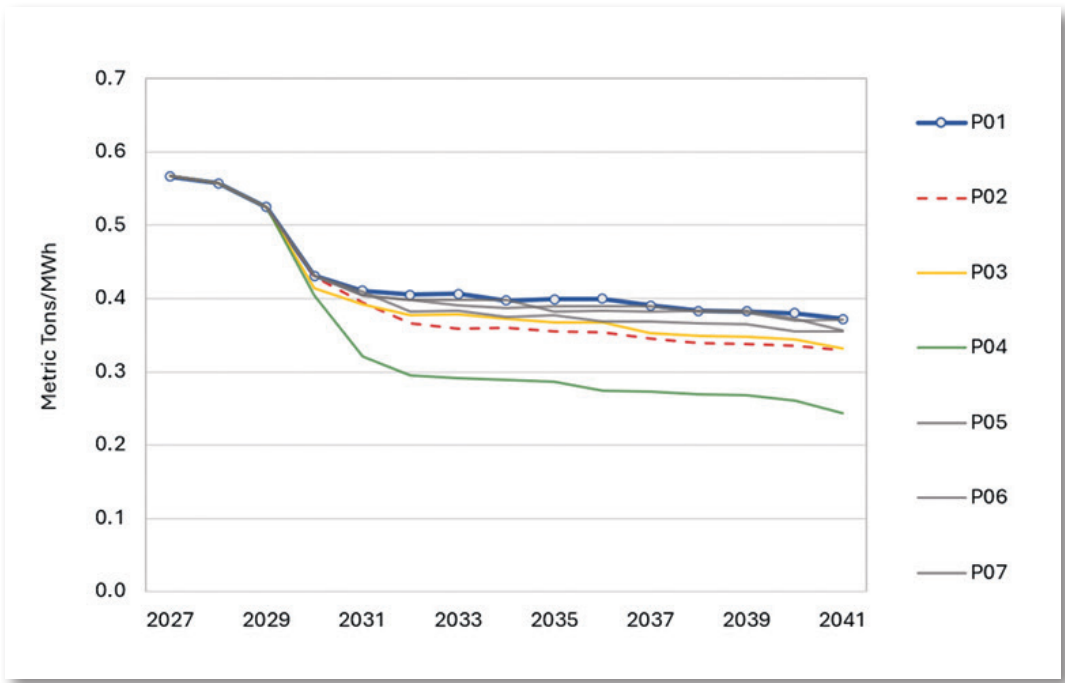


Figure 5.7 - NO_x Intensity

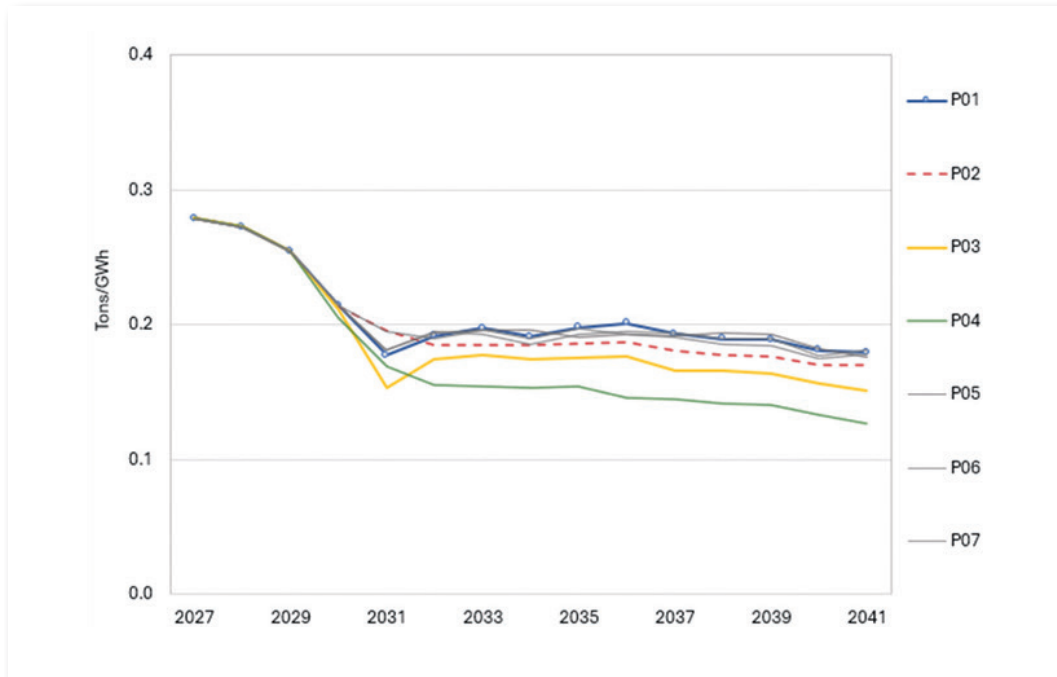
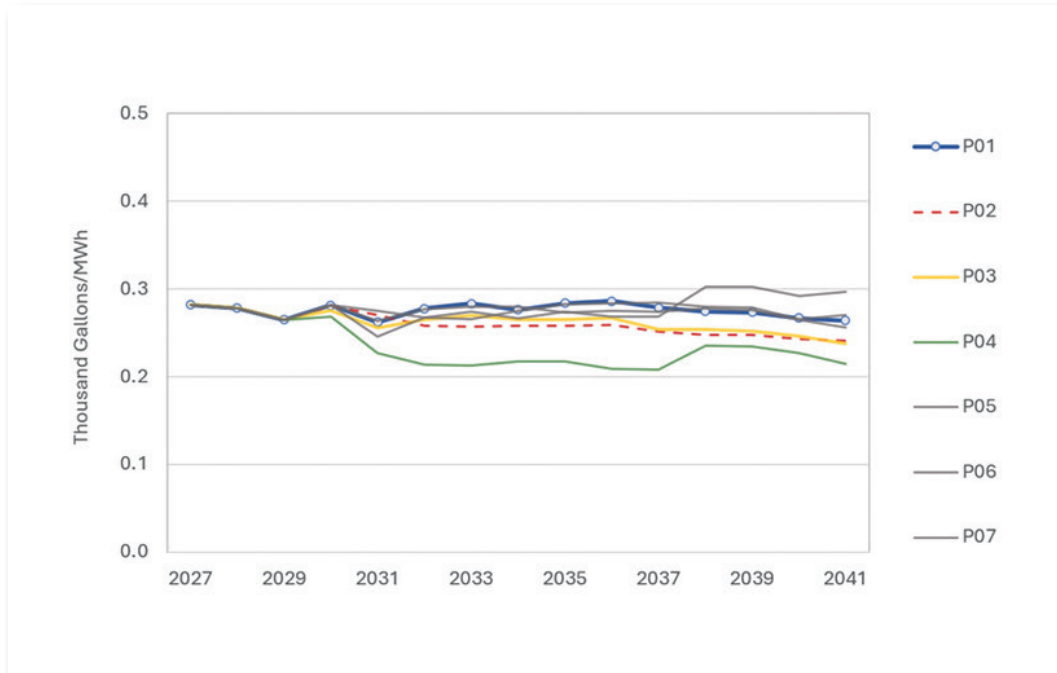


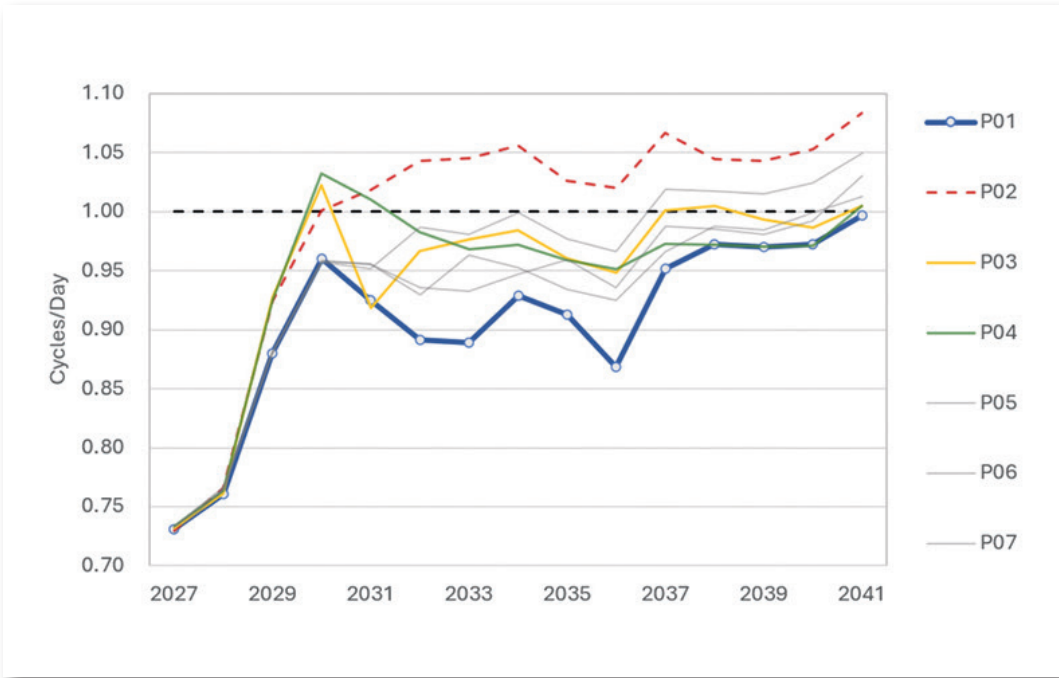
Figure 5.8 - Water Use Intensity



Battery Storage Cycling

Figure 5.9 shows the capacity-weighted, average daily cycling of each portfolio’s battery storage fleet. Although the size of the battery storage fleet is driven by the need for capacity, it serves an important function of storing excess renewable generation or low-cost market energy for later use during peak hours. This energy shifting maximizes the use of solar and wind power and reduces reliance on coal and natural gas generation as well as market purchases over peak. Unless otherwise needed for capacity, TEP designed its portfolios to target an average daily cycle of approximately one. Cycling levels below this target indicate underutilized storage capacity, while levels above the target indicate the need for additional storage capacity to support the system’s needs, as battery warranties often have limits on the number of annual cycles. As shown in Figure 5.9, P01 remains near the 1 Cycle/Day target indicating that the battery storage is being used effectively to shift energy and is not being over cycled.

Figure 5.9 - Battery Storage Fleet Average Daily Cycles



Portfolio Comparison

Table 5.2 summarizes the seven resource portfolios evaluated in the 2026 IRP. In addition to the 15-year NPVRR, cumulative resource additions and environmental intensities discussed previously, the table presents the projected reductions in carbon dioxide emissions, nitrogen oxide emissions, and water usage by 2041 relative to 2019 levels. Differences in environmental reductions reflect variations in resource additions and generation mix. These results illustrate each portfolio’s progress toward reducing environmental impacts from the historical baseline.

Table 5.2 - Portfolio Case Matrix Details

Portfolio #	Portfolio Name	Cumulative Additions (2027-2041)					
		Solar (MW)	Storage (MW)	Gas ¹ (MW)	Pumped Hydro (MW)	Geothermal (MW)	Nuclear (MW)
TEP P01	Technology Neutral	680	680	1,030	0	0	0
TEP P02	Clean Energy	1,280	1,180	730	0	0	0
TEP P03	HLFC Growth - Tech Neutral	1,380	1,180	1,430	0	0	0
TEP P04	HLFC Growth - Clean Energy	2,980	2,680	730	0	50	100
TEP P05	Pumped Storage Hydro	880	680	930	100	0	0
TEP P06	Geothermal	680	680	930	0	100	0
TEP P07	Nuclear	880	780	830	0	0	100

Notes:

1. In all portfolios, 730 MW of gas is associated with the conversion of SGS from coal to natural gas by 2030.

Portfolio #	Portfolio Name	NPV (\$ Millions)	Fuel NPV (\$ Millions)	Non-Fuel NPV (\$ Millions)	Avg System Cost (c/kWh)	Environmental Results ² (2041)		
						CO ₂ Reduction	NO _x Reduction	Water Reduction
TEP P01	Technology Neutral	\$17,225	\$5,690	\$11,535	15.52	53%	66%	38%
TEP P02	Clean Energy	\$17,484	\$5,412	\$12,071	15.76	57%	67%	42%
TEP P03	HLFC Growth - Tech Neutral	\$19,541	\$6,432	\$13,109	14.31	46%	65%	31%
TEP P04	HLFC Growth - Clean Energy	\$20,746	\$5,542	\$15,204	15.19	59%	70%	36%
TEP P05	Pumped Storage Hydro	\$17,388	\$5,650	\$11,738	17.22	54%	67%	40%
TEP P06	Geothermal	\$17,378	\$5,538	\$11,840	17.21	55%	67%	39%
TEP P07	Nuclear	\$17,411	\$5,545	\$11,866	17.26	56%	68%	33%

Notes:

2. Environmental reductions are measured relative to 2019 baseline levels.

5.3. Sensitivity Analysis

Modeling the performance of a resource portfolio requires assumptions regarding future conditions such as economic growth, fuel and wholesale power markets, regulatory requirements, and the pace of technological development. TEP seeks to identify a robust portfolio that delivers strong performance under these assumptions while preserving the flexibility to adapt to evolving market, policy, and operational conditions. Given the inherent uncertainty associated with long-term planning, each resource portfolio is evaluated across a range of future scenarios to assess its performance and resilience under a variety of potential outcomes. Because key market drivers do not move independently, alternative future scenarios must capture a range of plausible futures while maintaining internally consistent relationships among economic, market, regulatory, and technological assumptions.

TEP conducted high and low-market price sensitivity analyses for all portfolios. TEP also evaluated an environmental regulation sensitivity by removing the 40% capacity factor limitation on new natural gas-fired generation beginning in 2032 for the P01 Least-Cost, Technology Neutral and P03 HLFCG Technology Neutral portfolios.

Sensitivity analysis for market prices includes both low and high cases for natural gas and wholesale energy prices.

The low market case is based on E3's Southwest Region Market Price Forecast Core Case 2025 edition, which reflects increased renewable and storage deployment, as well as the impacts of the anticipated regional day-ahead market configuration. Under this outlook, energy prices are expected to remain relatively low in the near to medium term due to the increasing penetration of low-marginal-cost resources. Over the longer term, steady load growth from data centers and other factors with escalating gas prices contribute to higher energy market prices.

The high market case is derived from Siemens PTI's Fall 2025 Power Market Outlook. This outlook assumes natural gas will continue to serve as a critical firming and dispatchable resource, with its role reinforced by the reduction of renewable energy tax incentives and growing reliability needs from rising data center demand. The forecast also incorporates expanding U.S. liquid natural gas exports through the early 2030s, driven by sustained global demand and other geopolitical factors. These assumptions contribute to higher natural gas prices, which in turn increase wholesale energy prices. In addition, strong load growth and a slower pace of renewable resource additions further contribute to upward pressure on energy market prices.

Figure 5.10 - Palo Verde Wholesale Power Prices

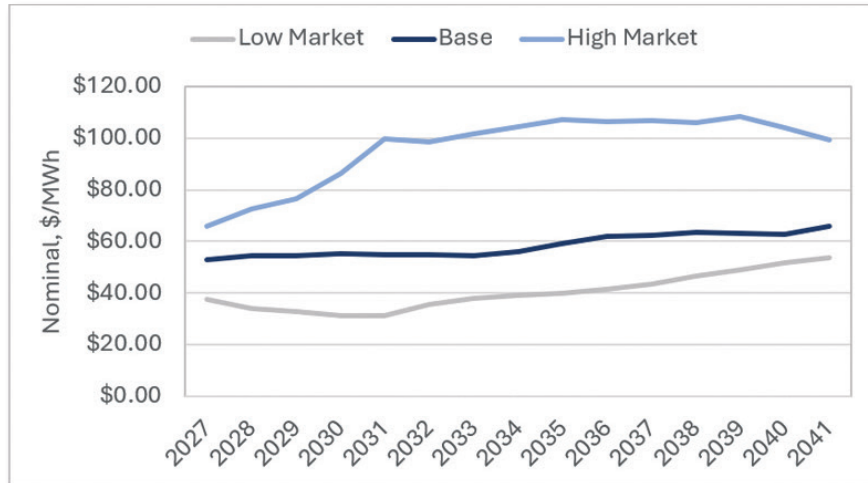
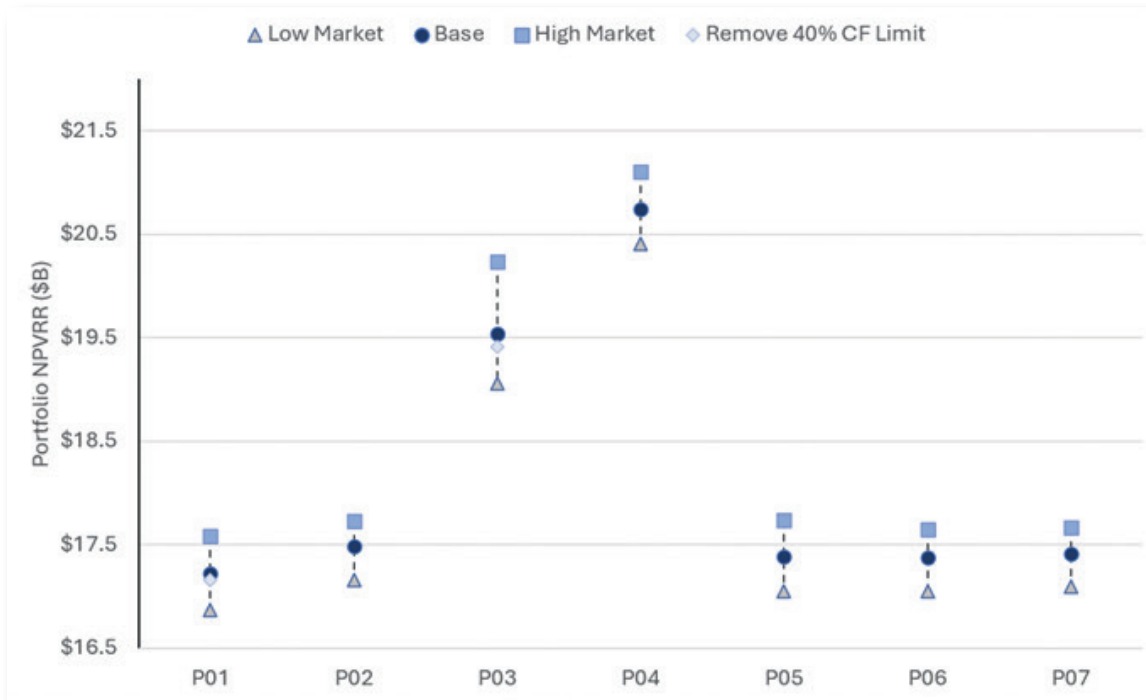


Figure 5.11 - Permian Basin Natural Gas Prices



Figure 5.12 shows each portfolio's NPVRR and the range of results of the sensitivity tests. The impacts of changes in wholesale energy and natural gas prices are generally consistent across portfolios, indicating the uncertainty in future market and gas prices does not place one portfolio at a particularly higher risk than any others. Removing the 40% capacity factor limitation on new natural gas-fired generation slightly lowers overall NPVRR due to the higher utilization of lower cost new natural gas resources.

Figure 5.12 - Portfolio NPVRR Sensitivity to Market Conditions



Additionally, TEP observed that total natural gas consumption is relatively insensitive to the lower market price assumptions. However, under higher market price scenarios, all portfolios exhibit increased utilization of TEP's natural gas-fired generation resources. This outcome is driven by wholesale energy prices remaining above the marginal cost of TEP's natural gas generation, creating additional opportunities for economic dispatch and market sales. **Figure 5.13** and **Figure 5.14** illustrate this behavior for Portfolio P01.

Figure 5.13 - Total Natural Gas Consumption Across P01 Sensitivity Analysis

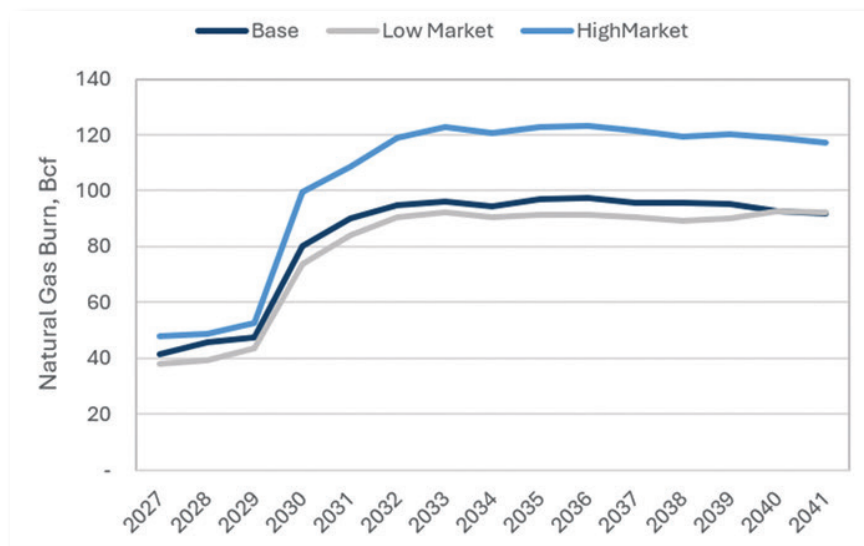


Figure 5.14 - Total Market Sales Across P01 Sensitivity Analysis



The ACC Decision No. 79589 requires each LSE to 'include in future IRPs portfolios which capture the benefits of joining a day-ahead market.' Day-ahead market frameworks in the Western Interconnection continue to evolve and the actual benefits will depend on factors including market participation levels, market design, transmission availability and operational performance. As such, TEP elected to incorporate the assumed benefits of joining a day-ahead market through sensitivity analysis.

TEP performed a sensitivity analysis using E3 market pricing based on the Southwest Region Market Price Forecast E3 Core Case 2025 edition on all the portfolios. E3's forecast models the Western Electricity Coordinating Council region as an integrated market and reflects the expected benefits of regional market participation based on expected CAISO Extended Day-Ahead Market and SPP Markets+ configurations and frameworks. These benefits arise from increased access to regional resources, broader economic dispatch across participating utilities and optimized transmission usage.

TEP'S 2026 PREFERRED PORTFOLIO

6.1 Portfolio Results

Project Overview

TEP's 2026 preferred portfolio is the P01 Least-Cost, Technology Neutral (LCTN) portfolio. This base case portfolio establishes an updated resource strategy that prioritizes affordability and reliability while continuing to deliver meaningful environmental benefits.

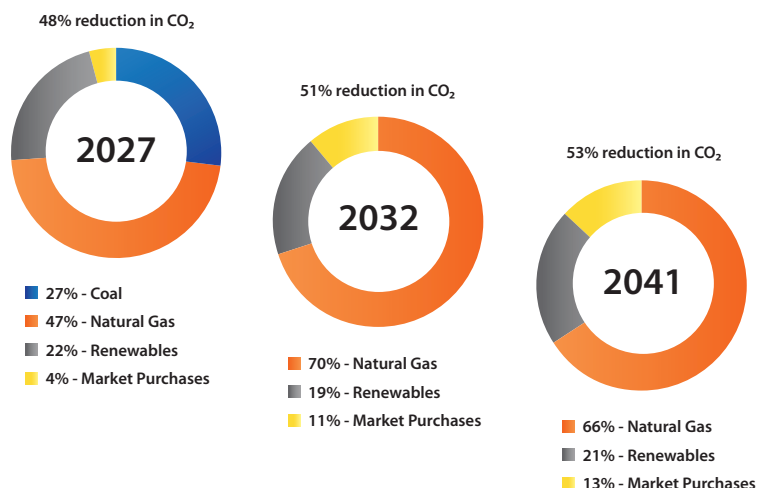
As compared to the 2023 IRP, the 2026 IRP reflects significant changes in environmental regulations, federal tax incentives, capital cost projections, load forecasts, and updates to TEP's planning methodology. These methodological enhancements include revised Planning Reserve Margin (PRM) requirements and updated Effective Load Carrying Capability (ELCC) study results, which affect the reliability value and relative economics of available resource options and contribute to the different resource mix selected in the optimization. As a result, TEP reassessed its planning objectives and resource strategy to ensure customers continue to receive reliable and affordable electric service under a wide range of future conditions.

The Least-Cost, Technology Neutral Portfolio represents the least-cost portfolio evaluated in this planning cycle while maintaining system reliability and achieving additional direct emissions reductions.

The Least-Cost, Technology Neutral Portfolio represents the least-cost portfolio evaluated in this planning cycle while maintaining system reliability and achieving additional direct emissions reductions (see **Figure 6.1**). The portfolio balances new resource additions and market purchases to meet projected load growth and reliability needs, resulting in a generation mix that eliminates dependence on coal while increasing the contribution of natural gas, renewable resources, and energy storage.

Figure 6.1 - LCTN Portfolio Energy Mix

Among the portfolios evaluated under the same load growth scenario in the 2026 IRP, the Least-Cost, Technology Neutral Portfolio requires approximately \$200 million to \$540 million less in cumulative capital investment over the 2027-2041 planning horizon. On a NPVRR basis, the portfolio is projected to reduce customer costs by approximately \$150 million to \$260 million relative to the other resource portfolios considered.



6.2. Least-Cost, Technology Neutral Portfolio Plan Attributes

The primary objective of the preferred portfolio is to reliably meet our customers’ energy needs at affordable rates, while mitigating potential risks to future costs. To meet projected load growth and replace capacity lost from future resource retirements, TEP’s preferred portfolio adds 980 MW of generating capacity and 680 MW of battery energy storage over the 15-year planning horizon. As shown in **Figure 6.2**, these additions include 680 MW of solar generation, 680 MW of energy storage, and 300 MW of new natural gas combined cycle generation in 2031. This portfolio also preserves 730 MW of dispatchable capacity through the Springerville coal to gas conversion in 2030.

The Least-Cost, Technology Neutral Portfolio assumes that all 680 MW of solar capacity will be paired with 680 MW of battery energy storage in a hybrid configuration. Co-locating solar and storage resources is expected to provide construction and operational efficiencies, maximize available battery storage tax incentives, and efficiently utilize available transmission infrastructure.

Figure 6.2 - LCTN Portfolio Future Capacity Additions, MW

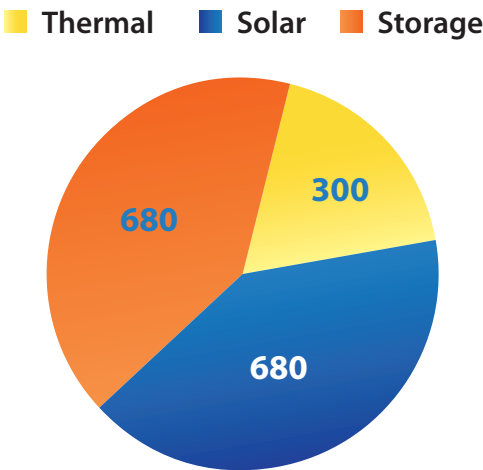


Figure 6.3 - LCTN Portfolio Capacity Additions by Year

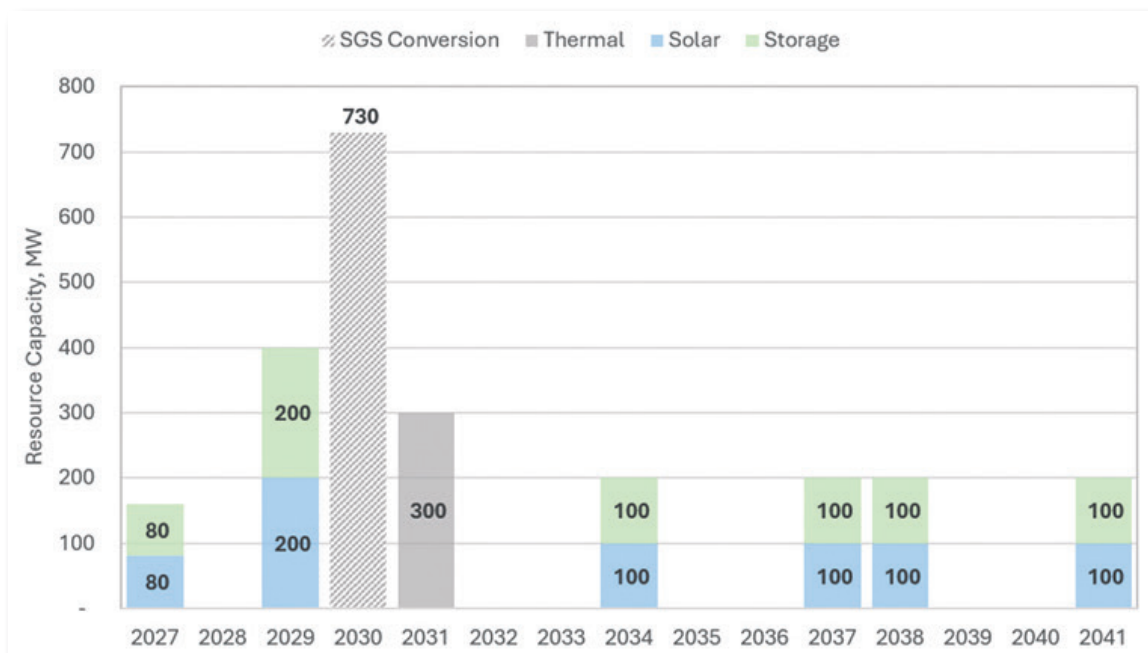


Figure 6.3 shows the Least-Cost, Technology Neutral Portfolio resource capacity additions through the planning period, and the conversion of Springerville in 2030. This chart highlights the source of replacement capacity needed due to unit retirements and increasing demand from customers. The portfolio includes 300 MW of natural gas capacity additions and 730 MW associated with the conversion of SGS from coal to natural gas. In combination with TEP's planned exit from Four Corners in 2031, the portfolio results in net thermal additions of 190 MW. Similarly, although the portfolio includes 680 MW of new solar and 680 MW battery storage, the net additions shown in **Figure 6.4** are lower due to the expiration of existing Purchased Power Agreements.

Figure 6.4 - LCTN Portfolio Net Additions and Retirements (2026 – 2041)

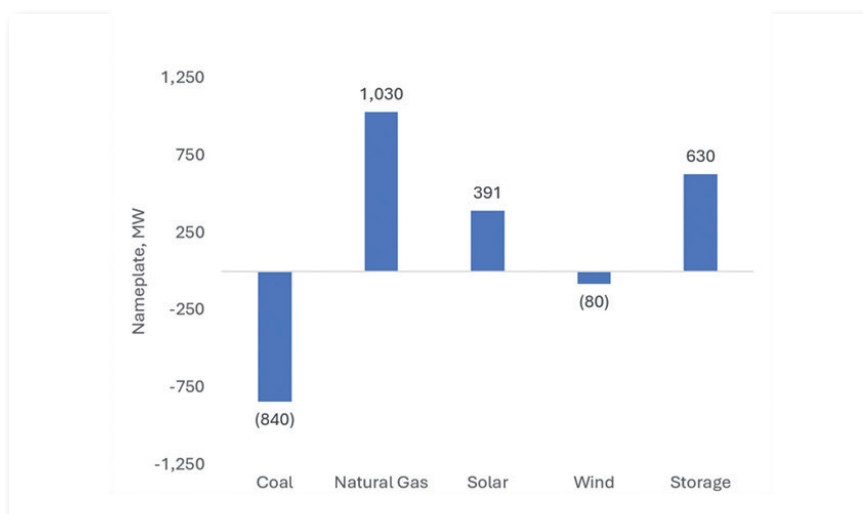


Figure 6.5 below shows the shift in energy mix over the planning period including the SGS coal to natural gas conversion in 2030 and the exit from Four Corners Units 4 and 5 in 2031. Renewable generation increases over the study period as additional solar capacity is added to the portfolio. Market purchases support the resource mix by providing a flexible source of energy when it is more economical than dispatching available resources or when additional energy is needed to meet demand.

Figure 6.5 - LCTN Portfolio Annual Energy by Resource Type

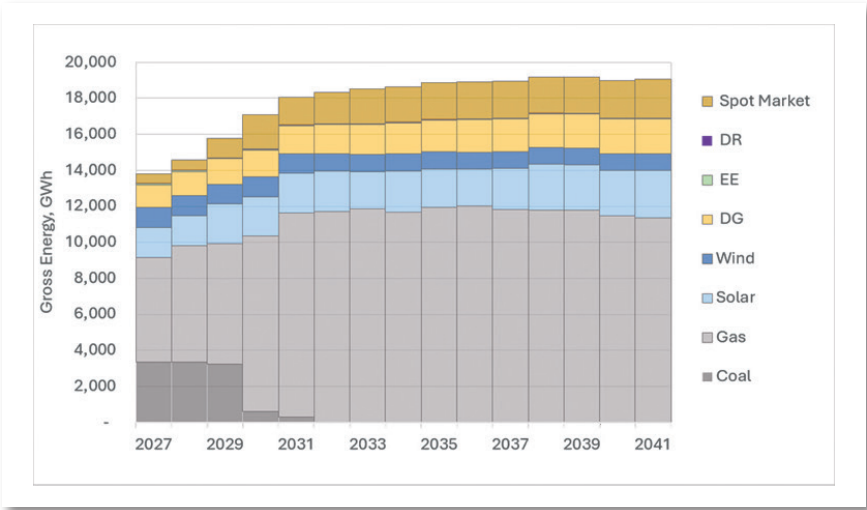


Figure 6.6 and **Table 6.1** below show the Load and Resources assessment of the Least-Cost, Technology Neutral Portfolio. While renewables and energy storage contribute significant nameplate capacity, only their ELCC values are reflected for resource adequacy purposes, representing the amount of capacity contributing towards meeting peak demand. As additional solar and storage resources are added over the study period, their incremental ELCC values decline due to diminishing capacity contribution at high levels of renewable penetration.

Figure 6.6 - LCTN Portfolio Loads and Resources Forecast

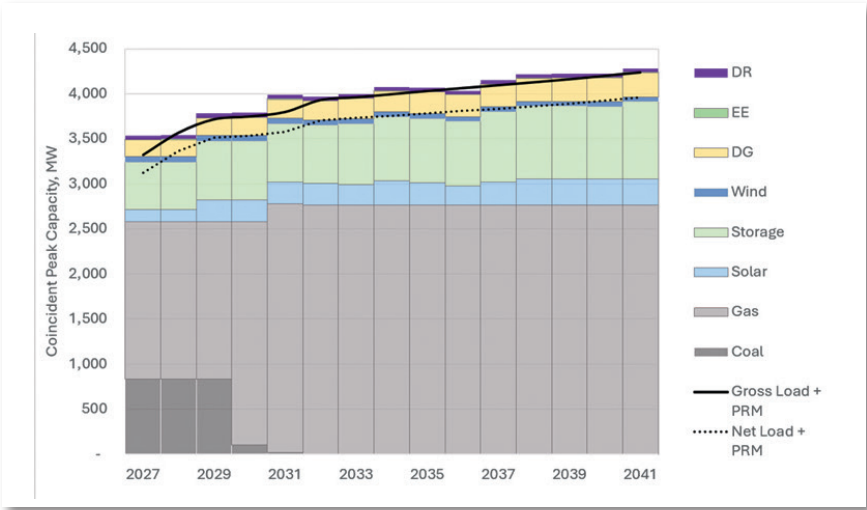


Table 6.1 - LCTN Portfolio Loads and Resources, MW

	2027	2028	2029	2030	2031	2032	2033	2034
Firm Load Obligation, MW	3,124	3,364	3,511	3,535	3,579	3,708	3,730	3,757
Retail	2,574	2,802	2,922	2,943	2,980	3,089	3,108	3,130
Firm Wholesale with Reserve	87	58	63	62	63	63	63	63
Retail Reserve Requirement	463	504	526	530	536	556	559	563
Coincident Peak Capacity, MW	3,387	3,392	3,621	3,621	3,816	3,793	3,811	3,883
Coal	832	832	832	102	16	0	0	0
Gas - Combined Cycle	1,129	1,129	1,129	1,129	1,411	1,411	1,411	1,411
Gas - Steam Boilers	253	253	253	983	983	983	983	983
Gas - Combustion Turbines	210	210	210	210	210	210	210	210
Gas - Reciprocating Engines	160	160	160	160	160	160	160	160
Wind	64	64	64	64	64	56	56	56
Solar	131	131	241	241	241	241	228	269
Storage	572	572	689	689	689	689	721	754
Demand Response	37	42	43	43	42	42	42	41
Retail Reserve Margin, MW	727	532	636	616	774	640	640	690
Retail Reserve Margin, %	28%	19%	22%	21%	26%	21%	21%	22%
Net Position	263	27	110	86	238	84	81	126

	2035	2036	2037	2038	2039	2040	2041
Firm Load Obligation, MW	3,784	3,809	3,835	3,861	3,889	3,922	3,958
Retail	3,153	3,174	3,195	3,218	3,241	3,269	3,299
Firm Wholesale with Reserve	63	64	64	64	64	65	65
Retail Reserve Requirement	568	571	575	579	583	588	594
Coincident Peak Capacity, MW	3,864	3,825	3,919	3,976	3,974	3,972	3,999
Coal	0	0	0	0	0	0	0
Gas - Combined Cycle	1,411	1,411	1,411	1,411	1,411	1,411	1,411
Gas - Steam Boilers	983	983	983	983	983	983	983
Gas - Combustion Turbines	210	210	210	210	210	210	210
Gas - Reciprocating Engines	160	160	160	160	160	160	160
Wind	56	52	52	52	52	52	52
Solar	249	216	259	295	295	293	292
Storage	754	754	805	826	826	826	856
Demand Response	41	40	39	39	38	37	36
Retail Reserve Margin, MW	647	587	659	694	669	638	635
Retail Reserve Margin, %	21%	19%	21%	22%	21%	20%	19%
Net Position	79	16	84	115	85	50	42



6.3. Coal Plant Transition

Coal-fired generation has historically played a key role in maintaining grid reliability and providing affordable electricity to TEP's customers. Natural gas-fired generation will play a critical role in maintaining resource adequacy, providing operational flexibility and supporting system needs during periods of high demand and low renewable output. Consistent with its commitment to reducing carbon emissions, maintaining affordable rates and providing reliable service, TEP plans to convert Springerville Units 1 and 2 from coal to natural gas-fired generation by 2030 and exit Four Corners Units 4 and 5 by 2031. TEP's Least-Cost, Technology Neutral portfolio includes the repowering of Springerville, which was selected through the LTCE optimization modeling process and enables TEP to utilize existing infrastructure at a strategic transmission location while maintaining reliability and lowering emissions.

TEP plans to convert Springerville Units 1 and 2 from coal to natural gas-fired generation by 2030 and exit Four Corners Units 4 and 5 by 2031.



6.4. Environmental Attributes

Although the Least-Cost, Technology Neutral portfolio was developed without specific emissions reduction criteria or renewable energy standards, the least-cost optimization selected a diverse mix of resources, including solar generation, battery energy storage, and natural gas-fired generation, and results in significant reductions in CO₂ and NO_x emissions and water use over the next 15 years relative to the 2019 baseline. CO₂ emissions decline from 10.8 million metric tons to 5.2 million metric tons by 2041, a 53% reduction. NO_x emissions decline from roughly 8,700 tons to 2,600 tons over the same period. Water consumption falls from more than 6.3 billion gallons in 2019 to roughly 3.9 billion gallons by 2041. The majority of these reductions are driven by coal retirements and the conversion of existing coal-fired units to natural gas. Continued investments in renewable generation and energy storage also contribute to lower emissions. These reductions reflect the transition efforts developed through prior IRP planning cycles and that continue through the 2026 IRP, as shown in **Figure 6.7** through **Figure 6.9**. Additional emissions reductions beyond those reflected in P01 would require additional investment in renewables and other low emitting resources.

Figure 6.7 - LCTN Portfolio CO₂ Emissions

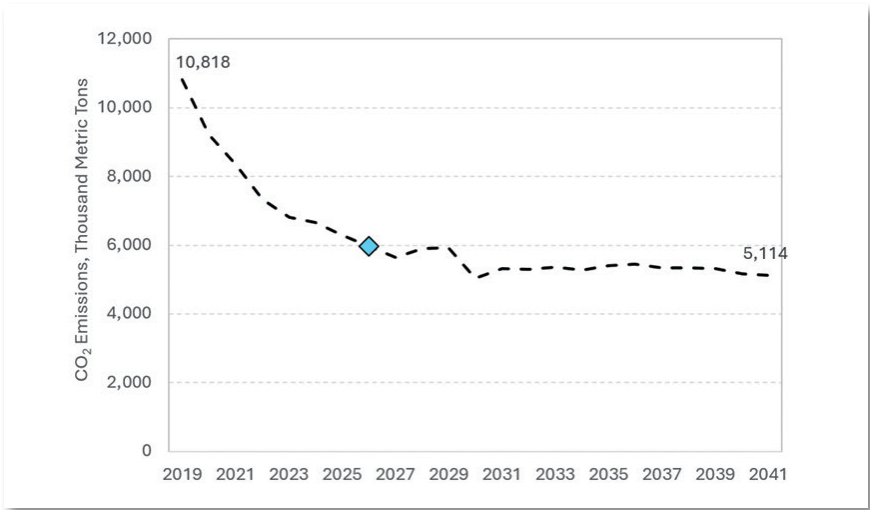


Figure 6.8 - LCTN Portfolio NO_x Emissions

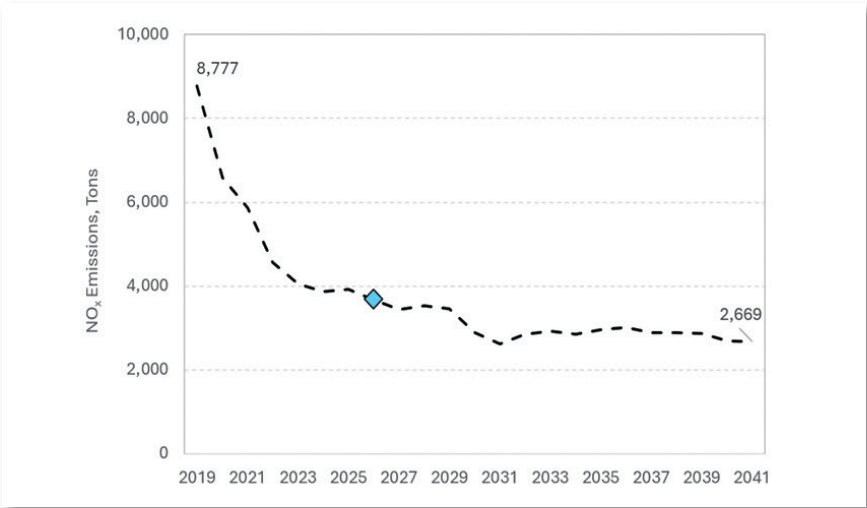
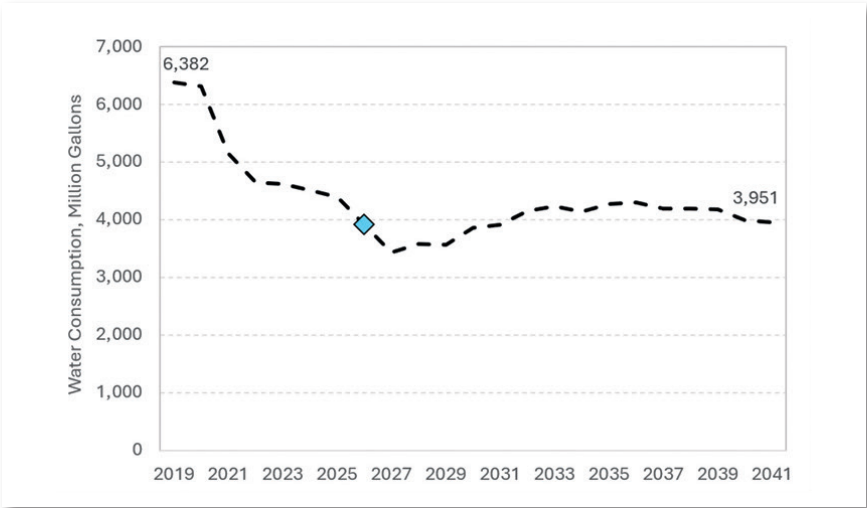


Figure 6.9 - LCTN Portfolio Water Usage

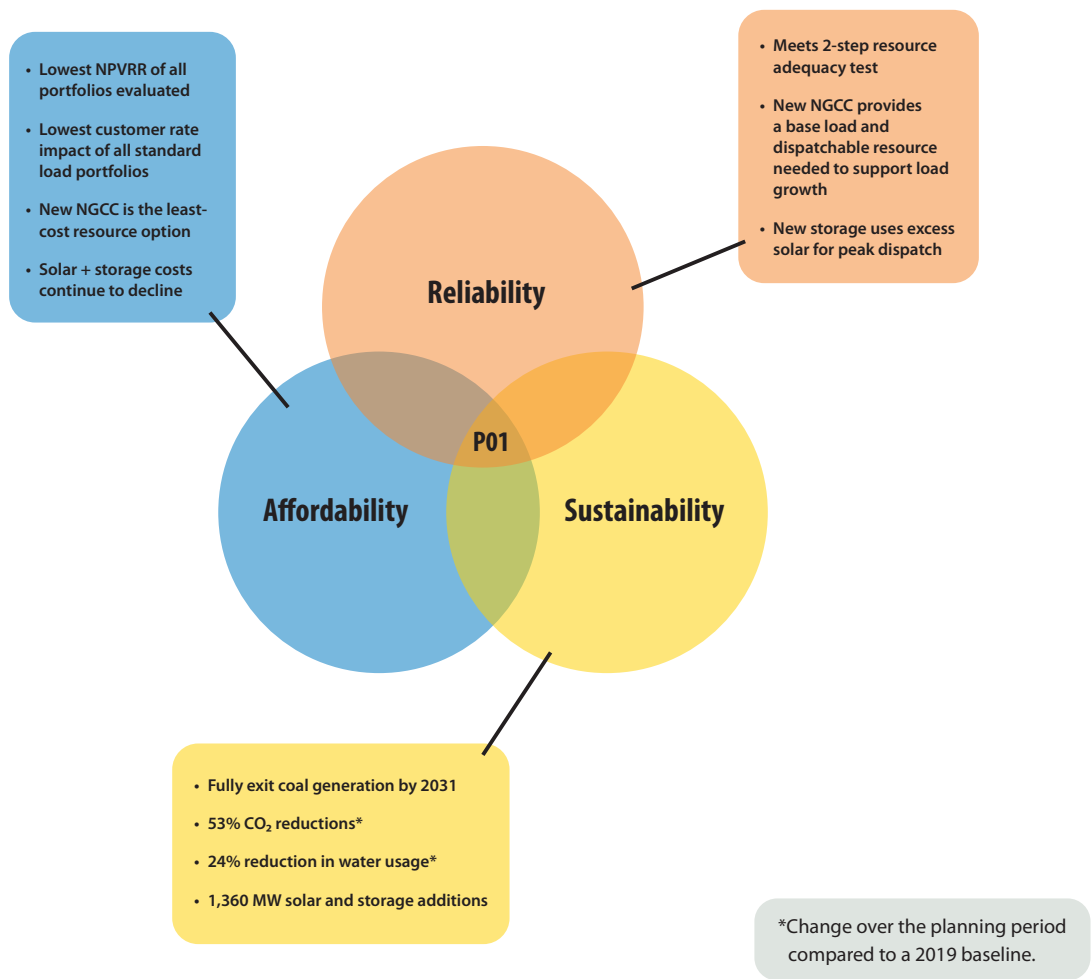


6.5. TEP’s Preferred Portfolio: Balanced Priorities

As discussed in section 3.2.1, TEP has a responsibility to provide power that is reliable, affordable, and sustainable. Achieving the correct balance between these guiding principles is essential for long-term planning, and depends on many factors including resource constraints, current and projected market conditions, economic outlooks, and technological breakthroughs.

Based on the modeling outcomes for current load projections, the P01 Least-Cost, Technology Neutral portfolio provides the best balance of reliability, affordability and sustainability, supporting each principle in concrete ways:

Figure 6.10 - Reliability, Affordability, and Sustainability



Section 7

FIVE-YEAR ACTION PLAN

Since the 2023 IRP, TEP has expanded its portfolio with approximately 760 MW of renewable and energy storage resources, including 260 MW of solar generation and 500 MW of 4hr battery storage, and has reduced CO₂ emissions from owned fossil-fueled generation by approximately 42% relative to 2019 levels.

With the results of this 2026 IRP, TEP will continue to pursue power that is reliable, affordable, and sustainable for all customers in its service territory. TEP has developed a five-year action plan based on the cost and load growth assumptions within this IRP. Under this plan, TEP will pursue new resources through future ASRFPs to monitor and validate resource costs, development timelines, and operational parameters prior to future decisions on acquisition. TEP's action plan also includes overseeing the items as outlined below.

TEP will monitor the development of Transwestern's Desert Southwest Expansion natural gas pipelines and its Springerville-Coronado Lateral natural gas pipeline, both projected to be in service in late 2029. The conversion of the Springerville Units 1 and 2 from coal to natural gas, projected in service prior to the summer of 2030, will begin in 2029. TEP will also oversee the completion of the Torch Winchester 80 MW solar plus 80 MW/320 MWh storage facility, set to be in service prior to the summer of 2027.

To ensure the deliverability of resources as outlined in the Company's Least-Cost, Technology Neutral portfolio, TEP plans to pursue the siting and development of new extra-high voltage transmission infrastructure to the east of the TEP service territory. These transmission resources will increase import capability and ease constraints on the transmission system.

TEP plans to enter SPP's Markets+ day ahead market in the fall of 2027, along with other Wave 1 participants. TEP will continue its engagement in the Markets+ stakeholder working groups and task forces to ensure market alignment with TEP's needs. TEP will also monitor resource adequacy standards established by WPP's WRAP to ensure compliance.

TEP recognizes that an IRP represents a snapshot based on a certain set of planning assumptions, and that these assumptions are subject to volatility and uncertainty. As TEP evaluates and refines its plans moving forward, the Company will analyze the impact of new changes to its assumptions before making final resource decisions. The Company will also engage with the Arizona Corporation Commission to communicate major changes to anticipated plans. TEP requests that the Commission acknowledge its 2026 IRP, and the associated actions herein, as provided in A.A.C. R14-2-704.B.

Section 8

APPENDICES

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Appendix A

RESPONSE TO RULES INDEX

Response to Rules Index (Resource Planning Rule A.A.C. R14-2-703)

Rule	Description	IRP Location
C	A load-serving entity shall, by April 1 of each even year, file with Docket Control a compilation of the following items of load data and analyses, which may include a reference to the last filing made under this subsection for each item for which there has been no change in forecast since the last filing:	
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;	See Appendix C
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; and	See Appendix C
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	See Section 4.2.1
D	A load-serving entity shall, by April 1 of each even year, file with Docket Control the following prospective analyses and plans, which shall compare a wide range of resource options and take into consideration expected duty cycles, cost projections, other analyses required under this Section, environmental impacts, and water consumption and may include a reference to the last filing made under this subsection for each item for which there has been no change since the last filing:	
D.1	A 15-year resource plan, providing for each year:	See 2026 IRP
D.1.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;	See Section 5 and Appendix B & C
D.1.b	Projected data for each of the items listed in subsection (B)(2), for the power supply system;	See Section 3.1.2 and Appendix B & C
D.1.c	The capital cost, construction time, and construction spending schedule for each generating unit expected to be new or refurbished during the period;	See Section 4.2.4 and Appendix C
D.1.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;	See Appendix C
D.1.e	If discontinuation, decommissioning, or mothballing of any power source or permanent derating of any generating facility is expected:	See Section 4.2.7
D.1.e.i	Identification of each power source or generating unit involved;	See Section 2.4, 4.2.7 and Appendix H
D.1.e.ii	The costs and spending schedule for each discontinuation, decommissioning, mothballing, or derating; and	See Section 2.4 and 4.2.7
D.1.e.iii	The reasons for each discontinuation, decommissioning, mothballing, or derating;	See Sections 2 and 6.3
D.1.f	The capital costs and operating and maintenance costs of all new or refurbished transmission and distribution facilities expected during the 15-year period;	See Appendix I
D.1.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; and	See Appendix I

Appendix A (cont.)

D.1.h	Cost analyses and cost projections;	See Appendix I
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;	See Section 4
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;	See Section 6 and Appendix C
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);	See Section 4.2.2 and Appendix B & J
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;	See Section 4.2.2 and Appendix B & J
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);	See Section 4.2.2 and Appendix B & J
D.7	Documentation of the analysis of the self generation under subsections (D)(4) through (6) ;	See Section 4.2.2 and Appendix B & J
D.8	A plan that considers using a wide range of resources and promotes fuel and technology diversity within its portfolio;	See Sections 4, 5 and 6
D.9	A calculation of the benefits of generation using renewable energy resources;	See Sections 4, 5 and 6
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;	See Sections 4, 5 and 6 and Appendix I
D.11	Analysis of integration costs for intermittent resources;	See Section 4.2
D.12	A plan to increase the efficiency of the load-serving entity's generation using fossil fuel;	See Section 6
D.13	Data to support technology choices for supply-side resources;	See Sections 4, 5 and 6 and Appendix C & K
D.14	A description of the demand management programs or measures included in the 15-year resource plan, including for each demand management program or measure:	See Sections 4.2.2 and Appendix J
D.14.a	How and when the program or measure will be implemented,	See Sections 4.2.2 and Appendix J
D.14.b	The projected participation rate by customer class for the program or measure;	See Sections 4.2.2 and Appendix J
D.14.c	The expected change in demand resulting from the program or measure;	See Sections 4.2.2 and Appendix J
D.14.d	The expected reductions in air emissions and water consumption attributable to the program or measure;	See Sections 4.2.2 and Appendix J
D.14.e	The expected societal benefits, societal costs, and cost-effectiveness of the program or measure	See Sections 4.2.2 and Appendix J
D.14.f	The expected life of the measure; and	See Sections 4.2.2 and Appendix J
D.14.g	The capital costs, operating costs, and maintenance costs of the measure;	See Sections 4.2.2 and Appendix J
D.15	For each demand management measure that was considered but rejected:	See Sections 4.2.2 and Appendix J
D.15.a	A description of the measure;	See Sections 4.2.2 and Appendix J
D.15.b	The estimated change in peak demand and energy consumption from the measure;	See Sections 4.2.2 and Appendix J
D.15.c	The estimated cost-effectiveness of the measure;	See Sections 4.2.2 and Appendix J
D.15.d	The capital costs, operating costs, and maintenance costs of the measure; and	See Sections 4.2.2 and Appendix J
D.15.e	The reasons for rejecting the measure; and	See Sections 4.2.2 and Appendix J
D.16	Analysis of future fuel supplies that are part of the resource plan;	See Sections 2.2 to 2.4, 3.1.2 and 4.2.5
D.17	A plan for reducing environmental impacts related to air emissions, solid waste, and other environmental factors, and for reducing water consumption.	See Section 6.4 and Appendix G
E	A load-serving entity shall, by April 1 of each even year, file with Docket Control a compilation of the following analyses and plan:	
E.1	Analyses to identify and assess errors, risks, and uncertainties in the following, completed using methods such as sensitivity analysis and probabilistic analysis:	See Sections 4.2.5, 5.3 and Appendix D
E.1.a	Demand forecasts;	See Sections 4.2.1, 5, and Appendix C

Appendix A (cont.)

E.1.b	The costs of demand management measures and power supply;	See Appendix I & J
E.1.c	The availability of sources of power;	See Section 3, 4, 5, 6 and Appendix E, H and K
E.1.d	The costs of compliance with existing and expected environmental regulations;	See Section 3.5 and Appendix G
E.1.e	Any analysis by the load-serving entity in anticipation of potential new or enhanced environmental regulations;	See Section 3.5, 5, 6 and Appendix G
E.1.f	Changes in fuel prices and availability;	See Section 4.2.5
E.1.g	Construction costs, capital costs, and operating costs; and	See Section 4.2.4 and Appendix C
E.1.h	Other factors the load-serving entity wishes to consider;	See Section 4
E.2	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; and	See Sections 2, 3, 4 and 6
E.3	A plan to manage the errors, risks, and uncertainties identified and analyzed in subsection (E)(1).	See Sections 2, 3, 4 and 6
F	A load-serving entity shall, by April 1 of each even year, file with Docket Control a 15-year resource plan that:	
F.1	Selects a portfolio of resources based upon comprehensive consideration of a wide range of supply- and demand-side options;	See Sections 4, 5 and 6
F.2	Will result in the load-serving entity's reliably serving the demand for electric energy services;	See Sections 2, 3, 4, 5 and 6
F.3	Will address the adverse environmental impacts of power production;	See Sections 3.5
F.4	Will include renewable energy resources so as to meet 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:	See Sections 4, 5 and 6
F.5	Will include distributed generation energy resources 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:	See Sections 4, 5, 6 and Appendix J
F.6	Will address energy efficiency so as to meet any requirements set in rule by the Commission;	See Sections 4, 5, 6 and Appendix J
F.7	Will effectively manage the uncertainty and risks associated with costs, environmental impacts, load forecasts, and other factors;	See Sections 4, 5, 6 and Appendix J
F.8	Will achieve a reasonable long-term total cost, taking into consideration the objectives set forth in subsections (F)(2)-(6) and the uncertainty of future costs; and	See Sections 4, 5, 6
F.9	Contains all of the following:	
F.9.a	A complete description and documentation of the plan, including supply and demand conditions, availability of transmission, costs, and discount rates utilized;	See Sections 4, 5, 6, Appendix I & J
F.9.b	A comprehensive, self-explanatory load and resources table summarizing the plan;	See Section 5.1
F.9.c	A brief executive summary;	See Section 1
F.9.d	An index to indicate where the responses to each filing requirement of these rules can be found; and	See Appendix A
F.9.e	Definitions of the terms used in the plan.	See Appendix L
G.1	An outline of the contents of the resource plan the load-serving entity is developing to be filed the following year as required under subsection (F);	See Contents and Appendix sections
G.2	The load-serving entity's method for assessing potential resources;	See Sections 3 and 4
G.3	The sources of the load-serving entity's current assumptions; and	See Sections 3 and 4
G.4	An outline of the timing and extent of public participation and advisory group meetings the load-serving entity intends to hold before completing and filing the resource plan.	See TEP website: https://www.tep.com/rpac/

Appendix A (cont.)

H.1	Includes a summary of actions to be taken on future resource acquisitions;	See Sections 3.2 and 7
H.2	Includes details on resource types, resources capacity, and resource timing; and	See Section 6.2
H.3	Covers the three-year period following the Commission's acknowledgment of the resource plan.	See Section 7
	Response to Rules: Other Compliance Requirements	
79589	Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc. shall include in future Integrated Resource Plans an analysis of a technology neutral 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.	See Section 5 and 6
79589	Tucson Electric Power Company shall include in future Integrated Resource Plans an analysis of a Balanced Portfolio with Natural Gas Combined Cycle (NGCC) as described in the letter dated August 23, 2024, filed in this docket. TEP shall include in its analysis a report on what actions it has taken, if any, to facilitate the development of cost-effective transmission and new pipeline upgrades needed for the Balanced Portfolio with NGCC.	See Sections 2.3, 5, 6 and 7
79589	Arizona Public Service Company, Tucson Electric Power Company and UNS Electric, Inc. include in the next IRP cycle an analysis of, at minimum, seven resource portfolios that are designed to evaluate the range of resource procurement actions.	See Section 5 and 6
79589	Arizona Public Service Company, Tucson Electric Power Company and UNS Electric, Inc. shall: provide modeling input and output files, for the preferred portfolio in the IRP filings to Staff and stakeholders who hold modeling licenses. Provide data in tabular form, similar to the D tables in APS's 2023 IRP, for the preferred portfolio they have modeled. Provide a robust inventory (candidate resource information and cost for each of the portfolios) listed in their IRPs.	See Appendix B and C
79589	Arizona Public Service Company, Tucson Electric Power Company and UNS Electric, Inc. shall include in future Integrated Resource Plans an analysis of cost savings and other benefits resulting from their participation in western regional markets. The analysis shall also include a discussion of how their participation in a real-time and/or day-ahead market has impacted their portfolio development and selection, and how market participation has impacted their reserve margin, resource adequacy, reliability during extreme weather events, transmission planning, and capacity needs.	See Section 3.4, 5.3 and Appendix F
79589	language in Decision No. 78499 that states "In future IRPs" be amended to "In the next IRP cycle", notwithstanding the foregoing, in all future Integrated Resource Plans APS, TEP and	See Sections 2, 3, 4 and 5
	UNSE shall discuss their natural gas price assumptions, the impact of those assumptions on resource acquisition decisions, and the implications of declining gas usage as the utilities resource mixes shift and shall continue to include capacity expansion modeling in their IRPs. Furthermore, in all future Integrated Resource Plans APS, TEP and UNSE shall closely monitor federal legislation relating to a carbon tax and discuss relevant impacts of any such legislation on the development of their Integrated Resource Plans.	
79589	Arizona Public Service, Tucson Electric Power Company and UNS Electric, Inc shall include in future IRPs portfolios which capture the benefits of joining a day-ahead market. Provide market enrollment assumptions in their preferred portfolios and specifically identify those assumptions in future IRPs. File ongoing, periodic reporting on activities relating to joining a day-ahead market, as well as metrics and other decision-making elements at a minimum semiannually, beginning November 1, 2024.	See Section 3.4, 5.3 and Appendix F
79589	Tucson Electric Power Company should consider the years 2031 and 2032 in its retirement analysis for Springerville Generating Station Unit 2.	See Sections 2.4, 5 and 6
79589	Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc. shall include a retirement analysis in future Integrated Resource Plans including specific estimated retirement dates for each resource. The retirement analysis shall include a dedicated and 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 due to the retirements. The retirement analysis shall discuss plans to replace retired capacity to ensure resource adequacy.	See Sections 2.4 and 4.2.7
79589	Arizona Public Service Company, Tucson Electric Power Company and UNS Electric, Inc. share base case input data and modeling information to the stakeholders at least 90 days before the LSEs final Integrated Resource Plans are due.	Section 3.1.3

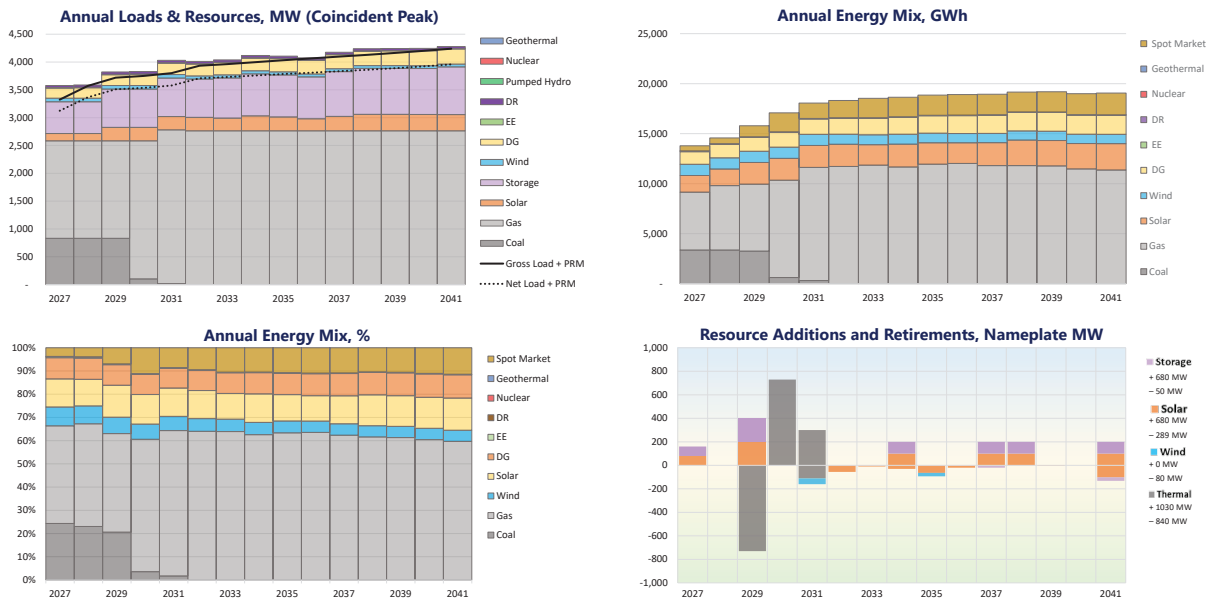
Appendix B

PORTFOLIO SUMMARY DASHBOARDS



Portfolio ID - P01
Portfolio Description - Technology Neutral

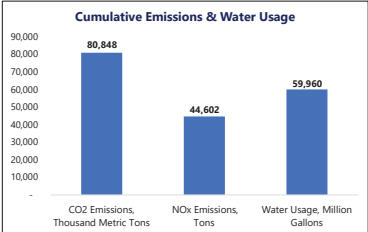
Loads & Resources Dashboard



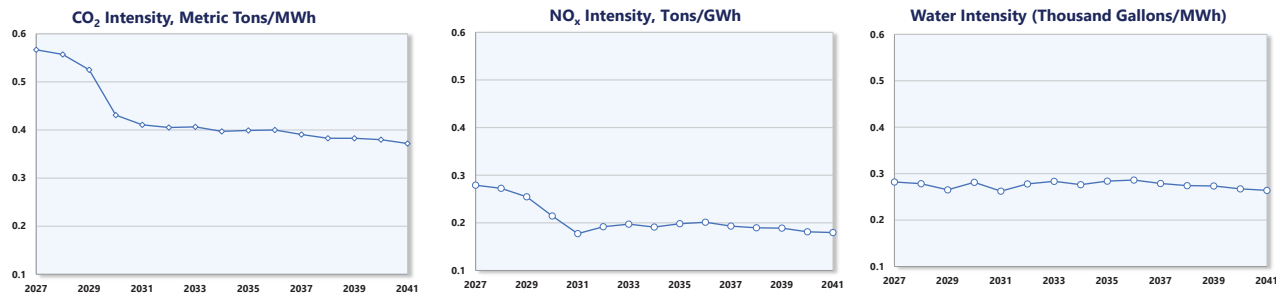
Annual Loads & Resources, MW	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Gross Load + PRIM	3,324	3,570	3,719	3,750	3,800	3,933	3,963	3,997	4,033	4,065	4,097	4,130	4,163	4,201	4,240
Net Load + PRIM	3,124	3,364	3,511	3,535	3,579	3,708	3,730	3,757	3,784	3,809	3,835	3,861	3,889	3,922	3,958
Coal	832	832	832	102	16	-	-	-	-	-	-	-	-	-	-
Gas	1,752	1,752	1,752	2,482	2,764	2,764	2,764	2,764	2,764	2,764	2,764	2,764	2,764	2,764	2,764
Wind	64	64	64	64	64	56	56	56	56	52	52	52	52	52	52
Solar	131	131	241	241	241	241	228	269	249	216	259	295	295	293	292
Storage	572	572	689	689	689	689	721	754	754	805	826	826	826	856	856
DG	181	187	193	200	206	214	221	229	237	245	252	258	263	268	273
EE	10	10	8	8	8	6	6	6	6	6	6	6	6	6	6
DR	37	42	43	43	42	42	42	41	41	40	39	39	38	37	36
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pumped Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Total NPVRR:	\$17,224,989
Fuel NPVRR:	\$5,689,871
Non-Fuel NPV:	\$11,535,118

Annual Loads & Resources, GWh	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Gross Energy	10,979	12,034	13,623	13,871	14,134	14,735	15,065	15,201	15,346	15,482	15,586	15,704	15,828	15,987	16,125
Coal	3,355	3,357	3,252	611	309	-	-	-	-	-	-	-	-	-	-
Gas	5,797	6,442	6,697	9,737	11,311	11,725	11,852	11,664	11,942	12,019	11,811	11,807	11,773	11,478	11,369
Wind	1,119	1,119	1,113	1,115	1,102	995	989	990	965	925	926	925	924	928	922
Solar	1,666	1,668	2,171	2,180	2,200	2,215	2,046	2,284	2,141	2,067	2,288	2,545	2,539	2,533	2,636
DG	1,260	1,333	1,398	1,478	1,542	1,603	1,655	1,701	1,737	1,790	1,819	1,853	1,883	1,912	1,909
EE	75	75	52	50	50	41	40	40	40	39	40	40	40	40	40
DR	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Spot Market	516	573	1,101	1,906	1,539	1,732	1,954	1,960	2,024	2,071	2,056	1,990	2,034	2,097	2,181



Environmental Dashboard



	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Percent CO ₂ Reductions from 2019 Levels	48%	45%	45%	53%	51%	51%	50%	51%	50%	50%	51%	51%	51%	52%	53%

Appendix B (cont.)



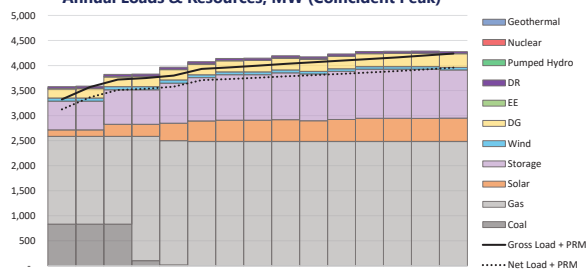
2026 Integrated Resource Plan

Portfolio ID - P02

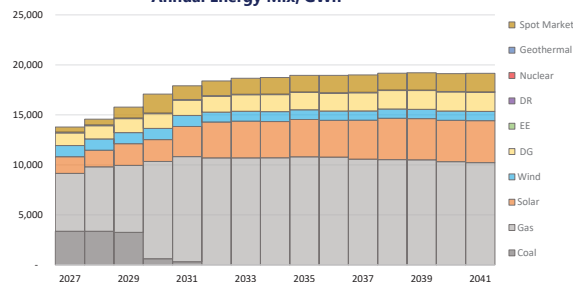
Portfolio Description - Clean Energy SGS Repower

Loads & Resources Dashboard

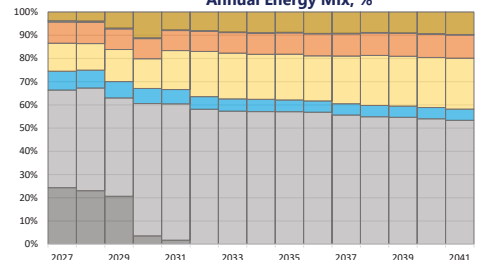
Annual Loads & Resources, MW (Coincident Peak)



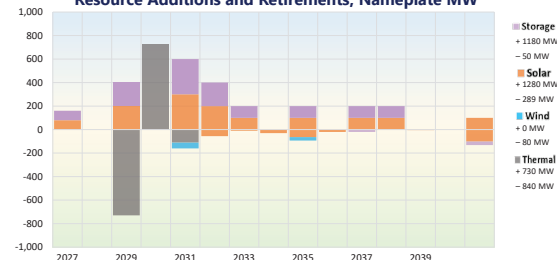
Annual Energy Mix, GWh



Annual Energy Mix, %



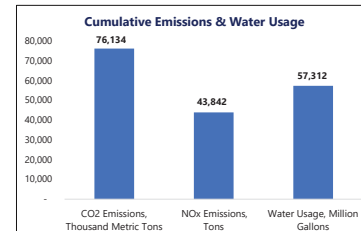
Resource Additions and Retirements, Nameplate MW



Annual Loads & Resources, MW	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Gross Load + PRM	3,324	3,570	3,719	3,750	3,800	3,933	3,963	3,997	4,033	4,065	4,097	4,130	4,163	4,201	4,240
Net Load + PRM	3,124	3,364	3,511	3,535	3,579	3,708	3,730	3,757	3,784	3,809	3,835	3,861	3,889	3,922	3,958
Coal	832	832	832	102	16	-	-	-	-	-	-	-	-	-	-
Gas	1,752	1,752	1,752	2,482	2,482	2,482	2,482	2,482	2,482	2,482	2,482	2,482	2,482	2,482	2,482
Wind	64	64	64	64	64	56	56	56	56	52	52	52	52	52	52
Solar	131	131	241	241	348	410	426	426	436	414	441	464	464	463	465
Storage	572	572	689	689	800	867	909	909	936	959	980	980	980	980	963
DG	181	187	193	200	206	214	221	229	237	245	252	258	263	268	273
EE	10	10	8	8	8	6	6	6	6	6	6	6	6	6	6
DR	37	42	43	43	42	42	42	41	41	40	39	39	38	37	36
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pumped Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

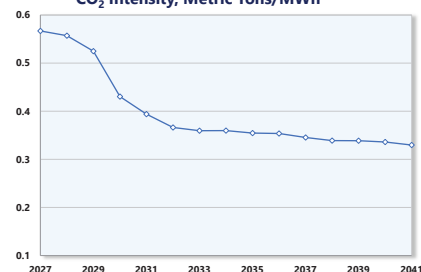
Total NPVRR: \$17,483,838
Fuel NPVRR: \$5,412,393
Non-Fuel NI: \$12,071,445

Annual Loads & Resources, GWh	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Gross Energy	13,789	14,568	15,779	17,084	17,911	18,396	18,665	18,740	18,948	18,953	18,997	19,171	19,205	19,124	19,153
Coal	3,356	3,358	3,253	611	311	-	-	-	-	-	-	-	-	-	-
Gas	5,795	6,442	6,687	9,736	10,517	10,698	10,693	10,703	10,808	10,770	10,569	10,526	10,499	10,326	10,220
Wind	1,119	1,120	1,113	1,116	1,102	995	989	990	965	925	926	925	925	929	922
Solar	1,665	1,667	2,176	2,185	3,009	3,582	3,675	3,632	3,732	3,680	3,895	4,132	4,124	4,128	4,203
DG	1,260	1,333	1,398	1,478	1,542	1,603	1,655	1,701	1,737	1,790	1,819	1,853	1,883	1,912	1,909
EE	75	75	52	50	50	41	40	40	39	40	40	40	40	40	40
DR	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Spot Market	518	573	1,099	1,906	1,380	1,476	1,612	1,672	1,663	1,748	1,748	1,694	1,733	1,787	1,857

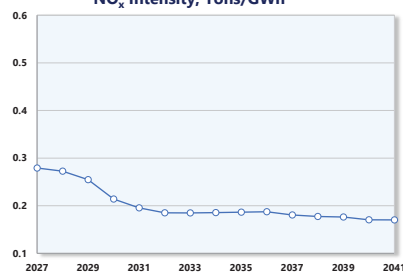


Environmental Dashboard

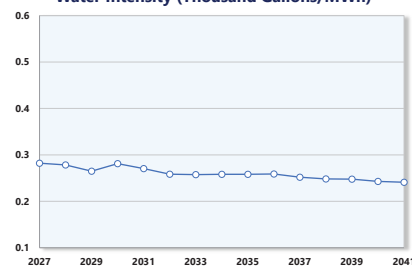
CO₂ Intensity, Metric Tons/MWh



NO_x Intensity, Tons/GWh



Water Intensity (Thousand Gallons/MWh)

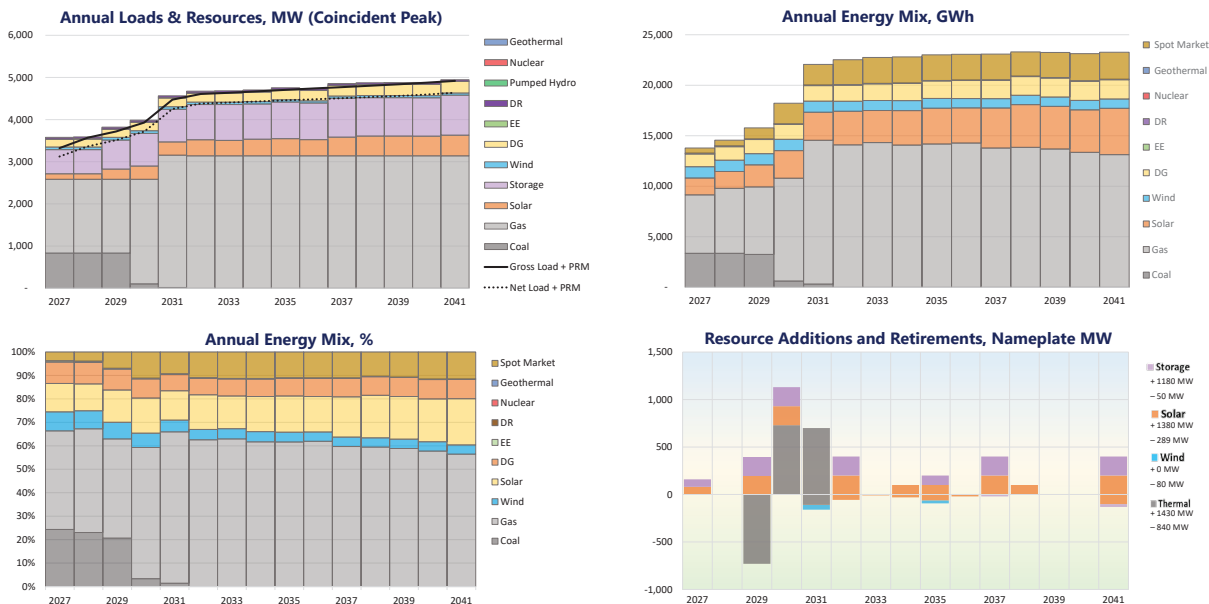


	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Percent CO ₂ Reductions from 2019 Levels	48%	45%	45%	53%	53%	55%	55%	55%	54%	54%	55%	55%	56%	56%	57%



Portfolio ID - P03
Portfolio Description - High Load Factor Customer Growth - Technology Neutral

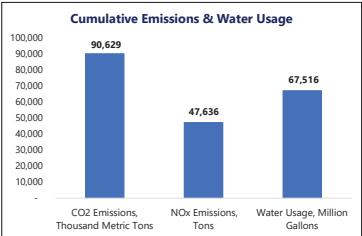
Loads & Resources Dashboard



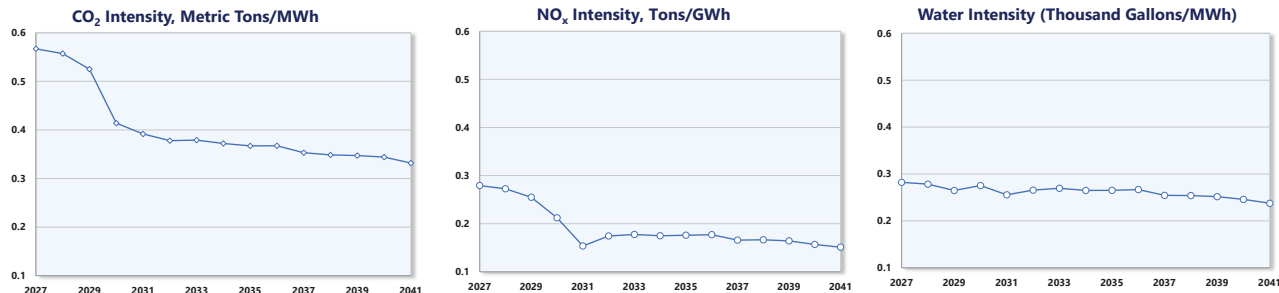
Annual Loads & Resources, MW	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Gross Load + PRM	3,324	3,570	3,719	3,930	4,474	4,607	4,636	4,671	4,706	4,738	4,771	4,803	4,837	4,875	4,919
Net Load + PRM	3,124	3,364	3,511	3,715	4,252	4,382	4,404	4,431	4,458	4,482	4,508	4,535	4,562	4,596	4,637
Coal	832	832	832	102	16	-	-	-	-	-	-	-	-	-	-
Gas	1,752	1,752	1,752	2,482	3,140	3,140	3,140	3,140	3,140	3,140	3,140	3,140	3,140	3,140	3,140
Wind	64	64	64	64	64	56	56	56	56	52	52	52	52	52	52
Solar	131	131	241	315	315	382	387	395	409	386	444	469	469	467	490
Storage	572	572	689	772	772	836	851	836	867	867	924	910	910	910	951
DG	181	187	193	200	206	214	221	229	237	245	252	258	263	268	273
EE	10	10	8	8	8	6	6	6	6	6	6	6	6	6	6
DR	37	42	43	43	42	42	42	41	41	40	39	39	38	37	36
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pumped Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Total NPVRR:	\$19,540,745
Fuel NPVRR:	\$6,431,668
Non-Fuel NF	\$13,109,077

Annual Loads & Resources, GWh	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Gross Energy	10,979	12,034	13,623	14,991	18,232	19,262	19,579	19,716	19,861	20,009	20,101	20,219	20,342	20,514	20,690
Coal	3,358	3,357	3,253	611	311	14,096	14,321	14,073	14,183	14,277	13,788	13,855	13,692	13,353	13,135
Gas	5,792	6,441	6,684	10,188	14,244	14,096	14,321	14,073	14,183	14,277	13,788	13,855	13,692	13,353	13,135
Wind	1,119	1,120	1,114	1,116	1,101	995	990	991	966	925	925	925	925	929	923
Solar	1,666	1,668	2,177	2,733	2,768	3,326	3,174	3,413	3,543	3,482	3,962	4,220	4,218	4,213	4,580
DG	1,260	1,333	1,398	1,478	1,542	1,603	1,655	1,701	1,737	1,790	1,819	1,853	1,883	1,912	1,909
EE	75	75	52	50	50	41	40	40	40	39	40	40	40	40	40
DR	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Spot Market	516	573	1,101	2,041	2,049	2,465	2,571	2,584	2,536	2,547	2,548	2,409	2,489	2,674	2,678



Environmental Dashboard



Percent CO2 Reductions from 2019 Levels	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
	48%	45%	45%	51%	40%	42%	41%	42%	42%	41%	44%	43%	44%	46%	46%

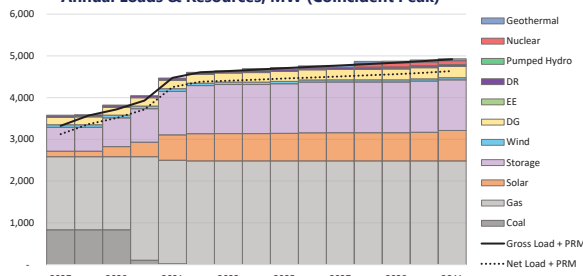


Portfolio ID - P04

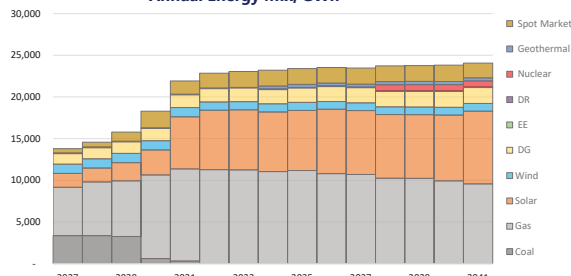
Portfolio Description - High Load Factor Customer Growth - Clean Energy

Loads & Resources Dashboard

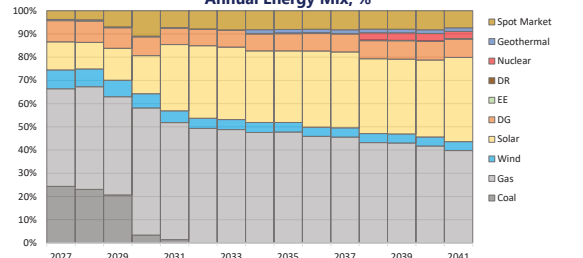
Annual Loads & Resources, MW (Coincident Peak)



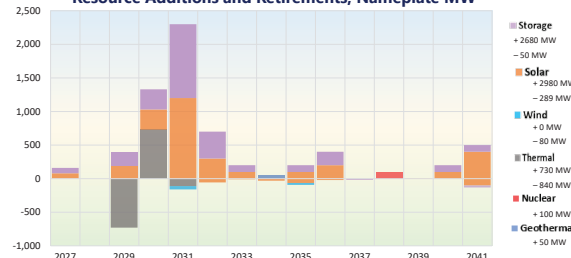
Annual Energy Mix, GWh



Annual Energy Mix, %



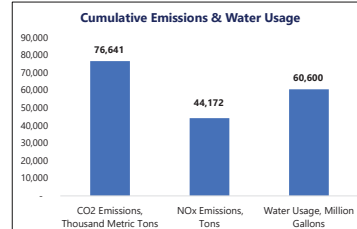
Resource Additions and Retirements, Nameplate MW



Annual Loads & Resources, MW	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Gross Load + PRM	3,324	3,570	3,719	3,930	4,474	4,607	4,636	4,671	4,706	4,738	4,771	4,803	4,837	4,875	4,919
Net Load + PRM	3,124	3,364	3,511	3,715	4,252	4,382	4,404	4,431	4,458	4,482	4,508	4,535	4,562	4,596	4,637
Coal	832	832	832	102	16	-	-	-	-	-	-	-	-	-	-
Gas	1,752	1,752	1,752	2,482	2,482	2,482	2,482	2,482	2,482	2,482	2,482	2,482	2,482	2,482	2,482
Wind	64	64	64	64	64	56	56	56	56	52	52	52	52	52	52
Solar	131	131	241	348	609	652	657	657	661	674	677	677	677	687	732
Storage	572	572	689	800	1,043	1,154	1,176	1,176	1,189	1,215	1,215	1,215	1,228	1,228	1,211
DG	181	187	193	200	206	214	221	229	237	245	252	258	263	268	273
EE	10	10	8	8	8	6	6	6	6	6	6	6	6	6	6
DR	37	42	43	43	42	42	42	41	41	40	39	39	38	37	36
Nuclear	-	-	-	-	-	-	-	-	-	-	-	94	94	94	94
Pumped Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Geothermal	-	-	-	-	-	-	-	-	47	47	47	47	47	47	47

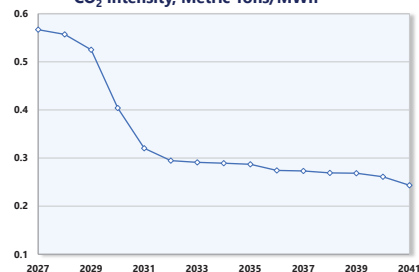
Total NPVRR:	\$20,745,606
Fuel NPVRR:	\$5,541,703
Non-Fuel NI	\$15,203,903

Annual Loads & Resources, GWh	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Gross Energy	10,979	12,034	13,623	14,991	18,232	19,262	19,579	19,716	19,861	20,009	20,101	20,219	20,342	20,514	20,690
Coal	3,356	3,358	3,254	611	309	-	-	-	-	-	-	-	-	-	-
Gas	5,794	6,439	6,683	10,025	11,052	11,272	11,255	11,041	11,169	10,799	10,695	10,246	10,222	9,929	9,571
Wind	1,119	1,119	1,113	1,116	1,102	995	989	991	966	925	927	925	924	929	923
Solar	1,666	1,667	2,174	2,998	6,259	7,135	7,196	7,151	7,215	7,726	7,674	7,639	7,650	7,894	8,720
DG	1,260	1,333	1,398	1,478	1,542	1,603	1,655	1,701	1,737	1,790	1,819	1,853	1,883	1,912	1,909
EE	75	75	52	50	50	41	40	40	40	39	40	40	40	40	40
DR	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2
Nuclear	-	-	-	-	-	-	-	-	-	-	-	761	762	767	750
Geothermal	-	-	-	-	-	-	-	383	378	376	376	377	376	377	371
Spot Market	517	578	1,105	2,010	1,600	1,803	1,920	1,896	1,892	1,877	1,929	1,879	1,902	1,959	1,773

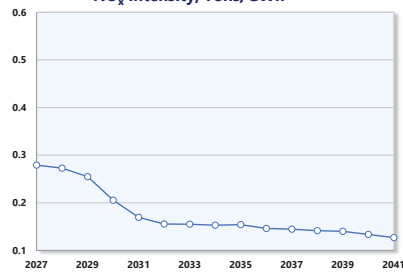


Environmental Dashboard

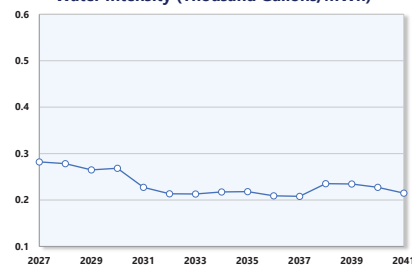
CO₂ Intensity, Metric Tons/MWh



NO_x Intensity, Tons/GWh



Water Intensity (Thousand Gallons/MWh)

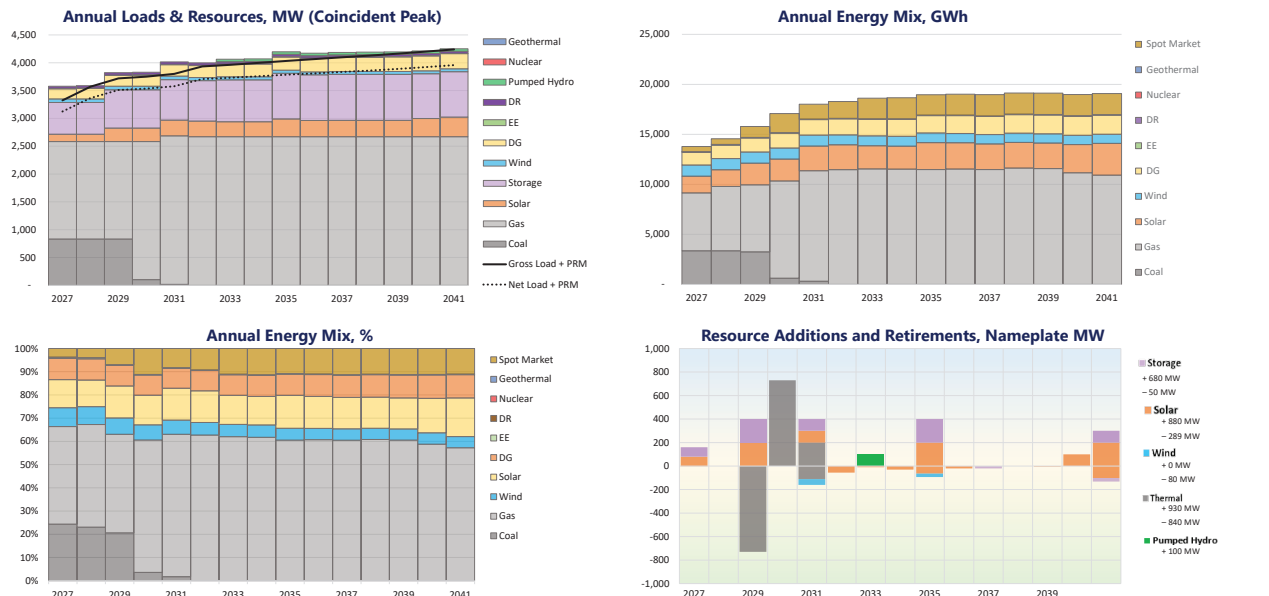


	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Percent CO ₂ Reductions from 2019 Levels	48%	45%	45%	52%	50%	52%	52%	53%	53%	54%	55%	57%	57%	58%	59%



Portfolio ID - P05
Portfolio Description - Pumped Hydro

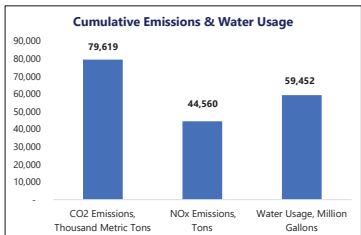
Loads & Resources Dashboard



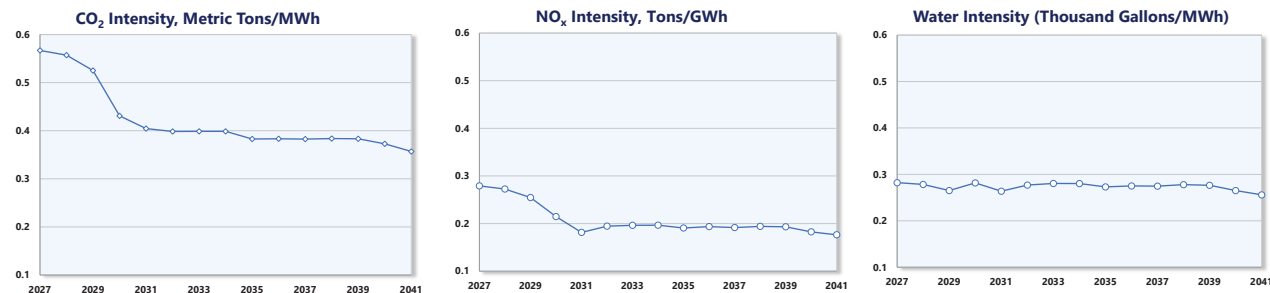
Annual Loads & Resources, MW	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Gross Load + PRM	3,324	3,570	3,719	3,750	3,800	3,933	3,963	3,997	4,033	4,065	4,097	4,130	4,163	4,201	4,240
Net Load + PRM	3,124	3,364	3,511	3,535	3,579	3,708	3,730	3,757	3,784	3,809	3,835	3,861	3,889	3,922	3,958
Coal	832	832	832	102	16	-	-	-	-	-	-	-	-	-	-
Gas	1,752	1,752	1,752	2,482	2,670	2,670	2,670	2,670	2,670	2,670	2,670	2,670	2,670	2,670	2,670
Wind	64	64	64	64	64	56	56	56	56	52	52	52	52	52	52
Solar	131	131	241	241	282	282	269	269	319	292	295	295	295	327	353
Storage	572	572	689	689	727	727	754	754	821	821	826	826	826	806	816
DG	181	187	193	200	206	214	221	229	237	245	252	258	263	268	273
EE	10	10	8	8	8	6	6	6	6	6	6	6	6	6	6
DR	37	42	43	43	42	42	42	41	41	40	39	39	38	37	36
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pumped Hydro	-	-	-	-	-	-	46	46	46	46	46	46	46	46	46
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Annual Loads & Resources, GWh	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Gross Energy	10,979	12,034	13,623	13,871	14,134	14,735	15,065	15,201	15,346	15,482	15,586	15,704	15,828	15,987	16,125
Coal	3,357	3,357	3,252	611	310	-	-	-	-	-	-	-	-	-	-
Gas	5,794	6,440	6,698	9,737	11,050	11,467	11,543	11,526	11,484	11,542	11,479	11,638	11,575	11,164	10,921
Wind	1,119	1,119	1,113	1,115	1,101	995	989	990	965	925	926	924	924	929	922
Solar	1,666	1,667	2,172	2,178	2,470	2,488	2,323	2,292	2,689	2,624	2,571	2,559	2,557	2,815	3,174
DG	1,260	1,333	1,398	1,478	1,542	1,603	1,655	1,701	1,737	1,790	1,819	1,853	1,883	1,912	1,909
EE	75	75	52	50	41	40	40	40	40	39	40	40	40	40	40
DR	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Spot Market	516	575	1,099	1,910	1,490	1,693	2,063	2,114	2,052	2,091	2,136	2,119	2,145	2,125	2,108

Total NPVRR:	\$17,388,185
Fuel NPVRR:	\$5,650,354
Non-Fuel NI	\$11,737,831



Environmental Dashboard

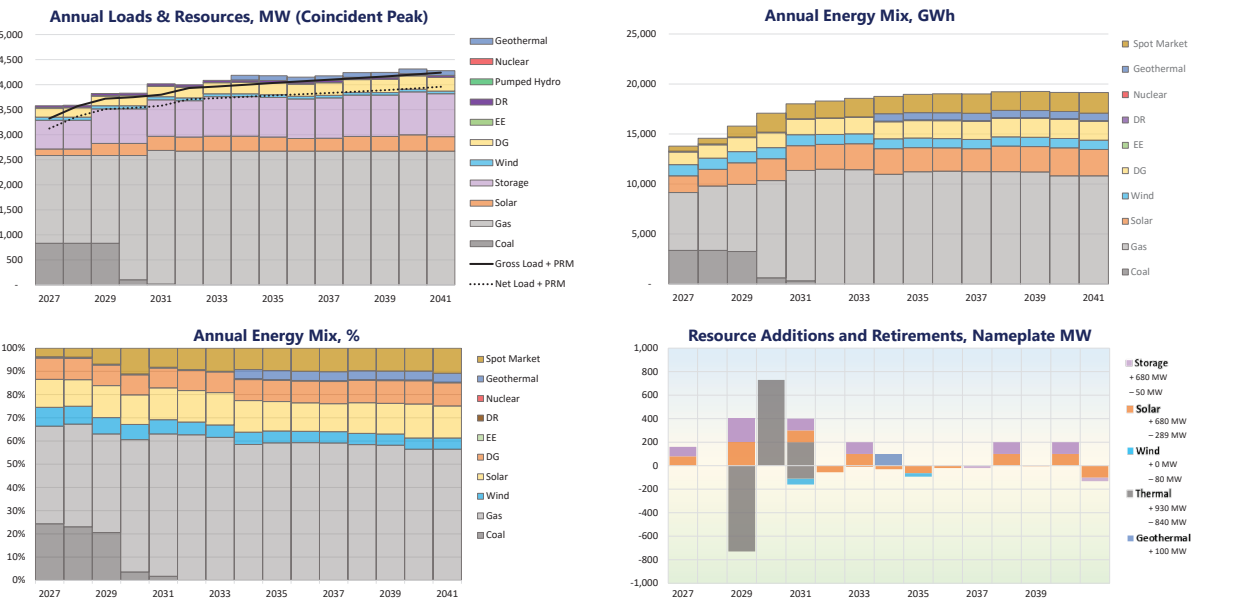


	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Percent CO ₂ Reductions from 2019 Levels	48%	45%	45%	53%	52%	52%	52%	52%	52%	52%	52%	51%	51%	53%	54%



Portfolio ID - P06
Portfolio Description - Geothermal

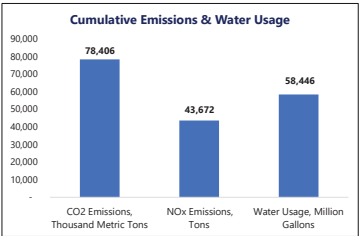
Loads & Resources Dashboard



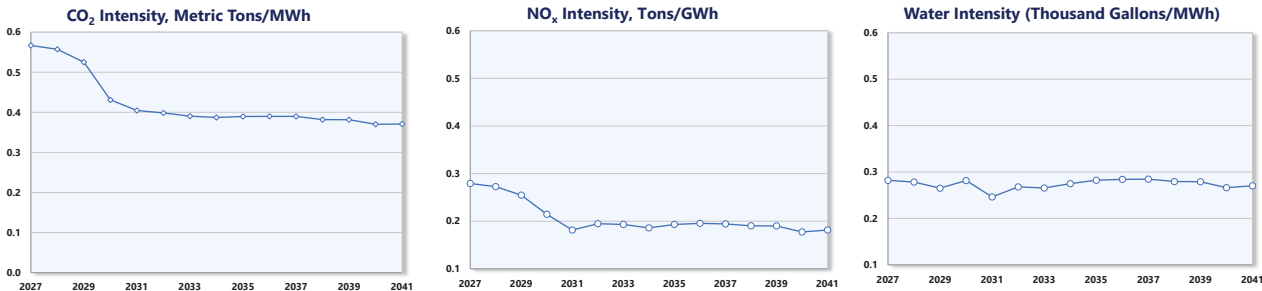
Annual Loads & Resources, MW	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Gross Load + PRM	3,324	3,570	3,719	3,750	3,800	3,933	3,963	3,997	4,033	4,065	4,097	4,130	4,163	4,201	4,240
Net Load + PRM	3,124	3,364	3,511	3,535	3,579	3,708	3,730	3,757	3,784	3,809	3,835	3,861	3,889	3,922	3,958
Coal	832	832	832	102	16	-	-	-	-	-	-	-	-	-	-
Gas	1,752	1,752	1,752	2,482	2,670	2,670	2,670	2,670	2,670	2,670	2,670	2,670	2,670	2,670	2,670
Wind	64	64	64	64	64	56	56	56	56	52	52	52	52	52	52
Solar	131	131	241	241	282	282	300	300	282	254	259	295	295	328	292
Storage	572	572	689	689	727	727	791	791	791	791	805	826	826	857	856
DG	181	187	193	200	206	214	221	229	237	245	252	258	263	268	273
EE	10	10	8	8	8	6	6	6	6	6	6	6	6	6	6
DR	37	42	43	43	42	42	42	41	41	40	39	39	38	37	36
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pumped Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Geothermal	-	-	-	-	-	-	-	-	94	94	94	94	94	94	94

Annual Loads & Resources, GWh	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Gross Energy	10,979	12,034	13,623	13,871	14,134	14,735	15,065	15,201	15,346	15,482	15,586	15,704	15,828	15,987	16,125
Coal	3,356	3,356	3,253	611	310	-	-	-	-	-	-	-	-	-	-
Gas	5,793	6,443	6,698	9,736	11,048	11,470	11,429	10,970	11,225	11,275	11,238	11,239	11,202	10,813	10,815
Wind	1,119	1,119	1,114	1,115	1,102	995	990	990	965	925	926	924	924	928	922
Solar	1,666	1,667	2,170	2,178	2,470	2,489	2,591	2,556	2,408	2,336	2,288	2,544	2,544	2,807	2,637
DG	1,260	1,333	1,398	1,478	1,542	1,603	1,655	1,701	1,737	1,790	1,819	1,853	1,883	1,912	1,909
EE	75	75	52	50	50	41	40	40	40	39	40	40	40	40	40
DR	1	1	1	1	1	1	1	1	1	1	1	2	2	2	2
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Geothermal	-	-	-	-	-	-	-	-	765	756	759	758	754	751	749
Spot Market	518	574	1,098	1,911	1,493	1,696	1,860	1,732	1,830	1,894	1,933	1,871	1,906	1,898	2,072

Total NPVRR: \$17,378,151
Fuel NPVRR: \$5,537,978
Non-Fuel NF: \$11,840,173



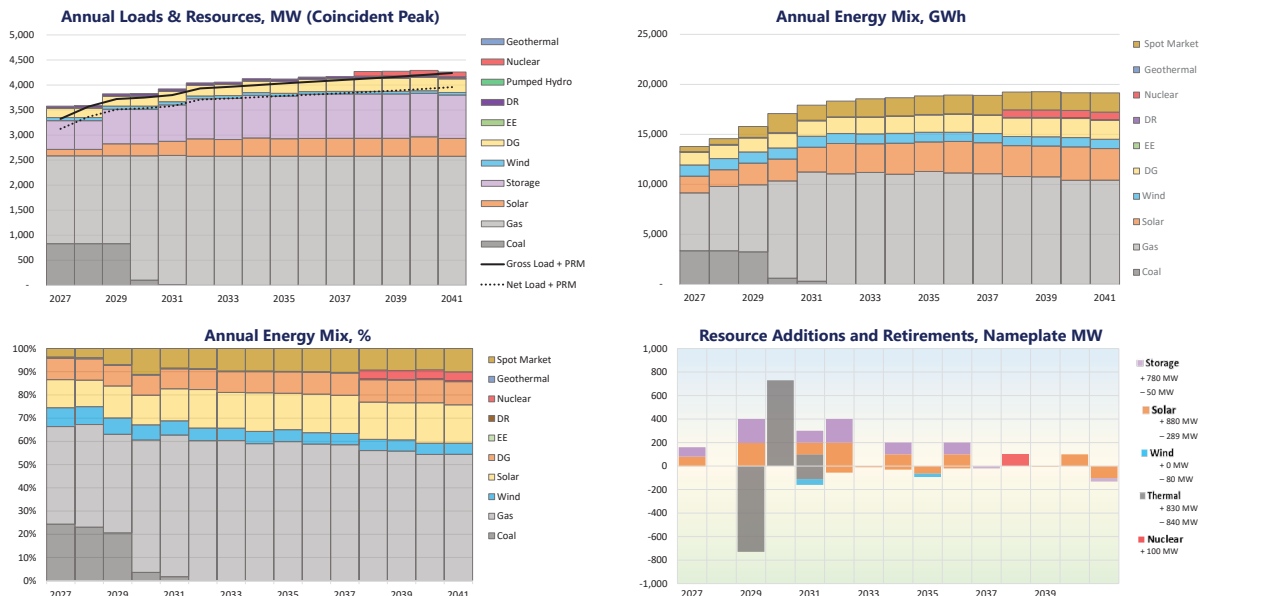
Environmental Dashboard



	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Percent CO2 Reductions from 2019 Levels	48%	45%	45%	53%	52%	52%	52%	54%	53%	53%	53%	53%	53%	53%	55%

Portfolio ID - P07
Portfolio Description - Nuclear

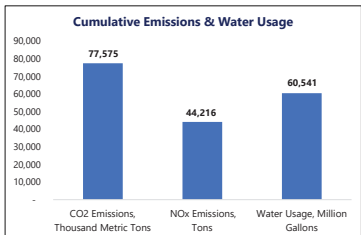
Loads & Resources Dashboard



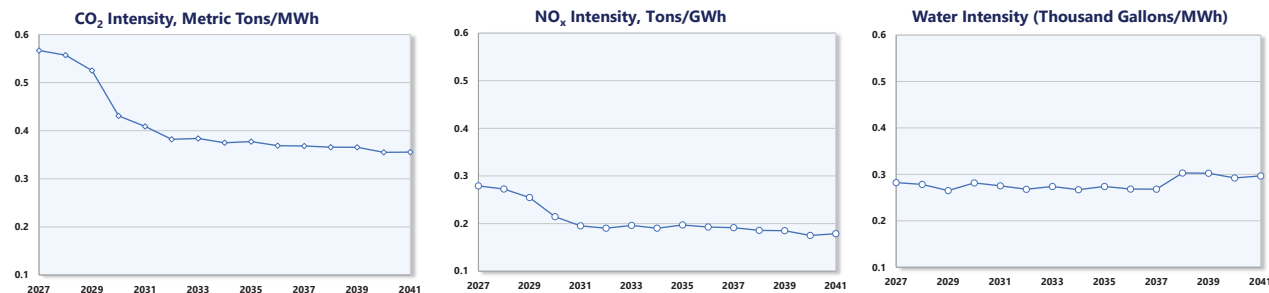
Annual Loads & Resources, MW	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Gross Load + PRM	3,324	3,570	3,719	3,750	3,800	3,933	3,963	3,997	4,033	4,065	4,097	4,130	4,163	4,201	4,240
Net Load + PRM	3,124	3,364	3,511	3,535	3,579	3,708	3,730	3,757	3,784	3,809	3,835	3,861	3,889	3,922	3,958
Coal	832	832	832	102	16	-	-	-	-	-	-	-	-	-	-
Gas	1,752	1,752	1,752	2,482	2,576	2,576	2,576	2,576	2,576	2,576	2,576	2,576	2,576	2,576	2,576
Wind	64	64	64	64	64	56	56	56	56	52	52	52	52	52	52
Solar	131	131	241	241	282	348	336	367	351	358	360	360	360	389	358
Storage	572	572	689	689	727	800	821	851	851	883	885	885	885	870	865
DG	181	187	193	200	206	214	221	229	237	245	252	258	263	268	273
EE	10	10	8	8	8	6	6	6	6	6	6	6	6	6	6
DR	37	42	43	43	42	42	42	41	41	40	39	39	38	37	36
Nuclear	-	-	-	-	-	-	-	-	-	-	-	94	94	94	94
Pumped Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Annual Loads & Resources, GWh	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Gross Energy	10,979	12,034	13,623	13,871	14,134	14,735	15,065	15,201	15,346	15,482	15,586	15,704	15,828	15,987	16,125
Coal	3,357	3,356	3,253	611	311	-	-	-	-	-	-	-	-	-	-
Gas	5,795	6,441	6,698	9,737	10,924	11,056	11,192	11,013	11,289	11,138	11,061	10,780	10,751	10,412	10,414
Wind	1,119	1,119	1,113	1,116	1,101	995	989	990	965	924	926	924	924	929	922
Solar	1,665	1,666	2,172	2,176	2,472	3,036	2,861	3,100	2,951	3,149	3,097	3,087	3,082	3,335	3,166
DG	1,260	1,333	1,398	1,478	1,542	1,603	1,655	1,701	1,737	1,790	1,819	1,853	1,883	1,912	1,909
EE	75	75	52	50	50	41	40	40	40	39	40	40	40	40	40
DR	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2
Nuclear	-	-	-	-	-	-	-	-	-	-	-	758	758	761	761
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Spot Market	515	578	1,100	1,911	1,518	1,596	1,812	1,819	1,861	1,890	1,956	1,786	1,823	1,762	1,929

Total NPVRR:	\$17,410,526
Fuel NPVRR:	\$5,544,776
Non-Fuel NI	\$11,865,749



Environmental Dashboard



	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Percent CO ₂ Reductions from 2019 Levels	48%	45%	45%	53%	51%	53%	53%	53%	52%	53%	53%	55%	55%	56%	56%

DETAILED BASE CASE DATA

Appendix C (cont.)

ATTACHMENT C.1(B): ENERGY CONSUMPTION BY MONTH AND CUSTOMER CLASS

Energy Consumption (MWh)													
Year: 2027	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Residential	264,320	220,157	206,545	219,491	324,107	475,155	547,578	506,556	421,329	283,495	209,353	251,906	3,929,994
Commercial	141,535	124,025	133,922	143,599	166,733	193,419	225,569	216,015	195,101	169,902	138,403	138,782	1,987,006
Industrial	156,024	145,155	153,016	163,449	172,824	185,109	205,226	208,031	189,142	180,635	154,679	151,441	2,064,732
Mining	89,813	83,985	94,621	83,527	85,272	80,684	93,379	93,067	87,975	94,139	92,851	96,210	1,075,523
Other	1,346	1,185	1,222	1,128	1,094	1,063	1,111	1,154	1,149	1,282	1,283	1,328	14,345
Total Net Energy Consumption	653,038	574,507	589,327	611,193	750,030	935,431	1,072,863	1,024,824	894,697	729,453	596,569	639,668	9,071,601
Firm Wholesale	74,439	64,913	48,189	41,767	18,600	18,000	18,600	18,600	18,000	18,600	28,800	29,760	398,268
System Losses	70,066	57,162	62,601	64,652	86,868	108,039	125,240	115,456	101,770	80,458	61,786	68,208	1,002,308
Distributed Generation	85,727	89,728	108,017	126,743	123,187	99,503	104,930	98,383	117,333	113,177	99,631	93,181	1,259,541
Energy Efficiency	5,196	4,410	4,874	5,066	6,199	8,046	10,017	9,338	6,840	5,262	4,538	5,052	74,837
Total Gross Energy Consumption	888,467	790,719	813,008	849,422	984,884	1,169,019	1,331,651	1,266,601	1,138,641	946,950	791,324	835,870	11,806,555

Energy Consumption (MWh)													
Year: 2028	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Residential	265,822	222,314	207,946	221,735	327,778	479,807	553,046	511,282	424,995	286,637	212,116	253,550	3,967,028
Commercial	142,927	125,359	135,006	144,644	167,943	194,417	226,861	217,524	196,760	171,974	140,622	140,998	2,005,035
Industrial	168,278	158,720	184,390	195,051	223,356	236,340	275,162	297,199	292,850	288,202	279,825	286,099	2,885,472
Mining	92,830	89,821	97,786	87,073	88,902	84,328	98,482	97,987	92,893	98,093	96,767	100,344	1,125,306
Other	1,341	1,172	1,213	1,124	1,088	1,060	1,119	1,160	1,147	1,290	1,291	1,339	14,344
Total Net Energy Consumption	671,198	597,386	626,340	649,626	809,067	995,952	1,154,670	1,125,152	1,008,647	846,196	730,621	782,331	9,997,184
Firm Wholesale	0	0	0	0	0	0	0	0	0	0	0	0	0
System Losses	71,808	59,410	66,065	68,265	93,120	114,564	134,223	126,031	113,814	92,144	74,052	81,761	1,095,258
Distributed Generation	91,021	98,677	115,413	133,335	129,671	104,242	110,534	105,693	123,118	120,091	103,424	97,285	1,332,505
Energy Efficiency	5,184	4,522	4,841	4,963	6,271	8,002	10,089	9,458	6,898	5,167	4,504	5,001	74,898
Total Gross Energy Consumption	839,210	759,995	812,659	856,190	1,038,129	1,222,759	1,409,516	1,366,333	1,252,476	1,063,599	912,601	966,378	12,499,845

Energy Consumption (MWh)													
Year: 2029	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Residential	267,055	224,148	208,925	223,481	330,968	484,222	558,293	515,748	428,406	289,383	214,437	254,663	3,999,728
Commercial	145,142	127,603	137,049	146,599	170,006	196,189	228,828	219,607	198,882	174,336	142,968	143,170	2,030,380
Industrial	307,516	308,978	315,016	342,318	358,887	375,998	389,571	398,928	380,061	366,138	345,002	333,722	4,222,135
Mining	96,853	90,376	102,005	90,695	92,551	88,081	101,471	101,014	95,577	100,325	98,843	102,495	1,160,286
Other	1,349	1,185	1,224	1,137	1,094	1,066	1,116	1,156	1,144	1,287	1,287	1,333	14,377
Total Net Energy Consumption	817,916	752,290	764,219	804,230	953,506	1,145,557	1,279,278	1,236,453	1,104,069	931,468	802,537	835,385	11,426,906
Firm Wholesale	0	0	0	0	0	0	0	0	0	0	0	0	0
System Losses	85,878	72,771	78,971	82,798	108,416	130,691	147,905	137,762	123,900	100,680	80,632	86,802	1,237,206
Distributed Generation	91,520	97,262	125,291	140,433	136,252	110,119	115,941	112,841	129,950	126,375	108,652	103,299	1,397,933
Energy Efficiency	3,191	2,696	2,967	3,075	4,296	5,976	7,969	7,418	5,049	3,284	2,769	3,144	51,834
Total Gross Energy Consumption	998,504	925,019	971,447	1,030,535	1,202,470	1,392,343	1,551,093	1,494,474	1,362,968	1,161,807	994,590	1,028,629	14,113,879

Energy Consumption (MWh)													
Year: 2030	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Residential	267,774	225,398	209,281	224,770	333,766	488,261	563,093	519,878	431,542	292,009	216,561	255,987	4,028,321
Commercial	148,279	130,772	139,992	149,456	173,066	198,966	231,821	222,827	202,214	178,094	146,878	146,999	2,069,362
Industrial	350,502	339,642	328,420	356,980	359,630	376,510	390,268	399,778	380,885	367,220	346,036	334,705	4,330,575
Mining	98,021	91,267	103,003	90,695	92,551	88,081	101,471	101,014	95,577	104,931	103,405	107,312	1,177,328
Other	1,345	1,181	1,220	1,129	1,092	1,063	1,115	1,157	1,147	1,286	1,287	1,334	14,355
Total Net Energy Consumption	865,921	788,260	781,915	823,029	960,106	1,152,880	1,287,768	1,244,654	1,111,364	943,541	814,167	846,337	11,619,942
Firm Wholesale	0	0	0	0	0	0	0	0	0	0	0	0	0
System Losses	90,482	75,929	80,627	84,565	109,115	131,481	148,837	138,626	124,671	101,888	81,696	87,842	1,255,760
Distributed Generation	98,140	102,999	128,528	146,198	145,175	120,061	121,543	114,064	137,577	135,615	115,916	112,331	1,478,148
Energy Efficiency	3,042	2,571	2,818	3,035	4,157	5,941	7,718	7,110	5,082	3,259	2,648	3,036	50,418
Total Gross Energy Consumption	1,057,585	969,759	993,889	1,056,827	1,218,553	1,410,363	1,565,865	1,504,454	1,378,695	1,184,303	1,014,428	1,049,545	14,404,267

Energy Consumption (MWh)													
Year: 2031	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Residential	268,653	226,949	209,991	226,421	337,040	492,788	568,525	524,747	435,311	295,120	218,969	257,437	4,061,952
Commercial	150,879	133,333	142,187	151,354	174,969	200,374	233,386	224,617	204,095	180,387	149,277	149,244	2,094,102
Industrial	351,138	340,179	328,901	357,335	360,058	376,663	390,589	400,237	381,286	367,865	346,614	335,202	4,336,065
Mining	109,419	101,617	114,959	100,744	102,836	98,407	113,039	112,165	106,725	120,118	118,447	123,193	1,321,667
Other	1,345	1,179	1,219	1,130	1,091	1,063	1,117	1,158	1,146	1,288	1,288	1,335	14,359
Total Net Energy Consumption	881,434	803,256	797,257	836,983	975,993	1,169,295	1,306,656	1,262,923	1,128,563	964,777	834,595	866,411	11,828,146
Firm Wholesale	0	0	0	0	0	0	0	0	0	0	0	0	0
System Losses	91,970	77,246	82,063	85,876	110,798	133,250	150,911	140,552	126,489	104,014	83,565	89,749	1,276,484
Distributed Generation	101,450	109,646	132,061	155,608	151,477	124,190	127,398	119,449	143,417	140,825	120,535	116,047	1,542,105
Energy Efficiency	2,915	2,466	2,722	2,941	4,107	5,924	7,803	7,152	4,998	3,151	2,531	2,908	49,616
Total Gross Energy Consumption	1,077,769	992,614	1,014,104	1,081,409	1,242,375	1,432,659	1,592,767	1,530,077	1,403,468	1,212,767	1,041,227	1,075,115	14,696,351

Energy Consumption (MWh)													
Year: 2032	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Residential	269,680	228,626	210,956	228,336	340,597	497,492	574,135	529,818	439,334	298,596	221,774	259,404	4,098,749
Commercial	153,070	135,543	144,116	153,156	176,922	201,902	235,140	226,595	206,187	182,936	151,914	151,760	2,119,240
Industrial	351,676	341,777	337,016	357,628	360,438	376,765	390,880	400,670	381,684	368,534	347,209	335,737	4,350,013
Mining	124,870	119,775	131,164	125,190	127,854	123,524	172,916	169,883	164,428	169,520	167,376	174,851	1,771,353
Other	1,347	1,181	1,221	1,132	1,092	1,064	1,116	1,157	1,145	1,287	1,287	1,334	14,364
Total Net Energy Consumption	900,642	826,903	824,474	865,441	1,006,903	1,200,748	1,374,187	1,328,123	1,192,779	1,020,873	889,560	923,087	12,353,719
Firm Wholesale	0	0	0	0	0	0	0	0	0	0	0	0	0
System Losses	93,812	79,562	84,611	88,551	114,071	136,641	158,326	147,424	133,277	109,629	88,595	95,133	1,329,631
Distributed Generation	107,102	119,243	137,918	161,707	156,994	126,717	133,531	124,896	148,596	143,180	125,744	117,483	1,603,112
Energy Efficiency	2,564	2,239	2,425	2,532	3,337	4,660	5,922	5,508	3,912	2,672	2,252	2,540	40,563
Total Gross Energy Consumption	1,104,119	1,027,946	1,049,428	1,118,231	1,281,306	1,468,765	1,671,966	1,605,951	1,478,564	1,276,355	1,106,151	1,138,243	15,327,025

Appendix C (cont.)

Energy Consumption (MWh)													
Year: 2033	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Residential	271,312	230,697	212,649	230,716	344,623	502,688	580,256	535,424	443,854	302,559	225,019	261,853	4,141,652
Commercial	155,520	137,978	146,226	155,112	178,985	203,541	236,990	228,667	208,356	185,558	154,638	154,389	2,145,959
Industrial	352,255	341,107	329,717	357,956	360,837	376,889	391,189	401,124	382,098	369,216	347,821	336,287	4,346,494
Mining	168,417	155,186	176,841	152,757	156,066	151,849	172,916	169,883	164,428	169,520	167,376	174,851	1,980,092
Other	1,346	1,180	1,220	1,130	1,092	1,063	1,116	1,157	1,146	1,287	1,287	1,334	14,359
Total Net Energy Consumption	948,850	866,148	866,652	897,672	1,041,604	1,236,030	1,382,467	1,336,255	1,199,883	1,028,140	896,142	928,715	12,628,557
Firm Wholesale	0	0	0	0	0	0	0	0	0	0	0	0	0
System Losses	98,435	82,768	88,559	91,581	117,746	140,444	159,235	148,281	134,028	110,357	89,197	95,668	1,356,298
Distributed Generation	114,529	119,269	143,451	166,717	161,857	130,311	137,240	130,596	152,524	148,278	128,688	121,195	1,654,656
Energy Efficiency	2,556	2,129	2,394	2,496	3,337	4,653	5,941	5,537	3,926	2,638	2,229	2,500	40,336
Total Gross Energy Consumption	1,164,370	1,070,314	1,101,056	1,158,466	1,324,543	1,511,438	1,684,883	1,620,669	1,490,361	1,289,412	1,116,256	1,148,079	15,679,846

Energy Consumption (MWh)													
Year: 2034	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Residential	273,474	233,528	214,912	233,676	349,196	508,421	586,946	541,602	448,918	307,006	228,689	264,733	4,191,100
Commercial	158,095	140,779	148,931	157,889	182,043	206,388	240,275	232,357	212,338	190,140	159,490	159,290	2,188,015
Industrial	352,834	341,659	330,266	358,474	361,473	377,319	391,874	402,006	383,010	370,450	349,062	337,534	4,355,962
Mining	168,417	155,186	176,841	152,757	156,066	151,849	172,916	169,883	164,428	169,520	167,376	174,851	1,980,092
Other	1,346	1,180	1,220	1,131	1,092	1,063	1,116	1,157	1,146	1,287	1,288	1,335	14,361
Total Net Energy Consumption	954,165	872,332	872,170	903,928	1,049,870	1,245,040	1,393,127	1,347,005	1,209,840	1,038,404	905,905	937,743	12,729,530
Firm Wholesale	0	0	0	0	0	0	0	0	0	0	0	0	0
System Losses	98,944	83,311	89,075	92,169	118,621	141,415	160,405	149,414	135,080	111,384	90,090	96,526	1,366,436
Distributed Generation	114,997	126,286	148,713	171,680	166,299	133,591	141,327	134,826	156,749	152,306	130,873	122,983	1,700,631
Energy Efficiency	2,541	2,093	2,369	2,454	3,358	4,624	5,954	5,569	3,936	2,607	2,205	2,473	40,184
Total Gross Energy Consumption	1,170,647	1,084,021	1,112,327	1,170,232	1,338,149	1,524,670	1,700,814	1,636,814	1,505,605	1,304,702	1,129,074	1,159,725	15,836,780

Energy Consumption (MWh)													
Year: 2035	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Residential	275,988	236,591	217,594	237,006	354,195	514,533	593,916	548,005	454,241	311,574	232,469	267,742	4,243,854
Commercial	163,071	145,656	153,311	161,928	186,003	209,773	243,704	235,820	215,763	193,847	163,183	162,710	2,234,769
Industrial	354,166	342,872	331,353	359,393	362,391	377,910	392,585	402,790	383,710	371,346	349,855	338,210	4,366,580
Mining	168,417	155,186	176,841	152,757	156,066	151,849	172,916	169,883	164,428	169,520	167,376	174,851	1,980,092
Other	1,346	1,181	1,220	1,131	1,092	1,064	1,116	1,157	1,146	1,287	1,287	1,334	14,361
Total Net Energy Consumption	962,988	881,485	880,320	912,215	1,059,747	1,255,129	1,404,238	1,357,655	1,219,288	1,047,573	914,171	944,848	12,839,657
Firm Wholesale	0	0	0	0	0	0	0	0	0	0	0	0	0
System Losses	99,791	84,114	89,838	92,948	119,667	142,503	161,625	150,537	136,079	112,302	90,847	97,201	1,377,451
Distributed Generation	115,332	122,299	157,003	175,596	170,000	136,931	143,865	139,724	160,376	155,640	133,538	126,510	1,736,815
Energy Efficiency	2,533	2,146	2,383	2,474	3,392	4,573	5,954	5,568	3,913	2,621	2,219	2,499	40,276
Total Gross Energy Consumption	1,180,644	1,090,044	1,129,543	1,183,233	1,352,807	1,539,136	1,715,682	1,653,485	1,519,656	1,318,137	1,140,775	1,171,058	15,994,200

Energy Consumption (MWh)													
Year: 2036	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Residential	278,634	239,739	220,221	240,311	359,216	520,607	600,919	554,683	459,923	316,571	236,683	271,139	4,298,647
Commercial	166,118	148,566	155,859	164,229	188,412	211,738	245,856	238,204	218,203	196,687	166,124	165,485	2,265,481
Industrial	354,775	344,519	339,504	359,691	362,766	378,006	392,848	403,207	384,088	371,991	350,471	338,758	4,380,624
Mining	168,417	160,728	176,841	152,757	156,066	151,849	172,916	169,883	164,428	169,520	167,376	174,851	1,985,634
Other	1,346	1,180	1,220	1,131	1,092	1,063	1,116	1,157	1,146	1,287	1,288	1,335	14,361
Total Net Energy Consumption	969,290	894,733	893,645	918,119	1,067,553	1,263,263	1,413,655	1,367,134	1,227,788	1,056,056	921,942	951,568	12,944,746
Firm Wholesale	0	0	0	0	0	0	0	0	0	0	0	0	0
System Losses	100,395	85,518	91,085	93,503	120,494	143,380	162,659	151,536	136,977	113,151	91,558	97,839	1,388,095
Distributed Generation	119,835	131,074	153,638	180,960	175,629	143,936	147,420	137,979	165,405	162,133	138,533	132,987	1,789,528
Energy Efficiency	2,463	2,168	2,324	2,467	3,291	4,512	5,748	5,287	3,859	2,591	2,154	2,453	39,317
Total Gross Energy Consumption	1,191,983	1,113,492	1,140,692	1,195,050	1,366,966	1,555,091	1,729,483	1,661,935	1,534,029	1,333,930	1,154,187	1,184,847	16,161,686

Energy Consumption (MWh)													
Year: 2037	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Residential	281,697	243,370	223,144	244,140	364,787	527,097	608,275	561,570	465,726	321,686	240,921	274,578	4,356,991
Commercial	168,652	151,103	158,072	166,252	190,593	213,463	247,824	240,430	220,541	199,497	169,061	168,286	2,293,773
Industrial	355,294	343,801	332,131	359,918	363,075	378,015	393,032	403,540	384,395	372,579	351,029	339,251	4,376,061
Mining	168,417	155,186	176,841	152,757	156,066	151,849	172,916	169,883	164,428	169,520	167,376	174,851	1,980,092
Other	1,346	1,181	1,220	1,131	1,092	1,063	1,116	1,157	1,146	1,287	1,288	1,335	14,361
Total Net Energy Consumption	975,406	894,639	891,409	924,199	1,075,613	1,271,488	1,423,164	1,376,580	1,236,236	1,064,569	929,675	958,301	13,021,278
Firm Wholesale	0	0	0	0	0	0	0	0	0	0	0	0	0
System Losses	100,981	85,269	90,876	94,075	121,347	144,266	163,703	152,531	137,870	114,003	92,265	98,479	1,395,667
Distributed Generation	122,715	130,835	156,658	185,179	179,007	145,145	151,468	140,732	168,898	164,800	140,218	132,971	1,818,623
Energy Efficiency	2,498	2,125	2,368	2,493	3,307	4,553	5,825	5,363	3,845	2,611	2,190	2,484	39,662
Total Gross Energy Consumption	1,201,600	1,112,868	1,141,310	1,205,945	1,379,275	1,565,452	1,744,160	1,675,206	1,546,849	1,345,983	1,164,348	1,192,234	16,275,230

Energy Consumption (MWh)													
Year: 2038	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Residential	284,814	247,022	226,205	247,958	370,327	533,525	615,606	568,541	471,668	327,018	245,173	278,261	4,416,118
Commercial	171,212	153,658	160,283	168,294	192,799	215,205	249,785	242,617	222,826	202,273	171,957	171,081	2,321,989
Industrial	355,757	344,181	332,418	360,086	363,319	377,954	393,145	403,802	384,639	373,116	351,530	339,696	4,379,643
Mining	168,417	155,186	176,841	152,757	156,066	151,849	172,916	169,883	164,428	169,520	167,376	174,851	1,980,092
Other	1,346	1,181	1,220	1,131	1,092	1,063	1,116	1,157	1,146	1,287	1,288	1,334	14,361
Total Net Energy Consumption	981,546	901,228	896,967	930,226	1,083,604	1,279,597	1,432,568	1,385,999	1,244,707	1,073,213	937,324	965,224	13,112,203
Firm Wholesale	0	0	0	0	0	0	0	0	0	0	0	0	0
System Losses	101,570	85,848	91,396	94,641	122,194	145,141	164,736	153,524	138,766	114,869	92,965	99,136	1,404,785</

Appendix C (cont.)

Energy Consumption (MWh)													
Year: 2039	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Residential	288,160	250,951	230,042	252,154	376,257	540,379	623,375	576,032	478,052	332,777	249,800	282,350	4,480,329
Commercial	173,720	156,212	162,520	170,389	195,051	217,032	251,873	245,002	225,350	205,323	175,167	174,222	2,351,862
Industrial	356,147	344,509	332,659	360,223	363,530	377,879	393,251	404,078	384,909	373,693	352,094	340,218	4,383,190
Mining	168,417	155,186	176,841	152,757	156,066	151,849	172,916	169,883	164,428	169,520	167,376	174,851	1,980,092
Other	1,346	1,181	1,220	1,131	1,092	1,063	1,116	1,157	1,146	1,287	1,288	1,335	14,361
Total Net Energy Consumption	987,790	908,038	903,283	936,654	1,091,996	1,288,203	1,442,531	1,396,153	1,253,884	1,082,600	945,726	972,976	13,209,834
Firm Wholesale	0	0	0	0	0	0	0	0	0	0	0	0	0
System Losses	102,169	86,446	91,987	95,245	123,082	146,068	165,830	154,594	139,736	115,808	93,734	99,873	1,414,573
Distributed Generation	131,106	136,509	164,132	190,472	184,407	148,443	156,108	148,144	173,189	167,909	145,516	136,849	1,882,783
Energy Efficiency	2,584	2,160	2,429	2,522	3,339	4,614	5,861	5,441	3,872	2,629	2,246	2,522	40,220
Total Gross Energy Consumption	1,223,650	1,133,153	1,161,832	1,224,893	1,402,824	1,587,328	1,770,329	1,704,332	1,570,680	1,368,946	1,187,222	1,212,219	16,547,410

Energy Consumption (MWh)													
Year: 2040	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Residential	291,908	255,258	234,352	256,554	382,578	547,623	631,531	583,914	484,893	339,000	254,985	287,036	4,549,631
Commercial	176,933	159,520	165,599	173,400	198,277	219,904	255,015	248,392	228,891	209,380	179,458	178,483	2,393,251
Industrial	356,731	346,192	340,846	360,589	363,976	378,066	393,636	404,636	385,486	374,577	352,998	341,097	4,398,831
Mining	168,417	160,728	176,841	152,757	156,066	151,849	172,916	169,883	164,428	169,520	167,376	174,851	1,985,634
Other	1,346	1,181	1,220	1,131	1,092	1,063	1,116	1,157	1,146	1,287	1,288	1,335	14,361
Total Net Energy Consumption	995,335	922,879	918,858	944,432	1,101,989	1,298,506	1,454,214	1,407,982	1,264,844	1,093,763	956,106	982,802	13,341,708
Firm Wholesale	0	0	0	0	0	0	0	0	0	0	0	0	0
System Losses	102,893	87,989	93,445	95,977	124,141	147,179	167,113	155,841	140,894	116,926	94,684	100,806	1,427,886
Distributed Generation	129,683	144,546	172,178	192,309	186,141	149,748	157,298	152,566	175,099	169,703	145,412	137,578	1,912,259
Energy Efficiency	2,619	2,241	2,434	2,509	3,402	4,551	5,898	5,495	3,870	2,619	2,245	2,538	40,421
Total Gross Energy Consumption	1,230,529	1,157,654	1,186,915	1,235,226	1,415,672	1,599,984	1,784,522	1,721,884	1,584,707	1,383,011	1,198,446	1,223,724	16,722,275

Energy Consumption (MWh)													
Year: 2041	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Residential	294,413	257,448	236,363	258,756	385,861	552,323	636,951	588,925	489,054	341,909	257,173	289,500	4,588,675
Commercial	178,451	160,889	167,020	174,888	199,978	221,791	257,203	250,524	230,855	211,176	180,999	180,015	2,413,790
Industrial	359,792	349,163	343,771	363,684	367,100	381,311	397,014	408,108	388,794	377,791	356,028	344,024	4,436,581
Mining	169,863	162,107	178,359	154,068	157,406	153,152	174,400	171,341	165,839	170,974	168,813	176,352	2,002,675
Other	1,357	1,191	1,231	1,141	1,101	1,073	1,126	1,167	1,156	1,298	1,299	1,346	14,484
Total Net Energy Consumption	1,003,877	930,799	926,743	952,537	1,111,446	1,309,650	1,466,694	1,420,065	1,275,698	1,103,150	964,311	991,236	13,456,205
Firm Wholesale	0	0	0	0	0	0	0	0	0	0	0	0	0
System Losses	103,712	88,444	94,183	96,738	125,142	148,380	168,483	157,115	142,041	117,865	95,434	101,607	1,439,146
Distributed Generation	128,572	134,691	167,522	190,208	188,473	155,188	157,000	146,865	176,828	173,501	147,831	142,807	1,909,487
Energy Efficiency	2,580	2,197	2,426	2,573	3,368	4,570	5,740	5,300	3,949	2,685	2,247	2,562	40,196
Total Gross Energy Consumption	1,238,740	1,156,130	1,190,875	1,242,056	1,428,430	1,617,788	1,797,917	1,729,345	1,598,517	1,397,201	1,209,823	1,238,213	16,845,035

Appendix C (cont.)

ATTACHMENT C.2: COINCIDENT PEAK DEMAND

Peak Demand (MW)													
Year: 2027	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Coincident Max
Net Retail Demand	1,296	1,161	1,153	1,485	1,834	2,287	2,480	2,405	2,135	1,686	1,341	1,306	2,480
Energy Efficiency	9	7	8	13	22	23	19	25	18	18	9	10	19
Distributed Generation	3	10	14	98	100	195	181	179	153	112	9	6	181
Firm Wholesale	125	124	87	75	25	25	25	25	25	25	40	40	25
System Losses	43	35	37	48	67	85	94	88	78	59	43	43	94
Gross System Demand with Losses	1,476	1,337	1,299	1,719	2,047	2,616	2,799	2,722	2,410	1,900	1,442	1,405	2,799

Peak Demand (MW)													
Year: 2028	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Coincident Max
Net Retail Demand	1,336	1,206	1,219	1,545	1,931	2,389	2,699	2,571	2,320	1,879	1,550	1,530	2,699
Energy Efficiency	9	7	8	13	22	23	19	25	18	18	9	10	19
Distributed Generation	3	11	18	106	106	203	187	184	157	113	13	7	187
Firm Wholesale	0	0	0	0	0	0	0	0	0	0	0	0	0
System Losses	44	37	39	50	71	89	103	94	85	65	49	50	103
Gross System Demand with Losses	1,393	1,260	1,284	1,714	2,130	2,704	3,008	2,874	2,580	2,075	1,621	1,597	3,008

Peak Demand (MW)													
Year: 2029	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Coincident Max
Net Retail Demand	1,564	1,443	1,449	1,778	2,157	2,620	2,815	2,746	2,470	2,018	1,661	1,616	2,815
Energy Efficiency	5	4	5	8	15	18	15	20	13	11	5	6	15
Distributed Generation	3	12	22	114	114	210	193	189	161	114	17	7	193
Firm Wholesale	0	0	0	0	0	0	0	0	0	0	0	0	0
System Losses	52	44	47	58	79	98	107	100	90	70	53	53	107
Gross System Demand with Losses	1,625	1,503	1,524	1,957	2,365	2,945	3,130	3,055	2,735	2,213	1,735	1,682	3,130

Peak Demand (MW)													
Year: 2030	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Coincident Max
Net Retail Demand	1,646	1,503	1,481	1,807	2,171	2,638	2,836	2,769	2,491	2,045	1,683	1,637	2,836
Energy Efficiency	5	4	5	8	14	17	15	20	13	11	5	6	15
Distributed Generation	3	13	27	122	121	218	200	194	165	115	20	8	200
Firm Wholesale	0	0	0	0	0	0	0	0	0	0	0	0	0
System Losses	55	46	48	59	80	98	108	101	91	71	53	54	108
Gross System Demand with Losses	1,709	1,566	1,561	1,996	2,386	2,972	3,158	3,084	2,760	2,242	1,761	1,705	3,158

Peak Demand (MW)													
Year: 2031	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Coincident Max
Net Retail Demand	1,680	1,534	1,506	1,831	2,201	2,671	2,871	2,806	2,526	2,086	1,717	1,671	2,871
Energy Efficiency	5	4	5	7	14	17	15	20	13	11	5	6	15
Distributed Generation	3	15	32	131	129	226	206	199	169	116	24	8	206
Firm Wholesale	0	0	0	0	0	0	0	0	0	0	0	0	0
System Losses	56	47	49	60	81	100	109	102	92	72	54	55	109
Gross System Demand with Losses	1,744	1,600	1,592	2,030	2,425	3,014	3,201	3,128	2,800	2,285	1,801	1,741	3,201

Peak Demand (MW)													
Year: 2032	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Coincident Max
Net Retail Demand	1,718	1,578	1,541	1,879	2,254	2,728	2,976	2,914	2,632	2,179	1,805	1,758	2,976
Energy Efficiency	4	3	4	6	12	13	11	15	10	9	4	5	11
Distributed Generation	3	16	37	141	138	235	214	205	174	117	28	9	214
Firm Wholesale	0	0	0	0	0	0	0	0	0	0	0	0	0
System Losses	57	48	50	61	83	102	113	106	96	76	57	58	113
Gross System Demand with Losses	1,783	1,646	1,632	2,087	2,486	3,078	3,314	3,240	2,912	2,381	1,895	1,830	3,314

Peak Demand (MW)													
Year: 2033	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Coincident Max
Net Retail Demand	1,799	1,649	1,610	1,933	2,314	2,791	2,994	2,934	2,650	2,198	1,819	1,771	2,994
Energy Efficiency	4	3	4	6	12	13	11	15	10	9	4	5	11
Distributed Generation	3	18	43	150	146	243	221	211	178	118	33	10	221
Firm Wholesale	0	0	0	0	0	0	0	0	0	0	0	0	0
System Losses	60	50	52	63	85	104	114	107	97	76	58	58	114
Gross System Demand with Losses	1,867	1,720	1,709	2,152	2,556	3,152	3,340	3,267	2,936	2,401	1,913	1,844	3,340

Appendix C (cont.)

Peak Demand (MW)													
Year: 2034	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Coincident Max
Net Retail Demand	1,817	1,665	1,620	1,942	2,330	2,811	3,016	2,958	2,674	2,223	1,838	1,789	3,016
Energy Efficiency	4	3	4	6	12	13	11	15	10	9	4	5	11
Distributed Generation	4	19	48	160	155	252	229	218	183	119	37	10	229
Firm Wholesale	0	0	0	0	0	0	0	0	0	0	0	0	0
System Losses	60	51	52	63	86	105	115	108	98	77	58	59	115
Gross System Demand with Losses	1,885	1,738	1,725	2,172	2,582	3,181	3,371	3,299	2,965	2,428	1,937	1,864	3,371

Peak Demand (MW)													
Year: 2035	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Coincident Max
Net Retail Demand	1,840	1,686	1,634	1,954	2,348	2,831	3,038	2,982	2,696	2,246	1,854	1,804	3,038
Energy Efficiency	4	3	4	6	12	13	11	15	10	9	4	5	11
Distributed Generation	4	21	55	171	165	263	237	224	188	120	42	11	237
Firm Wholesale	0	0	0	0	0	0	0	0	0	0	0	0	0
System Losses	61	51	53	64	86	106	115	109	99	78	59	59	115
Gross System Demand with Losses	1,910	1,761	1,746	2,195	2,611	3,213	3,402	3,330	2,993	2,453	1,959	1,880	3,402

Peak Demand (MW)													
Year: 2036	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Coincident Max
Net Retail Demand	1,859	1,715	1,666	1,963	2,363	2,849	3,058	3,004	2,717	2,268	1,870	1,819	3,058
Energy Efficiency	4	3	4	6	11	13	11	15	10	9	4	5	11
Distributed Generation	4	23	60	182	174	272	245	230	193	121	46	12	245
Firm Wholesale	0	0	0	0	0	0	0	0	0	0	0	0	0
System Losses	62	52	54	64	87	106	116	110	99	79	59	60	116
Gross System Demand with Losses	1,929	1,793	1,784	2,215	2,635	3,240	3,430	3,358	3,019	2,476	1,980	1,895	3,430

Peak Demand (MW)													
Year: 2037	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Coincident Max
Net Retail Demand	1,878	1,719	1,655	1,974	2,380	2,868	3,078	3,026	2,738	2,290	1,887	1,834	3,078
Energy Efficiency	4	3	4	6	12	13	11	15	10	9	4	5	11
Distributed Generation	4	24	66	191	182	280	252	236	197	122	49	12	252
Firm Wholesale	0	0	0	0	0	0	0	0	0	0	0	0	0
System Losses	62	52	54	64	87	107	117	110	100	79	60	60	117
Gross System Demand with Losses	1,949	1,798	1,778	2,235	2,660	3,268	3,458	3,387	3,045	2,500	2,001	1,911	3,458

Peak Demand (MW)													
Year: 2038	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Coincident Max
Net Retail Demand	1,897	1,736	1,666	1,986	2,397	2,888	3,100	3,049	2,760	2,313	1,904	1,849	3,100
Energy Efficiency	4	3	4	6	12	13	11	15	10	9	4	5	11
Distributed Generation	4	25	70	199	188	287	258	240	200	122	53	13	258
Firm Wholesale	0	0	0	0	0	0	0	0	0	0	0	0	0
System Losses	63	53	54	65	88	108	118	111	101	80	60	61	118
Gross System Demand with Losses	1,968	1,817	1,794	2,256	2,685	3,295	3,486	3,416	3,071	2,525	2,022	1,927	3,486

Peak Demand (MW)													
Year: 2039	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Coincident Max
Net Retail Demand	1,916	1,753	1,679	2,000	2,416	2,908	3,123	3,074	2,783	2,337	1,923	1,866	3,123
Energy Efficiency	4	3	4	6	12	13	11	15	10	9	4	5	11
Distributed Generation	4	27	74	206	195	294	263	245	204	123	56	13	263
Firm Wholesale	0	0	0	0	0	0	0	0	0	0	0	0	0
System Losses	64	53	54	65	89	108	119	112	102	81	61	61	119
Gross System Demand with Losses	1,988	1,836	1,812	2,278	2,711	3,324	3,516	3,446	3,099	2,550	2,044	1,945	3,516

Peak Demand (MW)													
Year: 2040	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Coincident Max
Net Retail Demand	1,938	1,786	1,717	2,018	2,438	2,933	3,149	3,102	2,811	2,365	1,947	1,887	3,149
Energy Efficiency	4	3	4	6	12	13	11	15	10	9	4	5	11
Distributed Generation	4	28	78	213	201	300	268	249	207	124	59	14	268
Firm Wholesale	0	0	0	0	0	0	0	0	0	0	0	0	0
System Losses	64	54	56	66	89	109	120	113	103	82	62	62	120
Gross System Demand with Losses	2,010	1,871	1,855	2,303	2,741	3,356	3,548	3,479	3,130	2,580	2,072	1,968	3,548

Peak Demand (MW)													
Year: 2041	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Coincident Max
Net Retail Demand	1,954	1,802	1,734	2,038	2,462	2,961	3,178	3,130	2,836	2,385	1,966	1,903	3,178
Energy Efficiency	4	3	4	6	12	13	11	15	10	9	4	5	11
Distributed Generation	4	29	81	219	206	305	273	252	209	124	61	14	273
Firm Wholesale	0	0	0	0	0	0	0	0	0	0	0	0	0
System Losses	65	55	56	66	90	110	121	114	104	83	62	63	121
Gross System Demand with Losses	2,028	1,889	1,876	2,330	2,770	3,390	3,583	3,511	3,159	2,601	2,093	1,985	3,583

Appendix C (cont.)

ATTACHMENT D.1(A)(1): POWER SUPPLY

Data in columns with red headers (G,H) are confidential and competitively sensitive.

POWER SUPPLY - ESTIMATES FOR 2027-2041													
Plant/Unit/Contract	In Service Year	Retirement Year	Type	Owned Capacity (MW)		Max Capacity (MW)	Average Heat Rate	Variable O&M Cost (\$/MWh)	Fuel	Capacity (MW)		Baseload	
										Must Run	Intermediate Peaking		
Coal													
Four Corners 4	1969	2031	Steam Turbine		55	55			Coal	1	Yes	Base Load	
Four Corners 5	1970	2031	Steam Turbine		55	55			Coal	1	Yes	Base Load	
Springerville 1 Coal	1985	2029	Steam Turbine		387	365			Coal	150	Yes	Base Load	
Springerville 2 Coal	1990	2029	Steam Turbine		406	365			Coal	150	Yes	Base Load	
Gas													
Sundt ST3	1962	2046	Steam Turbine		104	104			Gas	19	No	Intermediate	
Sundt ST4	1967	2046	Steam Turbine		156	153			Gas	20	No	Intermediate	
Sundt CT 1	1972	2046	Combustion Turbine		25	25			Gas	16	No	Peaking	
Sundt CT 2	1972	2046	Combustion Turbine		25	25			Gas	16	No	Peaking	
North Loop CT 1	1970	2046	Combustion Turbine		25	22			Gas	15	No	Peaking	
North Loop CT 2	1971	2046	Combustion Turbine		25	22			Gas	15	No	Peaking	
North Loop CT 3	1972	2046	Combustion Turbine		25	22			Gas	15	No	Peaking	
North Loop CT 4	2001	2046	Combustion Turbine		21	19			Gas	10	No	Peaking	
DeMoss Petrie	2001	2046	Combustion Turbine		75	75			Gas	39	No	Peaking	
Luna	2008	2051	Combined Cycle		185	185			Gas	1	No	Intermediate	
Gila River 2	2003	2048	Combined Cycle		607	500			Gas	103	No	Intermediate	
Gila River 3 (TEP)	2003	2048	Combined Cycle		455	443			Gas	77	No	Intermediate	
RICE 1	2020	2065	Reciprocating Internal Combustion Engine		18.8	16			Gas	5	No	Peaking	
RICE 2	2020	2065	Reciprocating Internal Combustion Engine		18.8	16			Gas	5	No	Peaking	
RICE 3	2020	2065	Reciprocating Internal Combustion Engine		18.8	16			Gas	5	No	Peaking	
RICE 4	2020	2065	Reciprocating Internal Combustion Engine		18.8	16			Gas	5	No	Peaking	
RICE 5	2020	2065	Reciprocating Internal Combustion Engine		18.8	16			Gas	5	No	Peaking	
RICE 6	2019	2065	Reciprocating Internal Combustion Engine		18.8	16			Gas	5	No	Peaking	
RICE 7	2019	2065	Reciprocating Internal Combustion Engine		18.8	16			Gas	5	No	Peaking	
RICE 8	2019	2065	Reciprocating Internal Combustion Engine		18.8	16			Gas	5	No	Peaking	
RICE 9	2019	2065	Reciprocating Internal Combustion Engine		18.8	16			Gas	5	No	Peaking	
RICE 10	2019	2065	Reciprocating Internal Combustion Engine		18.8	16			Gas	5	No	Peaking	
Springerville 1 Gas	2030	2045	Steam Turbine		365	365			Gas	128	No	Intermediate	
Springerville 2 Gas	2030	2050	Steam Turbine		365	365			Gas	128	No	Intermediate	
Owned Renewables													
Ft Huachuca I	2014	2042	Fixed-Tilt Solar		13.6	13.6			Solar		Yes	Intermittent	
Ft Huachuca II	2017	2045	Fixed-Tilt Solar		4.4	4.4			Solar		Yes	Intermittent	
Oso Grande	2021	2051	Onshore Wind		250	250			Wind		Yes	Intermittent	
Solon Prairie Fire	2012	2040	Fixed-Tilt Solar		4.5	4.5			Solar		Yes	Intermittent	
Springerville Solar	2004	2032	Fixed-Tilt Solar		3.7	3.7			Solar		Yes	Intermittent	
Springerville Solar Expansic	2010	2038	Fixed-Tilt Solar		1.6	1.6			Solar		Yes	Intermittent	
UASTP I	2010	2038	Fixed-Tilt Solar		1.5	1.5			Solar		Yes	Intermittent	
UASTP II	2011	2039	Photovoltaic - Tracking (PVT)		4.5	4.5			Solar		Yes	Intermittent	
White Mountain	2014	2042	Photovoltaic - Tracking (PVT)		8.5	8.5			Solar		Yes	Intermittent	
Raptor Ridge	2022	2050	Photovoltaic - Tracking (PVT)		13.0	13.0			Solar		Yes	Intermittent	
Renewable PPAs													
Amonix UASTP II	2011	2031	Fixed-Tilt Solar		2.0	2.0			Solar		Yes	Intermittent	
Avalon 1	2014	2034	Photovoltaic - Tracking (PVT)		29.0	29.0			Solar		Yes	Intermittent	
Avalon 2	2016	2036	Photovoltaic - Tracking (PVT)		16.0	16.0			Solar		Yes	Intermittent	
Avra Valley	2012	2032	Photovoltaic - Tracking (PVT)		25.0	25.0			Solar		Yes	Intermittent	
Borderlands	2021	2051	Onshore Wind		99.0	99.0			Wind		Yes	Intermittent	
Cogenera	2014	2034	Photovoltaic - Tracking (PVT)		1.1	1.1			Solar		Yes	Intermittent	
E.On Tech Park	2012	2032	Photovoltaic - Tracking (PVT)		4.8	4.8			Solar		Yes	Intermittent	
Gato Montes Solar	2012	2032	Fixed-Tilt Solar		5.0	5.0			Solar		Yes	Intermittent	
Iron Horse Solar	2017	2027	Fixed-Tilt Solar		2.0	2.0			Solar		Yes	Intermittent	
Macho Springs	2011	2031	Onshore Wind		50.4	50.4			Wind		Yes	Intermittent	
Picture Rocks	2012	2032	Photovoltaic - Tracking (PVT)		20.0	20.0			Solar		Yes	Intermittent	
Red Horse Solar	2015	2035	Photovoltaic - Tracking (PVT)		41.0	41.0			Solar		Yes	Intermittent	
Red Horse Wind	2015	2035	Onshore Wind		30.0	30.0			Wind		Yes	Intermittent	
Valencia Solar	2013	2033	Photovoltaic - Tracking (PVT)		9.9	9.9			Solar		Yes	Intermittent	
Wilmot Solar	2021	2041	Photovoltaic - Tracking (PVT)		100.0	100.0			Solar		Yes	Intermittent	
Babacomari Solar	2026	2044	Photovoltaic - Tracking (PVT)		160.0	160.0			Solar		Yes	Intermittent	
Wilmot Solar II	2026	2050	Photovoltaic - Tracking (PVT)		100	100			Solar		Yes	Intermittent	
Winchester Solar	2027	2047	Photovoltaic - Tracking (PVT)		80	80			Solar		Yes	Intermittent	
Energy Storage													
Wilmot Battery Storage	2021	2041	Energy Storage		30	30			Energy Storage		No	Intermittent	
Pima Battery Storage	2017	2027	Energy Storage		10	10			Energy Storage		No	Intermittent	
Iron Horse Battery Storage	2017	2027	Energy Storage		10	10			Energy Storage		No	Intermittent	
Roadrunner Reserve 1	2025	2050	Energy Storage		200	200			Energy Storage		No	Intermittent	
Roadrunner Reserve 2	2026	2050	Energy Storage		200	200			Energy Storage		No	Intermittent	
Wilmot Battery Storage II	2026	2050	Energy Storage		100	100			Energy Storage		No	Intermittent	
Winchester Energy Storage	2027	2047	Energy Storage		80	80			Energy Storage		No	Intermittent	
Future Gas													
Future NGCC 1	2031		Combined Cycle		300	300			Gas	75	No	Intermediate	
Future Renewables													
Future Hybrid Solar 1	2029		Photovoltaic - Tracking (PVT)		200	200			Solar		Yes	Intermittent	
Future Hybrid Solar 2	2034		Photovoltaic - Tracking (PVT)		100	100			Solar		Yes	Intermittent	
Future Hybrid Solar 3	2037		Photovoltaic - Tracking (PVT)		100	100			Solar		Yes	Intermittent	
Future Hybrid Solar 4	2038		Photovoltaic - Tracking (PVT)		100	100			Solar		Yes	Intermittent	
Future Hybrid Solar 5	2041		Photovoltaic - Tracking (PVT)		100	100			Solar		Yes	Intermittent	
Future Energy Storage													
Future Hybrid Storage 1	2029		Energy Storage		200	200			Energy Storage		No	Intermittent	
Future Hybrid Storage 2	2034		Energy Storage		100	100			Energy Storage		No	Intermittent	
Future Hybrid Storage 3	2037		Energy Storage		100	100			Energy Storage		No	Intermittent	
Future Hybrid Storage 4	2038		Energy Storage		100	100			Energy Storage		No	Intermittent	
Future Hybrid Storage 5	2041		Energy Storage		100	100			Energy Storage		No	Intermittent	

ATTACHMENT D.1(A)1(): ANNUAL CAPACITY FACTOR

Data in this table is Confidential and Competitively Sensitive

Annual Capacity Factor - Existing Resources

The chart displays the annual capacity factor for existing resources from 2000 to 2050. The resources are categorized into three groups: Coal, Gas, and Nuclear (top); Wind, Solar, and Hydro (middle); and Biomass, Geothermal, and Small Hydro (bottom). The capacity factor is measured on a scale from 0 to 100. The chart shows that coal and gas capacity factors are generally high, while wind and solar capacity factors are lower and more variable. Hydro capacity factors are relatively stable. Biomass, geothermal, and small hydro capacity factors are also relatively stable but lower than coal and gas.

Appendix C (cont.)

ATTACHMENT D.1(A)1(): ANNUAL CAPACITY FACTOR
Data in this table is Confidential and Competitively Sensitive
Annual Capacity Factor - Future Resources

[illegible]

Appendix C (cont.)

ATTACHMENT D.1(A)(3): AVERAGE HEAT RATE

Data in this table is Confidential and Competitively Sensitive

ATTACHMENT D.1(A)(4): AVERAGE FUEL COST
Data in this table is Confidential and Competitively Sensitive

Average Fuel Cost (\$/MMBtu)									

Appendix C (cont.)

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Appendix C (cont.)

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Appendix C (cont.)

[illegible]

ATTACHMENT D.1(A)(8): ENVIRONMENTAL IMPACTS

Data in this table is Confidential and Competitively Sensitive

NOx Emissions (Metric Tons)

NOx Emissions (Metric Tons)

Appendix C (cont.)

[illegible]

Appendix C (cont.)

ATTACHMENT D.2, D.3: GENERATION TECHNOLOGY AND FINANCIAL ASSUMPTIONS

Resource					
Category for Cost Reductions	Resource Category		Solar	Wind	Battery Storage-Hybrid
	Technology Type		Utility-Scale PV	Onshore	Lithium ion (4-Hour) - Utility-Scale PV
Performance Inputs		Units			
Plant Output	Capacity Factor	%	31.0%	40.0%	33.4%
Plant Cost Inputs					
Capital Costs	Installed Cost (2030\$)	\$/kW-ac	\$1,575	\$2,118	\$2,818
Fixed O&M	Annual Fixed O&M (2030\$)	\$/kW-yr	\$23	\$51	\$45
	Annual Escalation	%/yr	3.0%	3.0%	3.0%
Transmission Wheeling	Transmission (2026\$)	\$/kW-yr	\$0	\$48	\$0
Property Tax	Property Tax	%	0.9%	0.9%	0.9%
Insurance	Insurance	%	0.3%	0.3%	0.3%
Financial Assumptions	Financing Lifetime	yr	30	20	20
	Equity Share	%	54.3%	54.3%	54.3%
	Debt Share	%	45.7%	45.7%	45.7%
	Debt Cost	%	3.8%	3.8%	3.8%
	Equity Return	%	9.6%	9.6%	9.6%
ITC	Credit	%	0.0%	0.0%	15.0%
	Capital Costs Eligible	%	0%	0%	95%
MACRS	Term	yr	5	5	5

Resource					
Category for Cost Reductions	Resource Category		Battery Storage	Battery Storage	Battery Storage
	Technology Type		Lithium ion (4-Hour)	Lithium ion (8-Hour)	Flow (10-hour)
Performance Inputs		Units			
Plant Output	Capacity Factor	%	16.7%	33.3%	41.7%
Plant Cost Inputs					
Capital Costs	Installed Cost (2030\$)	\$/kW-ac	\$2,162	\$3,680	\$3,925
Fixed O&M	Annual Fixed O&M (2030\$)	\$/kW-yr	\$44	\$44	\$26
	Annual Escalation	%/yr	3.0%	3.0%	3.0%
Transmission Wheeling	Transmission (2026\$)	\$/kW-yr	\$0	\$0	\$0
Property Tax	Property Tax	%	0.9%	0.9%	0.9%
Insurance	Insurance	%	0.3%	0.3%	0.3%
Financial Assumptions	Financing Lifetime	yr	20	20	20
	Equity Share	%	54.3%	54.3%	54.3%
	Debt Share	%	45.7%	45.7%	45.7%
	Debt Cost	%	3.8%	3.8%	3.8%
	Equity Return	%	9.6%	9.6%	9.6%
ITC	Credit	%	30.0%	30.0%	30.0%
	Capital Costs Eligible	%	95%	95%	95%
MACRS	Term	yr	5	5	5

Appendix C (cont.)

Resource					
Category for Cost Reductions	Resource Category		Natural Gas	Natural Gas	Geothermal
	Technology Type		Combustion Turbine	Combined Cycle	Enhanced
Performance Inputs		Units			
Plant Output	Capacity Factor	%	20.0%	60.0%	85.0%
Plant Cost Inputs					
Capital Costs	Installed Cost (2030\$)	\$/kW-ac	\$2,506	\$2,304	\$7,192
Fixed O&M	Annual Fixed O&M (2030\$)	\$/kW-yr	\$26	\$15	\$160
	Annual Escalation	%/yr	3.0%	3.0%	3.0%
Transmission Wheeling	Transmission (2026\$)	\$/kW-yr	\$0	\$0	\$48.00
Property Tax	Property Tax	%	0.9%	0.9%	0.9%
Insurance	Insurance	%	0.3%	0.3%	0.3%
Financial Assumptions	Financing Lifetime	yrs	30	30	40
	Equity Share	%	54.3%	54.3%	54.3%
	Debt Share	%	45.7%	45.7%	45.7%
	Debt Cost	%	3.8%	3.8%	3.8%
	Equity Return	%	9.6%	9.6%	9.6%
ITC	Credit	%	0.0%	0.0%	30%
	Capital Costs Eligible	%	0%	0%	95%
MACRS	Term	yrs	20	20	5

Resource					
Category for Cost Reductions	Resource Category		Pumped Hydro Storage	Nuclear	Nuclear
	Technology Type		10 Hour	SMRs	Large - PWR
Performance Inputs		Units			
Plant Output	Capacity Factor	%	41.7%	90.0%	90.0%
Plant Cost Inputs					
Capital Costs	Installed Cost (2030\$)	\$/kW-ac	\$4,980	\$12,699	\$12,443
Fixed O&M	Annual Fixed O&M (2030\$)	\$/kW-yr	\$13	\$134	\$172
	Annual Escalation	%/yr	3.0%	3.0%	3.0%
Transmission Wheeling	Transmission (2026\$)	\$/kW-yr	\$48.00	\$0	\$0
Property Tax	Property Tax	%	0.9%	0.9%	0.9%
Insurance	Insurance	%	0.3%	0.3%	0.3%
Financial Assumptions	Financing Lifetime	yrs	40	40	40
	Equity Share	%	54.3%	54.3%	54.3%
	Debt Share	%	45.7%	45.7%	45.7%
	Debt Cost	%	3.8%	3.8%	3.8%
	Equity Return	%	9.6%	9.6%	9.6%
ITC	Credit	%	40%	50%	50%
	Capital Costs Eligible	%	95%	95%	95%
MACRS	Term	yrs	20	15	15

STOCHASTICS ANALYSIS

Fuel, Market and Demand Risk Analysis

TEP developed explicit market risk analytics for each portfolio using Monte Carlo computer simulations in Aurora. Specifically, a stochastic dispatch simulation was used to evaluate future uncertainty related to fuel prices, wholesale market prices, and peak retail demand. The results of this modeling were employed to quantify the risk of uncertainty and evaluate the cost performance of each portfolio. This type of analysis ensures that the selected portfolio not only has a low expected cost but is also robust enough to perform well against a wide range of future load and market conditions.

As part of the Company's 2026 resource plan, TEP conducted risk simulations around the following key variables:

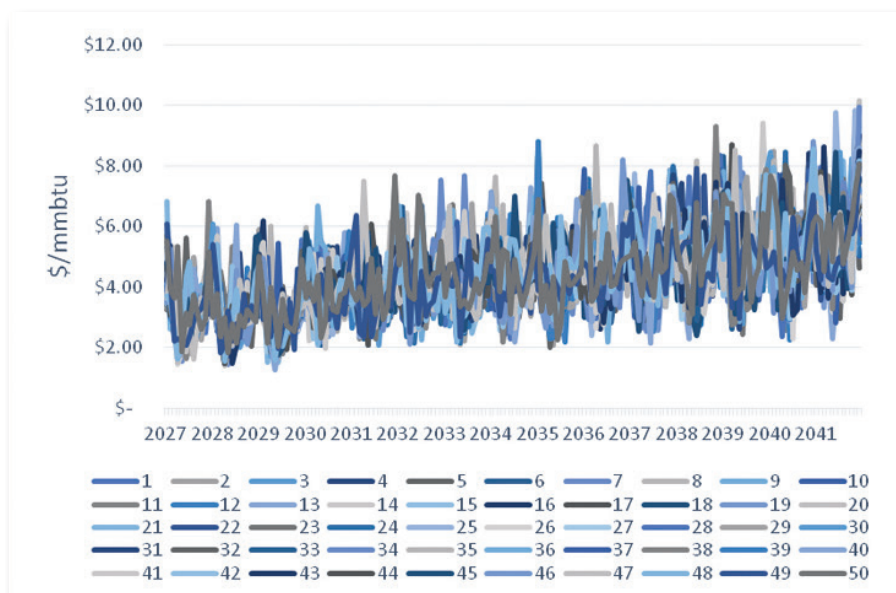
- Natural Gas Prices
- Wholesale Market Prices
- Retail Load and Demand

Correlations among these variables were preserved within the simulations to capture the combined effects of changing market and load conditions on portfolio performance.

Permian Basin Natural Gas Prices

TEP ran fifty individual risk simulations to quantify the risk of uncertainty related to Permian Basin natural gas prices. **Chart 1** details the natural gas price simulations against which the portfolios were evaluated.

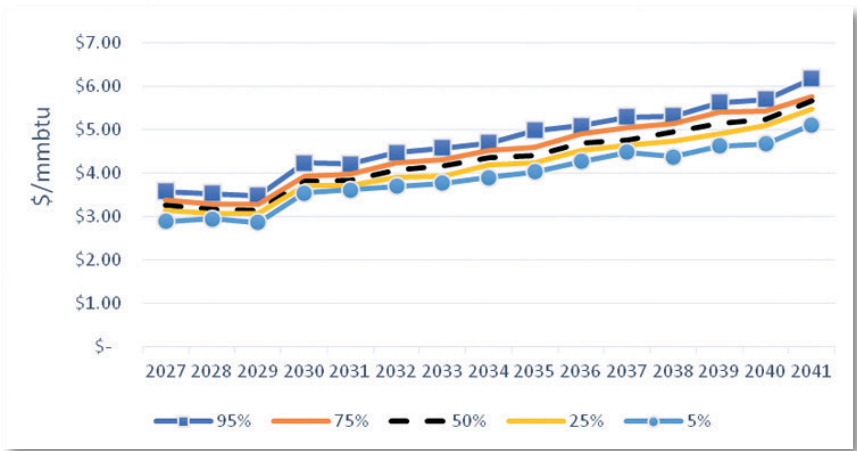
Chart 1 – Permian Basin Natural Gas Price Simulations



Permian Basin Natural Gas Price Distributions

Chart 2 shows the expected annual price distributions for natural gas sourced from the Permian Basin. These distributions are based on the stochastic data simulations shown in Chart 1.

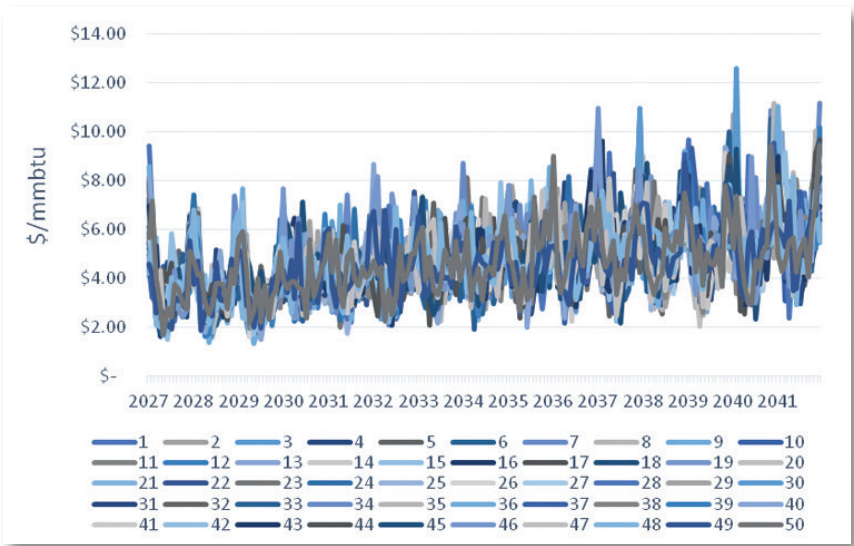
Chart 2 - Permian Basin Natural Gas Price Distributions



San Juan Basin Natural Gas Prices

TEP ran fifty individual risk simulations to quantify the risk of uncertainty related to San Juan Basin natural gas prices. Chart 3 details the natural gas price simulations against which the portfolios were evaluated.

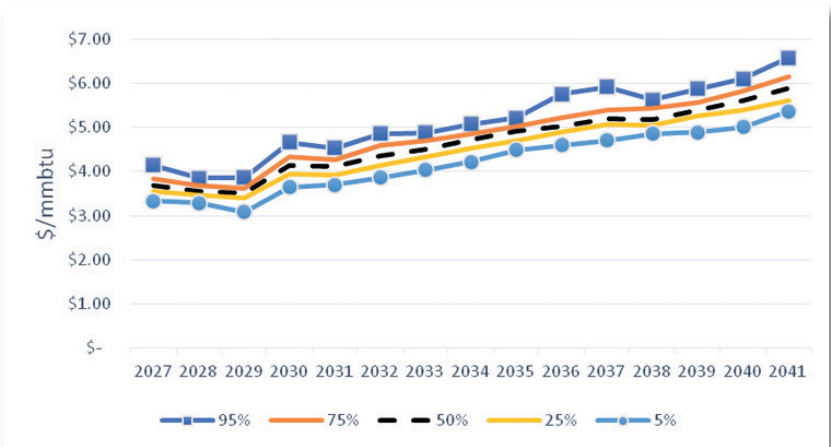
Chart 3 - San Juan Basin Natural Gas Price Simulations



San Juan Basin Natural Gas Price Distributions

Chart 4 shows the expected annual price distributions for natural gas sourced from the San Juan Basin. These distributions are based on the stochastic data simulations shown in Chart 3.

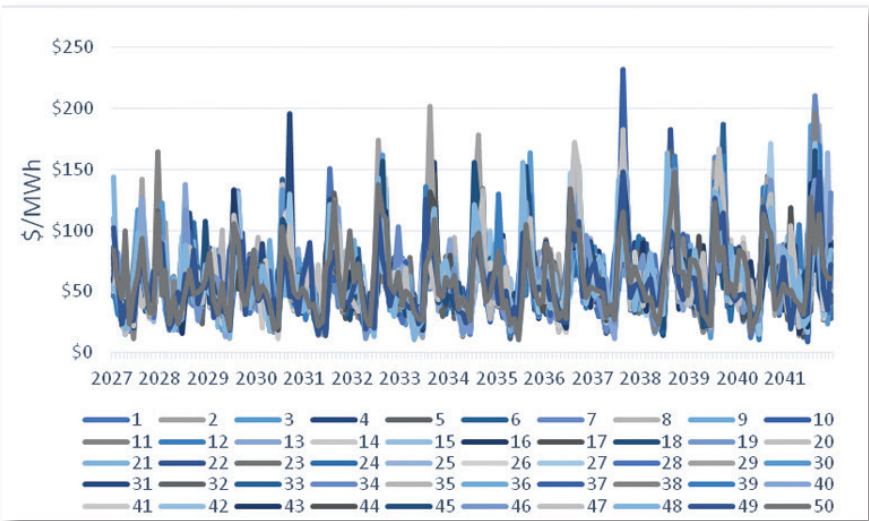
Chart 4 - San Juan Basin Natural Gas Price Distributions



Palo Verde (7x24) Wholesale Market Prices

TEP ran fifty individual risk simulations to quantify the risk of uncertainty related to wholesale Palo Verde market power prices. Chart 5 details the wholesale power price simulations against which the portfolios were evaluated.

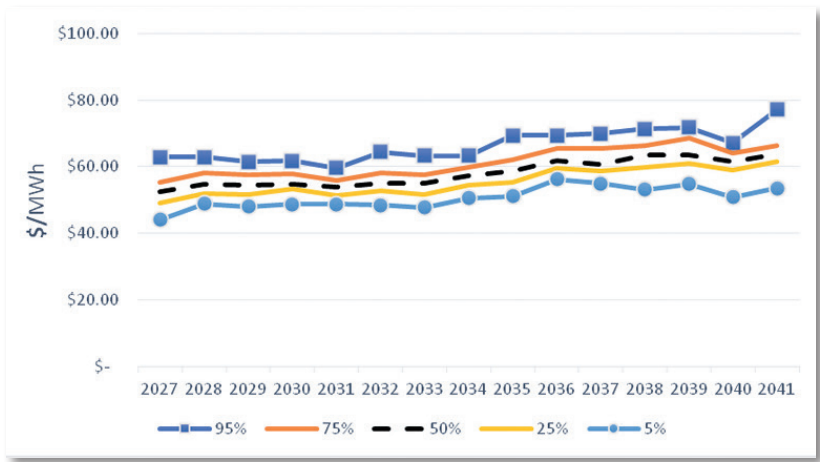
Chart 5 - Palo Verde Wholesale Power Price Simulations



Palo Verde (7x24) Wholesale Market Price Distributions

Chart 6 shows the expected annual price distributions for wholesale power purchased from the Palo Verde market. These distributions are based on the stochastic data simulations shown in **Chart 5**.

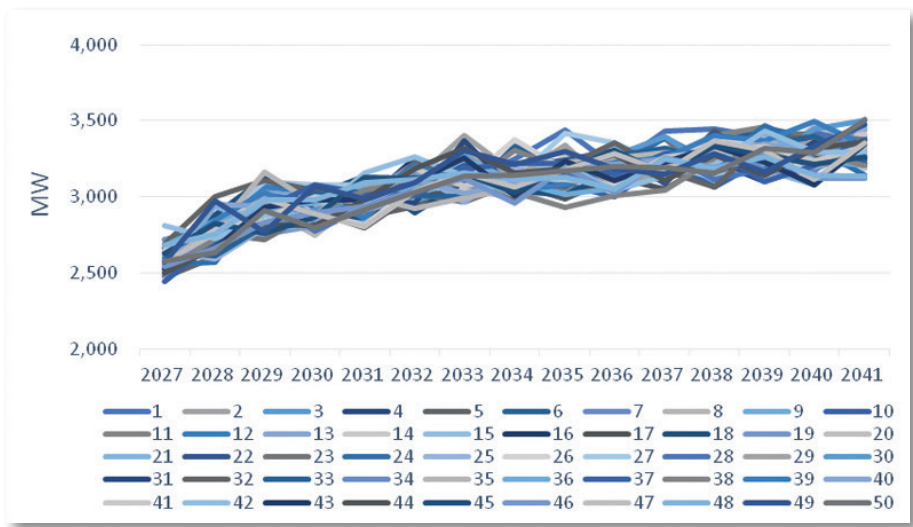
Chart 6 - Palo Verde (7x24) Market Price Distributions



Load Variability and Risk

As outlined in the previous sections, TEP also conducted Monte Carlo simulations to quantify the uncertainty associated with retail load growth. **Chart 7** below shows the results of the stochastic load simulations.

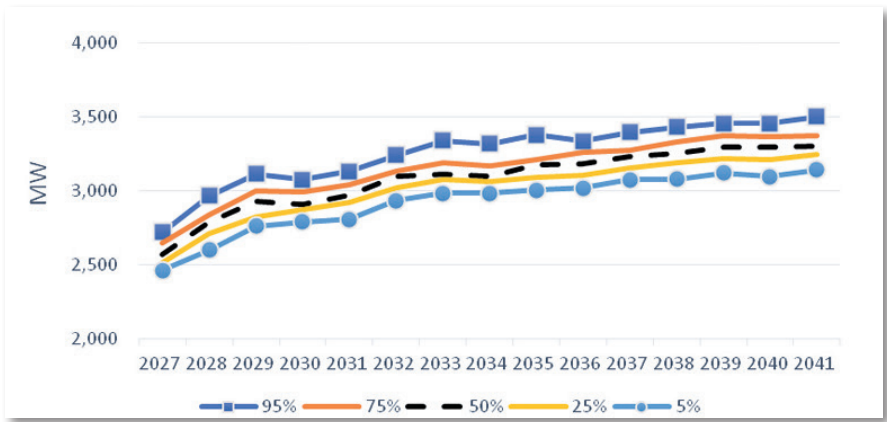
Chart 7 - TEP Peak Retail Demand Simulations



Load Variability and Peak Demand Distributions

Chart 8 shows the expected demand distributions for TEP’s peak demand forecast. These distributions are based on the stochastic data simulations shown in Chart 7.

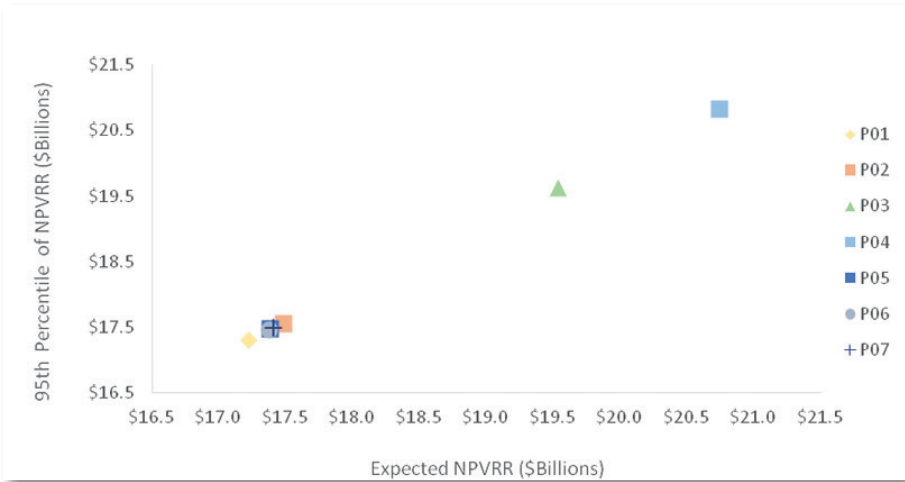
Chart 8 - TEP Peak Retail Demand Distributions



NPVRR Mean and Worst-Case Risk

The degree to which each portfolio can adequately meet future load serving requirements at a reasonable cost is measured by examining the distribution of its net present value revenue requirement (NPVRR) outcomes for each portfolio across multiple stochastic iterations. The performance of each portfolio is summarized in the charts below under the Distribution of NPVRR Risk Results section. Chart 9 summarizes select portfolios with respect to both the expected average NPVRR and the “worst case” outcome risk as represented by the 95th percentile of its NPVRR outcomes. Values lower on the graph and farther to the left represent lower risk and lower cost portfolios.

Chart 9 - NPVRR Mean and 95th Percentile



Distribution of NPV Revenue Requirement Risk Results

Chart 10 shows the results of a Monte Carlo risk analysis performed on the NPV revenue requirements of the portfolios considered in this IRP. In this analysis, fifty iterations were performed on each portfolio, in which retail demand, natural gas prices, and Palo Verde market prices were randomly varied while preserving a high degree of correlation between gas and market prices. **Chart 11** combines the results of each portfolio analysis. The peak of the curves indicates the most frequent revenue requirement outcomes, while the width of the curves reflects the potential range (i.e., risk) of outcomes.

Chart 10 - NPVRR Risk Analysis Distributions by Portfolio

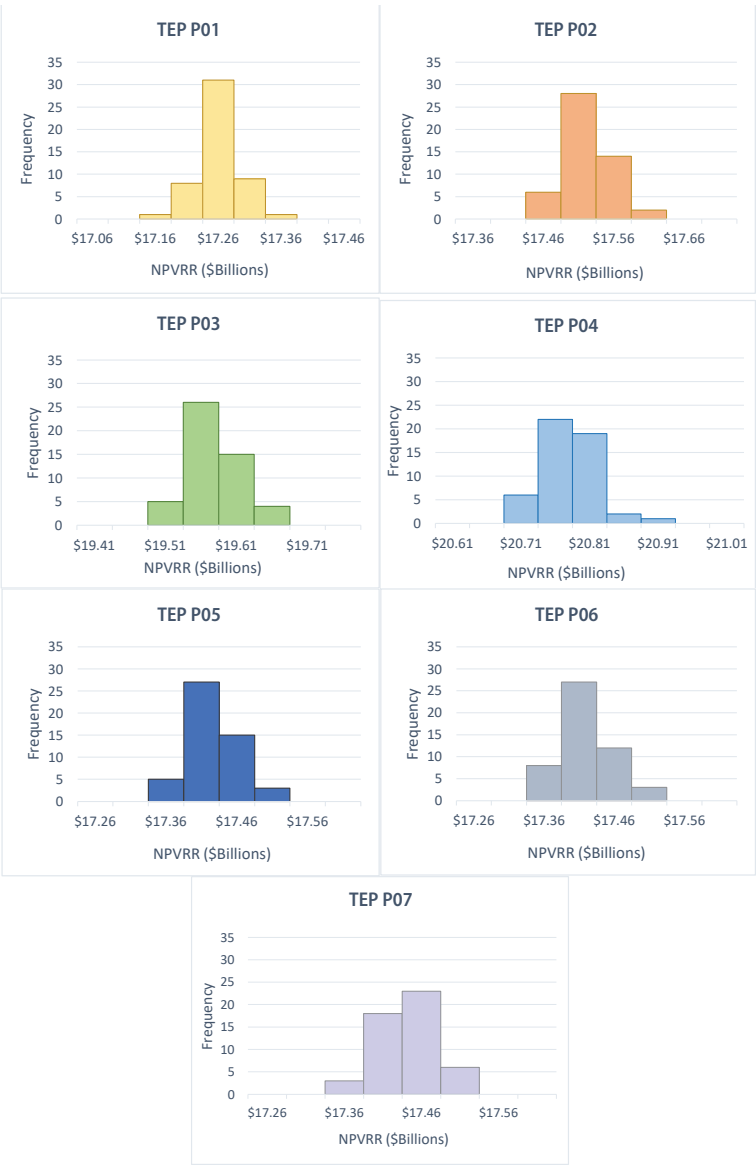
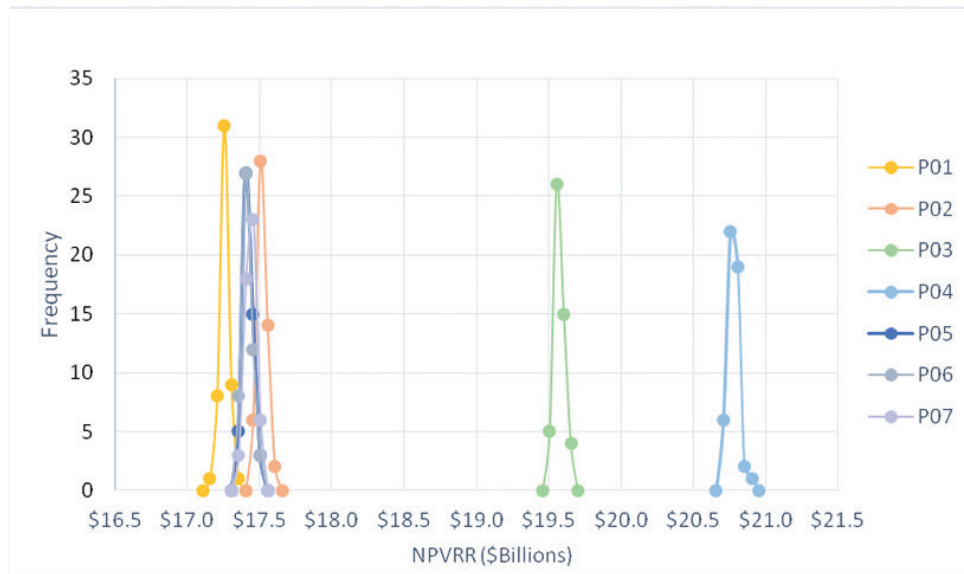


Chart 11 - NPVRR Risk Analysis Distributions



Appendix E

RESOURCE ADEQUACY STUDY

Tucson Electric Power PRM and ELCC Study

Prepared for TEP Resource Planning Advisory Council Meeting

Jan 27th, 2026



Energy+Environmental Economics

Nick Schlag, Partner
Ruoshui Li, Managing Consultant
Melissa Rodas, Senior Consultant
Les Armstrong, Consultant

Agenda

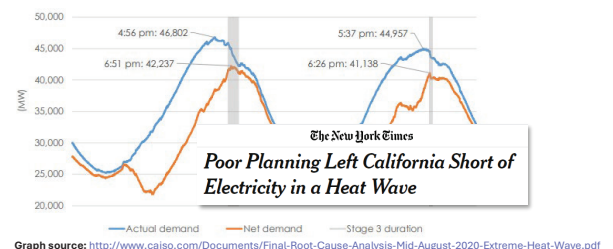
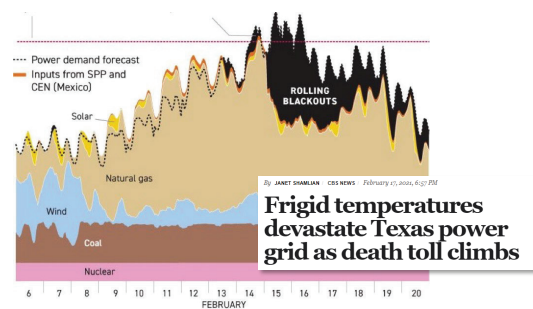
- + Introduction
- + Resource Adequacy Best Practices
- + Methods & Assumptions
- + PRM and ELCC Results

Background



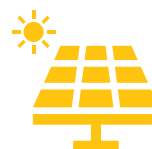
Resource adequacy is increasing in complexity – and importance

- + **Transition towards renewables and storage introduces new sources of complexity in resource adequacy planning**
 - The concept of planning exclusively for “peak” demand is quickly becoming obsolete
 - Frameworks for resource adequacy must be modernized to consider conditions across all hours of the year – as underscored by California’s rotating outages during August 2020 “net peak” period
- + **Reliable electricity supply is becoming increasingly important to society:**
 - Ability to supply cooling and heating electric demands in more frequent extreme weather events is increasingly a matter of life or death
 - Economy-wide decarbonization goals will drive electrification of transportation and buildings, making the electric industry the keystone of future energy economy



Study purpose

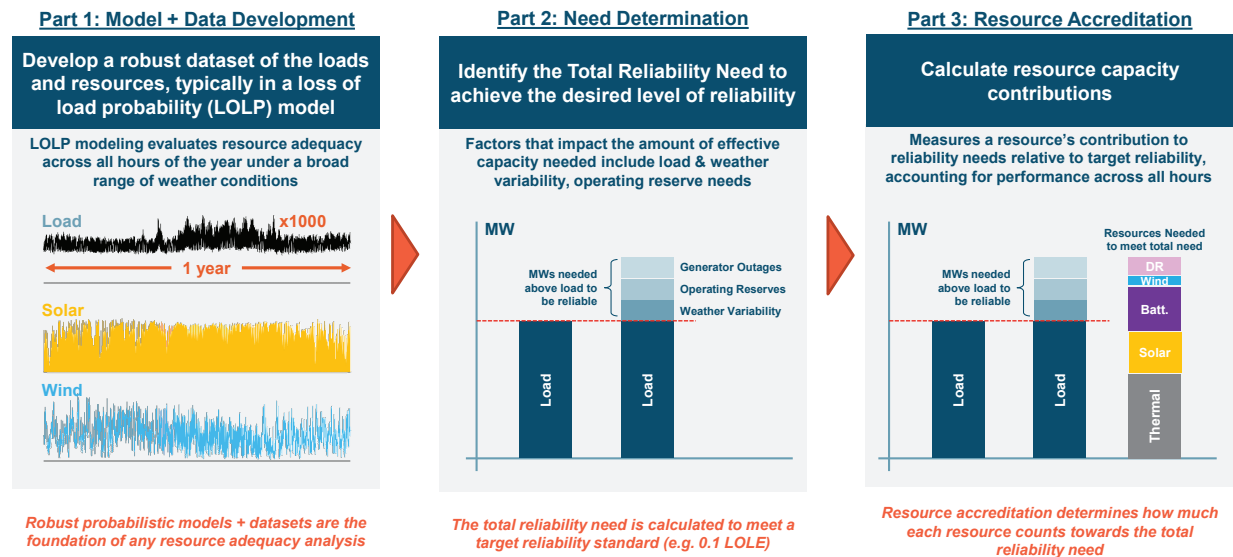
- + TEP retained E3 to conduct an RA study to establish PRM requirement and ELCC values for use in the development of TEP and UNSE's upcoming IRPs
- + This study was built on E3's previous study for TEP as well as data sets developed as part of an ongoing effort to update E3's study "Resource Adequacy in the Desert southwest"
- + Relatively to the last analysis in 2023, the major updates include:
 1. Updates to TEP and UNSE's load forecasts (including updated outlook for new large customers) and existing resource portfolio (based on recent RFP outcomes)
 2. Additional granularity in quantification of ELCC values to better capture dynamic of saturation effects
 3. Independent technology ELCCs for TEP and UNSE systems separately



Resource Adequacy Best Practices

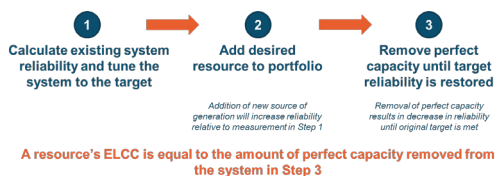
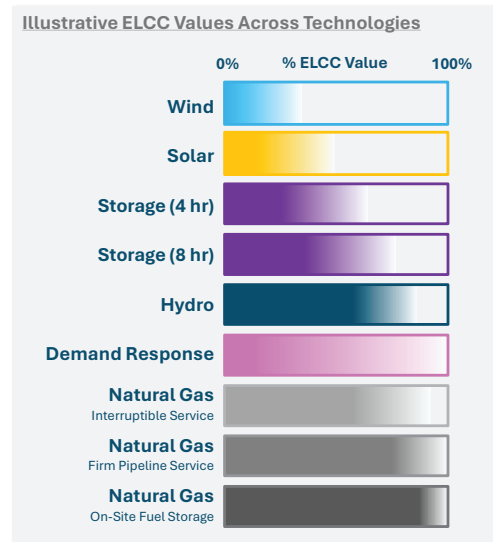


Planners are increasingly using LOLP models to support enhancements to resource adequacy



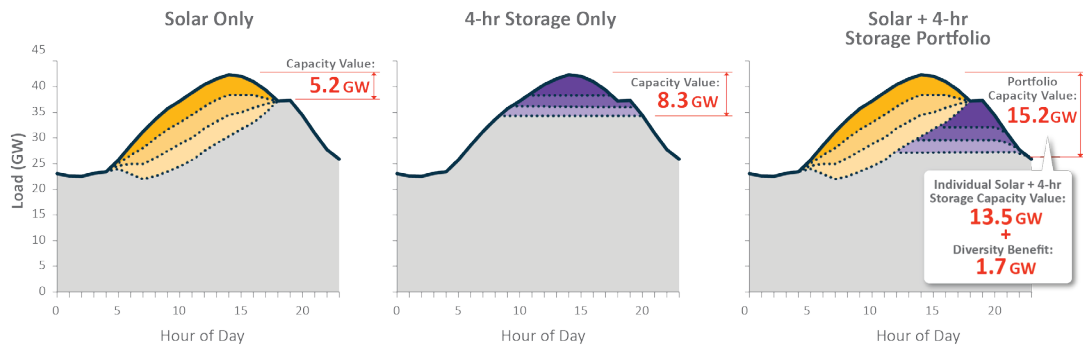
Using ELCC to accredit resource contribution to system needs

- + Effective Load Carrying Capability (ELCC) represents the equivalent “perfect” capacity that a resource provides in meeting the target reliability metric (e.g., 0.1 day/year LOLE)
- + ELCC is a technology-agnostic metric of capacity value and accounts for all factors that can limit availability:
 - Energy availability
 - Hourly variability in output
 - Duration and/or use limitations
 - Temperature-related de-rates and outage rates
 - Correlated outage risk...
- + Calculation of ELCC requires iterative use of LOLP modeling:



ELCC captures diversity benefits among technologies

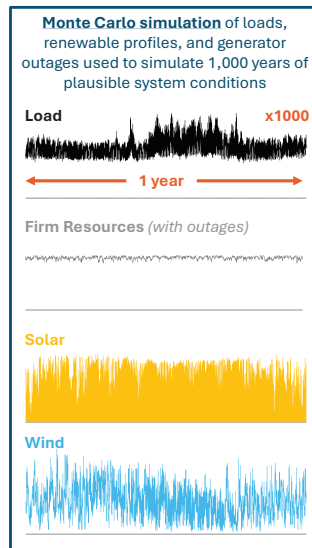
- + Resources with complementary characteristics produce the opposite effect, synergistic interactions (also described as a “diversity benefit”)
- + As penetrations of intermittent and energy-limited resource grow, the magnitude of these interactive effects will increase and become non-negligible



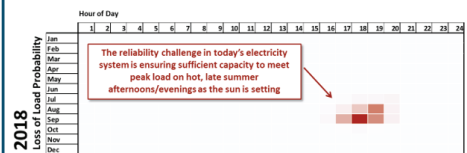
Methodology and Input Assumptions

Setting up E3's RECAP model

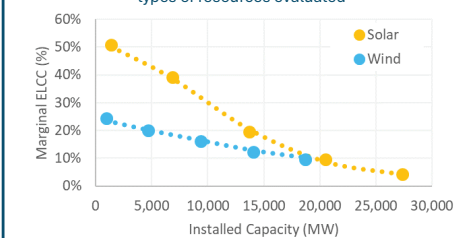
- + E3's Renewable Energy Capacity Planning (RECAP) model is a probabilistic method to consider system reliability across a wide range of load and weather conditions
- + Monte Carlo simulations consider system operations across a range of conditions
 - Broad range of loads & renewables
 - Randomly simulated plant outages
 - Dispatch of use-limited resources
- + Model results include:
 - Loss of load expectation (LOLE) and other reliability statistics
 - PRM requirements
 - ELCCs of different resources



System reliability measured relative to “one day in ten year” standard; periods of high loss of load probability identified



Effective load carrying capability (ELCC) for a wide range of types of resources evaluated



Example RECAP result from Long-Run Resource Adequacy under Deep Decarbonization Pathways for California (Calpine, 2018)

Using RECAP for Need Determination and Resource Accreditation



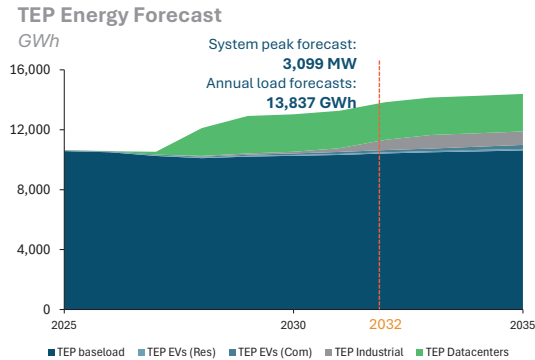
Need Determination Deliverable:

Total Reliability Need measured in ICAP, converted to an **PRM target** for UNSE +TEP system

Resource Accreditation Deliverable:

1. **Static capacity value provided by *existing and committed resources* in the portfolio**
 - Summer net dependable capacity for thermal resources
 - ELCC for existing renewable and storage resources
2. **Dynamic capacity accreditation for *generic resources* evaluated in IRP analyses (changes with penetration)**
 - Incremental wind curves
 - Incremental Solar – Storage surfaces

TEP Loads and Existing Resources



- + Load among existing end uses projected to remain relatively flat (includes impacts of energy efficiency and behind-the-meter solar)
- + Significant increases in load projected as a result of new large customers (primarily data centers)

TEP Total Capacity by Type, 2025 & 2032 (MW)

	2025	2032	Change
Coal (<i>summer</i>)	838	0	-838
Natural Gas (<i>summer</i>)	1,757	2,487	+730
Wind	428	378	-50
Utility-scale Solar	321	652	+331
Battery Storage	250	630	+380
Demand Response	10	10	-
Total	3,604	4,157	+553

Key portfolio changes

- + Springerville coal-to-gas conversion (734 MW -> 730 MW, 2030)
- + Four Corners exit in 2031 (104 MW)
- + New solar (331 MW UPV), storage (380 MW), and wind contract expiry (-50 MW Macho Springs)

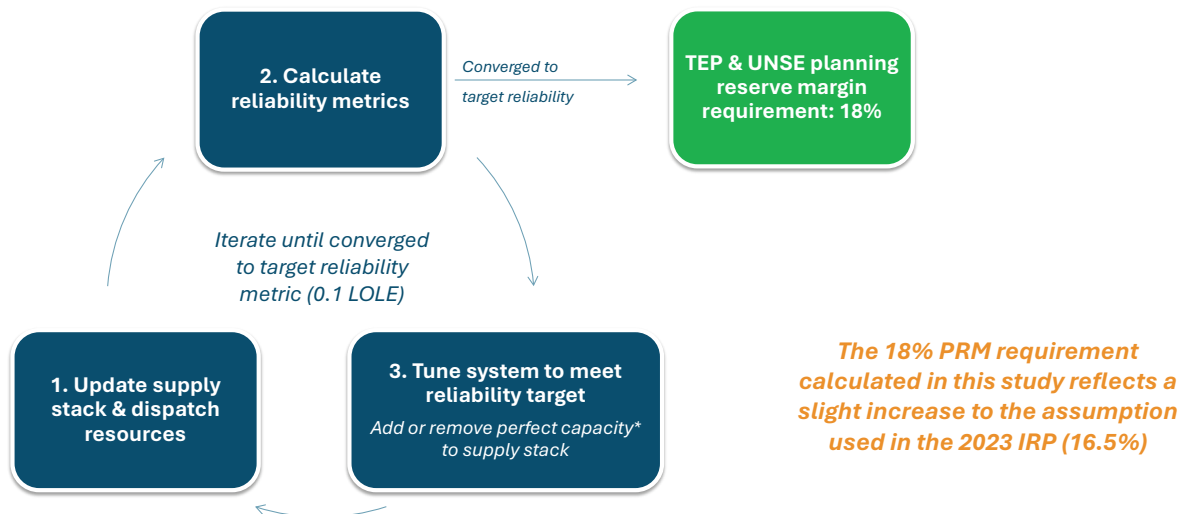
A Rich Temporal Library of Load & Renewable Profiles

Profile	Primary Source(s)	Weather Conditions Captured	Notes
Loads	TEP Hourly Historical Load	2017 2024	<ul style="list-style-type: none"> Neural network regression used to back-cast hourly load patterns under broad range of weather conditions using recent historical load data (2017-2024 for TEP, 2020-2024 for UNSE) and long-term weather data (1970-2024) Historical shape scaled to match future forecasts of regional energy demand Shapes for load modifiers (e.g., transportation electrification) layered on top of neural network results
	ERA5 Land Historical Weather Data	1970 2024	
Wind	NREL WIND Toolkit	2007 2012	<ul style="list-style-type: none"> Profiles for existing wind resources simulated based on plant locations, known characteristics (e.g., hub height & power curve) Profiles for additional wind resources simulated based on generic locations chosen by E3 with input from TEP
Solar	NREL System Advisor Model	1998 2022	<ul style="list-style-type: none"> Profiles for existing utility-scale solar resources simulated based on plant locations, known characteristics (tracking vs. tilt, inverter loading ratio) Profiles for additional utility-scale solar resources simulated based on generic locations and technology characteristics chosen by E3 with input from TEP Profiles for behind-the-meter/distributed solar simulated for TEP/UNSE service area

Planning Reserve Margin Requirement



Calculating Target PRM using LOLP Modeling



Illustrative Example of Tuning to Calculate the PRM Requirement*

Without tuning adjustment (system “as specified”)

	Installed Capacity (MW)	Accredited Capacity (MW)**
Coal	0	0
Natural Gas	2,918	2,918
Wind	628	1,287
Solar	1,298	
Storage	1,030	
DR	10	
Tuning Adjustment	0	0
Total Capacity (MW)		4,205
Median Peak Demand (MW)**		3,779
Achieved PRM (%)		13%
Loss of Load Expectation (days/yr)		1 ❌

With tuning adjustment (calibrated to 0.1 days/yr)

	Installed Capacity (MW)	Accredited Capacity (MW)**
Coal	0	0
Natural Gas	2,918	2,918
Wind	628	1,287
Solar	1,298	
Storage	1,030	
DR	10	
Tuning Adjustment	+267	+267
Total Capacity (MW)		4,472
Median Peak Demand (MW)**		3,779
Achieved PRM (%)		18%
Loss of Load Expectation (days/yr)		0.1 ✅

* Results shown for joint system (TEP & UNSE), capturing benefits of existing load and resource diversity between the two systems; illustrative resource portfolio includes existing & committed resources and generic renewable & storage additions from previous IRP

** Thermal resources are accredited at summer net dependable capacity; renewables, storage, and DR are accredited using ELCC

*** The median peak demand outputs from RECAP differ slightly (<2% difference) from sum of UNSE and TEP forecasts as RECAP captures the coincident peak from all load components in two systems

TEP Current Load Resource Balance in 2032

TEP Load-Resource Balance in 2032

Existing & Committed Resources

	Installed Capacity (MW)	Accredited Capacity (MW)
Median Peak Demand (MW)		3,099
PRM Requirement (%)		18%
PRM Requirement (MW)		3,657
Coal	0	0
Natural Gas	2,487	2,487
Wind	378	56
Solar	652	128
Storage	630	572
DR	10	9
Tuning Adjustment	0	0
Total Capacity (MW)		3,252
Capacity Shortfall (MW)		405

+ In 2032, TEP’s forecasted peak demand is 3,099 MW, resulting in a total requirement for accredited capacity of **3,657 MW** at 18% PRM

+ TEP’s existing portfolio of resources provides **3,252 MW** of accredited capacity towards the PRM requirement

- Includes existing resources that will remain in TEP’s portfolio and resources under development with executed contracts

+ Maintaining a reliability standard of 0.1 days per year would require procurement of an additional **400 MW** of accredited capacity

- This serves as the starting point for the ELCC analysis

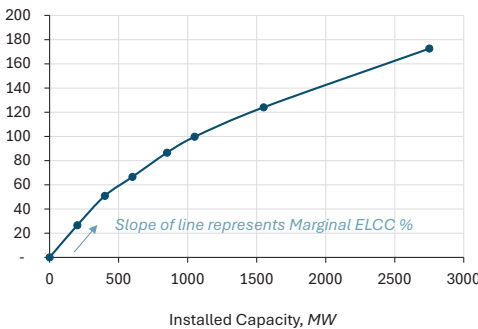
Effective Load Carrying Capacity Results



Capacity Value for Generic TEP Wind Additions

Cumulative Wind ELCC

Perfect MW



Cumulative and Marginal Wind ELCC

Wind Capacity MW	Cumulative ELCC (MW)	Average ELCC(%)	Marginal ELCC(%)
-	-	-	-
200	27	13%	13%
400	51	13%	12%
600	68	11%	8%
850	87	10%	8%
1,050	100	9%	7%
1,550	124	8%	5%
2,750	173	6%	4%

Cumulative ELCC (MW)
represents total capacity contribution of the incremental resources

Adding more resource capacity brings higher capacity value

Average ELCC (%)
represents percentage ELCC of the total capacity contribution of the incremental resource

Adding more resource capacity brings higher capacity value

Marginal ELCC (%) for wind measures how effective the additional wind can increase the portfolio ELCC

Adding the initial **200 MW** adds **27 MW** of incremental value, equivalent to a 13% marginal ELCC

Marginal ELCC decline to single digit after 400 MW penetration – at higher penetrations, loss-of-load risks shift to periods of low wind

Cumulative Portfolio Capacity Value provided by Generic Solar and Storage Addition in TEP

Cumulative portfolio ELCC of Incremental Resource Additions

Perfect MW

Increasing Storage Capacity

		4-hour Battery Storage Capacity (MW)										
		-	100	200	300	550	800	1,050	1,300	1,800	2,300	3,300
<i>Increasing Solar Capacity</i>	Solar Capacity (MW)	-	85	165	239	368	452	518	554	615	660	725
	250	34	121	204	283	416	512	582	621	685	735	793
	500	50	143	231	312	459	564	633	683	748	800	862
	750	67	160	247	335	489	604	683	739	808	857	930
	1,000	76	169	257	343	511	631	723	783	863	912	986
	1,500	87	180	270	359	544	666	764	844	945	1,011	1,097
	2,000	97	190	284	367	558	688	791	874	996	1,086	1,192
	3,000	112	206	301	383	576	718	823	906	1,037	1,155	1,290
	4,500	129	222	315	400	598	745	850	929	1,062	1,182	1,332
	6,000	141	232	323	410	614	763	867	948	1,077	1,196	1,340
	7,500	148	240	331	420	625	778	880	957	1,091	1,200	1,347
	9,000	155	247	339	426	630	785	887	965	1,099	1,205	1,351

800 MW 4-hr Storage and 1,500 MW Solar can provide 666 MW perfect capacity toward reliability need

As the penetration of either resource increases, the total capacity contribution of the incremental resources also increases, reflecting their additional reliability contribution to the system

Marginal ELCC for TEP Solar

Marginal ELCC of Incremental Solar Additions

% ELCC of marginal storage additions

Increasing Storage Capacity

		4-hour Battery Storage Capacity (MW)										
		-	100	200	300	550	800	1,050	1,300	1,800	2,300	3,300
<i>Increasing Solar Capacity</i>	Solar Capacity (MW)	-	-	-	-	-	-	-	-	-	-	-
	250	14%	15%	16%	18%	19%	24%	26%	27%	28%	30%	28%
	500	7%	9%	11%	12%	17%	21%	20%	25%	25%	26%	28%
	750	7%	7%	7%	9%	12%	16%	20%	22%	24%	23%	27%
	1,000	4%	4%	4%	3%	9%	11%	16%	18%	22%	22%	22%
	1,500	2%	2%	3%	3%	7%	7%	8%	12%	16%	20%	22%
	2,000	2%	2%	3%	2%	3%	4%	5%	6%	10%	15%	19%
	3,000	1%	2%	2%	2%	2%	3%	3%	3%	4%	7%	10%
	4,500	1%	1%	1%	1%	1%	2%	2%	2%	2%	2%	3%
	6,000	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
	7,500	0%	1%	1%	1%	1%	1%	1%	1%	1%	0%	0%
	9,000	0%	0%	1%	0%	0%	1%	1%	1%	1%	0%	0%

Diminishing solar ELCCs at higher penetrations

Marginal solar ELCC is high in the first 250 MW addition but decline to single digit quickly afterwards (“diminishing returns”) As more solar is added to the system, periods of risk move to low-solar generation hours, reducing its ELCC

At higher penetration of storage, marginal ELCC of solar increases (“diversity benefit”) Storage can charge from excess solar in the mid day and discharge in sunset hours / late afternoons when solar output is low, creating a positive interactive benefit

Marginal ELCC for TEP Storage

Marginal ELCC of Incremental Storage Additions

% ELCC of marginal storage additions

Increasing Storage Capacity →

		4-hour Battery Storage Capacity (MW)										
Increasing Solar Capacity	Solar Capacity (MW)	-	100	200	300	550	800	1,050	1,300	1,800	2,300	3,300
	-	-	85%	80%	74%	52%	34%	26%	14%	12%	9%	6%
	250	-	87%	83%	78%	53%	39%	28%	15%	13%	10%	6%
	500	-	92%	88%	82%	59%	42%	28%	20%	13%	10%	6%
	750	-	93%	87%	87%	62%	46%	32%	22%	14%	10%	7%
	1,000	-	93%	88%	86%	67%	48%	37%	24%	16%	10%	7%
	1,500	-	93%	91%	88%	74%	49%	39%	32%	20%	13%	9%
	2,000	-	93%	93%	83%	76%	52%	41%	33%	25%	18%	11%
	3,000	-	95%	95%	82%	77%	57%	42%	33%	26%	23%	14%
	4,500	-	93%	93%	85%	79%	59%	42%	32%	27%	24%	15%
	6,000	-	91%	91%	87%	81%	60%	41%	33%	26%	24%	14%
	7,500	-	92%	91%	89%	82%	61%	41%	31%	27%	22%	15%
	9,000	-	92%	92%	87%	82%	62%	41%	31%	27%	21%	15%

Similar diminishing return is observed in storage marginal ELCC (85% to 26% after 1 GW addition)
As more of the same duration (4-hr) storage is added to the system, system increasingly need resources that can sustain output for longer duration

Similarly, at higher penetration of solar, marginal ELCC of storage increases, demonstrating the diversity effect

Thank You

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Ruoshui Li, Ruoshui.li@ethree.com

DAY-AHEAD MARKET DEVELOPMENT IN THE WEST

Market Reform in the Western Interconnection

The Western Interconnection continues to undergo significant transformation driven by increasing renewable energy penetration, electrification trends, evolving policy objectives, and heightened reliability expectations. Regional electricity markets play an important role in facilitating efficient resource dispatch, improving reliability, and managing costs during this transition.

Two primary day-ahead market initiatives have emerged in the Western Interconnection: the California Independent System Operator (CAISO) Extended Day-Ahead Market (EDAM) and the Southwest Power Pool (SPP) Markets+ (Markets+). Both are designed to expand beyond traditional bilateral trading frameworks by providing centralized day-ahead and real-time market services across a broader geographic footprint.

Following a comprehensive evaluation of regional market alternatives, TEP has selected participation in SPP Markets+, with market launch currently expected in October 2027. This decision reflects a determination that Markets+ aligns with operational priorities, governance preferences, and long-term resource planning objectives.

Markets+ is designed as a western-focused, stakeholder-driven market platform that builds on SPP's experience in reliability coordination and organized market operations. It is intended to provide coordinated day-ahead and real-time dispatch, expanded access to transmission, and enhanced operational visibility across participating balancing authorities.¹ Stakeholder engagement through working groups, task forces, and governance structures remains ongoing and supports continued alignment between market design and participant needs.

Markets+ Participation Framework

Participation in Markets+ represents a key component of long-term strategy to enhance reliability, flexibility, and cost-effectiveness relative to a purely bilateral framework.

Markets+ will provide centralized day-ahead and real-time market functions that enable coordinated dispatch across a diverse regional resource base. Participation is expected to improve system efficiency by enabling access to least-cost resources across a broader geographic footprint while maintaining full responsibility for serving native load.

¹ Southwest Power Pool, Markets+ Overview and Design Principles, <https://www.marketsplus.org/about>

Participation is guided by several core principles:

- **Reliability** – Maintaining sufficient resources and operational coordination to meet demand under a range of system conditions.
- **Customer Value** – Delivering long-term cost efficiency while prudently managing exposure to market risks.
- **Renewable Integration** – Supporting increased deployment and utilization of variable renewable resources.
- **Governance and Transparency** – Maintaining meaningful participation in market design, rulemaking, and oversight.

Markets+ incorporates a stakeholder-driven governance structure, including an Executive Committee, independent panels, and technical working groups. This structure is designed to provide participants with an active role in market evolution while maintaining transparent and balanced decision-making processes. Independent market monitoring is also expected to support fair and efficient market outcomes.²

Participation in Markets+ will require compliance with regional resource adequacy requirements. Markets+ participants are expected to utilize the Western Resource Adequacy Program (WRAP), which requires demonstration of sufficient capacity to meet load obligations and includes compliance and enforcement mechanisms.³ Accordingly, market participation complements, but does not replace, the obligation to maintain adequate resources to ensure reliability.

Impacts on Near-Term Procurement

Participation in Markets+ will influence near-term procurement of electricity and fuel through centralized day-ahead and real-time dispatch mechanisms. The following factors are expected to enhance operational efficiency while requiring continued attention to risk management, system operations, and alignment with market rules.

² Southwest Power Pool, Markets+ Governance and Market Monitoring Frameworks. <https://southwestpowerpool.s3.amazonaws.com/newsstories/SPP009-Markets-Plus-Governance-1.pdf>

³ Western Power Pool, Western Resource Adequacy Program (WRAP) Overview. <https://www.spp.org/western-services/western-resource-adequacy-program/>

Key considerations include:	
Price Formation and Volatility	Centralized markets reflect system-wide supply and demand conditions, resulting in price variability driven by weather, load fluctuations, outages, fuel prices, and transmission constraints. Participation enables access to lower-cost energy when available, while requiring active management of price volatility.
Operational Coordination	Markets+ incorporates transmission constraints, reserve requirements, and system conditions into dispatch decisions, improving overall system efficiency and reliability while influencing dispatch patterns of individual resources.
Resource Optimization Across a Broader Footprint	Regional dispatch enables access to a diverse portfolio of generation resources across a wider geographic area, including renewable energy, storage, and dispatchable generation, improving overall system flexibility.
Market Liquidity and Competition	Broader participation increases market liquidity and competition, which may lead to more efficient pricing and improved procurement opportunities.

Impacts on Long-Term Resource Planning

Participation in Markets+ is expected to influence long-term resource planning decisions over a planning horizon of five to 25 years.

Key impacts:	
Resource Diversification and Reliability	Access to a broader regional resource mix enhances reliability and reduces exposure to localized supply disruptions or constraints.
Economic Efficiency and Cost Management	Centralized dispatch and access to regional resources may reduce production costs and improve utilization of existing assets, contributing to long-term customer value.
Infrastructure and Investment Signals	Market price signals and congestion patterns provide insight that supports planning decisions for generation and transmission infrastructure.
Alignment with Environmental Objectives	Regional markets facilitate increased utilization of renewable resources through broader geographic coordination, supporting emissions reduction and energy transition goals.

Participation in Markets+ supports the development of a flexible, resilient, and cost-effective resource portfolio while maintaining responsibility for long-term planning and resource adequacy.

Key Drivers and Implementation Considerations

As Markets+ advances toward implementation, several key considerations will continue to influence outcomes:

- **Transmission Constraints and Congestion Management:** Market benefits depend on available transmission capacity and effective congestion management practices.
- **Cost Allocation and Benefit Realization:** Appropriate allocation of costs and equitable realization of benefits remain important considerations.
- **Resource Adequacy Integration:** Coordination between Markets+ and WRAP will influence reliability planning and compliance requirements.
- **Market Seams:** Interfaces between Markets+, other organized markets (such as EDAM), and bilateral regions may introduce operational and pricing complexities.
- **Evolving Policy and Emissions Objectives:** Market frameworks must adapt to changing regulatory and environmental requirements.

Appendix F (cont.)

Markets+ is designed to economically dispatch resources across a large and diverse geographic footprint, increasing reliance on variable renewable generation and long-distance energy transfers. Effective coordination at market seams, robust transmission frameworks, and transparent operational processes will be essential to achieving intended reliability and cost benefits.⁴

Active participation in market development and implementation will continue to ensure that final market structures remain aligned with reliability needs, regulatory expectations, and customer interests.

Western Resource Adequacy Program

The Western Resource Adequacy Program (WRAP) is a regional reliability planning and compliance program administered by the Western Power Pool (WPP) with program operator services provided by the Southwest Power Pool (SPP). The program was initiated in 2019 in response to growing concerns regarding resource adequacy across the Western Interconnection, driven by thermal fleet retirements, increasing renewable penetration, and evolving load patterns. WRAP is the designated resource adequacy program of SPP's Markets+, which TEP has joined as a Phase 2 member (see above).

WRAP is the first region-wide resource adequacy framework in the Western Interconnection and is designed to provide a coordinated approach for ensuring sufficient generation and transmission capacity to meet demand during periods of system stress. The program establishes common reliability metrics and introduces compliance obligations to ensure that participating entities contribute to regional reliability while maintaining their independent planning and operational responsibilities.⁵

The WRAP includes two primary components:

- Forward Showing Program (FS Program): The planning component of WRAP, which requires participants to demonstrate, prior to each season, that they have secured sufficient capacity and transmission rights to meet their assigned share of regional reliability requirements.
- Operational Program (Ops Program): The real-time component, which facilitates the sharing of capacity among participants during periods of scarcity by requiring entities with surplus resources to assist those with deficiencies.⁶

WRAP implementation is proceeding through a phased transition. The program entered a non-binding transition period beginning in 2023 and implemented forward showing and operational requirements. The transition period is defined in the WRAP tariff as spanning from June 1, 2025 (Summer 2025) through March 15, 2028 (Winter 2027–2028). The program will become fully binding in the 2027–2028 timeframe.⁷

As of 2026, multiple utilities, including Tucson Electric Power, have indicated interest in or commitment to participating in WRAP's binding phase beginning in the winter 2027–2028 season. WRAP is intended to complement and not replace existing utility resource planning and emerging market structures but provides a near-term regional framework for addressing reliability challenges.⁸

⁴ Federal Energy Regulatory Commission (FERC), Wholesale Electricity Market Design and Regional Coordination Principles, as reflected in Commission orders and related literature.

⁵ <https://www.westernpowerpool.org/about/programs/western-resource-adequacy-program>

⁶ https://gridlab.org/wp-content/uploads/2023/09/GridLab_WRAP-Report_Slides_reducedsize.pdf

⁷ WRAP Committee of State Representatives Revised Transition Plan presentation; 9/10/24

⁸ NW Council Presentation, 9/2024

Appendix F (cont.)

As WRAP practices mature and participants gain operating experience, TEP will evaluate how regional diversity benefits and WRAP metrics can be incorporated into resource planning. Until additional experience is gained and participation levels stabilize, TEP will rely primarily on its own reliability assessments and Planning Reserve Margin targets.

WRAP Reliability Metrics

WRAP establishes a common regional resource adequacy framework using a probabilistic reliability standard of approximately one loss-of-load event day in ten years (1-day-in-10-years LOLE). Based on this reliability target, the Program Operator develops seasonal Forward Showing Planning Reserve Margins (FSPRMs) and associated regional capacity requirements. These requirements incorporate the benefits of geographic load diversity, resource diversity, and the binding operational obligations that allow participants to aid one another during scarcity conditions. Resource contributions are measured using WRAP's standardized Qualifying Capacity Contribution (QCC) methodology, which assigns each resource an accredited capacity value representing its expected contribution to meeting system reliability needs during periods of greatest stress.

The accreditation process is based in part on Capacity Critical Hours (CCHs), which are historical hours identified as having the highest reliability risk based on load, resource availability, and system conditions. CCHs help establish when capacity is most valuable and are used in the evaluation of resource performance and accreditation. For variable generation and storage resources, QCCs are determined using Effective Load Carrying Capability (ELCC) methodologies. ELCC measures the amount of additional load that a resource can reliably support while maintaining the same system reliability standard, thereby quantifying the resource's capacity value during periods of highest reliability risk. Thermal resources are accredited using outage-adjusted methodologies that reflect expected availability during system stress conditions.

Program Design and Compliance Framework

In addition to demonstrating adequate accredited capacity, WRAP participants must secure sufficient transmission rights to ensure that capacity can be delivered when needed. Compliance is evaluated separately for defined summer and winter seasons, reflecting differing regional reliability risks. WRAP is not an organized wholesale energy market and does not establish energy prices; rather, it is a capacity adequacy and reliability framework designed to complement emerging market structures such as Markets+.

Participation in WRAP provides access to regional diversity benefits and coordinated capacity sharing, which can improve resource utilization and reduce overall capacity requirements across the region. However, those benefits depend on the availability of transmission, participant performance, and continued program participation. As a result, utilities remain exposed to potential regional scarcity events, transmission constraints, and uncertainty regarding future market participation levels, particularly during widespread extreme system conditions. These considerations support TEP's continued use of utility-specific reliability assessments and planning reserve margin targets for long-term resource planning.

WRAP's governance structure is intended to provide independent, stakeholder-driven oversight through the Western Power Pool and the Resource Adequacy Participants Committee (RAPC), enabling participants to help shape program rules, tariff revisions, and business practices.

Appendix G

ENVIRONMENTAL REGULATIONS OVERVIEW

Overview

The U.S. Environmental Protection Agency (EPA) has the authority to regulate emissions and by-products produced by power generation facilities. These power plant emissions and by-products are regulated by statutory and regulatory programs. As these programs continue to evolve, they have had and will continue to have important implications for public health, the mix of U.S. generating resources, and economic growth by driving investment in new and cleaner technologies and contributing to the retirement of the more inefficient and higher emitting plants.

The discussion below provides a snapshot of the major environmental regulatory programs and recent proposals that may have an impact on TEP and its resource planning efforts. Existing and future resources are modeled taking into account the potential impact of environmental regulations in effect at that time.

Regional Haze

The EPA's Clean Air Act Regional Haze Rule¹ establishes a goal to reduce visibility impairment in national parks, national monuments, and wilderness areas (identified as Class I areas) to natural conditions (eliminating manmade visibility impairment) by 2064. Progress toward this long-term goal is measured in 10-year planning periods. For each planning period, states must develop plans that establish goals and emission reduction strategies for improving visibility by reducing emissions from sources located within their respective jurisdictions. States must submit these goals and strategies to the EPA for approval in the form of a State Implementation Plan (SIP) and must review and submit revisions to the SIP on a periodic basis. SIPs must achieve "Reasonable Progress" toward the 2064 goal and are reviewed by the EPA in relation to that objective. Reasonable Progress is an evaluation of the cost effectiveness of emission reductions based on four factors set forth in the regulation and in relation to the visibility improvement goals established by the state for the planning period.

In October 2018, the Arizona Department of Environmental Quality (ADEQ) began a stakeholder process to develop a control strategy for making Reasonable Progress toward the national visibility goal for the second implementation period (originally defined as the period from 2018 to 2028). During the spring of 2019, ADEQ developed and implemented a Source Screening Methodology² to identify sources to be considered for reasonable potential controls analysis. As a result, ADEQ notified TEP that Sundt Unit 3 and Springerville Units 1 and 2 had been selected for potential emissions controls analysis. TEP conducted the potential emissions controls evaluation, commonly referred to as the four-factor analysis, for the three units. These evaluations were submitted to the ADEQ in March 2020 and compliance measures for the three units were included in the revised SIP.

¹ U.S. EPA, Regional Haze Rule, 40 C.F.R. §§ 51.300 to 51.309.

² ADEQ, Air Quality Division, 2021 Regional Haze State Implementation Plan Source Screening Methodology (Mar. 2020)
https://static.azdeq.gov/aqd/haze/4_factor_screening_approach.pdf

Appendix G (cont.)

The ADEQ submitted the revised SIP³ to the EPA in August 2022. In December 2024, the EPA published a final rule⁴ partially approving and partially disapproving the ADEQ's Regional Haze SIP revision. The EPA disapproved ADEQ's control strategy in the revised SIP, which relies, in part, on the compliance measures for Sundt Unit 3 and Springerville Units 1 and 2. The EPA also disapproved the ADEQ's selection of sources for potential emissions controls evaluations and requested further evaluation of Sundt Unit 4.

In February 2025 (and supplemented in July 2025), TEP, along with other parties, filed Petitions for Administrative Reconsideration with the EPA, requesting that the EPA reconsider the final rule and act to approve the ADEQ's Regional Haze SIP revision. In July 2025, the EPA granted the request for reconsideration. In October 2025, TEP filed a modification to the Petition, providing further justification for the reconsideration, addressing the changed circumstances related to Sundt Unit 3 and Springerville Units 1 and 2.

In addition, various legal challenges to the final rules are pending before the U.S. Court of Appeals for the Ninth Circuit.

TEP cannot predict when or if the EPA will take action under the second implementation period for facilities located on the Navajo Nation (e.g., the Four Corners Power Plant). TEP will work with the operating agent, Arizona Public Service (APS), to develop compliance strategies as needed.

Greenhouse Gas Regulation

In May 2024, the EPA published final rules to regulate greenhouse gas (GHG) emissions from two categories of fossil-based electric generating units (EGUs) under Section 111 of the Clean Air Act: (i) existing steam units (including coal- and natural gas-fired); and (ii) new natural gas-fired turbines.⁵

The final rules established:

- Emission guidelines for existing coal-fired steam EGUs, which are subcategorized based on federally enforceable retirement dates. These emission guidelines affect Springerville Units 1 and 2, as well as Four Corners Units 4 and 5;
- Emission guidelines for existing natural gas- and oil-fired steam EGUs aligned with routine methods of operation and maintenance, which are subcategorized based on the annual capacity factor of each unit beginning January 1, 2030. These emission guidelines affect Sundt Units 3 and 4;
- New source performance standards for new stationary natural gas-fired combustion turbines, which are subcategorized based on the annual capacity factor for each unit. For base load units (i.e., units with an annual capacity factor greater than 40%), the EPA established a two-phased performance standard. For phase 1, new base load units must initially meet performance standards based on the use of highly efficient combined cycle generation with the best operating and maintenance practices. For phase 2, the final rule requires that such base load units achieve emissions reductions equivalent to a 90% carbon capture and sequestration (CCS) rate beginning on January 1, 2032.

3 ADEQ, Air Quality Division, State Implementation Plan Revision: Regional Haze Program (2018–2028) (Aug. 2022) https://static.azdeq.gov/aqd/sip/2021_regionalhaze.pdf

4 U.S. EPA, Partial Approval and Disapproval of Air Quality Implementation Plans; Arizona; Regional Haze State Implementation Plan for the Second Implementation Period and Prong 4 (Visibility) for the 2015 Ozone and 2012 Particulate Matter Standards (Dec. 2024) <https://www.govinfo.gov/content/pkg/FR-2024-12-18/pdf/2024-29508.pdf>

5 U.S. EPA, New Source Performance Standards for Greenhouse Gas Emissions from New, Modified and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emissions Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generation Units; and Repeal of the Affordable Clean Energy Rule, 89 Fed. Reg. 39798 (May 9, 2024). <https://www.govinfo.gov/content/pkg/FR-2024-05-09/pdf/2024-10162.pdf>

Appendix G (cont.)

Various legal challenges to the final rules are pending before the U.S. Court of Appeals for the District of Columbia Circuit. In April 2025, the Court granted the EPA's unopposed motion to hold the case in abeyance indefinitely (following a previous sixty-day stay), while the EPA conducts a rulemaking to reassess the rules. In June 2025, the EPA published a proposed rule containing two co-proposals to address the 2024 final rules. In the primary proposal, the EPA proposed to repeal the 2024 final rules in their entirety based on a determination that fossil-based electric generating units do not contribute significantly to GHG air pollution. In the alternative proposal, the EPA proposed to:

- Repeal the Best System of Emission Reductions determinations, presumptive standards of performance, and all related requirements in the emission guidelines for existing coal-fired steam EGUs;
- Repeal the requirements for existing natural gas- and oil-fired steam EGUs; and
- Repeal the phase 2 CCS-based requirements for new base load natural gas-fired combustion turbine EGUs, keeping the phase 1 performance standards in the 2024 final rules.

In September 2026, the EPA published a rule finalizing the alternative proposal and also issued a supplemental proposal seeking additional comment on the primary proposal. On the same day, legal challenges to the new final rule were filed in the U.S. Court of Appeals for the District of Columbia Circuit.

We cannot predict the outcome of the rulemaking or the legal challenges at this time.

National Ambient Air Quality Standards

Ozone and Particulate Matter are two of the six “criteria pollutants” for which EPA must set national ambient air quality standards (NAAQS) under the Clean Air Act. Under the NAAQS program, EPA considers data and information from air quality monitors and “designates” areas as attainment or nonattainment with the standard. If an area cannot meet the standard, the area is designated as nonattainment and classified according to the amount of time that the area has remained above the NAAQS (classifications include marginal, moderate, serious, severe and extreme). States, tribes or EPA must develop plans to bring nonattainment areas back into compliance with the standard. A nonattainment designation may result in more stringent regulation and may impact economic growth in the relevant area.

Ozone NAAQS

In October 2015, the EPA finalized the 8-hour ozone NAAQS at 70 parts per billion (ppb)⁷ (the 2015 ozone NAAQS), lowering the 75 ppb standard set in 2008⁸ (the 2008 ozone NAAQS). In 2020, the ozone standards were reviewed by EPA and retained, without revision.⁹

6 U.S. EPA, Proposed Repeal of Greenhouse Gas Emissions Standards for Fossil Fuel-Fired Electric Generating Units, 90 Fed. Reg. 25752 (Jun. 17, 2025). <https://www.govinfo.gov/content/pkg/FR-2025-06-17/pdf/2025-10991.pdf>

7 U.S. EPA, National Ambient Air Quality Standards for Ozone, 80 Fed. Reg. 65,291 (Oct. 2015).

8 U.S. EPA, National Ambient Air Quality Standards for Ozone, 73 Fed. Reg. 16,436 (Mar. 2008).

9 U.S. EPA, Review of the Ozone National Ambient Air Quality Standards, 85 Fed. Reg. 87,256 (Dec. 2020).

Appendix G (cont.)

The Phoenix-Mesa area, where Gila River Power Station is located, is currently designated nonattainment and classified as “moderate” for both the 2008 and 2015 8-hour ozone NAAQS. The Phoenix-Mesa area recently was on track to be reclassified to “Serious” nonattainment. EPA addressed this matter in March of 2026 by finalizing, under Section §179(b) of the Clean Air Act, a determination that the area would have attained the standard “but for” the presence of international emissions.¹⁰ A more stringent nonattainment classification could have resulted in additional regulatory requirements for existing sources in the Phoenix-Mesa area. TEP will continue to monitor ozone NAAQS implementation and the EPA’s efforts to bring the regulated community into compliance with the ozone NAAQS.

Particulate Matter NAAQS

In March 2024 the EPA finalized a rule to lower the primary annual NAAQS for fine particulate matter (PM_{2.5}) from its current level of 12 micrograms per cubic meter (µg/m³) to 9 µg/m³.¹¹

Lowering this standard set in motion requirements for Arizona to identify areas that may not meet the new standard and recommend that EPA designate these areas as nonattainment.

Arizona’s initial evaluation found that parts of Maricopa County, Santa Cruz County, and Pinal County may not meet the new standard. Arizona has not yet submitted nonattainment area boundary recommendations to the EPA and the EPA has not yet designated any areas within the State as nonattainment.

Following the D.C. Circuit Court of Appeals’ decision denying EPA’s motion to vacate the 2024 final rule, a coalition of industry groups filed a petition for certiorari with the Supreme Court on August 28, 2026.

TEP will continue to monitor this matter.

Good Neighbor Federal Implementation Plan

In September 2018, the ADEQ submitted to the EPA the Arizona SIP Revision to address the interstate transport of ozone (Arizona Ozone Transport SIP Revision) under the 2015 ozone NAAQS. In June 2022, the EPA proposed to approve the Arizona Ozone Transport SIP Revision, finding that it contained adequate provisions to prohibit emissions that will significantly contribute to nonattainment or interference with maintenance of the 2015 ozone NAAQS in other states.

In March 2023, the EPA released its final FIP to address the interstate transport of ozone (Good Neighbor FIP) with an effective date of August 4, 2023. The Good Neighbor FIP establishes requirements for those states where the EPA disapproved Ozone Transport SIP Revisions in whole or part. The Good Neighbor FIP requires NO_x emission reductions from fossil-fueled generation facilities. The EPA provided an updated analysis in the Good Neighbor FIP that suggested Arizona may be significantly contributing to one or more nonattainment or maintenance receptors and that a separate action for Arizona was forthcoming.

In February 2024, the EPA published a proposed supplemental Good Neighbor rulemaking proposing to partially approve and partially disapprove the Arizona Ozone Transport SIP Revision and to expand the coverage of the Good Neighbor FIP to include Arizona. Arizona’s inclusion under the Good Neighbor FIP would subject certain of our fossil-fueled generation facilities to NO_x emission reduction requirements.

¹⁰ U.S. EPA, Determination of Attainment by the Attainment Date But for International Emissions for the 2015 Ozone National Ambient Air Quality Standards; Phoenix-Mesa Nonattainment Area, Arizona 91 Fed. Reg. 13,777 (Mar. 2026)

¹¹ U.S. EPA, Reconsideration of the National Ambient Air Quality Standards for Particulate Matter, 89 Fed. Reg. 16,202 (Mar. 2024)

Appendix G (cont.)

In June 2024, the U.S. Supreme Court granted a stay of the Good Neighbor FIP pending the disposition of the petitions for review of the Good Neighbor FIP currently pending in the U.S. Court of Appeals for the District of Columbia Circuit. In October 2024, the EPA issued an interim final rule administratively staying the effectiveness of the Good Neighbor FIP for all emissions sources subject to the plan as promulgated.

In September 2024, the U.S. Court of Appeals for the District of Columbia Circuit granted the EPA's request to remand the Good Neighbor FIP rulemaking record and further respond to comments related to the issues addressed in the U.S. Supreme Court's stay. The EPA published its updated response to comments for the Good Neighbor FIP in December 2024.

In March 2025, the EPA filed a motion in the U.S. Court of Appeals for the District of Columbia Circuit indicating it plans to reconsider the Good Neighbor Rule. In January 2026, the EPA published the first proposal of a two-phase plan to revise the interstate transport regulations for the 2015 ozone NAAQS. The EPA proposed to approve SIPs from eight states (including Arizona) based on a determination that emissions from these states do not significantly contribute to nonattainment or interfere with maintenance of the 2015 ozone NAAQS in downwind states.

Coal Combustion Residuals Regulation

In April 2015, the EPA issued a final rule requiring the disposal of coal ash and other coal combustion residuals (CCR) to be managed as a solid waste under Subtitle D of the Resource Conservation and Recovery Act for disposal in landfills and/or surface impoundments.¹² The 2015 CCR Rule established 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. TEP currently disposes of CCR in an ash landfill located at Springerville. SRP, the operator of Navajo, is completing closure activities at the facility's CCR landfill. At the Four Corners Power Plant, APS disposes of CCR in ash ponds and dry storage areas at the plant. In response to the detection of elevated concentrations of groundwater contaminants during CCR groundwater monitoring, APS began an assessment of corrective measures in 2019 for two CCR units at the facility and completed the assessment in 2022. Remedies were presented to the public in August 2022. The final remediation requirements represent operational costs and cannot be determined with certainty at this time.

In May 2024, the EPA published the final Legacy CCR Surface Impoundments Rule that expands the scope of the 2015 CCR Rule to address the impacts from historical CCR management and placement activities that would have ceased prior to 2015.¹³ The 2024 EPA rule establishes two new categories of federally regulated CCR including Coal Combustion Residual Management Units (CCRMUs) which broadly encompass any location at an operating coal-fired generation facility where CCR would have been placed on land. A CCRMU includes not only historically closed landfills and surface impoundments, but also prior applications of CCR on land, such as for structural fill. The final rule also establishes assessment, groundwater monitoring, closure, and post-closure requirements for CCRMUs.

12 U.S. EPA, Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals from Electric Utilities, 80 Fed. Reg. 21302 (Apr. 2025).

<https://www.govinfo.gov/content/pkg/FR-2015-04-17/pdf/2015-00257.pdf>

14 U.S. EPA, Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals from Electric Utilities; Legacy CCR Surface Impoundments, 89 Fed. Reg. 38950 (May 2024). <https://www.govinfo.gov/content/pkg/FR-2015-04-17/pdf/2015-00257.pdf>

Appendix G (cont.)

TEP continues to analyze the EPA's 2024 final rule for potential impacts to our operations. We anticipate CCRMUs will be identified at Springerville and Four Corners. The number, location, and size of these CCRMUs will be assessed in accordance with the compliance schedule outlined in the EPA's final rule; therefore, associated compliance costs cannot be accurately predicted at this time.

Legal challenges to the final rule are pending before the U.S. Court of Appeals for the District of Columbia Circuit.

In April 2026, EPA published a proposed rule that reconsiders many requirements that were established by the 2024 Rule as well as some requirements in the 2015 CCR Rule.¹⁴ The rule presents multiple proposals including potential removal of all requirements associated with CCRMUs or up to seven alternative amendments to the CCRMU requirements. EPA is also proposing to incorporate site-specific risk provisions into the 2015 CCR Rule requirements for CCR units.

Water Consumption

Water availability is a major consideration for utilities operating power plants or planning new resources in the desert southwest. For facilities already in operation, utilities need to be cognizant of water use and supply trends in the area immediately surrounding those facilities. While existing facilities have secured the legal rights to the water needed for operation, there can be a disconnect between the legal right to water and its physical availability. For this reason, technologies and strategies to decrease power plant water use become an important planning goal within the integrated resource planning process. The most effective means of reducing power plant water use is through transitioning to a less water-intensive generating resource. Increasing power plant water use efficiency may also be effective. This section provides an overview of TEP's water use at its existing generating facilities and discusses strategy to reduce overall water consumption intensity (i.e., gallons of water consumed per MWh generated). As TEP looks to expand and diversify our generation fleet, our focus is on lower water use technologies, such as natural gas-fired combined cycle and internal combustion turbines, and near zero-water use renewable and energy storage resources.

Water consumption also has a localized environmental impact. The availability of water that is withdrawn from surface waters, as in the case of the Four Corners Power Plant (Morgan Lake and the San Juan River) is highly dependent on precipitation and snowpack, as well as other uses. All of TEP's portfolios assume the retirement of or exit from this facility within the planning period, which significantly reduces and eventually eliminates any risk of water availability for power generation from surface waters.

The availability of water that is withdrawn from groundwater aquifers, as in the case of Springerville, Sundt, Gila River, and Luna power plants, is dependent on the recharge to and other withdrawals from the aquifer. Future reductions in Arizona's Colorado River surface water allocations have the potential to increase groundwater withdrawals creating additional local aquifer demand. Groundwater availability is also dependent on the hydrogeological characteristics of the aquifer itself.

¹⁴ U.S. EPA, Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals from Electric Utilities; Legacy/CCRMU Amendments, 91 Fed. Reg. 18968 (Apr 2026). <https://www.govinfo.gov/content/pkg/FR-2026-04-13/pdf/2026-07061.pdf>

Appendix G (cont.)

Facilities located in regions where local aquifers are stressed (e.g., within Active Management Areas) are subject to annual groundwater withdrawal limits and best management practices (BMPs) to minimize groundwater use. To the extent practicable, TEP implements water conservation BMPs at its power plants to minimize groundwater use. These BMPs include operating cooling towers at high cycles of concentration and recycling / re-using water across each facility where feasible.

The conversion of SGS Units 1 and 2 from coal-fired to natural gas-fired is not expected to increase water use intensity. Water use intensity may be slightly reduced overall due to the elimination of coal ash handling, hauling, and associated dust control.

EXISTING RESOURCES

Introduction to Existing Resources

This section presents an overview of TEP's existing generation and transmission assets, including thermal generation, renewable generation, energy storage, and transmission facilities. For each generating resource, information is provided regarding ownership, fuel supply, environmental controls, historical operating and emissions characteristics, and future operational considerations. Renewable generation and energy storage resources are described by technology type, capacity, ownership, and facility development characteristics. The section also summarizes TEP's transmission network and its function in maintaining system reliability, supporting customer load requirements, and enabling integration of regional energy resources.

TEP's Existing Resource Portfolio

TEP's thermal generation fleet represents a key component of the Company's resource portfolio, providing dispatchable capacity and operational flexibility to support reliability requirements. TEP may also supplement its owned and contracted resources through wholesale market transactions and firm capacity PPAs, as needed, to satisfy resource adequacy and summer peak load obligations. **Table 1** summarizes TEP's existing thermal generation resources.

Table 1 - TEP Existing Thermal Resources

Generating Station	Unit	Fuel Type	Full Net Nominal Capability (MW)	Commercial Operation Year	Operating Agent	TEP Ownership Share (%)	TEP Planning Capacity (MW)
Springerville	1	Coal	387	1985	TEP	100	365
Springerville	2	Coal	406	1990	TEP	100	365
Four Corners	4	Coal	785	1969	APS	7	50
Four Corners	5	Coal	785	1970	APS	7	52
Sundt Steam	3 & 4	Natural Gas	260	1962-1967	TEP	100	253
Sundt RICE	1-10	Natural Gas	188	2019-2020	TEP	100	160
Luna Energy Facility		Natural Gas	555	2006	PNM	33.3	190
Gila River	2	Natural Gas	619	2003	SRP	100	591
Gila River	3	Natural Gas	619	2003	SRP	75	422
Combustion Turbines		Natural Gas/Oil	219	1972-2001	TEP	100	210
Total Planning Capacity							2568

Springerville Generating Station

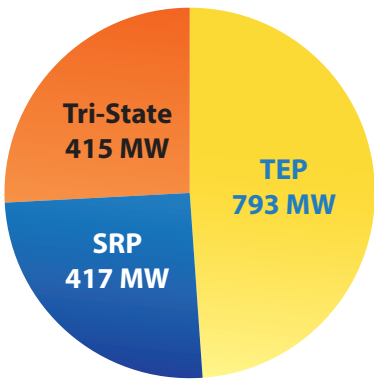
Springerville Generating Station (“Springerville”) is a four-unit generating facility located approximately 15 miles northeast of Springerville, Arizona. TEP serves as the operator for all four units. Ownership is divided among TEP (Units 1 and 2), Tri-State Generation and Transmission Association (Unit 3), and Salt River Project (Unit 4). The station has historically operated as a coal-fired generating facility; however, the owners are pursuing conversion of the units to natural gas-fired operations. This transition is expected to preserve dispatchable generation capability while reducing emissions and supporting long-term system reliability needs.



Table 2 - Springerville Ownership Structure

Units	Capacity (MW)	In-Service Date	Planned Retirement/ Conversion to Natural Gas
Unit 1	387	1985	2030
Unit 2	406	1990	2030
Unit 3	415	2006	2031
Unit 4	417	2009	2029

Figure 1 - Springerville Participation Agreement ¹



¹ Expires January 1, 2078

Springerville Coal Supply

TEP executed a coal supply agreement with Peabody Energy in 2023 for fuel sourced from the El Segundo and Lee Ranch mines. The agreement remains in effect through December 31, 2031; however, future fuel requirements will be evaluated in conjunction with the planned conversion of Springerville Generating Station to natural gas-fired operations.

Table 3 - Springerville Pollution Controls:

Unit	SO ₂	NO _x	PM	Hg
1	SDA	LNB SOFA	FF	ACI, CaBR2
2	SDA	LNB SOFA	FF	ACI, CaBR2

Legend

- SDA.....Spray Dry Absorber
- FF.....Fabric Filter (Baghouse)
- LNB SOFALow NO_x Burners – Separated Overfired Air
- SCRSelective Catalytic Reduction
- CaBR2Calcium Bromide (Added to Coal)
- ACIActivated Carbon Injection

Springerville Operational Outlook

Unit 2 and Unit 1 transitioned to seasonal operations in 2023 and 2024, respectively. In 2025, TEP announced plans to convert both Springerville Units 1 and 2 from coal to natural gas by 2030. The conversion is intended to maintain approximately 730 MW of dispatchable generating capacity while reducing carbon emissions and supporting long-term system reliability. Previously planned retirements are expected to be superseded by the natural gas conversion project.



Four Corners Power Plant

Four Corners Power Plant (“Four Corners”) is a two-unit coal-fired baseload generating station located approximately 18 miles west of Farmington, New Mexico. Arizona Public Service Company (“APS”) serves as the operating agent for Units 4 and 5. Ownership interests in the facility are held by Tucson Electric Power (“TEP”), APS, Salt River Project (“SRP”), and Public Service Company of New Mexico (“PNM”).

As a non-operating owner, TEP is responsible for its share of ongoing reclamation costs associated with the coal mines that supply Four Corners. These costs are recoverable from customers and are deferred as a regulatory asset for future recovery. Upon closure of the mines serving the facility, TEP will also be responsible for a portion of the final mine reclamation obligation. Management will continue to monitor changes in operating conditions, fuel supply arrangements, and reclamation obligations as part of its long-term resource planning process.

Table 4 - Four Corners Ownership Structure ²

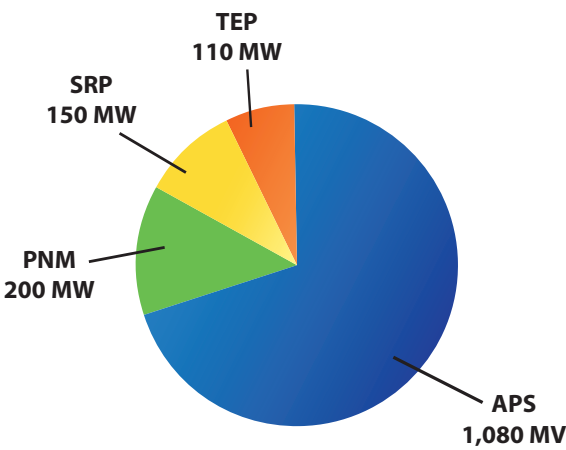
Units	Capacity (MW)	In-Service Date	In-Service Date
Unit 4	770	1969	2031
Unit 5	770	1970	2031

Four Corners Participation Agreement

The ownership, operating, and cost-sharing responsibilities of the Four Corners participants are governed by the Four Corners Project Co-Tenancy Agreement. The agreement establishes the rights and obligations of the project participants with respect to facility ownership, operation, maintenance, and project-related costs.

² APS shut down units 1-3 in December 2013 to comply with Regional Haze requirements.

Figure 2 – Four Corners Participation Agreement



Four Corners Coal Supply

Coal for Four Corners Power Plant is supplied by Navajo Transitional Energy Company (“NTEC”) from the Navajo Mine under a supply agreement, which extends through July 2031.

Table 5 - Four Corners Pollution Controls

Unit	SO ₂	NO _x	PM	Hg
4	FGD	SCR	FF	FGD, FF, CaBR2
5	FGD	SCR	FF	FGD, FF, CaBR2

Legend

- FGD Flue Gas Desulfurization-Wet
- FF Fabric Filter (Baghouse)
- SCR Selective Catalytic Reduction
- CaBR2 ... Calcium Bromide (Added to Coal)

Four Corners Outlook

Four Corners’ Units 4 and 5 are expected to cease coal-fired operations upon expiration of the supply agreement. Any future operation beyond 2031 would require additional fuel supply arrangements and approval by the participating owners.

H. Wilson Sundt Generating Station

The H. Wilson Sundt Generating Station, located in Tucson, Arizona, consists of ten natural gas-fired Reciprocating Internal Combustion Engine (“RICE”) generators rated at 18.8 MW each, and two natural gas-fired steam generating units (Sundt Units 3 and 4) rated at 104 MW and 156 MW, respectively. The facility is owned and operated by TEP.

The RICE generators replaced two 1950s-era steam generating units (Sundt Units 1 and 2) and provide fast-start, flexible generation that supports system reliability and the integration of increasing levels of renewable energy resources. Additional benefits of the RICE units include:



- **Improved Efficiency:** RICE units consume less natural gas per megawatt-hour generated than the units they replaced and are approximately 40 percent more efficient than the former steam units.
- **Lower Emissions:** The transition to RICE technology reduced local nitrogen oxide (NO_x) emissions by approximately 69 percent compared to the retired units, contributing to improved air quality.

Table 6 - Sundt Unit Profiles

Units	Capacity (MW)	Capacity (MW)	Planned Retirement
RICE Units 1-5	94	2020	Not Planned
RICE Units 6-10	94	2019	Not Planned
Steam Unit 3	104	1962	Not Planned
Steam Unit 4	156	1967	Not Planned

Table 7 - Sundt Pollution Controls

Units	SO ₂	NO _x	PM
RICE Units 1-5	N/A	SCR	N/A
RICE Units 6-10	N/A	SCR	N/A
Steam Unit 3	N/A	NA	N/A
Steam Unit 4	N/A	LNB SOFA	N/A

Legend

SCR Selective Catalytic Reduction

LNB SOFA Low NO_x Burners – Separated Overfire Air

NA Not Applicable

Sundt Fuel Supply

The primary fuel for the Sundt Generating Station is natural gas. TEP procures natural gas through a combination of spot market purchases and financial hedging arrangements consistent with the Company's fuel risk management strategy. Natural gas is transported to the facility via the Kinder Morgan pipeline system located adjacent to the station. Access to regional pipeline infrastructure supports reliable fuel delivery for both the steam generating units and the RICE generators.

Sundt Outlook

Sundt Generating Station is expected to remain an important component of TEP's resource portfolio, providing dispatchable capacity, operating flexibility, and ancillary services that support system reliability. The facility's natural gas-fired steam units and fast-start RICE generators complement increasing levels of renewable generation and energy storage resources. Access to reliable natural gas infrastructure and the flexibility of the RICE units position Sundt to continue supporting TEP's evolving energy needs and resource adequacy requirements.



Luna Energy Facility

Luna Energy Facility (“Luna”) is a 555-MW natural gas-fired combined-cycle generating facility located approximately three miles north of Deming, New Mexico. The facility consists of a single 2x1 combined-cycle power block incorporating two GE 7FA combustion turbines, two heat recovery steam generators (“HRSGs”), and one GE D11 steam turbine. Luna provides efficient, dispatchable generation that supports TEP’s reliability, capacity, and energy requirements.

Luna Energy Facility Ownership

Ownership of the Luna Energy Facility is held equally by Public Service Company of New Mexico (“PNM”), TEP, and Samchully Power & Utilities 1, LLC, with each owner holding a one-third interest in the facility. PNM serves as the facility operator and is responsible for the day-to-day operation and maintenance of the plant. TEP’s ownership share provides approximately 185 MW of accredited generating capacity and contributes to the Company’s long-term resource adequacy and reliability objectives.

Figure 3 – Luna Ownership

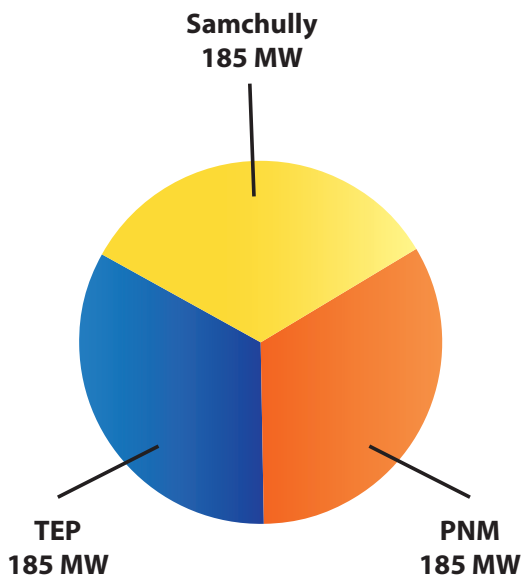


Table 8 – Luna Unit Profile

Units	Capacity (MW)	Entered Service	Planned Retirement
Power Block 1	555	2006	Not Planned

Luna Energy Facility Fuel Supply

Each Luna participant manages its own natural gas supply. TEP purchases natural gas on the spot market through hedging contracts consistent with the UNS Energy Hedging policy.

Luna Energy Facility Pollution Controls

Luna Energy Facility's turbine utilizes dry LNB and SCR for NO_x control. As a greenfield site, a Prevention of Significant Deterioration (PSD) permit was obtained prior to construction. A PSD permit requires that Best Available Control Technology ("BACT") be applied for control of SO₂ and NO_x, and the facility must comply with the Acid Rain program limits for SO₂ and NO_x.

Table 9 – Luna Pollution Controls

Unit	SO ₂	NO _x	PM	Hg
1	NA	LNB, SCR	N/A	N/A
2	NA	LNB, SCR	N/A	N/A

Legend

LNBLow NO_x Burners

SCRSelective Catalytic Reduction

NANot Applicable

Luna Energy Facility Outlook

Luna's high efficiency and operational flexibility make it a valuable resource within TEP's evolving generation portfolio. As TEP transitions the Springerville Generating Station from coal to natural gas, Luna will continue to provide reliable, lower-emitting capacity and energy while supporting the integration of renewable resources through its fast-ramping capabilities.

Gila River Generating Station

Gila River Generating Station (“Gila River”) is a 2,476 MW four block, 2 on 1 natural gas-fired combined cycle electric generating station located three miles north of the town of Gila Bend, in Maricopa County, Arizona. The plant is operated by SRP.

Gila River Ownership

Units 1 and 4 are owned by Salt River Project, Unit 2 is owned 100 percent by TEP, Unit 3 is owned 75 percent by TEP and 25 percent by UNSE.

Figure 4 – Gila River Ownership

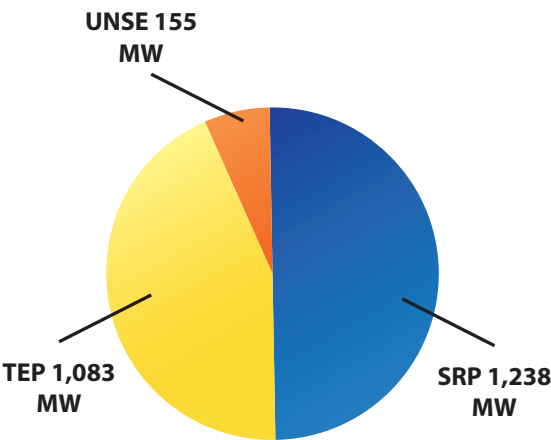


Table 10 – Gila River Unit Profiles

Units	Capacity (MW)	Entered Service	Planned Retirement
Power Block 1	619	2006	Not Planned
Power Block 2	619	2006	Not Planned
Power Block 3	619	2006	Not Planned
Power Block 4	619	2006	Not Planned

Appendix H (cont.)

Gila River Fuel Supply

Each Gila River participant manages its own gas supply. TEP and UNSE purchase natural gas on the spot market through hedging contracts consistent with the UNS Energy Hedging policy.

The plant has access to two separate pipelines operated by Kinder Morgan and Transwestern, enabling gas at the site from both the Permian and San Juan basins.

Table 11 - Gila River Pollution Controls:

Block	SO ₂	NO _x	PM	Hg
1	N/A	SCR	N/A	N/A
2	N/A	SCR	N/A	N/A
3	N/A	SCR	N/A	N/A
4	N/A	SCR	N/A	N/A

Legend

SCRSelective Catalytic Reduction

NANot Applicable

Gila River Outlook

Gila River remains one of TEP's most efficient thermal generation resources and provides significant dispatchable capacity, operational flexibility, and energy production capability. The facility's combined-cycle technology supports resource adequacy requirements and complements renewable generation and energy storage resources.

Local Area Combustion Turbines

TEP owns and operates 219 MW of natural gas- and fuel oil-fired combustion turbine capacity located within and around the Tucson metropolitan area. These resources provide peaking capacity, operational flexibility, and local reliability support during periods of high customer demand. The portfolio consists of seven combustion turbine units located at the Sundt, DeMoss-Petrie, and North Loop generating sites, as summarized in the table below.

Ownership

The combustion turbines are 100 percent owned by TEP.

Table 12 - Combustion Turbine Unit Profiles

Block	SO ₂	NO _x	PM
Sundt CT Unit 1	25	1972	Not Planned
Sundt CT Unit 2	25	1973	Not Planned
DeMoss Petrie	75	2001	Not Planned
North Loop Unit 1	25	1972	Not Planned
North Loop Unit 2	25	1972	Not Planned
North Loop Unit 3	23	1972	Not Planned
North Loop Unit 4	21	2001	1 Not Planned

Fuel Supply

The Company purchases natural gas for its combustion turbines on the spot market. Natural gas for the units at North Loop and DeMoss Petrie is delivered through Southwest Gas. Natural gas for the two Sundt turbines is delivered from TEP's Sundt connection to the Kinder Morgan pipeline.

Outlook

These resources provide dispatchable capacity, fast-response generation capability, and critical support for maintaining reliable electric service during peak demand periods and system emergencies. These units also help support the integration of renewable generation and energy storage resources.

Future retirement decisions will be evaluated through subsequent resource planning studies and will depend on system reliability requirements, resource adequacy needs, economic considerations, and the availability of replacement capacity. In addition, the Sundt combustion turbines currently provide black start capability to the Bulk Electric System. Retirement of these units would require the identification and implementation of an alternative black start resource capable of satisfying applicable reliability requirements.

Existing Renewable Resources

TEP has developed a diverse portfolio of renewable energy resources that includes utility-scale solar generation, wind resources, and renewable energy acquired through long-term power purchase agreements ("PPAs"). Over the past decade, TEP has significantly expanded its renewable resource portfolio through both owned generation and contracted resources located throughout Arizona and the western United States.

TEP's renewable energy portfolio reflects the Company's ongoing commitment to maintaining a diverse and increasingly clean energy resource mix. Renewable resources now provide a substantial portion of TEP's energy supply and are expected to remain a key component of the Company's long-term resource strategy.

Appendix H (cont.)

In combination with energy storage systems, flexible generation resources, and transmission infrastructure, renewable resources support TEP's objectives of providing reliable, affordable, and sustainable electric service while meeting evolving customer and system needs. The following table summarizes TEP's existing solar and wind resources.

Table 13 – TEP's Existing Solar and Wind Renewable Resources

Project Name	Owned or PPA	Location	Operator	Capacity MWAC
Amonix UASTP II	PPA	Tucson, AZ	Amonix	2
Avalon Solar I	PPA	Sahuarita, AZ	Avalon	29
Avalon Solar II	PPA	Sahuarita, AZ	Avalon	16
Avra Valley Solar	PPA	Tucson, AZ	First Solar	25
Babacomari Solar	PPA	Huachuca City, AZ	Babacomari Solar	160
Borderlands Wind	PPA	Catron, NM	NextEra	99
Cogenera	PPA	Tucson, AZ	SunPower	1.1
E.ON UASTP	PPA	Tucson, AZ	TEP	4.8
Ft Huachuca I	Owned	Sierra Vista, AZ	TEP	13.6
Ft Huachuca II	Owned	Sierra Vista, AZ	TEP	4.4
Gato Montes	PPA	Tucson, AZ	Astrosol	5
Iron Horse	PPA	Tucson, AZ	EON	2.04
Macho Springs	PPA	Deming, NM	Element Power	50.4
Oso Grande Wind	Owned	Roswell, NM	TEP	250
Picture Rocks	PPA	Tucson, AZ	Macquire	20
Prairie Fire	Owned	Tucson, AZ	TEP	4.5
Raptor Ridge Solar	Owned	Tucson, AZ	TEP	12.5
Red Horse Solar	PPA	Willcox, AZ	Torch	41
Red Horse Wind	PPA	Willcox, AZ	Torch	30
Solon UASTP I	Owned	Tucson, AZ	TEP	1.5
Solon UASTP II	Owned	Tucson, AZ	TEP	1.5
Springerville	Owned	Springerville, AZ	TEP	5.3
Valencia Solar	PPA	Tucson, AZ	Areva	9.9
White Mountain	Owned	Springerville, AZ	TEP	8.5
Wilmot Energy Center I	PPA	Tucson, AZ	NextEra	100
Wilmot Energy Center II	PPA	Tucson, AZ	NextEra	100

TEP's Energy Storage Projects

Battery Energy Storage Systems ("BESS") have become an increasingly important component of TEP's resource portfolio. Energy storage resources provide operational flexibility through their ability to rapidly respond to changes in system conditions, helping to maintain system reliability and balance supply and demand in real time. Compared to conventional thermal generation resources, BESS facilities can quickly transition between charging and discharging modes and provide a range of reliability services, including frequency regulation, operating reserves, ramping support, and peak demand management.

In addition to supporting reliability, energy storage resources enhance the value of renewable generation by shifting energy from periods of high renewable production to periods of higher customer demand. This capability helps reduce renewable energy curtailment, improves utilization of renewable resources, and supports integration of increasing levels of solar and wind generation.

Energy storage resources also provide operational benefits through reduced start-up requirements for thermal generation resources and through their ability to respond rapidly to changing system needs. As TEP continues to expand its renewable energy portfolio, battery energy storage systems are expected to play an increasingly important role in supporting resource adequacy, system reliability, and operational flexibility.

Existing Resources

TEP's first two battery energy storage systems, Pima Battery and Iron Horse Battery, are 10 MW / 2.5 MWh lithium-ion facilities that were commissioned in 2017. These systems provide frequency response services, support reliability of the Western Interconnection, and can be manually dispatched as needed to maintain system reliability during critical operating conditions.

In 2021, TEP added the Wilmot Battery, a 30 MW / 60 MWh lithium-ion battery energy storage system paired with the Wilmot Energy Center solar facility. The battery is charged using solar energy produced during periods of high solar output and discharged during peak demand periods, allowing midday renewable energy to be shifted into the late afternoon and evening when customer demand is typically highest. The system also provides operating flexibility and reliability benefits through manual and automated dispatch capabilities.

In 2025, TEP placed the Roadrunner Reserve Battery Energy Storage System into service. Roadrunner Reserve is a 200 MW / 800 MWh lithium-ion battery system and is the largest energy storage resource in TEP's portfolio. The facility enhances system reliability by storing energy during periods of abundant solar production and discharging during peak demand periods, while also supporting integration of increasing levels of renewable generation.



10 MW Battery Energy Storage System at Iron Horse

Appendix H (cont.)

Following the successful deployment of the Roadrunner Reserve battery energy storage system, TEP brought a second 200 MW / 800 MWh system, Roadrunner Reserve II, into service in 2026. Together, the facilities represent 400 MW of storage capacity and 1,600 MWh of energy storage, making them among the largest battery storage resources in Arizona.

In 2026, Wilmot Energy Center II entered service, adding a 100 MW battery energy storage system paired with a 100 MW solar facility. The project expands TEP's ability to shift renewable energy production to periods of highest customer demand and further strengthens grid reliability and operational flexibility.

Together, these resources provide TEP with approximately 550 MW of battery storage capacity and play an increasingly important role in supporting reliability, renewable energy integration, and peak load management.

Table 14 - TEP's Existing and Planned BESS

Project Name	Owned or PPA	Location	Operator	Capacity/Energy (MW/MWh)
Pima Battery	PPA	Tucson, AZ	NextEra	10/2.5
Iron Horse Battery	PPA	Tucson, AZ	EON	10/2.5
Wilmot Battery	PPA	Tucson, AZ	NextEra	30/60
Wilmot Energy Center II	PPA	Tucson, AZ	NextEra	100/400
Winchester Solar (Planned)	PPA	Willcox, AZ	Torch	80/80
Roadrunner Reserve	Owned	Tucson, AZ	TEP	200/800
Roadrunner Reserve II	Owned	Tucson, AZ	TEP	200/800

Planned Energy Storage Resources

Looking ahead, TEP plans to continue expanding its energy storage portfolio through projects such as Winchester Solar and Storage, which is expected to further increase the Company's ability to integrate renewable resources while maintaining reliable service for customers.

Distributed Energy Resources

Distributed Energy Resources (“DER”s) consist of customer-sited generation, energy storage systems, electric vehicle charging infrastructure, and other distributed technologies located throughout TEP’s service territory. The largest component of TEP’s existing DER portfolio is customer-owned rooftop solar generation, which has grown significantly over the past decade as customers have sought greater control over energy usage and costs.

Customer-sited solar resources provide clean energy directly to customer facilities and can reduce demand on the electric system during daylight hours. In addition to rooftop solar, TEP continues to support the deployment of customer-owned battery storage systems and other emerging distributed energy technologies that enhance customer resiliency and operational flexibility.

While individual DER installations are generally small compared to utility-scale resources, the aggregate contribution of distributed resources represents a meaningful component of TEP’s overall resource portfolio. These resources can help reduce system demand, improve local reliability, defer certain infrastructure investments, and support the Company’s broader sustainability objectives.

TEP monitors the growth and performance of distributed energy resources as part of its ongoing resource planning activities and evaluates their expected contribution to future energy and peak demand requirements.

DER Outlook

Distributed energy resources are expected to continue growing throughout the planning period as more customers adopt rooftop solar, battery storage, electric vehicles, and other distributed technologies. TEP expects DERs to play an increasingly important role in shaping future load forecasts, system operations, and resource planning activities. As technology capabilities continue to advance, distributed resources may provide additional opportunities to support reliability, customer resiliency, and grid modernization objectives.

Demand Response Resources

Demand Response resources provide system reliability benefits by reducing customer electricity consumption during periods of peak demand or system stress. Through voluntary customer participation programs and rate-based incentives, Demand Response can reduce peak load requirements and improve overall system efficiency.

TEP utilizes demand-side management and Demand Response initiatives to help customers manage energy consumption while supporting system reliability objectives. These programs encourage customers to reduce or shift electricity usage during periods of high demand, helping to lower system peak requirements and reduce reliance on higher-cost generation resources.

Demand Response resources provide operational flexibility and can serve as a cost-effective complement to generation, transmission, and energy storage investments. By reducing peak demand, Demand Response programs can improve resource adequacy and help defer future infrastructure requirements.

Demand Response Outlook

Demand Response is expected to remain an important component of TEP's resource planning strategy. Advances in smart meters, building automation systems, distributed energy technologies, and customer energy management tools are increasing the potential for customer participation in Demand Response programs.

TEP will continue to evaluate opportunities to expand Demand Response capabilities and incorporate demand-side resources into future resource planning efforts. As the electric system evolves and increasing levels of renewable generation are integrated into the grid, Demand Response may provide additional flexibility by shifting customer load to periods when renewable energy production is abundant and reducing demand during peak system conditions.

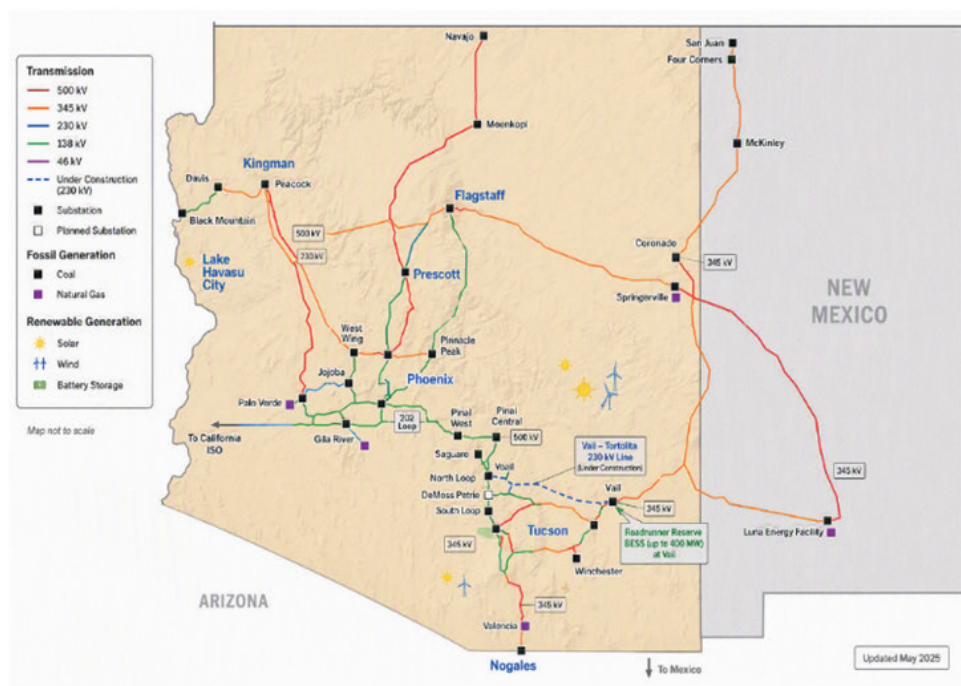
TEP's Transmission System

Transmission resources are a critical component of TEP's resource portfolio and are essential for maintaining reliable service to customers and integrating new generation resources. Adequate transmission capacity must be available to meet both existing and forecasted customer demand. TEP's Resource Planning and Transmission Planning teams coordinate closely to ensure consistency between long-term resource development strategies and transmission system expansion plans. As part of Arizona's statewide transmission planning process, TEP files a Ten-Year Transmission Plan with the Arizona Corporation Commission (ACC) and participates in the ACC's Biennial Transmission Assessment (BTA), which evaluates the adequacy of existing and planned transmission facilities to reliably meet Arizona's present and future energy needs. The BTA provides an independent review of transmission system reliability, identifies potential transmission constraints, and supports coordinated planning among Arizona utilities, transmission owners, and other stakeholders.

TEP's Existing Transmission Resources

TEP's transmission system has evolved over several decades from a network designed primarily to deliver energy from large baseload generating resources in Arizona and New Mexico into a more diverse system that supports a broad portfolio of owned generation, purchased power resources, renewable energy facilities, energy storage projects, and regional market transactions. The transmission network continues to serve as the backbone of TEP's ability to deliver reliable and economical electric service while supporting compliance with regional reliability standards and facilitating access to resources throughout the Western Interconnection.

Figure 5 - TEP's Existing Transmission Resources (including rights on other systems)



Appendix H (cont.)

Today, TEP owns and operates an extensive transmission network consisting of approximately 432 miles of 138-kV facilities, 1,143 miles of 345-kV facilities, and 42 miles of 500-kV facilities. Additionally, TEP has approximately 473 miles of 46-kV subtransmission facilities. These facilities provide both local delivery capability and access to regional generation and transmission resources across the Southwest. As shown in the following map, the Tucson service territory is interconnected with the Western Interconnection Bulk Electric System through major extra-high-voltage (EHV) interconnections at the South Loop and Vail 345-kV substations and the Tortolita 500-kV substation. These key delivery points connect the regional transmission network to TEP's local 138-kV transmission system, providing the capability to import and export energy, maintain reliability under a wide range of system conditions, and support the integration of new generation and energy storage resources. Consistent with TEP's resource planning process, transmission planning studies are performed to ensure that the transmission system can reliably accommodate forecasted load growth, resource additions, and evolving operational requirements while meeting North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) reliability standards.

Vail – Tortolita 230kV Transmission Project

The Vail–Tortolita 230-kV Transmission Project is a major transmission expansion initiative that will strengthen the reliability and flexibility of TEP's transmission system while supporting continued load growth and the integration of new generation and energy storage resources. The project involves reconstruction of approximately 64 miles of existing Western Area Power Administration ("WAPA") transmission facilities between the Vail and Tortolita substations as a double-circuit transmission line constructed to 230-kV standards. Under a joint participation agreement with WAPA, TEP will own and operate one 230-kV circuit, while WAPA will own and operate the second circuit.

TEP acquired the development rights for the western segment of the former Southline Transmission Project in 2021 and is advancing the project in partnership with WAPA. The line will extend from TEP's Vail 345-kV Substation to the Tortolita 500-kV Substation and will interconnect with TEP's transmission system at Vail, Tortolita, and a new 230-kV yard at the DeMoss Petrie Substation. The project includes new 345/230-kV transformers at Vail, new 500/230-kV transformers at Tortolita, and new 230/138-kV transformers at DeMoss Petrie, creating an additional high-voltage pathway between TEP's major transmission import points and the Tucson load pocket.

The project will improve transmission reliability, provide additional transfer capability onto TEP's 138-kV facilities and reduce the need for future upgrades to portions of the existing 138-kV network. By utilizing an existing transmission corridor and replacing aging infrastructure with modern steel monopole structures, the project provides these benefits while minimizing environmental, visual, and land-use impacts associated with development of a new transmission corridor.

The project is being constructed in phases. Based on TEP's most recent transmission planning filings, the Tortolita-to-DeMoss Petrie segment is expected to enter service in 2026, with the DeMoss Petrie-to-Vail segment expected to enter service in 2027. Upon completion, the Vail–Tortolita Project will establish a new 230-kV transmission backbone connecting TEP's 345-kV and 500-kV facilities and enhancing long-term reliability across the Tucson metropolitan area.

Midtown Reliability Project

The Midtown Reliability Project is a major transmission and distribution modernization initiative designed to improve electric reliability, increase system capacity, and support long-term growth in central Tucson. The project includes construction of a new 138-kV transmission line, a new Vine 138-kV Substation, and associated distribution system upgrades that will connect central Tucson to TEP's modern 138-kV network. The project is intended to address increasing demand on the area's aging 46-kV facilities which serves residential neighborhoods, commercial districts, the University of Arizona, and Banner-University Medical Center Tucson.

Upon completion, the project will establish a 138-kV transmission loop between TEP's DeMoss-Petrie and Kino substations, providing multiple sources of supply to customers in central Tucson and significantly improving system reliability and resiliency. The new facilities will provide more than three times the capacity of the existing system, support continued adoption of distributed energy resources and electrification technologies, and enable retirement of up to eight aging substations and associated lower-voltage facilities. The project also reduces stress on the remaining 46-kV facilities and supports anticipated customer and economic growth within the Tucson metropolitan area.

The Arizona Corporation Commission approved a Certificate of Environmental Compatibility for the project in September 2024. TEP currently plans to complete construction by 2029 to ensure reliable service can be maintained as demand continues to grow in central Tucson.

Transmission and Resource Adequacy

Transmission facilities play an increasingly important role in TEP's resource adequacy strategy. In addition to supporting reliable delivery of electricity to customers, the transmission system enables access to generating resources located throughout the Western Interconnection and facilitates the delivery of capacity resources needed to serve customer demand under a wide range of operating conditions. As part of the integrated resource planning process, TEP evaluates transmission capability together with generation and energy storage alternatives to ensure that future resource portfolios can be reliably delivered to load. Resource adequacy studies consider both generation sufficiency and transmission deliverability, recognizing that adequate transmission infrastructure is necessary to fully utilize available resources and maintain reliable service during peak demand periods and stressed system conditions.

Future Transmission Development

TEP continuously evaluates transmission system needs to support forecasted customer growth, changing system operating conditions, and the evolving resource portfolio. Long-term transmission planning considers reliability requirements, resource adequacy needs, economic efficiency, load growth, electrification trends, and the integration of new generation and energy storage resources. In addition to the Vail-Tortolita Project, recent transmission investments have included enhancements to the regional transmission network and bulk power system interconnections that strengthen transfer capability into the Tucson load area. Through participation in the ACC's Biennial Transmission Assessment process, regional planning organizations, and internal planning studies, TEP will continue to identify and develop transmission projects needed to maintain reliable electric service and provide access to future energy resources.

Appendix I

OPERATIONS AND PLANNING

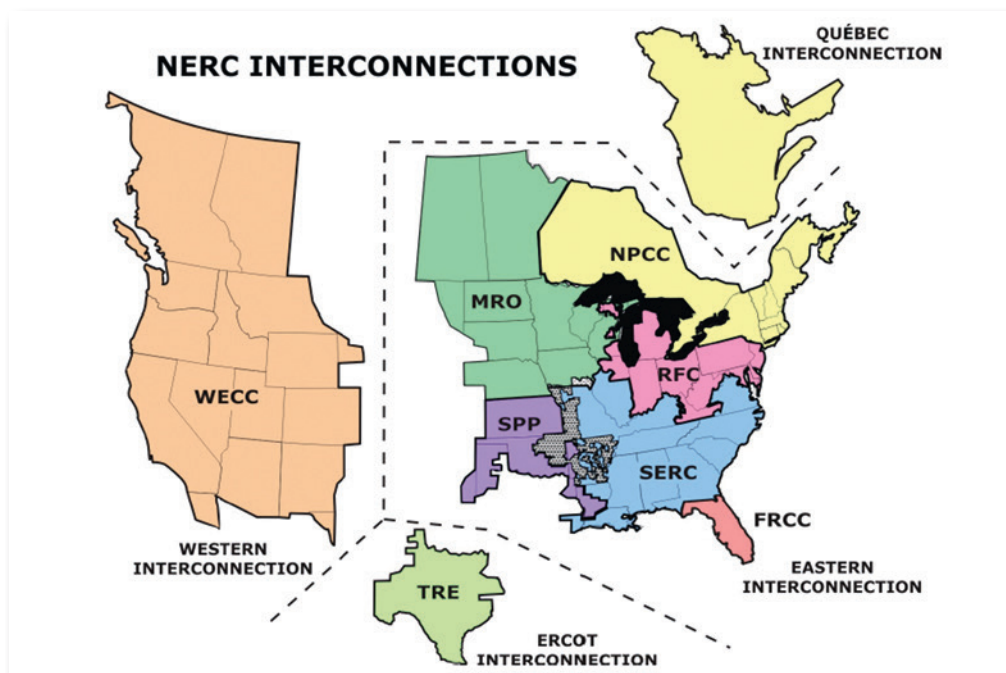
SECTION 1

SYSTEM OPERATIONS

1.1 Balancing Authority Operations and Standards

To describe TEP's utility operation with respect to the electric grid requires a review of electric grid fundamentals. There are several interconnections on the North American continent – the Eastern, Electric Reliability Council of Texas (ERCOT), Quebec, and the Western. These are each part of the North American Electric Reliability Corporation ("NERC"), see **Figure 1**.

Figure 1. NERC Interconnections



Appendix I (cont.)

There are over 30 Balancing Authorities (BA) within the Western Interconnection. Each BA is responsible for balancing its loads and resources so that the interconnection's alternating current frequency remains at or near 60 Hertz (Hz). This resource balance is important for the safe and reliable operation of generation resources and end-use equipment. Simply put, a BA is the collection of loads and resources within a metered boundary, connected to other BAs through transmission ties for the purpose of maintaining frequency.

Figure 2 details TEP's BA boundaries and its ties to five adjacent BAs.

The primary quantity established by NERC for determining a BA's reliability performance is Area Control Error (ACE). ACE is the instantaneous measure of a BA's ability to manage its load obligations and support the interconnection frequency. The following measures of ACE over time are the standards that each BA is expected to meet:

■ Control Performance Standard

Control Performance Standard is a measure of a BA's ACE over time with respect to frequency. The BA helps frequency by over-generating when frequency is low, and under-generating when frequency is high. This is known as having ACE on the opposite side of frequency.

■ Balancing Authority ACE Limit

Balancing Authority ACE Limit is a measure of how long a BA remains with an ACE that is hindering frequency. It is understood that no BA can always support frequency, but it is expected that a BA experiencing difficulties does not lean on the interconnection longer than 30 minutes.

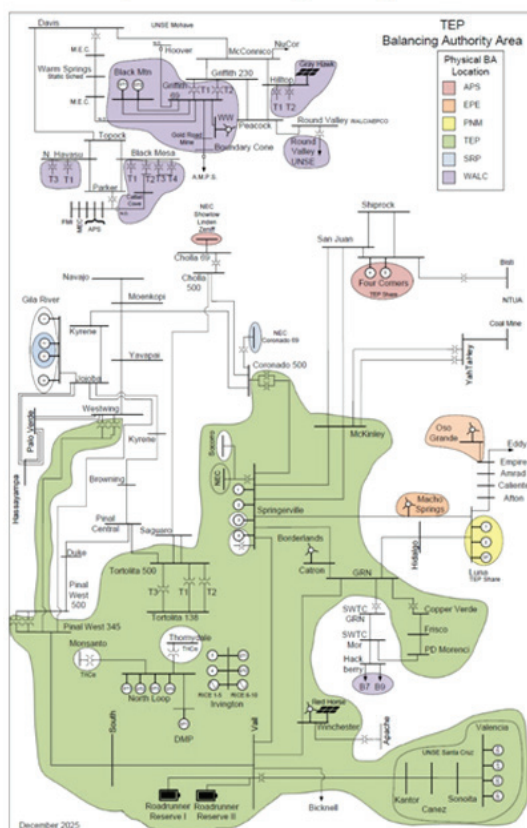
■ Disturbance Control Standard

Disturbance Control Standard is a measure of a BA's ability to replace its generating resources within 15 minutes following the unplanned loss of a resource.

■ Frequency Response Measure

Frequency Response Measure is a measure of a BA's ability to provide frequency response during a disturbance. Frequency response typically comes from governor response on generators with capacity to increase output, inductive loads, and, more recently, inverter-based resources with capacity to respond, such as batteries, or in some cases wind or solar.

Figure 2 - TEP Balancing Authority Area



1.2 Operating Reserves

Reserves are the key to providing a BA with the ability to respond to deviations in ACE and remain compliant with the measures described above. Reserves are often labeled by the function they are performing, such as regulating reserves for following load, contingency reserves for responding to a disturbance, and frequency responsive reserves that immediately respond to frequency excursions. Collectively, they are referred to as operating reserves. Reserves are also classified as spinning and non-spinning. Spin refers to generation that is online but unloaded so that it can immediately respond to an event. The reserve classification of non-spin or supplemental comes from generation that is not online but can be started and generate power within 10 minutes, such as a quick start turbine. Interruptible load contracts also fall into this non-spin category. Non-spin is primarily used for disturbance recovery. With the proliferation of power electronics, many utilities, reserve sharing groups, and regulating bodies recognize the value of storage systems and head room on renewable systems which factor into the reserve calculation.

TEP's operating reserve cost to ratepayers would be higher if not for its participation in the Northwest Power Pool Reserve Sharing Group (NWPP RSG) (see **Figure 3** for participating areas). By pooling resources, members of the RSG reduce the amount of contingency reserves they would be required to carry individually.

Figure 3 - Northwest Power Pool Reserve Sharing Group



1.3 Frequency Regulation

Frequency regulation refers to a BA's actions to regulate its supply in response to the load in its BA area. If each BA does not continuously balance its supply and demand, then the frequency of the entire Western Interconnect will be affected. To ensure this does not happen, each BA must comply with NERC's Real Power Balancing Control Performance and Disturbance Control Performance Standards.

Utilities rely on a mix of generation resources tied into their Energy Management Systems that provide Automatic Generation Control to manage their load following requirements. The increasing penetration of intermittent and variable renewable energy sources makes responding to supply variability more challenging than managing demand changes. Since these resources operate on both the supply and demand sides of the grid, their variability affects both generation assets and system load.

Moving cloud cover and variations in wind speed can, within minutes, cause large swings in renewable power, creating a need for fast-ramping resources that can, with proper AGC, ramp up and down quickly in order to maintain performance measures and regulate frequency.

1.4 Frequency Response

Frequency response is an ancillary service, as opposed to an energy or capacity service, that is similar to regulation except that frequency response automatically reacts to a system disturbance in seconds rather than minutes. Frequency disturbances occur when there is a sudden loss of a generating unit or a transmission line, disrupting the load and resource balance. As a result, other generating resources that are online must respond to counteract this sudden imbalance between load and generation and maintain the system frequency and stability of the grid.

System inertia provides resistance to a change in frequency before primary frequency control and influences the amount and timing of subsequent control needed to restore frequency. Inertia is provided by the rotating mass of generators, their prime movers, motors and their load, which together oppose changes in frequency. The magnitude of inertia in the system is changing as the industry moves from large, centralized steam plants to a more distributed network of gas turbines and renewable systems. As the inertia declines, the rate of change of frequency increases. Inverter Based Resources are moving in the direction with Fast Frequency Response to mimic the inertial response of generators.

1.5 Distribution Modernization

TEP is continually modernizing the distribution grid in order to operate the grid more safely, efficiently, and reliably while integrating new energy technologies. Current modernization programs include: The retirement of 46/13.8kV and 46/4kV substations with new 138kV looped substations to increase capacity and reliability and improve contingency options within the grid. This also includes the installation of a Field Area Network, the implementation of an Advanced Distribution Management System (ADMS), Automated Metering Infrastructure (AMI), and enhanced systems that improve situational awareness for field personnel. Distribution Line Sensors have also been installed at various locations to obtain feeder data where no data was previously available.

An ADMS is the central software application that will provide distribution supervisory control and data acquisition, outage management and geographical information in a single interface to TEP distribution operations personnel. By combining the information from these systems into a comprehensive view, an electrical distribution system model can be created for both real-time applications and planning needs. This single view improves situational awareness of the distribution system by providing additional information to operators that was not readily available in the past. Access to more information and system data will allow the opportunity for more in-depth analysis of evolving customer energy use patterns, which can be used to evaluate how customers' use of solar, energy storage, and electric vehicles impacts the load and resource balance.

The AMI system allows for two-way communication with customer meters. These meters communicate customer usage and grid data automatically, and in near-real time. This system reduces meter reading errors and allows for more frequent reads that support time-of-use and demand-based pricing plans. Sending fewer employees to physically read meters also reduces fuel consumption and pollution, allowing more efficient, environmentally sustainable operations.

In addition, AMI meters provide the Company with real-time grid information such as outages and fluctuations in voltage. This grid data is then integrated with the ADMS to further enhance the advanced capabilities of that system. This improves service restoration times, and assists with preventive maintenance that can prevent outages, and improves the reliability of electric service.

SECTION 2

DISTRIBUTION PLANNING

2.1 Overview

Distribution facilities are critical resources that enable TEP to provide safe and reliable service to its customers. Sufficient distribution capacity must exist throughout the system to meet TEP's existing and future load forecasts. TEP's transmission planning, asset management, and distribution planning groups coordinate their planning efforts to ensure the most cost-effective and beneficial system upgrades are planned and implemented to meet customer demand.

2.2 Distribution Planning Analysis

TEP's distribution system is planned in accordance with the Distribution Equipment Addition Analysis Workflow. A number of key metrics are analyzed throughout the year to ensure the distribution system is capable of providing safe and reliable service in all conditions.

Distribution substation transformers, switchgear, and feeder circuit loading and contingencies are analyzed on an annual basis to determine if system additions are needed. When loading or contingency issues are identified, several traditional and new technology system additions are evaluated to determine the most cost-effective solution.

Distribution system reliability is also analyzed on an annual basis to identify substations and feeder circuits that have poor reliability performance. System outage data is reviewed to determine the cause of outages in the area. Moreover, subsequent critical circuit patrols are conducted in the field to help further identify any system issues. Underground feeder cable replacements are also identified during the annual reliability analysis.

Power quality analyses are triggered by customer complaints or concerns on an as-needed basis. When voltage, flicker, or harmonic issues are identified by system operators, field personnel, or customers, monitoring equipment is installed in the field to collect data. This information is then analyzed by the distribution planning department to determine if the system is operating within industry standards. If necessary, additions are recommended to improve system performance.

Distributed generation (DG) is also closely monitored on a feeder level basis. Customer adoption of DG continues to grow and as it does, additional system studies are conducted to identify operational issues.

Appendix I (cont.)

The Distribution Planning department also coordinates very closely with the Asset Management group. When the Asset Management group identifies substation equipment for replacement, the Distribution Planning department will evaluate and direct many of the replacements. Additions to these projects are designed to support system voltage conversion from 4 kV to 13.8 kV and to add capacity to support future load growth. Many of these asset replacement projects have also included collaboration with the Transmission Planning department. Projects such as the Patriot and UA North 138 kV Substations will allow the Company to retire aging 46 kV substations, convert to 13.8 kV distribution voltage, increase capacity, and increase reliability.

Table 1 outlines major future system additions that have been identified through distribution planning analysis.

Table 1 - Future Distribution System Additions

Project	Description	Other Notes
HARTT (Santa Rita) SUBSTATION (ISD 2028)	New 138 kV substation with two 75 MVA 138/13.8 kV transformers, up to eight 13.8 kV circuits and two switchgear lineups.	Provides new looped 138kV source for surrounding area Resolves existing circuit overloads at Green Valley and South Loop Substations Resolves transformer and circuit contingencies at Green Valley, South Loop, and Hartt 46kV Substations Improves System Reliability Supports future retirement of the 46kV Hartt and La Vallita skid
Grier Substation (ISD 2028)	New 138 kV substation with two 75 MVA 138/13.8 kV transformers, up to eight 13.8 kV circuits and 2 switchgear lineups.	Provides new looped 138 kV source for residential and commercial development. Improve transformer contingencies at North Loop Substation Improves System Reliability Supports small- and large-scale renewable projects Supports future retirement of 46 kV Lateral 7.5 Substation and Tangerine Mobile Substation
VINE Substation (ISD 2027)	New 138 kV substation with two 75 MVA 138/13.8 kV transformers, up to eight 13.8 kV circuits and two switchgear lineups.	Provides new looped 138 kV source for residential and commercial development. Resolves transformer contingencies at Tucson, DMP, Sparkman, Country Club, and Olsen Substations. Improves System Reliability Supports future retirement of 46 kV UA Medical and Winnie Substations Supports delivery of renewable energy
Tucson Estates Substation	New 138 kV substation with two 75 MVA 138/13.8 kV transformers, up to eight 13.8 kV circuits and two switchgear lineups.	Provides new looped 138 kV source for residential and commercial development. Resolves contingency options on the Irvington 46kV circuits and transformer contingencies at Midvale. Improves System Reliability. Supports future retirement of 46kV Bopp Donald and Bilby Substations.

continued ►

Appendix I (cont.)

Naranja Substation (ISD 2029)	New 138 kV substation with two 75 MVA 138/13.8 kV transformers, up to eight 13.8 kV circuits and two switchgear lineups.	Provide new looped 138kV source for residential and commercial development. Resolves transformer contingencies at North Loop and Northeast Loop Substations. Improves System Reliability. Supports future retirement of 46kV Naranja and Overton-La-Cholla Substations
Wilmot Park Substation (ISD 2033)	New 138 kV substation with two 75 MVA 138/13.8 kV transformers, up to eight 13.8 kV circuits and two switchgear lineups.	Provides new looped 138 kV source for residential and commercial development Resolves transformer and circuit contingencies at East Loop, 22nd St, Arcadia, Van Buren, and Craycroft Substations Improves System Reliability Supports future retirement of 46 kV Sears and Wilmot Substations
Port Substation (ISD 2028)	New 138 kV substation with two 75 MVA 138/13.8 kV transformers, up to eight 13.8 kV circuits and two switchgear lineups.	Provides new looped 138 kV source for residential and commercial development Resolves transformer and circuit contingencies at Robert Bills, Los Reales, and Vail Substations. Improves System Reliability

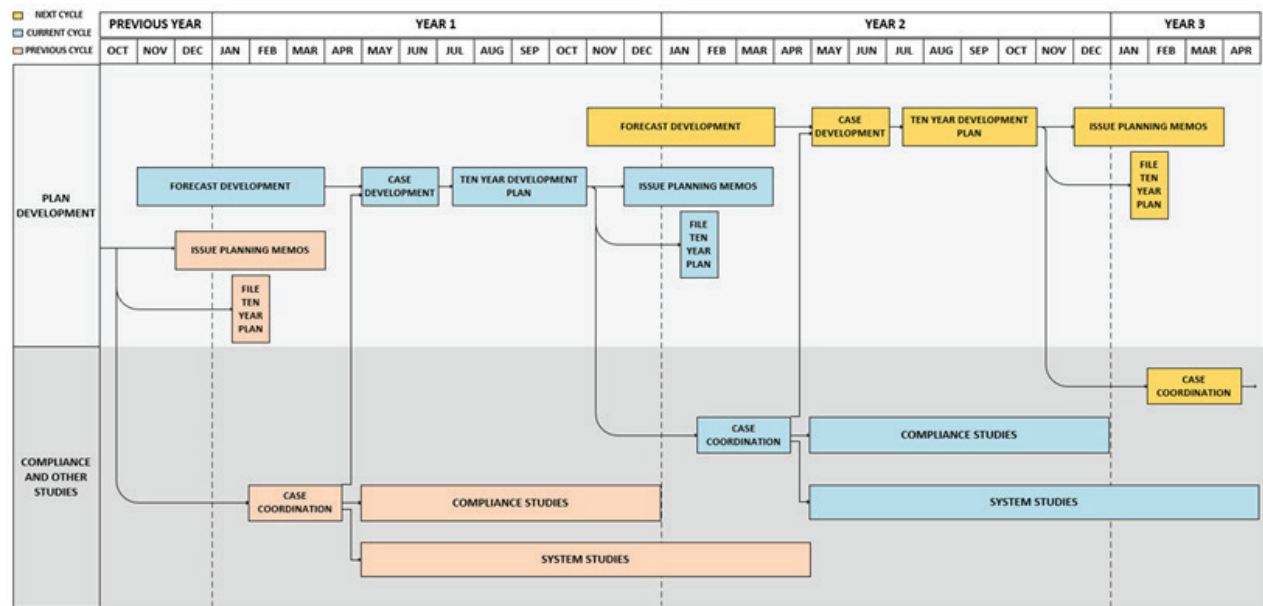
SECTION 3

TRANSMISSION PLANNING

3.1 Overview

TEP plans its transmission system in accordance with the NERC Transmission Planning System Performance Requirements (TPL-001-5.1) and the Western Electricity Coordinating Council (WECC) Transmission System Planning Performance Criteria (TPL-001-WECC-CRT-4). Using these requirements, TEP annually reviews the performance of its transmission system, consisting of extra-high voltage and high voltage elements, to identify upgrades to the existing system, as well as new facilities, to meet system performance requirements based on load and resource assumptions. This process is performed over a two-year cycle, as shown in **Figure 4**.

Figure 4 - TEP Transmission Planning Process Diagram



3.2 Ten-Year Transmission Plan

TEP develops a ten-year plan for its transmission system, based on the studies described above, that is filed with the Arizona Corporation Commission annually in January for the following ten years. This plan is a list of “planned” and “conceptual” projects with individual project descriptions.

Generating resource needs that are identified through the IRP process are included in the ten-year transmission plan. Transmission projects that are identified through the ten-year transmission plan are not directly incorporated into the IRP modeling as the Aurora model is run in a “zonal” simulation, meaning that the transfer capability between zones is represented by a single set of values versus multiple, individual paths. However, “planned” transmission projects that are expected to increase the transfer capability between zones are reviewed and adjustments to the transfer capability are made as appropriate.

On a statewide basis, TEP participates in the ACC’s Biennial Transmission Assessment (BTA), which produces a written decision by the ACC regarding the adequacy of the existing and planned transmission facilities in Arizona to meet the present and future energy needs of the state in a reliable manner. The Commission concluded in its most recent BTA¹ decision that the existing and planned transmission system is adequate to reliably serve the needs of the state during the study period.

3.3 Biennial Transmission Assessment

On a statewide basis, TEP participates in the ACC’s Biennial Transmission Assessment (BTA), which produces a written decision by the ACC regarding the adequacy of the existing and planned transmission facilities in Arizona to meet the present and future energy needs of the state in a reliable manner. The Commission concluded in its most recent BTA¹ decision that the existing and planned transmission system is adequate to reliably serve the needs of the state during the study period.

3.4 Reliability Must Run (“RMR”) Assessment

An RMR condition exists for the Tucson load pocket because the TEP load exceeds the system import limit of the existing and planned transmission system. However, the projected load can be served through a combination of power imports and local generation. In the 2012 BTA, the Commission ordered the suspension of RMR studies pending review of criteria that will trigger restarting RMR studies. TEP has not met any of the criteria, therefore, RMR studies were not performed for the 2025 BTA.

¹ Arizona Corporation Commission Thirteenth Biennial Transmission Assessment for 2024 Through 2033, Docket No. E-99999A-23-0016, October 23, 2025

3.5 Extreme Contingency Study

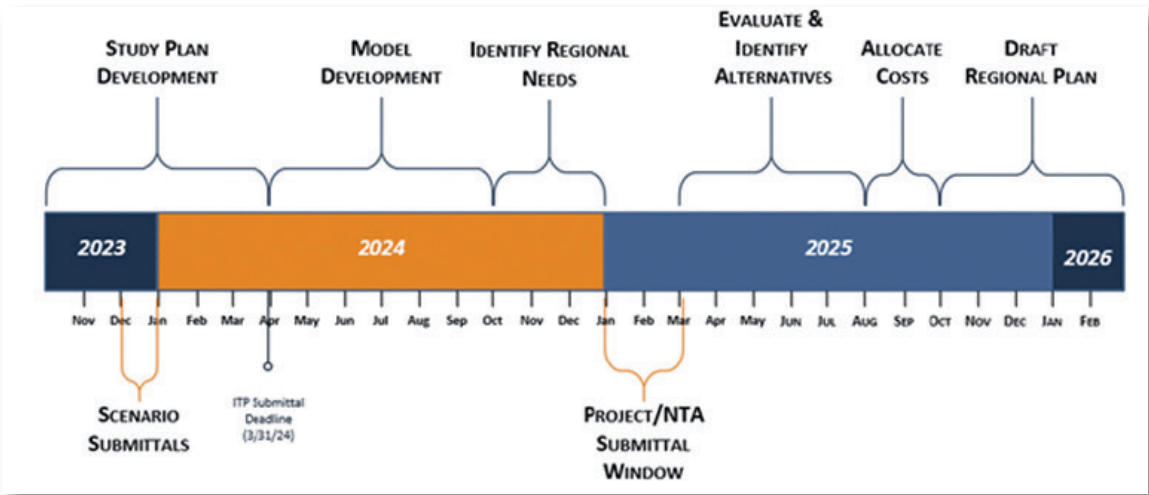
TEP conducted power flow analysis of outages involving TEP corridors that include three or more lines and TEP substations that include three or more transformers with a low side voltage of 100kV and higher. This evaluation is considered Critical Energy Infrastructure Information and was filed with the Commission under a confidentiality agreement.

3.6 Regional Planning

TEP actively participates in the regional transmission planning and cost allocation process of WestConnect as a member of the Enrolled Transmission Owners (ETO) member sector in compliance with FERC Order No. 1000 ("FERC Order 1000"). This final rule reformed FERC’s electric transmission planning and cost allocation requirements for public utility transmission providers. WestConnect is composed of utility companies providing transmission of electricity in the western United States working collaboratively to assess stakeholder and market needs and develop cost-effective enhancements to the western wholesale electricity market.

Preparation for the most recent WestConnect biennial regional transmission planning and cost allocation process (covering the period January 1, 2024, through December 31, 2025) began in the fourth quarter of 2023. A schedule for the recently completed planning cycle is presented in **Figure 5**.

Figure 5 - WestConnect Planning Timeline



WestConnect assesses transmission planning models incorporating different scenarios to identify the need for new transmission. The key deliverable is a regional transmission plan that selects regional transmission projects to meet identified reliability, economic, and public policy transmission needs. The 2024-2025 planning cycle identified no regional needs within the WestConnect footprint. Therefore, TEP’s 2026 IRP does not include an assessment of regional transmission projects that could be developed through the WestConnect process.

3.7 Other Regional Transmission Projects

Other large projects proposed for interconnection in eastern and southeastern Arizona may influence TEP's long-term resource planning decisions. TEP will continue to monitor the regional projects identified below in **Table 2** to determine how each project could impact TEP's resource plan. TEP will provide updates as these projects move into construction.

Table 2 - Regional Transmission Projects

Project	Description	Developer	Status
Nogales DC Intertie	300 MW DC, asynchronous interconnection to be developed in two 150 MW phases between the electric grids in southern Arizona and the northwest region of Mexico.	Nogales Transmission L.L.C., an indirect subsidiary of Hunt Power, L.P. and MEH Equities Management Company, a subsidiary of UNS Energy Corporation	Certificate of Environmental Compatibility was approved by the ACC in November 2017. Presidential Permit was received in 2018. FERC granted the project authority to sell transmission rights at negotiated rates on the line. Construction will commence pending sufficient subscriptions for service.
SunZia	3000MW 525 kV DC line between central New Mexico, near Ancho and the Pinal Central substation near Casa Grande, Arizona. New Build – 345 kV double-circuit line between the existing Afton Substation, south of Las Cruces, New Mexico, and the existing Apache Substation, south of Wilcox, Arizona	Pattern Energy	Pattern Energy purchased the single circuit dc transmission line from Southwestern Power Group II. According to Pattern Energy's SunZia Fact Sheet , construction is starting in 2023 with a commercial operating date in 2025/2026.
Southline	Upgrade – 230 kV double-circuit line between the Apache Substation and the existing Saguaro Substation northwest of Tucson, Arizona. The upgrade section will also interconnect at TEP's Vail, Tortolita and DeMoss Petrie substations.	Southline Transmission, L.L.C., a subsidiary of Hunt Power	Certificate of Environmental Compatibility was approved by the ACC in February 2017. NMPUC approval was received in August 2017. FERC granted the project authority to sell transmission rights at negotiated rates on the line. Project design of the Upgrade portion is under way with WAPA. Construction will commence pending sufficient subscriptions for service and land acquisition. TEP is working with the project developer on interconnections to the TEP system at three locations. In 2020, TEP acquired the rights to develop the Vail – Tortolita portion of the Southline Transmission Project.
Western Spirit Clean Line	Approximately 150-mile transmission beginning near Corona, NM and terminating at the Rio Puerco Substation..	Renewable Energy Transmission Authority of New Mexico ("RETA") and Pattern Development	Approval of the route was received from RETA. Bureau of Indian Affairs issued a Grant of Easement in 2017. FERC granted Pattern authority to sell transmission rights on the line at negotiated rates.

2 https://patternenergy.com/wp-content/uploads/2022/11/20221121-v4_SunZia-PROJECTS-Factsheet.pdf

Appendix J

CUSTOMER PROGRAMS AND DISTRIBUTED GENERATION

SECTION 1

INTRODUCTION TO CUSTOMER PROGRAMS

Energy Efficiency (EE) and Demand Response (DR) programs are foundational components of TEP's integrated resource plan. As cost-effective alternatives to traditional supply-side resources, these demand-side programs reduce the need for new generation capacity, defer transmission and distribution infrastructure investment, and deliver lasting value to customers and the grid alike. In the 2026 IRP, EE is reflected as adjustments to forecasted energy and peak demand levels used for resource planning. DR is modeled as a dispatchable demand-side resource.

As TEP's service territory experiences growing electrification of transportation and building end uses, such as data centers, the role of demand-side resources is expanding beyond load reduction to active load shaping. Managed EV charging, smart thermostats, battery storage, pool pump and water heater dispatch, and other flexible load technologies are increasingly capable of shifting consumption in ways that facilitate the integration of variable renewable generation and reduce system costs.

This transition underscores the need to move beyond traditional cost-effectiveness frameworks focused primarily on energy savings. For TEP, a more comprehensive approach that accounts for capacity value, grid stability, and customer responsiveness is essential to aligning program investments with long-term planning objectives. In this context, the program portfolio's evolution reflects not only a shift in available resources but also a broader industry-wide recognition that multiple value streams must be considered to support a reliable, resilient, and flexible energy system.

TEP is also committed to ensuring that the benefits of energy efficiency and demand response are accessible to all customers, including limited-income households and vulnerable customers. Program design, marketing, and delivery strategies are tailored to reduce participation barriers and to direct a meaningful share of program investment toward customers who stand to benefit most from reduced energy burden.

SECTION 2

DEMAND-SIDE MANAGEMENT PLAN AND TRANSPORTATION ELECTRIFICATION PROGRAMS

TEP's demand-side portfolio encompasses a broad range of programs serving residential, commercial, and industrial customers. Energy efficiency programs deliver permanent reductions in energy consumption through measures such as appliance and equipment upgrades, building shell improvements, lighting retrofits, and high-efficiency HVAC systems. Demand response programs provide the utility with access to dispatchable load reductions during periods of peak system stress or tight reserve margins, and in the future during high wholesale market prices. Together, these resources reduce system peak demand, lower customer bills, improve grid reliability and resilience, and support a cleaner energy future.

Energy Efficiency

Between 2024 and 2025, TEP's energy efficiency portfolio continued delivering measurable customer and system benefits through a diverse mix of residential, commercial, and income-qualified programs. Key highlights include:

- In 2025, residential programs delivered 54,020 MWhs and commercial programs delivered 38,782 MWh of energy savings.
- Multifamily Program Relaunch – This program expanded direct install offerings, including smart thermostats and energy efficiency measures, increasing annual savings to 3,582 MWh in 2025.
- Existing Homes Program – TEP expanded residential Existing Homes offerings, including increased participation in HVAC tune-up and home efficiency measures designed to improve customer access and energy savings opportunities. The Existing Homes Program had strong customer adoption, delivering approximately 11,272 annual MWh savings in 2025.

Energy efficiency program performance is evaluated through a measurement and verification (M&V) framework consistent with the protocols established by Energy Efficiency Rules and Arizona Corporation Commission direction¹. Reported savings and demand reductions are independently verified to ensure that the benefits credited to these programs in the IRP reflect actual, persistent, and replicable results.

As seen in **Table 1**, TEP exceeded Arizona's cumulative energy efficiency standard of 22% each year, achieving 28.5% cumulative annual savings as a percent of previous year's retail sales in 2024, and 29.8% in 2025.

¹ https://apps.azsos.gov/public_services/Title_14/14-02.pdf, Article 24.

Table 1 - Compliance with Energy Efficiency Standards

	Year	Incremental Annual Energy Savings (MWh)	Cumulative Annual Energy Savings (MWh)	Cumulative Annual Savings (% of previous year retail sales)	Cumulative EE Standard (ended 2020)
	2010-2023		2,239,368	27.25%	22.00%
Actual	2024	135,357	2,374,725	28.52%	22.00%
Actual	2025	104,558	2,479,283	29.72%	22.00%
Forecasted as of 4/1/26	2026*	81,715	2,560,998		22.00%

In July 2026, the ACC formally repealed Arizona's Electric Energy Efficiency Standard (EEES) rules. While TEP's approved three-year DSM plan is still tied to the EEES requirements and will remain in effect until further order of the Commission, there are currently no enforceable EE savings mandates applicable to regulated electric utilities in Arizona. In the absence of new rules, future DSM program development will be at the discretion of individual utilities, subject to Commission review and approval.

Demand Response

TEP's demand response portfolio continues to evolve to incorporate flexible customer resources that help reduce peak demand and improve grid reliability during high-demand periods. Highlights include:

- Smart Rewards – Utilizes connected smart thermostats to reduce system peak demand. This program grew to 22,669 devices and a max first hour load shed of 38.2 MW in 2025.
- Energy Storage Rewards – Utilizes residential battery systems to reduce system peak. By late 2025, the program had 262 enrolled devices. The program has seen consistent enrollment increases and an 80% rate of high satisfaction from participants.
- Innovative Customer Solutions Framework – Launched a micro-pilot initiative focused on load optimization and reducing customer peak consumption during high demand periods. The results of this pilot are expected in early 2027.

By the end of 2025, TEP's Load Management Pilots reached nearly 18,000 active participants, reflecting growing customer adoption of connected technologies and helping establish a foundation for future virtual power plant growth. TEP is also re-vamping its commercial direct load control program to align technology offering and price structure to more closely reflect existing conditions.

Transportation Electrification

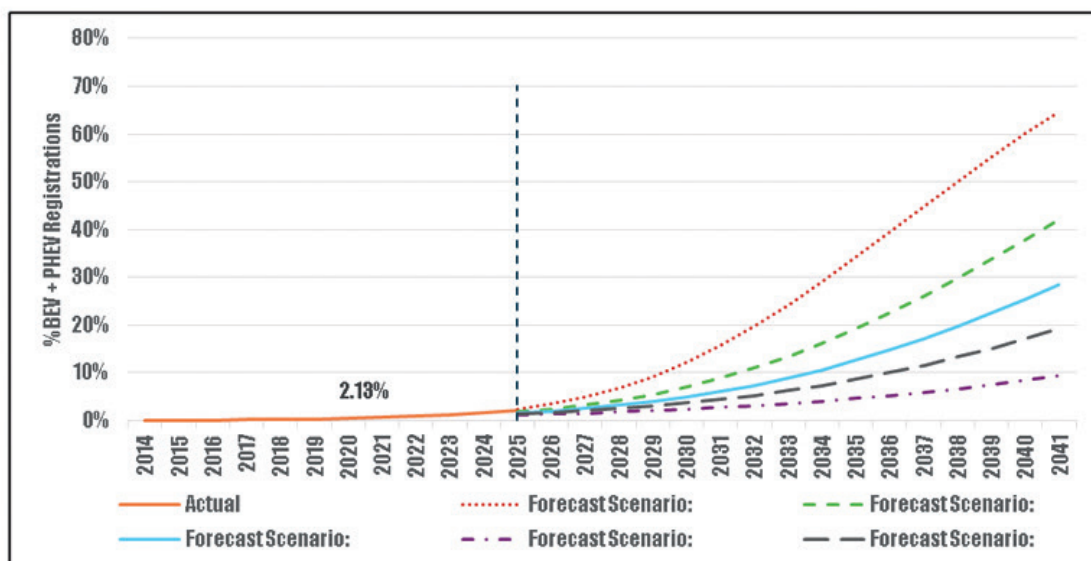
TEP's three-year Transportation Electrification Implementation Plan (2023-2025) increased awareness and adoption of transportation electrification, recognizing the benefits to the Company and the community of beneficial electrification. Highlights include:

- 1,398 residential EV charging ports installed
- 613 commercial EV charging ports contracted
- 11 electric school bus rebates provided in support of the state's first bidirectional vehicle-to-grid school bus pilot, offering just under 400 kW of capacity

Figure 1 displays the approximate percentage of total registrations within TEP's service territory for battery electric vehicles (BEVs) and plug-in hybrid electric vehicle (PHEVs). Actual percentages are displayed from 2014 through 2025, while projections from 2025 through 2041 are based on an EV Adoption and Grid Impact Study completed in 2024.

The study provided a forecast of BEV and PHEV registrations beginning in 2025, considering five different scenarios: 'Slow', 'Delayed', 'Average', 'Accelerated', and 'Aggressive'. The 2025 percentage of BEV and PHEV registrations, 2.13%, falls between the forecasted 'Aggressive' (2.38%) and 'Accelerated' (1.79%) scenario values. This demonstrates the continued strong growth of electric vehicles in TEP's service territory, which will provide additional beneficial electrification and demand response opportunities.

Figure 1 - Share of Electric Vehicle Registrations (BEVs and PHEVs)²



² Approximated based on Pima County data from EPRI.

Program Summaries

Table 2 - Program Summaries

Program	Sector	Status	Description
Efficient Products	Residential Energy Efficiency	On-going	Promotes the purchase of high-efficiency retail products through upstream and point-of-purchase incentives offered at participating retailers. Eligible products include energy efficient products and select demand response-enabled technologies.
Existing Homes	Residential Energy Efficiency	On-going	Promotes energy efficiency improvements in existing residential homes through instant rebates for products that support envelope sealing to reduce heating and cooling costs at a customer's home. The program also provides rebates for connected devices that support flexible energy use.
Limited Income	Residential Energy Efficiency	On-going	Designed to serve income-qualified customers whose household income is at or below 200 percent of the federal poverty guidelines. The program provides eligible customers with weatherization and other energy efficiency measures intended to reduce electricity consumption and associated utility costs, while ensuring health and safety of the customer's dwelling.
Multi-Family	Residential Energy Efficiency	On-going	Designed to deliver energy efficiency improvements to apartment and multi unit residential properties with individually metered complexes of two or more units. The program helps property owners and managers reduce energy use, lower operating costs, and increase tenant comfort, improve health and safety by offering rebates for HVAC replacements, HVAC tune ups, duct sealing, and direct install efficiency measures.
Residential New Construction	Residential Energy Efficiency	On-going	Promotes the construction of energy efficient homes through a whole-house system approach that promotes efficient building practices. The program provides incentives to compensate builders for constructing homes that exceed energy efficiency requirements of local building codes

continued ►

Table 2 - Program Summaries (cont.)

Shade Tree Program	Residential Energy Efficiency and Commercial Energy Efficiency	On-going	Support energy efficiency and environmental objectives by promoting the planting of shade by desert-adapted trees within TEP's service territory. Trees reduce direct solar heat gain on residential homes and commercial buildings, enhance shading, mitigate urban heat island effect, and improve neighborhood livability.
Commercial & Industrial Comprehensive	Commercial Energy Efficiency	On-going	Assists eligible commercial customers to reduce energy consumption, improve operational efficiency, and implement technologies that support grid reliability. The program offers incentives and technical assistance for energy efficiency and demand management measures through both prescriptive and custom project pathways, enabling cost-effective energy savings tailored to customer needs.
Commercial Direct Load Control	Commercial Demand Response	Re-launch in Progress	Supports peak demand reduction and assists in system emergencies through commercial and industrial (C&I) load curtailment.
Schools Energy Efficiency	Commercial Energy Efficiency	On-going	Provides 100% funding for qualified energy efficiency projects for K-12 schools. The program is designed to help schools reduce energy consumption, lower utility costs, and create better learning environments for students and staff.
Behavioral Comprehensive	Residential Energy Efficiency	On-going	Three coordinated subprograms: K-12 Education, Community Education, and Community Outreach, designed to educate current and future energy users on how awareness, behavior, and informed purchasing decisions can improve energy efficiency and reduce energy consumption.
Home Energy Reports	Residential Energy Efficiency	On-going	Provide energy savings and education for participating customers through printed and/or monthly digital reports. These personalized reports are designed to encourage customers to engage with their home's electricity use to motivate measurable savings in energy usage by driving conservation behavior.

continued ►

Table 2 - Program Summaries (cont.)

Innovative Customer Solutions	Commercial Demand Response	On-going	Provides TEP with a program to test emerging technologies and customer solutions in a controlled, real-world environment prior to seeking approval for full-scale program deployment. Under this framework, TEP launched the Advanced Load Management Pilot (Elexity-Micro Pilot) to evaluate the load shift and demand reduction capability of nascent HVAC optimization and control technologies.
Load Management Pilot - Smart Rewards and Energy Storage Rewards	Residential Demand Response	On-going	Establishes the foundational building blocks for TEP's long-term VPP strategy by enabling the aggregation and coordinated dispatch of distributed customer resources capable of responding dynamically to system conditions. The program evaluates demand shifting opportunities, peak load reduction, and system benefits associated with commercially available load management control systems and distributed energy resources ("DER") technologies. Current programs leverage smart thermostats and residential battery systems.
Education and Outreach	Residential Energy Efficiency	On-going	Provide customers, community stakeholders, and the general public with accurate and accessible information related to the Company's energy efficiency and demand response programs. The program supports awareness of available programs, rate and payment options while facilitating enrollments and encouraging actions that contribute to optimized energy consumption.
Smart EV Home	Residential EV Rebates	On-going	Provide residential customers with rebates for installing Level 2 chargers at their home address. Chargers must have capability of connecting to wi-fi to enable future participation in DR programs. In order to receive a rebate, participating customers must take service on a time-of-use (TOU) rate.
Smart EV Charging Program	Commercial EV Rebates	Closed	Provide commercial customers with rebates for installing Level 2 or DC Fast Chargers at their business or establishment. Open to all commercial electric service customers. In order to receive a rebate, participating customers must take service on a time-of-use (TOU) rate.

continued ►

Table 2 - Program Summaries (cont.)

Electric School Bus Program	EV Demand Response	On-going	Provides rebates to eligible school districts for electric school buses and charging infrastructure. School districts must participate in the vehicle-to-grid (V2G) pilot which will push the battery's capacity back onto the grid for support.
Smart Charge	EV Demand Response	On-going	Provides an incentive to customers who charge their electric vehicles during off-peak times.
Fleet Advisory Services	EV Education and Awareness	On-going	Offers to commercial customers with fleets a free, online total cost of ownership tool to explore fleet electrification, as well as a limited share of discounted custom fleet advisory analyses providing a full electrification roadmap.
Micromobility Program	Residential EV Rebates	Closed	Provided rebates for electric bikes to eligible residential customers, with increased rebates for qualifying low-to-moderate income customers.
Non-Profit Transportation Pilot	Commercial EV Rebates	Closed	Provided rebates for electric vehicles and charging infrastructure for non-profits providing transportation and services to seniors, low-to-moderate income customers, and workforce development participants.
Dealership Outreach	EV Education and Awareness	Closed	Deployed kiosks at participating dealerships providing information about EVs to customers, helping to inform purchase decision-making.

SECTION 3

DEMAND-SIDE RESOURCES MARKET POTENTIAL STUDY

Tucson Electric Power, with support from Dunskey, conducted a Demand-Side Resources Market Potential Study in 2025 to quantify the energy savings and peak demand reduction that could potentially be captured through demand-side programs over the 2026–2040 planning horizon. The results of this study inform the treatment of Energy Efficiency (EE) and Demand Response (DR) in the Integrated Resource Plan.

Energy efficiency programs continue to play a meaningful role in shaping future load, particularly through the accumulation of savings from long-lived measures over time. While incremental annual EE savings are more modest in the near term, cumulative impacts increase as those savings persist and compound over the planning horizon. At the same time, the study finds that achieving annual incremental EE savings becomes increasingly challenging in later years due to the phase-out of residential lighting savings resulting from federal standards and broader market transformation, as well as the gradual exhaustion of other discretionary efficiency opportunities. As a result, the marginal contribution of EE declines over time even as cumulative savings continue to grow.

Demand response provides an increasingly important source of peak demand reduction over the study period. Due to relatively limited historical program activity, achievable DR impacts are modest in the early years of the forecast; however, peak demand reductions grow over time as participation expands and program offerings mature. Residential DR ramps up more quickly in the near term, while commercial DR becomes the dominant contributor to peak reductions in later years. Sustained program support is required to fully realize this potential.

Study Scope and Resources Considered

The 2025 Market Potential Study evaluated energy efficiency and demand response opportunities for the TEP service territory for the years 2026–2040, considering electricity-only impacts across residential, commercial, industrial process, and mining customer classifications. Results were developed for technical, economic, and achievable levels of potential under three market scenarios:

- **BAU-** (Below Business-as-Usual): Reflects reduced program activity relative to recent experience, including lower participation rates and more limited program offerings.
- **BAU** (Business-as-Usual): Reflects continuation of current program designs, delivery approaches, participation trends, and budget levels consistent with recent TEP experience.
- **BAU+** (Above Business-as-Usual): Reflects expanded program activity, including enhanced incentives, marketing, and/or new program offerings that support higher customer participation.

Appendix J (cont.)

For purposes of the study scope and IRP integration, only the BAU scenario was used. All references to potential in this filing therefore reflect achievable potential under BAU assumptions, consistent with continuation of existing programs rather than program expansion or contraction.

During integration of the study results into the IRP, industrial process and mining impacts were excluded from the modeling framework to ensure consistency with TEP's load forecast and sector definitions. While the potential study classified customers based on the North American Industry Classification System (NAICS)-based industrial categories, these segments do not align directly with how TEP defines and models large customers for IRP planning purposes. As a result, the IRP focuses on residential and commercial demand-side impacts, which are more directly actionable within existing program structures and forecasting assumptions.

These results reflect achievable BAU potential estimates used for planning context and are not intended to represent binding acquisition targets. Rather, they provide an indication of the scale and timing of demand-side impacts that could be available under sustained implementation of current programs.

Energy Efficiency and Demand Response Potential

Energy Efficiency

Achievable energy efficiency and demand response potential reflects results developed under a Business-as-Usual (BAU) framework, which assumes the continuation of TEP's current program portfolio, incentive structures, delivery mechanisms, and customer participation trends. As illustrated in **Table 1**, achievable EE impacts are highest in the early study years and decline in the late 2020s before stabilizing through the remainder of the forecast period.

The projected reduction in first-year EE savings relative to recent historical performance is driven primarily by the implementation of Phase II of the federal EISA lighting standards, combined with ongoing market transformation effects that reduce available incremental savings from regulated end uses. Following this near-term adjustment and as seen in **Figure 2**, achievable EE savings remain relatively flat over the long-term under BAU conditions, reflecting a mature efficiency market and sustained, but not expanded, program activity.

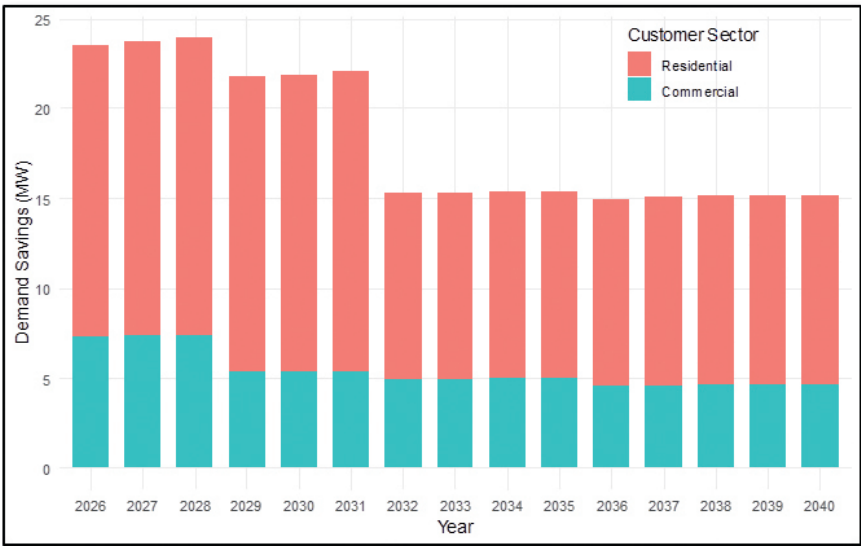
Figure 2 - Annual Incremental Energy Efficiency Savings by Customer Sector (BAU Scenario)



Note: Figure reflects first-year incremental energy savings by customer sector and does not represent cumulative impacts

Figure 3 represents achievable peak demand reductions from energy efficiency measures over the study horizon. The values shown reflect achievable energy efficiency impacts only and do not include demand response. Achievable EE demand reductions are highest in the near term, reflecting the availability of cost-effective efficiency opportunities and near-term program participation. Expected EE impacts decline modestly in the early 2030s and then stabilize through the remainder of the study period, consistent with assumptions regarding market saturation, technology adoption, and achievable participation level.

Figure 3 - Peak Demand Reductions from Energy Efficiency Measures Only



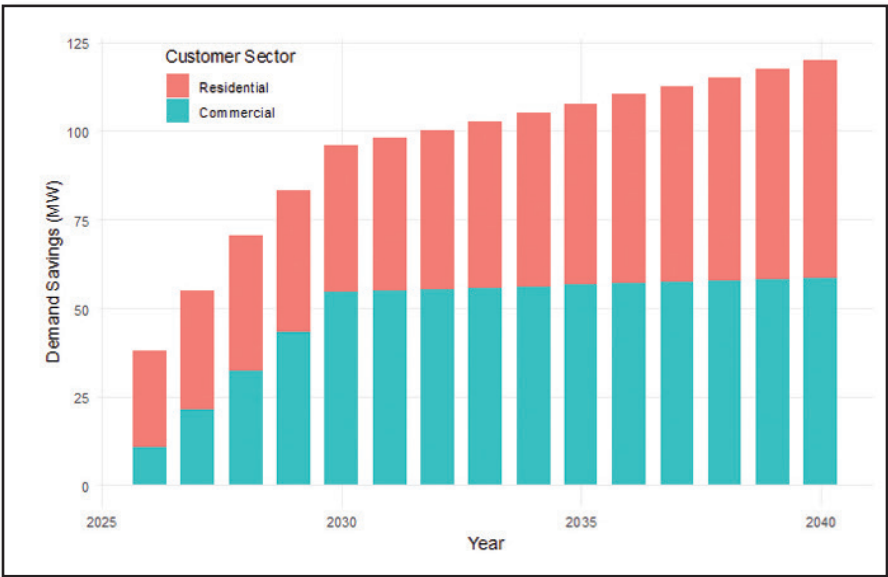
Demand Response

As shown **Figure 4**, demand response impacts increase steadily over the planning horizon across both customer classes. Residential demand response represents the largest share of total impacts and is the primary driver of growth over time, reflecting continued expansion and sustained performance of residential programs. Commercial demand response also grows throughout the study period, though at a more gradual pace, contributing to the overall upward trend. The increase in total demand response impacts reflect tracked program savings rather than modeled additions of new demand response resources.

The BAU- scenario was selected for TEP demand response because it reflects a more realistic growth trajectory given current program conditions. It captures expected constraints and implementation challenges associated with the commercial demand response program revamp that began this year. As a result, the trajectory shown provides a more achievable and credible outlook for demand response potential across both sectors.

The BAU- scenario for Tucson Electric Power illustrates the composition of demand response potential by demand response type across residential and commercial sectors in 2026 and 2040. Overall demand savings increase significantly over time, with both sectors contributing to long-term growth.

Figure 4 - Demand Response Potential (MW) by Sector for BAU- Scenario

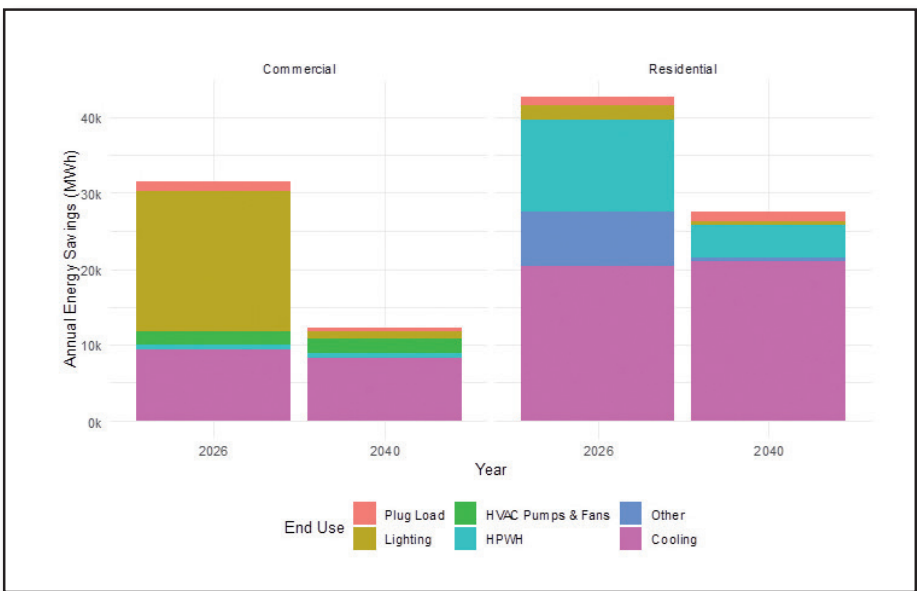


Primary Drivers of EE and DR Impacts

Energy Efficiency

In the post-lighting era, the primary drivers of residential energy efficiency savings shift toward HVAC systems, hot water heating, and building envelope measures, which represent the majority of remaining achievable potential (Figure 5). Behavioral programs continue to play an important role, particularly in supporting near-term, first-year savings. In the commercial sector, energy efficiency savings remain largely reliant on lighting measures through approximately 2029. Beyond that period, remaining commercial efficiency opportunities are increasingly concentrated in HVAC systems and related motor and drive applications as lighting savings decline due to federal standards and market transformation.

Figure 5 - Composition of Top Energy Efficiency End Use Measures by Energy Saving



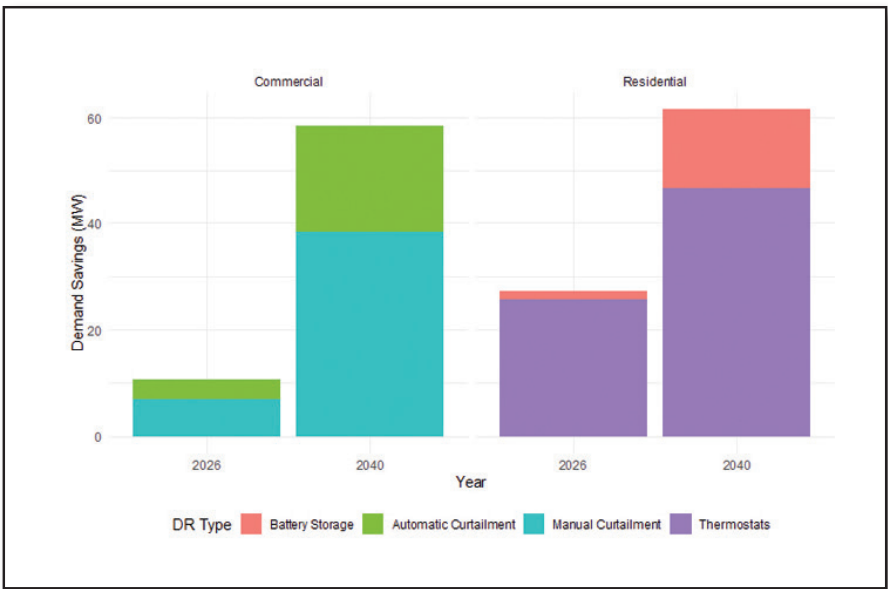
Demand Response

In the commercial sector, demand response is driven primarily by manual curtailment, supported by a meaningful contribution from automatic curtailment by 2040. This reflects the continued reliance on dispatchable, operations-based strategies to achieve peak demand reductions in commercial programs.

In the residential sector, demand response is dominated by smart thermostats, which account for the majority of savings in both early and later years. Battery storage emerges as a secondary contributor by 2040, indicating growing adoption of flexible, customer-sited technologies that enhance load shifting capabilities.

Overall, the BAU- results highlight a clear distinction in demand response approaches across sectors: dispatchable curtailment strategies drive commercial impacts, while customer-enabled technologies—particularly thermostats—anchor residential growth, with storage playing an increasing role over time (see Figure 6).

Figure 6 - Top Demand Response Measures by Demand Savings (MW) for BAU-



Section 4

FUTURE CUSTOMER PROGRAM OPPORTUNITIES AND EVOLVING PORTFOLIO PRIORITIES

As customer technology adoption evolves and system needs become more dynamic, Tucson Electric Power continues to evaluate demand-side resources that provide cost-effective energy savings, peak demand reduction, and greater operational flexibility.

Results from the Market Potential Study as well as other analyses inform future program design, customer targeting strategies, technology prioritization, and long-term resource planning by identifying where the greatest opportunities exist to expand cost-effective demand-side resources. Below are a summary of recommendations on the direction of customer programs that TEP will consider in the near future.

Energy Efficiency Opportunities

- Expand adoption of high-efficiency HVAC systems, heat pumps, smart thermostats, and building envelope improvements such as air sealing, duct sealing, insulation, and weatherization measures that reduce cooling demand.
- Continue expanding participation in multifamily housing, manufactured housing, and low-to-moderate income customer segments.
- Evaluate additional delivery models that improve customer participation while reducing administrative complexity.

Demand Response Opportunities

- Evaluate battery storage, managed EV charging, and additional flexible load opportunities that support TEP's evolving Virtual Power Plant strategy.
- Explore opportunities for small-to-medium business participation in flexible load programs.
- Continue expanding TEP's smart thermostat and battery storage programs and further optimize event strategies.

Beneficial Electrification

- Leverage capacity in EV batteries through managed charging, vehicle-to-grid (V2G), and vehicle-to-building (V2B) applications.
- Support EV infrastructure deployment to support public and home charging opportunities for low-to-moderate income customers, schools, and non-profits.
- Explore additional beneficial electrification opportunities, e.g., electric heat pumps that can participate in demand response opportunities.

TEP is planning for a future in traditional lighting EE measures—historically a source of exceptionally low-cost, high-volume savings—decline in availability. As these opportunities diminish, achieving future savings increasingly depends on non-lighting measures and demand-side resources that are inherently more capital-intensive and deliver impacts more gradually over time.

As a result, the portfolio is shifting toward resources that provide broader system value, including peak demand reduction, operational flexibility, and grid reliability. While these measures tend to have higher costs on a \$/kWh basis, they play a critical role in addressing emerging system needs and maintaining achievable savings trajectories. In particular, demand response is expected to play an increasingly important role in future program investments, providing flexible, dispatchable capacity that supports system operations under evolving load conditions.

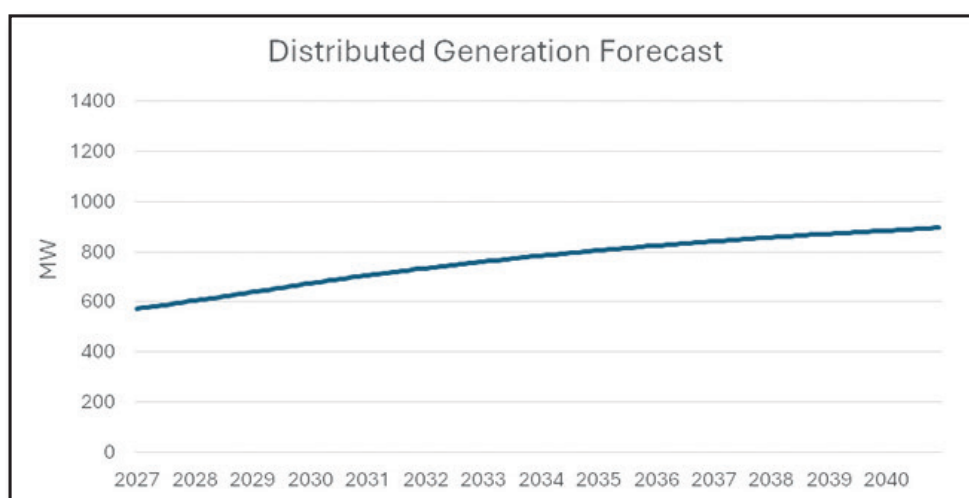
This shift also necessitates a move beyond traditional cost-effectiveness frameworks focused primarily on energy savings. A more comprehensive approach that accounts for capacity value, grid stability, and customer responsiveness is essential to aligning program investments with long-term planning objectives. It also reflects alignment with a broader industry-wide recognition that multiple value streams must be considered to support a reliable, resilient, and flexible energy system.

Section 5

FORECASTING DISTRIBUTED GENERATION

TEP supports a number of programs to promote the use of customer-sited distributed generation, specifically rooftop solar and battery storage. Forecast growth in DG adoption is shown in **Figure 7**. DG adoption is influenced by a combination of federal and state policy mechanisms, economic conditions, retail rate design, and customer technology incentives.

Figure 7 - TEP DG Adoption Forecast



Within TEP's service territory, DG adoption trends are generally shaped by long-term structural drivers rather than short-term market fluctuations. Long-term structural drivers of adoption include continued declines in solar and battery storage costs, improvements in technology performance and availability, and evolving customer economics driven by time-of-use rate structures. Adoption is further supported by a mature market environment, including an established installer network, high levels of customer awareness, and sustained program infrastructure such as demand response and distributed energy resource offerings. In addition, underlying building stock characteristics and the increasing electrification of end use, including electric vehicles and HVAC systems, contribute to consistent baseline growth in adoption over time.

Appendix J (cont.)

Federal tax incentives, including the Investment Tax Credit, have historically supported solar adoption, and while recent expirations and step-downs may create downward pressure on growth, the long-term impact is expected to be gradual. The continued availability of storage incentives remains an important driver of customer adoption; however, removal of these incentives could reduce the pace of future deployment.

Customer adoption trends are also influenced by rate design and rate case outcomes. While increases in retail rates can create economic signals that support DG adoption, TEP customers have historically demonstrated lower sensitivity to such changes.

Retail compensation mechanisms, including the Renewable Energy Credit Program known as the Resource Comparison Proxy (RCP), are evolving, with declining credit rates and potential future expiration. While such changes may result in a short-term increase in adoption as customers seek to capture existing benefits, they are not expected to materially alter long-term trends. Similarly, the expiration of the State's Renewable Energy Standard and Tariff (REST) rules is not expected to significantly impact adoption levels, although installers have utilized the program as a marketing mechanism to encourage near-term participation.

Macroeconomic conditions, including periods of economic uncertainty, may influence customer willingness to invest in customer-sited resources, particularly given the upfront capital requirements associated with solar and storage technologies. However, these impacts are generally moderated within the TEP territory relative to smaller service areas.

Finally, reported battery storage adoption and capacity within the TEP service territory are based on interconnection data and may include customers enrolled in demand response programs such as TEP Smart Rewards. As a result, certain customers may be represented across both distributed generation and demand-side program metrics, reflecting the increasing integration of storage resources into grid-interactive programs.

Appendix K

FUTURE RESOURCE TECHNOLOGIES

Section 1

INTRODUCTION TO FUTURE RESOURCE TECHNOLOGIES

This chapter provides an overview of the future resources considered for development in the Company's resource portfolio. The information here is based on best-available current information, the Company's current resource mix, and its commitment to reducing carbon emissions. If a particular technology is bid into the Company's All-Source Request for Proposals (ASRFP), it is considered equally with all other technologies based on the specific criteria established in the ASRFP.

Future resources considered for development can be divided into four categories: flexible resources, energy storage resources, advanced baseload resources, and conventional resources. The four categories are shown in Figure 1 and are described in more detail below. A combination of resources from these categories is needed to maintain a grid that is affordable, reliable, and sustainable. These three goals cannot be achieved by one technology alone. The combination that optimally supports the grid will depend on how individual technologies and the broader economy evolve over time.

Flexible Resources - Historically, grid operators serve variable demand from firm power resources using traditional supply-side techniques (e.g., generator droop control, peaker plant dispatch). As the portfolio share of intermittent renewable generation has grown, as bidirectional power flow has become more common, and as inverter-based resources have multiplied, grid operators face greater challenges managing a more dynamic grid. Flexible resources can support a more dynamic grid by controlling demand rather than supply. In addition to supporting a dynamic grid, flexible resources can be used to reduce the system peak demand, which is used to set capacity needs. Flexible resources can be deployed in place of other resources described below, thereby avoiding their cost.

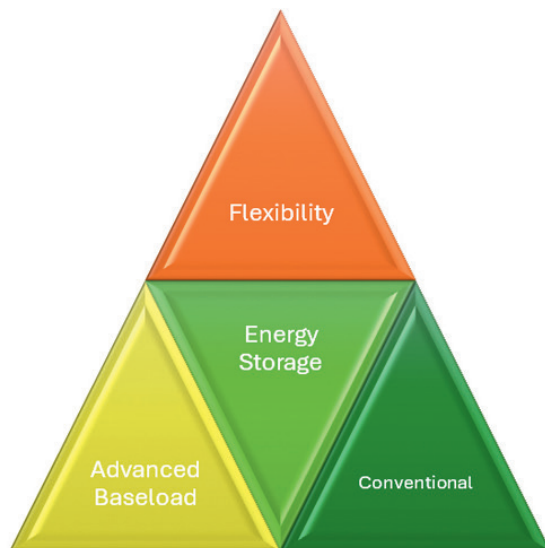
Energy Storage Resources – Unlike natural gas distribution systems, the electric grid was not originally designed to incorporate energy storage within the system. Storage serves as a buffer for any energy delivery system that can help improve stability and resilience. Storage is also one of the most versatile resource types with the ability to store or release energy depending on grid conditions and need. This is especially valuable with the rise of variable renewables, like wind and solar. Storage technologies can store energy when renewable energy exceeds demand on the grid and then discharge when demand exceeds renewable energy generation. The value of storage on the grid depends on its type, size, location, and operating modes. Energy storage resources include lithium-ion batteries, compressed air energy storage, pumped hydropower storage, liquid carbon dioxide storage, iron air batteries, and numerous other technologies.

Appendix K (cont.)

Advanced Baseload Resources – A new class of resources has emerged in recent years. These are near-zero carbon resources that can provide power whenever it is needed. This provides an advantage over variable renewables, like solar and wind, while avoiding the carbon emissions associated with other conventional resources like natural gas. These include advanced nuclear technologies, geothermal, and clean fuels, like biogas and hydrogen.

Conventional Resources – Conventional resources include solar, wind, reciprocating engines, and natural gas simple-cycle and combined-cycle turbines. These technologies support a stable grid today. Depending on how technologies evolve, these may be deployed into the future alongside a mix of other technologies mentioned here.¹

Figure 1. Resources that can contribute to a stable grid in the future.



¹ Additional conventional resources include natural gas and coal steam turbines. Existing steam turbines support our grid today and will continue to throughout their useful life, but, due to advancements in other technologies, it is unlikely that new steam turbines will be built.

Section 2

RESOURCE MATRIX

Technologies described in this section vary in how they support a grid that is affordable, reliable, and sustainable. Additionally, all technologies described here are expected to evolve over time in their ability to support these goals. Figure 2 provides a qualitative overview of the benefits these technologies can provide to the system. Details are provided in Section 3, where we describe grid benefits of each technology, their technical readiness, commercial readiness, and environmental performance.

Grid Support – Technologies support the grid by providing energy when it is needed and providing ancillary services to keep the grid stable. Load carrying capability is a quantification of the degree to which energy is available when it is needed. In addition to the availability of energy, it is important that systems are able to ramp up and down quickly to dispatch energy exactly when it is needed. Additionally, the grid needs certain services, like frequency and voltage support, to stay stable. Conventional resources that deploy synchronous turbines, like natural gas plants, provide these services. Other conventional resources, like solar and wind, generate direct current and require an inverter to inject alternating current to the grid. These inverter-based resources cannot provide all of these services today.

Technical Readiness - As technologies are developed, they go through various technology readiness levels. NASA developed a nine-point scale for technology readiness that describes how technologies advance from lab-scale operations to pilot-scale operations to full-scale operations in a variety of real-world conditions. This scale focuses on whether or not a technology works as designed. It does not take into account other factors that contribute to whether a technology is ready to be procured by a utility. In general, utilities will only start to consider technologies at very high readiness levels.

Commercial Readiness – This category covers factors beyond technical readiness that contribute to a utility's ability to procure a new technology. This includes cost and other factors, such as supply chain maturity, permitting difficulty, constructability, risk, site requirements, fuel availability, and other considerations. It is more often commercial readiness that constrains deployment of new technologies rather than technology readiness.

Environmental Considerations – Water use is a critical consideration in arid areas such as ours. In addition to water use, technologies vary in their land use and safety risks they pose to workers and nearby communities. We take these into account when we consider future resources.

Figure 2 - Heat map showing desirability of various technologies to supporting an affordable, reliable, and sustainable grid.

Category	Type	Grid Support: Load Carrying Capability	Grid Support: Dispatch Speed	Grid Support: Ancillary Services	Technical Readiness	Commercial Readiness	Commercial: Cost	Environmental: Water Use	Environmental: Carbon Emissions
Conventional Resources	Wind	2	1	1	5	5	5	5	5
	Solar Photovoltaics	1	1	1	5	5	5	5	5
	Recirculating Engines	5	5	3	5	5	4	5	1
	Natural Gas Simple Cycle	5	5	5	5	5	4	5	1
	Natural Gas Combined Cycle	5	3	5	5	5	5	4	2
Flexibility Resources	Demand Response	1	2	1	5	4	5	5	5
	Virtual Power Plants	2	3	3	3	2	3	5	5
Energy Storage Resources	Lithium Ion Batteries	2	5	3	5	5	5	5	3
	Compressed Air Energy Storage	3	5	4	3	1	2	5	3
	Pumped Hydropower Storage	3	5	4	5	2	4	2	3
	Liquid Carbon Dioxide Storage	3	5	4	3	2	3	5	3
	Iron Air Batteries	3	5	3	3	2	5	5	3
	Flow Batteries	3	5	3	3	2	3	4	3
Advanced Baseload Resources	Geothermal	5	4	5	4	3	3	4	5
	Nuclear - Advanced Large Reactor	5	2	5	4	3	2	3	5
	Nuclear - Small Modular Reactors	5	3	5	2	1	1	3	5
	Biogas Cofiring	5	3	5	5	2	4	2	4
	Hydrogen Cofiring	5	3	5	2	2	1	1	3
	Carbon Capture and Storage	5	3	5	3	1	1	1	4

Characteristics are qualitatively rated on a scale of 1 - 5, with 1 (white) being least desirable and 5 (dark green) being most desirable.

Section 3

RESOURCE TECHNOLOGY OVERVIEW

3.1 Flexible Resources

Demand Response

Dating back to the 1970's, curtailable loads and interruptible tariffs have been used to help utilities meet their capacity requirements, often using low-tech methods. Most commonly, grid operators would "dispatch" curtailable loads simply by picking up the phone and calling their large industrial customers and asking them to shut down equipment. In return, these customers were compensated in the form of lower rates or other financial incentives (e.g., bill credits, seasonal payments). This is a so-called "Capacity DR" program model, and it remains the most common in the utility industry.

Today, there are several DR program models as well as many enabling technologies and market mechanisms, including:

- **Automated demand response.** Where either the dispatch signal, load response, or both are automated requiring no human intervention or manual curtailment.
- **Economic demand response.** The grid operators call economic demand response events in response to market price signals. Participating companies get paid to reduce their load in response to high prices, helping to reduce their exposure to the highest-priced hours while lowering system-wide electricity prices.
- **Reverse demand response.** Loads ramp up (not down) or storage is charged in response to excess renewables availability, low energy pricing, or other real-time signals.
- **Ancillary demand response.** Ancillary programs provide another level of services to the grid to support localized issues. Services include frequency regulation, voltage control, and operating reserves to balance fluctuations in real-time. These are on-demand, instantaneous resources and they can be called upon for a number of reasons: power outages, extreme weather, high prices, or insufficient generation.
- **Flexible load management (FLM) or continuous load management (CLM).** For smaller loads and those that do not negatively impact customer comfort, satisfaction, and/or revenues, it is possible to move away from event-based DR to offer programs that flex loads whenever needed. For example, short duration dispatch (e.g., 15-minute) has the benefit of limiting negative impacts to customers and can therefore be called upon more times each season without risk of fatigue. Automation techniques include frequency response and smart devices that respond automatically to event or price signals.
- **Dynamic operating envelopes.** As part of a flexible interconnection agreement or similar arrangement, a customer, building, or end-use device is sent an acceptable power band in which it must operate, usually day-ahead. In some cases, actual power demand may be electronically limited to match requirements.

Appendix K (cont.)

Grid Support

DR resources are typically dispatched during a small fraction of hours each year when grid capacity is near its system peak, e.g., ~ 90 hours or 1% of the year. However, as capacity constraints emerge on the transmission or distribution system and the value of marginal capacity availability on these systems goes up, those hours of the year during which DR can deliver value will tend to grow. As mentioned above, this may take the form of flexible interconnection agreements, dynamic operating envelope requirements, or similar mechanisms for enabling dynamic demand.

Technical Readiness

Since DR is a broad category of programs and techniques, there are dozens of enabling technology types that have evolved over the last several decades. For example, the technologies used to enable capacity DR in its traditional form are very well established, while those for enabling economic DR and price-based load response are still being demonstrated in pre-commercial phase.

Commercial Readiness and Economics

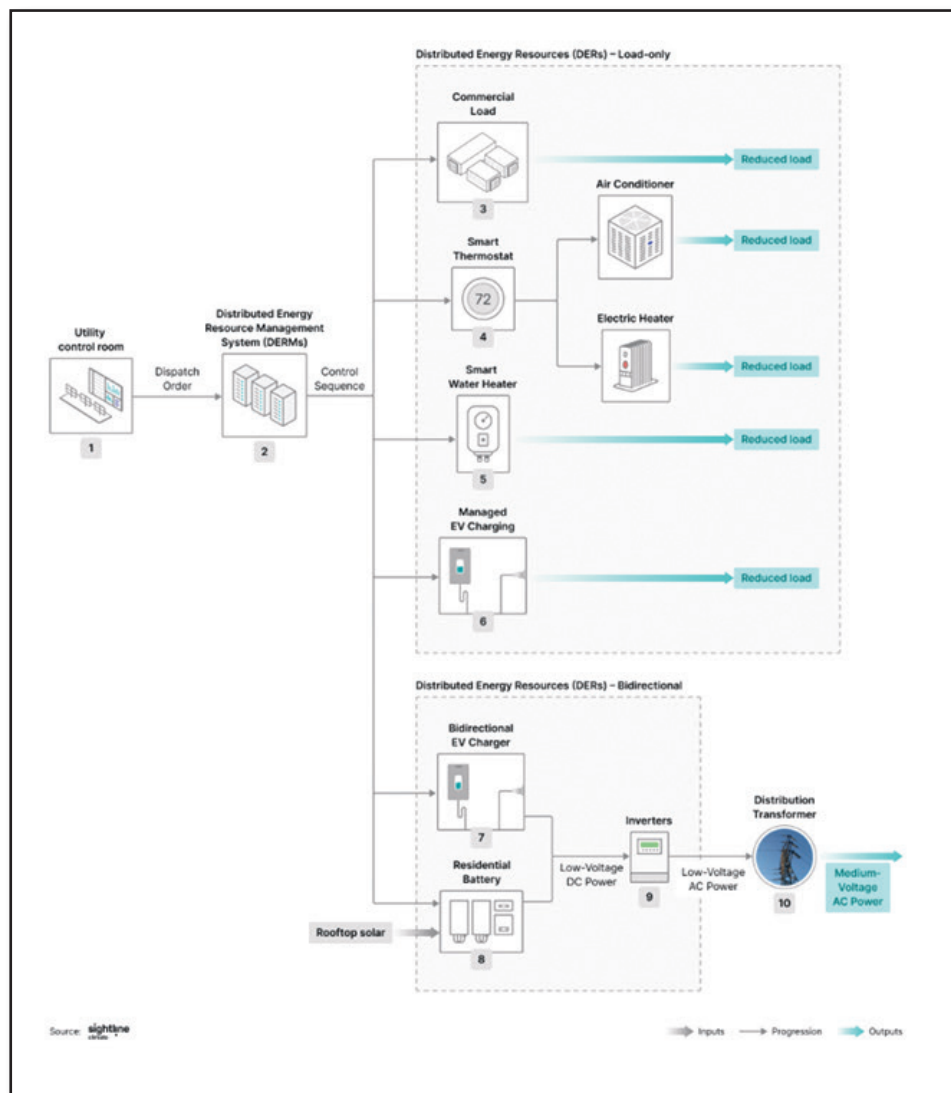
Similar to technical readiness, the relative degree of DR commercial readiness depends on the type of program being run and the given market or segment being served. Today, the most commercially mature programs manage residential thermostats, while battery and electric vehicle (EV) programs are growing in popularity. Any program that relies on customers to organically adopt new technology – be it a smart thermostat, battery, EV, or building controller – will be inherently limited in market reach by the diffusion rate of the technology.

Since DR resources are often dispatched during the most-expensive hours of the year, the economics tend to be favorable. How much a given DR resource is worth will depend upon many factors, including when it is called, how quickly it can respond, how much demand it drops, how often it can be called upon, and even where exactly the loads are located. Customer compensation for responding to DR event signals ranges from zero in the case of voluntary programs up hundreds of dollars per kW for locational and high-value resources.

Virtual Power Plants (VPPs)

Virtual Power Plants (VPPs) leverage the latest evolution of DR programs, incorporating many of the same technologies and techniques described in the previous section. What is unique about VPPs is the ability to expand capabilities beyond traditional DR to include multiple technology and load types, dispatching strategies, localized services, and distributed energy resource (DER) orchestration (Figure 3). By aggregating many small loads and managing them in concert, VPPs can deliver value in the aggregate for the bulk power system and with precision along the grid edge. This may take the form of congestion relief, voltage support, frequency response, infrastructure investment deferral, and other value streams.

Figure 3 - Generalized VPP configuration.



Like DR programs, VPPs are also dependent upon customer participation, customer-owned assets, and continuous communications and engagement. And unlike traditional grid assets, there are many variables that exist outside of the utility's sphere of control, including market influences, price sensitivities, and individual customer behaviors and choices. However, in spite of the challenges, utilities across North America have deployed more than 30 GW of VPP capacity in recent years and this growth trend seems likely to continue. Successful deployment of a VPP requires careful customer lifecycle management (CLM) in addition to technical solutions for managing edge devices and integrating them into grid operations (e.g., with the use of distributed energy resource management systems, or DERMS).

Appendix K (cont.)

Grid Support

VPPs offer many of the same grid services as DR programs but also expand capabilities further in terms of delivering on benefits from frequency response, locational value, and device coordination (e.g., dispatching batteries to manage snapback effects from thermostat DR). Where DR programs alone tend to be very limited in the total capacity they can deliver, VPPs have the potential to deliver upwards of 10 - 20% of system peak capacity.²

Technical Readiness

Similar to DR, some enabling technologies for VPPs are more developed than others, with thermostat and battery programs driving the large majority of VPP dispatchable capacity so far. While many VPPs operate more-or-less autonomously in parallel with centralized grid controls (e.g., SCADA, EMS, ADMS), integration of these systems has been demonstrated in numerous pilots and is steadily moving toward scaled operations.

Commercial Readiness and Economics

A relatively small number of solution providers have delivered the vast majority of dispatchable capacity for VPPs in North America so far. In order for VPPs to continue to scale, customer market adoption of enabling technologies and devices must continue to grow, and utilities must have effective CLM strategies.

Many technology pilots over the years have demonstrated that it is rarely cost-effective for utilities to attempt to own or manage customer-owned devices directly. Successful VPP operation requires the balancing of shared benefits between the utility, customer, and third-party aggregator and/or technology partner. When utilities are “long on capacity” it is difficult to justify the complicated arrangements needed to enable VPPs. But when capacity is constrained, there’s a willingness to pay a premium for capacity upgrades, and/or grid expansions are slow and expensive, the economics of VPPs become more favorable. The U.S. Department of Energy estimates that widespread VPP deployment in the U.S. could save on the order of \$10B in annual grid costs through avoided generation investments, deferred infrastructure investments, and reduced operation of peaker plants.³

² <https://www.energy.gov/edf/virtual-power-plants-projects>

³ Ibid

3.2 Energy Storage Resources

Lithium-Ion Batteries

As their name implies, Li-ion batteries store energy electrochemically through the movement of lithium ions. A liquid electrolyte (most commonly) is used to transfer ions between a solid anode and cathode as the battery is charged or discharged. Compared to other commercial battery chemistries like lead-acid or nickel-metal hydride, Li-ion batteries have a high energy density, making them ideal for mobile applications (e.g., consumer electronics, electric vehicles).

Early Li-ion technologies – such as those having a nickel cobalt aluminum (NCA) chemistry – had poor safety, social, and environmental profiles. NCA were prone to spontaneous combustion due to “thermal runaway,” made from rare cobalt sourced largely from Congo, and were non-recyclable. Around 2020, a competing Li-ion chemistry – called lithium-iron phosphate (LFP) – began to dominate the global market for large-format battery cells. LFP batteries had a lower energy density than NCA but also had a better safety profile and could be manufactured without the need for cobalt. LFP battery energy density continues to improve as does its recycling, though recycling techniques for LFP remain immature relative to other battery chemistries (e.g., lead-acid).

Grid Support

Since Li-ion batteries have exceptional responsiveness and high power density, they can be used to quickly respond to voltage or frequency irregularities on the grid and provide stabilizing support. Their operating characteristics make Li-ion an ideal resource for displacing expensive peaker plants.

Utility-scale Li-ion batteries have typically been designed for 2-to-4-hour discharge times, though developers continue to push the technology performance (e.g., 8-hour discharge). A battery that charges and discharges over 8-hour periods can deliver significant storage value for cost-effective operation of solar photovoltaic (PV) systems in Arizona. In addition to renewables storage, Li-ion batteries are used to deliver frequency regulation, black-start support, peak shaving, congestion relief, and backup power. Li-ion batteries are currently the most economical option for 8-hour storage.

Technical Readiness

Li-ion batteries are fully technically ready and widely deployed.

Commercial Readiness and Economics

A number of high-profile battery fires had an overall cooling effect on the early commercialization of Li-ion batteries for grid applications. However, as costs continued to fall and gradual improvements were made in manufacturing, monitoring, and managing Li-ion technologies, applications and use cases have continued to expand, and so has the total capacity of interconnected systems on the grid.

Li-ion batteries have now been widely deployed across numerous industries. The technology has been a key enabler of utility “steel for fuel” replacement strategies. For example, in California, the capacity of utility-scale batteries recently reached 17 GW, representing nearly 40% of the state’s system peak and effectively displacing peaker plant operation.⁴

⁴ <https://www.energy.ca.gov/news/2026-05/california-energy-leaders-report-progress-grid-reliability-ahead-summer-2026>

Appendix K (cont.)

For decades, developers have been striving to make Li-ion cost-competitive with many traditional energy resources. For utility-scale applications we are now approaching this threshold, but for most smaller storage systems, the installed costs are still significantly higher. As technology performance continues to improve, we expect that these cost targets will be hit in the coming years.

Pumped Hydropower Storage

Pumped hydropower storage (PHS) is the most well-established utility-scale storage technology, representing more than 80% of all grid-connected energy storage in North America. Like CAES, PHS is typically treated as an LDES technology with daily charge-discharge cycles. PHS is most commonly co-located with large hydropower dams that are geographically constrained by geologic features (e.g., canyons, gorges). However, closed-loop PHS systems can also be deployed independently of traditional hydropower facilities.

Grid Support

Most PHS facilities are designed to pump water into an upper reservoir when electricity demand and/or prices are low, then run the water back through a turbine to generate electricity when demand and/or prices are high.

Technical Readiness

PHS is very well established and technically ready but closed-loop PHS systems remain rare.

Commercial Readiness and Economics

PHS has been widely adopted in markets worldwide, but there is currently only one closed-loop PHS system in operation in the U.S. Due to site variability, no two PHS systems have the same economics. A recent study indicated that total installed costs for PHS system was on the order of \$2,400/kW.⁵

Other Long Duration Energy Storage Technologies

Numerous technologies are being developed to provide long-duration energy storage (LDES), typically defined as 8-hours or more. Both technologies detailed above are capable of providing storage for long durations. Numerous other technologies are being developed to compete with lithium batteries and pumped storage. These technologies include flow batteries, compressed air energy storage, liquid carbon dioxide storage, sodium-ion batteries, supercapacitors, thermal storage, and hydrogen. As described in Figure 2, none have yet reached technical and commercial readiness needed for adoption beyond a pilot scale. We will continue to monitor these technologies as they advance.

⁵ https://www.energy.gov/sites/default/files/2023-09/7_Technology%20Strategy%20Assessment%20-%20%237%20Pumped%20Storage_508.pdf

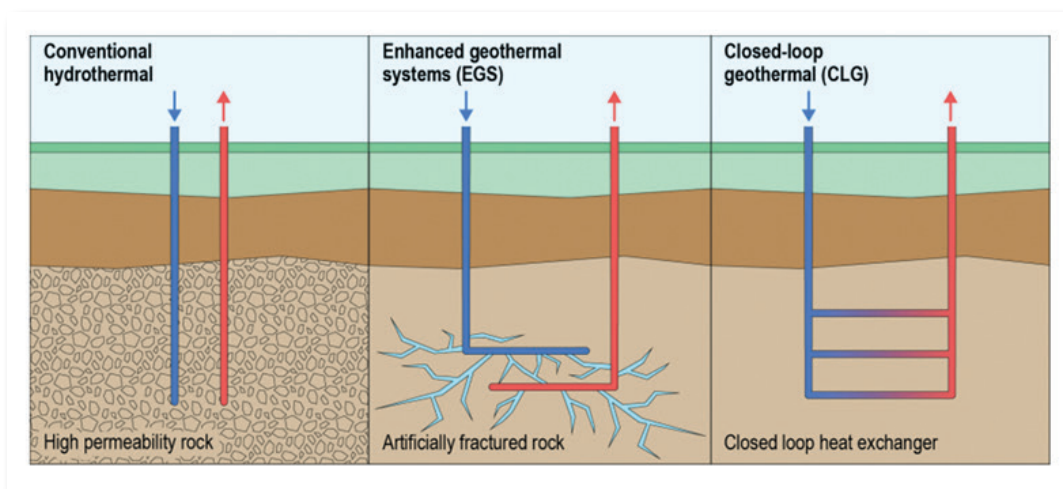
3.3 Advanced Baseload Resources

Geothermal

Geothermal energy systems generate electricity by extracting heat from deep in earth's subsurface and converting it to electricity. Pairs of wells are drilled thousands of feet into the earth. Water is circulated down one well, where it is heated by the heat of the earth. It is returned to the surface where it is processed in an Organic Rankine Cycle (ORC) to generate electricity.

Figure 4 shows different types of geothermal systems. In conventional geothermal systems (or "hydrothermal" systems), pairs of wells are drilled into rock formations with high permeability, allowing water to circulate and collect heat. Advanced geothermal systems enable extraction of heat from rock formations that are hot but not porous, which are ubiquitous. Enhanced geothermal systems (EGS) apply hydraulic fracturing to create porosity. In closed-loop geothermal systems, a series of horizontal wells are lined to create an underground radiator, allowing for circulation of water.

Figure 4 - Types of geothermal systems.⁶



⁶ <https://iea.blob.core.windows.net/assets/cbe6ad3a-eb3e-463f-8b2a-5d1fa4ce39bf/TheFutureofGeothermal.pdf>

Appendix K (cont.)

Grid Support

Since geothermal systems rely on the always-on heat of the earth, they can generate baseload electricity. However, ORCs rely on air cooling, so high ambient temperatures increase electricity used for cooling and reduce the overall power output significantly. This leads to a net efficiency of roughly 85%.

Geothermal systems can ramp up and down relatively quickly to balance supply and demand. ORCs use turbines like traditional power plants and can provide additional grid services like inertia.

Technical Readiness

Conventional geothermal systems have been in operation for more than 50 years and are fully technically ready for deployment.

EGS was successfully demonstrated for the first time in 2023. Since then, it has operated successfully. However, additional operational data and demonstrations in additional geologies are needed for full technical readiness.

Closed-loop systems are less technically ready – pilots have been completed but operational results have been mixed and further cost reductions are needed in order for closed-loop technologies to compete with other geothermal technologies.

Commercial Readiness and Economics

Geothermal's path to full commercial readiness is helped by its adoption of technologies developed in other sectors. ORC power plants are used in other technologies, so equipment is affordable and readily available. Drilling and fracturing techniques used in geothermal are very similar to those that have been perfected over decades in the oil and gas industry. This means there is a plentiful and skilled workforce available to transition into geothermal energy. For these reasons, geothermal plants have relatively short construction timelines.

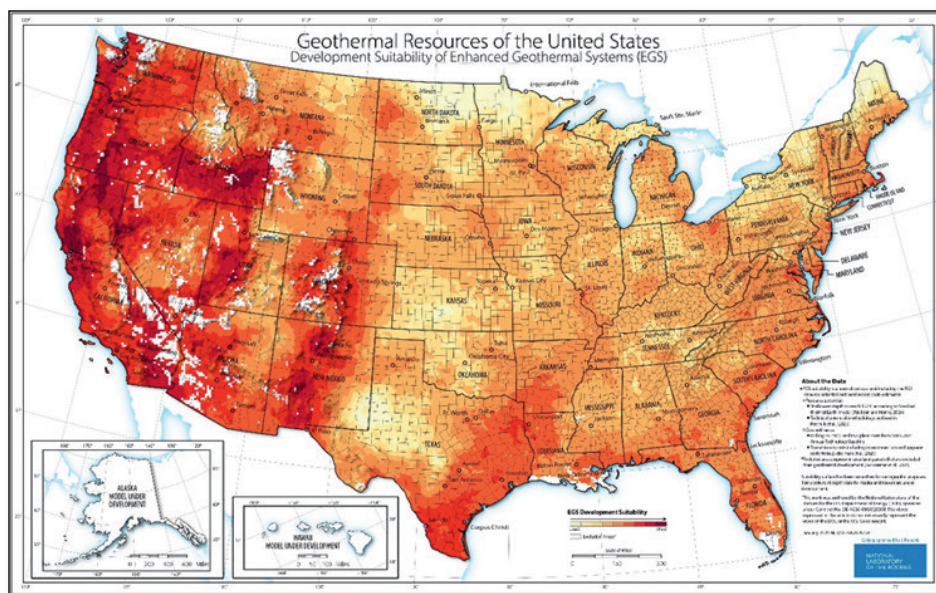
The path to full commercial readiness is hindered by drilling risk. Significant capital must be spent to drill a geothermal well, but heat, and thus energy production potential, cannot be fully confirmed without drilling. For this reason, energy project investors have been slow to enter this industry. Technological advances and development of new financing models are beginning to attract the first investors in EGS projects, but more traction is needed before this technology can reach its full potential.

Geothermal also faces unique siting challenges. Project sites must have access to transmission, land access, and other things all energy projects need. But these must occur in geographic locations where high temperatures can be accessed at relatively low depths. Figure 5 shows the suitability of land to geothermal development. While additional geological data is needed, it is likely Arizona has good geothermal resources.

Geothermal technologies, while expensive, are among the cheapest options for clean baseload power. Costs for EGS and closed-loop geothermal are currently higher than conventional geothermal but are expected to decline as the technology reaches maturity.

Figure 5 - Geothermal resources across the United States.⁷

Darker red indicates better geothermal potential.



Water Use and Environmental Considerations

Water use varies across conventional and advanced geothermal systems. Conventional geothermal systems use some water for initial drilling, but very little in operations – water that is circulated through the formation is often naturally occurring and little water is needed to supplement it over time. Water use is largely unknown for EGS systems. Initial operational results show significant water is lost through artificial fractures and therefore needs to be supplemented to maintain operations. This is expected to decrease over time as the formation becomes saturated, but this has yet to be proven. Closed-loop systems are theoretically expected to use significantly less water. Across all system types, many water needs can be met with non-potable water, such as reclaimed water or brackish water.

Other environmental impacts are limited – geothermal energy emits no carbon dioxide and its surface footprint is very low.

Nuclear – Advanced Large Reactors

Nuclear power plants generate electricity by splitting uranium atoms inside a nuclear reactor. This process, called “fission”, heats up a fluid, which is used to generate electricity. Nuclear reactors vary in size, fuel type, and the fluid used to generate electricity (often called a coolant or working fluid). The vast majority of nuclear reactors deployed today use water as a working fluid and low enriched uranium (LEU) as fuel. The next generation of nuclear reactors use other working fluids, such as liquid metals or molten salts, and more advanced fuels such as high-assay low-enriched uranium (HALEU). These advancements offer increased efficiency, reduced waste, and improved safety features. However, these reactors are still under development and not yet ready for procurement by utilities.

⁷ https://www.nrl.gov/docs/libraries/gds-maps/geothermal-resources-united-states-development-suitability-of-enhanced-geothermal-systems.jpg?sfvrsn=673331c2_2

Appendix K (cont.)

Nuclear reactors vary in size. Most reactors in operation today are considered large reactors (over 300 MW). Smaller reactors, often “small modular reactors” (SMRs), tend to be between 20 MW and 300 MW. This section focuses on large reactors while the subsequent section below focuses on SMRs.

Grid Support

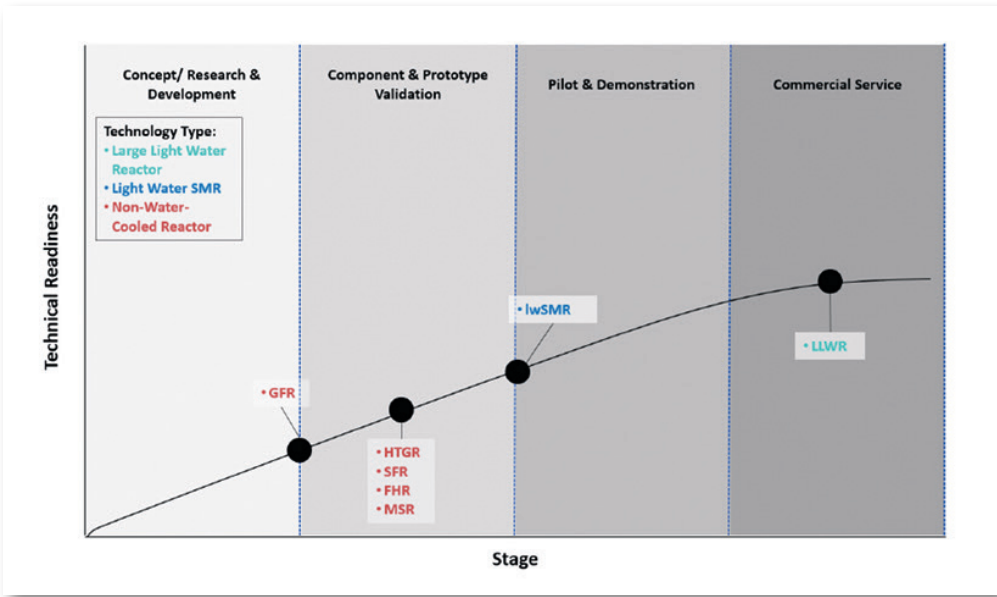
Nuclear reactors are able to provide baseload power. They operate continuously except during refueling outages, when spent nuclear fuel is replaced with fresh fuel. This leads to capacity factors generally exceeding 90%.

Nuclear systems can ramp up and down to balance supply and demand, but not as quickly as other technologies. Nuclear systems use turbines like traditional power plants, so they can provide additional grid services like inertia.

Technical Readiness

Nuclear energy has been operating for decades, so existing water-cooled designs are fully technically ready. However, newer designs that use different fuels or working fluids are less technically ready, as shown in Figure 6.

Figure 6 - Technical Readiness of various nuclear reactors as of 2025



Reactors include large light water reactors (LLWR), light water small modular reactors (lwSMR), high-temperature gas cooled reactors (HTGR), sodium-cooled fast reactors (SFR), fluoride-salt cooled high-temperature reactors (FHR), molten salt reactors (MSR), and gas-cooled fast reactors (GFR).⁸

8 <https://www.nyserda.ny.gov/-/media/Project/Nyserda/Files/Publications/Energy-Analysis/Zero-x-40-Technoeconomic-Assessment.pdf>

Commercial Readiness and Economics

While some nuclear reactors are technically mature, constructing new reactors of any kind faces significant hurdles. These include high capital costs, permitting complexity, workforce shortages, and additional challenges associated with completing construction of highly complex megaprojects. These factors make nuclear energy among the highest cost energy sources available today.

Relatively few nuclear reactors have been built in the United States in the past quarter century. In 2020 and 2024, two large, water-cooled reactors came online after a difficult construction period that resulted in seven years of delay and cost overruns exceeding \$16 billion⁹. No one factor can be blamed for these overruns, but it is likely that complex nuclear regulations and shortages of specialized workforces may have been partially responsible. The challenges faced by this project demonstrated that, while nuclear energy is technologically mature, it faces many of the same challenges other emerging technologies face.

These challenges must be resolved before additional large reactors can be constructed. The U.S. government across multiple administrations have prioritized regulatory simplification. This has resulted in several additional projects gaining regulatory approval. Successful completion of the projects above developed a nuclear workforce, which should lead to smoother implementation going forward. However, these improvements have not unlocked the market for large water-cooled reactors; to date, no entities have made firm financial commitments to move forward with additional large water-cooled nuclear reactors. A handful of other advanced reactors, including water-cooled SMRs and other advanced reactors, have broken ground in the US and Canada in recent years.

Water Use and Environmental Considerations

Nuclear reactors use water in ways similar to other thermal power plants, like natural gas and coal. However, existing nuclear plants in Arizona have pioneered using reclaimed water to reduce burdens on drinking water sources. Similar methods could be pursued if new nuclear development is pursued in Arizona, as long as plants are developed near large supplies of reclaimed water. Nuclear plants can further limit their water use by using air cooling rather than water cooling.

Nuclear reactors have significant safety features to prevent pollution and impacts to workers and communities in the unlikely event of an uncontrolled nuclear reaction. Advanced reactors, including those constructed recently in the US, include “passive” safety features. These use unique designs to physically prevent runaway reactions without human intervention, allowing for quick response to safety issues.

Nuclear reactors generate radioactive waste that must be managed properly. This includes proper handling and isolation for long periods of time to allow for natural radioactive decay to safe levels. This typically involves on-site storage of waste.

⁹ <https://www.eia.gov/todayinenergy/detail.php?id=61963>

Nuclear – Small Modular Reactors

Small modular reactors (SMRs) are similar to the large reactors addressed above in many ways. They can use similar fuels and working fluids but tend to be between 20 MW – 300 MW.

SMRs were developed in response to challenges associated with constructing large reactors, which contribute to the high cost of nuclear energy. In order to reduce costs, SMRs use standardized designs and modular construction techniques to simplify construction. SMRs are less mature than large reactors, both technically and commercially.

Grid Support

SMRs support the grid in ways similar to large nuclear reactors. They have a similar capacity factor and provide the same ancillary services as other spinning resources. SMRs are able to ramp up and down to balance supply and demands. Their smaller size enable quicker ramp rates compared to large nuclear reactors.

Technical Readiness

SMRs are less technically ready than large reactors, as shown in Figure 6 above. The most advanced SMRs are at the pilot stage, so additional projects are needed to demonstrate full technical readiness.

Commercial Readiness and Economics

SMRs are early in their path to commercial readiness. A small number have been successfully deployed internationally but have been used to generate industrial heat rather than electricity. The first SMRs for electricity generation in North America have broken ground recently. Numerous projects have been announced, but most are in the very early stages with limited development. Few have passed a final investment decision, indicating institutional capital is hesitant to invest in this space. However, SMRs are garnering significant interest from governments, utilities, and large electric customers, especially data centers, so this could change in the near future.

Today, SMRs are more expensive than their larger counterparts, since larger reactors can rely on economies of scale to reduce costs. SMRs should theoretically get cheaper over time. However, this relies on increasing modularization and construction simplification. SMRs currently under development have not fully realized these benefits. For example, GE Hitachi's BWRX-300, a 300 MW SMR, broke ground in 2025 in Ontario, Canada. This reactor provides less than one third of the power of GE Hitachi's 1000 MW large reactor, but takes up 80% of the footprint¹⁰. While some elements have been modularized, significant site work is still required, as shown in **Figure 7**. These elements limit the economic benefits of SMRs over large reactors.

¹⁰ Sightline Climate

Figure 7 - Construction of GE Hitachi's BWRX-300 SMR.¹¹



Water Use and Environmental Considerations

SMRs use water and impact the environment in ways similar to large nuclear reactors. Since SMRs are smaller, they contain a smaller volume of nuclear material compared to a large nuclear reactor. Therefore, the magnitude of environmental impacts at any one site would be reduced.

Other Advanced Baseload Resources

Depending on how technologies advance, the cheapest option for clean baseload power may be to construct new power plants, either nuclear or geothermal. In some cases, it may be more economical to decarbonize existing natural gas plants by cofiring a clean fuel like biogas or hydrogen, or capturing and storing the resulting carbon emissions. This class of technologies allows for reuse of existing assets to support a more sustainable grid. These technologies are approaching technical maturity in some respects, but they suffer from supply chain challenges and other considerations that limit their commercial maturity. We will continue to monitor these technologies as they advance.

¹¹ <https://www.gevernova.com/news/articles/ge-vernova-and-opg-are-writing-the-next-chapter-nuclear-power>

Appendix L

ACRONYMS AND ABBREVIATIONS

Appendix L (cont.)

ACC	Arizona Corporation Commission
ACE	Area Control Error
ADEQ	Arizona Department of Environmental Quality
ADMS	Advanced Distribution Management System
AMI	Advanced Metering Infrastructure
APS	Arizona Public Service Company
ASRFP	All-Source Request for Proposals
BA	Balancing Authority
BESS	Battery Energy Storage System
BEV	Battery Electric Vehicle
CAISO	California Independent System Operator
CEC	Certificate of Environmental Compatibility
CO₂	Carbon Dioxide
DAM	Day-Ahead Market
DER	Distributed Energy Resources
DG	Distributed Generation
DR	Demand Response
DSM	Demand Side Management
E3	Energy and Environmental Economics, Inc.
EDAM	Extended Day-Ahead Market
EE	Energy Efficiency
EEES	Electric Energy Efficiency Standard
EIM	Energy Imbalance Market
ELCC	Effective Load Carrying Capability
EPA	U.S. Environmental Protection Agency
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gas
HLFCG	High Load Factor Customer Growth
ICT	Internal Combustion Turbine
IRA	Inflation Reduction Act
IRP	Integrated Resource Plan
LCOC	Levelized Cost of Capacity
LCOE	Levelized Cost of Energy
LCTN	Least-Cost, Technology Neutral
LOLE	Loss of Load Expectation
LTCE	Long-Term Capacity Expansion
NGCC	Natural Gas Combined Cycle
NO_x	Nitrogen Oxides
NPV	Net Present Value
NPVRR	Net Present Value Revenue Requirement
O&M	Operations and Maintenance
OASIS	Open Access Same-time Information System

Appendix L (cont.)

OBBBA	One Big Beautiful Bill Act
OMS	Outage Management System
PCM	Production Cost Model
PHEV	Plug-in Hybrid Electric Vehicle
PPA	Power Purchase Agreement
PRM	Planning Reserve Margin
RA	Resource Adequacy
RICE	Reciprocating Internal Combustion Engine
RPAC	Resource Planning Advisory Council
SGS	Springerville Generating Station
SMR	Small Modular Reactor (nuclear)
SPP	Southwest Power Pool
TEP	Tucson Electric Power
UNSE	UNS Electric, Inc.
WECC	Western Electricity Coordinating Council
WEIM	Western Energy Imbalance Market
WEIS	Western Energy Imbalance Service
WPP	Western Power Pool
WRAP	Western Resource Adequacy Program
XHLF	Extra-High Load Factor