Tucson Electric Power

2023 Integrated Resource Plan

November 1, 2023






A Balanced Path to a Cleaner Energy Future

Energy providers must set a clear vision for the future. One in which we can safely and reliably meet our customers' growing energy needs at an affordable cost while effectively managing emerging challenges, from extreme weather to resource constraints across the Southwest.

Tucson Electric Power's 2023 Integrated Resource Plan (IRP) shows how we'll realize that vision. It outlines the sources we anticipate using to satisfy customers' need for reliable, affordable energy over the next 15 years while working toward a new, long-term objective of net zero direct greenhouse gas emissions by 2050.

The new goal keeps us on pace toward an 80 percent reduction in carbon dioxide (CO_2) emissions by 2035, a target we set in our 2020 IRP. We'll achieve this largely by steadily reducing emissions at our coal-fired power plants and replacing them with lower or no-carbon alternatives. While those coal-fired units are cost-effective for now, we don't expect that will remain true beyond their retirement dates due to increasing emission control costs, coal supply and delivery risks, and the increasing availability of cleaner and cheaper alternative resources.

As part of a balanced portfolio to meet our future needs, we plan to leverage cost-effective, abundant renewable resources as we develop 2,640 MW of new generating capacity overall, combined with 1,330 MW of new energy storage over the next 15 years. Our plan accelerates TEP's buildout of clean energy resources, with 1,520 MW of new renewable systems and storage coming online by 2030, a 44 percent increase over the level projected in the 2020 IRP.

Our balanced portfolio also identifies a need for 400 MW of new natural gas-fired generation by 2028 to replace output that will be lost when Springerville Unit 1 retires in 2027. Efficient, flexible and lower-carbon natural gas-fired resources help create a bridge to a cleaner energy future. Without it, our reliability could be undermined by a growing lack of dispatchable resources in the Desert Southwest, particularly during periods of extreme weather.

Our modeling has determined that this balanced portfolio outperforms other options, including alternatives that added only new renewables and storage and others that altered the retirement timelines for our coal plants. Of those options, our balanced portfolio would have the lowest impact on customers' rates while still achieving TEP's environmental objectives.

Because our new 2050 target lies outside the planning horizon for this IRP, we do not yet have details about how we'll achieve it. The goal is aspirational, reflecting our confidence that advancements in non-carbon emitting technologies such as long-duration storage, carbon capture and sequestration, hydrogen generation and small modular reactors will emerge as cost-effective options. It also provides a clear, easily understood goal that we will encourage customers to help us achieve through smart energy use that also contributes to lower cost and greater reliability.

Customers have already contributed to this plan through a local stakeholder group that provided input on the resource modeling. The Resource Planning Advisory Council (RPAC) included a wide range of perspectives, including residential and commercial customers, environmental activists and representatives from government agencies and outside advocacy groups.

The path charted by this new IRP is not set in stone. In the near term, our resource mix may vary based on the outcome of all-source requests for proposals that will identify the best resources available on the market to meet TEP's long-term goals. The process creates opportunities for developers to propose competing technologies that may prove more advantageous than those anticipated in the IRP. We'll also file regular updates with the Arizona Corporation Commission to ensure we've accounted for changes and that we remain on the right track.

The smart, clean, balanced and cost-effective plan outlined in these subsequent pages will help ensure that our service remains reliable and affordable while we execute a challenging but necessary transition to cleaner, less carbon-intensive resources.

Susan Gray
President and CEO

Table of Contents

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1 Executive Summary

Tucson Electric Power's (TEP or Company) 2023 Integrated Resource Plan (IRP) outlines how the company expects to satisfy customers' increasing energy needs over the next 15 years. The 2023 IRP presents the Company's current forward-looking cost assumptions while detailing its future energy and capacity needs through 2038. The Company's resource planning framework prioritizes reliability, affordability, and sustainability, and future resource acquisitions will be determined through All-Source Requests for Proposals (ASRFPs) to ensure these priorities are met. The 2023 IRP identifies the risks and opportunities facing the utility industry, and TEP specifically. This document outlines a plan to meet its customers' energy needs in a sustainable and reliable fashion.

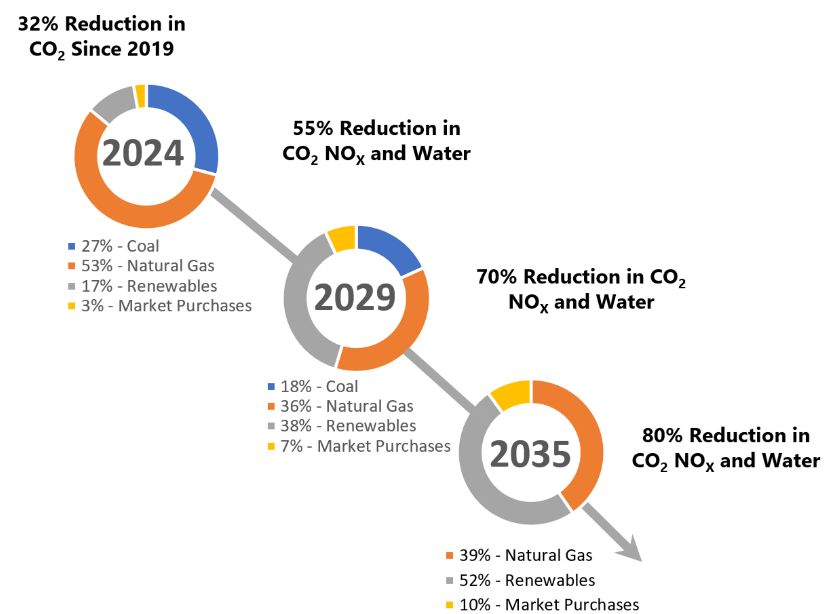
TEP's 2023 IRP establishes an updated roadmap for TEP's pursuit of a more sustainable energy supply. The 2023 IRP continues to move the Company forward with its clean energy goals that were established in TEP's 2020 IRP. The 2023 IRP continues to reflect our customers' desires to move toward a cleaner energy future with the goal established in the 2020 IRP to target an 80 percent reduction in carbon dioxide (CO_2) emissions from owned fossil generation by 2035. TEP has also committed to reducing Scope 1 greenhouse gas (GHG) emissions to net zero by 2050. Over the last few years, TEP has commissioned over 490 MW of new wind and solar plus storage projects, retired 339 MW of coal and has reduced its CO_2 emissions from owned fossil generation by 32%. The 2023 IRP builds on that goal and accelerates plans for developing new energy resources that will support affordable, reliable service while contributing to a cleaner, greener grid.

TEP projects that its peak energy demand will increase from 2,382 megawatts (MW) in 2024 to 2,800 MW in 2038, or 1.23 percent annually. The company also plans to retire its last 892 MW of coal-fired generation during this period with the retirement of Units 1 and 2 at TEP's Springerville Generating Station (in 2027 and 2032) and Units 4 and 5 at Arizona Public Service's (APS) Four Corners Generating Station in 2031.

To meet anticipated load growth and capacity lost to future coal plant retirements, TEP plans to secure over 3,970 MW of new resources, including 2,640 MW of new generating capacity and 1,330 MW of new energy storage over the next 15 years. While 90% of the new resource capacity will be sourced from renewable and energy storage projects, TEP anticipates a need to develop 400 MW of new natural gas-fired generation by 2028 in order to maintain reliable and affordable service for our customers.

TEP's 2023 IRP presents a balanced portfolio approach that supports a cost-effective way to maintain reliable service while achieving TEP's environmental objectives to mitigate climate risk. These position the company to achieve 80 percent reductions in CO_2 and nitrogen oxide (NO_X) emissions and water usage. TEP evaluated several portfolios including one that added only new renewables and storage without natural gas, and others that altered the retirement timelines for Units 1 and 2 at the Springerville Generating Station.

Figure 1. TEP's 2023 IRP Energy Transition



The company's balanced portfolio will accelerate TEP's buildout of clean energy resources, with 1,520 MW of new renewable systems and storage coming online by 2030 compared to the 1,050 MW that were anticipated in the 2020 IRP. The plan also is expected to mitigate impacts on customers' rates compared with other portfolio alternatives. TEP's ultimate resource mix may vary based on the outcome of future ASRFPs that will be used to develop future resources.

Notwithstanding, TEP presents its 2023 IRP targeted to achieve an affordable, reliable, and sustainable resource portfolio for our customers.

1.1 Major Initiatives Executed on from the 2020 IRP Action Plan

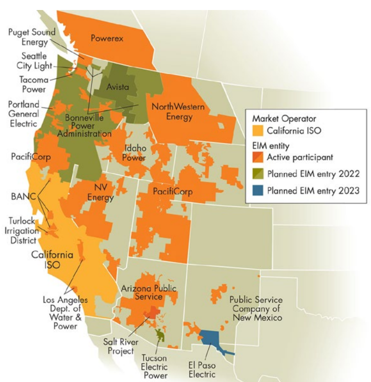
As part of the work done in the 2020 IRP, TEP moved forward with several planning commitments that were part of the Company's 2020 IRP Action Plan. The items below list the major initiatives completed since 2020.

San Juan Generating Station Retirement

San Juan Generating Station
Farmington New Mexico

Retired 170 MW of coal capacity at the San Juan Generating Station in June 2022

Western Energy Imbalance Market



Western Energy Imbalance Market
$40.9 Million Savings
(May 22 - Aug 23)

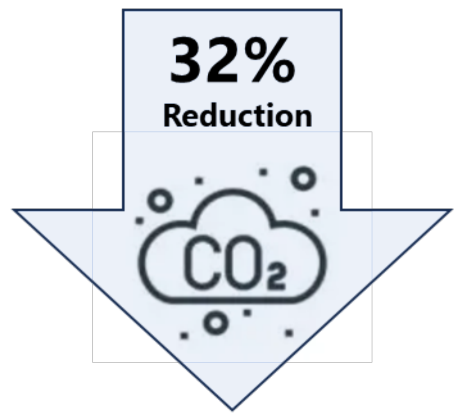
TEP joined the real-time Western Energy Imbalance Market in May 2022

All-Source Request for Proposals

2022 All-Source Request for Proposals
600 to 800 MW Solar + Energy Storage
by Summer 2026

TEP issued the Company's first All-Source Request for Proposal for new energy and capacity resources in April 2022

Steady Progress on CO_2 Reductions



TEP has reduced its CO_2 emissions from fossil generation by 32% since 2019

New Wind and Solar Projects

TEP commissioned 490 MW of new wind and solar plus storage projects in 2021 and 2022

Oso Grande

The 250 MW Oso Grande Wind Project, located near Roswell, New Mexico is owned and operated by TEP. It generates enough energy to serve the annual electric needs of about 100,000 homes.

Raptor Ridge

This efficient 12.5 MW Raptor Ridge solar system near Interstate 10 and Valencia Road in Tucson, AZ can produce enough power to meet the annual electric needs of about 2,500 homes. It provides power for homeowners and renters participating in TEP's GoSolar Home program.

Wilmot Energy Center

The Wilmot Energy Center includes a 100 MW solar array and a 30 MW energy storage system southeast of Tucson International Airport. It is owned and operated by NextEra.

Borderlands Wind

The 99 MW Borderlands Wind Project, located about 100 miles south of Gallup, New Mexico, is owned by NextEra. It includes 34 turbines that produce enough power to serve about 26,000 homes every year.

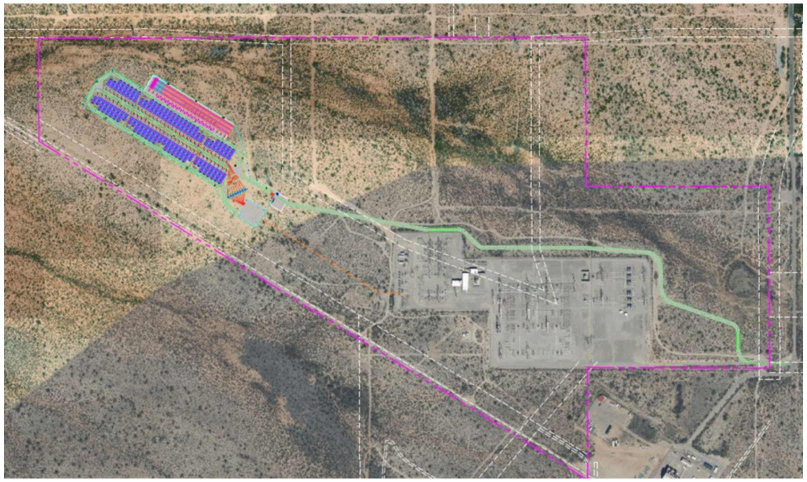
1.2 TEP's Newest Energy Storage Project – Roadrunner Reserve

TEP's Roadrunner Reserve system will serve as the largest energy storage system in our portfolio and among the largest in Arizona. The 200 MW system can store 800 megawatt-hours (MWh) of energy, enough to serve approximately 42,000 homes for four hours when deploying at full capacity. The system is scheduled to begin operation in the summer of 2025.

TEP expects to charge the grid-connected battery in the morning and early afternoon, when solar resources are most productive, then deliver stored energy later in the day when customers' energy use is typically highest. The system will be built next to a southeast-side TEP substation.

TEP will own and operate Roadrunner Reserve, which will be designed and built by Scottsdale-based DEPCOM Power, Inc. The new system will use lithium iron phosphate battery units, a newer technology that offers longer life and safer operation than other types of battery systems.

Roadrunner Reserve Site Layout



1.3 The Role of Existing Coal-Fired Generation Resources

Over the last decade, TEP has focused on transitioning to a lower cost, more diverse mix of resources to meet our customers' long-term sustainable energy needs. This strategy has focused on reducing the Company's exposure to fossil-fuel resources, which can be more costly and at risk of further environmental regulations, while making steady progress to a cleaner mix of energy resources.

Over the last six years, TEP has retired 638 MW of coal-fired generation as part of its ongoing planning efforts. These early coal retirements were made possible through strategic acquisitions of efficient and flexible natural gas resources to cost-effectively replace the retired coal capacity.

While coal is no longer the least-cost energy resource, it still provides cost-effective capacity, reliability, and ancillary services. To optimize the value of coal plant operations, the Springerville Generating Station (SGS) Units 1 and 2 will continue to operate on a seasonal basis through the eventual closures in 2027 and 2032, respectively.

TEP must continue to reduce and eventually eliminate its reliance on the existing 892 MW of coal-fired generation in its current resource portfolio. This will occur over the next 9 years. These planned closures are summarized in **Table 1**.

Table 1. Future Coal Plant Retirements

Facility	Location	Operator	TEP Ownership Interest	Scheduled Closure
Four Corners Units 4 & 5	Farmington, NM	APS	7% - 110 MW	2031
Springerville Units 1 & 2	Springerville, AZ	TEP	100% - 793 MW	2027, 2032

The Company will implement a measured and phased transition from its coal units that considers resource adequacy, workforce and community transition.

Springerville Generation Station

TEP is the owner and operator of SGS Units 1 and 2. A significant factor in the closure dates selected for these units relates to the time needed to develop and implement a community-driven transition plan to mitigate the impacts of closing these facilities. TEP is engaging employees, community leaders, and other key stakeholders as it begins to implement a workforce transition that addresses the needs of its employees and assisting the community in economic development.

Four Corners Power Plant

TEP has a partial ownership interest in Units 4 and 5 at the Four Corners Power Plant ("Four Corners"), which is operated by Arizona Public Service Company ("APS"). TEP is committed to working with APS on plant closure and transition activities at Four Corners through the retirement in 2031.

1.4 Net Zero by 2050

Both TEP and Fortis Inc, TEP's parent company, have established ambitious goals[1] to reduce collective carbon emissions. These goals reflect the Companies' commitment to a clean-energy transition while ensuring that customers continue to receive affordable and reliable service. Fortis' ultimate goal is to achieve net zero GHG emissions by 2050 across all its subsidiaries. TEP has also committed to reducing Scope 1 GHG emissions to net zero by 2050 and will accomplish this through coal plant retirements, future renewable additions and exploration of other clean technologies in future IRP planning cycles.

1.5 Net Zero Hero

Achieving net zero emissions by 2050 will depend in part on the Company's success in promoting participation in its energy efficiency programs and encouraging energy-smart behaviors by customers, including reduced usage during on-peak periods. To that end, TEP will launch an advertising campaign in late 2023 that invites customers to become a "net zero hero" by working with the Company toward a more sustainable energy future for our community. The campaign will continue into 2024 and beyond in hopes that it will make a lasting impact on customer energy usage patterns.

The Net Zero Hero campaign will highlight the broad benefits that can be achieved through simple measures like installing a smart thermostat, insulating windows and doors, changing air filters regularly, switching to LED lighting, selecting one of our optional time-of-use rate plans, and charging electric vehicles during off-peak periods. Such steps can make anyone a "hero," a message that will be reinforced through engaging,

[1] https://www.fortisinc.com/docs/default-source/environment-reports/2022-sustainability-report.pdf

comic book-style imagery and giveaway items that include capes for younger children. The Net Zero Hero campaign builds on previous comic-style campaigns that have encouraged residential customers to “Defeat the Peak” by shifting usage to off-peak hours.

1.6 TEP’s 2023 Preferred Portfolio and Future Action Plans

Section 8 describes TEP’s 2023 Preferred Portfolio and its 2023 Action Plan. While TEP’s 2023 Preferred Portfolio provides a roadmap for TEP’s pursuit of a more sustainable energy supply, circumstances and cost assumptions change over time. As such, TEP’s 2023 Preferred Portfolio will be ultimately shaped by future needs analyses and on-going all-source RFPs (ASRFPs). Future ASRFPs will be technology neutral, including supply- and demand-side resources, and will not unduly exclude any commercially available resource that can demonstrate adequate performance and cost-effectiveness.

Future ASRFPs will create opportunities for developers to propose competing technologies that may prove more advantageous than those anticipated in the 2023 IRP analysis. Finally, future resource plans will be updated as directed by the Arizona Corporation Commission (ACC) to reflect updated information, technology, and market trends.

2 Major Planning Considerations

The following section summarizes the most significant long-term planning challenges and opportunities facing TEP at this time and how the Company is addressing them in this IRP. Some of these topics are further addressed in subsequent sections.

2.1 Tucson's Near-Term Economic Development Opportunities

TEP's vision to be an exceptional energy provider that positively impacts the lives of our employees, customers, and communities means stewardship of the service area's economic development. Local industries will continue to grow with the support of the region's leadership and be impacted by rapidly changing trends in digitalization, decarbonization, and electrification, which will require larger and cleaner energy supply solutions. TEP's flexibility in accommodating these trends and new needs will support continued quality economic growth for its communities.

The Tucson metropolitan region, served by TEP, has a strong industrial base in advanced manufacturing, natural resources, clean technology, the biosciences, and innovation assets including the University of Arizona. In addition, it possesses logistical and connectivity advantages with I-10, Port of Tucson, Tucson International Airport, and intermodal rail facilities. As a result of these advantages and the efforts by state and regional leaders, local economic development pipelines are growing significantly. Not only are there more projects, but the power requirements of the projects are larger on average and demand a mix of energy resources that require increased reliability and a path toward carbon neutrality.

Arizona has positioned itself as a strong competitor in attracting new industry. As such, TEP is seeing an increase in activity in the economic development pipeline, as well as an increase in the prospective load associated with the potential projects. Loads larger than 5 megawatts have become common, and mega projects, which include indicated loads larger than 100 megawatts, have also begun surfacing in the prospective development pipeline. In addition to looking for assured reliability, many potential and existing customers have an evolving and elevated interest in low-carbon or carbon-free electricity. Should any of these projects come to fruition, TEP forecasting models would be significantly impacted.

2.2 Retirement of Coal-Fired Generation

For decades, TEP's coal-fired assets have provided reliable baseload power for its customers. Replacing these resources is a complex process that requires careful coordination with replacement resources in order to ensure the continuation of reliable, affordable power. Replacing these resources also impacts remote communities that have long supported TEP's use of these assets.

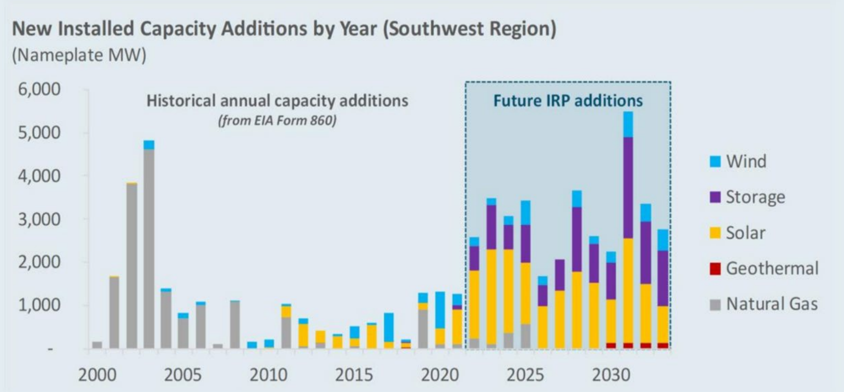
The continuation of seasonal operations at the Springerville Generating Station and our phased approach to reduce coal-fired generation is central to meeting our sustainability goals, while lowering our exposure to future environmental risks, and allows for a planned workforce and community transition.

2.3 Volatile Markets and Diminishing Regional Capacity

Figure 2 shows the historic and projected capacity additions in the Southwest. The projected additions are based on utility IRPs as of early 2022 and do not account for additional demand resulting from the Inflation Reduction Act, or for additional supply needed as a result of updated reliability analyses or renewable and storage capacity evaluations. The combination of utility resource plans clearly indicates the scale of infrastructure to be developed, which dwarfs any period in recent history, and which exerts further pressure on supply chains and development timelines.

Figure 2. A Historical Perspective on the Rate of New Capacity Additions in the Desert Southwest

The Western Energy Crisis of 2001 was followed by one of the most rapid periods of new resource development in the history of the Western Interconnection, as utilities around the region invested in new natural gas generation in response to acute reliability concerns. In the Southwest, nearly 10,000 MW of natural gas capacity was built between 2001-2004; most of these resources continue to operate today in support of utilities' resource adequacy needs. Since that time, the pace of new resource development in the region has been comparatively moderate. However, looking forward, the amount of new capacity reflected in utilities' plans represents a surge in the rate of new capacity additions and a sustained rate of new resource development that approaches the level experienced 20 years ago.



Source: Resource Adequacy in the Desert Southwest, Energy+Environmental Economics, 2022. Includes all balancing areas in AZ and NM.

2.4 Resource Adequacy and Reliability

Resource adequacy (RA) is the ability of a power provider to meet its customers' demand and necessary reserves under a variety of system conditions, including extreme weather, transmission system configuration, and other factors affecting generation capacity or load. While the need for RA remains unchanged, the methods utilities use to evaluate it and the resources used to supply it are swiftly changing. The California ISO's experience in August of 2020 highlights what can happen when there is a confluence of changing resource mix, climate change, and increasing customer demand in the age of electrification.

The North American Electric Reliability Corporation (NERC) has established several standards to measure a Balancing Authority's (BA) performance and its contribution to real-time grid stability. Some of these standards measure how much a BA is impacting system frequency requirements and for how long, whether a BA provides adequate assistance in recovering frequency after a disturbance, and whether a BA is carrying adequate contingency reserves to replace resources following an unplanned loss. A more detailed explanation of BA standards and operation are discussed in **Appendix J.** While RA is just one component of overall grid reliability, it can impact a BA's ability to respond to changing system conditions in real-time, impacting standard performance and the resiliency of the Bulk Power System (BPS).

Traditionally, RA has focused solely on capacity with the expectation that adequate capacity meant adequate energy. Utilities now recognize the impacts that variable and energy-limited resources have on net load and RA requirements. In addition, transmission availability, market liquidity, and long-term fuel supply all have impacts on RA. The increasing challenges and complexity of maintaining RA indicate that utilities need to focus on the diversity of resource types and geography to provide balance and prevent sole reliance on resources that may become exhausted or suddenly unavailable.

2.5 The Future Role for Natural Gas Resources

Over the last decade, the Company has transitioned its energy needs away from coal-fired generation towards cleaner natural gas and renewables. In prior IRP planning cycles the Company acquired, through merchant wholesale acquisitions, new natural gas generation capacity at the Gila River Power Station in 2014 and 2019 at a significant cost discount. In addition, TEP installed approximately 200 MW of new fast start, fast ramping natural gas reciprocating internal combustion engines (RICE) at the Sundt Generating Station in 2020 to support its expansion of renewable resources. Over the last few years, TEP has installed over 760 MW of new utility scale solar and wind resources and 50 MW of new energy storage to support on-going grid operations.

However, the California blackouts in the summer of 2020, winter storm Uri in Texas in the winter of 2021, and the on-going summer capacity shortfalls have shifted the planning focus to prioritize on meeting summer peak "capacity needs" in order to maintain reliability and resource adequacy in the near-term. The issue of reliability and resource adequacy has been noted in recent Desert Southwest risk assessment reports.

In December 2021, the NERC released its 2021 Long-Term Reliability Assessment (LTRA). The regional reliability assessment noted the need for natural gas resources to continue to play a role in supporting the BPS as it makes its transition to cleaner energy resources:

> *As governmental policies are developed, prioritizing reliability during the grid's transformation will support a transition that assures electric reliability in an efficient, effective, and environmentally sensitive manner. However, recognition of the challenges that the system faces during this transition requires action on key matters. Natural gas is the reliability "fuel that keeps the lights on," and natural gas policy must reflect this reality.*[2]

> *Recognition of the challenges that the system faces during this clean energy transition requires action on key matters. Natural gas is the reliability "fuel that keeps the lights on," and natural gas policy must reflect this reality.*

2.5.1 E3 Desert Southwest Study

In February 2022, Energy + Environmental Economics (E3) conducted a reliability study titled Resource Adequacy in the Desert Southwest (E3 Study), which highlighted some of the region's resource adequacy challenges it will face over the next decade and the role natural gas will need to play in maintaining reliability. Key excerpts from the E3 Study are provided below.[3]

E3 Study – Highlights and Recommendations

- Load growth and resource retirements are creating a significant and urgent need for new resources in the Southwest region; maintaining regional reliability will hinge on whether utilities can add new resources quickly enough to meet this growing need and will require a pace of development largely unprecedented for the region.
- An increasingly significant share of long-term resource needs is expected to be met with solar and storage resources, but a large quantity of "firm" generation capacity – including the region's nuclear and natural gas resources – will also be needed to maintain reliability.
- Substantial reliability risks remain as the region's electricity resource portfolio transitions, most notably: weather- and climate-related uncertainties, performance of battery storage, and risks related to the timing of new resource additions.

The E3 Study also noted that managing this pace of change presents the greatest challenge to reliability. One of the profound consequences of the region's increasing reliance on solar and storage resources is that the timing of the greatest reliability risks will change over time. By 2025, the evening "net peak" will become more constraining than the historical late afternoon peaks due to saturation by solar energy resources. Deployment of energy storage at scale will further extend the constraining periods into the late evening and nighttime hours.

E3 Study – The Changing Profile of Reliability Risk in the Desert Southwest

> *The changing profile of reliability risk in the Southwest as the region transitions to higher penetrations of solar and storage is shown in* **Figure 3** *below. As this transition occurs, the*

[2] NERC, 2021. 2021 Long-Term Reliability Assessment. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2021.pdf.

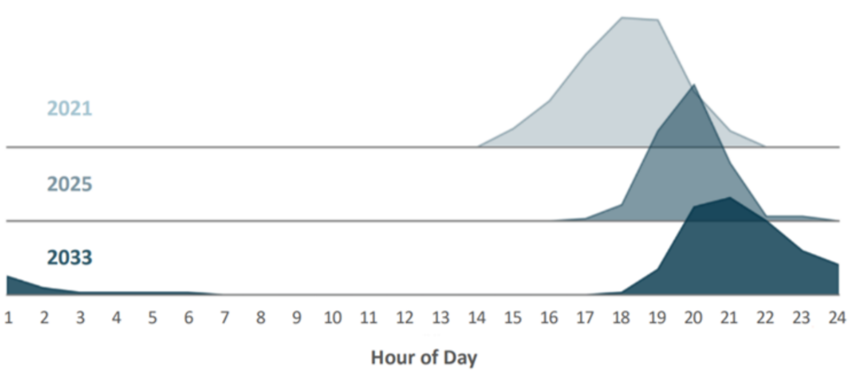
[3] Energy + Environmental Economics (E3) - Resource Adequacy in the Desert Southwest. https://www.ethree.com/wp-content/uploads/2022/02/E3_SW_Resource_Adequacy_Final_Report_FINAL.pdf

effectiveness of incremental solar and energy storage resources in their contributions to resource adequacy will diminish; this dynamic is reflected in their declining marginal Effective Load Carrying Capabilities (ELCC). By 2033, the marginal capacity value of solar is roughly 10%; of four-hour storage, 40%.

The changing character of this risk highlights the need for resources that are capable of delivering energy to the bulk power system for sustained periods from early evening until morning. For this reason, conventional firm capacity resources will continue to play a crucial role in meeting resource adequacy needs alongside a burgeoning portfolio of renewable, storage, and demand-side resources.

TEP's 2023 IRP highlights this need for a balanced portfolio approach of solar plus storage and wind resources with a continued reliance on "firm capacity" from natural gas resources to maintain resource adequacy.

Figure 3. The Changing Profile of Reliability Risk in the Desert Southwest (Relative Loss of Load Risk by Hour of the Day)



The changing composition of the portfolio impacts the timing of reliability risks:

- High levels of solar shift the loss of load risk later into the evening
- Storage flattens the net peak, extending the loss of load risk into the late evening and early morning hours

E3 Study – Recommendations on Timing of New Resource Additions

Meeting regional reliability needs in the next decade will require the addition of thousands of megawatts of new resource capacity each year. The processes surrounding new resource development – including siting and permitting; transmission interconnection studies; competitive solicitations and contract negotiation; regulatory approval processes; and engineering, procurement, and construction – require multiple years and are subject to risks of delay. Failure to bring resources online successfully before they are needed could compromise reliability and create a compounding deficit in a region where loads are growing quickly.

Utilities should account for reasonable possibilities of delays and project cancellations when assessing need and timing the procurement of new resources. This may reasonably lead to an outcome where, during periods of rapid change such as the next decade, utilities' actual reserve margins exceed the levels deemed strictly necessary to meet resource adequacy requirements in order to mitigate reliability risks associated with rapidly growing needs and unexpected changes in project development timelines. The need to mitigate timing-related risks during periods of transition has historically been recognized by regulators as justification that actual reserve margins may reasonably exceed minimum requirements.

One of the direct corollaries to this recommendation is that any replacement resources for planned retirements should be brought online in advance of the scheduled retirement to accommodate the risk of possible delays; a failure to account for some margin in a period of rapid transition could lead to either (a) a degradation of reliability, or (b) the need to extend the lifetime of retiring resources. Either of these outcomes could pose a significant setback to utilities' efforts to transition affordably to low-cost, low-carbon portfolios. Utilities, regulators, stakeholders and developers will all share responsibility for working cooperatively to achieve this significant buildout.[4]

> *An increasingly significant share of long-term resource needs is expected to be met with solar and storage resources, but a large quantity of "firm" generation capacity – including the region's nuclear and natural gas resources – will also be needed to maintain reliability.*

[4] Ibid.

2.6 Project Development Timelines and Technology Risks

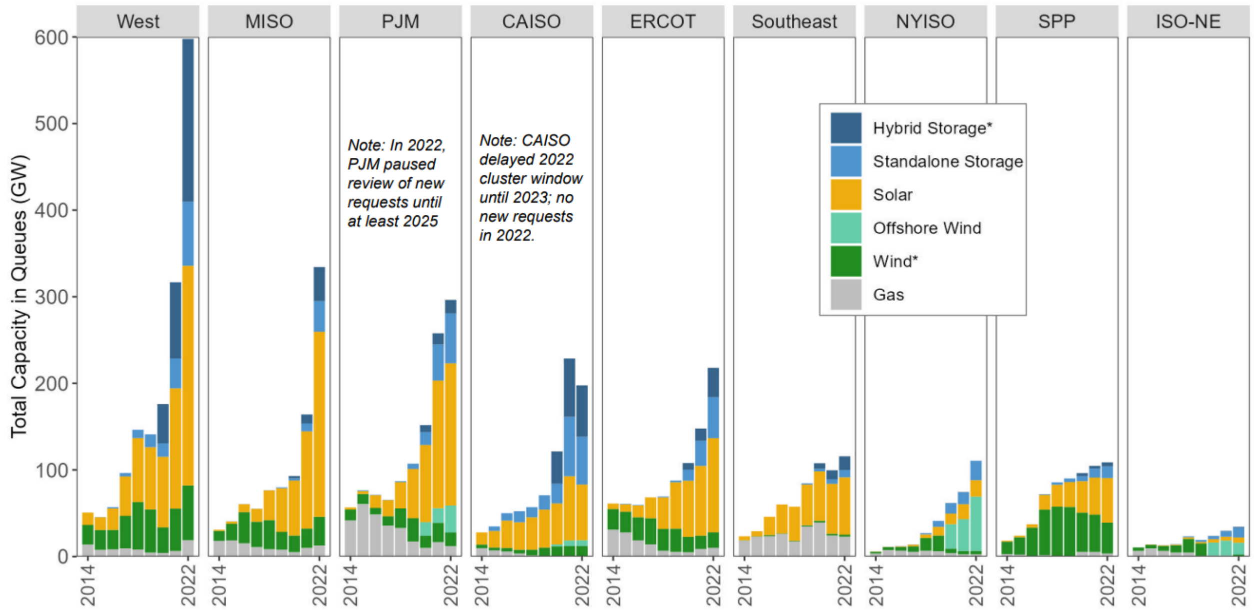
Supply chain issues, in the form of increased cost and prolonged commissioning dates, were evident in proposals received as part of the 2022 ASRFP solicitation. The company was optimistic about receiving proposals with two-to-three-year commissioning dates from notice to proceed to build. Beside the interconnection queue complexity and the potential for project delays discussed in Section 4 of this report, the supply chain issues are diverse and extend globally.

The ban on solar panel imports derived from verification of forced labor and other factors has created gridlock. In recent months, the imports have been steadily increasing through clearer federal guidance resulting in reduced detainment of imports. The raw materials used in solar panels is in abundance, but production is dominated by China. Stability in cost and vulnerabilities abroad are mitigated with expanding domestic production.

According to American Clean Power, 4 Gigawatts and 12 Gigawatt-hours of energy storage was commissioned in 2022. This likely represents planning and procurement ahead of the pandemic. The battery storage sector is more reliant on raw materials mined in specific countries.

Figure 4 shows the total capacity in interconnection queues by region. Standalone and hybrid storage represent a sizable amount for the west.[5] While lithium remains a dominant material in the production of batteries, the United States will rely mostly on imports for supply. According to the United States Geological Survey[6], Chile and Argentina hold over 66 % of the world reserves. To date however, China represents the bulk of the world lithium-ion manufacturing.

Figure 4. A Historical Perspective on the Rate of New Capacity Additions in the Desert Southwest



[5] Source: Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection, as of the end of 2021, Lawrence Berkeley National Laboratory.
[6] https://pubs.usgs.gov/periodicals/mcs2021/mcs2021-lithium.pdf

2.7 Evaluating the Cost of Energy and Capacity

In evaluating the long-term cost impacts of resource technologies, it is important to consider the value of energy, capacity and the role resources play in supporting resource adequacy. While renewable resources provide the resource portfolio with low-cost energy, the need for new capacity resources such as natural gas and energy storage technologies is the main focus of the 2023 IRP. This focus on capacity resources will enable the company to continue forward with its commitments to achieve an 80% reduction in carbon emissions by 2035 in an affordable and reliable manner. The following section details the cost of energy, the value of capacity and how these future capacity resources will contribute to the Company's long-term transition to net zero carbon emissions by 2050.

2.8 The Incremental Cost of Energy

The incremental cost of energy provides insights on the variable costs associated with different resource technologies. As shown below, variable costs for existing coal, new combined cycle and new combustion turbine resources reflect the cost of fuel and variable operations and maintenance (O&M) costs. Energy costs for renewable resources reflect the delivered costs of energy under a typical purchase power agreement. Both wind and solar resources are assumed to meet the prevailing wage and apprenticeship requirements in order to qualify for additional tax credits under the Investment Recovery Act. **Figure 5** and **Table 2** below provide an incremental cost of energy comparison for different resource types.

Figure 5. Incremental Cost of Energy

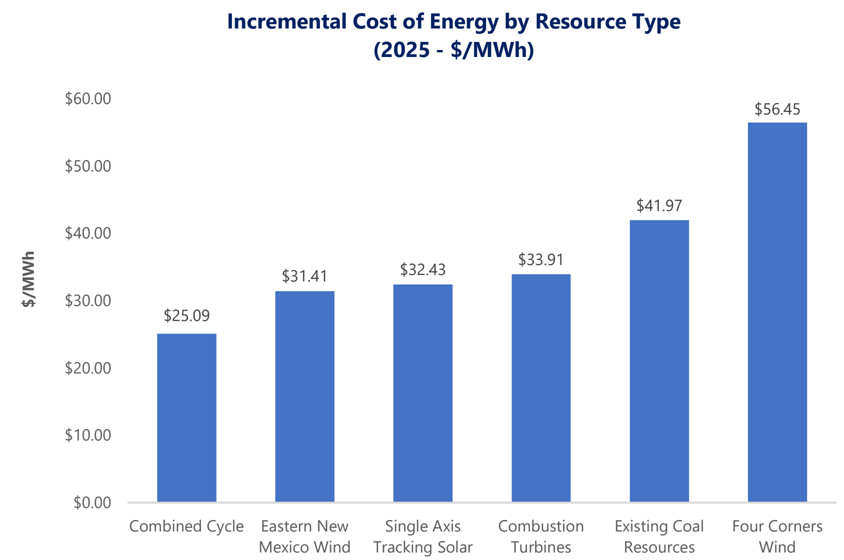
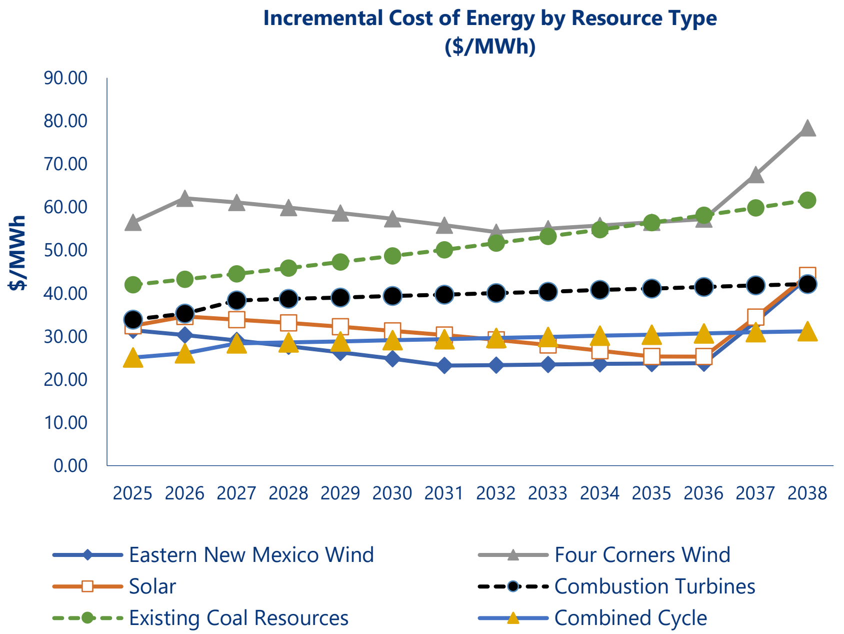


Table 2. Incremental Cost of Energy by Year

Incremental Cost of Energy	Combined Cycle	Eastern New Mexico Wind	Single Axis Tracking Solar	Combustion Turbines	Existing Coal Resources	Four Corners Wind
2025	$25.09	$31.41	$32.43	$33.91	$41.97	$56.45
2026	$26.10	$30.29	$34.60	$35.28	$43.23	$62.06
2027	$28.35	$29.07	$33.88	$38.32	$44.53	$61.04
2028	$28.64	$27.74	$33.10	$38.71	$45.86	$59.90
2029	$28.86	$26.32	$32.24	$39.00	$47.24	$58.65
2030	$29.15	$24.79	$31.31	$39.40	$48.65	$57.26
2031	$29.36	$23.23	$30.29	$39.69	$50.11	$55.80
2032	$29.65	$23.36	$29.19	$40.08	$51.62	$54.20
2033	$29.87	$23.49	$27.99	$40.38	$53.17	$54.96
2034	$30.16	$23.60	$26.70	$40.77	$54.76	$55.71
2035	$30.38	$23.70	$25.32	$41.06	$56.40	$56.46
2036	$30.67	$23.79	$25.30	$41.45	$58.10	$57.20
2037	$30.96	$33.43	$34.45	$41.85	$59.84	$67.51
2038	$31.18	$43.62	$44.14	$42.14	$61.63	$78.38

Figure 6 below provides an incremental cost of energy cost comparison for resources entering into service between 2025 and 2038. These cost projections are based on the assumptions that are used throughout the 2023 IRP analysis.

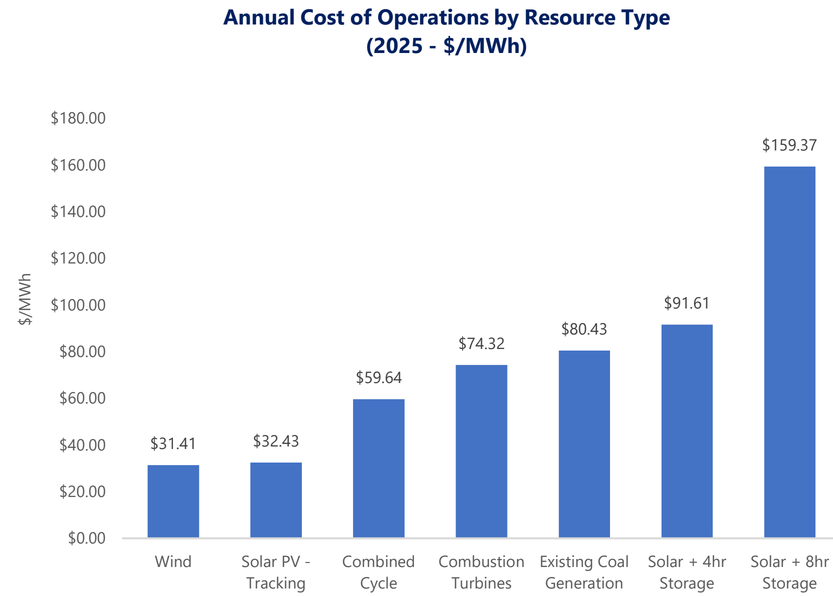
Figure 6. Incremental Cost of Energy by Year



2.9 Annual Cost of Operations

While the incremental cost of energy provides insights on the variable costs associated with different resource technologies, the annual cost of operations provides a means of comparing total cost of annual operations across different resource technology options at given points in time. In addition to the incremental cost of energy shown in the section above, the cost of operations includes all fixed O&M and capital costs associated with different technologies. Operating costs include the use of capital for construction, financing, fuel, and operation and maintenance. In addition, costs related to interconnection, transmission, permitting, and tax credits are also considered. **Figure 7** below shows the annual operating costs for technologies built in 2025 and exclude any environmental restrictions related to future EPA regulations. An existing coal generation resource is also included in this data to show the relative costs compared to other new resource technologies.

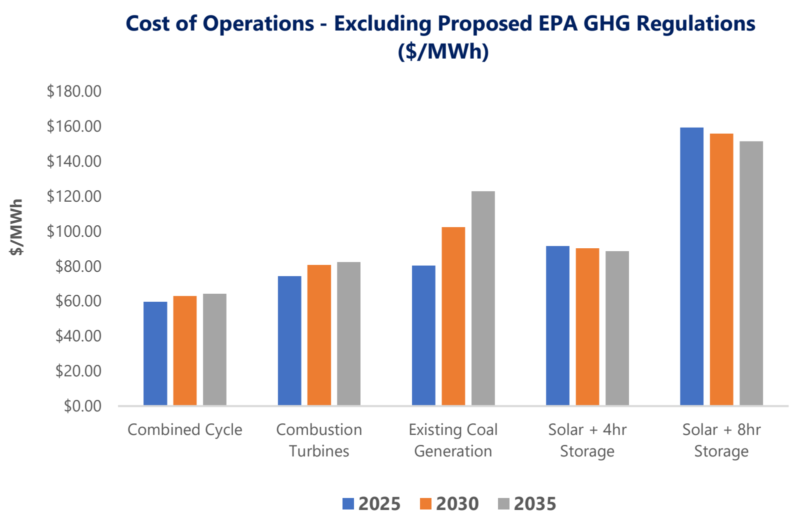
Figure 7. Annual Cost of Operations



2.10 Annual Cost of Operations over the Planning Period

Throughout the 15-year planning period the annual cost of operations for firm capacity resources will change based on variations in capacity factors, fuel prices, capital and operating costs, and environmental regulations. **Figure 8**. below highlights how the annual operating costs for each technology changes overtime. In 2025, both the existing coal and new natural gas resources have lower operating costs than solar plus storage resources. However, by 2030, future cost projections show that existing coal generation costs will rise significantly whereas natural gas and solar plus storage move towards cost parity. This data below excludes any environmental restrictions related to EPA's May 2023 proposal to regulate greenhouse gas (GHG) emissions from fossil fuel-fired electric generating units under Section 111 of the Clean Air Act.[7]

Figure 8. Annual Cost of Operations over the Planning Period

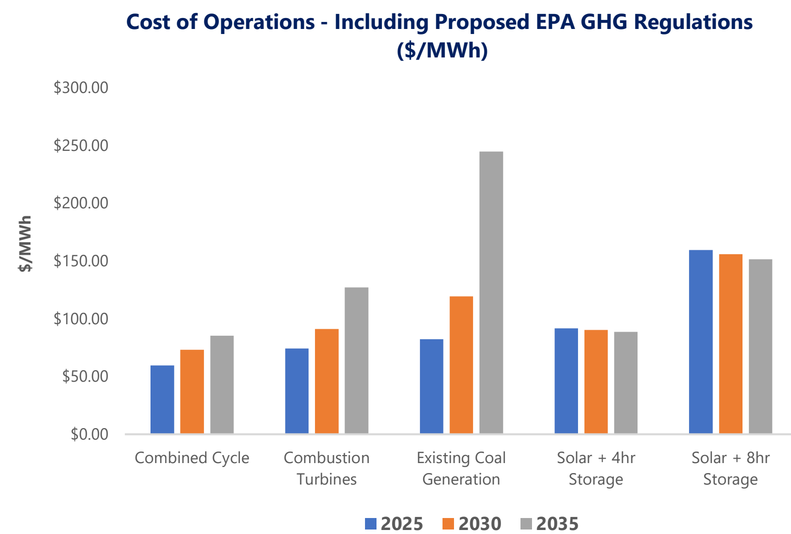


[7] 88 Fed. Reg. 33,240 (May 23, 2023).

2.11 Annual Cost of Operations Under Proposed GHG Regulations

As part of the 2023 IRP, the Company modeled the cost implications of EPA's May 2023 proposal to regulate greenhouse gas (GHG) emissions from fossil fuel-fired electric generating units under Section 111 of the Clean Air Act. **Figure 9** below highlights how these proposed environmental regulations will potentially impact future operating costs over time. The discussion in **Appendix H** provides a snapshot of other major environmental regulatory programs and recent proposals that may have an impact on TEP and our resource planning efforts. Since environmental regulations are focused on reducing the harmful impacts from fossil fuel resources, we can observe the potential future cost risk associated with remaining in existing coal operations. This future risk exposure validates the Company's plans to transition out of all coal fired generation by 2032.

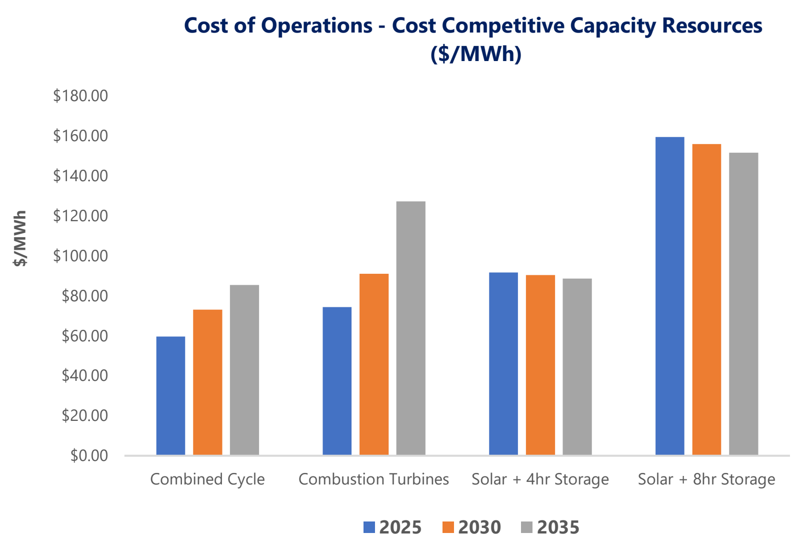
Figure 9. Annual Cost of Operations Under Proposed GHG Regulations



2.12 Investing in Future Cost Competitive Capacity Resources

As discussed above, the 2023 IRP is primarily focused on resource decisions linked to new capacity resources that will reduce long-term risks while maintaining affordability and reliability for our customers. The underlying analysis of the 2023 IRP planning cycle supports a balanced investment in both natural gas and solar plus storage. In the near-term, natural gas resources lowers the cost of operations and serves the long-duration capacity needs of the Company as TEP retires its existing baseload coal plants over the next decade. While solar plus storage is currently more expensive than natural gas resources, the Company believes in making significant investments in solar plus 4-hour storage alongside investments in new natural gas. These changes in the operating costs over time are shown in **Figure 10.**[8]

Figure 10. Costs of Operations for Future Capacity Resources



[8] Combustion turbines are more favorable versus NGCC due to; ramp up/down flexibility, faster start-up times, lower water consumption and reduced natural gas pipeline volume and pressure requirements.

2.13 Comparing the Economics of Solar + Storage to Natural Gas

Based on the Effective Load Carrying Capability (ELCC) studies done by E3 and explained in detail in **Section 5.4** and **Appendix D**, this section examines the potential loss of load risks for TEP under future capacity need scenarios and provides straight-forward cost comparisons between scenarios utilizing natural gas versus a combination of solar plus storage to meet future reliability requirements. While the detailed in-depth cost analysis is done within our capacity expansion and production cost models, the discussion and analysis below is presented to provide transparency on how the cost profiles change with the long-term capacity need that results from future load growth and planned baseload coal plant retirements.

In a similar comparison that was performed in the E3 Desert Southwest Study described in **Section 2.5.1**, the loss of load risk for TEP was examined through high-level analysis outside of the IRP modeling for three different time periods, 2025, 2028 and 2033. The 2028 and 2033 time periods were chosen due to the large changes in the resource mix that occur with the retirement of the Company's coal generation at Springerville and Four Corners. The time periods also demonstrate how the loss of load hour duration impacts the cost of capacity options when comparing natural gas to solar plus storage. **Table 3** summarizes the loss of load hours and viable replacement capacity options in the time periods shown below.

Table 3. Loss of Load and Replacement Capacity Options

Loss of Load Results	2025	2028	2033
Peak Shortfall, MW	216	692	1,450
Loss of Load Hours / Peak Day	5	12	21
Loss of Load Hours, MWh	712	4,479	15,054

Potential Capacity Expansion Options	2025	2028	2033
Natural Gas Combustion Turbines, MW	225	700	1,450
Solar + 4-Hour Storage, MW	225	800	2,000

2.14 Potential Capacity Expansion Options for 2025

Figure 11 below shows a 2025 peak summer day where the total loss of load hours is approximately 712 MWh spread across a 5-hour period with a peak shortfall of approximately 216 MW shown in hour ending 18:00. Under this scenario, the Company could choose to build approximately 225 MW of new natural gas combustion turbines to meet this loss of load requirement. Alternatively, the Company could use approximately 225 MW of solar with 225 MW of 4-hour storage to meet this same loss of load requirement.

Figure 11. Loss of Load Risk Under a 5-Hour Capacity Shortfall Scenario

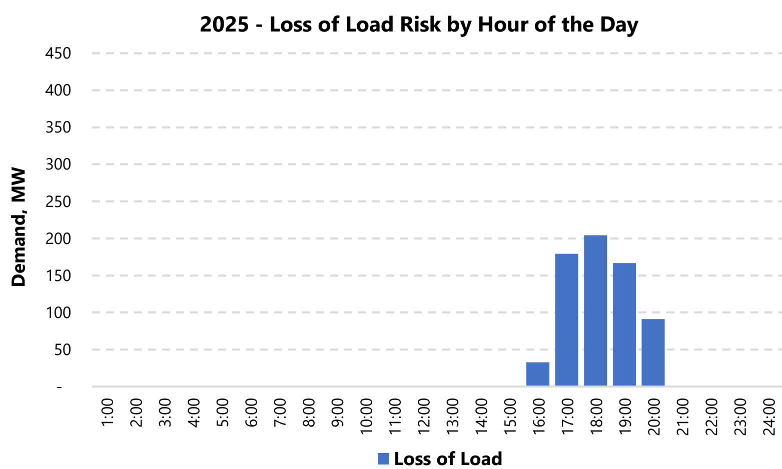


Figure 12 below shows how the use of both solar and 4-hour energy storage would be dispatched to serve these load requirements. The cost comparisons shown in **Table 4** below comparing the costs of both natural gas and solar plus storage resources options, shows that the use of solar plus storage to serve these future capacity needs would result in higher capital investments of approximately $67 million and an 20% higher annual revenue requirement of approximately $9.5 million per year.

Figure 12. 225 MW Solar + 225 MW of 4-Hour Solar Portfolio

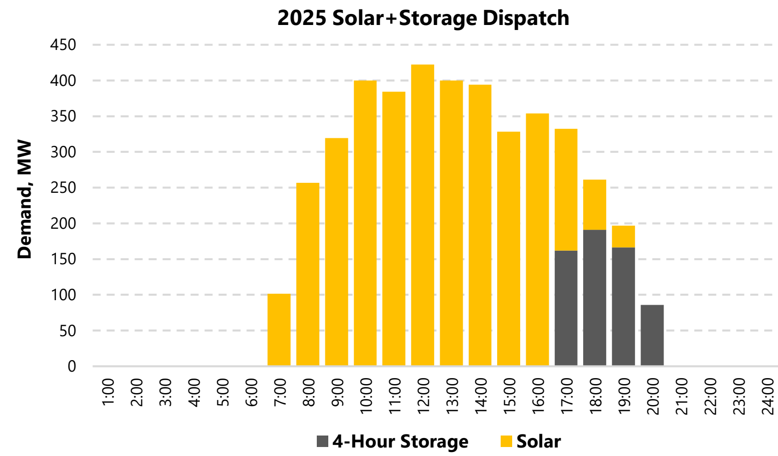


Table 4. 2025 Combustion Turbines vs Solar + Storage Cost Comparison

Resource Technologies	Combustion Turbines	Solar + 4hr Storage
Project Cost, $/kW ($2025)	$1,186	$1,485
Capital Investment, $000	**$266,850**	**$334,125**
Hours of Daily Dispatch Capacity, Hours	**24**	**4**
Capacity Factor, %	20%	31%
Heat Rate, Btu/KWh	9,800	0
Natural Gas, $/mmBtu	$3.45	$0.00
Resource Capacity Needed	**225**	**225**
Fuel Revenue Requirements, $000	$13,343	
Non-Fuel Revenue Requirements, $000	$33,191	$55,974
Annual Revenue Requirements, $000	**$46,534**	**$55,974**
Capital Investment Difference, $000		**$67,275**
Revenue Requirement Difference, $000		**$9,440**
Revenue Requirement Difference, %		**20%**

2.15 Potential Capacity Expansion Options for 2028

Figure 13 below shows a 2028 peak summer day where the total loss of load hours is approximately 4,479 MWh spread across a 12-hour period with a peak shortfall of approximately 692 MW shown in hour ending 18:00. Under this scenario, the Company could choose to build approximately 700 MW of new natural gas combustion turbines to meet this loss of load requirement. Alternatively, the Company could use approximately 800 MW of solar with 800 MW of 4-hour storage to meet this same loss of load requirement.

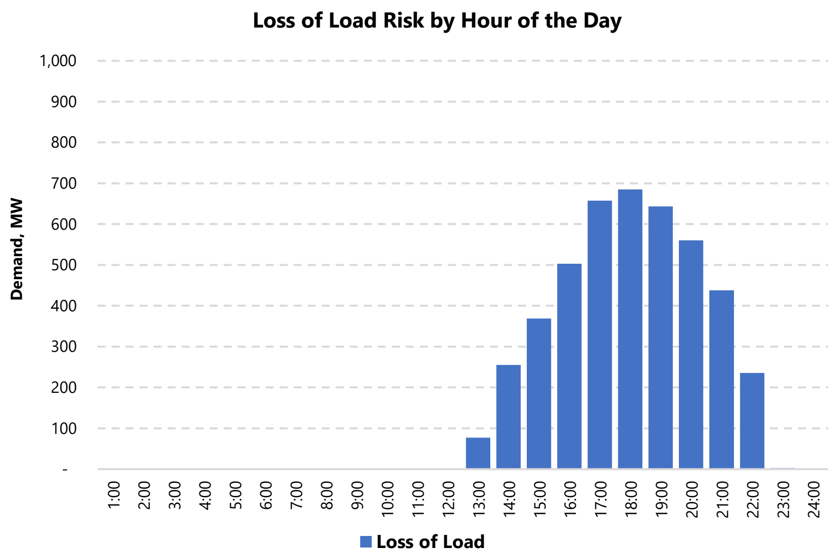


Figure 13. Loss of Load Risk Under a 12-Hour Capacity Shortfall Scenario

Figure 14 below shows how the use of both solar and 4-hour energy storage would be dispatched to serve these load requirements. The cost comparisons shown in **Table 5** below comparing the costs of both natural gas and solar plus storage resource options, show that the use of solar plus storage to serve these future capacity needs would result in higher capital investments of approximately $314 million and an 32% higher annual revenue requirement of approximately $48 million per year.

Figure 14. 800 MW Solar + 800 MW of 4-Hour Solar Portfolio

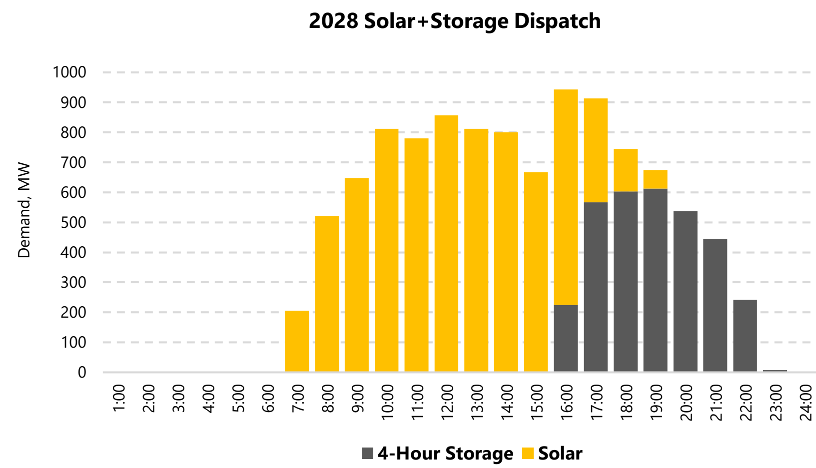


Table 5. 2028 Combustion Turbine – Solar + Storage Cost Comparison

Resource Technologies	Combustion Turbines	Solar + 4hr Storage
Project Cost, $/kW ($2028)	$1,259	$1,494
Capital Investment, $000	**$881,300**	**$1,195,200**
Hours of Daily Dispatch Capacity, Hours	**24**	**4**
Capacity Factor, %	20%	31%
Heat Rate, Btu/KWh	9,800	
Natural Gas, $/mmBtu	$3.45	
Resource Capacity Needed	**700**	**800**
Fuel Revenue Requirements, $000	$47,443	
Non-Fuel Revenue Requirements, $000	$103,262	$199,019
Annual Revenue Requirements, $000	**$150,705**	**$199,019**
Capital Investment Difference, $000		**$313,900**
Revenue Requirement Difference, $000		**$48,313**
Revenue Requirement Difference, %		**32%**

2.16 Potential Capacity Expansion Options for 2033

Figure 15 below shows a 2033 peak summer day where the total loss of load hours is approximately 15,054 MWh spread across a 21-hour period with a peak shortfall of approximately 1,450 MW shown in hour ending 18:00. Under this scenario, the Company could choose to build approximately 1,450 MW of new natural gas combustion turbines to meet this loss of load requirement. Alternatively, the Company could use approximately 2,000 MW of solar with 2,000 MW of 4-hour storage to meet this same loss of load requirement.

Figure 15. Loss of Load Risk Under a 21-Hour Capacity Shortfall Scenario

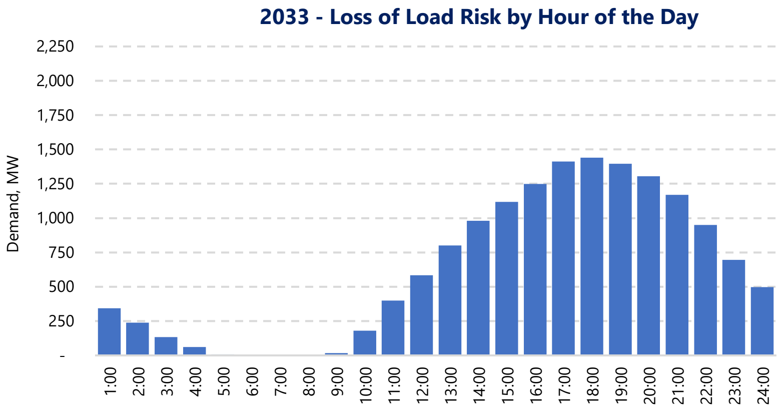


Figure 16 below shows how the use of both solar and 4-hour energy storage would be dispatched to serve these load requirements. The cost comparisons shown in **Table 6** below comparing the costs of both natural gas and solar plus storage resource options, shows that the use of solar plus storage to serve these future capacity needs would result in higher capital investments of approximately $878 million and an 57% higher annual revenue requirement of approximately $181 million per year.

Figure 16. 2,000 MW Solar + 2,000 MW of 4-Hour Solar Portfolio

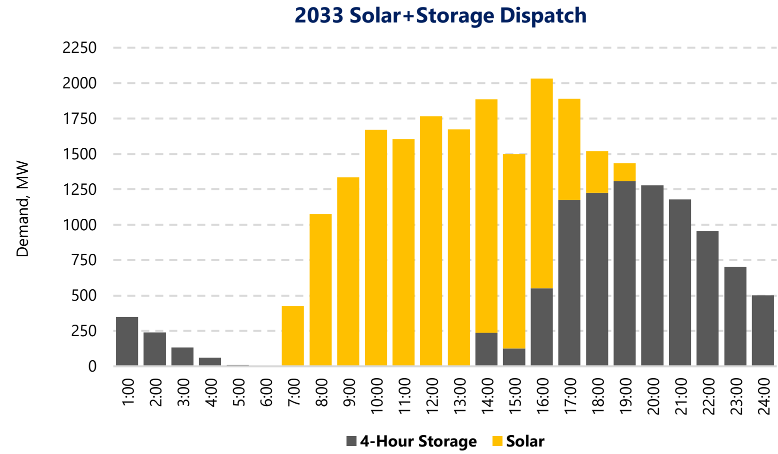


Table 6. Combustion Turbine – Solar + Storage Cost Comparison

Resource Technologies	Combustion Turbines	Solar + 4hr Storage
Project Cost, $/kW ($2033)	$1,390	$1,447
Capital Investment, $000	**$2,015,500**	**$2,893,000**
Hours of Daily Dispatch Capacity, Hours	**24**	**4**
Capacity Factor, %	20%	31%
Heat Rate, Btu/KWh	9,800	
Natural Gas, $/mmBtu	$3.45	
Resource Capacity Needed	**1450**	**2000**
Fuel Revenue Requirements, $000	$102,607	
Non-Fuel Revenue Requirements, $000	$213,900	$497,546
Annual Revenue Requirements, $000	**$316,508**	**$497,546**
Capital Investment Difference, $000		**$877,500**
Revenue Requirement Difference, $000		**$181,039**
Revenue Requirement Difference, %		**57%**

2.17 Inflation Reduction Act and Bipartisan Infrastructure Law

Energy Infrastructure Reinvestment (EIR) is a new loan program administered by the Department of Energy's Load Program Office (LPO) to promote clean energy. It provides financing for projects that (1) retool, repower, repurpose or replace energy infrastructure or (2) reduce greenhouse gas emissions. The LPO describes the program as an opportunity to support reinvestment in communities where there is existing energy infrastructure that has been challenged by market forces, resource depletions, age, technology advances or energy transitions.

Energy infrastructure includes facilities and associated equipment used for generation or transmission of electricity, fossil fuel extraction sites, pipelines, and other energy facilities. Under the EIR program, eligible projects include renewable energy, storage, transmission interconnections to off-site clean energy, reconductoring transmission lines and upgrading voltage, installing emission control technologies, repurposing oil and natural gas pipelines for hydrogen, and upgrading existing generation facilities with newer emissions control technologies.

To meet the program objectives of retool, repower, repurpose or replace, new projects must be located at or near the legacy infrastructure. Program requirements include a demonstration that loss of service and benefits from the legacy facility is replaced with new services and benefits from the new project. Additionally, projects involving electric utilities as an applicant must provide assurances that the benefits received from the loan guarantees will be passed along to customers or communities served.

The Company is committed to evaluating potential for new projects eligible for funding under this new program. Such projects could include reinvesting in energy infrastructure at the Springerville Generating Station, employing new technology for emission controls, and financing new renewable energy or storage facilities. The program has a sunset date of September 30, 2026, which affords the Company sufficient time to vet these and other potential projects eligible for EIR financing.

2.18 Wholesale Market Reform

2.18.1 Market Reform Throughout the Western Interconnect

There have been significant changes in the Western Interconnection in recent years as many states set ambitious targets to increase renewable energy resources in their electricity generation mix. Energy markets play critical roles in ensuring a reliable and efficient energy supply as this integration and transition occur.

The two major day-ahead market initiatives in the Western Interconnection are the California Independent System Operator (CAISO) Extended Day-Ahead Market (EDAM) and the Southwest Power Pool (SPP) Markets Plus (M+). TEP is actively engaged in the development of these markets, working with stakeholders in task forces, working groups, and committees. A summary of the CAISO EDAM and the SPP M+ characteristics are provided in **Table 7**.

While both CAISO EDAM and SPP M+ aim to enhance grid reliability and optimize resource utilization, they differ in terms of their geographic coverage, market structures, and specific objectives. The CAISO EDAM primarily focuses on balancing supply and demand within the California region and neighboring areas, while SPP M+ extends its footprint into additional states in the central and western U.S., allowing for broader coordination.

TEP's participation in the development of both markets is ongoing. The three factors that will determine TEP's choice of market are resource adequacy treatment, governance structure, and cost savings.

Table 7. Characteristics of Markets Available in the Western Interconnect

Characteristics	CAISO EDAM	SPP M+
Projected Geographic Coverage	California and neighboring areas in the West.	Parts of central and western U.S. states.
Purpose	Balancing energy supply and demand, optimizing use of renewable energy.	
Renewable Integration	Enhances integration of renewable resources, facilitates sharing of surplus renewable energy.	Same objectives as EDAM with additional focus on managing the variability of renewable energy, particularly wind.
Coordination	Enhances the coordination of day-ahead resource dispatch and energy imbalance across a broader region.	
Market Expansion	Expands the reach of CAISO's market beyond its original boundaries.	Creates a new market alternative within the Western Interconnection.
Optimization Horizon	Includes both day-ahead planning and real-time operations	
Reliability and Grid Resilience	Provides stable and efficient energy transactions to enhance grid reliability day-ahead and enhances grid reliability and resilience by optimizing energy use in real-time.	
Market Structure	Includes both day-ahead and real-time imbalance markets for energy transactions.	
Regulatory Oversight	Monitored by CAISO and regulated by relevant regulatory authorities.	Monitored by the Southwest Power Pool and regulated by relevant regulatory authorities.
Collaborative Benefits	Enables planning collaboration among multiple utilities for new transmission and generation resources.	

The discussion on resource adequacy is frequently concurrent with regional market participation. This coupling often leads to a misconception that markets collectively reduce the amount of capacity each individual utility needs for grid reliability to handle both expected and unexpected fluctuations in electricity demand.

It is important to note that both markets discussed above have strong resource adequacy requirements to participate, meaning that the participating utilities cannot "lean" on the market to meet their own RA requirements. The CAISO EDAM requires that market participants demonstrate that they have sufficient capacity commitments to cover their load-serving obligations, ensuring that there are enough resources available to meet electricity demand even in unexpected situations. Similarly, participants in SPP M+ are required to demonstrate their resource adequacy through various mechanisms, including capacity market commitments and planning processes. This ensures that there are adequate resources available to meet demand, support grid reliability, and respond to unexpected events, contributing to the stability of the electricity system.

TEP has several personnel participating in Markets+ Phase One Working Groups and Task Forces. These include the Markets Plus Executive Committee, the Market Design, Transmission, Operations and Reliability, and Seams Working Groups, as well as the Greenhouse Gas (GHG), Congestion Rent, Rates, and Resource Adequacy Task Forces. The CAISO EDAM tariff work has largely concluded, but TEP participates in stakeholder meetings and presentations as appropriate.

TEP has also participated in the Western Markets Exploratory Group (WMEG), a utility group formed to explore and evaluate the two markets available in the west. Details on WMEG and regional market development can be found in Appendix F.

2.18.2 Market Impacts on Near-Term Procurement

Market participation impacts the near-term (real-time and day-ahead) procurement of both wholesale electricity and gas. This is due to several underlying factors which include:

1. **Price Volatility:** All markets are subject to price volatility. Factors such as demand fluctuations, weather conditions, fuel prices, and unexpected outages can cause electricity prices to fluctuate rapidly. These price fluctuations directly influence the cost of procuring electricity in the near term creating both large price spikes as well as negative pricing.
2. **Operational Considerations:** Market operators must consider operational factors like transmission constraints, grid stability, and reserve requirements. This can affect the market participant's ability to deliver or procure electricity in the short term.

3. **Resource Optimization:** Market operators can optimize their generation portfolios across a broader geographic footprint to provide the advantage of resource diversity, optimizing costs and reliability.
4. **Market Liquidity**: Participation in regional markets typically leads to increased market liquidity due to the larger number of participants and resources. This liquidity can result in more competitive prices and better procurement opportunities.

Participating in regional electricity markets can offer numerous advantages for resource procurement, including access to diverse resources, enhanced supply reliability, better price management, and improved demand-response opportunities. There are also embedded risks from price volatility, and transmission constraints affecting resource deliverability. Market participants need to adapt their strategies to regional market rules, regulatory considerations, and transmission infrastructure constraints to maximize the benefits of participation.

2.18.3 Impacts on Long-Term Procurement

The time horizon for long-term resource procurement can span between five to 25 years. With access to resources across a broader geographic area, regional electricity markets promote efficiency, resource optimization, and competition in long-term procurement decisions. Some key impacts include:

1. **Resource Diversification and Supply Reliability:** Regional markets provide access to a wider range of electricity generation resources, including renewable energy sources, hydro, natural gas, and nuclear power. This diversification can influence long-term procurement decisions by enabling a broader mix of energy sources. This also reduces the impact of localized outages or generation constraints on long-term procurement plans.
2. **Economies of Scale:** Participation in regional markets can lead to economies of scale in procurement, especially for large consumers and utilities. Bulk purchases across a wider area can result in cost savings due to greater bargaining power.
3. **Investment Decisions & Infrastructure Planning:** Long-term procurement strategies are influenced by investment decisions in regional market infrastructure, such as transmission lines or interconnections, which impact the availability and cost of electricity procurement. It also provides insights into market expectations for future capacity needs. Market participants may choose to invest in infrastructure that facilitates access to regional markets, improving the reliability and availability of electricity procurement.
4. **Environmental Considerations:** Long-term procurement strategies can be influenced by regional market participation, particularly when regional markets support renewable energy or emissions reduction goals. Market participants can procure cleaner energy sources to align with regional environmental objectives.

Participation in regional electricity markets provide advantages utilities can leverage to develop resilient and cost-effective long-term procurement plans.

2.18.4 Emerging Issues Impacting Regional Market Participation

As markets evolve in response to region-specific needs and utility operation characteristics, electricity market participation faces complex challenges and opportunities. These challenges include but are not limited to: diversity of stakeholder needs and interests, transmission constraints, integration of costs and benefits, energy versus capacity markets[9], regional coordination, emissions reductions, and market seams treatment.

Markets are designed to efficiently dispatch resources to meet load requirements, and to react to changing system conditions in near-real-time. While a market will work to take advantage of renewable resources as a whole, individual participants may see their fossil fuel

[9] Energy markets and capacity markets serve different but complementary roles within the electricity industry. Energy markets ensure the immediate supply and demand balance for electricity via real-time trading, or instance. Capacity markets provide incentives for maintaining a reliable supply of electricity in the future and involve long-term contracts and commitments.

generation dispatched by the market more often than planned in response to fluctuations in variable resources. Market participants that offer dispatchable resources to the market will need to monitor the use of fossil resources to ensure that they can still meet their individual emissions goals.

Market seams refer to the points where different regional or jurisdictional markets meet. These junctures can lead to challenges in coordinating electricity flows and pricing mechanisms, as differing regulations, grid infrastructures, and supply-demand dynamics can create mismatches. Navigating market seams becomes increasingly important as renewable energy sources like wind and solar gain prominence. These renewable sources often have sporadic generation patterns and are geographically dispersed. Effectively integrating them into the broader electricity grid requires addressing the discrepancies and complexities that arise at market seams.

Regional electricity market participation faces complex challenges and opportunities linked to renewable energy integration, cybersecurity, electrification, technological advances, and equitable access. Navigating these issues will require collaboration among stakeholders and adaptive policies to ensure the resilience and sustainability of regional electricity markets.

2.19 Environmental Regulations

TEP is tracking and complying with a number of environmental regulations being developed or implemented at the state and federal level. As detailed in **Appendix H**, this includes the regulation of regional haze, greenhouse gases, criteria pollutants such as ozone, coal combustion residuals, and water consumption.

3 Resource Planning Advisory Council (RPAC)

3.1 TEP and UNSE Advisory Council

The IRP involves complex decisions that impact energy supply, demand, costs, the environment, and grid reliability. As TEP and UNSE solicited input on their next resource plans, the Companies considered it important to account for this complexity and the fact that the economic value of various resources is shifting. New renewable resources are now competitive if not cheaper than new fossil-based generation on an energy basis and provide many of the same ancillary, grid-support services as well.

Following on the success of the 2020 RPAC input and engagement, TEP and sister company UNS Electric recognized the need for greater education and stakeholder input regarding the implications of resource planning decisions in light of the aforementioned changes. The joint TEP and UNSE 2023 IRP RPAC was convened in October of 2022. As part of the RPAC process, a Modeling Committee was also convened and provided with access to the modeling software and data used by both Companies.

3.2 RPAC Members

The RPAC included a diverse group of stakeholders to enhance the quality, transparency, and inclusiveness of the IRP process so that the IRP reflects the values of the communities both Companies serve. The RPAC provided representation of a broad variety of perspectives. As such, the size of the RPAC was set to obtain this breadth while keeping the size of the advisory group small enough to provide effective dialogue and feedback. The Companies focused membership on the local community including customers from TEP and UNSE, governmental agencies, and advocacy groups. The membership of the 2023 IRP RPAC is provided in **Table 8.**

Table 8. RPAC Members

	Category	Organization
Customers	Residential	Residential Utility Consumer Office (RUCO)
	Commercial	GLHN Architects and Engineers (GLHN)
	Limited Income	Wildfire AZ
	Senior	American Association of Retired Persons (AARP)
Government	County	Pima County
	State	Arizona Corporation Commission (ACC)
		University of Arizona
	Federal	Davis-Monthan Air Force Base
Advocates	Solar Installers	Technicians for Sustainability (TFS)
	Environment	Sierra Club / Western Resource Advocates (WRA)
	Energy Efficiency	Southwest Energy Efficiency Project (SWEEP)
	Economic Development	Sun Corridor
	Commercial Industry	Fresh Produce Association of the Americas (FPAA)
	Electric Vehicles	General Motors (GM)
	Labor	International Brotherhood of Electrical Workers (IBEW 1116)
	Renewable Energy	Arizona Solar Energy Industries Association (ARiSEIA)

The RPAC met 13 times between October 2022 and October 2023. RPAC meetings addressed specific topics, and discussions were led by subject matter experts (SMEs) from within the companies as well as external SMEs as requested by RPAC members. The list of topics covered is provided in **Table 9.**

Table 9. RPAC Meeting Topics

Resource Planning Advisory Council Meeting Topics	
Planning for Uncertainty	Wholesale Market Prices
Load Forecast	Regional Market Engagement
Resource Adequacy	Carbon-Free Portfolios
Modeling Assumptions	Proposed Resource Additions
Inflation Reduction Act (IRA) Impacts	Major Cost Assumptions
All Source RFP	Electric Vehicles (EVs)
Portfolio Modeling	Scenarios & Sensitivities
Aurora Training	Effective Load Carrying Capability (ELCC) Studies

One of the primary objectives of the Advisory Council engagement was for advisors to provide TEP with preferred outcomes they would like to see from the resource plan and planning process. This was to ensure that the IRP was responsive to the needs and values of the communities that the Company serves.

Responses fell into five main tranches:

- The Companies' response to carbon emissions and coal plant generation;
- Energy affordability and reliability;
- Stakeholder involvement in resource planning and procurement activities;
- Robustness of the final resource plan; and
- A comprehensive analysis and assessment of resources and technologies.

There was also interest in electric vehicles, specifically regarding their impact on customer load growth, their rate of adoption over the near-term horizon, and utility impacts of the Inflation Reduction Act (IRA).

3.3 The TEP and UNSE RPAC Modeling Committee (RMC)

The RMC was comprised of interested members of the RPAC, their modeling consultants, and affiliated organizations as shown in **Table 10.** The RMC, which included ACC staff, was provided with a project-based limited license for the Aurora model, training on the model, as well as the necessary data to fully utilize the models. Some RPAC members and their affiliated groups only requested access to confidential data, provided subject to TEP and UNSE non-disclosure agreements.

Table 10. RPAC Modeling Committee Members

RPAC Member Group	Modeling Consultants
Arizona Corporation Commission	TBD
ARiSEIA	Rocky Mountain Institute (RMI)
Sierra Club	Synapse Energy Economics
WRA	Western Resource Advocates
	Energy Strategies
	GridLab
RPAC Member Groups and Affiliates Requesting Data-Only Access	
SWEEP	
Vote Solar	
Public Interest Research Group	
Interwest Energy Alliance	
Solar United Neighbors	

In order to take advantage of economies of scale to more efficiently utilize the modeling and training resources, the three utilities – TEP, UNSE, and APS – offered a series of coordinated training sessions on Aurora as well as utility-specific database overviews. The training was provided by the software vendor, Energy Exemplar, as well as each utility's modeling staff.

3.4 Public Workshops

Both companies offered two public workshops. The first workshop, in compliance with Decision 78499, was a joint Market Workshop of APS, TEP, and UNSE providing the status of the Companies' engagement in regional market forums. The Market Workshop was held on May 4, 2023, and was open to the RPAC as well as members of the public.

The second public workshop, held on October 2, 2023, was held near the culmination of the 2023 IRP activities. The workshop discussed the IRP report and portfolios that were analyzed. It was held virtually and provided a forum for attendees to engage with other stakeholders, the public, and both Companies regarding their 2023 IRPs.

The presentations and minutes of all RPAC meetings and public workshops are posted on the Companies' joint RPAC webpage: https://www.tep.com/irp-advisory-council/.

4 2022 All Source Request for Proposals (ASRFP)

4.1 Resources Requested

TEP issued an ASRFP to solicit bids for capacity and clean energy resources on April 19, 2022. The in-service dates preferred by TEP were indicated in the solicitations as May 1, 2024, but no later than May 1, 2025. The need for these resources – originally estimated for TEP at 300 MW of firm capacity and 250 MW of clean energy – was based primarily on the Company's 2020 IRP and a subsequent Needs Assessment performed prior to the release of the ASRFP. Results of the TEP needs assessment is shown in **Figure 17**, where the degree of shading is proportional to capacity shortfalls that would result assuming no future resource additions or market purchases between now and the years 2024 and 2028.

Figure 17. Needs Assessment

4.2 Shortlist Process

While cost is important for maintaining low customer rates, proposals were also ranked for their commercial operating dates (CODs) and the likelihood of the developers meeting their proposed project in-service dates. Ultimately, this criterion had a large impact on those proposals making the shortlist.

The COD was a priority for the Company to meet increasing summer demand and avoid unusually high summer capacity and energy prices. Deliverability was an important evaluation criterion for ranking the projects' interconnection status, regulatory status, and available transfer capability (ATC) at the time and point of interconnection such that the energy and capacity would be fully available to TEP retail customers. Projects having obtained or deemed well into the process of obtaining a Certificate of Environmental Compatibility (CEC) and those which were in advanced stages of the interconnection process ranked highest. Prices were also a major factor, but the ability to bring a project into service at the time proposed was vital to maintaining reliability and avoiding potentially expensive summer purchase power while transitioning to a cleaner resource portfolio. With these factors in mind, TEP identified nine shortlist projects and proceeded to negotiate contract terms with the top four counterparties.

To date, TEP has announced the Roadrunner Reserve project, which is a 200-megawatt (MW) system that can store 800 megawatt hours of energy. The system is scheduled to begin operation in summer 2025. TEP will own and operate Roadrunner Reserve, which will be designed and built by Scottsdale-based DEPCOM Power, Inc. Negotiations continue with the three remaining counterparties and TEP will make announcements upon contract execution. The Company expects that these negotiations will lead to the acquisition of another 520 MW of new solar plus storage projects. It is expected that these three additional projects will be in-service by the summer of 2026.

While these projects proceed toward commissioning, TEP will maintain communication with other short-listed developers to keep abreast of near- and mid-term opportunities. Each of these developers proposed electrically viable projects near TEP's load center. TEP looks forward to their participation and others in the next ASRFP.

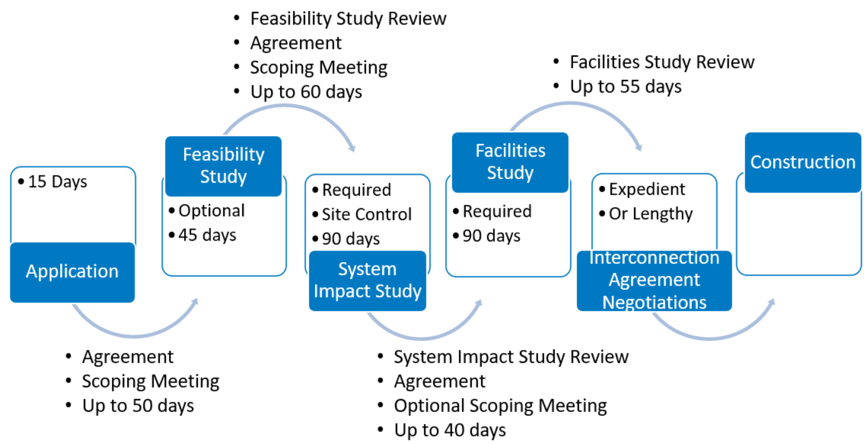
4.3 ASRFP Lessons Learned: Project Development Timelines

Supply chain issues were evident in proposals received as part of the 2022 ASRFP solicitation. At the time that the ASRFP was released, the companies were cautiously optimistic about receiving proposals with CODs prior to summer 2024. Project proposals with 2024 and 2025 CODs were received but several factors in addition to supply chain issues made it evident that caution was not misplaced. Price offers received were higher than expected based on projections from prior years. Passage of the Inflation Reduction Act, after the submittal of proposals, was cause for renewed optimism as refreshed proposals generally trended downward in cost. However, the refreshed bids were also updated to include schedule extensions, not only because of supply chain issues, such as longer lead times for generator step-up transformers, but also because of limited available transfer capability, interconnection status, and regulatory approval 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.

Figure 18 below illustrates a 'no-delay' timeline for interconnection requests. The intermediate review process for each study phase has the potential for an interconnection request to be extended past a two-year period. The calendar days shown for each study phase, to include the application and interconnection agreement, demonstrate a minimum timeline of nearly one year. Due diligence expected of the interconnection customer and the transmission owner includes intermediate review of each study before commencing subsequent studies, which prolongs the timeline. Based on the Companies' experience, from start to finish, an interconnection request resulting in an interconnection agreement is expected to take at least two years to complete.

Figure 18. Interconnection Timeline



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 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.

5 Portfolio Development and Analysis

5.1 Portfolio Requirements

For the 2023 IRP, TEP is required to develop and evaluate at least 10 resource portfolios, which must include:

- One least-cost, technology agnostic portfolio developed without regard for emission reductions or renewable energy goals;
- One or more portfolios which eliminates coal unit must-run designations;
- One or more portfolios which remove modeling restrictions on the economic cycling and economic retirement of coal units;
- One or more portfolios which removes modeling restrictions that limit the amount of energy efficiency that can be selected;
- A 1.3% annual increase in energy efficiency over the next three years;
- A demand-side resource capacity equal to at least 35% of TEP's 2020 peak demand; and
- One or more portfolios which achieve at least 40% cumulative energy savings by 2030.

All portfolios evaluated by TEP eliminate coal unit must-run designations, restrictions on economic cycling and energy efficiency, and achieve a demand-side resource capacity of at least 35% of TEP's 2020 peak demand.

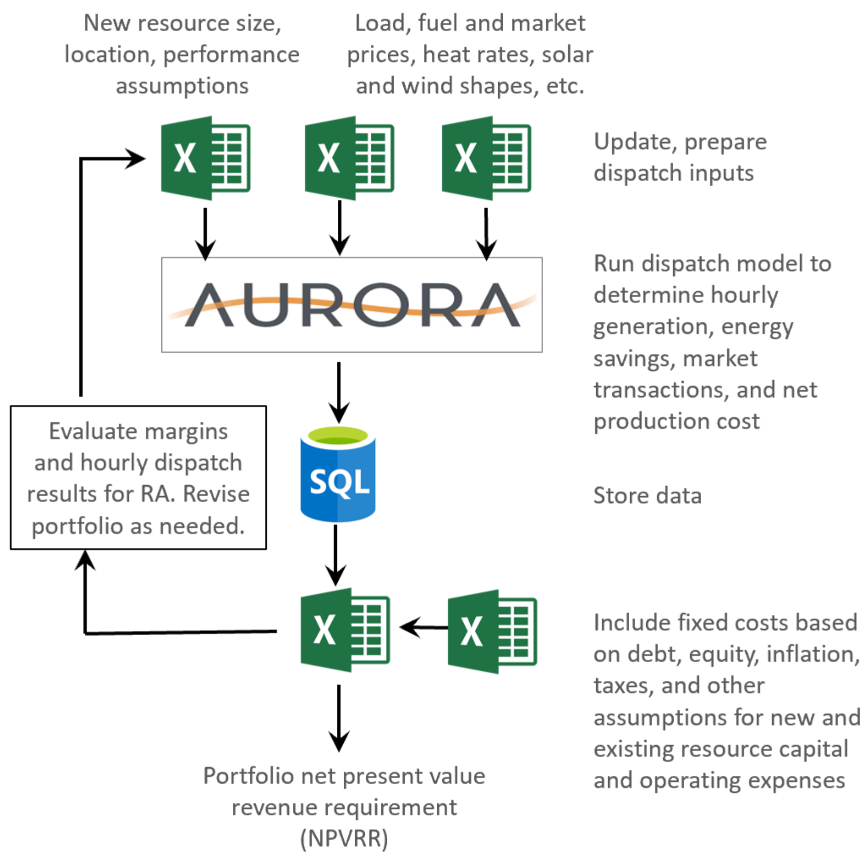
5.2 Modeling Process

TEP developed and evaluated 10 portfolios using two different but related modeling approaches: 1.) iterations of hand-crafted portfolios and 2.) long-term capacity expansion.

5.2.1 Iterations of Hand-Crafted Portfolios

As shown in **Figure 19**, portfolio results are based on two bodies of inputs. The first, shown at the top of **Figure 19**, are inputs for a proprietary electricity market simulation model called Aurora. Given inputs such as electricity demand, fuel costs, generator and energy storage operating costs and performance characteristics, transmission costs and flow limits, and regional market prices, Aurora provides hourly results over a 15-year period on unit generation, conservation, market transactions, renewable curtailment, emissions, net production costs, and any shortfalls in serving demand.

Figure 19. Summary of TEP Portfolio Modeling Process



The second body of inputs, shown at the bottom of **Figure 19**, is used to calculate the annual fixed costs of existing and new resources. These annual costs are combined with the annual production costs described above to determine a 15-year net present value revenue requirement (NPVRR) for each portfolio. The NPVRR serves as the principal basis for comparing costs across portfolios, as well as the costs of a given portfolio under different assumptions for load growth, fuel and market prices, and new resource capital costs.

The iterative process typically begins with an estimate of the amount of solar and storage needed in addition to the wind power assumptions to meet firm demand reliably and cost-effectively in all hours of the 15-year planning period. The resulting reserve margin is compared to a minimum planning reserve margin (PRM) of 16.5% of peak demand. In most cases, solar and storage deployments are adjusted and remodeled until both the CO_2 goal and PRM target is met each year.

5.2.2 Capacity Expansion Modeling

To gain further insight into portfolios that effectively and robustly balance cost, sustainability, and reliability, TEP utilized Aurora's long-term capacity expansion (LTCE) functionality. LTCE modeling self-generates portfolio solutions by taking a highly iterative approach to evaluating a large number and combination of resource retirements and additions over time. Such results can guide and verify results derived from the modeling approach described above. However, because this semi-independent methodology evaluates a large number of potential resource combinations, it must make simplifying assumptions about the electric generation and transmission systems and therefore cannot be relied upon as the sole basis for evaluating portfolio costs and reliability. As stated by the National Renewable Energy Lab (NREL):

> *Capacity expansion modeling (CEM) is a tool or suite of tools used in long-term planning studies for the power sector. CEMs are used to identify the least-cost mix of power system resources, taking into consideration factors such as new policies, technological advancement, changing fuel prices, and electricity demand projections, among other factors. In many power systems globally, CEM analysis serves as a key tool for the development of power sector master plans or integrated resource plans. CEMs are not suited for planning the technical details of grid operations. Other tools, including production cost models, power flow models, and power system dynamic stability simulations are needed alongside CEMs to capture the full spectrum of grid planning and operations. Also, questions related to the social justice and environmental impacts of power sector development are outside the scope of CEMs. These factors can be addressed with a robust stakeholder engagement process that includes diverse perspectives from civil society organizations and public advocates* [10]

NREL also identifies the complexity that clean energy resource variability and other emerging technologies present for capacity expansion modeling. LTCE case studies performed by TEP provided insight to the capacity and energy value of resources within each portfolio. This was especially critical for maintaining planning reserve margins in portfolios with large amounts of renewables and storage, whose capacity contributions typically diminish with greater penetrations.

LTCE was useful for determining the ultimate magnitude, number, and timing of resources needed under different scenarios driven by constraints or circumstances associated with company goals, infrastructure limitations, and technology viability. TEP's Balanced Portfolio, for example, was informed by applying the Company's carbon reduction commitment as a constraint (or requirement) within the LTCE modeling.

The least-cost portfolio built by LTCE modeling included large natural gas combined cycle (NGCC) plants. Recognizing that natural gas pipeline capacity in Arizona is limited, that NGCC units could face new restrictions from proposed environmental regulations, and that prices for solar and storage are expected to decline over the next 15-years, the LTCE model was re-run to exclude NGCC as a potential resource.

The Balanced Portfolio is the least cost portfolio based on the set of constraints discussed above. The Balanced Portfolio includes the construction of smaller, aeroderivative combustion turbines (CTs) and significant amounts of battery storage and renewables. Aeroderivative CTs are more flexible than larger gas units and will help balance

[10] https://www.nrel.gov/docs/fy21osti/80192.pdf

increasingly variable loads and renewable generation, thereby providing a reliable bridge towards the Company's 2050 net zero goal.

5.2.3 Other Portfolio Design Assumptions

Based on current project development risks and timelines, TEP's experience with resource procurement, and information gleaned from the 2022 ASRFP, the following assumptions were made when designing the portfolios and running the LTCE model:

- Aeroderivative CTs are more favorable versus NGCC due to ramp up/down flexibility, faster start-up times, lower water consumption and reduced natural gas pipeline volume and pressure requirements.
- There are no PURPA qualifying facilities (QFs) interconnection requests in the TEP queue. No representation of QFs were modeled.
- Clean energy resources intended to replace large retirements should be implemented over at least a three-year period.
- Replacement resources were generally limited to 400 to 600 MW per year, especially for solar and storage.
- Future solar and 4-hour storage resources are added in relatively equal amounts of capacity. This reflects TEP's increased need for capacity over the short- and medium-term and mimics the trend seen in recent ASRFP hybrid proposals and other utility project announcements.
- Actual implementation rates will vary based on real-world challenges, but on average, for planning purposes, the net effect is assumed to result in relatively consistent project implementation from year to year. This also reduces the risk of replacement power being insufficient at the time of resource retirements.

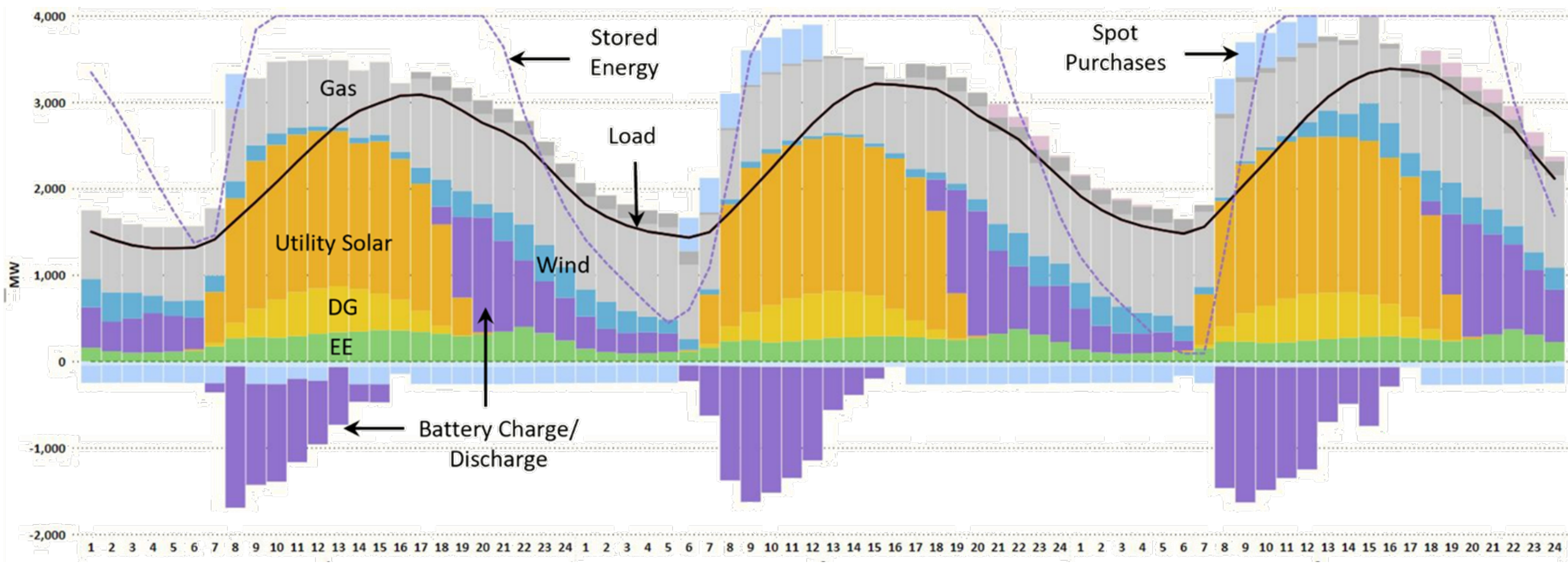
5.3 Resource Adequacy (RA)

The RA of each portfolio was determined through a two-step process. First, each year was required to meet a PRM of 16.5%, updated from a value of 15.0% used in prior IRPs. This assumes a 6% margin for forecast error (based on 40 weather years modeled by E3), a 6% margin for operating reserves, and a 4.5% margin for thermal forced outages, which are becoming a smaller part of TEP's portfolio. To determine whether the PRM is met, solar, wind, and storage resources are given a capacity value based on their ELCC, as described in **Section 5.4**

Second, TEP performed a "stress test" on each portfolio in which peak demand and sales are increased by 16.5%, market purchases are not permitted during summer afternoons and evenings, and TEP must meet extended hours of peak loads with only 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. They are also examined for potential over-build of resources by quantifying any capacity remaining during the most stressed hours.

An example of the hourly results used to verify RA is provided in **Figure 20**, 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 20** are typical of summer days, and the daily charging and discharging of the storage fleet cycles as expected.

Figure 20. Example of Hourly Load and Dispatch Results Used to Ensure Resource Adequacy (July 1-3, 2033)



5.4 Effective Load Carrying Capability (ELCC)

The ELCC applies statistical techniques to multiple years of hourly weather, load, and renewable generation data to determine the additional load that renewable and storage resources can accommodate while maintaining the same level of system reliability given their intermittency, correlation with weather, and, in the case of storage, its charging and discharging limitations. ELCCs were developed for TEP's system according to the E3 study work included in **Appendix D**.

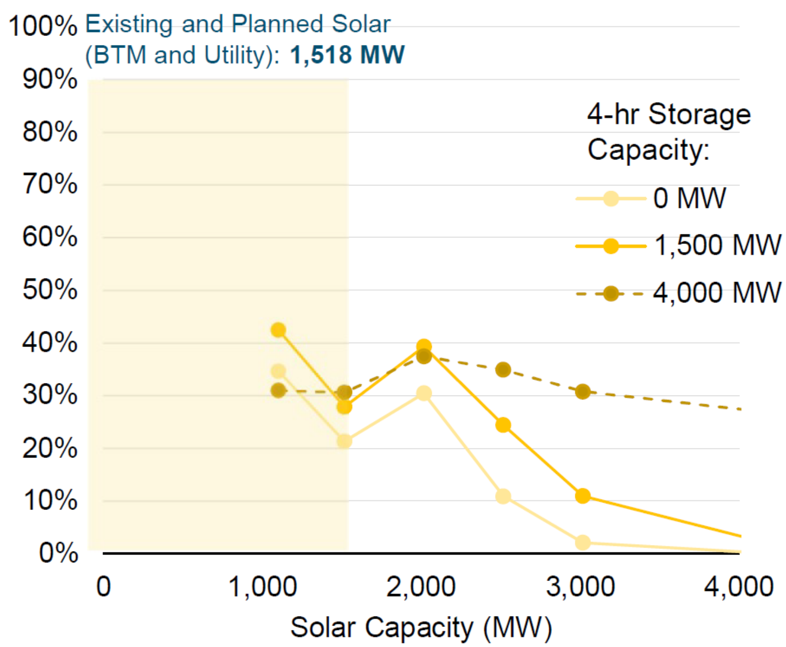
Whereas previous IRPs accredited capacity to renewable resources based on their average output during peak summer hours, ELCCs apply more rigorous, industry-standard methods that account for the decreasing capacity value of renewable resources as their penetration increases, as well as the synergistic effects among these resources and benefits that can occur through geographic diversity of their locations.

Each of these effects can be seen in **Figure 21**, which shows the percent of solar nameplate capacity that should be accredited for planning purposes. Currently, there is approximately 1,000 MW of utility-scale and distributed generation (DG) nameplate capacity on TEP's system, whose effective capacity is about 35% of total nameplate. According to the ELCC results, the next 500 MW of solar – the approximate amount to be added between now and 2026 – would be accredited at only 20% of nameplate. This is a well-understood effect in which adding more solar power only decreases the load during daylight hours, thereby shifting the net peak into the evening hours when solar power eventually becomes ineffective at providing any more capacity.

From there, the ELCC study assumed additional future solar capacity would be deployed at a variety of utility-scale locations in addition to those currently relied upon for solar power. This results in a geographic diversity benefit of approximately 10% because solar power will be available from some regions when it may be hindered at others. As more solar power is added, however, the penetration effect previously mentioned overcomes any geographic diversity benefit and the capacity value of solar approaches zero.

Finally, **Figure 21** below illustrates how the capacity value of solar can be increased when implemented in concert with 4-hour storage. Likewise, the capacity value of storage is increased when implemented in concert with solar. Wind power too can influence the capacity value of other resources depending on how its hourly generation profile complements solar generation and load shapes.

Figure 21. Incremental ELCC for Solar Given Alternative Amounts of Storage on TEP's System



5.5 Load Forecast

This section summarizes TEP's customer base and load forecast methodology and subsequently details some of the major forecast components, such as Energy Efficiency, Distributed Generation, and Electric Vehicles, and concludes with a summary of forecast results. Detailed forecast results can be found in **Appendix A.**

5.5.1 Service Territory and Customer Base

Figure 22 shows TEP's service territory, and that of its sister company, UNSE. TEP currently provides electricity to more than 445,000 customers in the Tucson metro area, located within Pima County, which has an estimated population of 1,030,000 people. The number of historic and projected residential customers is shown in **Figure 23**, while the current sales by customer class are shown in **Figure 24.**

Figure 22. TEP and UNSE Service Territories

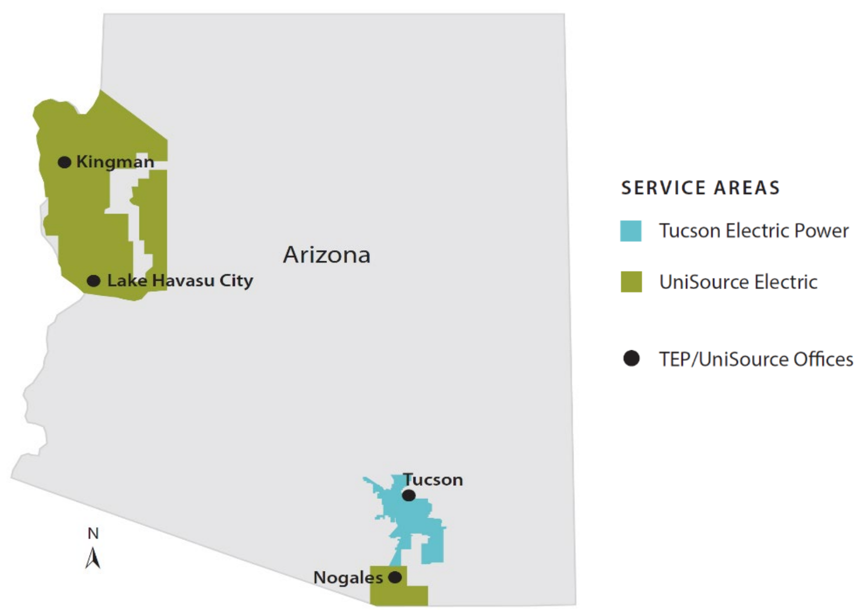


Figure 23. Historic and Projected Number of Residential Customers

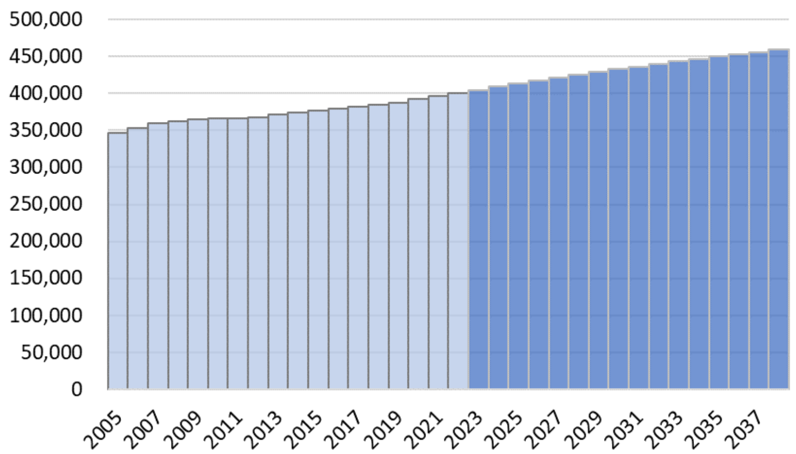
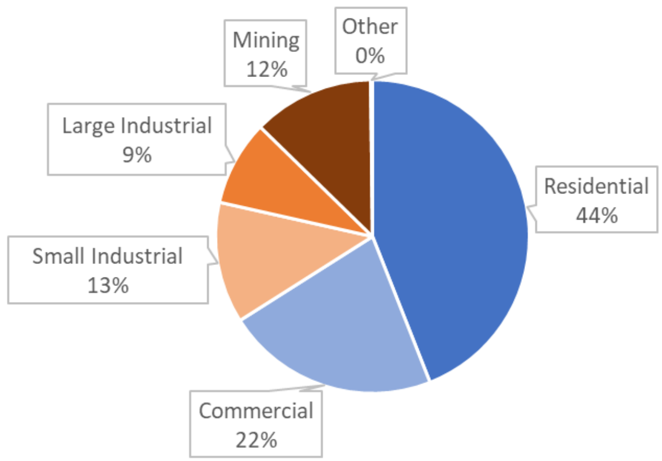


Figure 24. 2022 Retail Sales by Customer Class



5.5.2 Methodology, Data Sources, and Uncertainties

TEP's load forecast methodology is illustrated in **Figure 25** on the following page. Residential, commercial, and small industrial customer sales are forecast on a monthly basis using statistical models based on factors such as historical usage, weather, demographic forecasts, and economic conditions. Large industrial and mining sales are also forecasted monthly but on a per customer basis based on factors such as historical use patterns, information from customers themselves, and information from internal company resources working closely with the customers. After the monthly customer class sales forecasts are generated, they are aggregated and used as an input for another statistical model used to estimate the retail peak demand. The peak demand model is based on historical relationships between hourly load, weather, calendar effects, and sales growth.

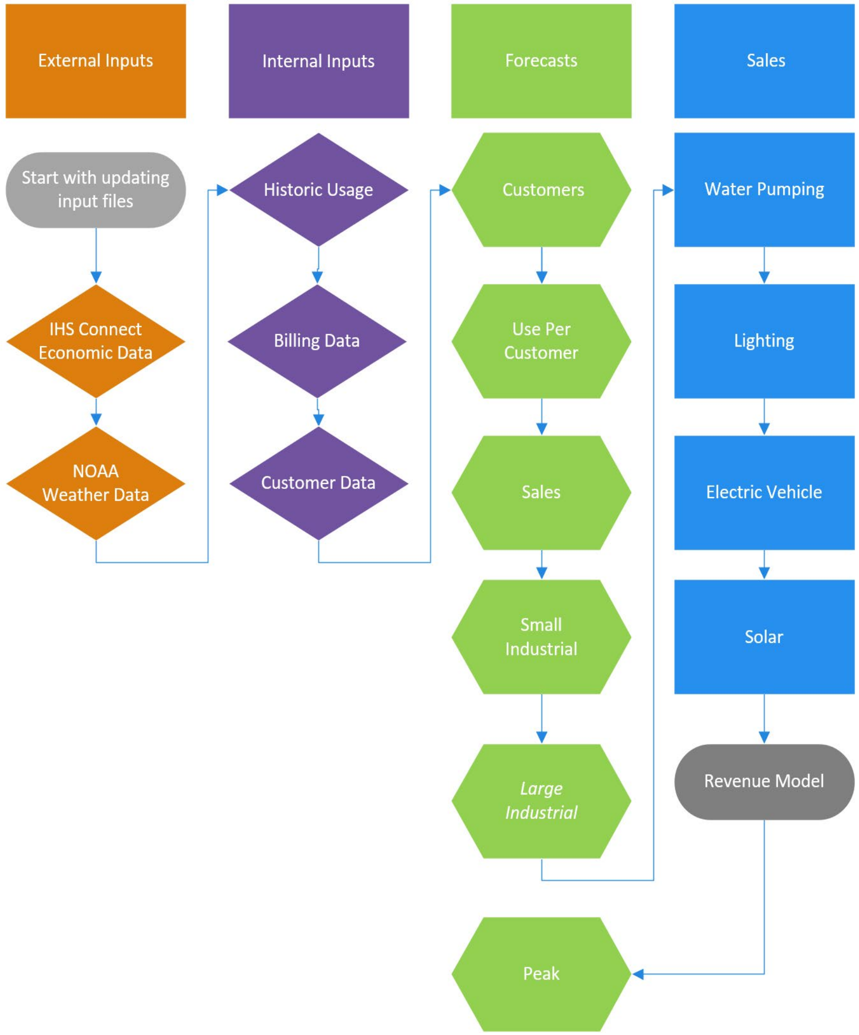
Data sources used in the forecast include:

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

As always, there is a large amount of uncertainty with regard to projected load growth. While not all inclusive, some of the key risks to the current forecast are listed below:

- 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

Figure 25. Load Forecast Process



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. In addition to the simulation analysis, a more specific discussion of how resource decisions and timing would be affected in the case of sustained higher or lower loads. A more in-depth discussion of the risk analysis process is provided in **Section 7**.

5.5.3 Energy Efficiency and Demand Response

As required by the ACC, **Table 11** provides TEP's most recent Energy Efficiency (EE) savings. Although the state EE standard expired in 2020, TEP has continued helping customers reduce energy use and demand by targeting a 1.3% incremental savings through its 2022 and 2023 Demand-Side Management (DSM) Plans. TEP's recent DSM plan, approved by the ACC on August 25, 2023 (Decision No. 79065), has a three-year savings goal of 4.2% of annual retail sales. This new DSM Plan continues TEP's efforts to redirect DSM programs to achieve both energy and demand savings through cost-effective energy efficiency and load management programs.

Table 11. Recent Annual Energy Savings Through TEP DSM Programs

Year	Retail Energy Sales (MWh)	Incremental Savings (MWh)	% of Sales	Cumulative Annual Savings (MWh)
2020	8,506,505	212,972	2.61%	1,779,778
2021	8,156,610	144,893	1.7%	1,924,671
2022	8,219,222	158,965	1.95%	2,083,636

The high-level goals and objectives of the DSM Plan are to:

- Implement cost-effective EE programs;
- Align portfolio to focus on peak, and load shifting programs;
- Target EE programs that meet system needs in order to benefit all customers;
- Develop strategic learnings to guide future customer program offerings;
- Transform the market for efficient technologies;
- Inform and educate customers to modify behaviors that enable them to use energy more efficiently;
- Provide demand reduction opportunities for system reliability; and
- Provide the latest technologies to allow our customers to monitor and maintain the most efficient electric use in their homes and businesses as possible.

To achieve these objectives, TEP offers a variety of programs across customer classes. As shown in **Table 12.** and **Figure 26** these programs provide customers with information to help manage and control their energy use, making it more efficient and affordable to adopt DSM measures, with an emphasis on load shifting and reducing peak demand.

A new program being offered by TEP, targeting 4,873 MWh of savings, is the Advanced Rooftop Controls Pilot, which is designed to manage energy use and maximize efficiency while increasing fresh air ventilation to improve indoor air quality in schools and non-profit facilities with high occupancy.

Table 12. Summary of TEP DSM Programs

Residential Sector	Low Income Weatherization
	Multi-Family
	Residential New Construction
	Shade Trees
	Existing Homes
	Efficient Products
Commercial Sector	Advanced Rooftop Controls Pilot Program
	C&I Comprehensive
	Commercial DLC
	Commercial Schools

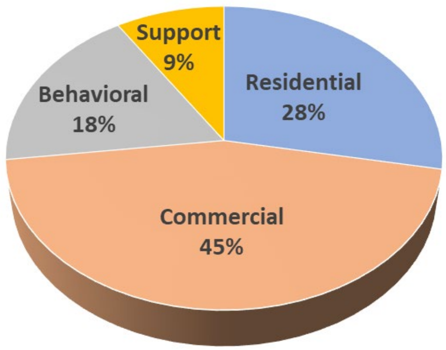
Behavioral Sector	Home Energy Reports
	Behavioral Comprehensive
DSM Initiatives	Load Management Pilot Program
	Beneficial Electrification Program
	Innovative Customer Solutions Framework
Support Sector	Education & Outreach
	Energy Codes and Standards
	Generation Improvement and Facility Upgrades
	Research & Development

Another new TEP DSM program is the Load Management Pilot, or TEP Smart Rewards Program. This program includes the following options, plus a platform for TEP to manage the devices:

- TEP Smart Rewards – TEP has enrolled over 7,000 residential customers in this demand response program, in which it can control smart thermostats to reduce load during summer peak hours. By the end of 2026, TEP expects to enroll up to 24,000 thermostats.
- Bring your own device battery storage implementation is targeted for late 2023.

- Bring your own device electric vehicle charger implementation is targeted for late 2024.

Figure 26. DSM Energy Savings by Sector, 2024 - 2026



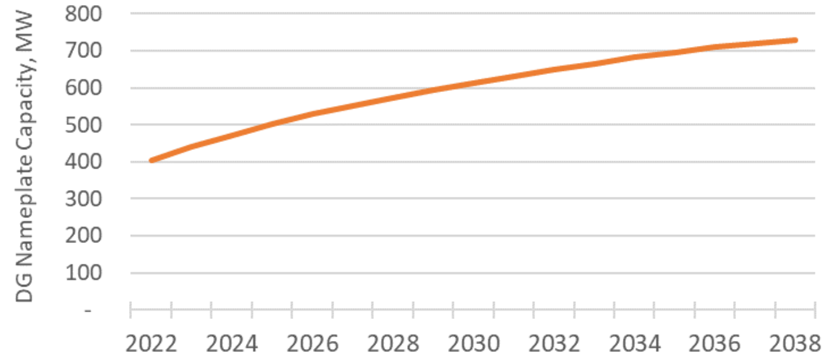
5.5.4 Distributed Generation (DG)

TEP supports a number of programs to promote the use of customer-sited, solar distributed generation. The number of customers and total capacity deployment through 2022 is shown in **Table 13** and the forecasted growth in DG adoption is shown in **Figure 27**.

Table 13. Adoption Rates for TEP DG Programs

	Total All-Time Customers Through 2022	Total MW
3rd Party Residential DG	40,473	324
3rd Party Non-Residential DG	1,021	186
TEP-Owned Residential Solar	464	3
GoSolar Shares	1,822	30
GoSolar Homes	1,689	11

Figure 27. TEP DG Adoption Forecast



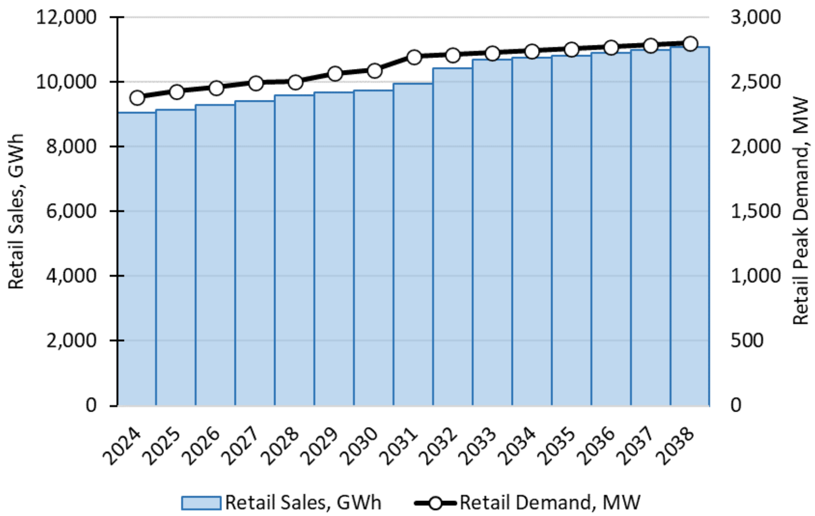
5.5.5 Electric Vehicles (EVs)

EV adoption rates are based on national adoption forecasts from Navigant, the Energy Information Administration, and JP Morgan. These data sources are used to average and scale to Pima County's population to arrive at an EV adoption forecast for TEP. Annual kilowatt sales are calculated using an energy equivalent of a gallon of gasoline and thermal efficiency. Future forecasts will be improved upon by including the results of a locational grid study recently completed for TEP by 1898 & Co. The study considered where and when EV adoption is likely to occur and how TEP can accommodate load from increased EV adoption. The adoption model associates technical circuit information with aggregated consumer data (census, vehicle registration, fleet information and TEP distribution grid data) to characterize regions of the TEP system in terms of adoption. The model assumes the adoption of new technology generally follows the diffusion of innovation theory, from which 1898 & Co. developed curves to model adoption over time. It is assumed that demographics of the census tracks determine how large adoption will be in early years and that technology, economics, policy, incentives, and environmental considerations will increase the steepness of the adoption curve. Additional information on the EV market and TEP EV programs can be found in **Appendix G.**

5.5.6 Load Forecast Results

Figure 28 summarizes TEP's forecasted annual retail sales and peak demand. The average annual growth rate of sales and demand over the planning period is 1.50% and 1.23% respectively. This load forecast was used to develop all portfolios except for the high- and no-load growth sensitivity tests and the portfolio achieving a 40% cumulative savings by 2030. Detailed forecast results are provided in **Appendix A**.

Figure 28. TEP Forecasted Annual Retail Sales and Peak Demand



5.6 Resource Costs

TEP modeled future resource costs based primarily on the additions of utility-scale solar, two classes of wind power, 4-hour Lithium-ion battery storage, and aeroderivative combustion turbines (CTs). Except for battery storage, O&M costs were assumed to equal those in the 2023 Electricity Annual Technology Baseline (ATB), published by NREL.[11] O&M costs for batteries are based on the average maintenance costs, including electrolyte replenishment, and were based on the bids received from the 2022 ASRFP.

Capital costs are also assumed to equal those in the ATB except that the early years are based on a combination of the ATB data and the average price of bids received from the ASRFP, as shown in **Figure 29** through **Figure 33**. The red dot represents the average bid received for an in-service date of 2025. All costs are presented in nominal terms assuming a 3.0% inflation rate. The ATB was also the source of cost assumptions used to model pumped hydro and small modular reactors.

It was further assumed that, on average, all solar, wind, and storage projects would qualify for the prevailing wage and apprenticeship tax credits authorized in the Inflation Reduction Act (e.g., 30% for the investment tax credit). Solar and wind projects were assumed to take advantage of the production tax credit; storage projects were assumed to take advantage of the investment tax credit. While individual projects may qualify for more or less credit depending on their domestic content, location, and other factors, TEP's assumptions for low and high capital cost scenarios inherently includes cost effects and ranges that could materialize from more or fewer projects qualifying for these credits.

[11] https://atb.nrel.gov/electricity/2023/technologies

Figure 29. Utility-Scale Solar Capital Cost Assumptions, $/kW

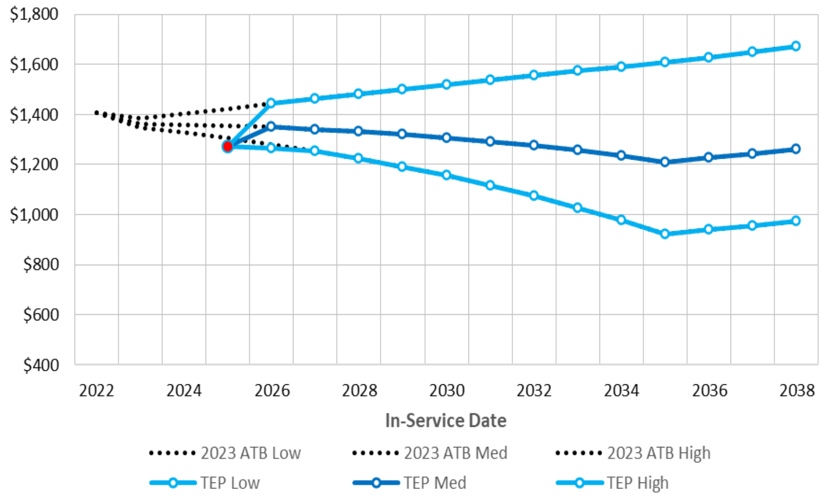


Figure 31. Four Corners Wind Capital Cost Assumptions, $/kW

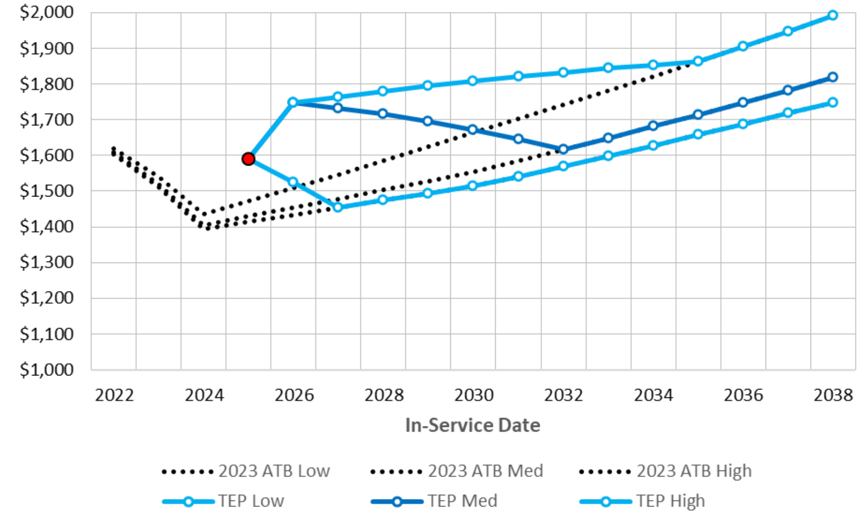


Figure 30. East NM Wind Capital Cost Assumptions, $/kW

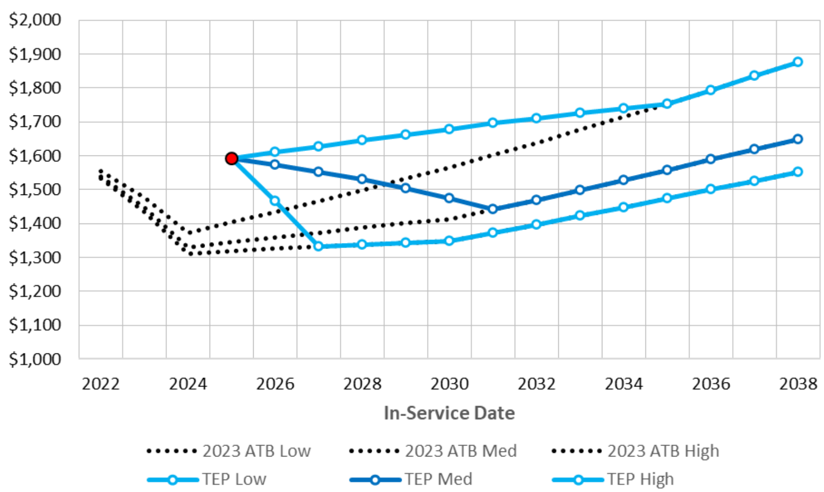


Figure 32. 4h Li-ion Storage Capital Cost Assumptions, $/kW

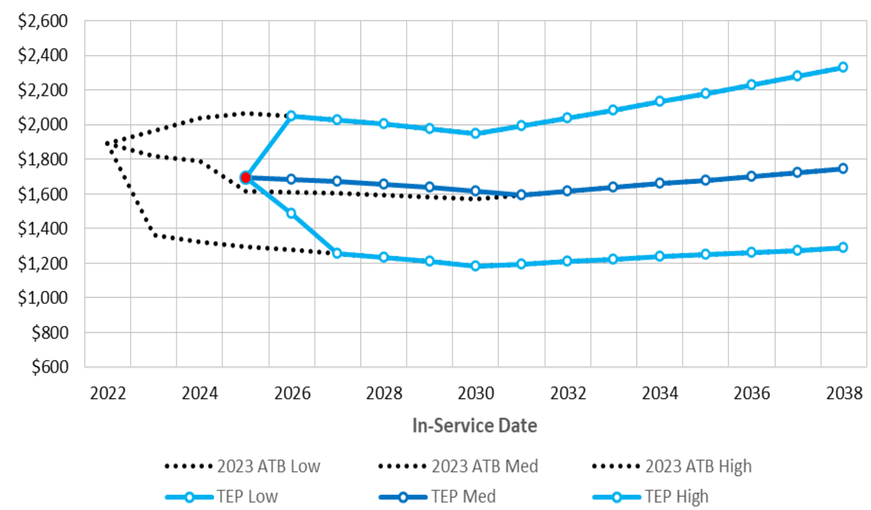
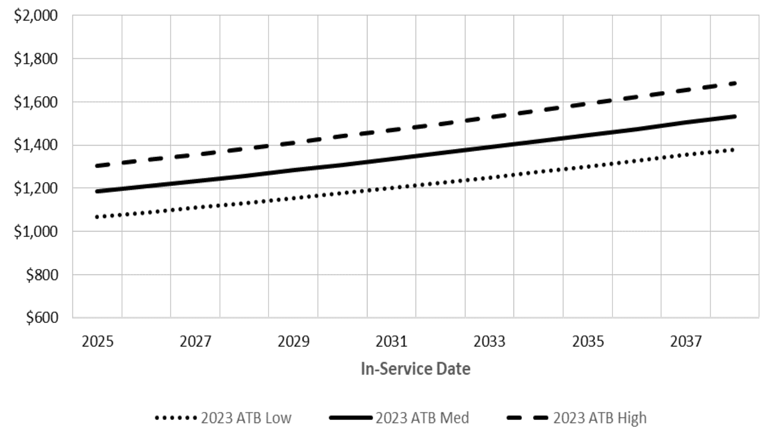


Figure 33. Aeroderivative CT Capital Cost Assumptions, $/kW



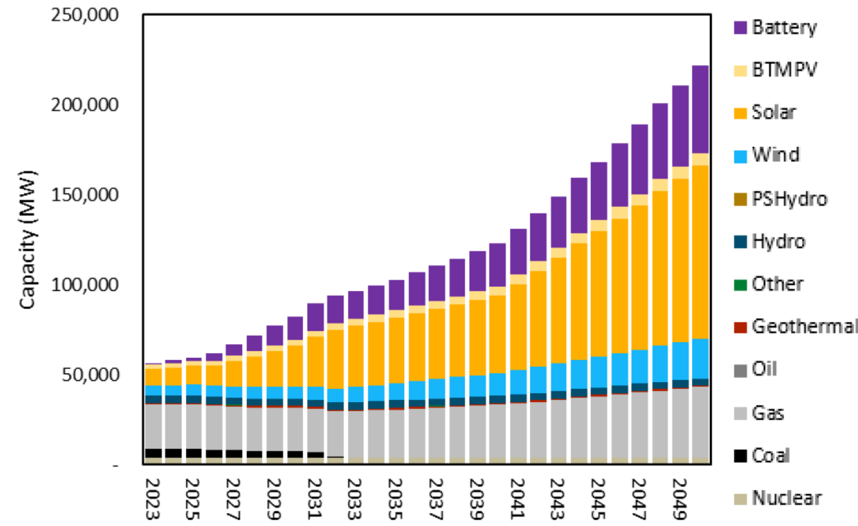
5.7 Market and Fuel Prices

Although TEP does not rely on the market as a firm resource in its long-term planning, economic market purchases and sales are permitted to occur in the modeling after each resource-adequate portfolio is determined. Because the market will at times offer lower-cost energy to purchase, or higher-priced energy to sell than what it costs TEP to produce, it has a large potential to reduce fuel and purchased power expenses normally passed on to customers at cost.

To account for these market benefits, TEP retained E3 to develop an hourly market price forecast for the entire 15-year planning period. The full report and summary of results can be found in **Appendix E**.

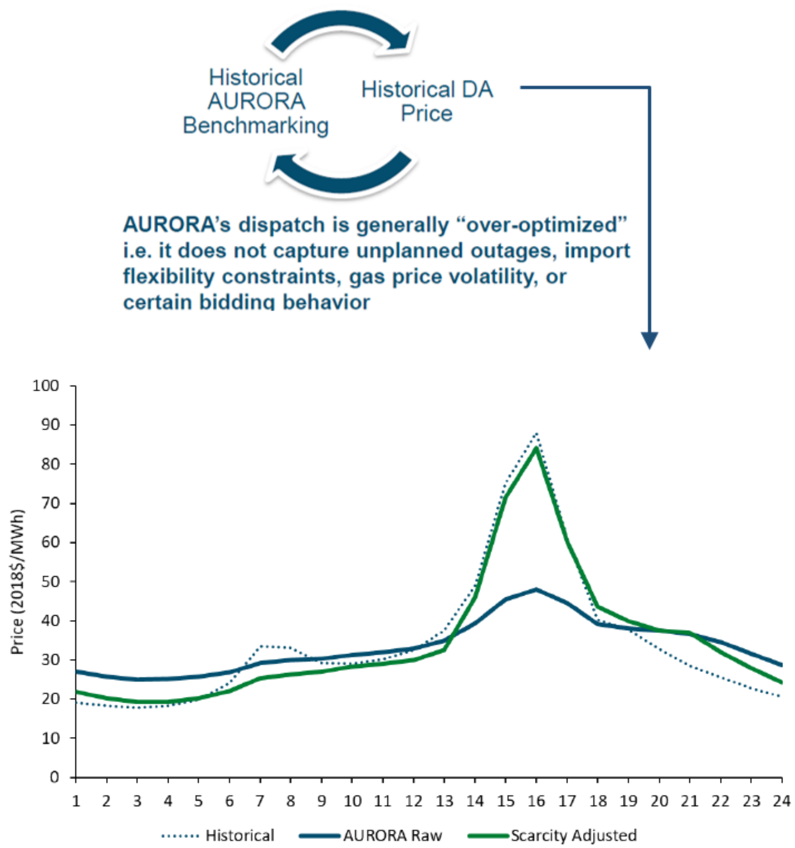
To determine these prices, E3 ran a capacity expansion model for the western United Sates based on planned retirements, expected load changes, federal and state policies affecting the power sector (including the Inflation Reduction Act), transmission limits, new resource cost trends, and future expectations for natural gas prices. **Figure 34** summarizes the capacity expansion results for the Desert Southwest.

Figure 34. Capacity Expansion Results Used as Basis for TEP's Market Price Forecast (Total Capacity in AZ, NM, and NV)



The E3 study produced an hourly price forecast for the Palo Verde trading hub, where most of TEP's market transactions occur. Prices generated by the model are subsequently refined to account for price factors in the Palo Verde marketplace that are not well represented by the model, such as scarcity premiums during system peak hours and the fact that Palo Verde prices are based on bilateral trades that do not necessarily reflect the marginal cost of generation. A simplified representation of this post-modeling process and an example of how it captures real-world price volatility is shown in **Figure 35** below.

Figure 35. Illustration of Hourly Palo Verde Market Price Forecast Derivation



Another aspect of the long-term price forecast is how it captures fundamental price shifts caused by the changing resource mix in the region. As shown in **Figure 36**, as more solar power is brought online in the region, average daytime prices are further depressed and peak prices last further into the evening.

Figure 37 shows Palo Verde historic prices and forecast prices. Power prices are currently high relative to historic levels, partly due to higher natural gas prices at the time of the forecast and partly due to diminishing generation capacity within the region, especially during summer peak periods. Over the next few years, natural gas prices are expected to decline to their historic levels as new resource additions, in particular energy storage, are expected to increase regional capacity and help restore average prices to their historic levels.

Figure 36. Average Hourly Palo Verde Market Prices for Select Years

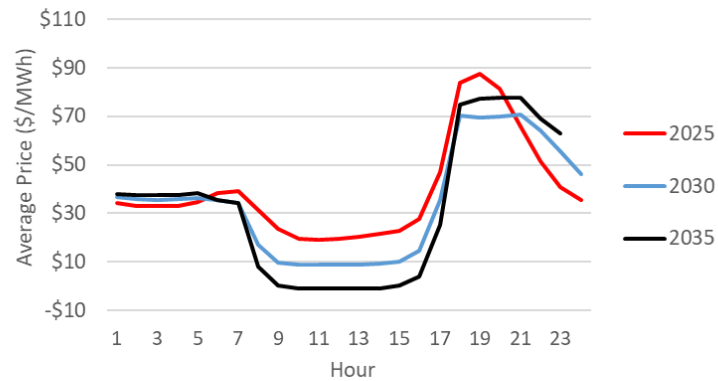


Figure 37. Historic and Forecast Palo Verde Market Prices

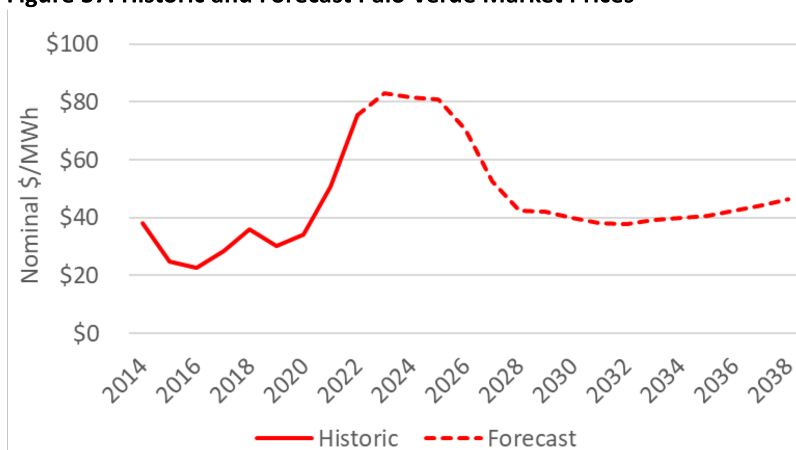
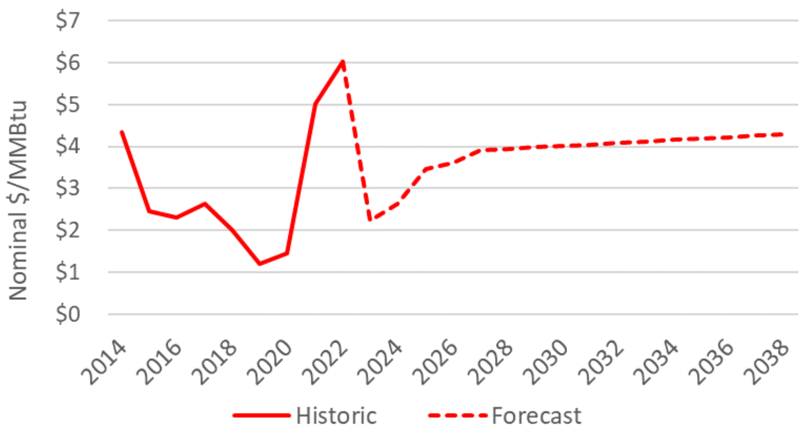


Figure 38 shows historic and forecast natural gas prices. Because TEP is using the market price forecast developed by E3, it is important that TEP also use E3's natural gas price forecast, given overlapping assumptions and the fact that gas prices influence power prices. Details on E3's natural gas price forecast can be found in **Appendix E**.

Figure 38. Historic and Forecast Permian Natural Gas Prices



5.7.1 Future Delivered Coal Price Forecast

Figure 39 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. The Four Corners' coal supply agreement runs through June 2031.

5.8 Transmission

Figure 40 shows TEP's generation and transmission assets. For information on existing generation, transmission, and distribution assets and planning processes, see **Appendix B** and **Appendix J**.

Figure 39. Delivered Coal Price Forecast

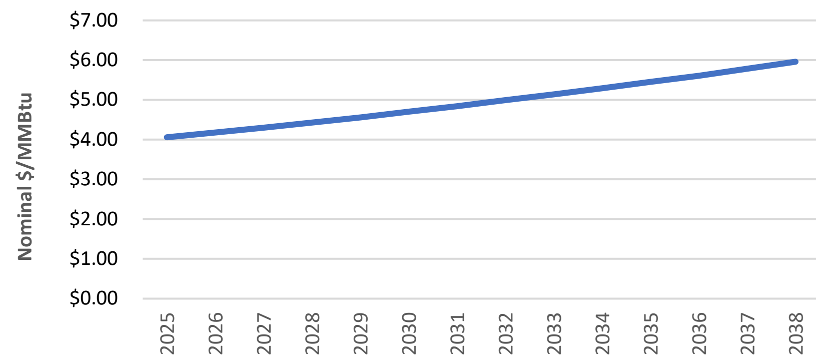


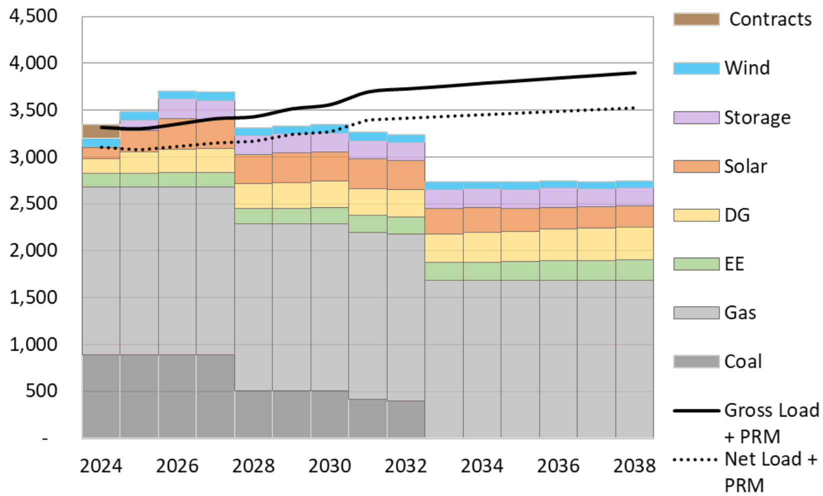
Figure 40. TEP Transmission and Generation Assets

5.9 Base Case Loads and Resources

Figure 40 shows TEP's forecasted gross and net peak demand and the effective capacity of resources available to meet that demand. Gross and net peak each include the capacity needed for a planning reserve margin (PRM). The net peak also includes the effects of EE and DG. The resource schedule includes the planned retirements of all TEP coal facilities as described in the 2020 IRP, but no future resources beyond those currently under negotiation for deployment in 2025 and 2026 as a result of TEP's first ASRFP in 2022. The gap between gross load and the top of the resource stack represents the effective capacity additions or load reductions that must occur to continue serving TEP customers reliably. **Table 14** below summarizes the current loads and resource outlook for TEP. This table includes all existing resources and the planned resources for 2025-2026. **Table 14** does not include any future resources in 2026 and beyond.

Table 14 provides annual details on a net load basis. The coincident peak capacity contributions for DG, utility-scale solar, wind, and 4-hour storage are based on their ELCCs.

Figure 41. Annual Loads and Resource with No Future Resources Assumed (coincident peak), MW



5.10 Portfolios Evaluated and Sensitivity Tests

As summarized in **Table 15**, TEP developed a number of diverse portfolios covering a range of potential future loads, resources, costs, and market and fuel prices to comprehensively evaluate its ability to adapt to changing load and market conditions while achieving least-cost and emission reduction objectives. Taken together, these portfolios, their two-pronged RA tests, their sensitivity tests, and the capacity expansion results are intended to meet the requirements outlined in **Section 5.1** as well as requirements to evaluate alternative resource options, early resource retirements, no- and high-growth load scenarios, and the costs and benefits of emission reduction commitments.

Sensitivity tests for market prices include a high case of a 50% increase in natural gas and energy prices and a low case of a 25% decrease in natural gas and energy prices. These tests were not performed on P10 because by definition the portfolio is based on a more liquid and efficient energy market with lower prices. Sensitivity tests for new resource capital costs assume the high and low forward cost curves described in **Section 5.6.1**. These tests were not performed on P06 through P10 because they already include resources with substantially different cost structures or would not provide any further insight into the effect of cost assumptions on portfolio results.

Sensitivity tests for high- and no-load growth are applied only to P01 and P02 in order to gauge how new resource needs and costs can be affected by load growth in futures that include or exclude new natural gas. The no-growth test assumes no net growth in either energy or peak demand after 2024 and also addresses the requirement that at least one portfolio include cumulative energy savings of at least 40% by 2030. This is representative of a scenario in which TEP achieves a 40% cumulative energy savings by 2030 and there is an economic downturn and an ability for standards and incentives to significantly reduce per capita electricity consumption. The high-growth test assumes a 1.0 percentage point increase in the average annual rate of energy and peak demand growth, which equates to 2.50 and 2.23% respectively. This is also representative of a scenario in which there is strong customer and economic growth in TEP's service territory or a greater-than-expected trend in electrification.

Table 14 below summarizes the current loads and resource outlook for TEP. This table includes all existing resources and the planned resources for 2025-2026. **Table 14** does not include any future resources in 2026 and beyond.

Table 14. Base Case Loads and Resources, MW

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Firm Load Obligation	**3,102**	**3,073**	**3,109**	**3,152**	**3,163**	**3,237**	**3,269**	**3,396**	**3,416**	**3,433**	**3,452**	**3,469**	**3,486**	**3,504**	**3,523**
Retail	2,472	2,520	2,551	2,588	2,598	2,661	2,689	2,797	2,814	2,829	2,846	2,860	2,875	2,890	2,906
Retail Reserve Requirement	408	416	421	427	429	439	444	462	464	467	470	472	474	477	480
Firm Wholesale	168	83	83	83	83	83	83	83	83	83	83	83	83	83	83
Firm Wholesale Reserve Requirement	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54
Firm Resource Capacity*	**3,049**	**3,110**	**3,302**	**3,279**	**2,889**	**2,889**	**2,889**	**2,795**	**2,757**	**2,235**	**2,226**	**2,206**	**2,192**	**2,173**	**2,173**
Coal	892	892	892	892	502	502	502	410	392	0	0	0	0	0	0
Gas - Combined Cycle	1,165	1,165	1,165	1,165	1,165	1,165	1,165	1,165	1,165	1,165	1,165	1,165	1,165	1,165	1,165
Gas - Steam Boilers	261	261	261	261	261	261	261	261	261	156	156	156	156	156	156
Gas - Combustion Turbines	189	189	189	189	189	189	189	189	189	189	189	189	189	189	189
Gas - Reciprocating Engines	172	172	172	172	172	172	172	172	172	172	172	172	172	172	172
Wind	87	87	87	87	87	87	87	87	77	77	77	77	71	71	71
Solar	116	229	328	313	313	313	313	311	305	276	267	247	232	222	222
Storage	17	115	208	200	200	200	200	200	196	200	200	200	208	198	198
Contracts	150	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reserve Available for Retail	355	453	614	555	155	91	64	-140	-195	-731	-757	-791	-820	-855	-871
Reserve Margin as Percent of Retail	14%	18%	24%	21%	6%	3%	2%	-5%	-7%	-26%	-27%	-28%	-29%	-30%	-30%
Net Position	-53	37	193	128	-274	-348	-380	-601	-659	-1,198	-1,226	-1,263	-1,294	-1,332	-1,350

* Capacities reflect summer derates as well as the effective load carrying capability of storage and renewables.

Table 15. Portfolios Evaluated in TEP's 2023 IRP

Portfolio Number and Name	Description / Design Objectives	Sensitivity Tests
P01 - Solar + Storage	• Re-evaluates TEP's long-term plan acknowledged by the ACC in 2022 given new outlooks in future loads and resource costs and updated modeling capabilities.	High/Low Market Prices High/Low Capital Costs High/No Load Growth
P02 - Balanced Portfolio	• Adds 400 MW of eight new, fast-start, fast-ramping aeroderivative CTs brought into service in 2028 in lieu of an equivalently-reliable amount of future solar and storage.	High/Low Market Prices High/Low Capital Costs High/No Load Growth
P03 – SGS Early Retirement (2027)	• Retires SGS 2 five years early (2027), the same year as SGS 1. • Includes costs for coal contract liquidated damages, coal contract early termination costs, and cost recovery through treatment of SGS 2 as a lower-return regulatory asset.	High/Low Market Prices High/Low Capital Costs
P04 - SGS Retirement (2030)	• Retires both SGS units in 2030 instead of 2027 and 2032. • Assumes same amount of must-take coal volume but includes coal contract early termination costs.	High/Low Market Prices High/Low Capital Costs
P05 - SGS Retirement (2034)	• Retires both SGS units in 2034 instead of 2027 and 2032. • Extends annual must-take coal volumes through 2034. • Includes low-sulfur coal handling upgrades for future coal supply sources.	High/Low Market Prices High/Low Capital Costs
P06 - Heavy Solar	• Evaluates appropriateness of wind/solar capacity mix assumed in other portfolios. • Evaluates cost differences and system integration capabilities in the event market conditions, load patterns, or system operations favor relatively more solar. • Decreases future wind from 500 MW to 250 MW and adds solar (and storage if necessary) to reliably achieve the same amount of CO_2 reduction. • Assumes low capital cost only for solar.	High/Low Market Prices
P07 - Heavy Wind	• Evaluates appropriateness of wind/solar capacity mix assumed in other portfolios. • Evaluates cost differences and system integration capabilities in the event that market conditions, load patterns, or system operations favor relatively more wind. • Increase future wind from 500 MW to 750 MW and decrease solar (and storage if possible) to reliably achieve the same amount of CO_2 reduction. • Assumes low capital cost only for wind. Also assumes a $48/kW-year transmission wheeling cost for the additional 250 MW given the lack of available transmission capacity on the east side of TEP's transmission system, which is located closest to high-value wind resources in eastern New Mexico.	High/Low Market Prices
P08 - Pumped Hydro	• Replaces all Li-ion battery storage brought into service from 2033-2038 with an equivalently reliable amount of 10-hour storage brought into service in 2033 with ATB assumptions for cost and round-trip efficiency (80%) and a capacity credit of 75% based on interpretation of TEP's ELCC study. • Assumes reservoir would be located in northern Arizona and that only 300 MW could be transmitted before having to purchase additional capacity at $48/kW-year. • Relocates 1,000 MW of solar to the Four Corners area to support this remote storage and avoid transmission costs.	High/Low Market Prices
P09 - Small Modular Reactors	• Replaces all Li-ion battery storage brought into service from 2033-2038 with an equivalently-reliable amount of nuclear power brought into service in 2033.	High/Low Market Prices
P10 - Market and Transmission Reform	• Increases market depth by assuming 50% more import/export capability and 25% lower market prices.	

6 Portfolio Results and 15-Year Resource Plan

Figure 42 provides detailed results for four select portfolios. P01 - Solar + Storage is based on the 2020 Preferred Portfolio in that it assumes coal unit retirements in 2027, 2031, and 2032, no addition of future fossil-fueled generation, and a similar mix of future solar, wind, and 4-hour duration battery storage. However, as a result of modeling improvements since 2020, especially the development of ELCCs, P01 contains significantly more solar and storage than the 2020 Preferred Portfolio and a slight advancement in the timing of wind deployments.

By contrast, the P02 - Balanced Portfolio has approximately the same amount of clean energy resources as the 2020 Preferred Portfolio but includes 400 MW of new gas-fired CTs for reliability and clean energy integration purposes. This can be seen on the right side of the charts, where P01 has 1,153 MW of thermal retirements and no thermal additions, and P02 has the same retirements but includes the addition of 400 MW of natural gas in 2028. As a result, P02 requires 850 MW less of 4-hour storage and 200 MW less of solar capacity. Solar power is reduced to a lesser extent than storage (and wind power is not reduced at all) because these energy resources are needed to maintain progress towards TEP's CO_2 reduction goal. Because these resources have some capacity value, they contribute to the reserve margin, which is therefore about 2 to 3 percentage points higher in P02 than P01.

Results for P03 and P05 are included in **Figure 42** to provide contrast and a range of comparison across portfolios, since these portfolios retire the Company's major coal assets earlier and later than all the other cases. Although their resource schedules and portfolio costs are different from P01, their total resource additions are the same over the planning period. This is because by 2038, the P03 and P05 future capacity requirements, without any new natural gas, are the same as P01 by the end of the 15-year planning period.

The red line and percentages shown in **Figure 42** is the reserve margin, which should be at least 16.5% as part of the Company's reliability criteria. The pattern in these charts is typical of all portfolios, in which the reserve margin increases well above 16.5% because of the large amount of resources that must be implemented in the years prior to retiring large thermal units (at least 3 MW of solar, wind, and storage for each MW of coal or gas). After the thermal retirements, reserve margins return much closer to their targeted level.

Figure 43 shows the total resource additions for each of the 10 portfolios, including four portfolios based on no- and high-load growth assumptions. As seen in the figure, the biggest impact on resource additions is not so much the type of future resources considered but the extent of load growth, which is difficult to predict. While load growth has a less profound impact on rates, because additional resource costs are spread over a greater sales volume, it will clearly have an effect on the amount of resources required, the total capital outlay and how quickly the Company must on-board new resources.

The NPVRR across the 10 portfolios (excluding the load sensitivity portfolios) are relatively close to each other. One explanation for this is the amount of fixed costs that change very little across portfolios but are present in each, such as transmission and distribution and existing generation assets, which must still be depreciated even if retired early. Another explanation is the degree of parity between competing resource types, such as solar versus wind and batteries versus natural gas.

Figure 44 shows the net present value of the revenue requirements for each of the portfolios shown in **Figure 43**, as well as an indicative retail rate for each portfolio, which is the annual revenue requirement divided total annual retail sales averaged across all years.

Figure 45 shows each portfolio's NPVRR and the range of results of the sensitivity tests on electricity and natural gas prices and capital costs. The impacts are similar across portfolios, meaning the uncertainty in future electricity and gas prices and capital costs do not place one portfolio at a particularly higher risk than any other. **Figure 45** also shows a bit more clearly how the NPVRR compares across Portfolios 1 through 9.

Figure 42. Annual Additions, Retirements & Reserve Margins for Select Portfolios

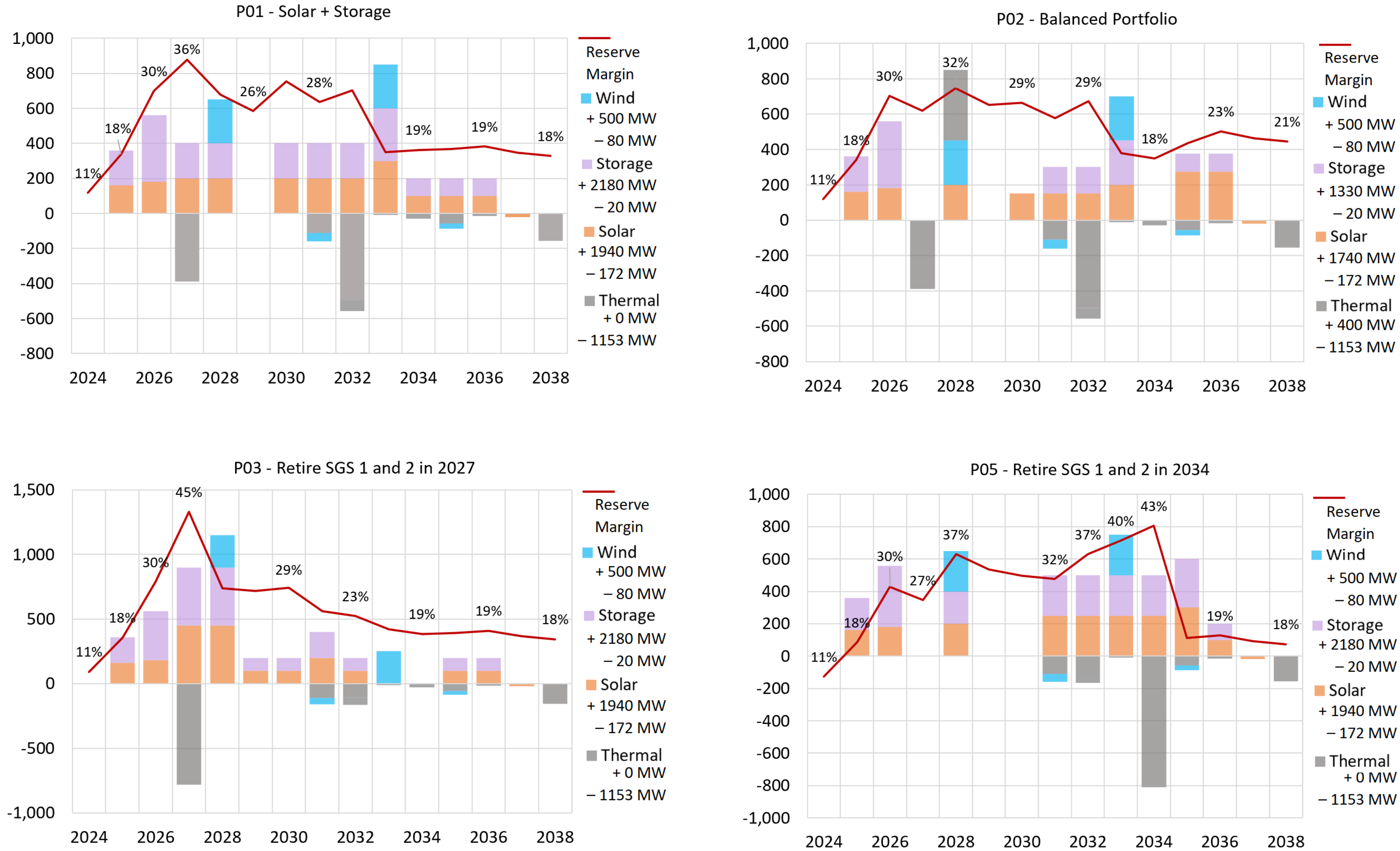


Figure 43. Total Resource Additions for Each Portfolio

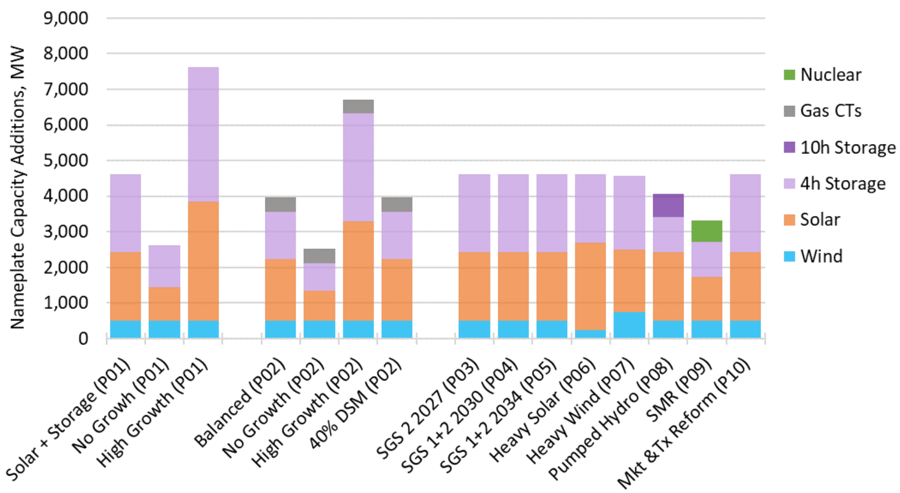


Figure 44. Net Present Value Revenue Requirements (NPVRR) for each Portfolio and Indicative Retail Rate Rates

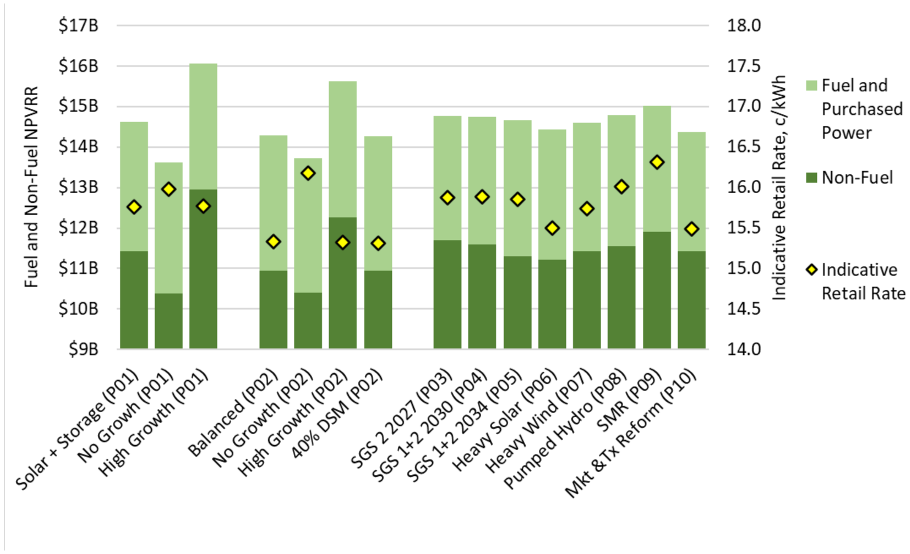
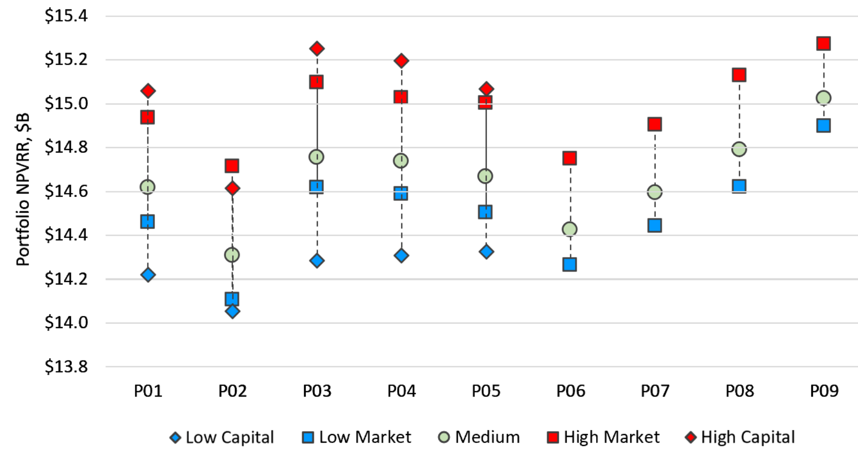


Figure 45. Range of NPVRR Resulting from Sensitivity Tests



Portfolios P06 and P07 were designed to test the appropriateness of the Company's assumptions around the relative mix of wind and solar assumed in other portfolios. One factor that could lead to a greater mix of solar, in P06 for example, is its cost relative to wind. P06 therefore assumes the low capital cost forecast for just solar, and this impact can be seen in **Figure 45**. Likewise, P07 assumes the low capital cost forecast for just wind, but additional wind beyond the 500 MW assumed in other portfolios is likely to require transmission capacity not currently available to TEP, so additional transmission costs offset any savings realized through relatively cheaper wind generation. Also, because of southern Arizona's climate, all portfolios contain substantially more solar than wind, so relative price reductions in this resource will have a greater impact on total revenue requirements than relative reductions in wind costs. Because the revenue requirements of P06 and P07 fall between those of P01 and P02, and because they both meet the Company's CO_2 goals and reliability targets, the Company concludes that the relative mix of solar and wind assumed in its other portfolios is appropriate, at least for planning purposes. The ultimate mix, of course, will depend on economics, system needs (e.g., for night-time power from wind), and transmission availability at the time of procurement.

Portfolios P08 and P09, although they require fewer megawatts of new resource capacity, are expected to cost more than other portfolios because of the large capital costs and lead times associated with the construction of Pumped Storage Hydropower (PSH) facilities and the siting of Small Modular Nuclear Reactors (SMR). Nonetheless, the Company will continue to monitor these resource costs through future ASRFPs, especially as the Company invests heavily in lithium-ion battery technology in the mid-term and considers its longer term needs for resource diversity, reliability, and emission reductions to support the Company's longer-term net zero goal by 2050.

Portfolio P10, which is the same as P01 but assumes greater market depth and lower prices, reduces revenue requirements by approximately $0.25B and is an indicator of the benefits that might be realized through future transmission investments and market reform.

Figure 46 through **Figure 48** compare the environmental attributes of each portfolio. The P02 - Balanced Portfolio is shown in a thick blue line with yellow circles. The three coal retirement portfolios (P03 through P05) are shown in dotted lines. It is clear that air emissions and water use are most heavily influenced by the timing of the coal unit retirements. The Balanced Portfolio retires the coal units in the same years as the P01 -Solar + Storage Portfolio, so their environmental impacts are very similar. The portfolio with the lowest CO_2 emissions and water use in the 2030s is the P09 - SMR Portfolio.

Figure 46. CO_2 Emissions

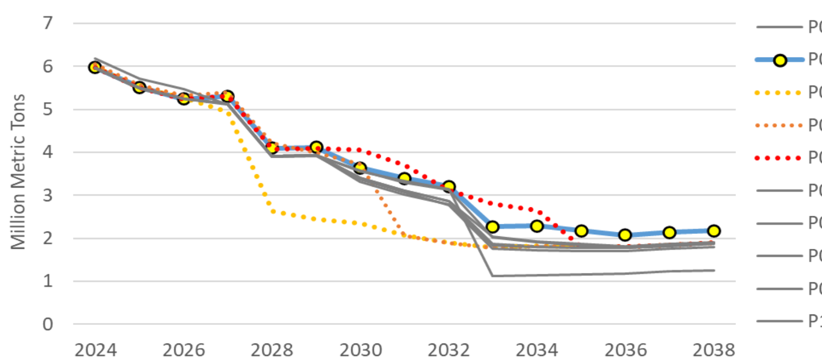


Figure 47. NOx Emissions

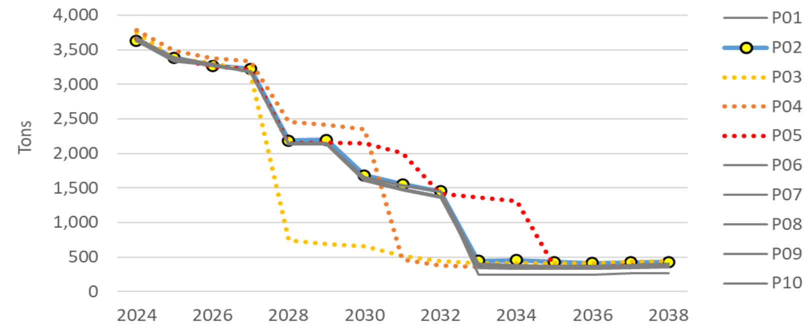


Figure 48. Water Use

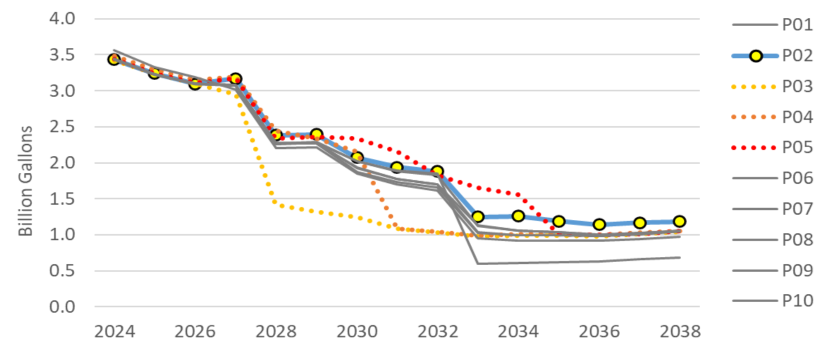


Figure 49 shows the capacity-weighted, fleet-wide capacity factor for TEP's gas-fired generators. Each portfolio's use of natural gas, despite retirement of its coal units, decreases through the 2020s, primarily due to displacement by renewable generation, and increases slightly and stabilizes at about 27% in the 2030s. The portfolio that deviates somewhat from this trend is the P09 - SMR Portfolio because SMRs are designed as baseload, high-capacity factor generators that displace more natural gas than renewables.

Figure 49. Gas Fleet Capacity Factor

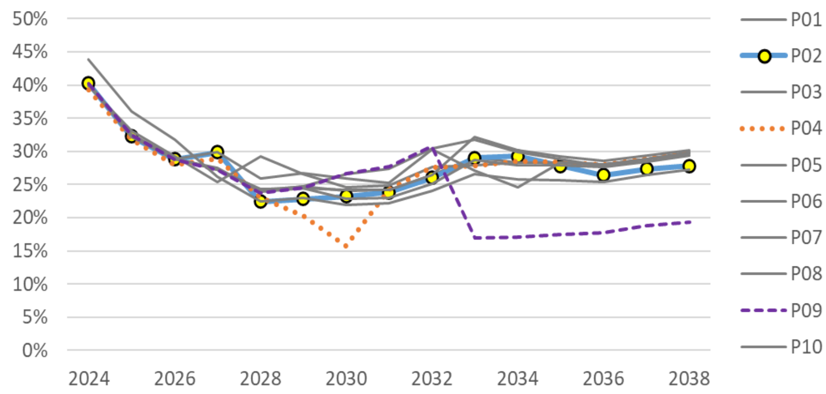


Figure 50 shows the capacity-weighted, average daily cycling of each portfolio's battery storage fleet. Although the size of the battery storage fleet is driven largely by the need for capacity, it serves an important and related function of storing excess renewable generation for later use, during non-peak hours. This energy shifting maximizes the use of solar and wind power and reduces the amount of coal and natural gas generation, as well as market purchases. Unless otherwise needed for capacity, TEP designed its portfolios to target an average daily cycle close to 1.0. This indicates that the battery storage is being used effectively to shift energy and is not being over cycled, as battery warranties often have limits on the number of annual cycles.

Figure 50. Battery Storage Fleet Average Daily Cycle

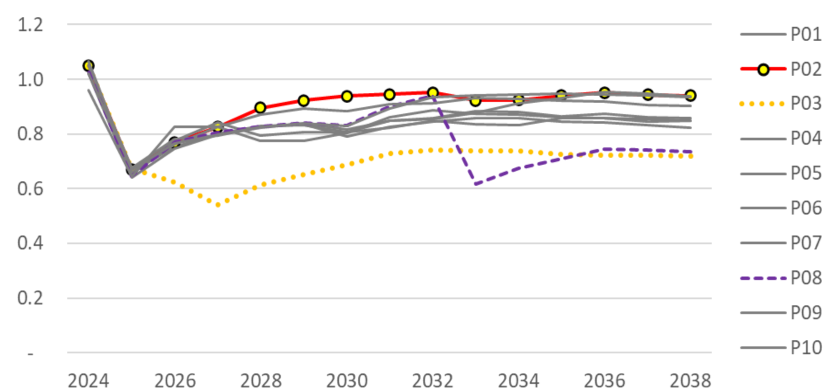
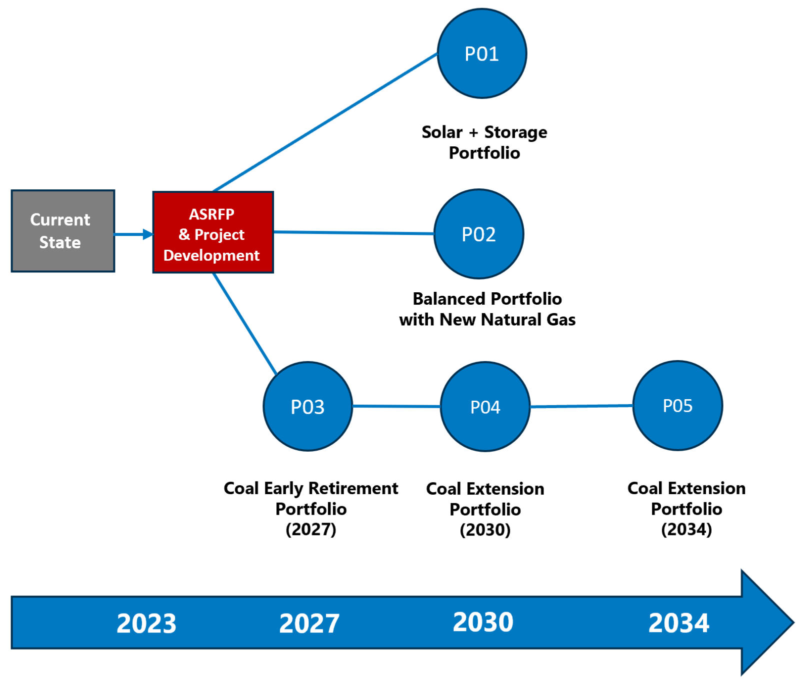


Figure 51 is a simplified illustration of the pathways the Company sees towards achieving its resource needs and clean energy goals. These pathways do not preclude outcomes described in P06 through P10, as they would probably be realized in the later years of the planning period. Rather, the figure highlights the most significant near- and medium-term decisions facing the company – that is, whether to add no new thermal resources, add natural gas-fired CTs, and/or modify its coal retirement plans.

Figure 51. Short- and Mid-Term Pathways to Meeting TEP's Resource Needs and Clean Energy Goals



TEP developed and analyzed ten different resource portfolios as part of the 2023 IRP. A summary of the 15-year net present value, cumulative capacity additions and environmental outcomes by 2038 are shown in **Table 16** below.

Table 16. Portfolio Case Matrix Details

					Cumulative Additions (2024-2038)					Environmental Results (2038)		
Portfolio #	Portfolio Name	NPV ($000)	Fuel NPV ($000)	Non-Fuel NPV ($000)	Solar (MW)	Storage (MW)	Wind (MW)	Gas (MW)	Other (MW)	CO_2 Reduction	NOx Reduction	Water Reduction
TEP P01	Solar + Storage	$14,619	$3,188	$11,431	1,940	2,180	500	0	0	83%	96%	84%
TEP P02	Balanced Portfolio	$14,308	$3,364	$10,944	1,740	1,330	500	400	0	80%	95%	81%
TEP P03	Springerville Early Retirement (2027)	$14,755	$3,049	$11,706	1,940	2,180	500	0	0	83%	95%	84%
TEP P04	Springerville Retirement (2030)	$14,738	$3,152	$11,586	1,940	2,180	500	0	0	83%	96%	84%
TEP P05	Springerville Retirement (2034)	$14,669	$3,357	$11,311	1,940	2,180	500	0	0	83%	96%	84%
TEP P06	Heavy Solar	$14,425	$3,208	$11,218	2,440	1,930	250	0	0	83%	95%	83%
TEP P07	Heavy Wind	$14,594	$3,168	$11,426	1,740	2,080	750	0	0	83%	96%	84%
TEP P08	Pumped Hydro	$14,789	$3,238	$11,551	1,940	980	500	0	650	83%	96%	84%
TEP P09	Small Modular Reactors	$15,023	$3,120	$11,903	1,240	980	500	0	600	89%	97%	89%
TEP P10	Market and Transmission Reform	$14,292	$2,930	$11,431	1,940	2,180	500	0	0	82%	95%	83%

Notes:

1. Springerville Unit 1 retires in 2027 and Springerville Unit 2 retires in 2032 in all portfolios except P03, P04, and P05. Portfolios P03-P05 assume simultaneous unit retirements of both Units 1 and 2 at Springerville for the dates shown in their portfolio names. Four Corners Unit 4 & 5 are assumed to retire in 2031 in all portfolios.
2. CO_2 reduction percentage is calculate based on 2005 levels, NOx and water reductions are based on 2019 levels.
3. P08 assumes that 650 MW of pumped hydro capacity is included in the portfolio.
4. P09 assumes that 600 MW of small modular reactors are included in the portfolio.
5. P10 is a sensitivity analysis utilizing the P01 portfolio and reflects a cost savings of approximately $258M due expanded market and transmission access. Cost reductions in similar magnitude would be observed across the remaining portfolios (P02-P09) if similar market and transmission access assumptions were applied.

Based on the portfolio analysis done in this 2023 IRP and other implementation and risk management considerations, the Company expects the P02 – Balanced Portfolio to be the most likely outcome of its clean energy transition and resource acquisition activities. **Table 17** Below provides a load and resource forecast for the Balance Portfolio (P02).

Table 17. Balanced Portfolio (P02) Loads and Resources, MW

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Firm Load Obligation	**3,101**	**3,071**	**3,106**	**3,149**	**3,161**	**3,235**	**3,267**	**3,393**	**3,413**	**3,430**	**3,450**	**3,466**	**3,484**	**3,502**	**3,521**
Retail	2,471	2,518	2,549	2,585	2,596	2,659	2,686	2,795	2,812	2,827	2,844	2,858	2,873	2,888	2,904
Retail Reserve Requirement	408	416	421	427	428	439	443	461	464	466	469	472	474	477	479
Firm Wholesale	168	83	83	83	83	83	83	83	83	83	83	83	83	83	83
Firm Wholesale Reserve Requirement	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54
Firm Resource Capacity*	**3,049**	**3,110**	**3,453**	**3,427**	**3,552**	**3,552**	**3,598**	**3,656**	**3,766**	**3,511**	**3,501**	**3,600**	**3,683**	**3,665**	**3,665**
Coal	892	892	892	892	502	502	502	410	392	0	0	0	0	0	0
Gas - Combined Cycle	1,165	1,165	1,165	1,165	1,165	1,165	1,165	1,165	1,165	1,165	1,165	1,165	1,165	1,165	1,165
Gas - Steam Boilers	261	261	261	261	261	261	261	261	261	156	156	156	156	156	156
Gas - Combustion Turbines	189	189	189	189	589	589	589	589	589	589	589	589	589	589	589
Gas - Reciprocating Engines	172	172	172	172	172	172	172	172	172	172	172	172	172	172	172
Wind	87	87	87	87	128	128	128	128	119	169	169	169	164	164	164
Solar	116	229	356	341	427	427	483	558	626	692	683	761	829	819	819
Storage	17	115	331	320	308	308	298	373	442	567	567	588	609	600	600
Contracts	150	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reserve Available for Retail	356	454	768	704	819	756	774	724	817	547	521	605	673	639	623
Reserve Margin as Percent of Retail	14%	18%	30%	27%	32%	28%	29%	26%	29%	19%	18%	21%	23%	22%	21%
Net Position	-52	39	347	278	391	317	331	263	353	80	52	134	199	163	144

* Capacities reflect summer derates as well as the effective load carrying capability of storage and renewables.

7 Risk Management Plan

7.1 Analysis of TEP Power System Resilience to Extreme Weather and Correlated Gas-Power Risks

Correlated gas-power risks are associated with reliance on natural gas for electricity generation. Factors such as disruptions due to geopolitical events, infrastructure overlap due to shared utility corridors, cybersecurity risks due to co-located infrastructure, and extreme weather events, such as hurricanes, heatwaves, and severe cold snaps can disrupt power generation, transmission, and distribution infrastructure. These disruptions can result in power outages, affecting homes, businesses, and essential services.

This interdependency creates vulnerabilities related to supply reliability, resilience degradation, and economic consequences in the power system. To enhance power system resilience, TEP employs several strategies including:

1. **Diversifying Energy Sources:** TEP reduces reliance on a single fuel source like natural gas by promoting a diverse energy mix that includes renewable energy sources, energy storage, and grid flexibility. TEP also takes advantage of the regional diversity of resources available through the Western Energy Imbalance Market (WEIM) as well as our ASRFP process. The ASRFP addresses resource adequacy needs to meet environmental, resilience, and economic goals. This strategy ensures a diversification of energy sources that improves resilience to fuel supply disruptions and mitigates the impacts of extreme weather events within and outside TEP's service area.

2. **Coordination Between Plant and Gas Supply Operators:** TEP generates a formal daily dispatch plan with a diversified mix of assets beyond natural gas. In addition, the company has a formal process for scheduling, coordinating, and hedging outages – planned, unplanned, or forced. This helps power plant operators plan and schedule gas deliveries based on electricity generation needs, while gas supply operators ensure timely and consistent gas supply.

   Physical assets are either staffed around the clock or regularly patrolled by personnel. These assets have been stocked with critical inventory, and/or have asset criticality assessments performed on them, with state-of-the-art predictive maintenance technology to predict failure and make repairs or replacements before failure.

   The gas operations department monitors real-time gas flow, communicates with the generation supervisors to address any issues, and plans maintenance activities to minimize disruptions. In emergencies or gas supply disruptions, contingency plans are implemented to maintain grid stability. TEP ensures open communication, data sharing, and compliance with regulations which are crucial for this coordination, supporting efficient power generation while adhering to safety and environmental standards.

3. **Advanced Monitoring Systems:** TEP has invested and continues to invest in grid modernization technologies for real-time data collection, sensors, and predictive analytics that continuously monitor infrastructure and operational parameters. Advanced monitoring systems incorporate local as well as remote monitoring systems for facility and plant reliability.

   Grid modernization technologies provide early detection of anomalies, equipment failures, and potential threats, allowing for proactive responses and preventive maintenance. By providing real-time insights and enabling rapid decision-making, these systems minimize downtime, reduce risks, and enhance overall system reliability and resilience. These systems safeguard essential services and critical infrastructure in the face of challenges like extreme weather events and cyberattacks.

4. **Redundancy and Backup systems:** TEP generation, transmission, and distribution systems employ various redundancy systems at both the plant and system 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's tools for system operations have redundancy in the Energy Management System (EMS) and the communication equipment tying the remote substations and power plants to the EMS. All applications for interconnected operations are designed so that the primary and backup control centers are redundant and independent from one another. These systems are patched by the EMS team and checked by operating personnel on a regular basis. In addition, the primary and backup control centers have redundant utility feeds and backup generators.

Analyzing and addressing power system resilience to extreme weather and correlated gas-power risks is essential for ensuring the reliability and stability of electricity supply. Employing these and other mitigation strategies limit severe impacts from unexpected operating events.

7.2 Assessing the Value of Distribution Grid-Connected Resources

The Company favors a combination of both large-scale grid resources connected to the transmission grid as well as distributed grid-connected resources. For the latter, challenges include predictability of the value proposition seen by third parties needed to install distributed generation facilities. That uncertainty proves challenging to resource planning assumptions such as location, output, and reliable performance of distributed generation. Understanding these factors is critical for ensuring resource adequacy during peak demand.

Notwithstanding, the Company sees value in co-optimizing distributed generation along with large scale resources. Resource benefits of distributed generation include reduced line losses that would otherwise occur through the transmission and distribution of electricity, increased grid resilience, increased voltage support on the distribution network, and potential for the ability to provide standby capacity during peak hours of electrical use.

Other factors to be considered include wear and tear of distributed generation on the overall system, cost impacts on customers without distributed generation, and economies of scale for distributed generation as opposed to large scale systems. More importantly, customer adoptability of installing distributed generation is largely unknown in both quantity and location. Without this key input, the quantification of these benefits and other factors are difficult at best and therefore reported as qualitative.

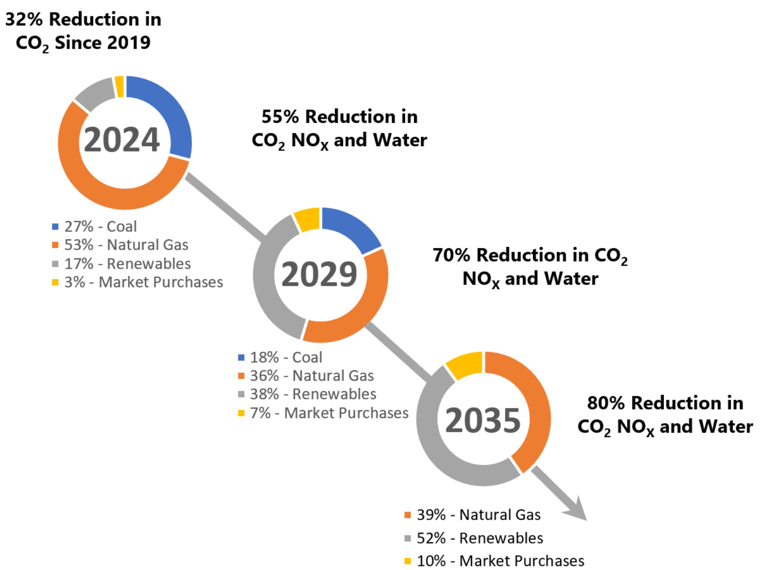
As stated above, the Company does not favor an either-or approach and is supportive of both distribution and transmission connected resources. Further, the Company will continue to encourage the solicitation of distributed generation resources in its future All Source RFPs

8 TEP's 2023 Preferred Portfolio

8.1 TEP's 2023 Preferred Portfolio (P02 - Balanced Portfolio)

TEP's 2023 Preferred Portfolio (P02 - Balanced Portfolio) establishes an updated roadmap for TEP's pursuit of a more sustainable energy supply. The Balanced Portfolio continues to move the Company forward with its clean energy goals that were established in TEP's 2020 IRP. Over the last few years, TEP has commissioned over 490 MW of new wind and solar plus storage projects, retired 339 MW of coal and has reduced CO_2 emissions from owned fossil generation by 32%. The 2023 IRP builds from the 2020 IRP goals and accelerates its current plans for developing new energy resources that will support affordable, reliable service while contributing to a cleaner, greener grid. As shown in **Figure 52**. the Balanced Portfolio is the most cost-effective way to maintain reliable, affordable service while achieving meaningful reductions in CO_2 and nitrogen oxide (NO_X) emissions and water usage.

Figure 52. Balanced Portfolio Energy Mix



In contrast to the other portfolios analyzed in this planning cycle, the Balanced Portfolio reduces the future capital expenditures by about $1 billion over the 15-year timeframe. On a net present value basis, the Balanced Portfolio saves customers over $300 million (2024-2038) relative to the other portfolio options. A 15-year timeline of the Balanced Portfolio is shown in **Figure 63** on **Page 62**.

8.2 Changes in Coal Plant Operations

The 2023 IRP acknowledges that the economics of coal-fired generation have shifted. Current and proposed environmental regulations will only further disadvantage the economics of coal in the future. TEP's Balanced Portfolio maintains the retirement timeframes established in the 2020 IRP to allow for a staggered workforce transition while mitigating future high operating costs and environmental risks that are associated with coal-fired generation.

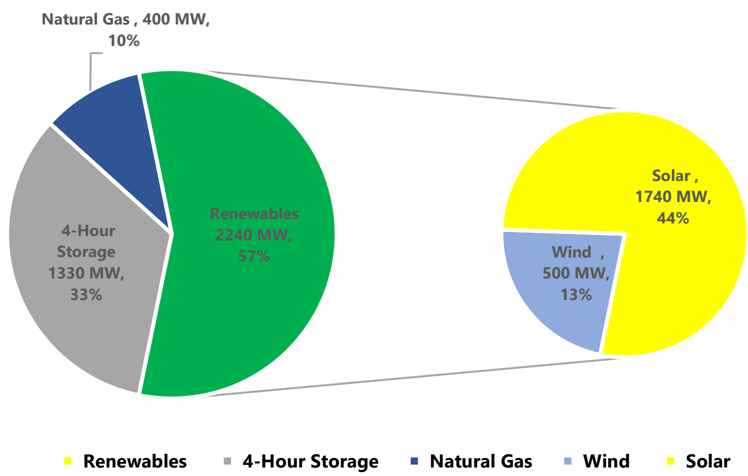
The Balanced Portfolio also maintains the Company's commitment to seasonal operations at Springerville. Planned seasonal operations involve extended planned outages for an anticipated three-month period during the fall, winter, and spring seasons for both Units 1 and 2. Initially, the units will alternate idling between spring and fall (both seasons include the adjacent winter months). TEP plans to transition Unit 1 to summer-only operations prior to full retirement at the end of 2027. Unit 2 will then transition to a 9-month operating year and over time, TEP plans to transition Unit 2 to summer-only operations starting in 2030 through its retirement date at the end of the 2032 summer season. The Company also plans to retire 110 MW of coal-fired generation from Units 4 and 5 at the Four Corners Power Plant in 2031. During this transition, TEP will continue to work closely with employees and local leaders within these communities to prepare for the units' eventual retirements.

8.3 Future Resource Additions

To meet anticipated load growth and capacity lost to future coal plant retirements, TEP plans to secure 2,640 MW of new generating capacity and 1,330 MW of new energy storage over the next 15 years. As shown in **Figure 53**, while 90% of the new resource capacity will be sourced from renewable and energy storage projects, TEP anticipates a need to develop 400 MW of new natural gas-fired generation by 2028 in order to maintain reliable and affordable service for our customers. Moreover, today's natural gas technologies provide optionality for power generation to eventually pursue the use of hydrogen as a carbon-free fuel source in the future.[12]

The Balanced Portfolio assumes the implementation of 1,330 MW of new energy storage. In general, the energy storage additions are paired with solar and coincide with 1,740 MW of new solar additions to take advantage of construction efficiencies, tax incentives, and available transmission capacity. This pairing of solar and storage resources mimics the trend seen in recent ASRFP hybrid proposals and other utility project announcements over the last couple of years.

Figure 53. Future Capacity Additions



As shown in **Figure 54** through **Figure 56** the Balanced Portfolio accelerates TEP's buildout of clean energy resources, with 1,520 MW of new renewable and storage coming online by 2030 compared to the 1,050 MW that were anticipated in the 2020 IRP. As discussed above, this plan is expected to have a lower impact on customers' rates than other portfolio alternatives.

Figure 54. New Resource Differences between the 2020 and 2023 IRPs

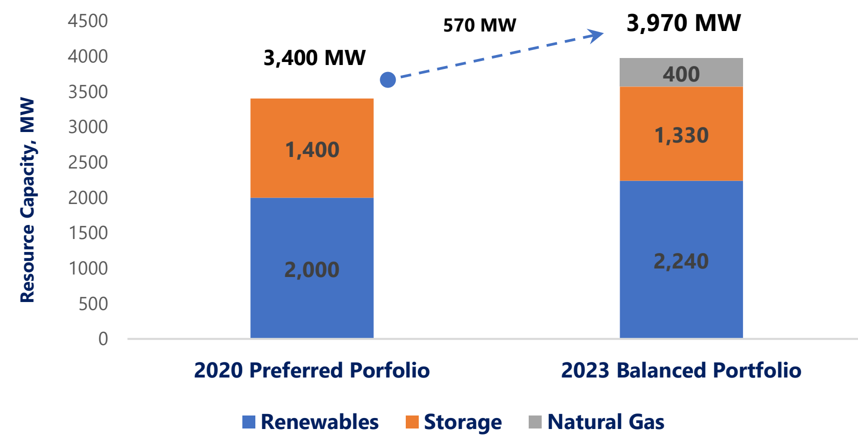
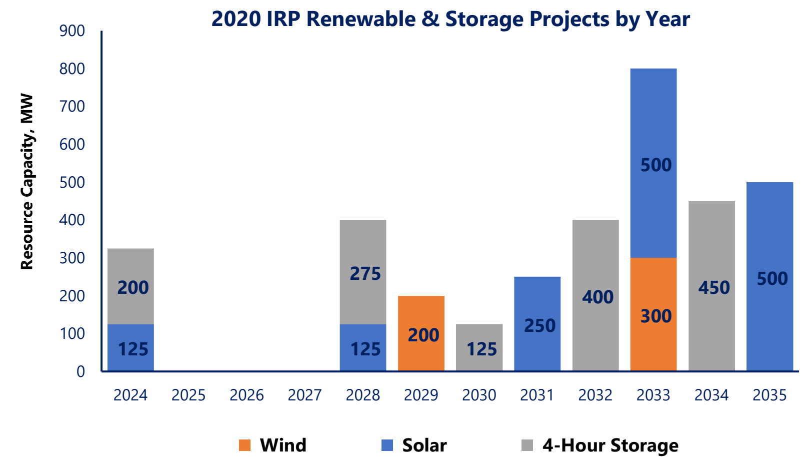


Figure 55. 2020 IRP Renewable and Storage Capacity Additions



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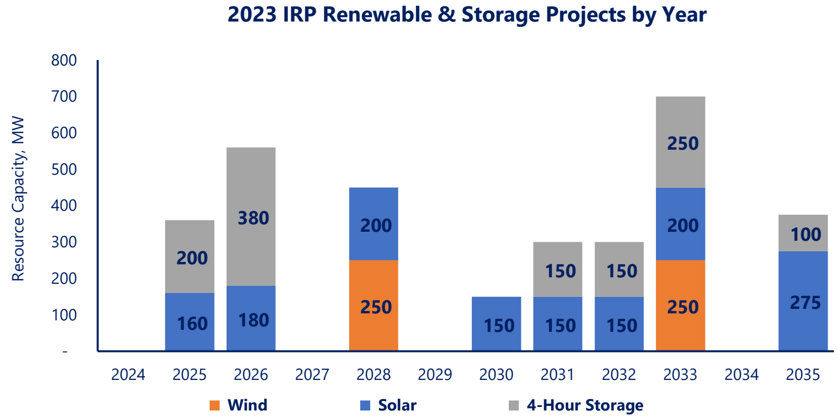
[12] *See Hydrogen - Carbon-Free Fuel Blending as a Transition Fuel to the Future on* **Page 63.**

Figure 56. 2023 IRP Renewable and Storage Capacity Additions



8.4 Balanced Portfolio Environmental Attributes

TEP's Balanced Portfolio will result in significant reductions in CO_2 and NO_X emissions and water use over the next 15-years. This shift started with the Company's transition efforts developed through prior IRP planning cycles and the efforts continue today as shown in **Figure 57** through **Figure 59.**

Figure 57. Balanced Portfolio – CO_2 Emissions

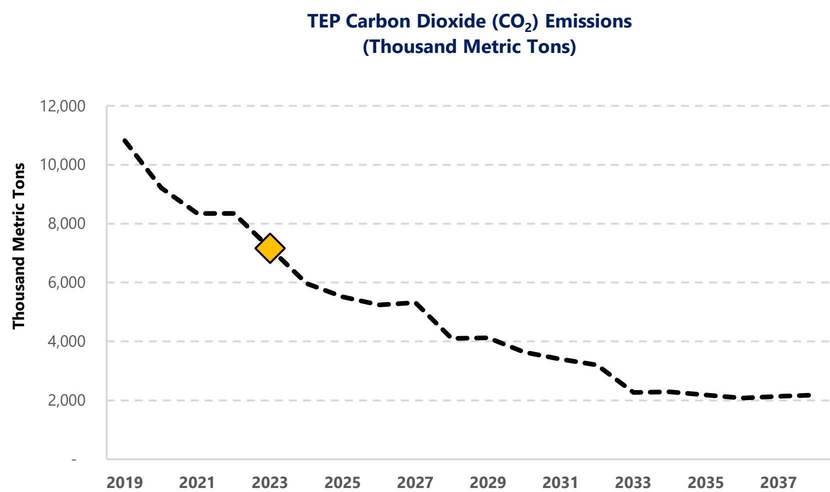


Figure 58. Balanced Portfolio – NO_X Emissions

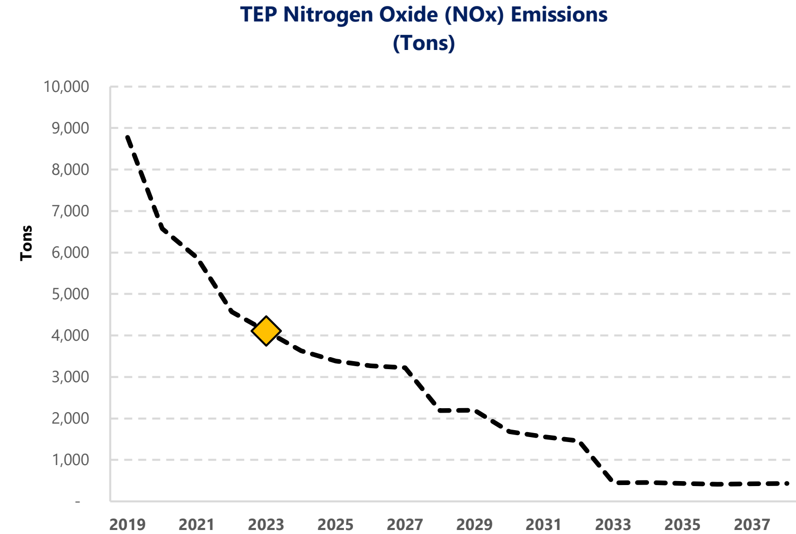
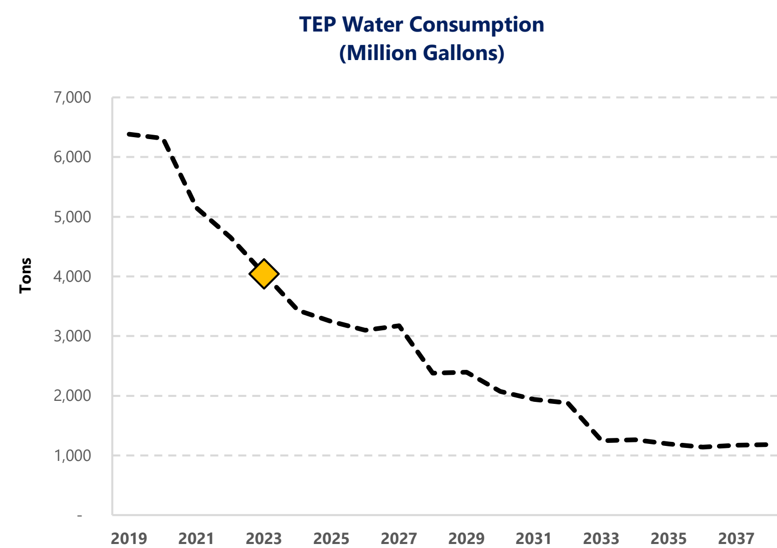


Figure 59. Balanced Portfolio – Water Usage



8.5 Future Energy Efficiency

The Balanced Portfolio will continue to incorporate high levels of EE. TEP's recent DSM plan approved by the ACC on August 25, 2023 (Decision No. 79065), has a three-year savings goal of 4.2% of annual retail sales (2024-2026). This new DSM Plan continues TEP's efforts to redirect DSM programs to achieve both energy and demand savings through cost-effective energy efficiency and load management programs. TEP believes that incorporating EE at levels consistent with recent historical years (incremental annual increases of 1.3 percent to 1.5 percent of the previous year's retail load) is cost-effective for both participating and non-participating customers, provided that a full suite of EE programs and measures are available in future years.

8.6 Demand Response

TEP currently implements a voluntary load control program for larger commercial and industrial customers in TEP's service territory. During peak hours of the summer months, commercial and industrial load represents a total of approximately 22% of system demand. Controls for chillers, rooftop AC units, lighting, fans, and other end uses are modified to allow for curtailment of load, thus reducing power demand from customers at specified times. Participating customers voluntarily reduce their electricity consumption during times of peak electricity demand when called upon by TEP. Customers are compensated with incentives for their participation at negotiated levels that will vary depending on multiple factors including the size of the facility, amount of load that can be curtailed, and the frequency with which the resource can be utilized.

Under the Company's current DSM plans, TEP has a new residential load management pilot program called Smart Rewards. TEP's Smart Rewards program has enrolled over 8,400 residential thermostats in this demand response program. Under this program, TEP, working with the thermostat providers, can request smart thermostats to reduce load during summer peak hours.

Smart Rewards program participants have agreed to brief adjustments of up to 4 degrees or less to their thermostats during peak electric demand periods from June 1 through September 30, including weekends and holidays. Adjustments typically last no more than three hours and are limited up to 20 events per summer. By the end of 2026, TEP expects to enroll up to 24,000 additional thermostats for residential customers.

8.7 Balanced Portfolio Plan Attributes

The primary objective of the Balanced Portfolio is to provide a portfolio of resources that reliably meets our customers' energy needs at affordable rates, while mitigating potential risks to future costs. TEP's 2023 Balanced Portfolio achieves all of these objectives in the near-term and sets the stage for transitioning to a more sustainable portfolio over the longer-term. **Figure 60** shows the Balanced Portfolio resource capacity additions and retirements through the planning period. This chart highlights the source of replacement capacity needed due to unit retirements and increasing demand by customers.

Figure 60. Balanced Portfolio – Net Additions and Retirements (2024-2038)

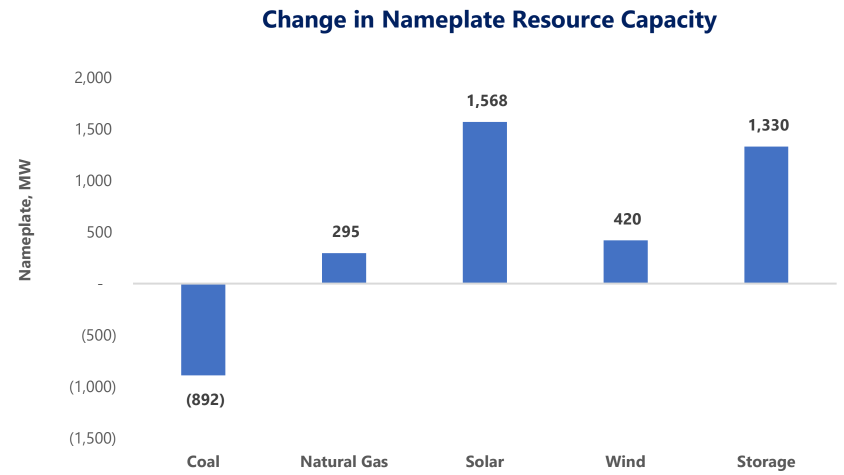


Figure 61 below shows the shift in energy mix over the planning period including the elimination of coal by the end of 2032.

Figure 61. Balanced Portfolio – Annual Energy by Resource Type

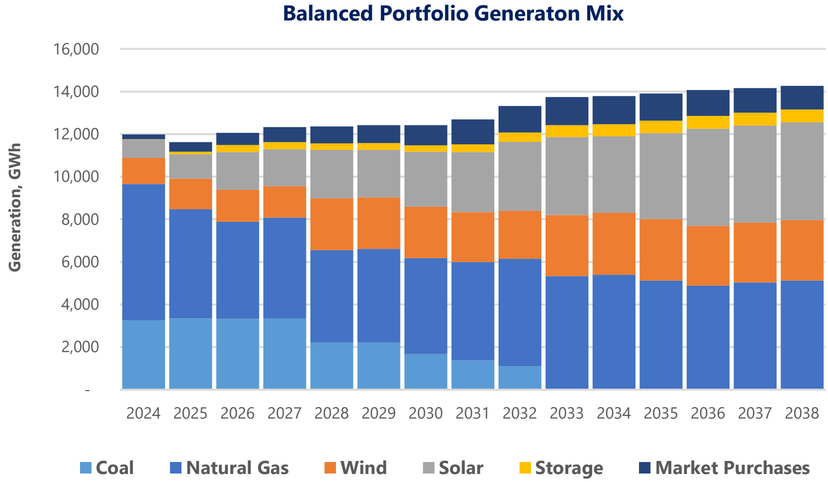
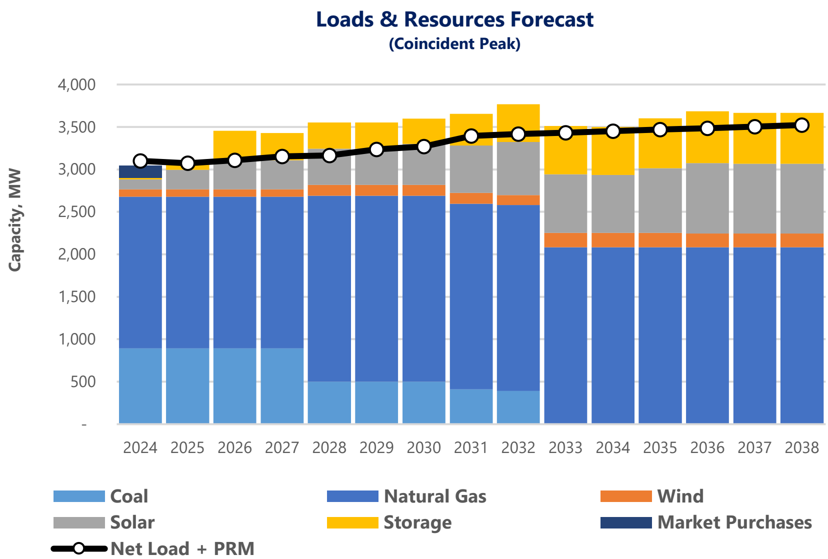


Figure 62 below shows final Load and Resources assessment of the Preferred Portfolio.

Figure 62. Balanced Portfolio – Loads and Resources



8.8 Future ASRFPs

The Balanced Portfolio will be developed through future needs analyses and on-going ASRFPs. Future ASRFPs will be technology neutral, including supply- and demand-side resources, and will not unduly exclude any commercially available resource that can demonstrate adequate performance and cost-effectiveness. Inherently, these ASRFPs put downward pressure on resource costs as the bidders seek to compete with alternative suppliers.

TEP's ultimate resource mix in the Balanced Portfolio may vary based on the outcome of future ASRFPs. Future ASRFPs will create opportunities for developers to propose competing technologies that may prove more advantageous than those anticipated in the 2023 IRP analysis. Finally, as circumstances change, future resource plans will be updated every three-years or as ordered by the ACC to reflect updated information, technology, and market trends.

8.9 2023 IRP Action Plan

TEP has developed a 2023 Action Plan based on the Company's forward-looking customer growth and cost assumptions that are detailed in Section 5. Under this action plan, additional ASRFP solicitations will be conducted to validate all technical and financial assumptions prior to any acquisition decisions. TEP's action plan includes the following:

TEP will complete the build-out of its planned 200 MW storage project Road Runner Reserve that was announced in October 2023. TEP continues to negotiate several new solar and storage project solicitations that were received through the Company's 2022 ASRFP. The Company expects that these negotiations will lead to the acquisition of another 520 MW of new solar plus storage projects. All of these new projects are planned to be in-service by the summer of 2026.

At the Springerville Generating Station, seasonal operations will continue through 2032. The Company will continue discussions with the ACC, employees, the IBEW Union, and leaders of the communities related to future plans on workforce and community transition.

TEP will continue to implement cost-effective energy efficiency programs. Through future implementation plans developed in coordination with the Commission, TEP will target a 1.4% incremental energy savings over the prior year's retail sales in each year through 2026. Moreover, TEP will continue to solicit new demand response programs that are mutually beneficial to the Company and its customers.

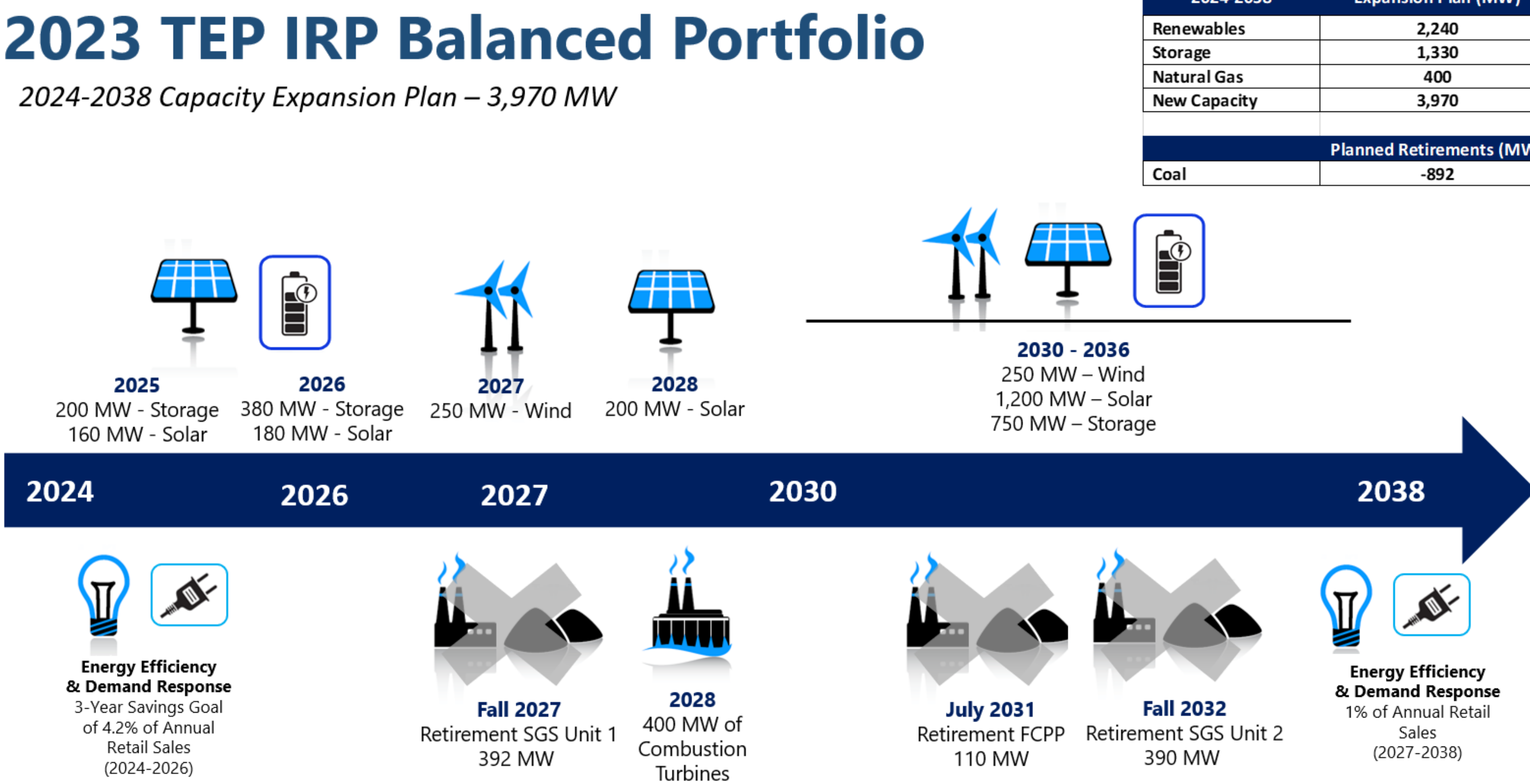
TEP plans to take a phased approach toward future participation in western regional market initiatives. While market development is a complex process, a West-wide organized market or combination of markets must allow for independent governance, inclusion of resource adequacy standards, and increasing integration of clean energy sources. This phased approach will allow for a careful weighing of costs and benefits while maintaining autonomy at the state and utility level.

The Preferred Portfolio will ultimately be defined by future All-Source Request for Proposals

As with any planning analysis, the 2023 IRP represents a snapshot in time based on known and reasonable planning assumptions. The implementation of specific actions involves complex issues surrounding operating agreements, resource procurement contracts, land leases, economic analysis, and environmental impact reviews before any final resource decisions are made.

Given the confidential nature of some of these decisions, TEP plans to communicate any major change in its anticipated resource plan with the Arizona Corporation Commission (ACC) as part of its ongoing planning activities. TEP hopes this dialog will engage the Commission on important resource planning issues while providing TEP with greater regulatory certainty with regards to future resource decisions. TEP requests that the Commission acknowledge its 2023 IRP as provided in A.A.C. R14-2-704.B. and the associated actions herein.

Figure 63. Balanced Portfolio Project Timeline



2024-2038	Expansion Plan (MW)
Renewables	2,240
Storage	1,330
Natural Gas	400
New Capacity	3,970
	Planned Retirements (MW)
Coal	-892

Note: *TEP retires 1,183 MW of fossil generation, 172 MW of solar, 80 MW of wind, and 20 MW of energy storage by 2038.*

Hydrogen - Carbon-Free Fuel Blending as a Transition Fuel to the Future

Takasago Hydrogen Park

At present, a large portion of energy production in the world relies on thermal power using natural gas. Today's natural gas power plant manufacturers are working to reduce CO_2 emissions. New modern day natural gas power plants will be able to blend hydrogen as a primary carbon-free fuel source. Today's new natural gas combustion turbines are capable of blending both natural gas and hydrogen. Mitsubishi Power has cutting-edge hydrogen combustion technologies, and its hydrogen gas turbine requires minimum modification to the existing infrastructures at the power plants. In September 2023, Mitsubishi Power announced that Takasago Hydrogen Park, the world's first integrated hydrogen validation facility, entered full-scale operation. The park is located at Mitsubishi's Takasago Machinery Works in Hyogo Prefecture in west central Japan.

Electrolysis hydrogen production recently began operation at the park, and Mitsubishi Power aims to improve product reliability through the validation of hydrogen co-firing and 100% hydrogen firing of gas turbines. The validation of hydrogen firing equipment will be done at the T-Point 2 power plant validation facility located in the utilization area, using a Mitsubishi Power combustion turbine. The hydrogen produced at Takasago Hydrogen Park will be used to validate 30% hydrogen firing. Validation of 100% hydrogen firing in the H-25 gas turbine is planned for 2024. Mitsubishi Power will leverage the Takasago Hydrogen Park to accelerate the development and actual equipment validation of hydrogen production and power generation technologies.

Cost is a challenge today, however as technology evolves, we will continue to reduce the cost of green hydrogen. Today's new natural gas technologies will provide options for companies to eventually move to a carbon-free fuel source in the future.

Source:
https://power.mhi.com/news/230920.html
https://solutions.mhi.com/sites/default/files/assets/pdf/power/hydrogen_power-handbook.pdf

H2 Demonstration with Reciprocating Engines (RICE)

WEC Energy Group and EPRI announced the successful demonstration of blending hydrogen in a natural gas generator. The project is the first hydrogen power test of a utility-scale, grid-connected reciprocating engine generator in the world. During two weeks of testing in mid-October, hydrogen and natural gas were tested in blends up to 75 percent by volume to power one of the reciprocating engine generating units that serves customers of Upper Michigan Energy Resources, a WEC Energy Group subsidiary.

Source:

https://investor.wecenergygroup.com/investors/news-releases/press-release-details/2022/WEC-Energy-Group-EPRI-complete-worlds-first-of-its-kind-hydrogen-power-test/default.aspx

List of Appendices

2023 TEP Integrated Resource Plan: Appendices

Appendix A: Load Forecast

Table A1. TEP Monthly Energy Forecast, MWh

Month	Residential	Commercial	Industrial	Mining	Other	Firm Wholesale	System Losses	Total
1/1/2024	257,868	134,818	164,753	97,112	1,441	103,651	70,739	830,383
2/1/2024	216,713	117,876	155,660	89,936	1,352	90,821	58,344	730,703
3/1/2024	208,668	129,110	169,559	95,484	1,357	79,263	64,386	747,828
4/1/2024	214,290	129,410	169,260	92,643	1,243	68,693	64,625	740,164
5/1/2024	325,566	158,455	177,197	95,135	1,193	74,694	88,052	920,292
6/1/2024	458,038	195,883	203,454	91,680	1,128	65,839	109,986	1,126,008
7/1/2024	515,839	208,168	219,928	91,487	1,172	103,056	121,577	1,261,227
8/1/2024	488,259	206,889	227,141	91,313	1,223	98,608	114,779	1,228,212
9/1/2024	398,684	187,491	209,517	92,742	1,319	88,636	101,566	1,079,955
10/1/2024	264,358	157,241	188,965	83,157	1,399	81,003	77,456	853,579
11/1/2024	207,187	128,617	163,958	91,434	1,416	93,101	61,762	747,476
12/1/2024	254,581	132,075	164,748	95,831	1,479	106,817	69,418	824,950
1/1/2025	257,345	134,043	171,783	97,032	1,462	50,877	71,256	783,799
2/1/2025	217,260	117,272	161,061	86,418	1,338	44,058	58,317	685,724
3/1/2025	209,042	128,335	175,406	95,541	1,357	42,167	64,927	716,774
4/1/2025	215,556	128,622	178,062	91,828	1,240	33,179	65,437	713,923
5/1/2025	328,148	157,587	184,892	94,945	1,192	36,219	93,700	896,682
6/1/2025	462,215	195,184	210,961	91,350	1,127	36,388	114,669	1,111,893
7/1/2025	520,238	207,457	227,800	91,467	1,169	40,043	126,931	1,215,104
8/1/2025	491,708	206,212	234,500	90,998	1,215	35,400	119,967	1,180,001
9/1/2025	401,401	187,095	216,593	92,354	1,334	30,794	106,460	1,036,030
10/1/2025	265,439	156,943	197,044	83,361	1,402	38,140	82,615	824,944
11/1/2025	207,979	128,722	171,463	90,660	1,416	45,835	66,239	712,315
12/1/2025	254,656	132,237	172,650	95,513	1,482	52,754	74,281	783,574
1/1/2026	257,319	134,143	174,529	97,122	1,462	51,105	79,237	794,917
2/1/2026	218,195	117,392	163,237	87,189	1,346	43,654	66,454	697,466
3/1/2026	209,681	128,153	177,011	95,659	1,356	41,799	76,671	730,330
4/1/2026	216,929	128,318	190,623	92,503	1,240	33,295	78,969	741,877
5/1/2026	330,705	157,122	197,905	95,060	1,192	36,692	102,857	921,534
6/1/2026	466,241	194,805	224,510	91,700	1,126	36,430	122,815	1,137,626
7/1/2026	524,439	206,966	240,734	91,702	1,172	40,271	131,479	1,236,762
8/1/2026	494,982	205,664	248,508	91,008	1,212	35,403	128,228	1,205,004
9/1/2026	403,886	186,721	230,364	92,367	1,334	30,046	109,617	1,054,336
10/1/2026	266,211	156,550	209,975	82,738	1,401	38,508	90,459	845,842
11/1/2026	208,290	128,611	184,854	90,864	1,416	45,741	72,208	731,984
12/1/2026	254,163	132,082	185,392	95,630	1,483	52,971	79,050	800,771
1/1/2027	257,029	133,974	186,650	97,113	1,455	51,326	87,560	815,108
2/1/2027	218,977	117,270	175,438	86,836	1,345	43,464	73,309	716,639
3/1/2027	210,235	127,782	188,150	95,585	1,357	41,328	81,240	745,677
4/1/2027	218,242	127,889	191,083	92,348	1,241	33,274	83,147	747,225
5/1/2027	333,182	156,598	198,118	95,071	1,192	37,283	106,756	928,200
6/1/2027	470,261	194,428	224,987	91,601	1,127	36,414	127,070	1,145,888
7/1/2027	528,760	206,547	252,738	91,577	1,171	40,490	138,773	1,260,056
8/1/2027	498,686	205,286	260,740	91,129	1,217	35,401	130,597	1,223,057
9/1/2027	407,062	186,592	242,660	92,510	1,329	29,329	113,829	1,073,310
10/1/2027	267,793	156,458	221,703	84,714	1,401	38,689	96,898	867,656
11/1/2027	209,364	128,811	197,018	92,891	1,416	45,835	79,536	754,872
12/1/2027	254,290	132,207	197,175	97,665	1,482	53,077	81,264	817,159
1/1/2028	257,271	134,075	199,366	100,154	1,460	50,895	91,285	834,505
2/1/2028	220,355	117,466	189,521	92,733	1,343	47,378	78,440	747,235
3/1/2028	211,545	127,804	201,828	98,584	1,357	42,813	86,334	770,264
4/1/2028	220,527	127,939	203,787	96,092	1,240	33,201	88,565	771,352
5/1/2028	336,900	156,632	210,347	99,032	1,192	34,475	113,185	951,764
6/1/2028	475,512	194,649	237,601	95,440	1,127	36,178	130,718	1,171,224
7/1/2028	534,200	206,696	253,577	96,492	1,170	39,458	144,557	1,276,151
8/1/2028	503,143	205,421	261,506	95,818	1,215	35,368	136,773	1,239,244
9/1/2028	410,532	186,928	243,276	97,359	1,332	33,024	120,168	1,092,619
10/1/2028	269,518	156,842	222,516	87,898	1,401	37,008	101,493	876,676
11/1/2028	210,601	129,521	197,599	96,483	1,416	45,959	84,763	766,342
12/1/2028	254,552	132,839	197,857	101,559	1,482	51,781	89,429	829,499
1/1/2029	257,764	134,724	200,045	104,256	1,459	50,409	91,771	840,428
2/1/2029	222,102	118,216	188,625	93,308	1,345	45,414	77,308	746,317
3/1/2029	213,214	128,340	200,365	102,581	1,356	42,520	86,756	775,131
4/1/2029	223,159	128,432	204,429	100,298	1,241	33,193	89,918	780,670
5/1/2029	340,905	157,015	211,148	103,254	1,192	35,100	114,042	962,657
6/1/2029	481,047	195,118	238,522	99,442	1,127	36,214	133,843	1,185,312
7/1/2029	539,908	207,044	254,449	99,458	1,171	39,652	145,447	1,287,129
8/1/2029	507,978	205,762	262,529	98,794	1,214	35,370	137,909	1,249,555
9/1/2029	414,428	187,478	244,198	100,545	1,332	32,298	121,313	1,101,591

Table A1. TEP Monthly Energy Forecast, MWh

Month	Residential	Commercial	Industrial	Mining	Other	Firm Wholesale	System Losses	Total
10/1/2029	271,591	157,424	223,292	89,580	1,401	37,219	101,361	881,867
11/1/2029	211,978	130,380	198,351	98,526	1,416	46,125	84,853	771,630
12/1/2029	255,217	133,676	198,565	103,804	1,482	52,217	90,176	835,137
1/1/2030	258,450	135,500	200,620	105,467	1,458	50,565	96,001	848,061
2/1/2030	223,878	119,061	189,168	94,357	1,344	44,713	81,394	753,916
3/1/2030	214,992	128,971	200,987	103,711	1,357	42,327	90,353	782,697
4/1/2030	225,862	128,954	205,074	100,247	1,241	33,135	94,535	789,048
5/1/2030	344,912	157,414	211,728	103,251	1,192	35,735	118,650	972,882
6/1/2030	486,521	195,639	239,218	99,411	1,127	36,302	136,626	1,194,844
7/1/2030	545,581	207,447	255,166	99,429	1,171	39,818	148,370	1,296,983
8/1/2030	512,883	206,134	263,218	98,816	1,215	35,412	139,563	1,257,240
9/1/2030	418,477	188,057	244,835	100,564	1,331	31,526	125,087	1,109,878
10/1/2030	273,843	158,040	223,892	93,408	1,401	37,649	104,116	892,349
11/1/2030	213,488	131,321	198,895	102,925	1,416	46,058	89,209	783,312
12/1/2030	255,912	134,635	199,147	108,428	1,482	52,467	92,548	844,619
1/1/2031	259,848	136,613	201,389	117,039	1,459	50,877	101,903	869,128
2/1/2031	226,142	120,251	189,855	104,658	1,344	44,058	87,662	773,969
3/1/2031	217,136	129,894	201,753	115,001	1,356	42,167	95,974	803,281
4/1/2031	228,851	129,923	205,838	111,194	1,241	33,179	100,705	810,931
5/1/2031	349,171	158,242	212,483	114,594	1,192	36,219	125,146	997,048
6/1/2031	492,294	196,519	240,038	110,431	1,127	36,388	142,267	1,219,064
7/1/2031	551,609	208,198	256,003	110,566	1,171	40,043	155,009	1,322,599
8/1/2031	518,112	206,844	264,060	109,612	1,215	35,400	147,987	1,283,230
9/1/2031	422,683	189,029	245,573	111,765	1,332	30,794	130,797	1,131,972
10/1/2031	276,084	159,024	224,636	105,736	1,401	38,140	110,788	915,809
11/1/2031	214,806	132,635	199,538	117,340	1,416	45,835	96,088	807,659
12/1/2031	256,327	135,931	199,827	123,649	1,482	52,754	98,335	868,306
1/1/2032	261,665	138,209	202,179	132,730	1,458	51,105	107,014	894,361
2/1/2032	228,846	121,876	192,142	122,868	1,344	45,247	93,840	806,163
3/1/2032	219,735	131,202	204,759	130,295	1,356	41,328	103,155	831,830
4/1/2032	232,198	131,162	206,617	137,893	1,241	33,274	107,738	850,123
5/1/2032	353,577	159,154	213,279	142,209	1,192	37,283	133,873	1,040,567
6/1/2032	497,837	197,395	240,918	137,270	1,127	36,414	153,073	1,264,033
7/1/2032	557,091	208,797	256,861	168,186	1,171	40,490	166,015	1,398,611
8/1/2032	522,761	207,302	264,944	165,600	1,215	35,401	157,319	1,354,542
9/1/2032	426,378	189,679	246,365	169,863	1,332	29,329	142,441	1,205,385
10/1/2032	277,798	159,758	225,366	145,857	1,401	38,689	118,725	967,594
11/1/2032	215,448	133,718	200,210	164,378	1,416	45,835	103,743	864,749
12/1/2032	255,921	136,981	200,503	173,216	1,482	53,077	105,671	926,851
1/1/2033	263,781	139,883	203,017	176,368	1,458	50,895	116,569	951,972
2/1/2033	231,787	123,581	191,364	157,904	1,344	45,919	101,464	853,364
3/1/2033	222,534	132,622	203,407	172,488	1,356	43,068	111,825	887,302
4/1/2033	235,760	132,520	207,446	167,515	1,241	33,478	117,487	895,446
5/1/2033	358,246	160,312	214,074	172,776	1,192	33,713	143,568	1,083,881
6/1/2033	503,693	198,584	241,780	165,716	1,127	36,161	161,681	1,308,743
7/1/2033	562,771	209,702	257,707	165,868	1,171	39,264	175,242	1,411,725
8/1/2033	527,250	207,879	265,772	164,376	1,215	35,387	168,305	1,370,183
9/1/2033	429,520	190,459	247,102	169,338	1,332	33,707	151,220	1,222,678
10/1/2033	278,782	160,542	226,068	145,711	1,401	36,727	125,679	974,910
11/1/2033	215,304	134,906	200,845	163,119	1,416	45,851	108,789	870,229
12/1/2033	254,690	138,153	201,153	173,000	1,482	51,206	112,792	932,477
1/1/2034	266,250	142,004	203,931	176,369	1,459	50,647	119,466	960,125
2/1/2034	234,989	125,722	192,205	157,918	1,344	45,807	102,313	860,299
3/1/2034	225,572	134,433	204,315	172,490	1,356	42,813	114,317	895,296
4/1/2034	239,522	134,288	208,326	167,514	1,241	33,201	120,973	905,066
5/1/2034	363,082	161,779	214,933	172,775	1,192	34,475	146,645	1,094,881
6/1/2034	509,689	199,956	242,689	165,717	1,127	36,178	164,464	1,319,821
7/1/2034	568,627	210,556	258,586	165,871	1,171	39,458	177,614	1,421,883
8/1/2034	532,035	208,614	266,638	164,366	1,215	35,368	171,994	1,380,231
9/1/2034	432,981	191,436	247,869	169,333	1,332	33,024	153,817	1,229,791
10/1/2034	279,952	161,490	226,802	145,704	1,401	37,008	127,734	980,091
11/1/2034	215,109	136,269	201,512	163,108	1,416	45,959	110,807	874,180
12/1/2034	253,213	139,423	201,829	172,997	1,482	51,781	112,621	933,346
1/1/2035	269,359	144,442	204,891	176,370	1,458	50,409	121,293	968,222
2/1/2035	238,766	128,053	193,092	157,923	1,344	45,414	104,536	869,128
3/1/2035	229,206	136,236	205,256	172,490	1,356	42,520	116,513	903,578
4/1/2035	243,859	135,947	209,232	167,522	1,241	33,193	122,932	913,926
5/1/2035	368,424	162,988	215,806	172,777	1,192	35,100	149,084	1,105,370
6/1/2035	516,091	201,060	243,599	165,721	1,127	36,214	167,612	1,331,425

Table A1. TEP Monthly Energy Forecast, MWh

Month	Residential	Commercial	Industrial	Mining	Other	Firm Wholesale	System Losses	Total
7/1/2035	574,814	211,549	259,443	165,871	1,171	39,652	179,295	1,431,796
8/1/2035	537,136	209,469	267,469	164,370	1,215	35,370	172,409	1,387,438
9/1/2035	436,738	192,380	248,602	169,337	1,332	32,298	155,174	1,235,860
10/1/2035	281,384	162,490	227,491	145,699	1,401	37,219	128,472	984,156
11/1/2035	215,065	137,624	202,149	163,116	1,416	46,125	111,515	877,012
12/1/2035	251,674	140,725	202,459	173,000	1,482	52,217	114,572	936,128
1/1/2036	273,198	147,173	205,871	176,369	1,458	50,565	123,626	978,260
2/1/2036	243,070	130,681	195,558	163,555	1,344	46,027	109,811	890,045
3/1/2036	233,281	138,489	208,415	172,489	1,356	42,167	119,239	915,435
4/1/2036	248,571	138,031	210,174	167,517	1,241	33,179	126,173	924,886
5/1/2036	374,108	164,728	216,708	172,776	1,192	36,219	151,615	1,117,345
6/1/2036	522,810	202,636	244,535	165,718	1,127	36,388	171,354	1,344,568
7/1/2036	581,315	212,692	260,329	165,870	1,171	40,043	182,816	1,444,235
8/1/2036	542,550	210,260	268,326	164,371	1,215	35,400	174,619	1,396,740
9/1/2036	440,750	193,413	249,367	169,336	1,332	30,794	158,453	1,243,444
10/1/2036	282,928	163,448	228,224	145,704	1,401	38,140	131,421	991,267
11/1/2036	214,918	138,995	202,830	163,114	1,416	45,835	115,689	882,798
12/1/2036	249,884	141,996	203,148	172,999	1,482	52,754	115,335	937,597
1/1/2037	277,776	150,178	206,970	176,369	1,458	51,105	123,057	986,913
2/1/2037	247,947	133,634	195,029	157,919	1,344	43,654	109,298	888,824
3/1/2037	237,740	141,065	207,283	172,490	1,356	41,799	119,257	920,990
4/1/2037	253,495	140,562	211,205	167,518	1,241	33,295	126,490	933,805
5/1/2037	379,812	166,976	217,693	172,776	1,192	36,692	153,100	1,128,241
6/1/2037	529,457	204,725	245,540	165,719	1,127	36,430	170,624	1,353,622
7/1/2037	587,740	214,364	261,269	165,871	1,171	40,271	181,815	1,452,500
8/1/2037	547,855	211,737	269,225	164,369	1,215	35,403	176,078	1,405,881
9/1/2037	444,618	194,938	250,165	169,335	1,332	30,046	158,193	1,248,626
10/1/2037	284,358	165,025	228,984	145,702	1,401	38,508	133,857	997,835
11/1/2037	214,695	140,829	203,536	163,113	1,416	45,741	113,817	883,148
12/1/2037	247,990	143,632	203,850	172,998	1,482	52,971	113,999	936,923
1/1/2038	283,265	153,896	208,126	176,369	1,458	51,326	124,622	999,062
2/1/2038	253,642	137,224	196,104	157,919	1,344	43,464	107,921	897,618
3/1/2038	242,991	144,311	208,387	172,490	1,356	41,328	121,010	931,872
4/1/2038	259,273	143,585	212,269	167,519	1,241	33,274	127,843	945,003
5/1/2038	386,317	169,605	218,696	172,776	1,192	37,283	154,599	1,140,468
6/1/2038	536,620	207,135	246,544	165,720	1,127	36,414	173,047	1,366,606
7/1/2038	594,282	216,250	262,186	165,871	1,171	40,490	183,498	1,463,747
8/1/2038	553,030	213,294	270,084	164,370	1,215	35,401	174,987	1,412,381
9/1/2038	448,224	196,529	250,922	169,336	1,332	29,329	159,313	1,254,984
10/1/2038	285,416	166,464	229,700	145,702	1,401	38,689	134,118	1,001,492
11/1/2038	213,990	142,485	204,210	163,115	1,416	45,835	114,836	885,887
12/1/2038	245,381	145,033	204,509	172,999	1,482	53,077	110,952	933,434

Table A2. TEP Monthly Coincident Peak Demand Forecast, MW

Month	Retail	Firm Wholesale	EHV Losses	Total
1/1/2024	1,290	180	43	1,513
2/1/2024	1,198	179	36	1,413
3/1/2024	1,261	167	41	1,469
4/1/2024	1,398	155	46	1,599
5/1/2024	1,758	155	65	1,977
6/1/2024	2,337	164	87	2,588
7/1/2024	2,382	168	91	2,640
8/1/2024	2,297	154	84	2,535
9/1/2024	2,075	155	76	2,305
10/1/2024	1,639	157	57	1,854
11/1/2024	1,202	172	38	1,412
12/1/2024	1,357	180	45	1,582
1/1/2025	1,292	95	43	1,430
2/1/2025	1,227	94	37	1,358
3/1/2025	1,270	82	41	1,393
4/1/2025	1,408	70	46	1,523
5/1/2025	1,756	70	64	1,890
6/1/2025	2,330	79	87	2,496
7/1/2025	2,428	83	92	2,603
8/1/2025	2,333	69	85	2,487
9/1/2025	2,103	70	77	2,250
10/1/2025	1,640	72	57	1,769
11/1/2025	1,192	87	38	1,316
12/1/2025	1,370	95	45	1,510
1/1/2026	1,318	95	44	1,457
2/1/2026	1,245	94	38	1,377
3/1/2026	1,287	82	42	1,411
4/1/2026	1,434	70	47	1,551
5/1/2026	1,800	70	66	1,936
6/1/2026	2,379	79	89	2,546
7/1/2026	2,457	83	93	2,634
8/1/2026	2,420	69	88	2,577
9/1/2026	2,132	70	78	2,280
10/1/2026	1,667	72	58	1,798
11/1/2026	1,209	87	38	1,334
12/1/2026	1,422	95	47	1,564
1/1/2027	1,336	95	44	1,475
2/1/2027	1,262	94	38	1,394
3/1/2027	1,309	82	42	1,433
4/1/2027	1,439	70	47	1,556
5/1/2027	1,822	70	67	1,959
6/1/2027	2,424	79	90	2,593
7/1/2027	2,493	83	95	2,671
8/1/2027	2,461	69	90	2,620
9/1/2027	2,162	70	79	2,311
10/1/2027	1,722	72	60	1,855
11/1/2027	1,232	87	39	1,358
12/1/2027	1,436	95	47	1,578
1/1/2028	1,334	95	44	1,473
2/1/2028	1,254	94	38	1,386
3/1/2028	1,315	82	43	1,439
4/1/2028	1,422	70	46	1,538
5/1/2028	1,805	70	66	1,941
6/1/2028	2,420	79	90	2,589
7/1/2028	2,503	83	95	2,681
8/1/2028	2,443	69	89	2,601
9/1/2028	2,180	70	80	2,330
10/1/2028	1,730	72	60	1,862
11/1/2028	1,241	87	39	1,367
12/1/2028	1,438	95	47	1,580
1/1/2029	1,349	95	45	1,488

Table A2. TEP Monthly Coincident Peak Demand Forecast, MW

Month	Retail	Firm Wholesale	EHV Losses	Total
2/1/2029	1,258	94	38	1,391
3/1/2029	1,331	82	43	1,456
4/1/2029	1,484	70	48	1,602
5/1/2029	1,857	70	68	1,995
6/1/2029	2,511	79	94	2,684
7/1/2029	2,564	83	97	2,744
8/1/2029	2,455	69	90	2,614
9/1/2029	2,207	70	81	2,358
10/1/2029	1,763	72	61	1,897
11/1/2029	1,258	87	40	1,384
12/1/2029	1,434	95	47	1,576
1/1/2030	1,393	95	46	1,534
2/1/2030	1,256	94	38	1,388
3/1/2030	1,336	82	43	1,461
4/1/2030	1,486	70	48	1,604
5/1/2030	1,879	70	69	2,018
6/1/2030	2,524	79	94	2,697
7/1/2030	2,573	83	98	2,754
8/1/2030	2,485	69	91	2,645
9/1/2030	2,242	70	82	2,394
10/1/2030	1,778	72	62	1,912
11/1/2030	1,265	87	40	1,392
12/1/2030	1,458	95	48	1,601
1/1/2031	1,349	95	45	1,488
2/1/2031	1,280	94	39	1,413
3/1/2031	1,337	82	43	1,462
4/1/2031	1,492	70	49	1,611
5/1/2031	1,859	70	68	1,997
6/1/2031	2,493	79	93	2,665
7/1/2031	2,590	83	98	2,771
8/1/2031	2,495	69	91	2,655
9/1/2031	2,249	70	82	2,401
10/1/2031	1,771	72	61	1,905
11/1/2031	1,257	87	40	1,383
12/1/2031	1,470	95	48	1,613
1/1/2032	1,360	95	45	1,500
2/1/2032	1,286	94	39	1,419
3/1/2032	1,345	82	44	1,471
4/1/2032	1,485	70	48	1,603
5/1/2032	1,875	70	69	2,014
6/1/2032	2,497	79	93	2,669
7/1/2032	2,606	83	99	2,788
8/1/2032	2,571	69	94	2,734
9/1/2032	2,277	70	83	2,430
10/1/2032	1,829	72	63	1,965
11/1/2032	1,301	87	41	1,429
12/1/2032	1,531	95	50	1,676
1/1/2033	1,451	95	48	1,594
2/1/2033	1,353	94	41	1,488
3/1/2033	1,426	82	46	1,554
4/1/2033	1,543	70	50	1,664
5/1/2033	1,934	70	71	2,075
6/1/2033	2,576	79	96	2,751
7/1/2033	2,620	83	100	2,803
8/1/2033	2,599	69	95	2,763
9/1/2033	2,342	70	86	2,498
10/1/2033	1,868	72	65	2,005
11/1/2033	1,325	87	42	1,454
12/1/2033	1,554	95	51	1,700
1/1/2034	1,412	95	47	1,554
2/1/2034	1,330	94	40	1,464

Table A2. TEP Monthly Coincident Peak Demand Forecast, MW

Month	Retail	Firm Wholesale	EHV Losses	Total
3/1/2034	1,406	82	46	1,533
4/1/2034	1,529	70	50	1,648
5/1/2034	1,913	70	70	2,053
6/1/2034	2,555	79	95	2,729
7/1/2034	2,637	83	100	2,820
8/1/2034	2,576	69	94	2,739
9/1/2034	2,310	70	85	2,464
10/1/2034	1,853	72	64	1,990
11/1/2034	1,321	87	42	1,450
12/1/2034	1,536	95	51	1,682
1/1/2035	1,422	95	47	1,564
2/1/2035	1,327	94	40	1,462
3/1/2035	1,405	82	46	1,532
4/1/2035	1,556	70	51	1,676
5/1/2035	1,933	70	71	2,074
6/1/2035	2,597	79	97	2,772
7/1/2035	2,650	83	101	2,834
8/1/2035	2,541	69	93	2,703
9/1/2035	2,300	70	84	2,454
10/1/2035	1,852	72	64	1,989
11/1/2035	1,325	87	42	1,454
12/1/2035	1,514	95	50	1,659
1/1/2036	1,434	95	48	1,576
2/1/2036	1,313	94	40	1,447
3/1/2036	1,422	82	46	1,550
4/1/2036	1,562	70	51	1,683
5/1/2036	1,926	70	71	2,066
6/1/2036	2,575	79	96	2,750
7/1/2036	2,665	83	101	2,849
8/1/2036	2,576	69	94	2,739
9/1/2036	2,330	70	85	2,485
10/1/2036	1,845	72	64	1,981
11/1/2036	1,301	87	41	1,429
12/1/2036	1,530	95	50	1,675
1/1/2037	1,429	95	47	1,572
2/1/2037	1,356	94	41	1,491
3/1/2037	1,436	82	47	1,564
4/1/2037	1,586	70	52	1,707
5/1/2037	1,957	70	72	2,099
6/1/2037	2,609	79	97	2,784
7/1/2037	2,680	83	102	2,865
8/1/2037	2,649	69	97	2,815
9/1/2037	2,352	70	86	2,507
10/1/2037	1,870	72	65	2,008
11/1/2037	1,319	87	42	1,448
12/1/2037	1,565	95	52	1,712
1/1/2038	1,447	95	48	1,590
2/1/2038	1,368	94	42	1,504
3/1/2038	1,438	82	47	1,567
4/1/2038	1,572	70	51	1,693
5/1/2038	1,966	70	72	2,109
6/1/2038	2,617	79	98	2,793
7/1/2038	2,695	83	102	2,881
8/1/2038	2,651	69	97	2,817
9/1/2038	2,358	70	86	2,514
10/1/2038	1,898	72	66	2,036
11/1/2038	1,324	87	42	1,453
12/1/2038	1,567	95	52	1,713

Appendix B: Existing Resources

Existing Resources

This section provides an overview of TEP's existing thermal generation, renewable generation, energy storage, and transmission resources. It also provides details on each existing station's ownership structure, fuel supply, environmental controls, historical emissions, and a brief future outlook. For the renewable generation and storage resources, this section provides capacity and technology information as well as details on the construction of the facilities. Information on TEP's existing transmission system is also included below.

TEP's Existing Resource Portfolio

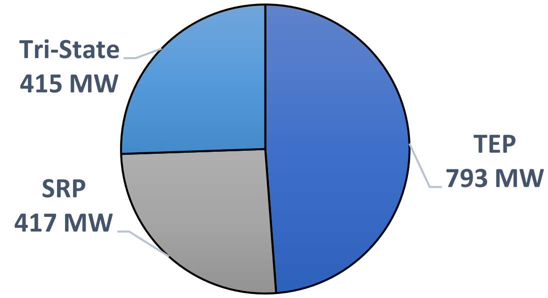
TEP's existing thermal resource capacity is 2,718 MW. In addition, the Company may utilize the wholesale market for firm capacity PPAs to meet its summer peak obligations. **Table 1** provides a summary of TEP's existing thermal resources.

Table 1. TEP Existing Thermal Resources

Generating Station	Unit	Fuel Type	Full Net Nominal Capability (MW)	Commercial Operation Year	Operating Agent	TEP's Ownership Share (%)	TEP Planning Capacity (MW)
Springerville	1	Coal	387	1985	TEP	100	387
Springerville	2	Coal	406	1990	TEP	100	406
Four Corners	4	Coal	785	1969	APS	7	55
Four Corners	5	Coal	785	1970	APS	7	55
Sundt Steam	3 & 4	Natural Gas	260	1962-1967	TEP	100	260
Sundt RICE	1- 10	Natural Gas	188	2019 -2020	TEP	100	188
Luna Energy Facility		Natural Gas	555	2006	PNM	33.3	185
Gila River	2	Natural Gas	550	2003	SRP	100	550
Gila River	3	Natural Gas	550	2003	SRP	75	413
Combustion Turbines		Natural Gas/Oil	219	1972-2001	TEP	100	219
Total Planning Capacity							**2,718**

Springerville Generating Station

Springerville Generating Station ("Springerville") is a four-unit, coal-fired steam electric generating station located 15 miles northeast of Springerville, Arizona. TEP operates all four units. Units 1 and 2 are owned by TEP. Tri-State Generation and Transmission owns Unit 3, and Salt River Project owns Unit 4.



Springerville Ownership Structure

Units	Capacity (MW)	In-Service Date	Planned Retirement
Unit 1	387	1985	2027
Unit 2	406	1990	2032
Unit 3	415	2006	Not Planned
Unit 4	417	2009	Not Planned

Springerville Participation Agreement

Expires January 1, 2078

Springerville Coal Supply

Agreement signed in 2023 with Peabody Energy sourced from El Segundo / Lee Ranch, expires December 31, 2031.

Springerville Pollution Controls:

Unit	SO_2	NOx	PM	Hg
1	SDA	LNB SOFA	FF	**ACI,** $CaBR_2$
2	SDA	LNB SOFA	FF	**ACI,** $CaBR_2$

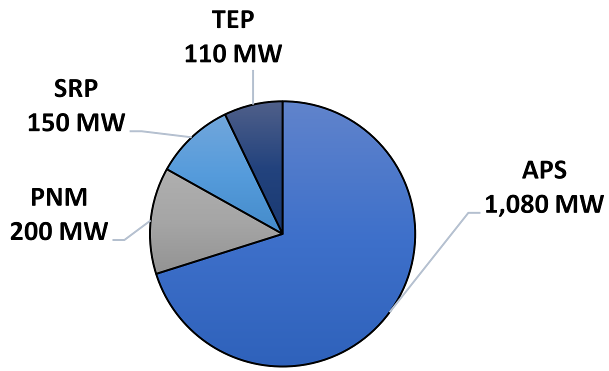
SDA – Spray Dry Absorber
FF – Fabric Filter (Baghouse)
LNB SOFA – Low NOx Burners – Separated Overfired Air
SCR – Selective Catalytic Reduction
$CaBR_2$ – Calcium Bromide (Added to Coal)
ACI – Activated Carbon Injection

Springerville Operational Outlook

Unit 1 has transitioned to seasonal operations as of 2023, and Unit 2 is planned to transition in 2024. Unit 1 is scheduled to retire at the end of 2027. Unit 2 is scheduled to transition to summer only operation in 2030 and retire after the summer of 2032.

Four Corners Power Plant

Four Corners Power Plant ("Four Corners") is a two-unit, coal-fired baseload steam electric generating station located 18 miles west of Farmington, New Mexico. APS is the operating agent for both units 4 and 5. Plant participants include TEP, APS, Salt River Project (SRP), and PNM.



Four Corners Participation Agreement

Co-tenancy agreement expires July 2041.

Four Corners Coal Supply

Agreement with Navajo Transitional Energy Company sourced from the Navajo Mine expires July 2031.

Four Corners Pollution Controls

Unit	SO_2	NOx	PM	Hg
4	FGD	SCR	FF	FGD, FF, $CaBR_2$
5	FGD	SCR	FF	FGD, FF, $CaBR_2$

FGD – Flue Gas Desulfurization-Wet
FF – Fabric Filter (Baghouse)
SCR – Selective Catalytic Reduction
$CaBR_2$ – Calcium Bromide (Added to Coal)

Four Corners Ownership Structure

Units(1)	Capacity (MW)	In-Service Date	**Planned Retirement**
Unit 4	770	1969	2031
Unit 5	770	1970	2031

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

Four Corners Outlook

Both units are scheduled to retire at the end of July 2031, coinciding with the expiration of current coal supply contract in 2031.

H. Wilson Sundt Generating Station

The H. Wilson Sundt Generating Station in Tucson, Arizona is comprised of 10 natural gas fired Reciprocating Internal Combustion Engine ("RICE") generators rated at 18.8 MW each and two gas fired steam generators (Sundt Units 3 and 4) rated at 104 MW and 156 MW respectively. The plant is owned and operated by TEP.

The RICE generators replaced two 1950s vintage steam generators (Sundt Units 1 and 2) and provide fast, flexible operations to support the expansion of TEP renewable resources. Other benefits of the RICE units:

- **Improved efficiency:** RICE units use less natural gas to generate the same amount of energy as a conventional natural gas-fired generator. They are 40 percent more efficient than the units they replaced.
- **Lower emissions**: Transitioning to the RICE generators reduce local NOx emissions by 69 percent, contributing to cleaner air.

Sundt Fuel Supply

The primary fuel at Sundt Generating Station is natural gas. The station is supplied by gas purchased on the spot market and through gas hedging agreements consistent with the Company's Hedging Policy. Natural gas is delivered through the Kinder Morgan natural gas pipeline located adjacent to the Sundt property.

Units	Capacity (MW)	In-Service Date	Planned Retirement
RICE Units 1-5	94	2020	Not Planned
RICE Units 6-10	94	2019	Not Planned
Steam Unit 3	104	1962	2032
Steam Unit 4	156	1967	Not Planned

Sundt Pollution Controls

Unit	SO_2	NOx	PM
RICE Units 1-5	NA	SCR	NA
RICE Units 6-10	NA	SCR	NA
Steam Unit 3	NA	NA	NA
Steam Unit 4	NA	LNB SOFA	NA

SCR – Selective Catalytic Reduction
LNB SOFA – Low NOx Burners – Separated Overfire Air
NA – Not Applicable

Sundt Outlook

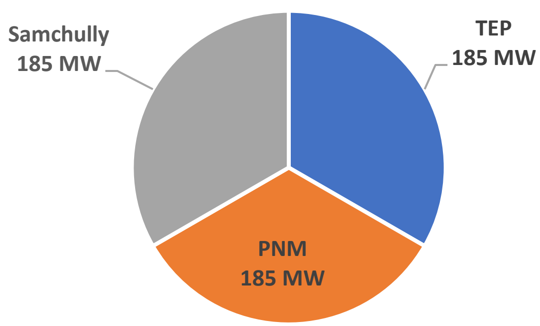
In 2015, Sundt Unit 4 permanently eliminated the use of coal to comply with Regional Haze requirements. Historically low natural gas prices have resulted in higher utilization of both the Sundt and RICE units.

Luna Energy Facility

Luna Energy Facility ("Luna") is a 555 MW natural gas-fired power plant consisting of a single 2 on 1 combined cycle power block. The power block utilizes two GE 7FA gas turbines, two heat recovery steam generators (HRSG), and a GE D11 steam turbine. The facility is located three miles north of the town of Deming, New Mexico.

Luna Energy Facility Ownership

Luna ownership shares are divided by one-third PNM, one-third TEP and one-third Samchully Co. Ltd. PNM is the plant operator.



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 is a natural gas-fired combined cycle combustion turbine with 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 SO_2 and NO_x, and the facility must comply with the Acid Rain program limits for SO_2 and NO_x.

Unit	SO_2	NOx	PM	Hg
1	NA	LNB, SCR	NA	NA
2	NA	LNB, SCR	NA	NA

LNB - Low NOx Burners
SCR – Selective Catalytic Reduction
NA – Not Applicable

Luna Energy Facility Outlook

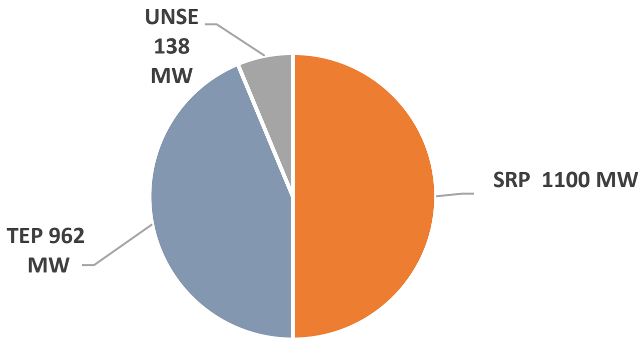
Luna's high efficiency along with low natural gas prices make it a low-cost resource to replace the energy and capacity of TEP retiring coal plants. In addition, Luna's fast ramping capabilities support the integration of renewables.

Gila River Generating Station

Gila River Generating Station ("Gila River") is a 2,200 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.



Units	Capacity (MW)	Entered Service	Planned Retirement
Power Block 1	550	2006	Not Planned
Power Block 2	550	2006	Not Planned
Power Block 3	550	2006	Not Planned
Power Block 4	550	2006	Not Planned

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.

Gila River Pollution Controls:

Block	SO_2	NOx	PM	Hg
1	NA	SCR	NA	NA
2	NA	SCR	NA	NA
3	NA	SCR	NA	NA
4	NA	SCR	NA	NA

SCR – Selective Catalytic Reduction
NA – Not Applicable

Gila River Outlook

Low natural gas prices make Gila River Blocks 2 and 3 some of the lowest cost generation assets for both TEP and UNSE. Gila River's fast ramping capabilities, along with its real-time integration into TEP's Balancing Authority, provide both TEP and UNSE with an ideal resource to support the integration of future renewables.

Local Area Combustion Turbines

The Company owns 219 MW of gas or oil-fired combustion turbines for peaking capacity located in or around Tucson. This capacity is comprised of 7 units at three locations detailed in the table below.

Ownership

The combustion turbines are 100 percent owned by TEP.

Units	Capacity (MW)	Entered Service	Planned Retirement
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	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

Plant retirement dates will be determined in subsequent planning studies. Firm retirement will be dependent on the acquisition of replacement capacity as needed. In addition, the Sundt combustion turbines provide black start capability to the Bulk Electric System. An alternative black start resource would be needed before retiring these units.

Existing Renewable Resources

In compliance with the Arizona Renewable Energy Standard ("RES"), the Company had an initial target of serving 15% of its retail load with renewable energy by 2025. TEP's renewable deployment has far exceeded that requirement, further demonstrating its commitment to clean energy. Over the last several years, TEP has constructed or entered into Purchased Power Agreements ("PPA") for solar and wind resources to provide renewable energy for its service territory. In 2023, TEP expects to serve 32% of its retail sales with renewable resources. **Table 2** provides TEP's existing solar and wind renewable resources.

Facilities Located at the University of Arizona Tech Park

TEP's Existing Solar and Wind Renewable Resources

Project Name	Owned or PPA	Location	Operator	Capacity MW_{AC}
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
Borderlands Wind	PPA	Catron, NM	NextEra	99
Cogenera	PPA	Tucson, AZ	SunPower	1.1
E.ON UASTP	Owned	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	4.5
Springerville	Owned	Springerville, AZ	TEP	5.3
TEP Rooftop	Owned	Tucson, AZ	TEP	0.04
Valencia Solar	PPA	Tucson, AZ	Areva	9.9
White Mountain	Owned	Springerville, AZ	TEP	8.5
Wilmot Solar	PPA	Tucson, AZ	NextEra	100

Notes: PPA – Purchased Power Agreement - Energy is purchased from a third-party provider

TEP's Energy Storage Projects

For large utilities, a primary advantage of a BESS is its ability to rapidly change power output levels, much faster than the proportional governor response rate of any conventional thermal generation system. This naturally leads to the use cases of a BESS being centered on short term balancing-type activities. An additional strength is that operating costs of a BESS are generally fixed and independent of usage. In contrast, gas turbine systems have a limited number of start and stop cycles and therefore have an appreciable cost to activate. These constraints can impede their ability to be online when needed.

Existing Resources

TEP's first two battery storage systems are 10 MW/2.5 MWh facilities, both Lithium-Ion and commissioned during the early months of 2017. In general, the batteries are used several times a month to respond to frequency deviations and support the greater reliability of the Western Interconnection. Additionally, the balancing of the grid occasionally requires manual dispatch of these systems. Both Facilities are regularly manually dispatched to ensure reliable operation in both power and energy at critical times.

In 2021, TEP commissioned the Wilmot Battery, a 30 MW/ 60 MWh Li-Ion battery coupled with the Wilmot Solar facility. The solar field charges the battery during peak solar times and the battery is dispatched over peak load times, allowing TEP to use midday solar to meet customers' needs in the late afternoon and evening. The BESS system can also be dispatching manually in support of grid reliability.

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
Roadrunner Reserve	Owned	Tucson, AZ	TEP	200/800

10 MW Battery Energy Storage System at DeMoss Petrie

Planned Resources

TEP recently announced plans for the new Roadrunner Reserve, which came out of the 2022 All-Source RFP. TEP will own and operate the 200 MW/800 MWh facility, which is scheduled to be in service in the summer of 2025. The new system will use lithium iron phosphate battery units, a newer technology that offers longer life and safer operation than other types of battery systems. TEP expects to charge the grid-connected battery in the morning and early afternoon, when solar resources are most productive, then deliver stored energy later in the day when customers' energy use is typically highest. Roadrunner Reserve will help TEP make better use of wind and solar resources by "shifting" their output to periods of greatest need.

New Projects since the 2020 IRP

Oso Grande
The 250 MW Oso Grande Wind Project, located near Roswell, New Mexico is owned and operated by TEP. It generates enough energy to serve the annual electric needs of about 100,000 homes.

Raptor Ridge
This efficient 12.5 MW Raptor Ridge solar system near Interstate 10 and Valencia Road can produce enough power to meet the annual electric needs of about 2,500 homes. It provides power for homeowners and renters participating in TEP's GoSolar Home program.

Wilmot Energy Center
The Wilmot Energy Center includes a 100 MW solar array and a 30 MW battery energy storage system southeast of Tucson International Airport. It is owned and operated by NextEra.

Borderlands Wind
The 99 MW Borderlands Wind Project, located about 100 miles south of Gallup, New Mexico, is owned by NextEra. It includes 34 turbines that produce enough power to serve about 26,000 homes every year.

TEP's Transmission System

Transmission resources are a key element in TEP's resource portfolio. Adequate transmission capacity must exist to meet TEP's existing and future load obligations. TEP's resource planning and transmission planning groups coordinate their planning efforts to ensure consistency in development of its long-term planning strategy. On a statewide basis, TEP participates in the ACC's 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 Arizona in a reliable manner (see Appendix J).

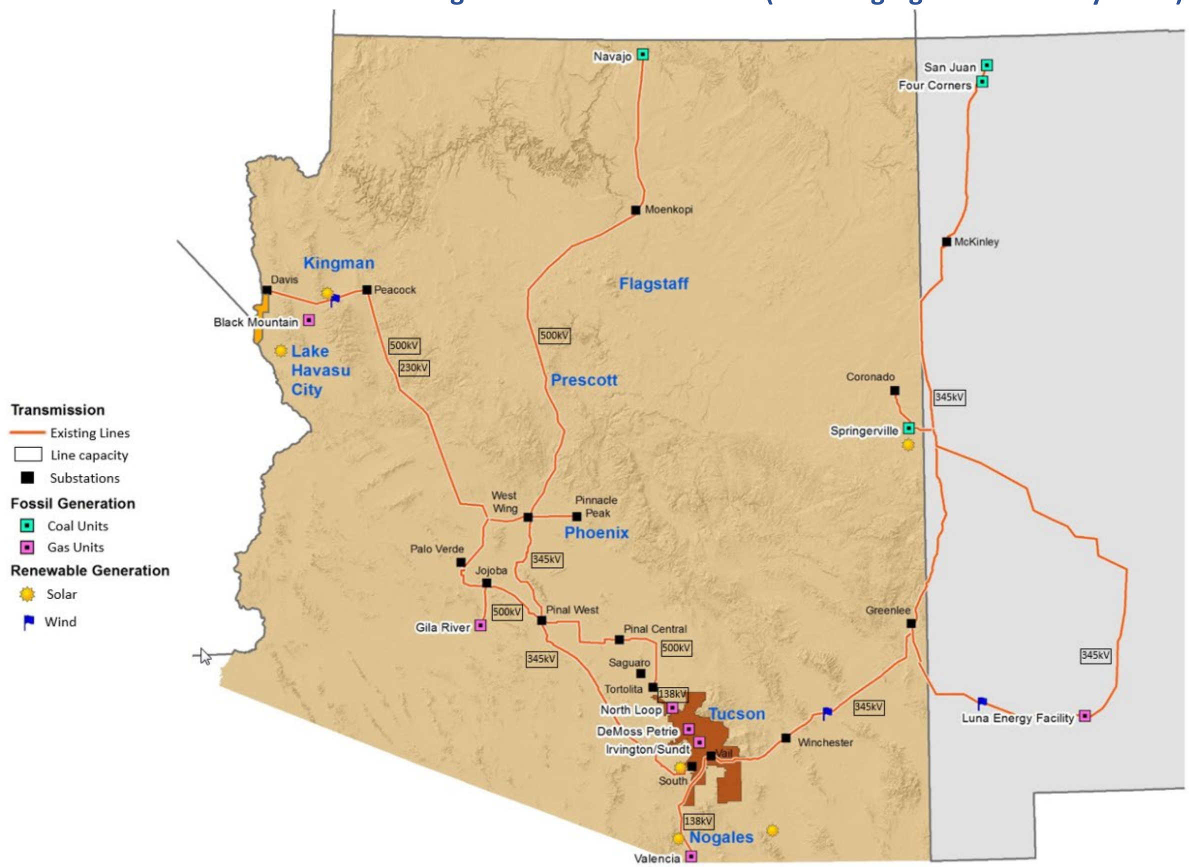
TEP's Existing Transmission Resources

TEP's existing transmission system was constructed over several decades to support the delivery of the base load coal generation resources in northern Arizona and New Mexico. Today, TEP owns approximately 473 miles of 46 kV lines, 432 miles of 138 kV lines, and is owner and part owner of 1,143 miles of 345 kV lines and 657 miles of 500 kV lines. As shown on the map at right, the Tucson service territory area is interconnected to the Western Interconnection Bulk Electric System via 345 kV interconnections at the South Loop and Vail substations, and a 500 kV interconnection at the Tortolita substation. These three substations interconnect and deliver energy from the EHV transmission network to the local TEP 138 kV system.

Vail – Tortolita 230kV Project

TEP has acquired the rights to develop the Vail – Tortolita portion of the Southline Transmission Project. Once final permitting and all agreements are completed, this project will rebuild a 62-mile portion of the existing Western Area Power Administration's (WAPA) 115 kV transmission line between the Apache and Saguaro Generating Stations. This line, which follows a route to the south and west of Tucson, will be rebuilt as a double circuit transmission line designed to 230 kV standards with the TEP circuit operating at 230 kV and the WAPA circuit continuing to operate at 115 kV for the foreseeable future. The TEP 230 kV circuit will have tie points at three TEP substations; Vail 345 kV, DeMoss Petrie 138 kV, and Tortolita 500 kV.

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



Appendix C: Portfolio Summaries

![TEP Tucson Electric Power]

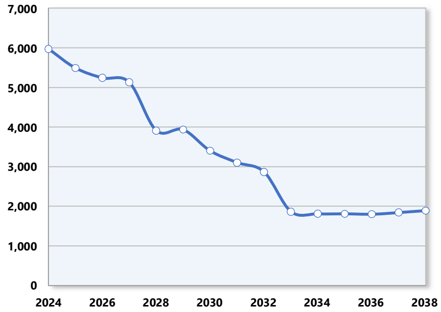
2023 Integrated Resource Plan

Portfolio ID - P01

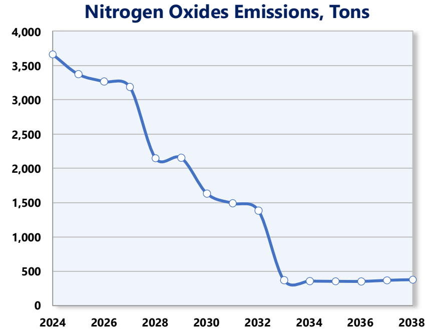
Portfolio Description - Solar + Storage Portfolio

Environmental Dashboard

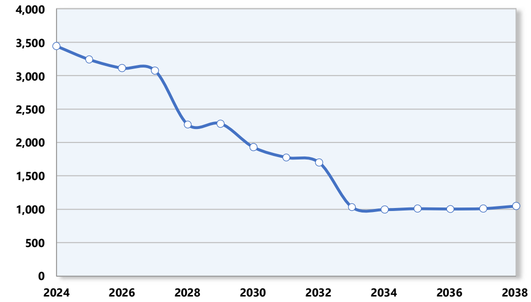
CO_2 Emissions, Thousand Metric Tons



Nitrogen Oxides Emissions, Tons



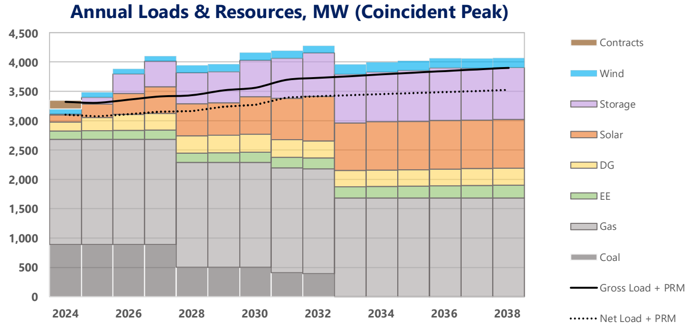
Water Use, Million Gallons



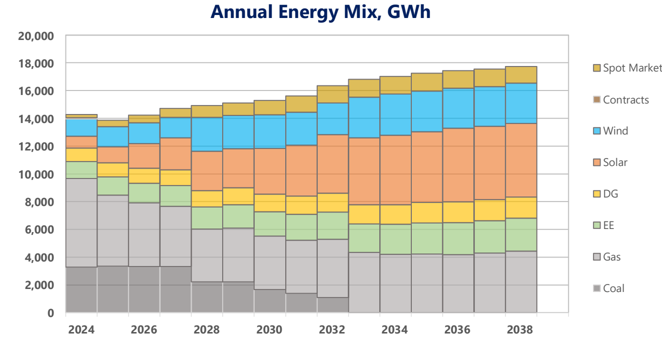
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Percent CO_2 Reductions from 2005 Levels	46%	50%	53%	54%	65%	64%	69%	72%	74%	83%	84%	84%	84%	83%	83%

Loads & Resources Dashboard

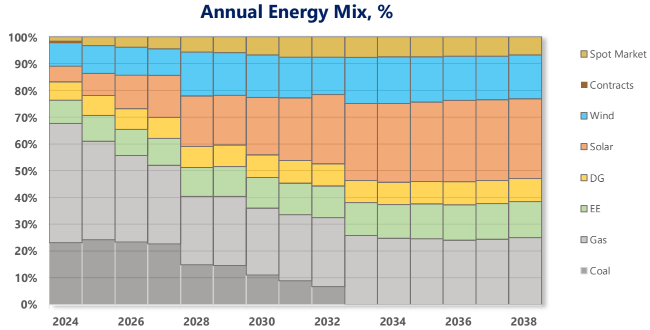
Annual Loads & Resources, MW (Coincident Peak)



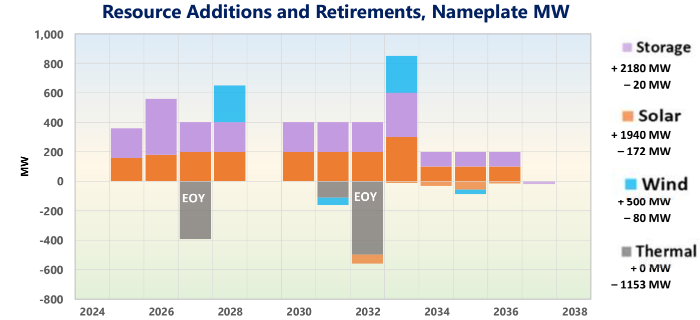
Annual Energy Mix, GWh



Annual Energy Mix, %



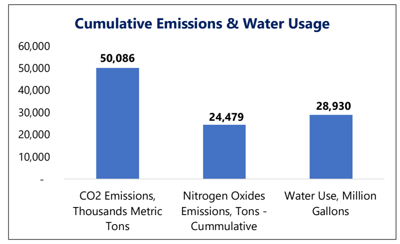
Resource Additions and Retirements, Nameplate MW



Annual Loads & Resources, MW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Gross Load + PRM	3,319	3,305	3,356	3,412	3,432	3,517	3,561	3,697	3,728	3,756	3,788	3,816	3,844	3,872	3,899
Net Load + PRM	3,102	3,073	3,109	3,152	3,163	3,237	3,269	3,396	3,416	3,433	3,452	3,469	3,486	3,504	3,523
Coal	892	892	892	892	502	502	502	410	392	-	-	-	-	-	-
Gas	1,787	1,787	1,787	1,787	1,787	1,787	1,787	1,787	1,787	1,682	1,682	1,682	1,682	1,682	1,682
Wind	87	87	87	87	128	128	128	128	119	169	169	169	164	164	164
Solar	116	229	356	456	549	549	642	703	758	809	821	823	832	824	824
Storage	17	115	331	434	528	528	621	686	741	825	845	864	893	885	885
DG	158	225	272	284	290	300	305	299	291	280	280	280	282	287	290
EE	142	148	153	159	160	166	172	178	184	190	196	203	209	215	221

Total NPVRR:	**$14,618,876**
Fuel NPVRR:	$3,187,980
Non-Fuel NP'	$11,430,896

Cumulative Emissions & Water Usage



Annual Loads & Resources, GWh	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Gross Energy	14,272	13,861	14,229	14,718	14,915	15,106	15,292	15,626	16,351	16,803	17,021	17,241	17,428	17,547	17,726
Coal	3,285	3,350	3,323	3,327	2,218	2,209	1,672	1,385	1,091	-	-	-	-	-	-
Gas	6,369	5,109	4,591	4,330	3,810	3,897	3,838	3,842	4,201	4,351	4,212	4,220	4,192	4,292	4,428
Wind	1,244	1,449	1,494	1,467	2,432	2,409	2,441	2,372	2,281	2,909	2,961	2,922	2,877	2,856	2,904
Solar	850	1,145	1,776	2,308	2,823	2,796	3,274	3,670	4,220	4,820	4,995	5,104	5,303	5,291	5,300
DG	966	1,029	1,088	1,141	1,192	1,232	1,273	1,312	1,353	1,383	1,418	1,454	1,488	1,507	1,527
EE	1,240	1,321	1,406	1,491	1,583	1,668	1,758	1,851	1,955	2,050	2,153	2,256	2,300	2,335	2,374

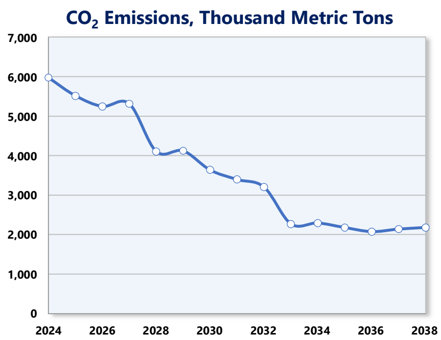
TEP
Tucson Electric Power

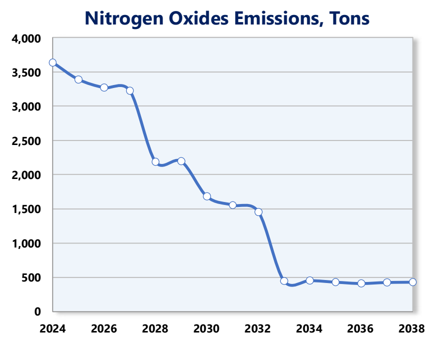
2023 Integrated Resource Plan

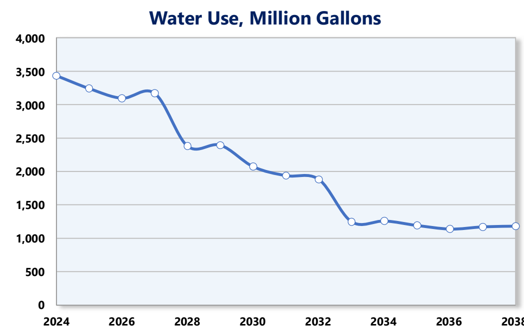
Portfolio ID - P02

Portfolio Description - Balanced Portfolio

Environmental Dashboard

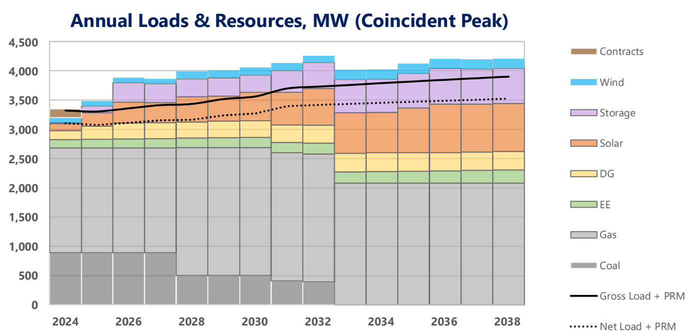


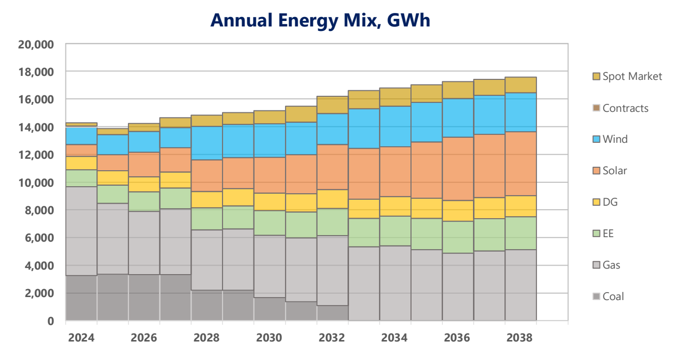


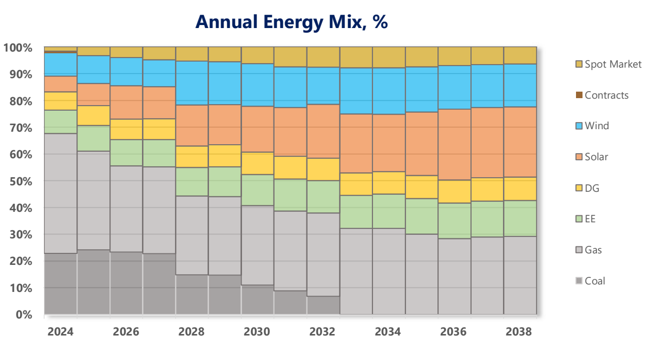


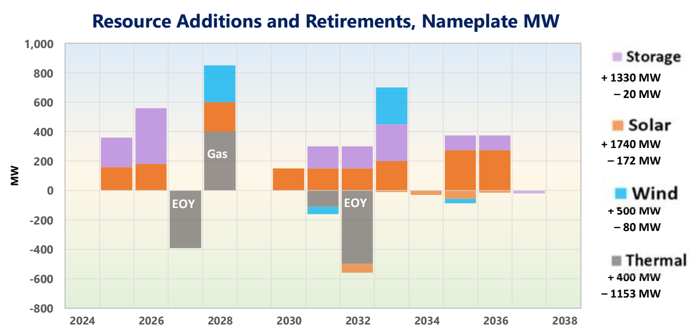
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Percent CO_2 Reductions from 2005 Levels	46%	50%	53%	52%	63%	63%	67%	69%	71%	79%	79%	80%	81%	81%	80%

Loads & Resources Dashboard



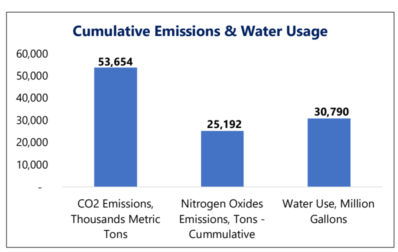






Annual Loads & Resources, MW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Gross Load + PRM	3,319	3,305	3,356	3,412	3,432	3,517	3,561	3,697	3,728	3,756	3,788	3,816	3,844	3,872	3,899
Net Load + PRM	3,102	3,073	3,109	3,152	3,163	3,237	3,269	3,396	3,416	3,433	3,452	3,469	3,486	3,504	3,523
Coal	892	892	892	892	502	502	502	410	392	-	-	-	-	-	-
Gas	1,787	1,787	1,787	1,787	2,187	2,187	2,187	2,187	2,187	2,082	2,082	2,082	2,082	2,082	2,082
Wind	87	87	87	87	128	128	128	128	119	169	169	169	164	164	164
Solar	116	229	356	341	427	427	483	558	626	692	683	761	829	819	819
Storage	17	115	331	320	308	308	298	373	442	567	567	588	609	600	600
DG	158	225	272	276	276	287	286	298	305	315	324	317	311	316	320
EE	142	148	153	159	160	166	172	178	184	190	196	203	209	215	221

Total NPVRR:	**$14,308,091**
Fuel NPVRR:	$3,364,075
Non-Fuel NP'	$10,944,016

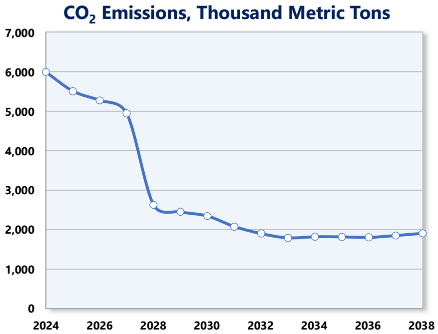


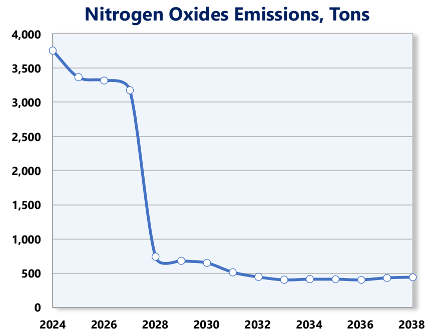
Annual Loads & Resources, GWh	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Gross Energy	14,270	13,856	14,218	14,646	14,826	15,008	15,151	15,478	16,180	16,599	16,786	17,026	17,251	17,400	17,570
Coal	3,268	3,355	3,321	3,335	2,207	2,207	1,674	1,377	1,096	-	-	-	-	-	-
Gas	6,384	5,110	4,569	4,743	4,350	4,410	4,493	4,612	5,052	5,341	5,393	5,127	4,884	5,039	5,123
Wind	1,244	1,449	1,494	1,467	2,429	2,404	2,428	2,350	2,245	2,858	2,910	2,875	2,802	2,795	2,835
Solar	850	1,145	1,776	1,755	2,271	2,248	2,579	2,814	3,243	3,661	3,596	4,041	4,565	4,572	4,594
DG	966	1,029	1,088	1,141	1,192	1,232	1,273	1,312	1,353	1,383	1,418	1,454	1,488	1,507	1,527
EE	1,240	1,321	1,406	1,491	1,583	1,668	1,758	1,851	1,955	2,050	2,153	2,256	2,300	2,335	2,374

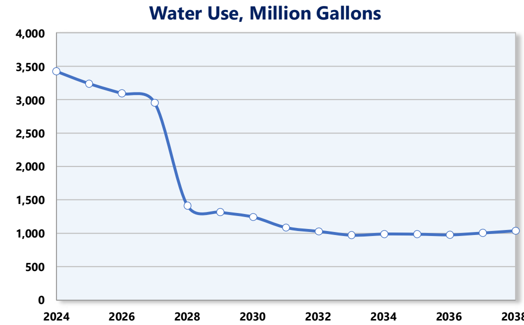
Portfolio ID - P03

Portfolio Description - Retire SGS 1 and SGS 2 in 2027 Portfolio

Environmental Dashboard

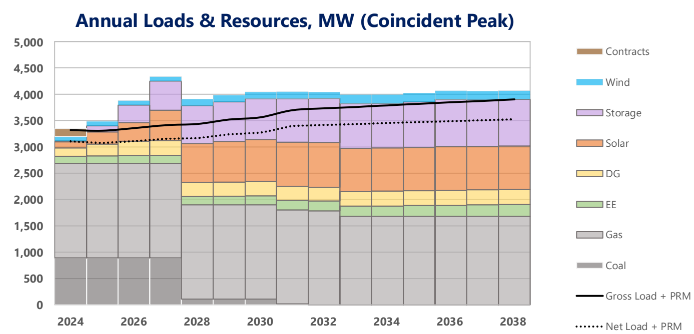


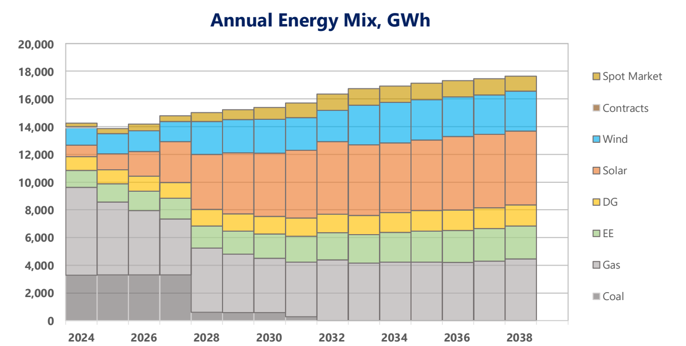


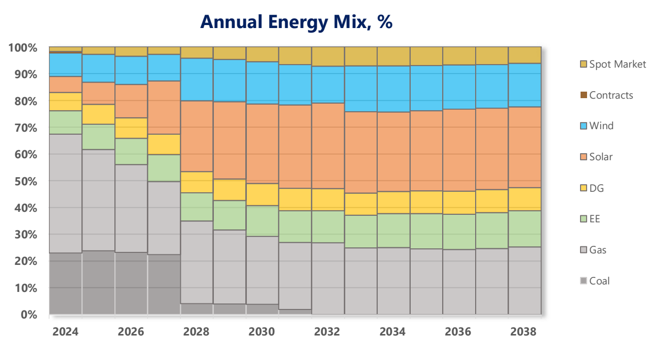


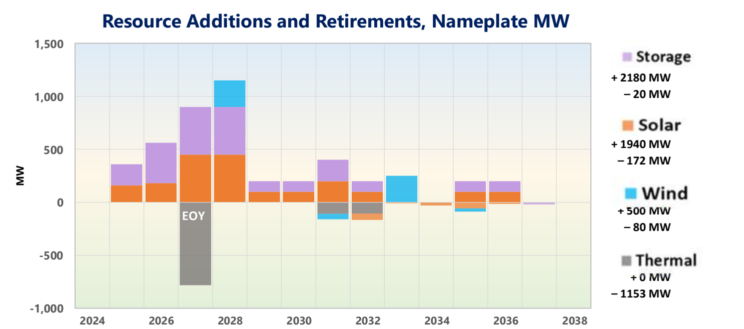
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Percent CO_2 Reductions from 2005 Levels	46%	50%	52%	55%	76%	78%	79%	81%	83%	84%	84%	84%	84%	83%	83%

Loads & Resources Dashboard



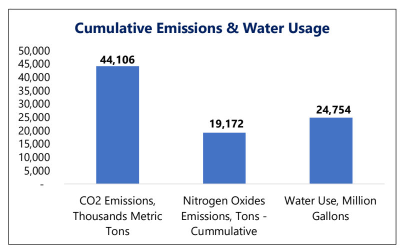






Annual Loads & Resources, MW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Gross Load + PRM	3,319	3,305	3,356	3,412	3,432	3,517	3,561	3,697	3,728	3,756	3,788	3,816	3,844	3,872	3,899
Net Load + PRM	3,102	3,073	3,109	3,152	3,163	3,237	3,269	3,396	3,416	3,433	3,452	3,469	3,486	3,504	3,523
Coal	892	892	892	892	110	110	110	18	-	-	-	-	-	-	-
Gas	1,787	1,787	1,787	1,787	1,787	1,787	1,787	1,787	1,787	1,682	1,682	1,682	1,682	1,682	1,682
Wind	87	87	87	87	128	128	128	128	119	169	169	169	164	164	164
Solar	116	229	356	575	737	769	796	841	849	829	821	823	832	824	824
Storage	17	115	331	553	717	750	777	825	834	845	845	864	893	885	885
DG	158	225	272	278	265	270	272	266	263	273	280	280	282	287	290
EE	142	148	153	159	160	166	172	178	184	190	196	203	209	215	221

Total NPVRR:	**$14,755,339**
Fuel NPVRR:	$3,049,207
Non-Fuel NP'	$11,706,132



Annual Loads & Resources, GWh	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Gross Energy	14,245	13,873	14,192	14,785	15,013	15,218	15,370	15,699	16,352	16,742	16,937	17,142	17,323	17,449	17,643
Coal	3,278	3,306	3,299	3,300	605	595	593	294	-	-	-	-	-	-	-
Gas	6,331	5,239	4,640	4,036	4,643	4,215	3,898	3,939	4,383	4,159	4,223	4,216	4,199	4,307	4,459
Wind	1,244	1,449	1,494	1,467	2,384	2,398	2,425	2,363	2,261	2,871	2,923	2,904	2,854	2,842	2,884
Solar	850	1,144	1,763	2,937	3,966	4,392	4,570	4,894	5,225	5,081	5,023	5,111	5,311	5,300	5,319
DG	966	1,029	1,088	1,141	1,192	1,232	1,273	1,312	1,353	1,383	1,418	1,454	1,488	1,507	1,527
EE	1,240	1,321	1,406	1,491	1,583	1,668	1,758	1,851	1,955	2,050	2,153	2,256	2,300	2,335	2,374

![TEP Tucson Electric Power]

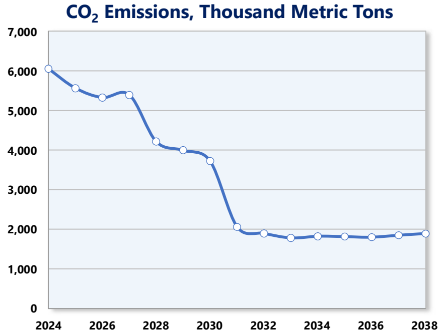
2023 Integrated Resource Plan

Portfolio ID - P04

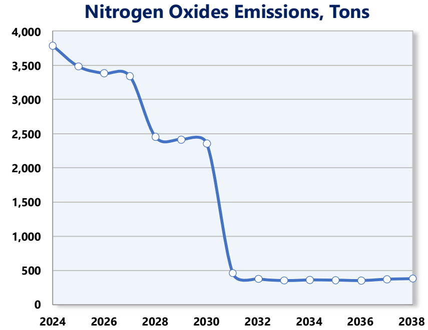
Portfolio Description - Retire SGS 1 and SGS 2 in 2030 Portfolio

Environmental Dashboard

CO_2 Emissions, Thousand Metric Tons



Nitrogen Oxides Emissions, Tons

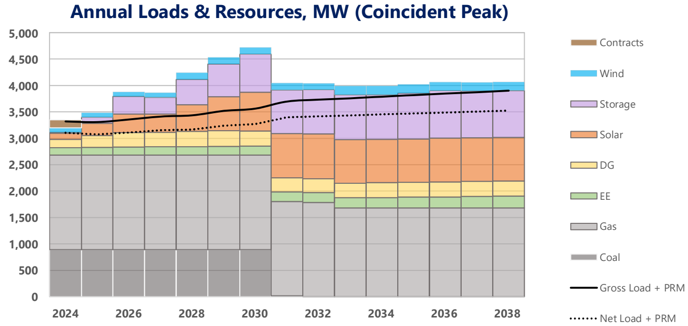


Water Use, Million Gallons

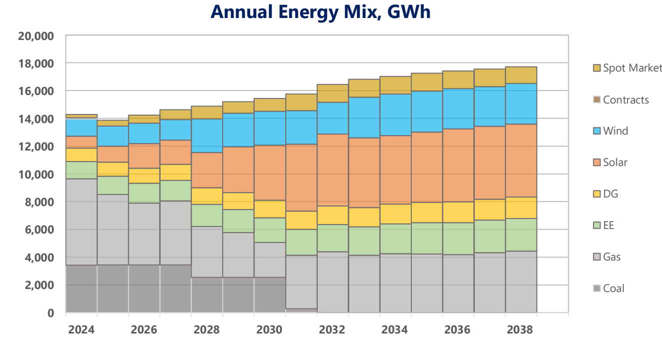
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Percent CO_2 Reductions from 2005 Levels	45%	50%	52%	51%	62%	64%	66%	81%	83%	84%	83%	84%	84%	83%	83%

Loads & Resources Dashboard

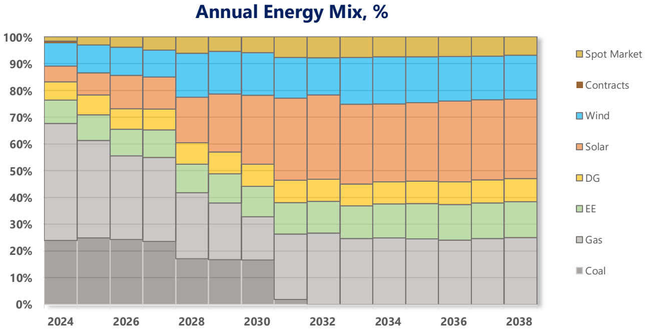
Annual Loads & Resources, MW (Coincident Peak)



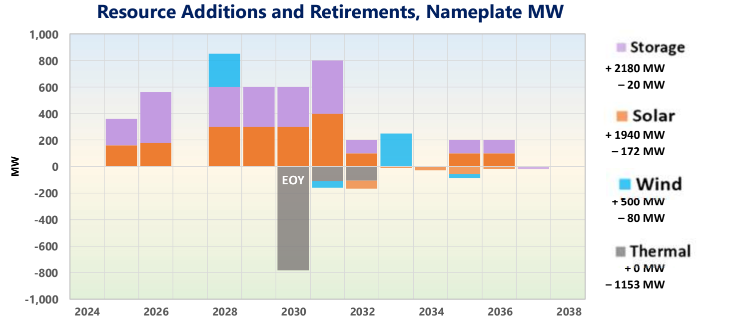
Annual Energy Mix, GWh



Annual Energy Mix, %



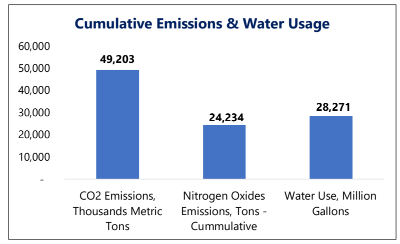
Resource Additions and Retirements, Nameplate MW



Annual Loads & Resources, MW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Gross Load + PRM	3,319	3,305	3,356	3,412	3,432	3,517	3,561	3,697	3,728	3,756	3,788	3,816	3,844	3,872	3,899
Net Load + PRM	3,102	3,073	3,109	3,152	3,163	3,237	3,269	3,396	3,416	3,433	3,452	3,469	3,486	3,504	3,523
Coal	892	892	892	892	892	892	892	18	-	-	-	-	-	-	-
Gas	1,787	1,787	1,787	1,787	1,787	1,787	1,787	1,787	1,787	1,682	1,682	1,682	1,682	1,682	1,682
Wind	87	87	87	87	128	128	128	128	119	169	169	169	164	164	164
Solar	116	229	356	341	502	642	737	841	849	829	821	823	832	824	824
Storage	17	115	331	320	480	621	717	825	834	845	845	864	893	885	885
DG	158	225	272	276	292	296	284	266	263	273	280	280	282	287	290
EE	142	148	153	159	160	166	172	178	184	190	196	203	209	215	221

Total NPVRR:	**$14,737,918**
Fuel NPVRR:	$3,152,309
Non-Fuel NP'	$11,585,609

Cumulative Emissions & Water Usage



Annual Loads & Resources, GWh	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Gross Energy	14,261	13,868	14,226	14,627	14,870	15,200	15,426	15,750	16,442	16,820	17,027	17,236	17,413	17,548	17,717
Coal	3,415	3,452	3,452	3,449	2,550	2,552	2,557	293	-	-	-	-	-	-	-
Gas	6,231	5,049	4,451	4,594	3,664	3,208	2,504	3,853	4,385	4,144	4,243	4,230	4,190	4,323	4,426
Wind	1,244	1,449	1,494	1,467	2,437	2,419	2,450	2,402	2,296	2,935	2,989	2,943	2,892	2,870	2,919
Solar	850	1,145	1,774	1,757	2,532	3,286	3,965	4,828	5,166	5,006	4,942	5,062	5,262	5,250	5,258
DG	966	1,029	1,088	1,141	1,192	1,232	1,273	1,312	1,353	1,383	1,418	1,454	1,488	1,507	1,527
EE	1,240	1,321	1,406	1,491	1,583	1,668	1,758	1,851	1,955	2,050	2,153	2,256	2,300	2,335	2,374

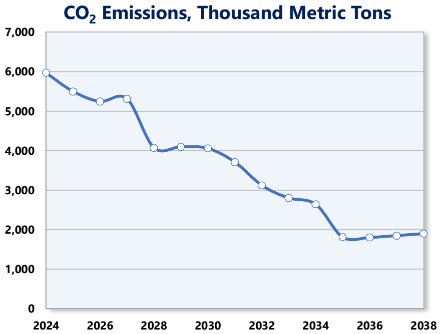
Tucson Electric Power

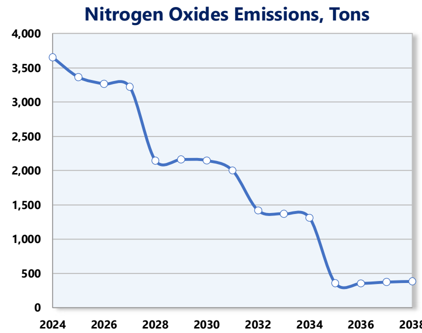
2023 Integrated Resource Plan

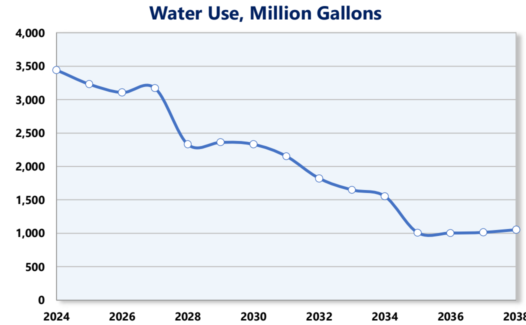
Portfolio ID - P05

Portfolio Description - Retire SGS 1 and SGS 2 in 2034 Portfolio

Environmental Dashboard

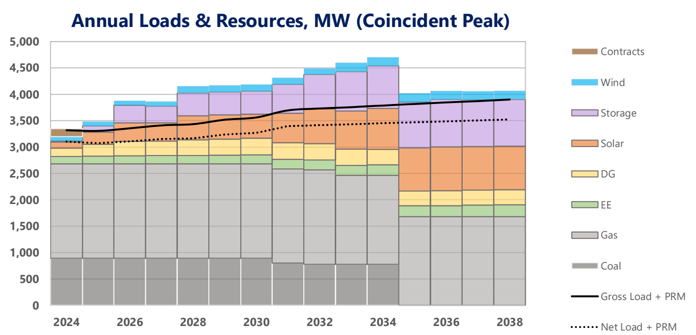


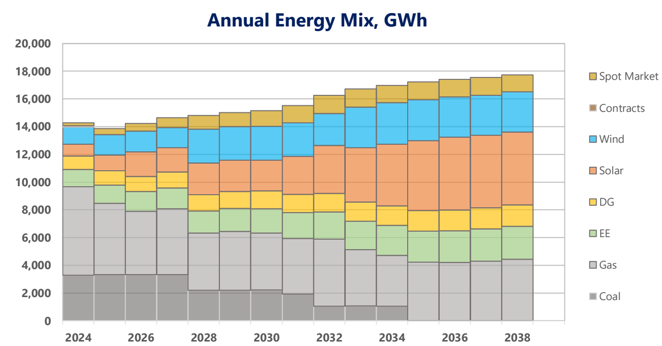


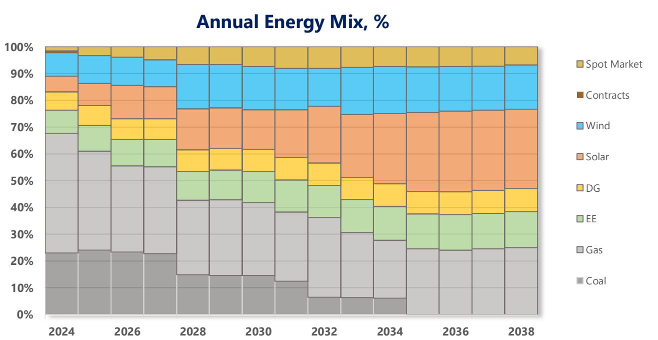


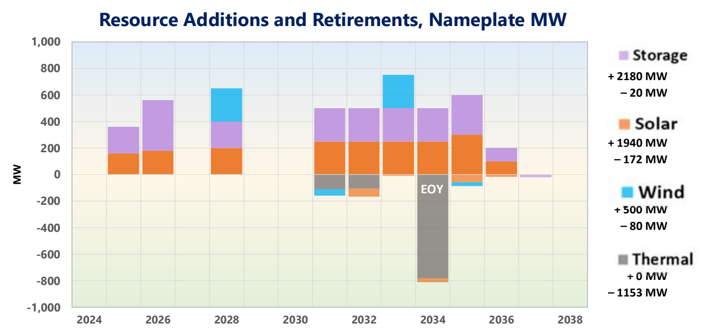
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Percent CO_2 Reductions from 2005 Levels	46%	50%	53%	52%	63%	63%	63%	66%	72%	75%	76%	84%	84%	83%	83%

Loads & Resources Dashboard



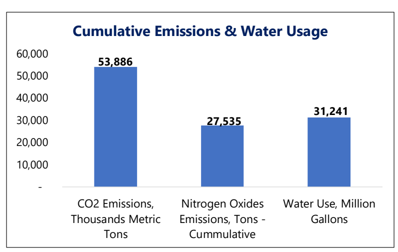






Annual Loads & Resources, MW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Gross Load + PRM	3,319	3,305	3,356	3,412	3,432	3,517	3,561	3,697	3,728	3,756	3,788	3,816	3,844	3,872	3,899
Net Load + PRM	3,102	3,073	3,109	3,152	3,163	3,237	3,269	3,396	3,416	3,433	3,452	3,469	3,486	3,504	3,523
Coal	892	892	892	892	892	892	892	800	782	782	782	-	-	-	-
Gas	1,787	1,787	1,787	1,787	1,787	1,787	1,787	1,787	1,787	1,682	1,682	1,682	1,682	1,682	1,682
Wind	87	87	87	87	128	128	128	128	119	169	169	169	164	164	164
Solar	116	229	356	341	456	456	456	562	662	723	777	823	832	824	824
Storage	17	115	331	320	434	434	434	544	644	741	802	864	893	885	885
DG	158	225	272	276	295	306	316	314	310	308	295	280	282	287	290
EE	142	148	153	159	160	166	172	178	184	190	196	203	209	215	221

Total NPVRR:	**$14,668,588**
Fuel NPVRR:	$3,357,404
Non-Fuel NP'	$11,311,184



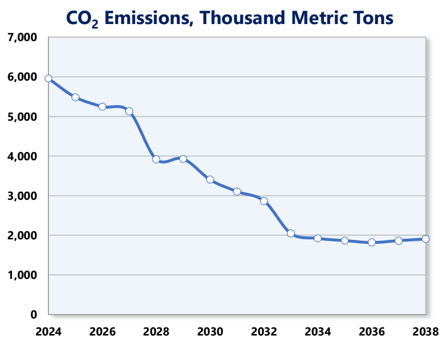
Annual Loads & Resources, GWh	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Gross Energy	14,273	13,861	14,220	14,644	14,805	15,010	15,143	15,518	16,250	16,706	16,978	17,231	17,419	17,535	17,721
Coal	3,284	3,337	3,323	3,335	2,197	2,200	2,211	1,925	1,053	1,062	1,043	-	-	-	-
Gas	6,379	5,125	4,584	4,746	4,127	4,233	4,114	4,015	4,828	4,060	3,673	4,216	4,195	4,296	4,442
Wind	1,244	1,449	1,494	1,467	2,440	2,418	2,449	2,394	2,298	2,940	2,993	2,940	2,894	2,871	2,918
Solar	850	1,145	1,774	1,756	2,274	2,256	2,219	2,765	3,455	3,909	4,446	5,065	5,261	5,249	5,259
DG	966	1,029	1,088	1,141	1,192	1,232	1,273	1,312	1,353	1,383	1,418	1,454	1,488	1,507	1,527
EE	1,240	1,321	1,406	1,491	1,583	1,668	1,758	1,851	1,955	2,050	2,153	2,256	2,300	2,335	2,374

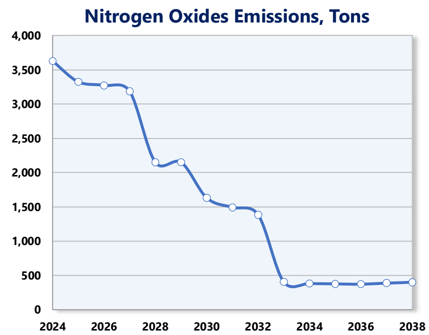
2023 Integrated Resource Plan

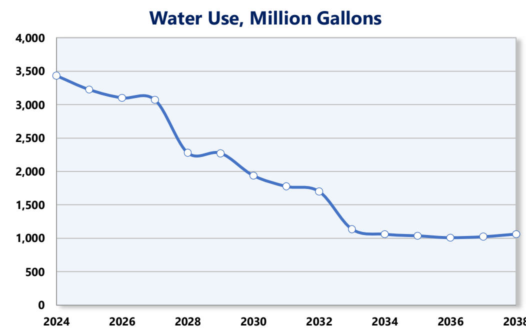
Portfolio ID - P06

Portfolio Description - Heavy Solar Portfolio

Environmental Dashboard

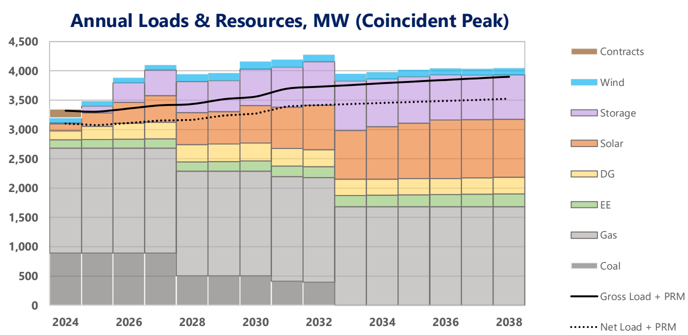


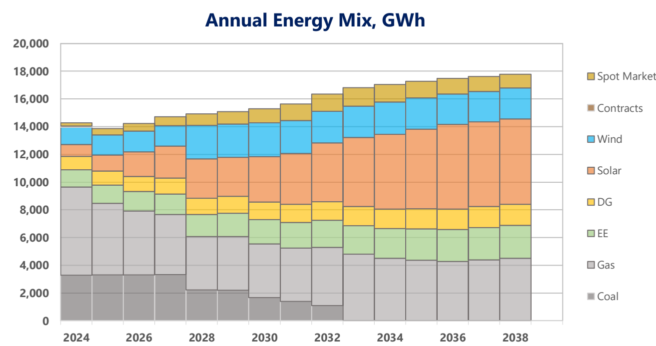


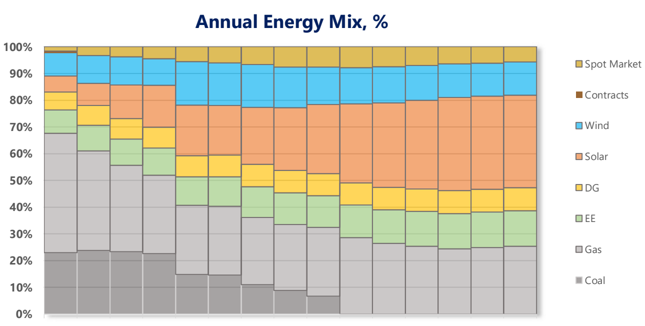


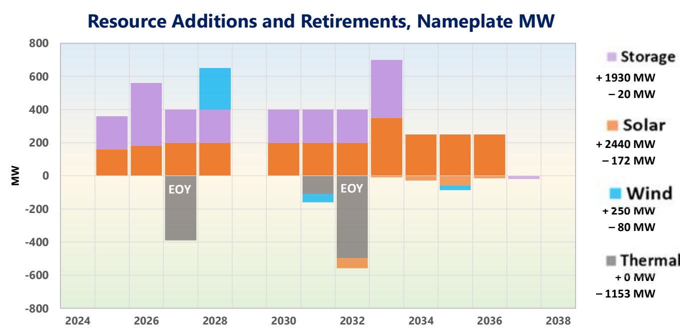
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Percent CO_2 Reductions from 2005 Levels	46%	50%	52%	54%	65%	64%	69%	72%	74%	81%	83%	83%	84%	83%	83%

Loads & Resources Dashboard



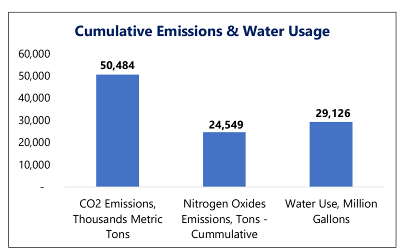






Annual Loads & Resources, MW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Gross Load + PRM	3,319	3,305	3,356	3,412	3,432	3,517	3,561	3,697	3,728	3,756	3,788	3,816	3,844	3,872	3,899
Net Load + PRM	3,102	3,073	3,109	3,152	3,163	3,237	3,269	3,396	3,416	3,433	3,452	3,469	3,486	3,504	3,523
Coal	892	892	892	892	502	502	502	410	392	-	-	-	-	-	-
Gas	1,787	1,787	1,787	1,787	1,787	1,787	1,787	1,787	1,787	1,682	1,682	1,682	1,682	1,682	1,682
Wind	87	87	87	87	128	128	128	128	119	119	119	119	113	113	113
Solar	116	229	356	456	549	549	642	703	758	830	891	949	998	990	990
Storage	17	115	331	434	528	528	621	686	741	846	812	789	766	759	759
DG	158	225	272	284	290	300	305	299	291	280	276	275	273	277	281
EE	142	148	153	159	160	166	172	178	184	190	196	203	209	215	221

Total NPVRR:	**$14,425,444**
Fuel NPVRR:	$3,207,727
Non-Fuel NP'	$11,217,717



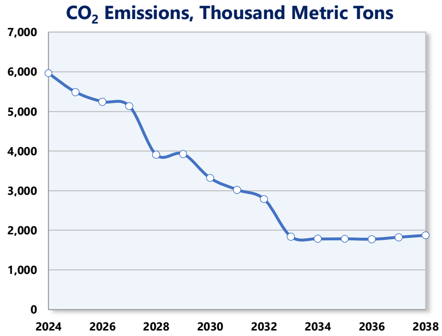
Annual Loads & Resources, GWh	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Gross Energy	14,272	13,858	14,217	14,717	14,929	15,091	15,297	15,632	16,351	16,795	17,032	17,264	17,474	17,607	17,788
Coal	3,272	3,296	3,310	3,331	2,221	2,206	1,678	1,386	1,090	-	-	-	-	-	-
Gas	6,377	5,161	4,602	4,319	3,851	3,874	3,847	3,848	4,201	4,805	4,495	4,373	4,273	4,383	4,507
Wind	1,244	1,449	1,494	1,467	2,431	2,407	2,441	2,372	2,278	2,261	2,306	2,257	2,201	2,180	2,222
Solar	850	1,145	1,774	2,308	2,819	2,794	3,274	3,672	4,224	4,972	5,393	5,720	6,100	6,123	6,149
DG	966	1,029	1,088	1,141	1,192	1,232	1,273	1,312	1,353	1,383	1,418	1,454	1,488	1,507	1,527
EE	1,240	1,321	1,406	1,491	1,583	1,668	1,758	1,851	1,955	2,050	2,153	2,256	2,300	2,335	2,374

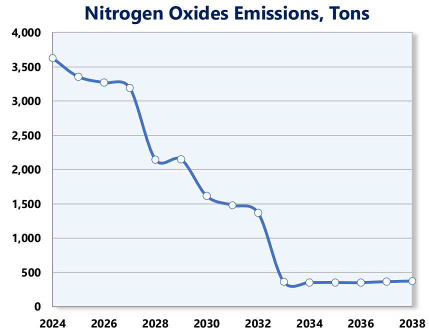
TEP
Tucson Electric Power

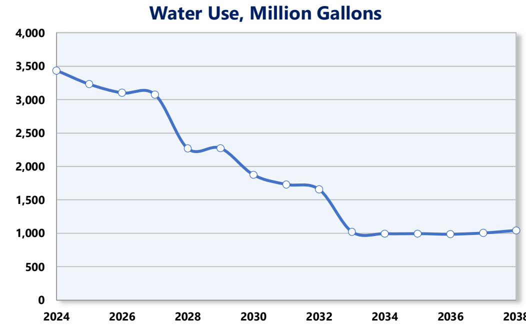
Portfolio ID - P07

Portfolio Description - Heavy Wind Portfolio

Environmental Dashboard

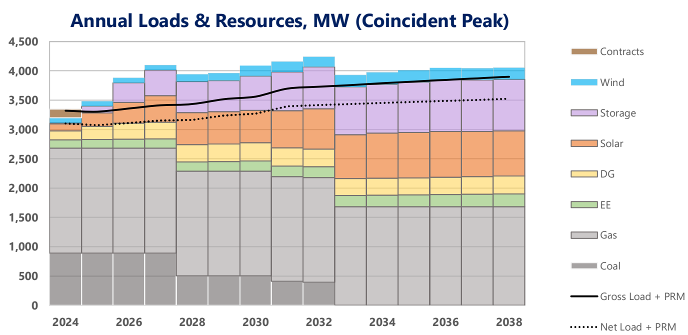


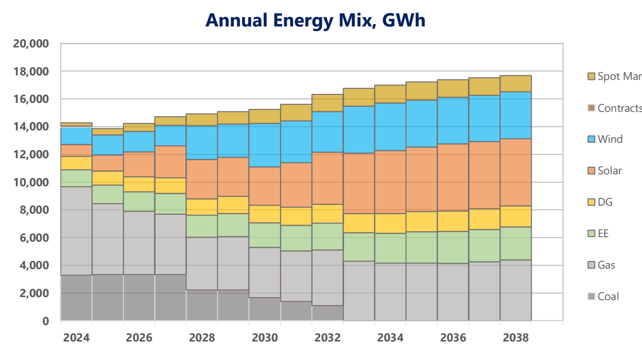


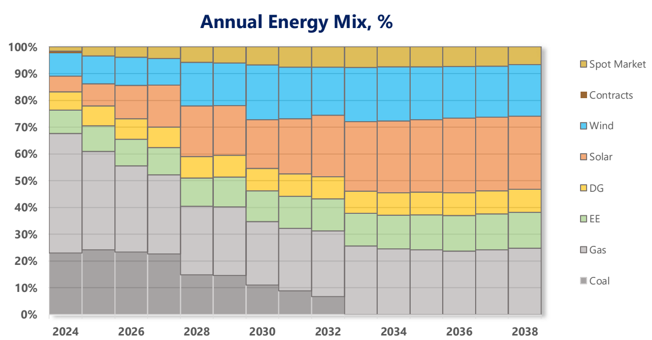


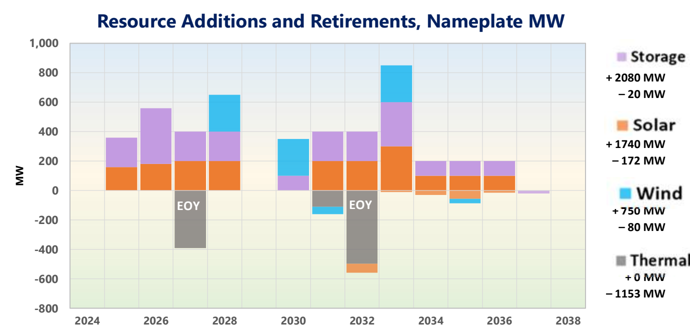
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Percent CO_2 Reductions from 2005 Levels	46%	50%	53%	54%	65%	64%	70%	73%	75%	83%	84%	84%	84%	83%	83%

Loads & Resources Dashboard



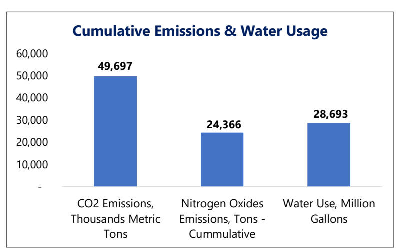






Annual Loads & Resources, MW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Gross Load + PRM	3,319	3,305	3,356	3,412	3,432	3,517	3,561	3,697	3,728	3,756	3,788	3,816	3,844	3,872	3,899
Net Load + PRM	3,102	3,073	3,109	3,152	3,163	3,237	3,269	3,396	3,416	3,433	3,452	3,469	3,486	3,504	3,523
Coal	892	892	892	892	502	502	502	410	392	-	-	-	-	-	-
Gas	1,787	1,787	1,787	1,787	1,787	1,787	1,787	1,787	1,787	1,682	1,682	1,682	1,682	1,682	1,682
Wind	87	87	87	87	128	128	178	178	169	206	206	206	201	201	201
Solar	116	229	356	456	549	549	554	632	688	749	766	772	781	772	772
Storage	17	115	331	434	528	528	583	663	717	811	834	856	886	877	877
DG	158	225	272	284	290	300	312	311	301	291	291	291	293	298	301
EE	142	148	153	159	160	166	172	178	184	190	196	203	209	215	221

Total NPVRR:	**$14,593,774**
Fuel NPVRR:	$3,167,526
Non-Fuel NP'	$11,426,249



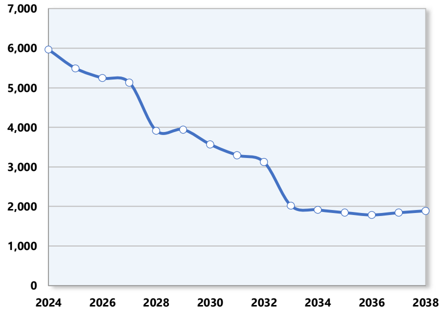
Annual Loads & Resources, GWh	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Gross Energy	14,270	13,857	14,223	14,723	14,917	15,094	15,251	15,601	16,326	16,766	16,991	17,208	17,392	17,515	17,693
Coal	3,271	3,340	3,319	3,327	2,222	2,208	1,673	1,391	1,091	-	-	-	-	-	-
Gas	6,381	5,106	4,583	4,357	3,804	3,865	3,622	3,641	4,003	4,290	4,160	4,154	4,126	4,244	4,383
Wind	1,244	1,449	1,494	1,467	2,432	2,409	3,117	3,014	2,919	3,386	3,438	3,401	3,362	3,342	3,390
Solar	850	1,145	1,774	2,306	2,821	2,798	2,773	3,205	3,755	4,363	4,542	4,655	4,844	4,826	4,831
DG	966	1,029	1,088	1,141	1,192	1,232	1,273	1,312	1,353	1,383	1,418	1,454	1,488	1,507	1,527
EE	1,240	1,321	1,406	1,491	1,583	1,668	1,758	1,851	1,955	2,050	2,153	2,256	2,300	2,335	2,374

2023 Integrated Resource Plan

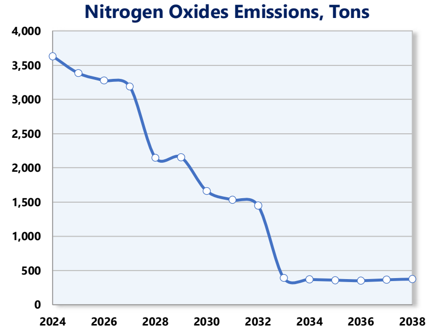
Portfolio ID - P08
Portfolio Description - Pumped Hydro Portfolio

Environmental Dashboard

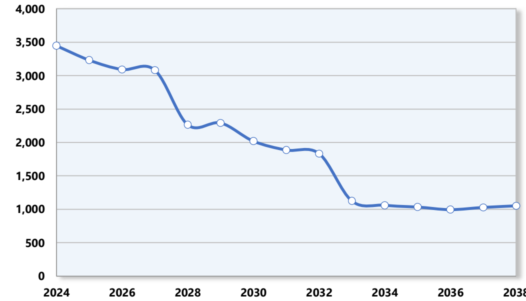
CO_2 Emissions, Thousand Metric Tons



Nitrogen Oxides Emissions, Tons



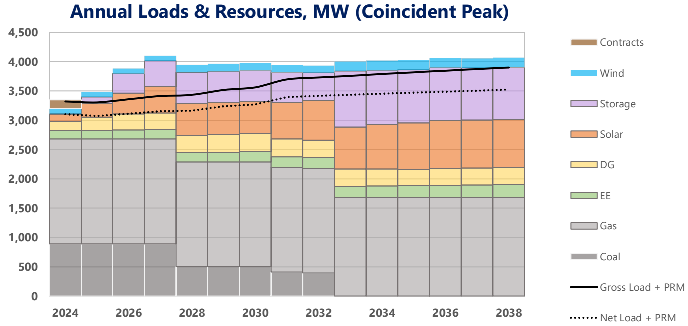
Water Use, Million Gallons



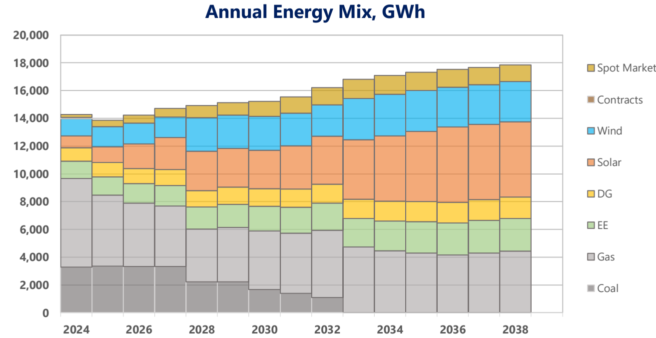
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Percent CO_2 Reductions from 2005 Levels	46%	50%	52%	54%	65%	64%	68%	70%	72%	82%	83%	83%	84%	83%	83%

Loads & Resources Dashboard

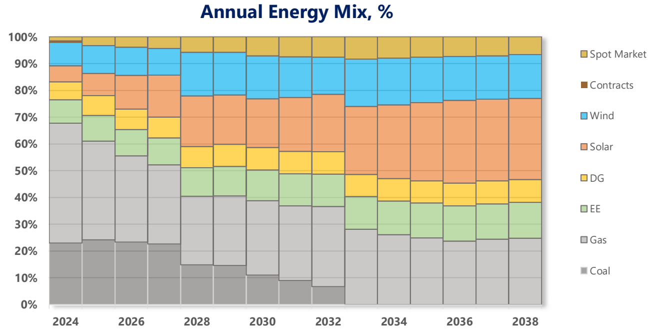
Annual Loads & Resources, MW (Coincident Peak)



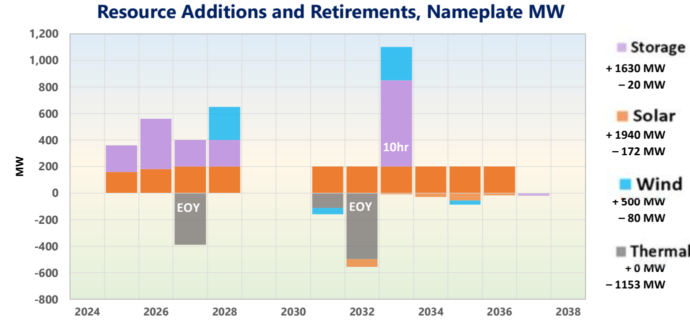
Annual Energy Mix, GWh



Annual Energy Mix, %



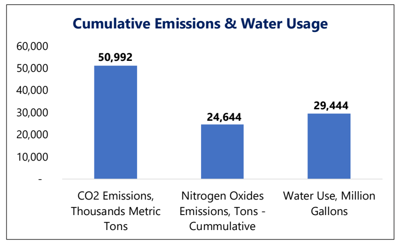
Resource Additions and Retirements, Nameplate MW



Annual Loads & Resources, MW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Gross Load + PRM	3,319	3,305	3,356	3,412	3,432	3,517	3,561	3,697	3,728	3,756	3,788	3,816	3,844	3,872	3,899
Net Load + PRM	3,102	3,073	3,109	3,152	3,163	3,237	3,269	3,396	3,416	3,433	3,452	3,469	3,486	3,504	3,523
Coal	892	892	892	892	502	502	502	410	392	-	-	-	-	-	-
Gas	1,787	1,787	1,787	1,787	1,787	1,787	1,787	1,787	1,787	1,682	1,682	1,682	1,682	1,682	1,682
Wind	87	87	87	87	128	128	128	128	119	169	169	169	164	164	164
Solar	116	229	356	456	549	549	549	624	676	716	757	787	828	820	820
Storage	17	115	331	434	528	528	528	508	475	951	927	907	898	890	890
DG	158	225	272	284	290	300	310	307	296	295	288	281	281	285	289
EE	142	148	153	159	160	166	172	178	184	190	196	203	209	215	221

Total NPVRR:	**$14,788,895**
Fuel NPVRR:	$3,237,713
Non-Fuel NP'	$11,551,182

Cumulative Emissions & Water Usage



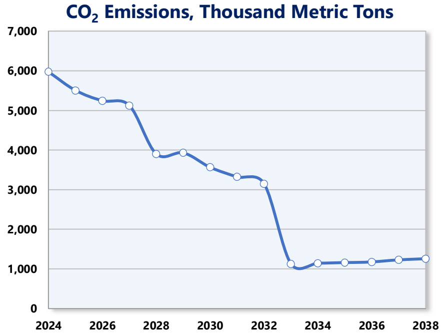
Annual Loads & Resources, GWh	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Gross Energy	14,276	13,861	14,219	14,727	14,914	15,117	15,215	15,541	16,206	16,568	16,786	16,991	17,164	17,308	17,482
Coal	3,275	3,350	3,324	3,325	2,219	2,211	1,674	1,387	1,097	-	-	-	-	-	-
Gas	6,400	5,110	4,568	4,354	3,809	3,923	4,221	4,345	4,841	4,739	4,457	4,303	4,151	4,310	4,422
Wind	1,244	1,449	1,494	1,467	2,428	2,405	2,441	2,356	2,253	2,972	2,995	2,938	2,877	2,867	2,911
Solar	850	1,145	1,777	2,308	2,815	2,790	2,764	3,123	3,468	4,276	4,711	5,050	5,423	5,401	5,407
DG	966	1,029	1,088	1,141	1,192	1,232	1,273	1,312	1,353	1,383	1,418	1,454	1,488	1,507	1,527
EE	1,240	1,321	1,406	1,491	1,583	1,668	1,758	1,851	1,955	2,050	2,153	2,256	2,300	2,335	2,374

Portfolio ID - P09

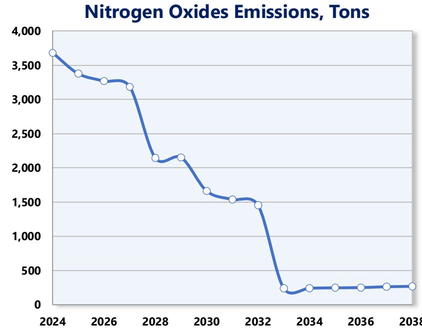
Portfolio Description - Small Modular Reactors Portfolio

Environmental Dashboard

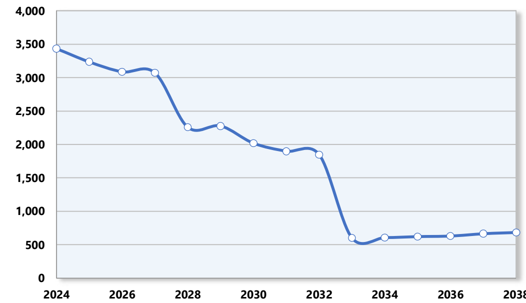
CO_2 Emissions, Thousand Metric Tons



Nitrogen Oxides Emissions, Tons



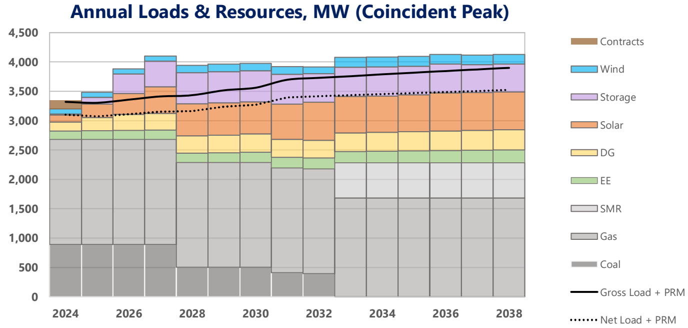
Water Use, Million Gallons



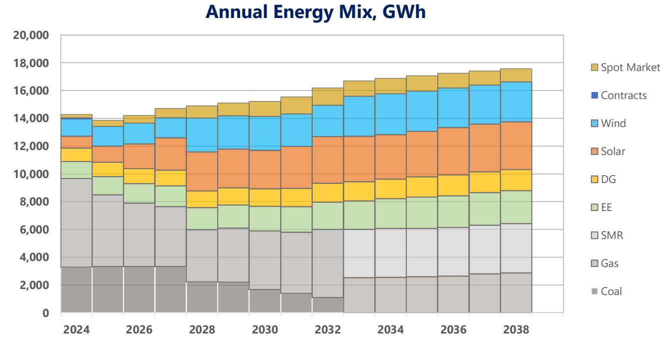
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Percent CO_2 Reductions from 2005 Levels	46%	50%	53%	54%	65%	64%	68%	70%	71%	90%	90%	89%	89%	89%	89%

Loads & Resources Dashboard

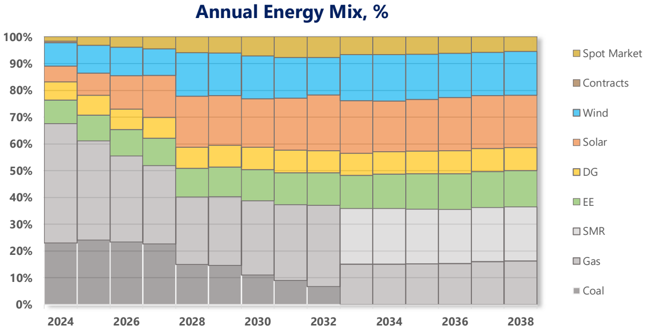
Annual Loads & Resources, MW (Coincident Peak)



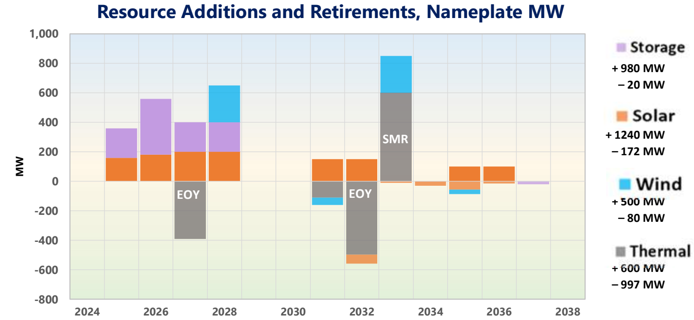
Annual Energy Mix, GWh



Annual Energy Mix, %



Resource Additions and Retirements, Nameplate MW

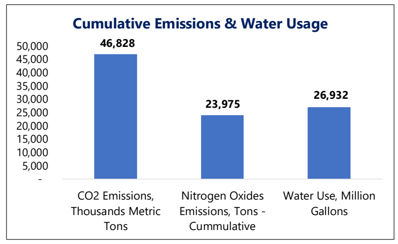


Annual Loads & Resources, MW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Gross Load + PRM	3,319	3,305	3,356	3,412	3,432	3,517	3,561	3,697	3,728	3,756	3,788	3,816	3,844	3,872	3,899
Net Load + PRM	3,102	3,073	3,109	3,152	3,163	3,237	3,269	3,396	3,416	3,433	3,452	3,469	3,486	3,504	3,523
Coal	892	892	892	892	502	502	502	410	392	-	-	-	-	-	-
Gas	1,787	1,787	1,787	1,787	1,787	1,787	1,787	1,787	1,787	1,682	1,682	1,682	1,682	1,682	1,682
SMR	-	-	-	-	-	-	-	-	-	600	600	600	600	600	600
Wind	87	87	87	87	128	128	128	128	119	169	169	169	164	164	164
Solar	116	229	356	456	549	549	549	600	645	623	614	628	651	641	641
Storage	17	115	331	434	528	528	528	508	486	497	497	486	486	477	477
DG	158	225	272	284	290	300	310	307	303	316	325	326	333	338	342

Total NPVRR:	**$15,022,709**
Fuel NPVRR:	$3,119,614
Non-Fuel NP'	$11,903,095

0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Annual Loads & Resources, GWh	2,024	2,025	2,026	2,027	2,028	2,029	2,030	2,031	2,032	2,033	2,034	2,035	2,036	2,037	2,038
Gross Energy	14,266	13,870	14,214	14,712	14,902	15,100	15,207	15,530	16,197	16,691	16,878	17,073	17,249	17,406	17,574
Coal	3,272	3,337	3,322	3,333	2,220	2,206	1,674	1,385	1,096	-	-	-	-	-	-
Gas	6,380	5,151	4,566	4,311	3,770	3,881	4,222	4,404	4,905	2,518	2,547	2,596	2,645	2,792	2,871
SMR	-	-	-	-	-	-	-	-	-	3,481	3,512	3,481	3,482	3,522	3,539
Wind	1,244	1,449	1,494	1,467	2,430	2,408	2,441	2,362	2,254	2,878	2,932	2,895	2,844	2,832	2,877
Solar	850	1,145	1,773	2,308	2,822	2,796	2,764	3,015	3,376	3,267	3,201	3,277	3,426	3,416	3,430

Cumulative Emissions & Water Usage

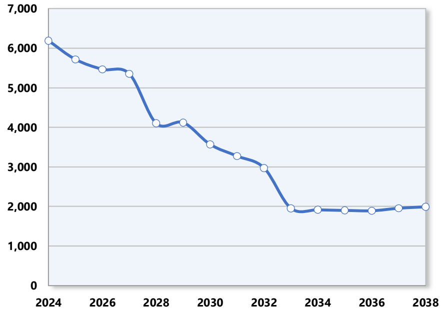


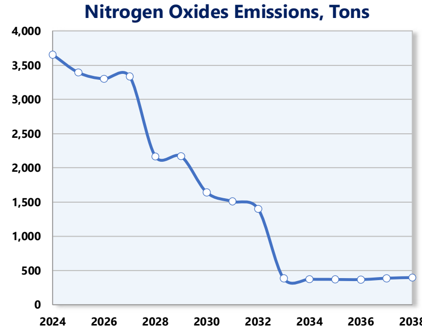
2023 Integrated Resource Plan

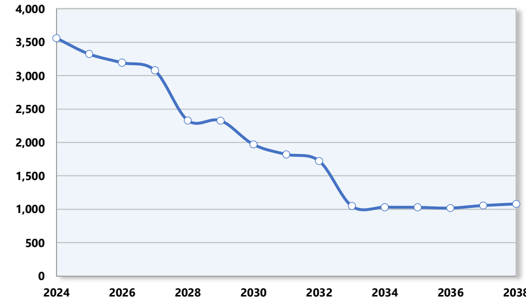
Portfolio ID - P10

Portfolio Description - Market and Transmission Remission Portfolio

Environmental Dashboard

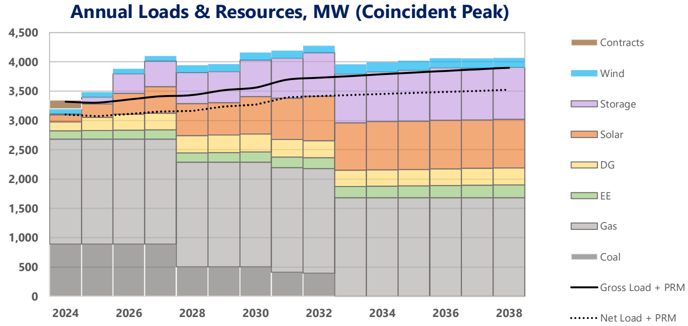


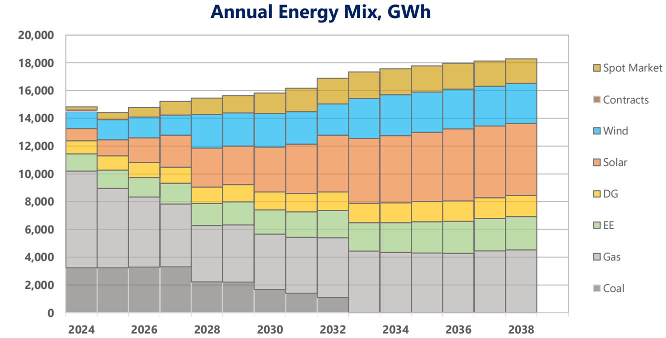


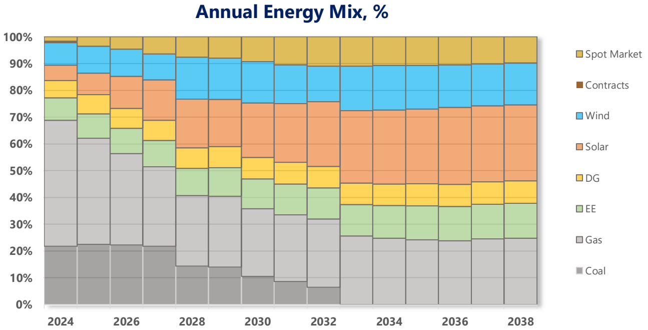


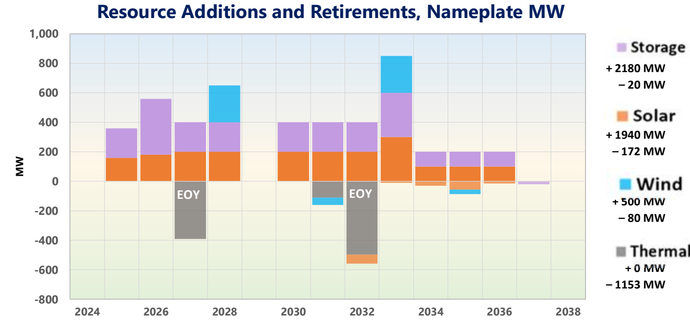
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Percent CO_2 Reductions from 2005 Levels	44%	48%	51%	52%	63%	63%	68%	70%	73%	82%	83%	83%	83%	82%	82%

Loads & Resources Dashboard



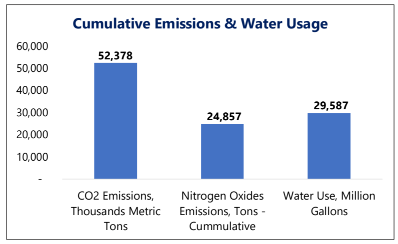




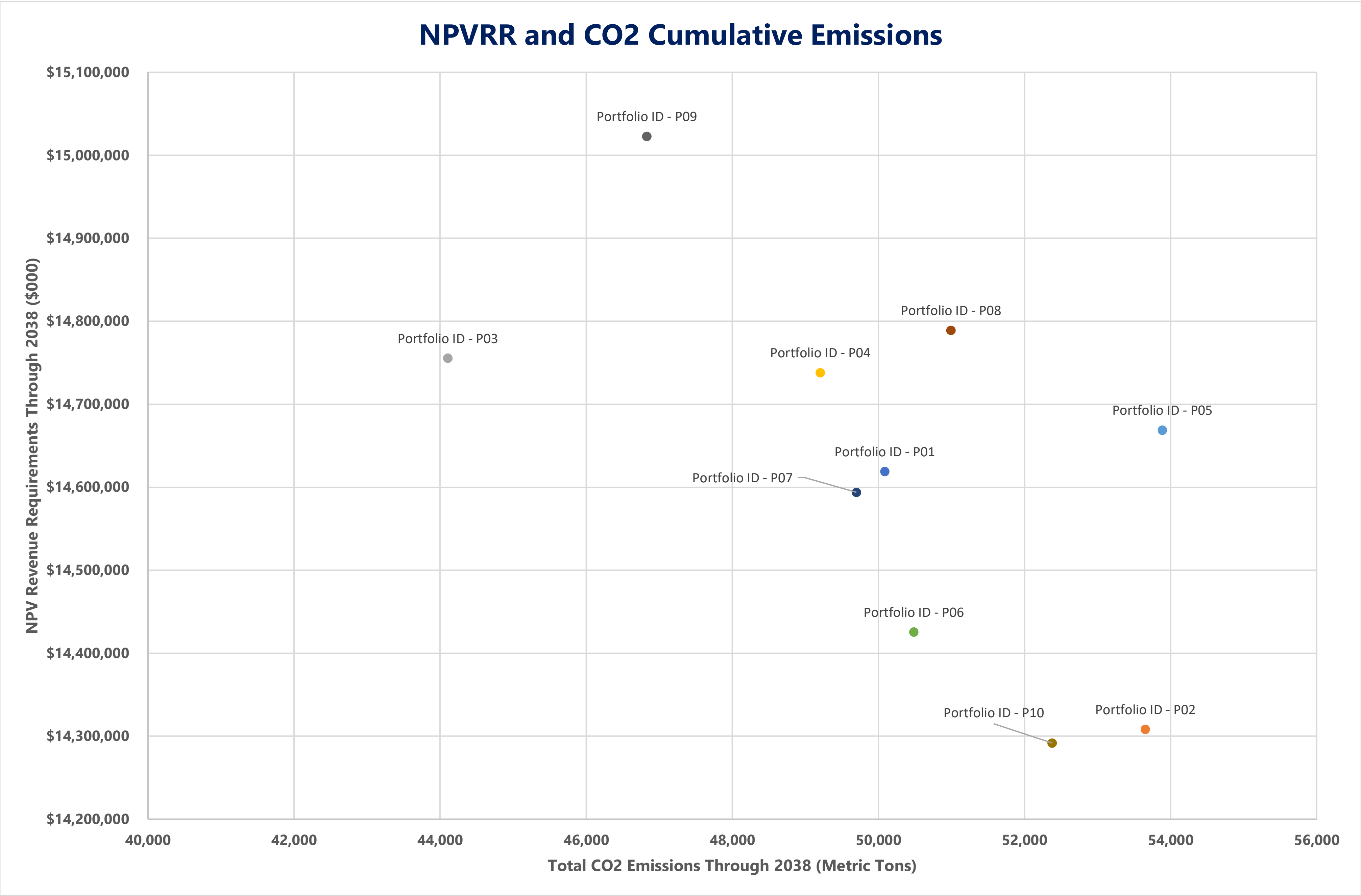


Annual Loads & Resources, MW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Gross Load + PRM	3,319	3,305	3,356	3,412	3,432	3,517	3,561	3,697	3,728	3,756	3,788	3,816	3,844	3,872	3,899
Net Load + PRM	3,102	3,073	3,109	3,152	3,163	3,237	3,269	3,396	3,416	3,433	3,452	3,469	3,486	3,504	3,523
Coal	892	892	892	892	502	502	502	410	392	-	-	-	-	-	-
Gas	1,787	1,787	1,787	1,787	1,787	1,787	1,787	1,787	1,787	1,682	1,682	1,682	1,682	1,682	1,682
Wind	87	87	87	87	128	128	128	128	119	169	169	169	164	164	164
Solar	116	229	356	456	549	549	642	703	758	809	821	823	832	824	824
Storage	17	115	331	434	528	528	621	686	741	825	845	864	893	885	885
DG	158	225	272	284	290	300	305	299	291	280	280	280	282	287	290
EE	142	148	153	159	160	166	172	178	184	190	196	203	209	215	221

Total NPVRR:	$14,291,759
Fuel NPVRR:	$2,860,863
Non-Fuel NP'	$11,430,896



Annual Loads & Resources, GWh	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Gross Energy	14,819	14,413	14,780	15,215	15,459	15,638	15,819	16,162	16,882	17,327	17,567	17,782	17,968	18,119	18,290
Coal	3,233	3,230	3,290	3,304	2,210	2,193	1,674	1,382	1,088	-	-	-	-	-	-
Gas	6,959	5,723	5,037	4,529	4,070	4,126	3,988	4,038	4,310	4,428	4,340	4,304	4,279	4,448	4,536
Wind	1,244	1,449	1,494	1,467	2,429	2,405	2,436	2,353	2,258	2,879	2,929	2,901	2,855	2,840	2,884
Solar	850	1,145	1,776	2,306	2,797	2,763	3,222	3,539	4,075	4,678	4,856	4,973	5,166	5,165	5,191
DG	966	1,029	1,088	1,141	1,192	1,232	1,273	1,312	1,353	1,383	1,418	1,454	1,488	1,507	1,527
EE	1,240	1,321	1,406	1,491	1,583	1,668	1,758	1,851	1,955	2,050	2,153	2,256	2,300	2,335	2,374


NPVRR and CO2 Cumulative Emissions
NPV Revenue Requirements Through 2038 ($000)
$15,100,000
$15,000,000
$14,900,000
$14,800,000
$14,700,000
$14,600,000
$14,500,000
$14,400,000
$14,300,000
$14,200,000
40,000
42,000
44,000
46,000
48,000
50,000
52,000
54,000
56,000
Total CO2 Emissions Through 2038 (Metric Tons)
Portfolio ID - P09
Portfolio ID - P08
Portfolio ID - P03
Portfolio ID - P04
Portfolio ID - P05
Portfolio ID - P01
Portfolio ID - P07
Portfolio ID - P06
Portfolio ID - P10
Portfolio ID - P02

Appendix D: Effective Load Carrying Capability

Tucson Electric Power ELCC Study

Final Report

03/23/2023

Vignesh Venugopal, Managing Consultant
Angineh Zohrabian, Sr. Consultant
Ruoshui Li, Consultant
Zach Ming, Director
Nick Schlag, Partner

Energy+Environmental Economics

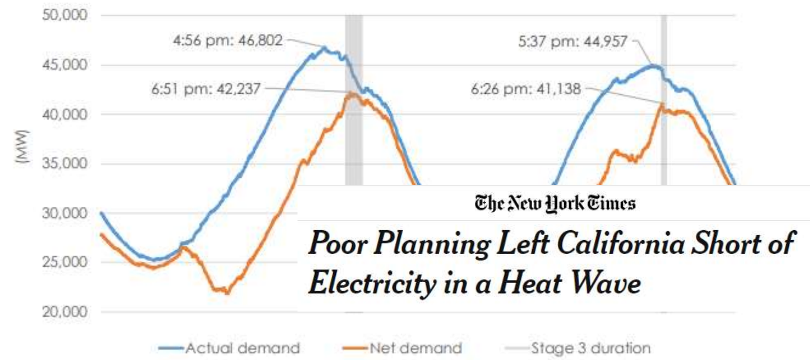
List of contents

Background

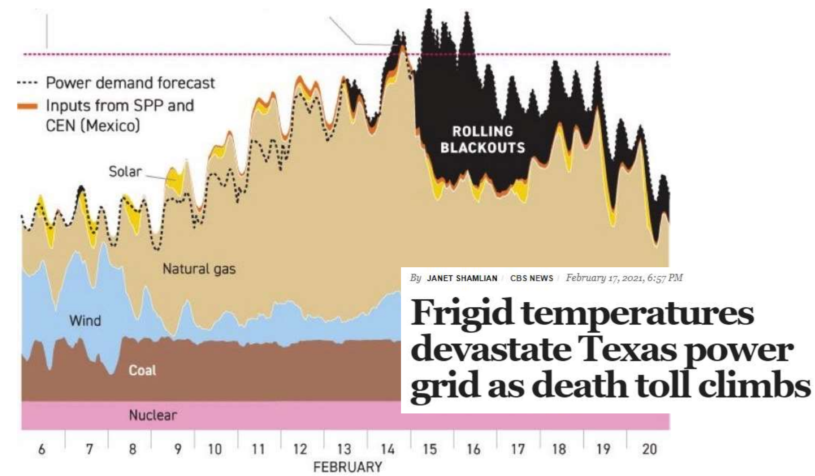
Energy+Environmental Economics

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



Graph source: http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf

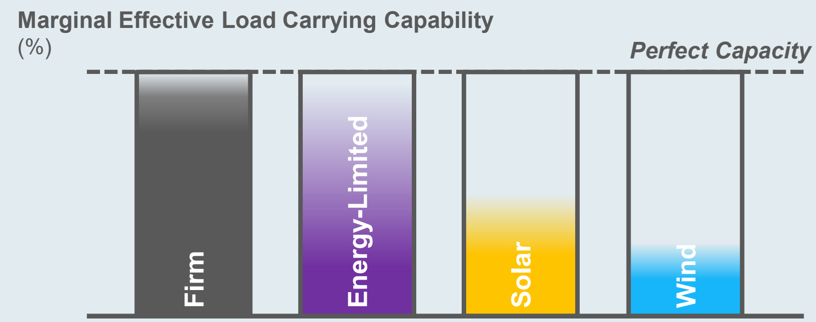


Graph source: https://twitter.com/bcshaffer/status/1364635609214586882

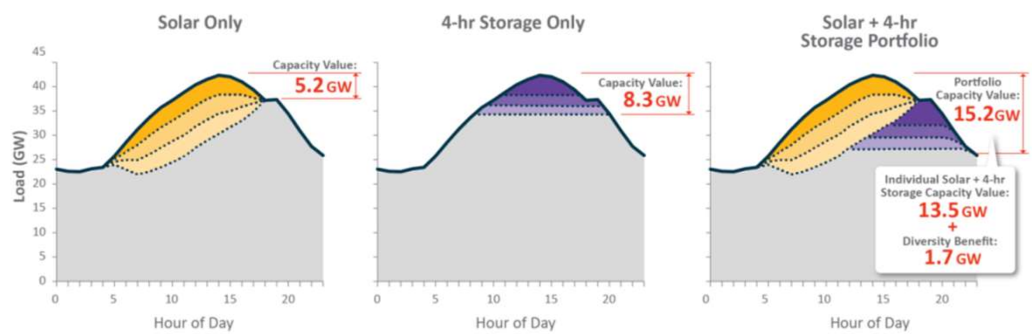
Accurately accounting for resources' reliability contribution is necessary to ensure reliable electric service

- **Renewables and storage penetration will continue to grow, driven by deep-decarbonization goals and economics**
- **Accurately measuring the effective capacity contribution of these resources with an Effective Load Carrying Capability (ELCC) is important to maintain reliability.**
- **ELCC:**
  - Captures capacity contribution across a broad range of system conditions
  - Robustly accounts for saturation effects and interactive effects between resources
  - Allows system to function efficiently and effectively even as it transitions away from reliance on firm resources

ELCC measures a resource's contribution to the system's needs relative to perfect capacity, accounting for its limitations and constraints

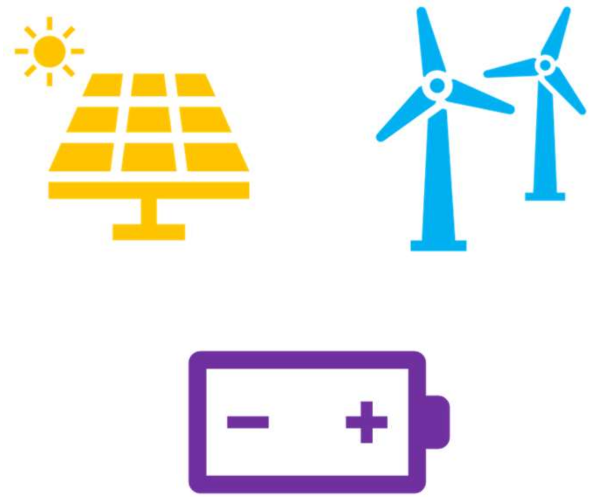


Saturation effect with increasing penetration **Interactive effect**



Study purpose

- **TEP retained E3 to calculate the ELCC for variable renewable and energy/duration-limited resources**
  - These include, solar, wind, 4 and 8-hr storage
- **Study results can be used to:**
  - Accurately account for the value of these resources in future IRPs to build a cost-effective resource portfolio that will also be reliable
  - Inform resource procurement in the near-term for summer preparedness
- **Optionally, TEP may extend the scope and budget to have E3 calculate the following for the TEP system:**
  - Target Planning Reserve Margin (PRM)
  - Achieved PRM
  - Capacity shortfall/excess



Scope of work

ELCC study

1. **Develop model inputs for ELCC analysis**
2. **Setup E3's RECAP model for ELCC calculations**
3. **Calculate ELCC values for various resource types**
4. **Prepare final PowerPoint report**

Objective: Characterizing capacity contributions of variable renewable and duration/energy-limited resources to TEP in the near term. TEP's conventional resources will not be modeled

Full LOLP study (Optional)

5. **Gather additional inputs for LOLP study**
6. **Calculate PRM**
7. **Simulate portfolio reliability**

Objective: More detailed representation of TEP with its conventional resources to assess TEP's reliability standing

Methodology

Task 1. Develop model inputs

- E3 developed a combined representation of the **TEP + UNSE service territory in 2028**
- E3 relied on some inputs developed in the 2021 SWRA study and developed the rest with input from TEP
  - Based on a combination of public sources, commercial datasets, and TEP input
- TEP helped refine assumptions and provide supplemental inputs

Summary of RECAP Inputs

Category	Data
Loads	Historical Hourly Loads
	Annual and Peak Load Forecasts
Thermal Units	Plant Capacity
	Online & Retirement Dates
	Seasonal Derates to Plant Capacity
Renewables	Plant Capacity, Location and Hourly Profiles
	Online & Retirement Dates
Storage	Plant Capacity (and Duration)
	Round Trip Efficiency
	Forced Outage Rate

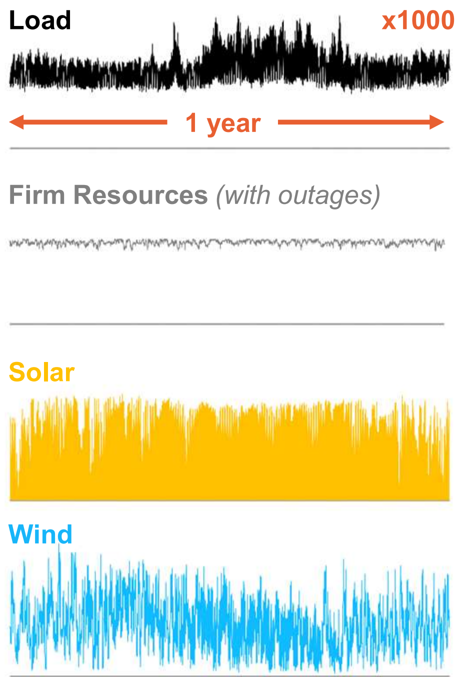
Task 1. Develop model inputs

Profile	Primary Source(s)	Weather Conditions Captured	Notes
Loads	**EIA** Hourly Electric Grid Monitor **NOAA** Historical Weather Data	1979 2020	• Neural network regression used to back-cast hourly load patterns under broad range of weather conditions using recent historical load data (2011-2020) and long-term weather data (1979-2020) • 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
Wind	**NREL** WIND Toolkit	2007 2012	• 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 2019	• 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

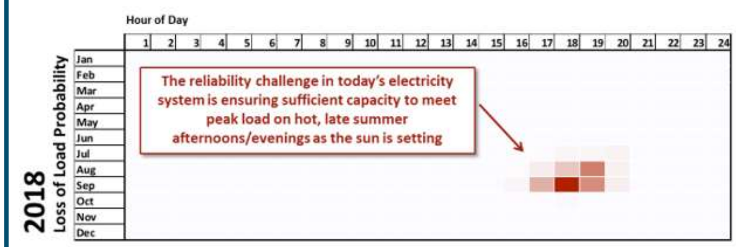
Task 2. Setting up E3's RECAP model

+ **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
+ **Primary results are probability-weighted statistics of loss of load frequency, duration, and magnitude – but can also be used to derive PRM requirements and ELCCs of different resources**

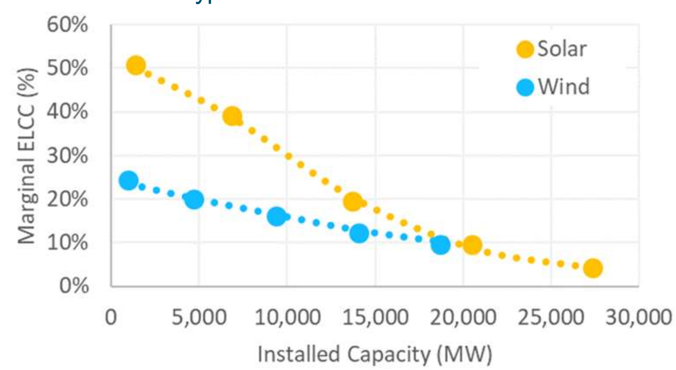
Monte Carlo simulation of loads, renewable profiles, and generator outages used to simulate 1,000 years of plausible system conditions



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

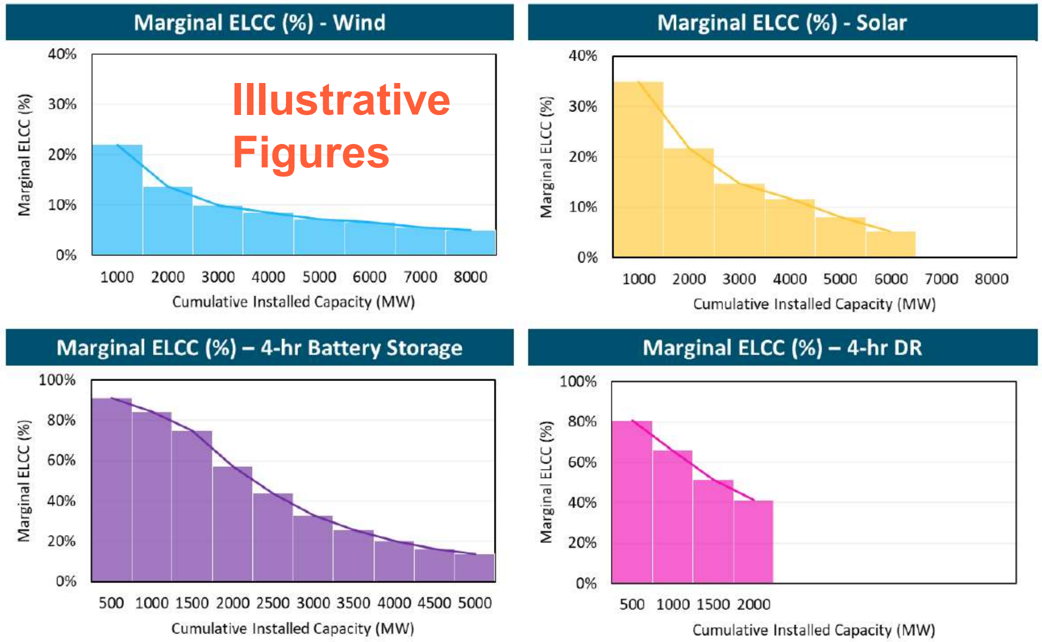


Example RECAP result from *Long-Run Resource Adequacy under Deep Decarbonization Pathways for California* (Calpine, 2019)

Task 3. Calculate ELCCs

Developing ELCC Curves for Various Resources

- **Marginal ELCC curves can show the incremental ELCC of individual resources at increasing penetration**
  - Solar (blend of several locations)
  - Wind (blend of several locations)
  - Storage/Demand Response
- **While these curves capture saturation effects for a single resource, they do not capture interactions between different resources at varying penetrations**

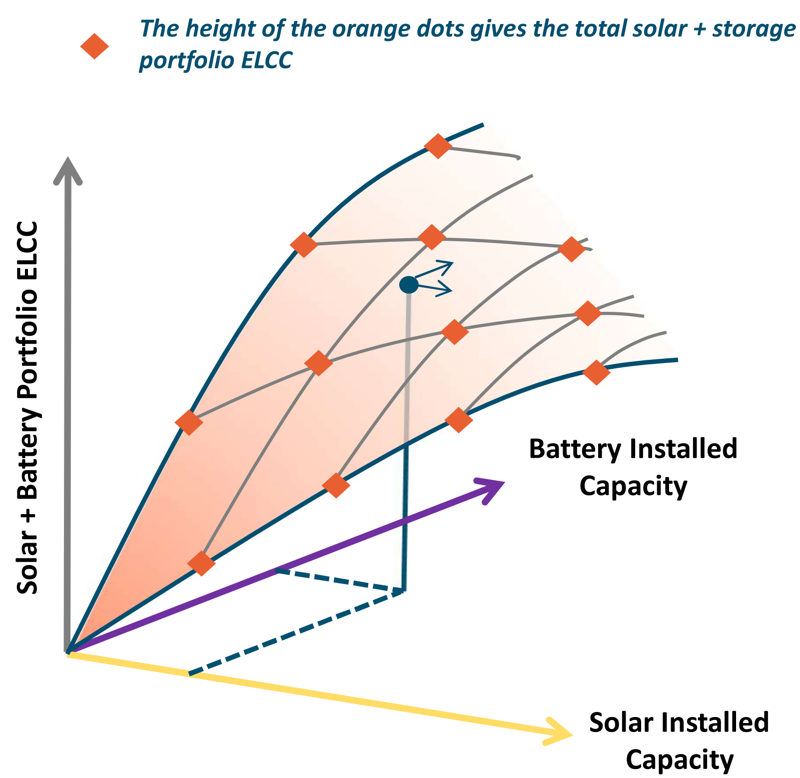


Task 3. Calculate ELCCs

Developing ELCC surfaces

- A multi-dimension ELCC surface can capture interactive effects between multiple resources and show combined capacity contribution
- Account for both diminishing returns and interactive effects between resources
- E3 constructed ELCC curves and surfaces for the combined TEP+UNSE system in 2028, chosen by TEP
  - Wind ELCC curve
  - Solar-4-hr Storage ELCC surface
  - 8-hr Storage ELCC curve

Illustrative ELCC surface



Full LOLP study (Optional)

+ **E3 could develop a full representation of the TEP+UNSE system in RECAP and determine the planning reserve margin needed to ensure an appropriate standard of reliability**

Key data to update for the full LOLP study

Inputs

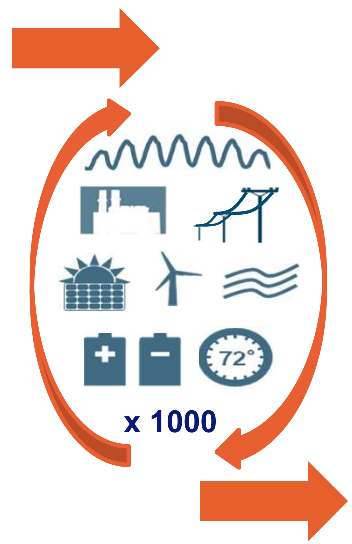
Load
- *Hourly load for multiple weather years*

Thermal resources
- *Seasonal capacity ratings*
- *Forced outage rate*
- *Maintenance outage schedules*

Renewable resources
- *Capacity*
- *Hourly generation profiles for 250 weather years*

Energy storage resources
- *Capacity and Duration*
- *Round-trip efficiency*
- *Forced outage rate*

Demand response
- *Capacity*
- *Max number of calls per season*
- *Max duration of each call*



Outputs

Loss of Load Expectation (LOLE)
- *Expected number of days in which loss-of-load events occur in each year*

Target Planning Reserve Margin (PRM)
- *PRM required to achieve a specified reliability threshold (i.e., 0.1 LOLE)*

Achieved Planning Reserve Margin (PRM)
- *PRM achieved in the current TEP/UNSE system*

Capacity Shortfall / Excess
- *Amount of perfect capacity required / excess in the system to achieve the reliability threshold*

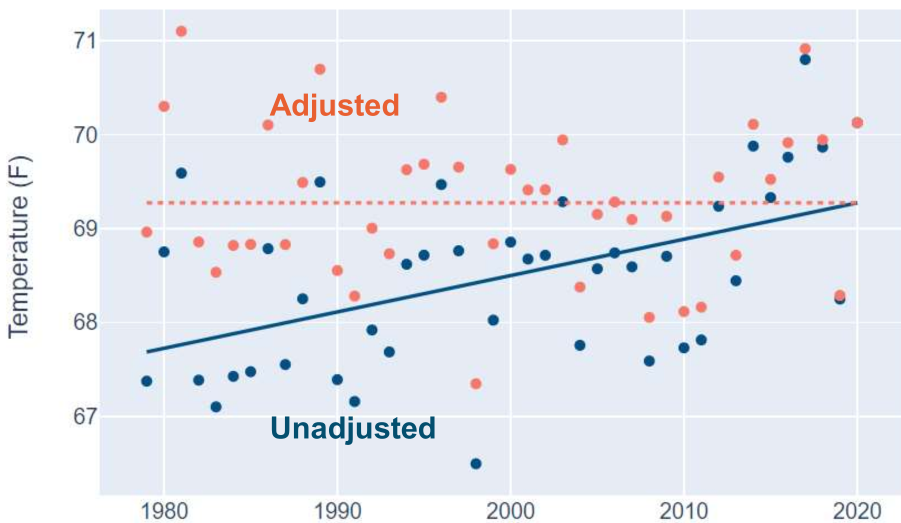
Loss-of-load Events Analysis
- *Month-hour LOLE distribution*
- *Loss-of-load events duration distribution*
- *…*

Inputs and Assumptions

Energy+Environmental Economics

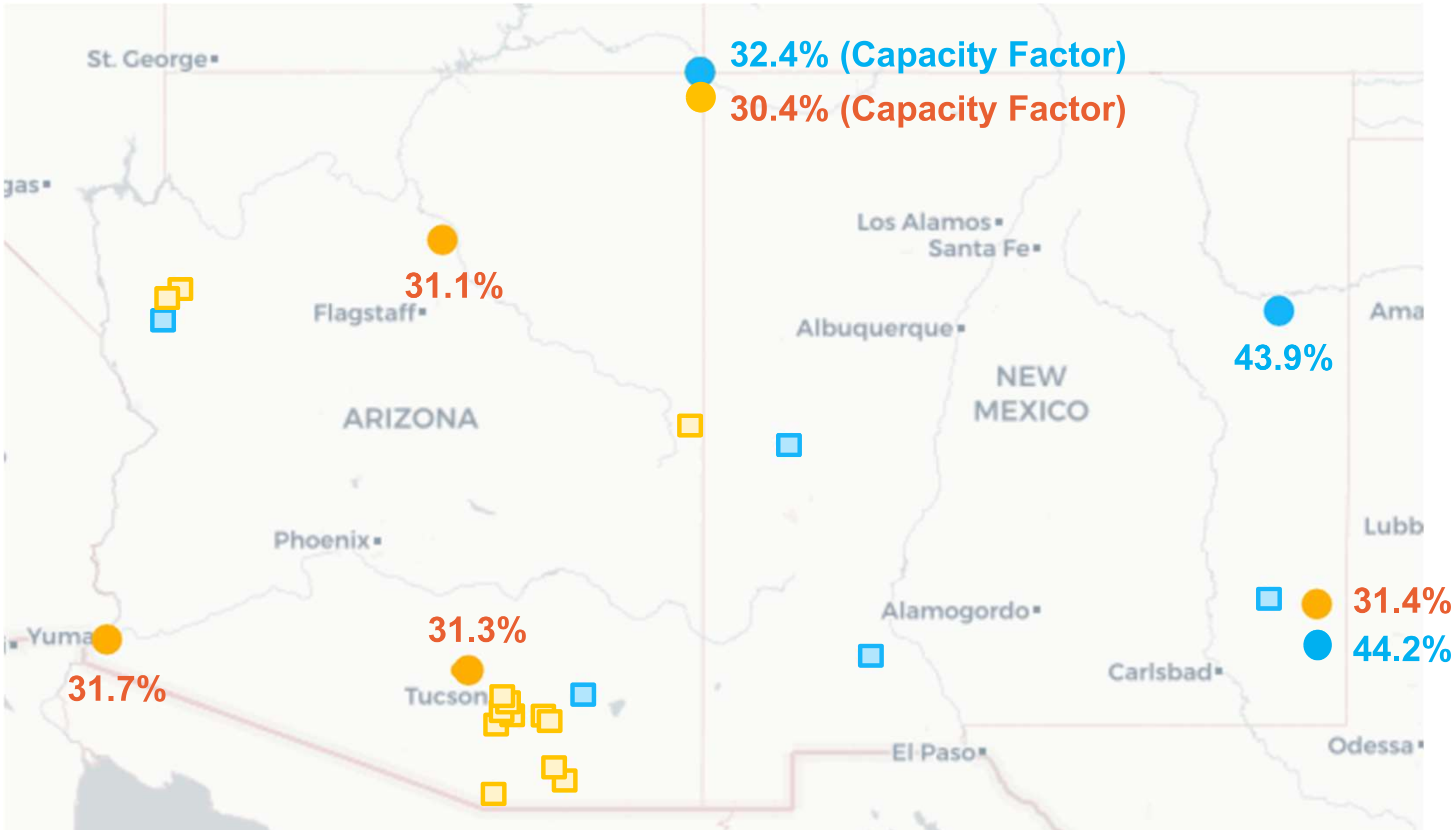
Temperature detrending

Average Annual Temperature, 1979-2020



+ Like in the SWRA study, load shapes were developed using temperature data from 40 years
+ Temperature from 1979-2020 was adjusted to account for warming observed in that period
+ This allows stress-testing the system under different *weather* conditions adjusted for 2020 *climate*

Solar and wind locations



Additional resource profiles considered to capture geographic diversity

- Solar
- Wind

Existing resources

- Solar
- Wind

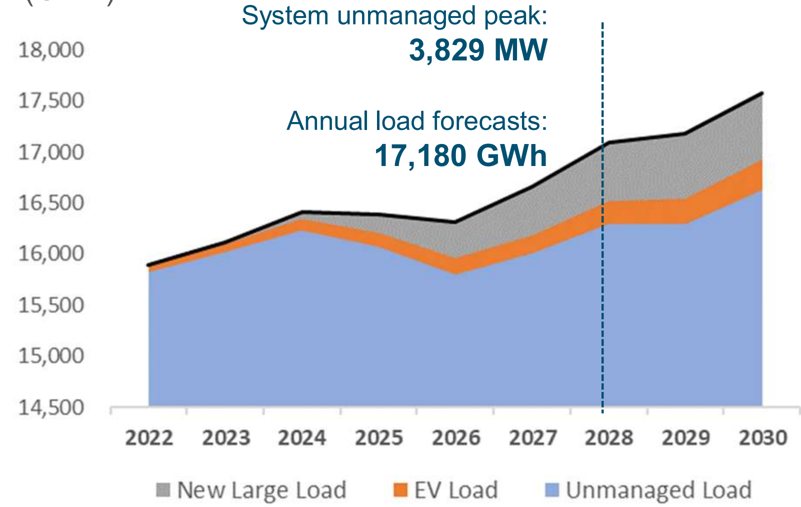
Profile simulation methodology

- Historical generation record for renewable resources are typically limited. To capture the variability over several weather years, RECAP relies upon simulated solar and wind profiles from NREL's WIND Toolkit and NREL's System Advisor Model (SAM)
- For TEP existing resources, plant-level generation profile is simulated based on location, panel characteristics, hub heights, etc. identified
- For additional resource profiles considered in this ELCC study, profiles are simulated at locations chosen in collaboration with TEP
- Weather conditions captured:
  - Solar: 1998 – 2019
  - Wind: 2007 - 2012

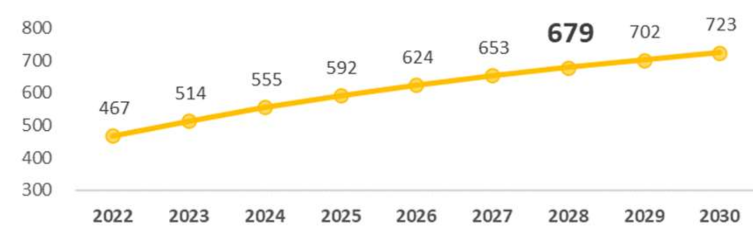
Other inputs and assumptions

- **Load expected in 2028 was modeled**
  - TEP + UNSE combined peak load is about 3.8 GW
  - Existing and planned resources through 2028 were modeled
  - Higher penetration of solar, wind and storage were also modeled to build a more comprehensive ELCC curve/surface
- **Behind-the-meter PV installation grows steadily from 2022-2030, with 2028 penetration at 679 MW in TEP + UNSE system**
- **Storage resources are modeled with 10% forced outage rate (FOR)**
- **Thermal outages are not modeled. Uniform seasonal derates are applied**
  - Detailed modeling of thermal fleet may be conducted under the optional, full LOLP study

Annual gross load forecasts for TEP & UNSE (GWh)



BTM PV forecasts for TEP & UNSE (MW)



Resource tiers modeled

Wind

Tier Size (MW)	Cumulative Nameplate Capacity (MW)	Assumptions
437	437	Represents existing wind projects
200	637	Represents existing and 200 MW new wind at Oso Grande.
250	887	Avg of wind profiles from Four corners, East NM and Oso Grande locations
250	1,137	
250	1,387	
250	1,637	
2,363	4,000	

Solar

Tier Size (MW)	Cumulative Nameplate Capacity (MW)	Assumptions
1,103	1,103	Represents existing solar (588 MW utility solar and 514 MW BTM solar)
415	1,518	Represents existing solar and new solar projects (250 MW new utility solar and 165 MW new BTM solar)
500	2,018	Avg of utility-scale solar profiles from Flagstaff, Four Corners, Oso Grande, Tucson, and Yuma
500	2,518	
500	3,018	
1,000	4,018	

4-hr Storage

Tier Size (MW)	Cumulative Nameplate Capacity (MW)	Assumptions
150	150	30 MW existing, 120 MW new. Not location-specific 10% FOR
150	300	Not location-specific 10% FOR
300	600	
400	1,000	
500	1,500	
500	2,000	
2,000	4,000	

- **Wind ELCC curve was calculated without any solar or storage in the base system**
- **Solar-4-hr storage ELCC surface was built for a base portfolio containing 1637 MW of wind**
- **Each combination of solar and storage penetration in these tables was modeled to construct the full solar-storage ELCC surface**

Results

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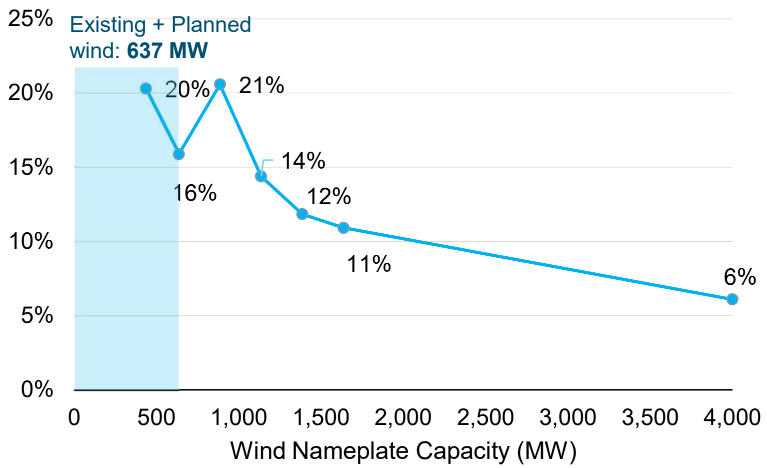
Wind ELCCs

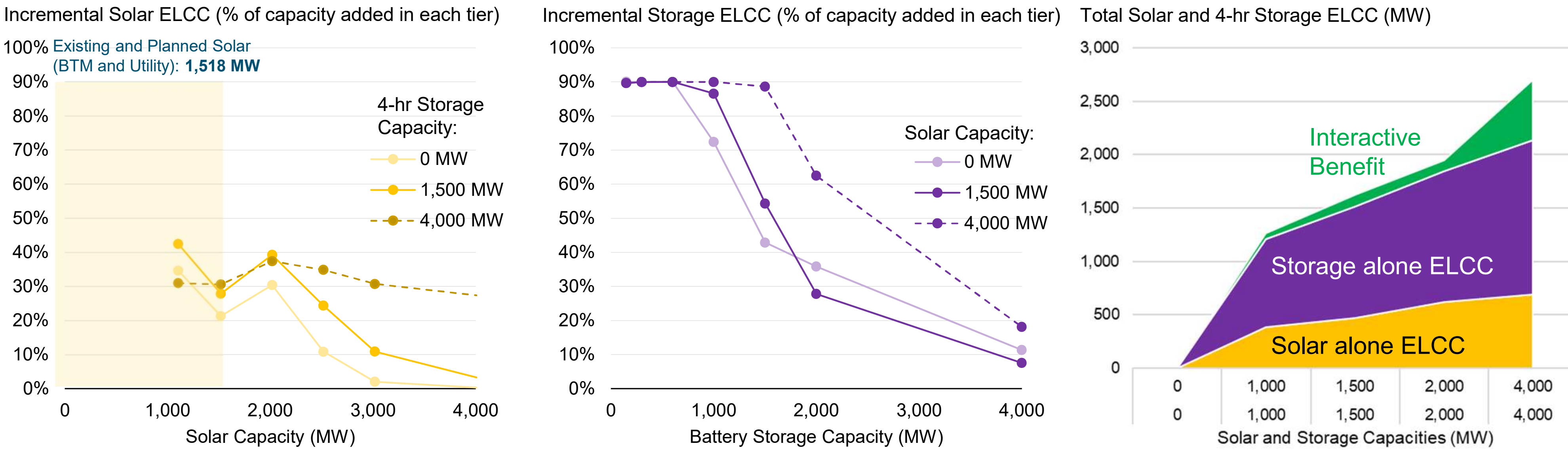
Incremental Wind ELCC (% of capacity added in each tier)



Wind Capacity (MW)	Incremental ELCC (MW)	Average ELCC (MW)	Incremental ELCC (%)	Average ELCC (%)
437	89	89	20%	20%
637	32	120	16%	19%
887	51	172	21%	19%
1,137	36	208	14%	18%
1,387	30	237	12%	17%
1,637	27	265	11%	16%
4,000	144	408	6%	10%

+ **Existing wind gets 20% ELCC. 200 MW of additional wind at Oso Grande receives 16% ELCC**
+ **Third tranche onward, additional wind is assumed to be a mix of wind from 3 different locations – Eastern NM, Oso Grande and Four corners**
  - Diversity in location and generation helps boost wind ELCC from tranche 2 to 3
+ **Diminishing returns are observed as expected with every additional tranche**

Solar and 4-hr storage ELCCs



- First 1500 MW of solar is a mix of existing and expected BTM and utility-scale solar expected by 2028
- Third tranche onward only utility-scale solar (mix of 5 different locations) is introduced, leading to temporary boost in ELCC
- Diminishing returns are observed as expected as net peak shifts into the evening
- Storage is modeled with a 10% FOR, that impacts ELCC by approx. 10%
- 4-hr Storage ELCC is reasonably high until 1.5 GW is added. Sharp drop in ELCC beyond that unless solar penetration is high
- Given existing and planned demand response programs offer 4-5 hrs of duration, 4-hr storage ELCC would be a reasonable proxy in the near term. Additional derates may be applied if # of calls offered is very small

Solar and 4-hr storage ELCCs

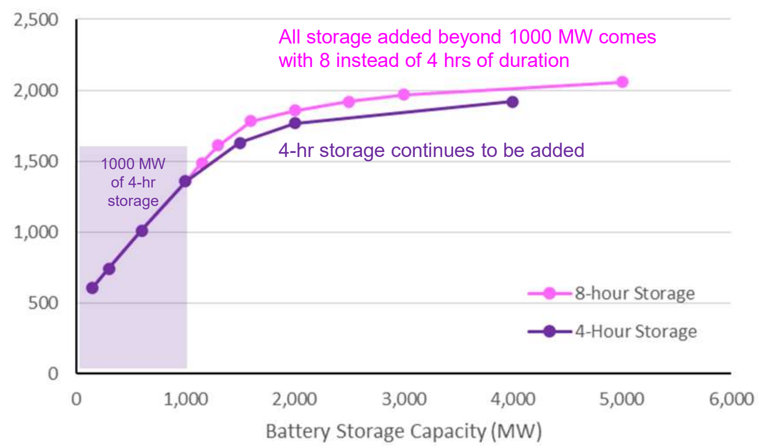
4-hr Storage Nameplate Capacity (MW)

Total ELCC for a given combination of solar and storage (MW)

Solar Capacity (MW)	0	150	300	600	1,000	1,500	2,000	4,000
0	0	135	270	540	830	1,044	1,223	1,449
1,103	382	517	652	920	1,261	1,512	1,640	1,791
1,518	471	605	740	1,010	1,356	1,628	1,767	1,919
2,018	623	757	892	1,162	1,512	1,824	1,946	2,106
2,518	677	811	946	1,216	1,574	1,946	2,110	2,280
3,018	687	821	956	1,226	1,584	2,001	2,237	2,434
4,018	690	824	959	1,229	1,589	2,033	2,345	2,707

8-hr Storage ELCCs

ELCC (MW) of 1500 MW Solar + Battery Storage



8-hr Battery Storage Capacity (MW)	Incremental ELCC (MW)	Average ELCC (MW)	Incremental ELCC (%)	Average ELCC (%)
150	129	129	86%	86%
300	126	256	84%	85%
600	169	425	56%	71%
1,000	76	501	19%	50%
1,500	62	562	12%	37%
2,000	50	612	10%	31%
4,000	90	702	4%	18%

- **8-hr storage curve assumes 1,000 MW of 4-hr storage is in the base portfolio**
  - **1,518 MW solar and 1,637 MW wind are also in the base portfolio**
- **10% FOR is modeled akin to 4-hr storage**
- **With these assumptions, 8-hr storage provides slightly higher ELCC relative to 4-hr storage**
- **Adding duration alone doesn't help much at relatively low renewable penetrations. There is value in adding more storage (both capacity and duration) in conjunction with more renewables to see big interactive benefits, as shown on slide 23**

Thank You

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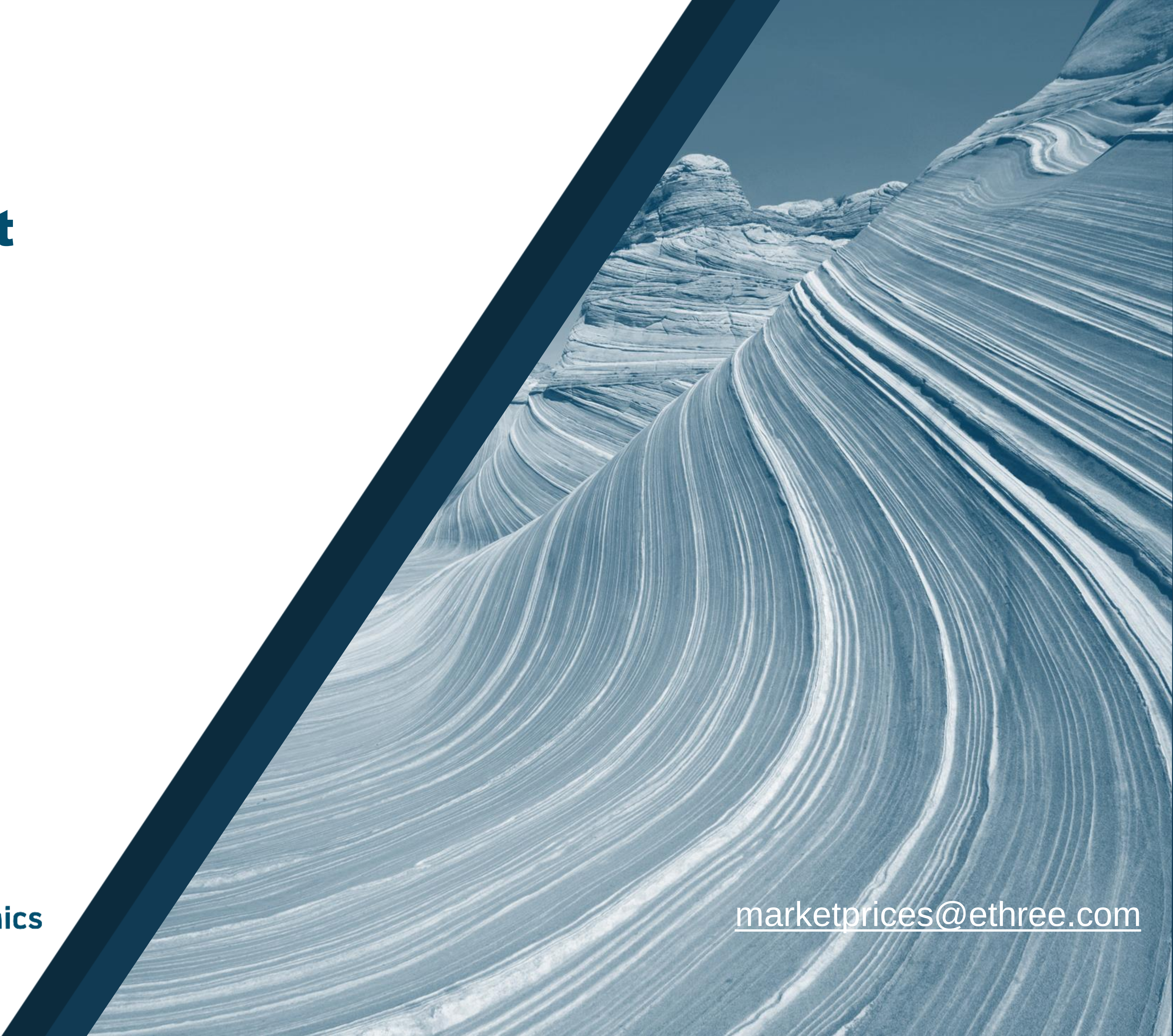
Appendix E: Wholesale Power Price Forecast

Southwest
Market Price Forecast
E3 Core Case

March 2023 edition



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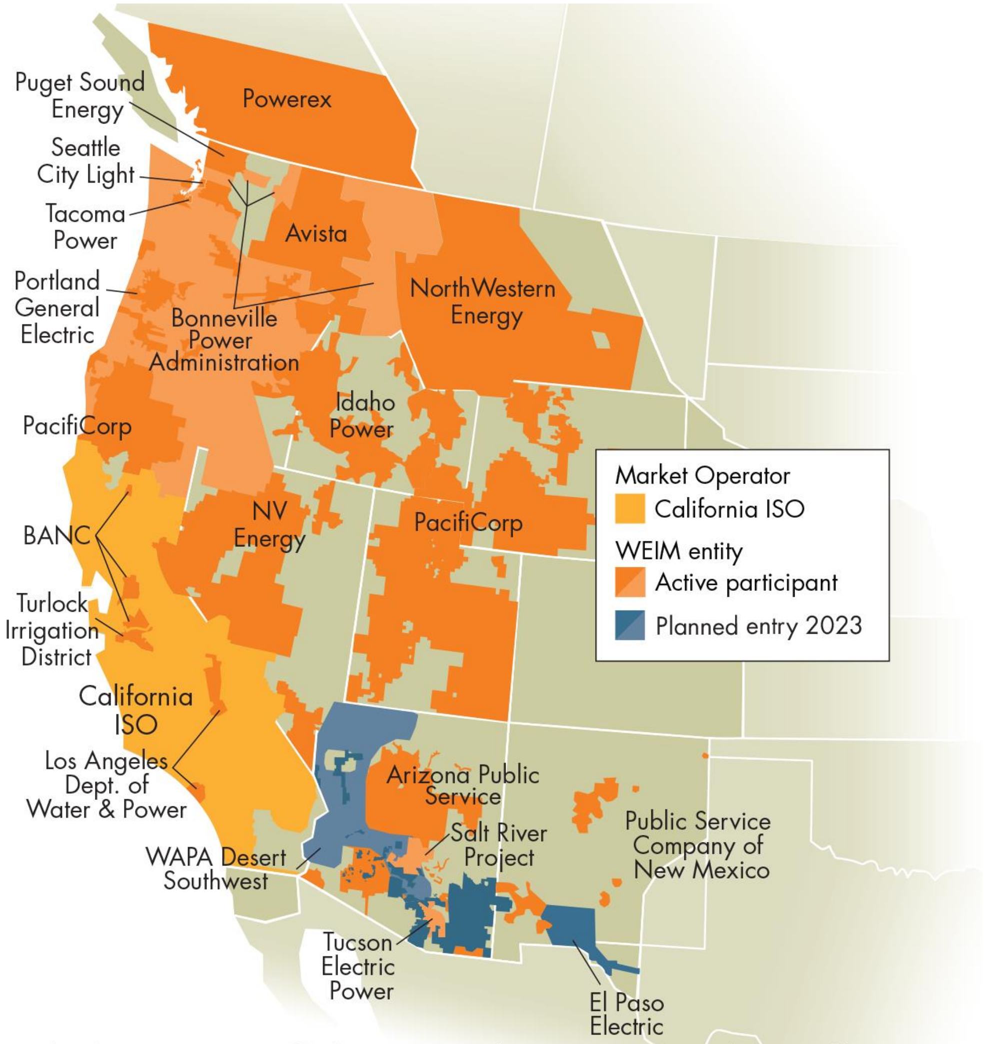
Disclaimer

E3 created the following forecasts and analyses using the best available public information and our expertise and knowledge of the relevant markets, along with commercially available 3rd party software models and proprietary in-house energy market price forecasting tools. However, the future is uncertain, and these forecasts (along with underlying market expectations) may change due to many factors, including unforeseen events, new technology adoption or inventions, new market structures, regulatory actions, and changes in both state and federal government policies. E3 makes no guarantees related to these forecasts or the information presented herein and should not be held liable for any economic damages associated with independent investment decisions.

Energy Markets in the West: CAISO

- **CA Independent System Operator (CAISO) manages the only wholesale energy market in the West**
  - Day-Ahead Energy Market (hourly)
  - Real-time Energy Markets (15-min and 5-min)
  - Ancillary Services Markets
  - Resource Adequacy Program (bilateral contract market)
- **CAISO also manages the Energy Imbalance Market (EIM)**
  - EIM is fully integrated within the CAISO real-time energy market
  - Participants are Balancing Authorities across the West
  - Facilitates and settles transactions for energy transferred between BAs
- **Proposed Day-Ahead Regional Markets**
  - **CAISO Extended Day-Ahead Market (EDAM)** (proposed)
  - **SPP Markets+** (proposed)
  - CAISO and SPP offer competing proposals for WECC utilities to join
  - Significant potential benefits, but these depend on which utilities participate in which initiative…

CAISO EIM Participants



Map boundaries are approximate and for illustrative purposes only.

Energy Markets in the West: Bilateral Trading

- Outside of the CAISO wholesale market, energy trading is done bilaterally in the West through exchanges which match buyers and sellers (for example, the Intercontinental Exchange or ICE)
- Two major trading hubs exist:
  - Mid-Columbia (“Mid-C”) in Washington
  - Palo Verde in Arizona
- Energy is traded in hourly “blocks” through standardized “Over the Counter” (OTC) contracts
  - “On-Peak” | hours ending 7 to 22 (7am to 10pm) Mon. to Sat.*
  - “Off-Peak” | hours ending 23 to 6 (11pm to 6am) Mon. to Sat. and hours 1-24 Sun. + Holidays*
  - These blocks are traded for the next day (Day-Ahead) and for specific months in the future (i.e. the On-Peak period in August)
- Traded prices are set based on suppliers’ willingness to sell and buyers’ willingness to buy
- Traded volumes of power (MWh) at bilateral hubs cover only a small portion of total electricity demand in each region → this is different from the CAISO market, in which 100% of generation is cleared at the market price in each hour of every day.

* ICE Product Specification: PSpec_OTC_Electricity.pdf (theice.com)

What are E3's Palo Verde Market Price Forecasts?

+ **E3 provides an <u>hourly price forecast</u> that reflects the market premiums and bidding behavior expected in future Day-Ahead On-Peak/Off-Peak trades at Palo Verde**
+ **These "future day-ahead prices" are different from month-ahead forward prices at Palo Verde**
  - For example, forward prices (On-Peak energy for August next year) will be different from On-Peak energy traded one day in advance of a day in August of next year
  - This is because i) there is greater risk to sell power forward at a fixed price farther in the future (vs. tomorrow), and ii) the commitment to deliver power far in the future (next August) represents a firm commitment with capacity value, and this capacity value has a cost—for example, if a generator commits to selling power in AZ next August, this same generator cannot participate in California's Resource Adequacy market for next August.
+ **Why does E3 forecast an hourly price stream at Palo Verde and not simply an On-Peak and Off-Peak block price?**
  - Hourly price shapes are more informative for resource planning and procurement decisions, especially because hourly price shapes are likely to change over time as loads and resources change (especially with renewables)
  - CAISO has a network point at Palo Verde which has a Locational Marginal Price (LMP) in CAISO's Day-Ahead and Real-Time energy markets—these prices inform Day-Ahead traded block prices at Palo Verde
  - E3 produces hourly shapes by modeling the Western Interconnect on an hourly basis over the next 30 years.

Modeling Approach for E3 Price Forecasts

Baseline Data
Current load, existing resources, planned retirements, Tx

Resource Buildout
Build out resources that are economic over time

Scenario-specific Assumptions
RPS policies, gas prices, load growth, technology costs, renewable shapes, etc.

Resource Revenues
Hourly output * market prices

System Dispatch
Dispatch, renewable curtailment, and transmission flows

$

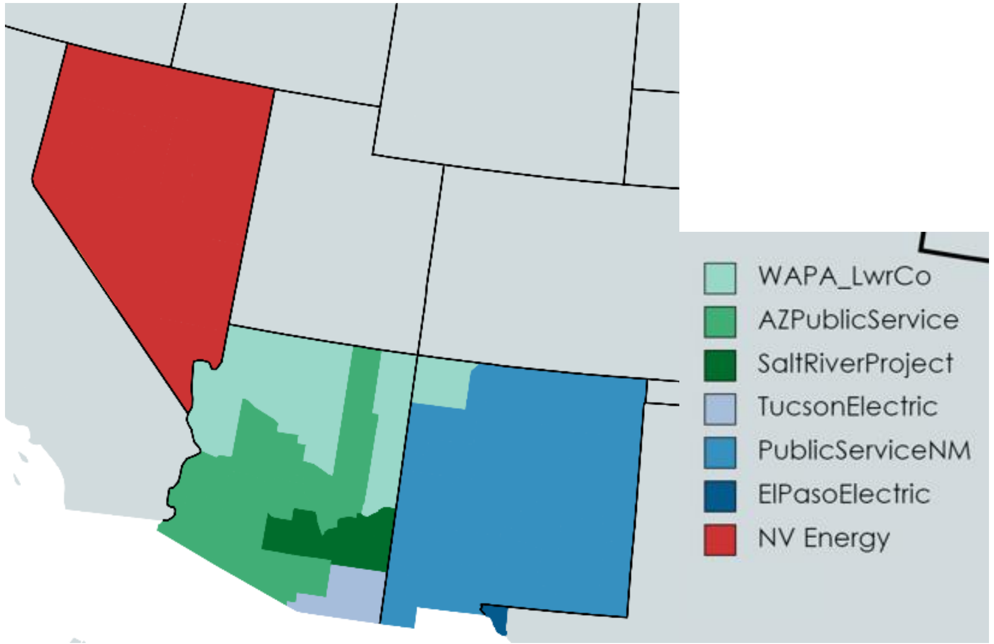
Market Prices
Marginal cost of resources used in dispatch

Energy Market Price Forecasts

- Energy: DA by zone (hr) and RT by zone (15 min & hr)
- System Operations: Zone and ISO wide (hr/mn/yr)

Southwest Region: Model Footprint

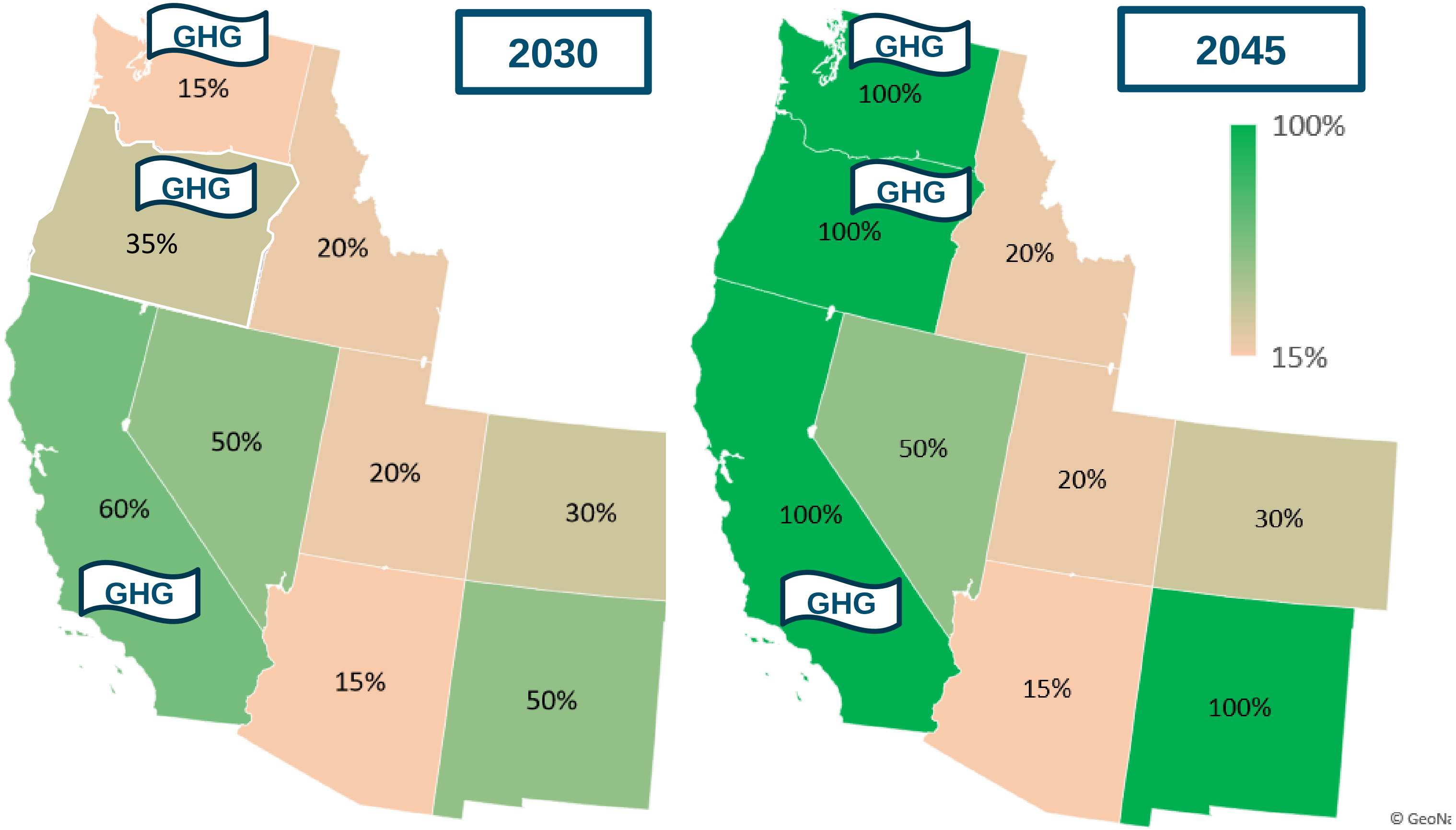
- **E3's market forecasts of the Southwest region include 6 Balancing Authorities across 3 states:**
  - Arizona: APS, SRP, TEP, WAPA Lower Colorado
  - Nevada: Nevada Energy
  - New Mexico: PNM, ElPasoElectric
- **Energy prices are forecasted as marginal costs of generation by Balancing Authority region**



https://www.wecc.org/epubs/StateOfTheInterconnection/Pages/Western-Interconnection.aspx

Clean Energy and Renewable Portfolio Standards (CES and RPS) by 2030 and 2045 in the West

State Level Targets



Many utilities have commitments that exceed those of their states, especially in states with low or minimal policy goals

Utility Targets

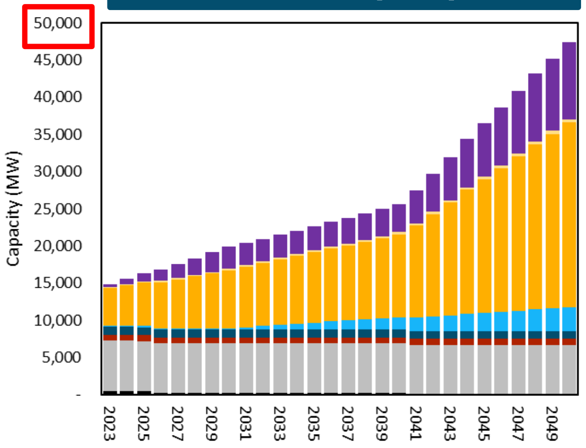
*Utility has CES and GHG target

Region	Utility	2030	2045	2050
SW	SRP	GHG Target		
	APS	65%	65%	100%
	TEP	GHG Target		
	EPE		100%	100%
	PNM*		100%	100%
	NV Energy			100%
RMT	Black Hills	GHG Target		
	Xcel CO*			100%
	Tri-State*	50%	50%	50%
Basin	Idaho Power		100%	100%
	PacifiCorp East	GHG Target		
PNW	NW Energy			
	Portland General			
	BPA			
	PSE			
	Avista			
	Seattle City Light			
	Tacoma Power	90%	90%	90%
CA	PG&E			
	SCE			
	SDG&E			
	LADWP		100%	100%
	SMUD	100%	100%	100%
	IID			

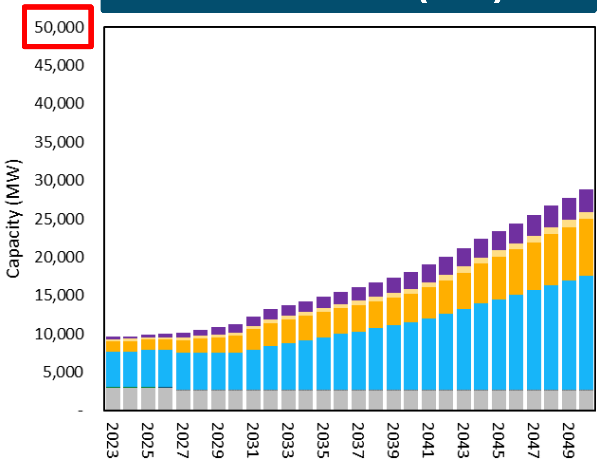
Installed Generation Capacity (MW)

*Note the difference in y-axes

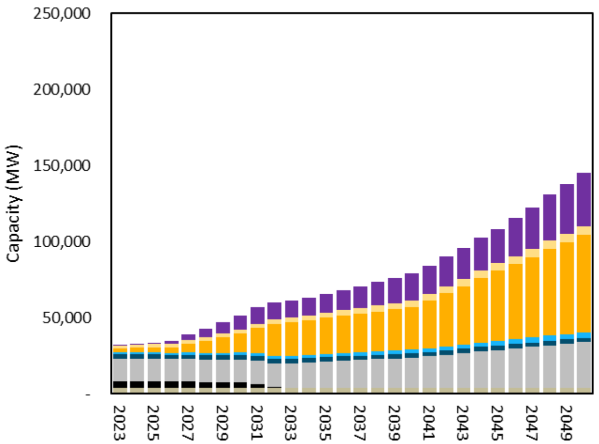
Nevada (MW)



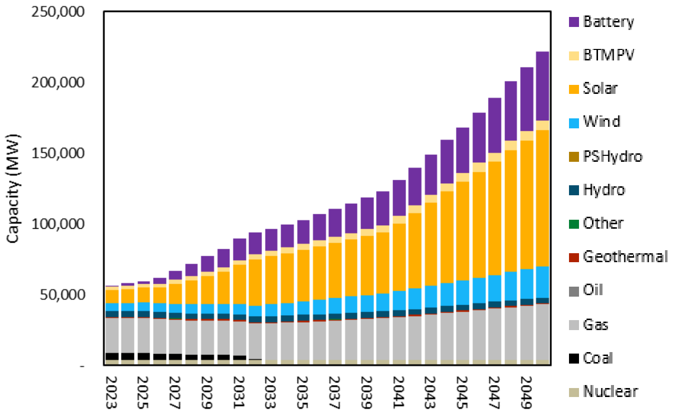
New Mexico (MW)



Arizona (MW)



Southwest Total (MW)

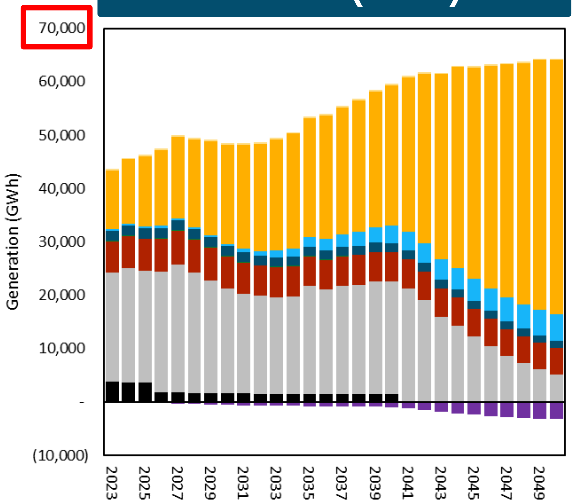


- Solar is expected to be the largest renewable resource overall in the region over the forecast period
- Wind is the largest renewable resource in New Mexico which serves in-state and out-of-state demand
- Storage is added to integrate solar, shift solar generation into evening hours, and provide capacity value
- All coal capacity is assumed to retire by 2040 (most by early 2030s based on public retirement dates)
- Palo Verde assumed to remain online through 2050 (past current retirement date)
- Some new combustion turbines are added to support system capacity needs (alongside battery storage), while gas generation declines over the forecast period to meet clean energy targets

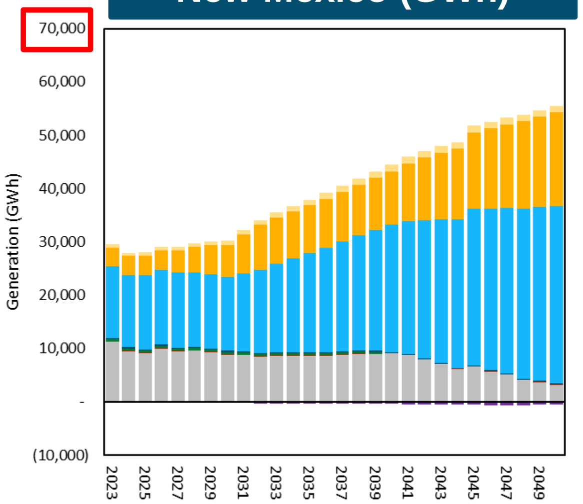
Annual Generation (GWh)

*Note the difference in y-axes

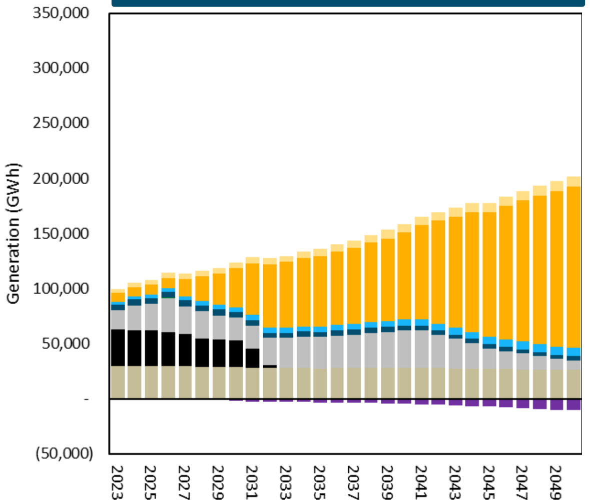
Nevada (GWh)



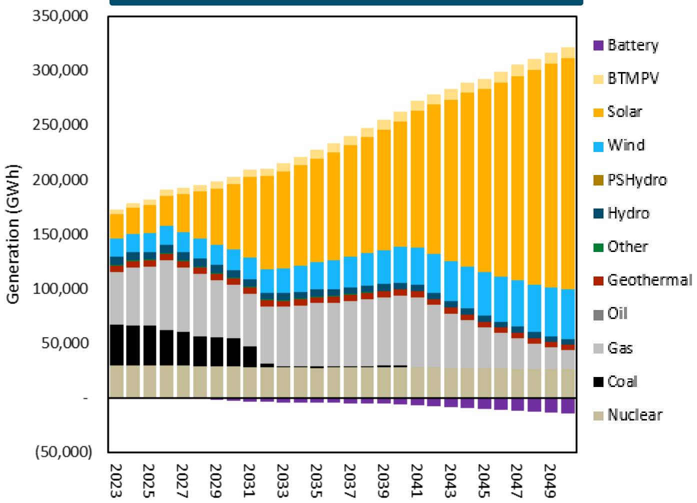
New Mexico (GWh)



Arizona(GWh)



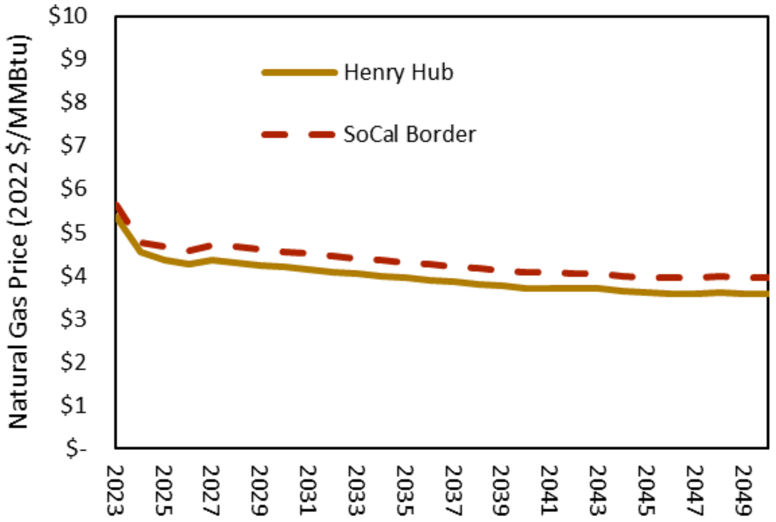
Southwest Total (GWh)



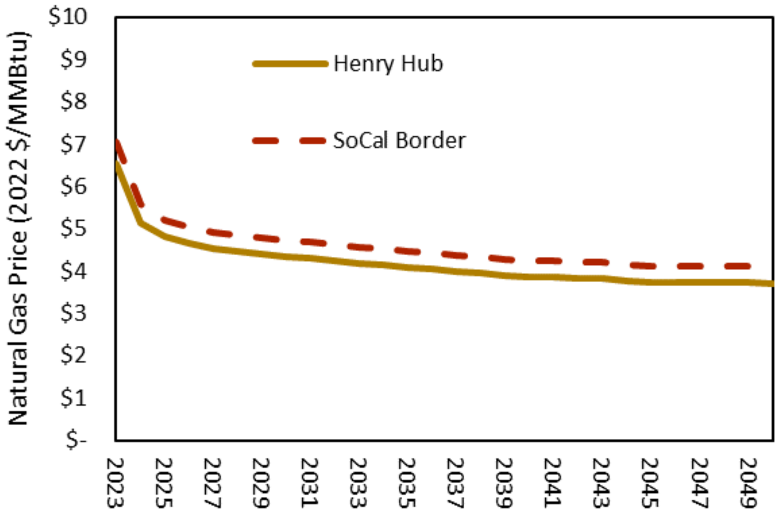
- **Solar generation is the dominant new renewable resource in Nevada and Arizona, while wind is the most significant resource in New Mexico**
- **Thermal generation decreases significantly over time and is replaced by solar and wind generation**
  - Most coal generation phases out by 2032 and the last coal plant in the region is retired in 2040
  - Gas generation remains flat through 2040 (while renewables increase to cover load growth)
  - Gas generation declines from 2040-2050 to meet long-term policy targets
- **New Mexico wind is exported to other states as a low-cost complement to in-state solar resources**

Gas Price Forecast

Summer Gas Price (2022 $/MMBtu)

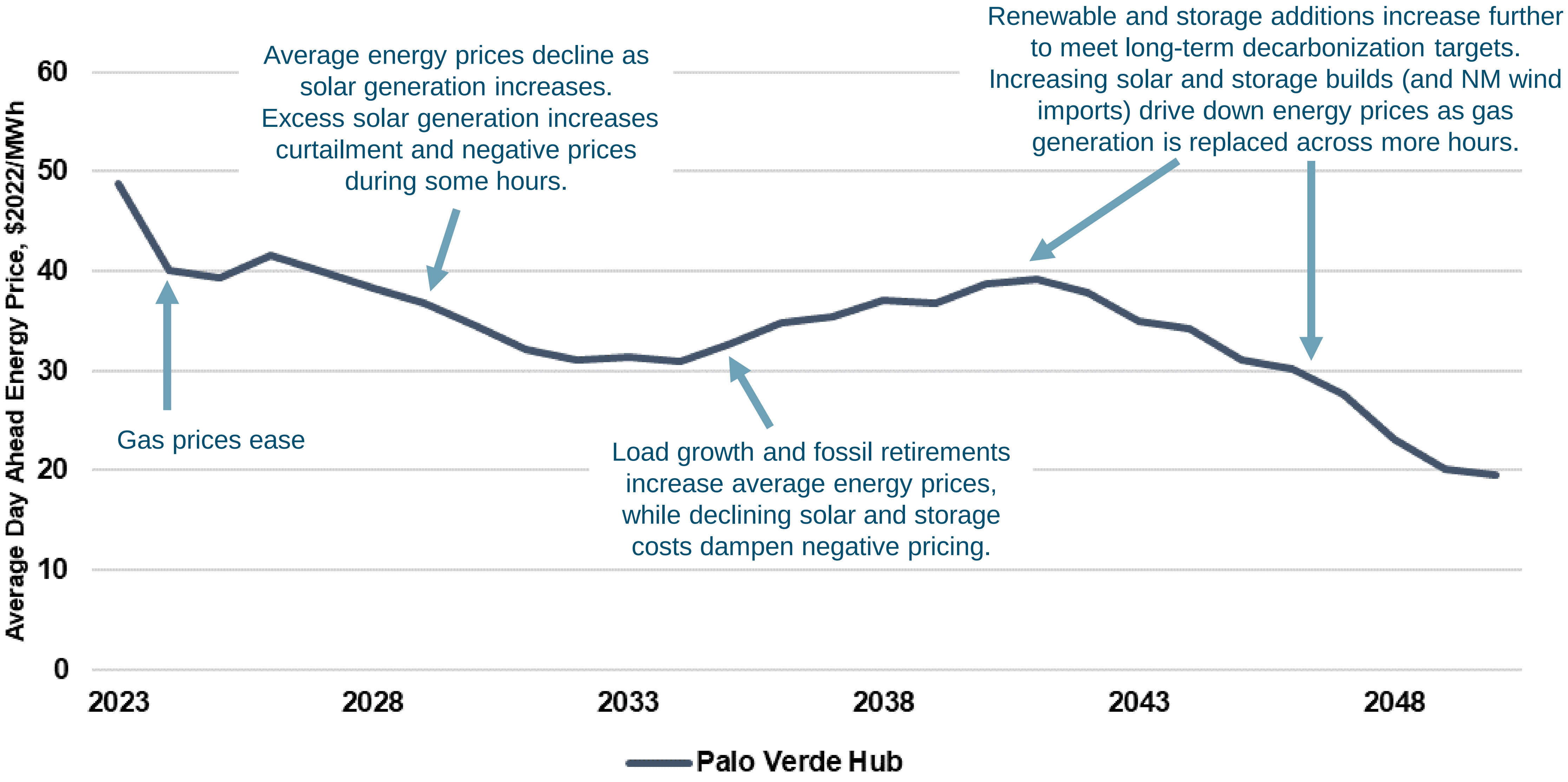


Winter Gas Price (2022 $/MMBtu)



+ **Forecast incorporates a drop in prices from 2022 highs in the near term, with slower declines thereafter**
+ **Gas prices derived from forwards in the near-term and EIA Annual Energy Outlook in the long term**
  - Monthly SNL forwards for Henry Hub used through 2026
  - Past 2026, Henry Hub forecast is trended to EIA forecasts in 2040 and beyond
+ **For all other hubs, monthly basis differentials are derived from SNL forwards in the near term**
  - 3 years of monthly basis differentials derived from forwards are averaged and assumed to hold constant longer term

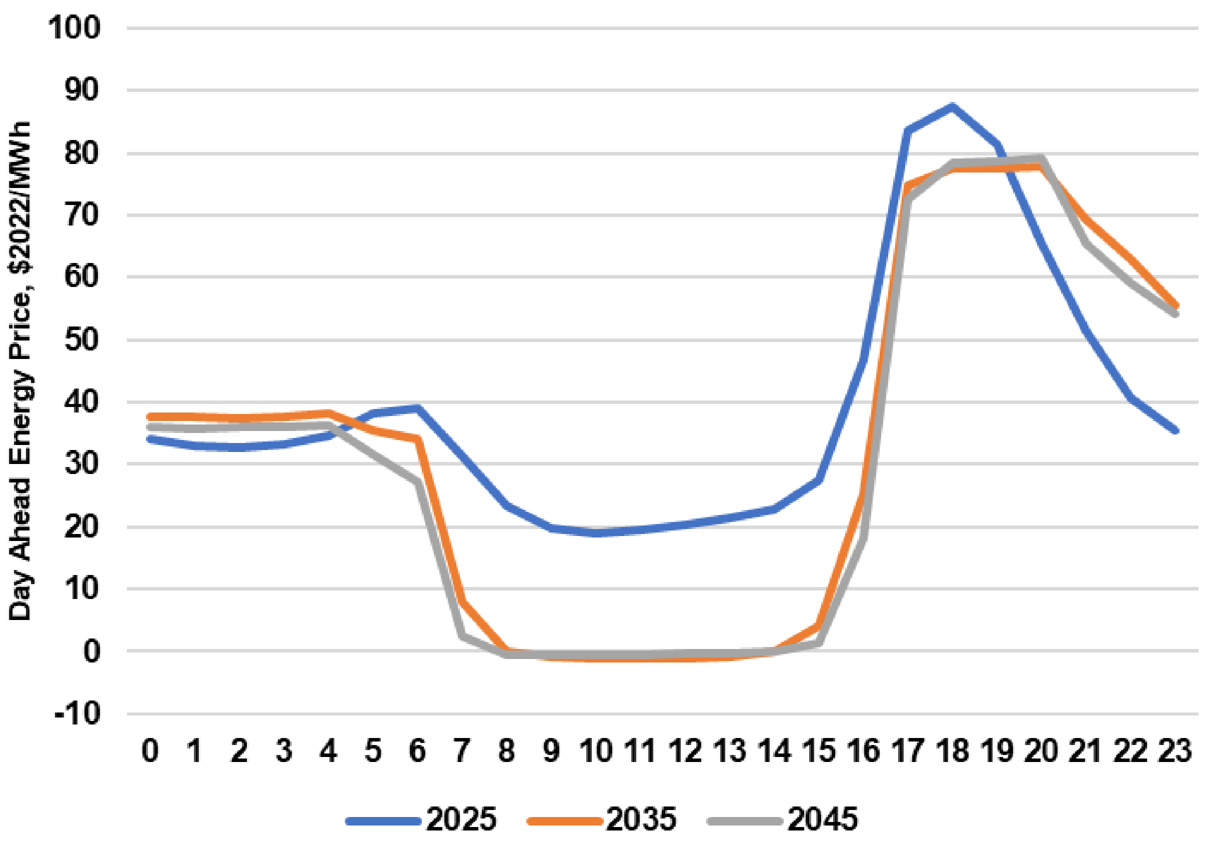
Avg. Annual Day Ahead Energy Prices ($2022/MWh)



Solar and Storage Drive Hourly Price Patterns

+ **Overall trend shows an initial deepening of the duck curve followed by flattening of high and low-priced hours due to storage charge and discharge**
  - Increasing solar generation drives down daytime prices—midday price lows are somewhat mitigated by increased demand to charge batteries
  - Nocturnal prices are driven up by increasing electrification load and gas prices, but dampened by storage discharge
+ **Relative changes year to year in the trough and the peaks of the duck curve are driven primarily by the balance of solar to storage installations over time and load growth**

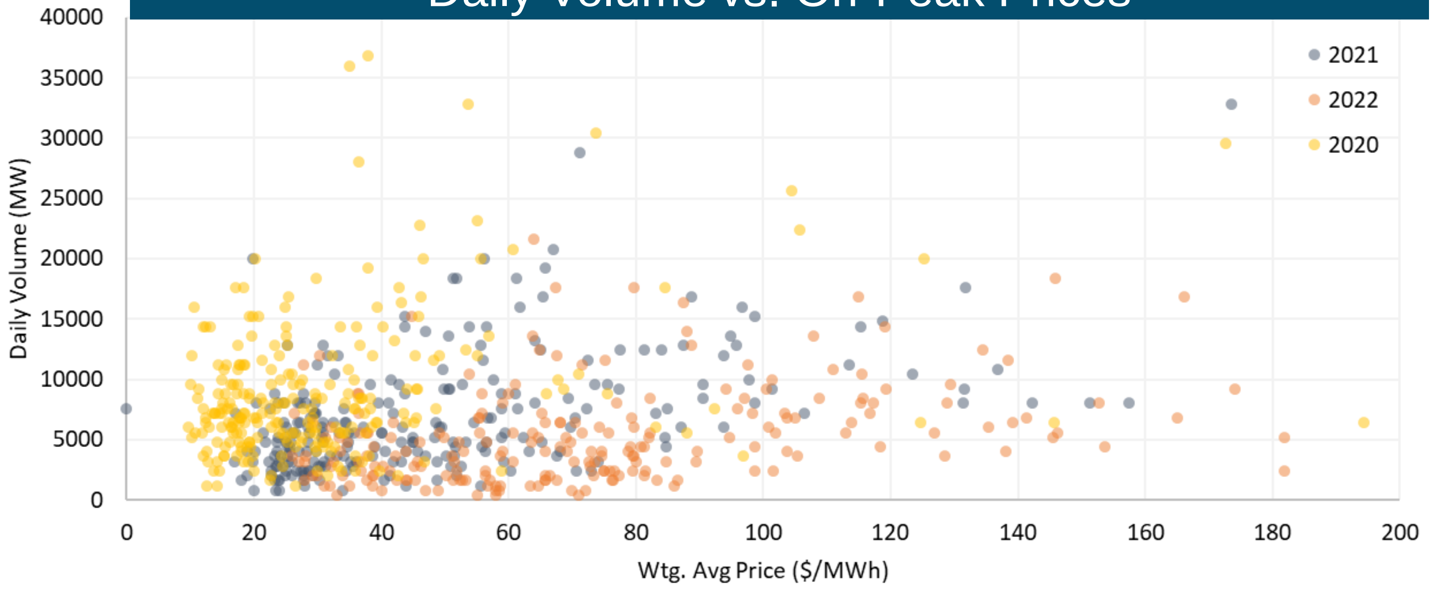
Palo Verde Hub



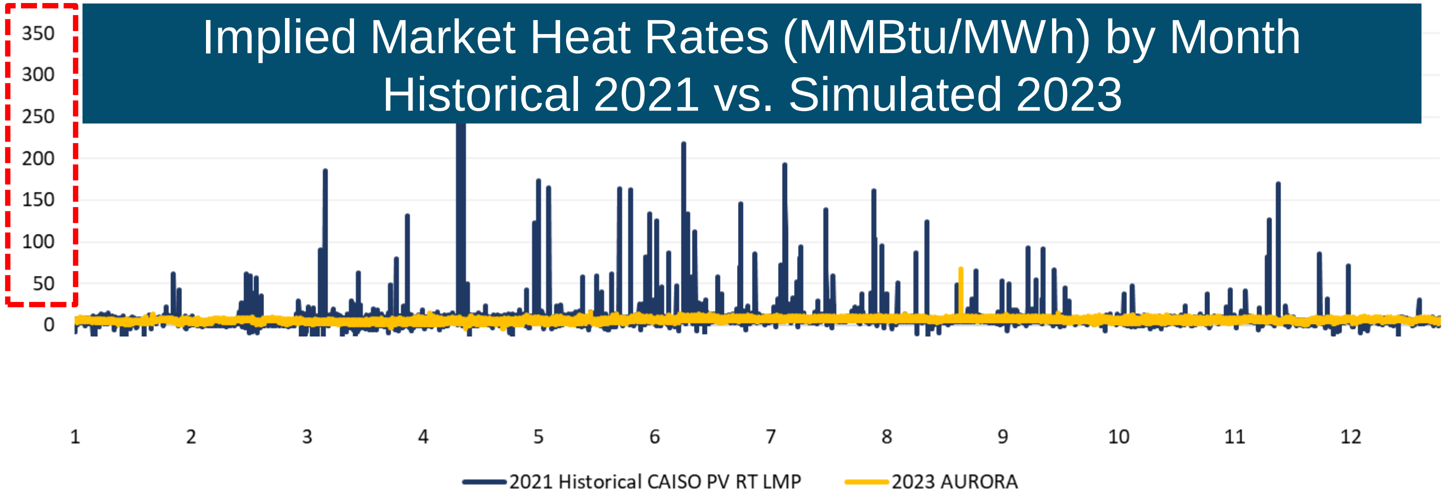
Historical Palo Verde Price Trends

- **Intercontinental Exchange (ICE) offers on-peak/off-peak* Day-Ahead and Futures products for the Palo Verde Hub**
  - Historical offers are much higher than realistic marginal peaking heat rates would imply
  - Traded volumes at Palo Verde are consistently much lower than regional electricity demand
- **We observe a strong premium in historical prices versus simulated (modeled) prices in many hours**
  - Market behavior creates "scarcity pricing" in many hours in which prices are higher than short-run marginal costs
  - Scarcity pricing enables generators to earn a premium to pay for their fixed costs, and persistent scarcity pricing acts as a strong price signal for new resources

Daily Volume vs. On-Peak Prices



Implied Market Heat Rates (MMBtu/MWh) by Month
Historical 2021 vs. Simulated 2023

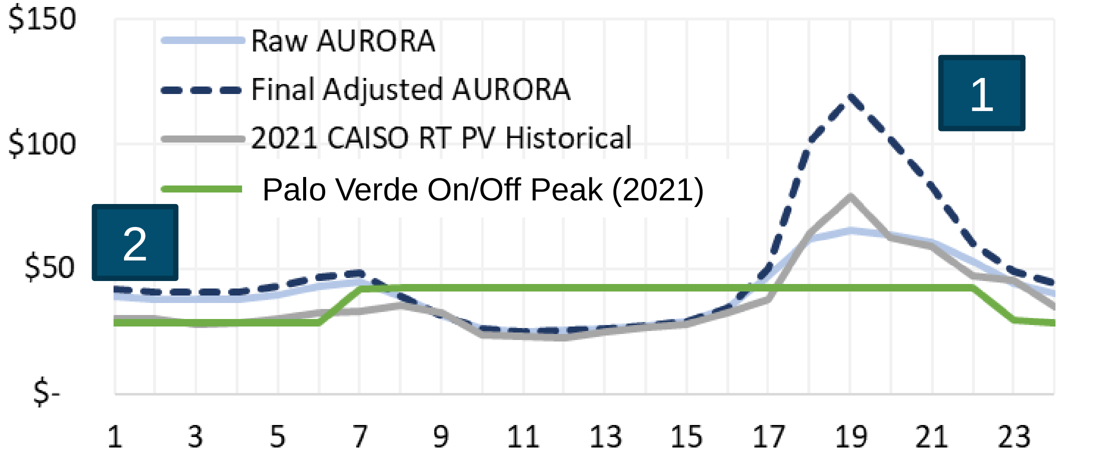


*On-peak hours are defined as hours ending 7am through 10pm, Monday through Saturday (16x6)

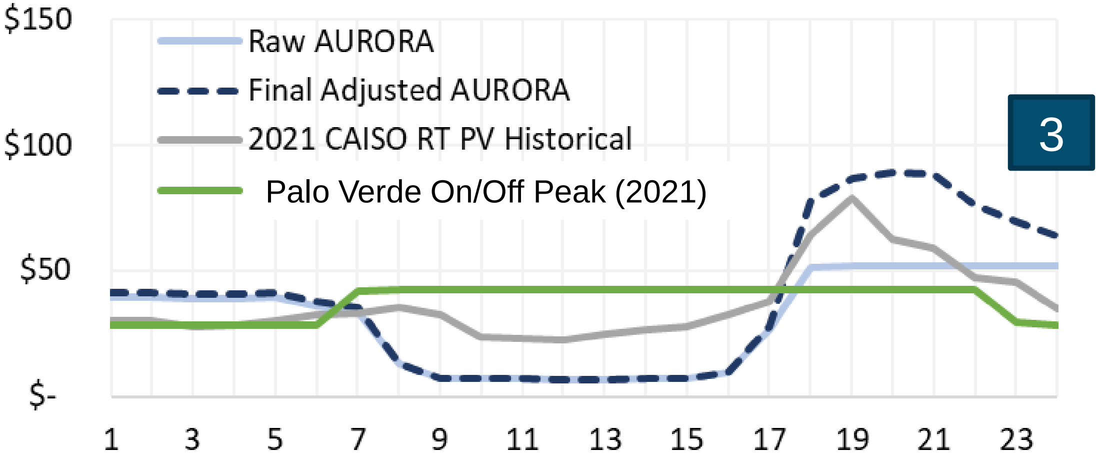
Capturing Historical Price Premiums and Bidding Behavior in E3's Price Forecast

+ **We apply three (3) post-processing steps based on our observations of historical price trends**
  - Prices in the evening and nighttime suggest a very high premium above marginal costs
  - Prices during peak hours exhibit significant scarcity premiums
  - Modeled forecasts indicate a fundamental shift in the nighttime peak driven by increasing nighttime loads and battery operations: peak is pushed later and becomes flatter/broader.
+ **Post-process adjustments to fundamental price streams:**
  1. Scaled up pricing during system peak hours to reflect scarcity premiums
  2. Nighttime off-peak periods are increased to reflect traded premiums during these hours
  3. Scarcity pricing expected to moderate in extended late-night load hours

2023



2040



Appendix F: Regional Market Report

WESTERN MARKETS EXPLORATORY GROUP

Regional Market Report

TUCSON ELECTRIC POWER AND UNS ELECTRIC, INC.

June 1, 2023

Background

This Market Report is filed in compliance with Decision No.78664, ordering Tucson Electric Power (TEP) and UNS Electric, Inc. (UNSE) to file, by June 1, 2023, a report on "the status of their engagement in regional market development forums including, but not limited to, the Energy Imbalance Market, the Western Market Exploratory Group, the Enhanced Day Ahead Market of the California Independent System Operator, and the Western Resource Adequacy Program." It also discusses the Companies' participation, intentions for future participation, and related benefits, barriers, and concerns.

Table of Contents

Introduction

Energy markets are broadly divided into bilateral and organized markets. TEP and UNSE have historically participated in a bilateral market, purchasing power from other utilities or a third-party via Power Purchase Agreements (PPAs) and short-term market transactions. Demand and generation balancing occurs at a more localized level, more commonly within defined Balancing Authorities (BA). Organized markets can optimize the balancing of demand and generation through a more efficient dispatch of resources in a large market footprint.

Organized markets are typically operated by an Independent System Operator (ISO) or Regional Transmission Operator (RTO). RTOs and ISOs manage markets, operate the transmission system, and balance the electricity system to ensure demand is met by generation. They are also responsible for ensuring resource adequacy and adequate transmission, amongst other planning activities. Much of the U.S. is organized into RTOs or ISOs, but most of the western interconnection outside of the California ISO is primarily reliant on bilateral power transactions that occur throughout 38 separate balancing authorities.

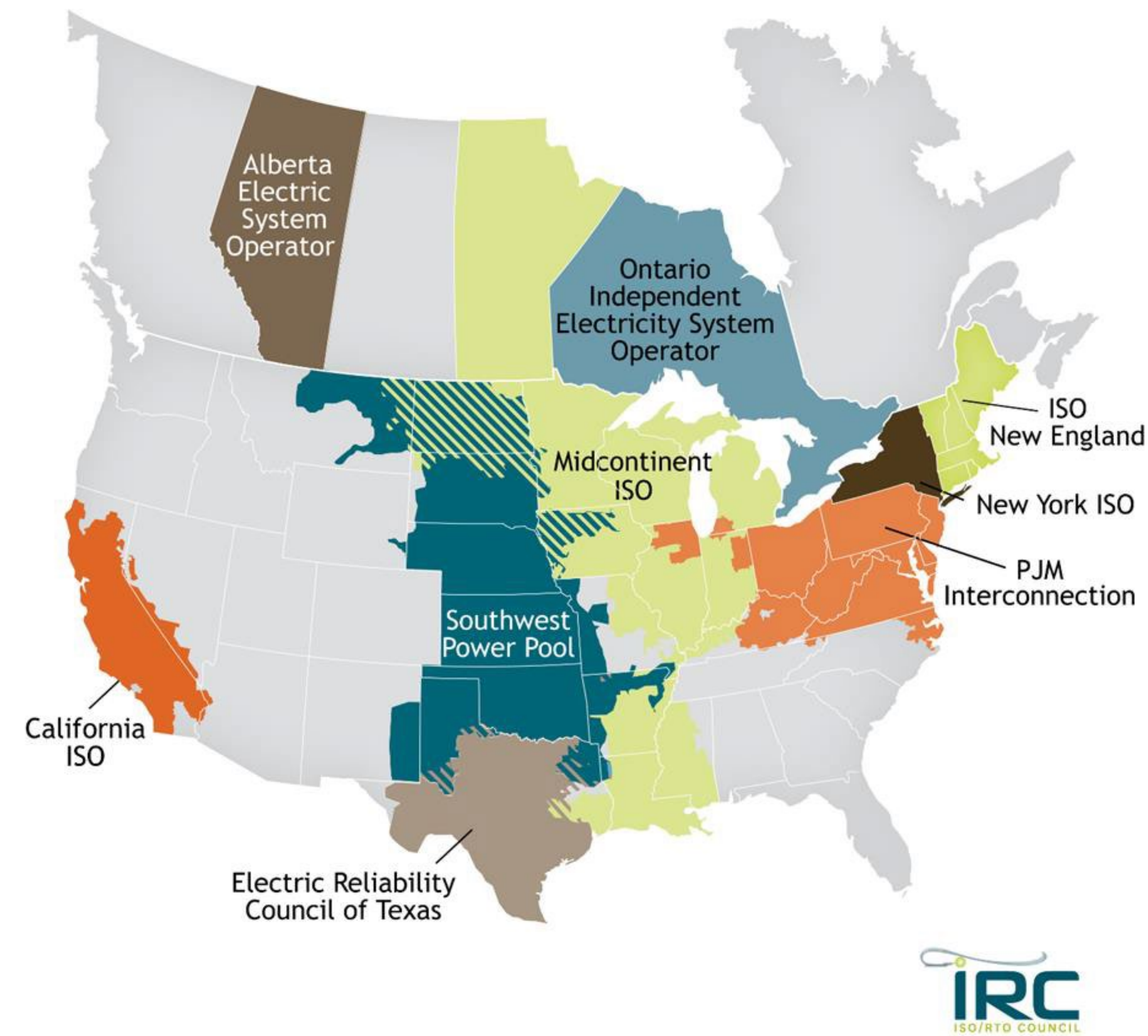


Figure 1. Current Organized Markets in North America.

Similar to most Load Serving Entities (LSEs) in Arizona, TEP and UNSE are vertically integrated utilities serving both retail and wholesale electricity customers. Interest in regional markets is driven by the Companies' three major objectives: maintaining or improving reliability, reducing costs for customers, and integration of clean energy. TEP's and UNSE's current and anticipated participation in the various market forums are discussed below[1].

Current Market Participation

The California Independent System Operator (CAISO) Western Energy Imbalance Market (WEIM)

The CAISO WEIM is a real-time imbalance market than incorporates economic dispatch of generating resources on a least-cost basis, subject to transmission constraints. Since joining the WEIM in 2022, TEP has taken advantage of the increased integration of wind and solar energy the market offers. TEP's customers have realized considerable value through participation in the WEIM. A further advantage is the resource and load diversity across the region that the WEIM optimizes by utilizing unused transmission. The WEIM has also reduced the availability and liquidity of the traditional bilateral power market.

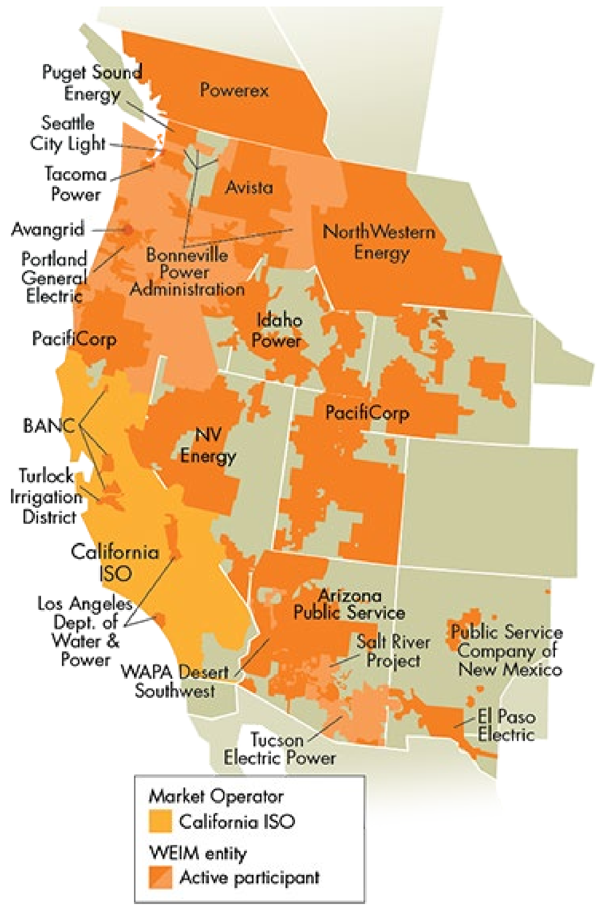


Figure 2. WEIM Participants

Other Market Efforts

TEP believes there may be significant benefits associated with joining a regional market and/or an RTO. Such potential benefits include system optimization of both generation and transmission infrastructure resulting in reduced costs for customers through energy trades - that capitalize on regional diversity in generation technology, peak load, and geography. This diversity allows for increased reliability as the

[1] While TEP is named as the market participant in WEIM, UNSE's market participation in WEIM is managed through TEP's BA.

need for new transmission is identified and built to relieve constraints that would otherwise increase the price to deliver energy and impact reliability.

TEP plans to take a phased approach toward potential participation in a regional market initiative or RTO. Market phases may include participation in a day ahead market, consolidation of Balancing Authorities and/or development of a common tariff among others. The phased approach will allow for a careful weighing of costs and benefits while maintaining autonomy at the state and utility level.

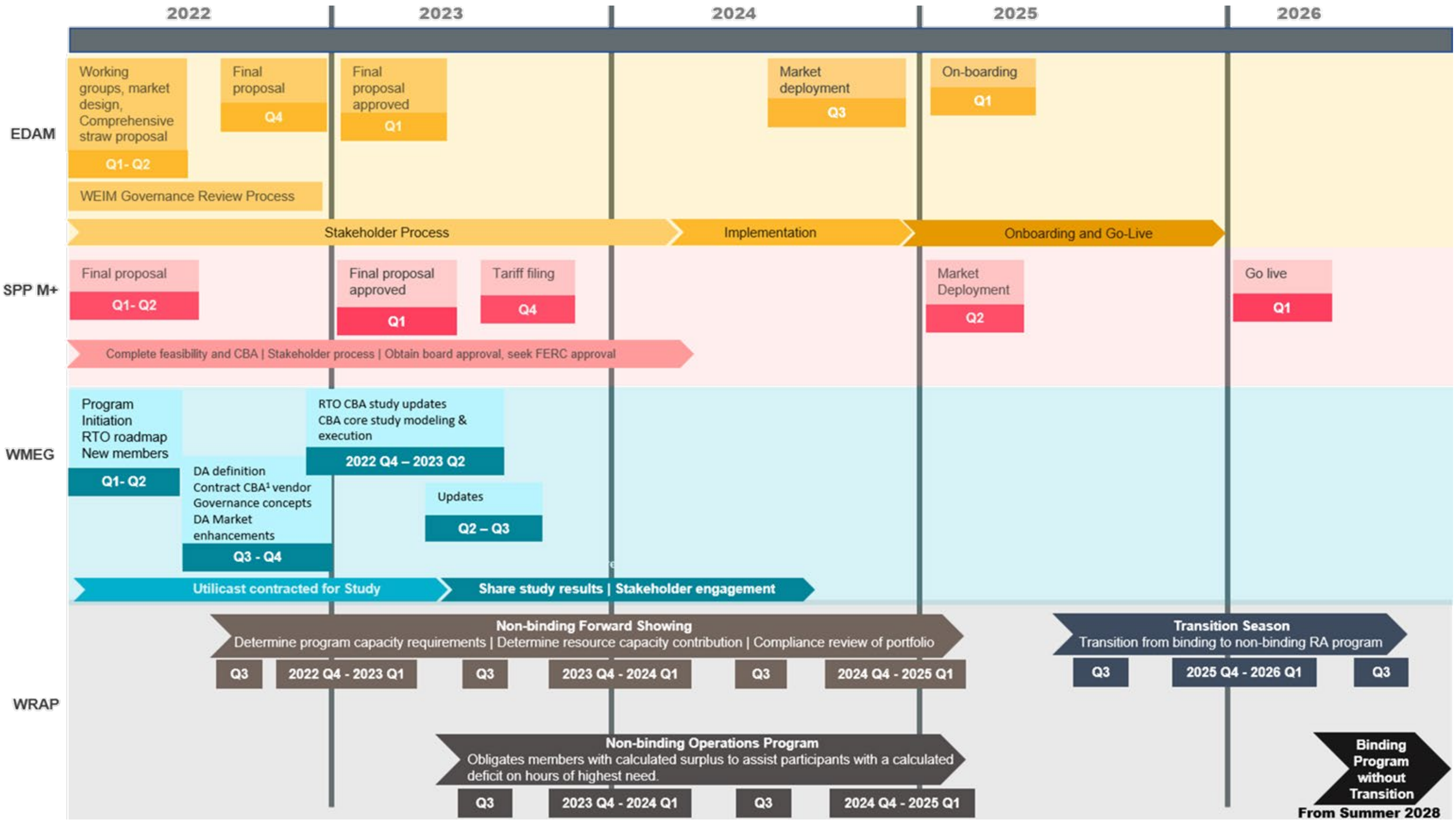


Figure 3. Timelines and Decision Points for Markets and Resource Adequacy Initiatives under Development

CAISO Extended Day Ahead Market (EDAM)

The EDAM initiative plans to develop an approach similar to the WEIM. Meaning, entities that wish to participate in this day-ahead market may do so on a voluntary basis, without full integration into the CAISO balancing area. It is anticipated to expand market efficiency by integrating renewable resources using day-ahead unit commitment and scheduling across a larger market footprint. A bill is moving through the California State Legislature, AB 538, that potentially creates a pathway for CAISO to form an RTO with entities outside of the state.[2]

TEP is exploring the potential for joining the CAISO's EDAM when it becomes viable to potentially take advantage of purchase and sale opportunities over a longer horizon than is currently available in the WEIM. Final development of the EDAM is anticipated by the end of 2023 with on-boarding and implementation between 2024 and 2025.

Southwest Power Pool's Markets+ (SPPM+)

The Southwest Power Pool (SPP) became an RTO in 2004 and launched an Energy Imbalance Service in 2007 for its members in the Eastern Interconnection. In 2019, SPP launched its western reliability coordination services. That was followed by the real-time Western Energy Imbalance Services (WEIS) market in 2021. Participants include several utilities in Colorado, Wyoming, Montana, South Dakota, and Nebraska as well as portions of the Western Area Power Administration (WAPA Rocky Mountain Region). SPP is currently developing a framework for a Western RTO with a phased implementation that includes a day-ahead market called Market+ (SPPM+).

The SPPM+ has multiple technical advisory groups (working groups) that provide guidance on the different issues under consideration. Working groups are composed of Phase 1 members of Markets+. TEP is participating in the Market Design Working Group, Operations and Reliability Working Group, and the Seams Working Group, to explore day ahead market options and other services that could improve the efficient operation of our regional grid. These working groups will send recommendations on their focus areas to the Participant Executive Committee (MPEC), for consideration.

The SPPM+ program is currently in Phase 1 - to develop the tariff and submit it to FERC by the end of 2023. It is anticipated that the SPP day ahead market in the West will be launched in 2024.

SPP currently serves as TEP's Reliability Coordinator.

Western Market Exploratory Group (WMEG)

The Western Markets Exploratory Group (WMEG) is a group of 25 western utilities across the Desert Southwest, Pacific Northwest, California, and the Mountain West regions of the Western Interconnection. The group was formed to evaluate the potential of joining regional market structures in a staged approach.

[2] https://leginfo.legislature.ca.gov/faces/billStatusClient.xhtml?bill_id=202320240AB538

WMEG is exploring pathways to Western organized markets, including the development of a roadmap for potential options up to and including operating in an RTO, depending upon what each state or utility determines is in the best interest of its customers. As part of the effort, WMEG group is evaluating new market services and market footprints, including the offerings under development by the CAISO and SPP, as well as considering potential transmission expansion and coordination, and other power supply and grid solutions consistent with various state regulations and policies.

WMEG has contracted consulting services[3] to evaluate regional market structures to improve affordability, reliability, and decarbonization opportunities across the West, and to perform a production cost benefit study that evaluates day-ahead and other markets services potentially resulting in future RTO development. WMEG anticipates the study will assist participants in future market design decisions and is anticipating deliverables near the end of the second quarter of 2023. Once the WMEG has reviewed and validated the results of the study, the WMEG, as a group, will provide an overview of the study with a webinar for all interested parties.

TEP anticipates providing the study as an attachment to the Company's 2023 Integrated Resource Plan filing later this year.

Western Resource Adequacy Program (WRAP)

Beginning in early 2019, the Western Power Pool (WPP) initiated a program to develop consensus around a regional reliability standard for meeting future load in a reliable manner. The WRAP includes compliance mechanisms to ensure participants contribute their part to ensure reliable supply for the grid. The WRAP includes both a planning component, known as the Forward Showing Program (FS Program) and an Operational Program (Ops Program).

The WRAP began a transition period in January 2023, with binding participation transition between 2025 and 2028. In March 2023, WRAP released its *Western Resource Adequacy Program Detailed Design* document which summarizes the WRAP governance structure, the FS Program, and the Ops Program.[4] TEP is currently considering joining the WRAP but has not committed to participation at this point.

Benefits, Barriers, and Concerns

There have been recent changes in the electricity sector, from retirement of coal fleets, increase in deployment of distributed energy resources and electric vehicles, significant integration of renewable resources, and other changes in both the magnitude and profile of electricity consumption. Markets provide one mechanism to collaboratively manage resource adequacy and capacity needs in a coordinated manner.

[3] https://www.pacificorp.com/about/newsroom/news-releases/energy-companies-engage-utilicast-strategic-planning.html
[4] https://www.westernpowerpool.org/resources/2023-detailed-design-document

Benefits

The potential benefits of regional market coordination are obvious: there is greater operational efficiency derived from the optimization of generation and transmission resources across a larger market footprint. Markets have the potential for increased access to renewable generation from other geographic regions and the potential to export local excess renewable generation without paying fees to multiple transmission providers (called pancaked rates).

Resource optimization provides short-term savings via intra-hour balancing, medium-term savings from day ahead unit commitment, and overall long-term savings from lower capital investment costs. Regional diversity of both traditional and renewable generation can compensate for the intermittent nature of renewable resources, reduce curtailment of renewable resources, and support statutory requirements and energy policy goals.

Barriers and Concerns

While market environments and priorities vary, there are common themes across all markets – implementation cost, governance, resource adequacy, price formation, transmission planning, and financial transmission rights. TEP will continue to evaluate overall market entrant costs weighed against customer value, throughout the process.

Governance

Governance is a key concern of market participation and extends to operating rules, the internal structure of the market, external influences and market decision-making processes. Independence of the market operator and a balanced and equitable governance are currently under discussion for all markets and initiatives.

Of the market and resource adequacy initiatives currently developing in the West, CAISO is directly governed by California utility boards within the California administrative branch of the state government. Conversely, the others are governed by independent boards and market participants.
The WRAP weights participant votes by the median of their nine historic monthly peak demand.
SPPM+, and the WRAP have independent boards. There is a strong preference for an independent and member-driven board. State oversight of an ISO or RTO might subject market participants to multiple state energy policies resulting in potential conflicts. Further, seams management – the overlap of the different kinds of market participants from Balancing Authorities, Reliability Coordinators, Transmission Service Providers – requires leveraging the relationships between functions and services. These should be properly addressed by market governance with collaborative stakeholder engagement. Lack of independence of a market board may complicate the ability to do so.

Resource Adequacy

Resource adequacy - the ability of the electricity system to meet electricity demand at all times – has varying definitions and metrics across different markets. CAISO and SPP require resource adequacy standards to meet load obligations, whereas other RTOs may have resource adequacy standards to augment reliability metrics from capacity markets. Discussions are currently underway within each of the market initiatives to ensure that resource adequacy requirements have a consistent methodology and floor reserve margins for each Balancing Authority Area.

Price Formation & Cost Allocation

Price formation and cost allocation methodologies vary across markets. The WRAP allocates Base costs, Load costs, and Dual Benefit costs across its participants. The EDAM price formation is anticipated to be based on extended locational marginal pricing mechanism, scarcity pricing and market power mitigation mechanisms. The SPPM+ regional state committee has oversight of the cost allocation methodology. They determine if participant funding will be used for transmission enhancements and whether license plate or postage stamp rates will be used for the regional access charge. SPPM+ is still in the process of developing market price mechanisms.

Transmission Planning and Financial Transmission Rights

The level to which market participants retain existing autonomy and responsibility over transmission operations and service varies by the type of market operator and whether a full RTO is developed and implemented in the West. This determines the administration of the Open Access Transmission Tariffs and transmission planning functions. It is imperative that each of these initiatives allow the market to maximize transmission availability and ensure that congestion rents are equitable across participants. The Financial Transmission Rights (FTRs) where a locational price methodology is used, and the transition mechanism needed to assure that existing firm customers receive FTRs equivalent to the customers' existing firm rights, require consistent treatment.

Future Steps

TEP is currently evaluating all markets under development and has retained the services of consultants to provide a cost-benefit analysis through our WMEG participation. While market development is a complex process, a west-wide organized market or combination of markets, must allow for independent governance, transparent and stakeholder-focused engagement, and increasing integration of clean energy sources.

Appendix A: TEP-UNSE Markets Workshop Presentation

Market Workshop
Arizona Public Service

Brian Cole
General Manager Western Market Evolution

May 4, 2023

Goals of Western Market Efforts

- **Reliability**
  - Maintain or improve
  - Will be challenged with changing resources
- **Customer cost savings**
  - Via utilization of both load and resource diversity
  - Needed to offset increases in costs
- **Integration of clean energy**
  - Cannot meet clean energy goals without it

Background & Drivers

- Previous efforts
  - RTO discussions have occurred intermittently for over 20 years
- Current effort
  - It's different this time
  - Needed for clean energy integration
- ACC Docket tracking market efforts

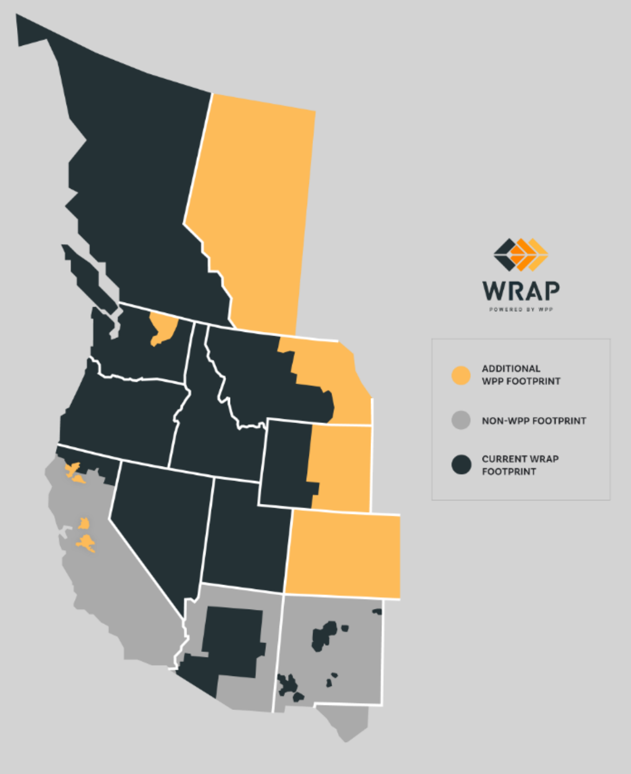
Recall APS's goals

1. Reliability
2. Customer Savings
3. Clean energy integration

Ongoing Engagement

- Western Resource Adequacy Program **(WRAP)**
- CAISO Extended Day Ahead Market **(EDAM)**
- Southwest Power Pool **(SPP)** Markets+ Day Ahead Market
- Western Market Exploratory Group **(WMEG)**

Western Resource Adequacy Program (WRAP)

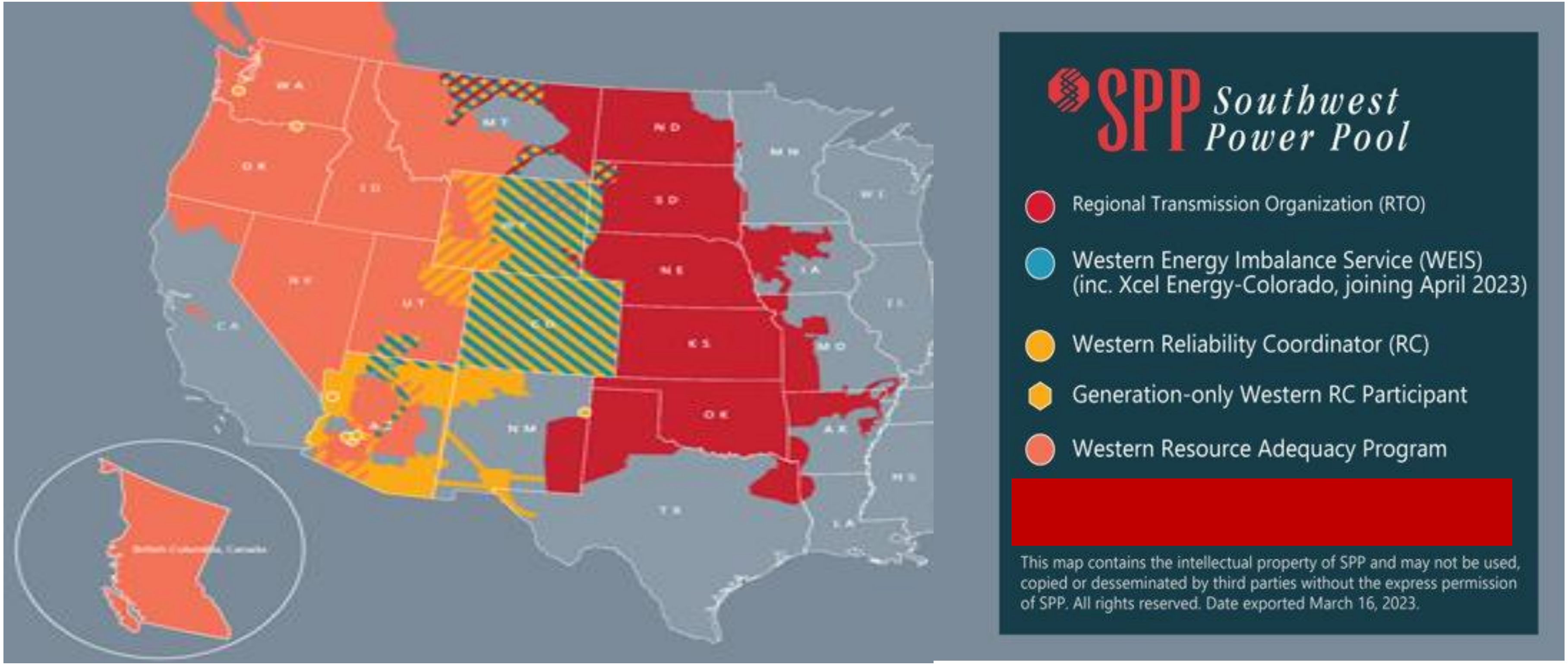


1. Arizona Public Service
2. Avista
3. Bonneville Power Administration
4. Calpine
5. Chelan County PUD
6. Clatskanie PUD
7. Eugene Water & Electric Board
8. Grant PUD
9. Idaho Power
10. Northwestern Energy
11. NVEnergy
12. PacifiCorp
13. Portland General Electric
14. Powerex
15. Public Service Company of New Mexico
16. Puget Sound Energy
17. Salt River Project
18. Seattle City Light
19. Shell Energy
20. Snohomish PUD
21. Tacoma Power
22. The Energy Authority

CAISO

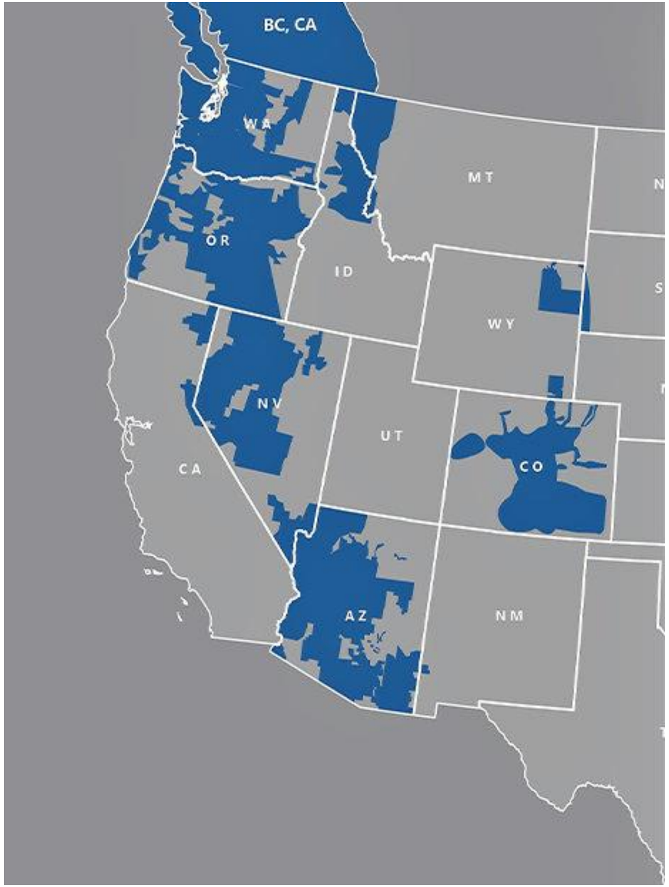
Western Energy Imbalance Market (WEIM)

Southwest Power Pool (SPP) in the West

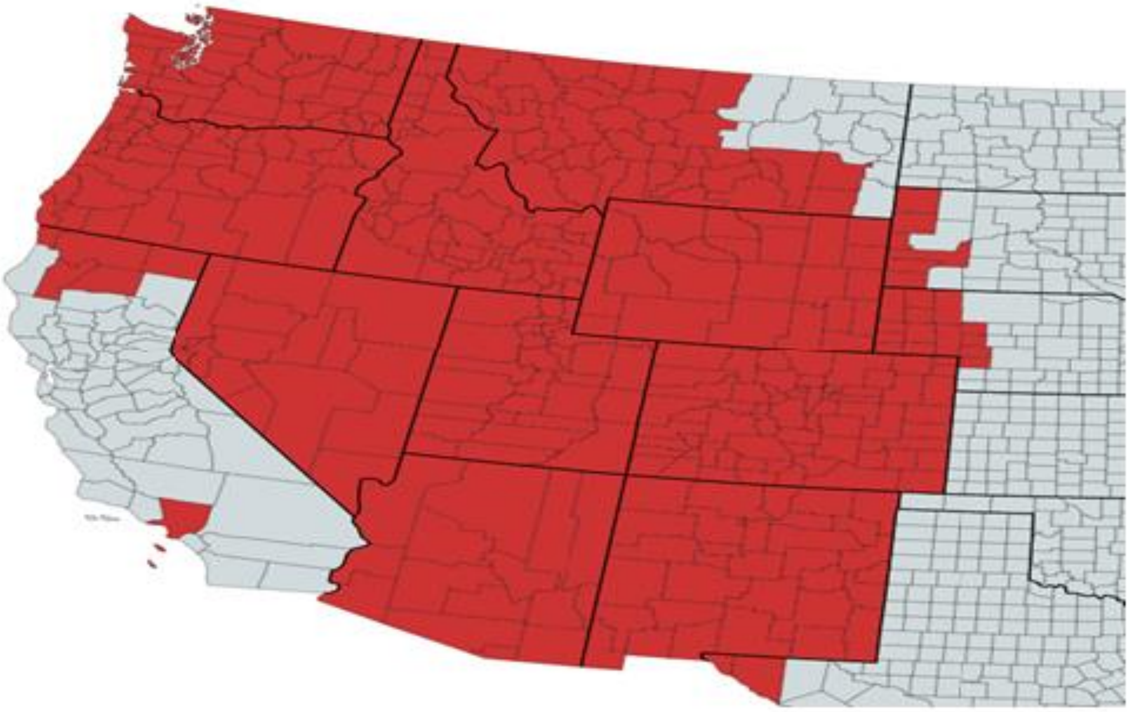


SPP Markets+ Phase 1

1. American Clean Power Association
2. Arizona Electric Power Cooperative
3. Arizona Public Service Company
4. Black Hills Colorado Electric & Black Hills Power, Inc.
5. Bonneville Power Administration
6. Chelan (PUD No.1 of Chelan County)
7. Cheyenne Light, Fuel & Power Co.
8. Clean Energy Buyers Association
9. Interwest Energy Alliance
10. Liberty Utilities (Calpeco Electric)
11. Municipal Energy Agency of Nebraska
12. National Resource Defense Council
13. Northwest & Intermountain Power Producers Coalition
14. NV Energy
15. Pattern Energy
16. Powerex Corp.
17. Public Generating Pool
18. Public Power Council
19. Public Service Company of Colorado
20. PUD No. 2 of Grant County, Washington
21. Puget Sound Energy
22. Renewable Northwest
23. Salt River Project
24. Snohomish Public Utility
25. Tacoma Power
26. The Energy Authority
27. Tri-State
28. Tucson Electric Power Company
29. Western Energy Freedom Action
30. Western Power Trading Forum
31. Western Resource Advocates



Western Market Exploratory Group (WMEG)



1. APS
2. SRP
3. TEP
4. PNM
5. Black Hills
6. LDWP
7. Portland General
8. Seattle City & Light
9. Platte River
10. NV Energy
11. PacifiCorp
12. Idaho
13. Puget Sound
14. Xcel Energy
15. Arizona Electric Co-Op
16. Avista Corp.
17. BANC
18. BPA
19. Chelan County PUD
20. El Paso Electric
21. Grant County PUD
22. NorthWestern Energy
23. Tacoma Power
24. Tri-State
25. WAPA

Target Milestones

- WRAP began transition period on January 1, 2023.
  - Binding participation will transition between 2025 and 2028.
- Day Ahead market option work and commitments – 2023/2024
  - Includes participation in Tariff and Business Practices for each option (CAISO/SPP)
- Day ahead market operation – Late 2025/Early 2026
- Future market steps “up to and including RTO” – 2026-2030 and beyond

UNS

UNS Energy Corporation

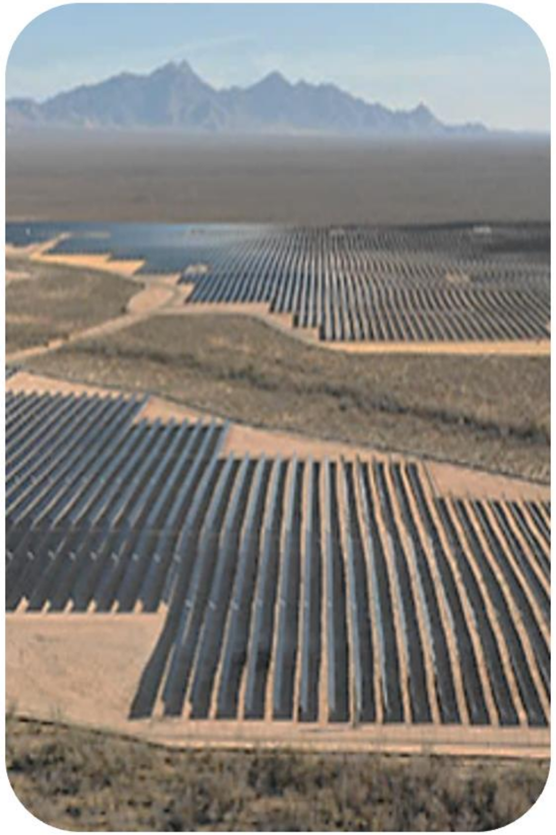
A Fortis Company

Western Market Exploration

Sam Rugel

Director, System Control

May 4, 2023



Energy Markets 101

Energy Markets 101

Markets for delivering power to consumers in the United States are split into two systems: traditionally regulated bilateral markets, and those run by RTO/ISOs

Traditional wholesale electricity markets exist primarily in the Southeast U.S. and the West outside of California

- Utilities are responsible for system operations and for providing power to retail consumers

Two-thirds of the population of the United States is served by electricity markets run by Regional Transmission Organizations or Independent System Operators (RTO/ISOs or organized markets)

RTO/ISO markets optimize electricity through structured market design/mechanisms

Day Ahead & Real Time Optimization

Day Ahead: Run Generation Optimization for next 7 days

Create Day Ahead Plan and submit to the market

- Generation Base Schedules, Intertie Base Schedules, & Ancillary Services

Create Bids and submit to the market

Input all Generation & Transmission Outage

Day Ahead: Run Generation Optimization for next 7 days

Real Time: Run Generation Optimization for next open hour through balance of day

Ensure generation follows real-time (5 minute) Dispatch Instructions from market

Manage Unit Startup/Shutdown

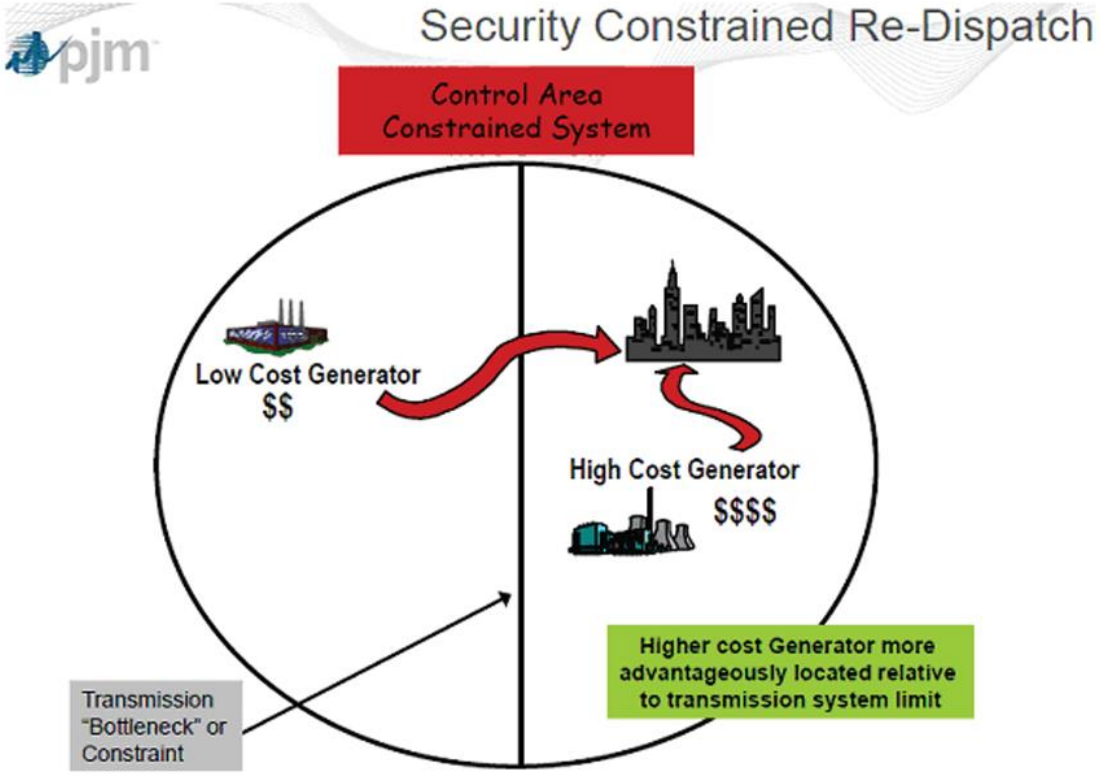
Monitor load and renewable forecasts & update Generation/Transmission Outages

Congestion management via Security-Constrained Economic Dispatch (SCED)

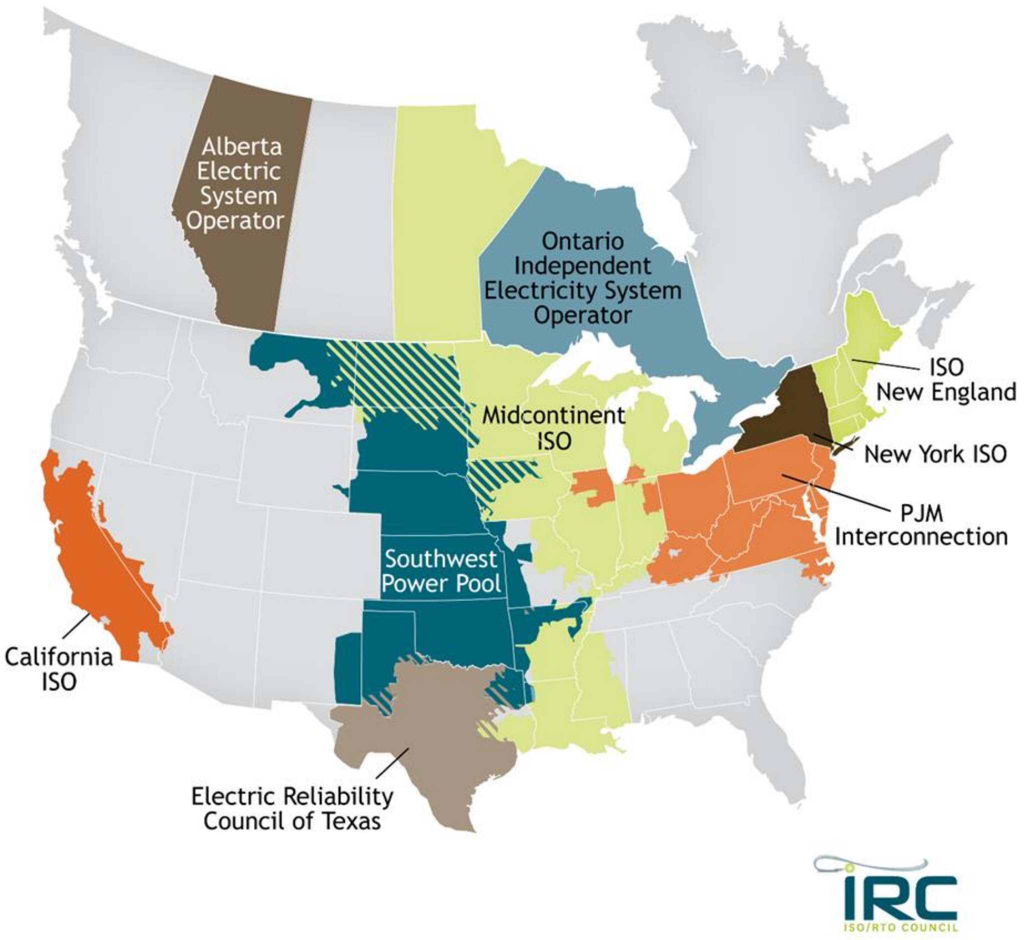
Security-Constrained Economic Dispatch (SCED)

- Optimizes generation to the extent the transmission system can support it
- Identifies and encourages addition of transmission investments needed to alleviate congestion

Security Constrained Re-Dispatch



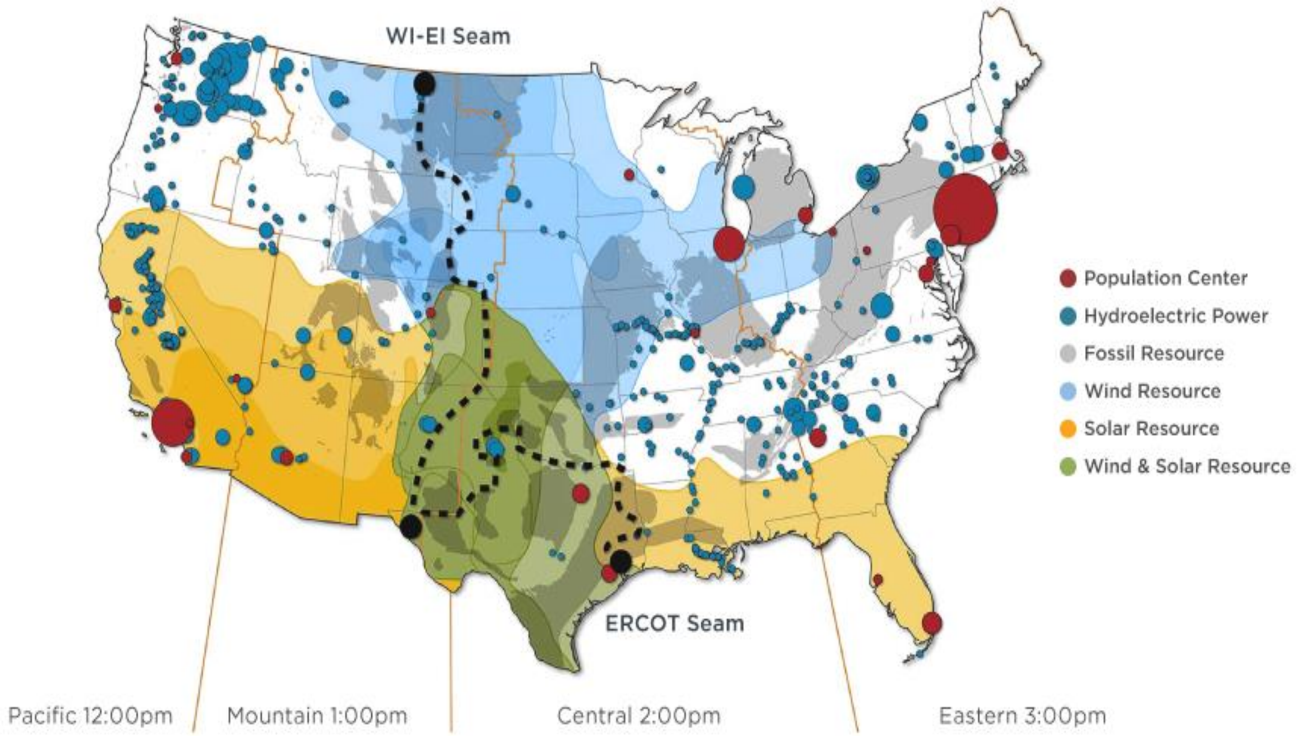
Existing Structured Markets



Current organized markets in North America

Market Evolution

Drivers: Geographic Diversity



Resource Diversity

- Southwest utilities have access to northwest hydro capacity in summer
- Northwest utilities have access to southwest gas and renewable capacity in winter

Peak Diversity

- Utilities peak at different times of day and year
- Allows for resource optimization, especially renewables

Drivers: Resource Adequacy

Members must ensure their own resource adequacy

- Supports reliability of entire region

Resource optimization/efficient dispatch

- Carried out across entire footprint instead of individual utilities

Liquid Market

- Improves reliability
- Efficient, low-cost transactions

Benefits

Reliability

- Resource adequacy requirements ensure reasonable reserve margins
- Compensates owners to add resources to support load growth
- Compensates owners to add transmission to alleviate congestion

Customer value

- Economic dispatch of all resources across the market footprint results in savings for the customer

Renewable Integration

- System-wide resources used to support intermittency
- Results in fewer renewable curtailments

Stakeholder Collaboration

- Members have a voice in market rules
- Effective resolutions achieved between differing parties

Market Evolution

Most organized markets in North America evolved by forming collective reliability organizations responsible for different aspects of operations:

Transmission Operations	Generation Dispatch	Reliability Coordinator

Over time, they added additional functions:

Tariff consolidation	Transmission Planning	Imbalance Markets

Until they eventually launched full markets for participants

Most began organizing shortly after FERC Order 888 (1998)

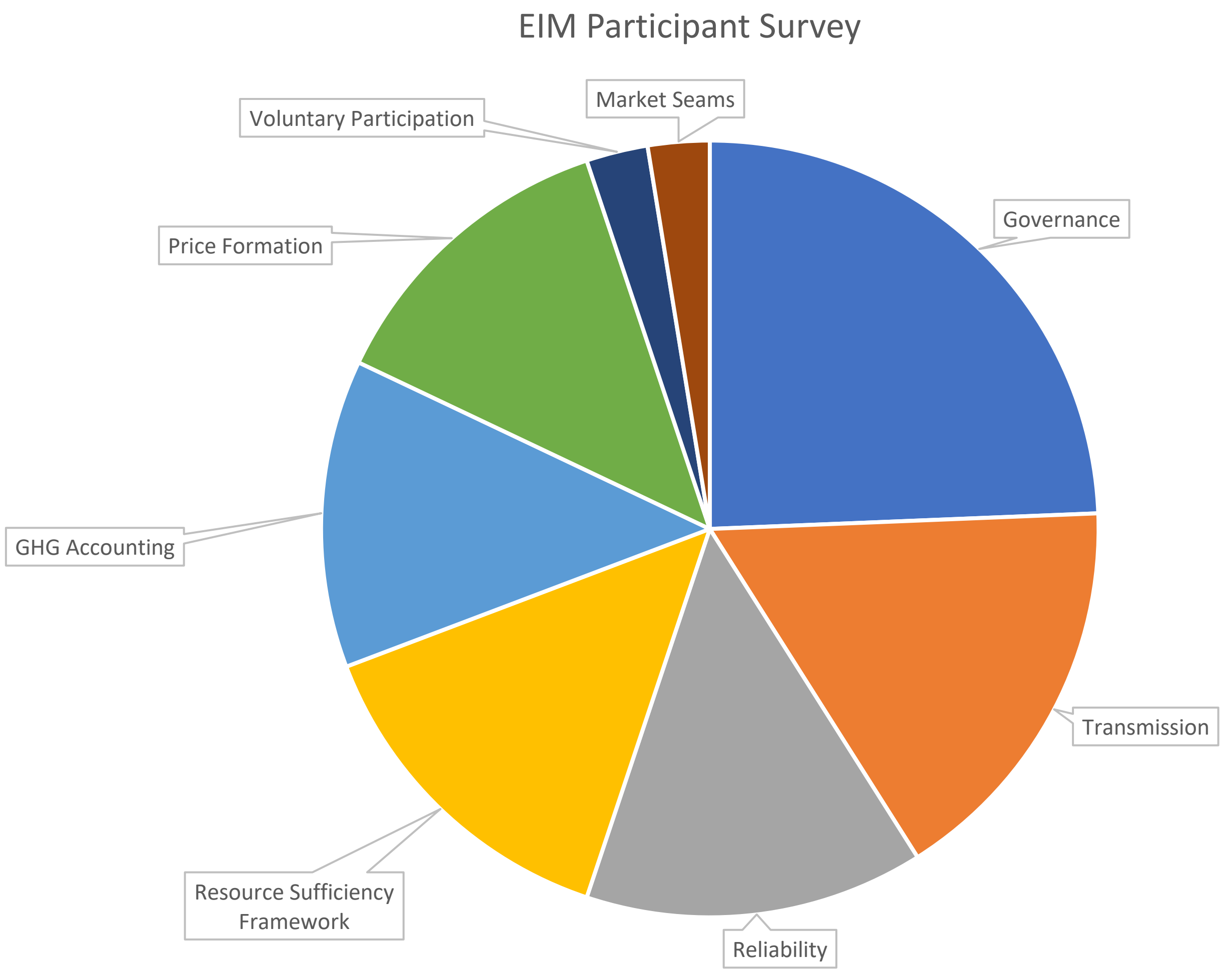
Market Features

Bi-Lateral Market	Real-Time Market	Day Ahead Market	Regional Transmission Organization
Balancing Authority	Balancing Authority	Balancing Authority	Balancing Authority
Resource Adequacy	Resource Adequacy	Resource Adequacy	Resource Adequacy
Trans Planning	Trans Planning	Trans Planning	Trans Planning
Trans Service Provider	Trans Service Provider	Trans Service Provider	Trans Service Provider
Bi-Lateral Market	Bi-Lateral Market	Bi-Lateral Market	Bi-Lateral Market
Real-Time Market	Real-Time Market	Real-Time Market	Real-Time Market
Day-Ahead Market	*Day-Ahead Market*	Day-Ahead Market	Day-Ahead Market
RC Services	RC Services	RC Services	RC Services

Not Offered | Self-provided or procured | Market feature

Day Ahead Market Priorities

- Governance
- Transmission
- Reliability
- Resource Adequacy Framework
- GHG Accounting
- Price Formation
- Voluntary Participation
- Market Seams



Western Market Efforts

EDAM	Develop an approach to extend participation in the day-ahead market to the Western Energy Imbalance Market (EIM) entities in a framework like the existing EIM approach for the real-time market, rather than requiring full integration into the California ISO balancing area. A bill is moving through the CA legislator, AB 538, that potentially creates a pathway for CAISO to form an RTO with entities outside of the state.
SPP Markets+	It's a conceptual bundle of services proposed by SPP that would centralize day-ahead and real-time unit commitment and dispatch, provide service across its footprint and pave the way for the reliable integration of a rapidly growing fleet of renewable generation.
WMEG	Utility executives are exploring the potential for a staged approach to new market services, including day-ahead energy sales, transmission system expansion, and other power supply and grid solutions consistent with existing state regulations.

Appendix G: Electric Vehicle Market Overview and TEP Programs

Electric Vehicle Market Overview and TEP Programs

Global

Global sales of conventional fuel vehicles reached its height in 2017 and have been in decline ever since. Electric vehicle sales reached 10.5 million in 2022, representing 14% of new passenger vehicle sales and are expected to reach 27 million (30% of new passenger vehicle sales) in 2026. In 2022, China, the United Kingdom, and France experienced EV sales above 20%. The Nordic countries lead EV sales with 59.5% of all passenger vehicle sold being electric. Of the electric vehicle market, BEVs represented 72% of the sales, an increase of 3% from 2021. Plug-in hybrids continue to lose ground worldwide, particularly as automakers focus on the development of all-electric vehicles.[1]

National

Federal policy directions and initiatives from the Biden Administration have had a significant impact on EV adoption projections in the U.S. The Inflation Reduction Act (IRA) of 2022 provides a tax credit of up to $7,500 toward the purchase of a qualifying EV. [2] BNEF estimates that by 2026, 28% of passenger vehicle sales will be EVs.[3] California has enacted Zero Emission Vehicle standards, calling for a phase out of all internal combustion engine vehicle sales by 2035, which according to BNEF, will lead to EV adoption of 61% of sales by 2030. Colorado, Connecticut, Maine, Maryland, Massachusetts, New Jersey, New York, Oregon, Rhode Island and Vermont are following California and implementing the Zero Emission Vehicle (ZEV) regulations, including the requirements that about 7 to 10 percent of new vehicles must be electric vehicles in 2025.[4]

State

While Arizona is not a ZEV state, the Arizona Corporation Commission directed the investor-owned utilities to conduct a Statewide Transportation Electrification Plan.[5] This plan outlined the opportunities and constraints associated with electrification and highlighted actions by stakeholder groups that would be needed to reach the goal of 1.076 million light-duty vehicles by 2030. The EV market share continues to increase rapidly in Arizona with adoption slightly behind the U.S average. However, Arizona's EV sales growth is out pacing the U.S. average.

Table 1. Electric Battery Light-Duty Sales Growth[6]

	Electric Battery Light-Duty Market Share	Market Share Growth	Sales Growth (Year over Year)
Arizona	7.13%	181%	205%
United States	7.32%	200%	190%

Local – Pima County

In Pima County, electric vehicle registrations are in line with the U.S average and have increased steadily since 2014, with a 43% increase from December 2021 to December 2022. By 2030, TEP anticipates 46,662 BEV to be registered in Pima County, which represents 6.98% of all registered vehicles.[7]

TEP expects EV adoption in its service territory to follow an accelerated adoption curve for residential customers. By 2030, this would equate to 364 MW of non-coincident peak load, or 18 MW of coincident peak load under a time-of-use managed scenario. In terms of public charging, TEP anticipates 374, 150 kW chargers and 1,839 Level 2 chargers on the system by 2030. This would represent 150 MW of non-coincident peak load with 31.7 MW of coincident peak load. Finally, fleets will have an anticipated non-coincident peak load of 127 MW with 25 MW of coincident peak load. Across the system, TEP anticipates 641 MW of non-coincident peak load and 75 MW of coincident peak by 2030.

[1] Bloomberg, Electric Vehicle Outlook, 2023.
[2] https://www.irs.gov/credits-deductions/credits-for-new-clean-vehicles-purchased-in-2023-or-after
[3] Bloomberg, Electric Vehicle Outlook, 2023
[4] https://www.autosinnovate.org/initiatives/energy-and-environment/electric-drive
[5] https://docket.images.azcc.gov/0000205573.pdf?i=1694473890481
[6] 1898 &Co. TEP EV Adoption Forecast, 2023.
[7] 1898 & Co., 2023.

Figure 1. Pima County Electric Vehicle Registrations (2013-2022)

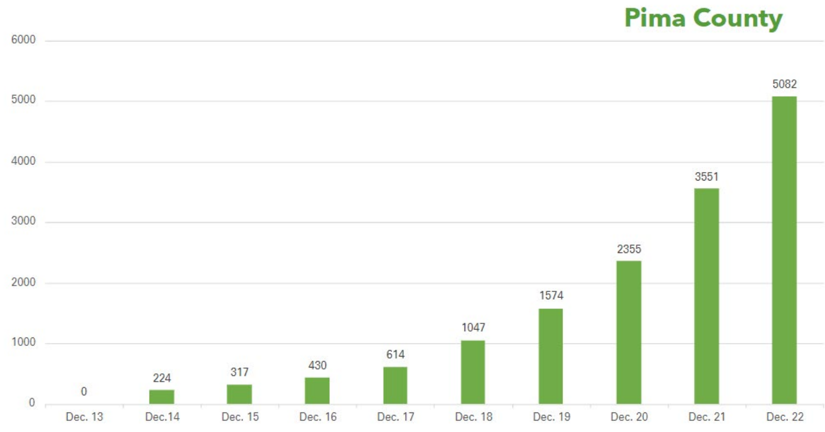


Table 2. TEP EV Adoption Forecast[8]

EV Registration Scenario	2023	2024	2025	2026		2027	2028	2029	2030
Average	5,929	7,767	10,122	13,051		16,653	21,035	26,398	32,775
Accelerated	6,285	8,723	11,956	16,137		21,457	28,169	36,510	46,662

Product Development and Evolution

While the number and model availability of electric vehicles on the market remained limited for a number of years, vehicle manufacturers are now heavily invested in the electric transition. Tesla continues to lead the way with number of EV sales. According to the Edison Electric Institute, by 2030, other manufacturers will play a much larger role. Since 2020, numerous auto makers have announced investments in BEV and or the phasing out of ICE vehicles and Plug-in Hybrid Electric Vehicles. (PHEV). [9]

Table 3. Analysis of Projected EV Sales in 2030 by Vehicle Manufacturer

Manufacturer	EEI estimated light-duty vehicle sales in U.S. in 2030	Manufacturer announced EV sales targets in 2030*	Estimated EV sales in 2030
BMW	420,000	50%	210,000
Ford	2,150,000	40%	860,000
General Motors	2,580,000	50%	1,290,000
Honda	1,660,000	40%	664,000
Hyundai-Kia	1,650,000	50%	825,000
Jaguar Land Rover	120,000	100%	120,000
Mazda	370,000	25%	92,500
Mercedes	370,000	100%	370,000
Nissan	1,230,000	40%	492,000
Stellantis	2,010,000	50%	1,005,000
Subaru	680,000	40%	272,000
Tesla	880,000	100%	880,000
Toyota	2,540,000	30%**	762,000
Volkswagen	720,000	55%	396,000
Volvo	140,000	100%	140,000
Total	**17,520,000**	**48%**	**8,378,500**

*Percentages are based on most recently announced sales targets for EVs.
**Estimated based on announced global EV sales target of 3.5 million in 2030.

Future Adoption Rate Influencers

Much research around the country has focused on understanding the factors that support BEV and PHEV adoption. While many innovative programs and initiatives have been launched to support EV adoption, the three most significant influencers of adoption rates are:

- Policies
- Advances in battery technology
- Charging infrastructure

Policy

The most clearly demonstrable influencer of EV adoption to date has been federal and state policies creating incentives directly reducing the cost of EV purchases. The Inflation Reduction Act of 2022 and the Infrastructure Investment and Jobs Act were turning points in EV adoption by providing incentives for both vehicles and associated charging infrastructure. Additionally, the Biden administration has a set

[8] 1898 & Co, 2023.

[9] BNEF, 2023.

a goal for the U.S. economy to achieve net-zero greenhouse emissions by 2050. EVs are a significant contributor to that goal.

On the consumer side, environmental protection was the most prevalent motivation for EV adoption, with 41% of existing EV owners and 39% of those intending to purchase an EV noting it as the most important factor in owning an EV.[10] The long-term commitment of the Federal government to invest in the EV ecosystem provides an impetus for the private sector to shift its investment strategies, as seen by the recent EV model lineup announcements by automakers. General Motors, Ford, and Chrysler have jointly announced they expect 40-50% of their new sales in the U.S. to be electric models by 2030. [11] States with the highest incentives and most directive policies, such as California and Oregon, experience an EV adoption rate 2 to 4 times above the national average. Additionally, the proposed EPA emissions standards will put more pressure on the number of vehicles that will need to be replaced to meet the proposed standards. While the proposed standards are expected to change, any tightening of these standards will have a positive impact on EV adoption.

Battery Technology

The opportunity that holds the greatest promise to increase future EV adoption rates is improvements to battery and manufacturing technology that reduce the cost of batteries. As the result of the Inflation Reduction Act (IRA) and the Infrastructure Investment and Jobs Act (IIJA), significant investment in battery technology and manufacturing is anticipated in the coming years. Combined, those federal funding opportunities provide eligible battery manufacturers a $35/kWh tax credit for battery cells and $10/kWh for a battery pack. Ford recently secured a U.S. Department of Energy loan of $11.4 billion for three new battery facilities in Kentucky and Tennessee. Breakthroughs in next-generation battery components and energy density present numerous opportunities for the EV market and supply chain. According to BNEF, prices of lithium-ion batteries increased for the first time in 2022, after a decade of price decline. While this delays the price parity with comparable combustion engine vehicles, BNEF estimates that price parity in the US will occur in the 2027-28 timeframe without subsidies and in 2023 with the approved subsidies.[12]

Charging Infrastructure

Significant advancements in the deployment of EV charging infrastructure have occurred in the last few years. Of note is the development of the National Electric Vehicle Infrastructure (NEVI) Formula Program authorized through the Bipartisan Infrastructure Bill, which will bring a network of charging stations located along designated alternative fuel corridors. The State of Arizona submitted and received approval for its NEVI plan, securing nearly $76 million in federal dollars to establish publicly-accessible EV charging stations.[13] The current plan calls for the development of up to four NEVI charging locations. Each location will have at least four 150 kW charging stations.[14]

Limited charger availability will be further addressed by Tesla's announcement that its North American Charging Standard (NACS) connector will be used on Ford, GM, Rivian, Volvo and Polestar vehicles by 2025, opening Tesla's Supercharger network to other EVs. Currently, Tesla has the highest number of public DCFC connectors in the U.S.

While improvements in vehicle range have helped address driver range anxiety, charger reliability is a main point of concern for EV customers. TEP continues to engage with industry organizations as well as state and local entities to ensure a focus on charger uptime to improve reliability and customer experience.

TEP Advancement in Transportation Electrification

<u>Regulatory Approvals</u>

- Statewide Transportation Electrification Plan approved December 2021

[10] Plug In America, EV Driver Survey, 2023.
[11] ICF, The Impact of Electric Vehicles on Climate Change, 2023
[12] BNEF, 2023.
[13] https://azdot.gov/planning/transportation-studies/arizona-electric-vehicle-program
[14] EPRI Electric Transportation Update, June 2023.

- Transportation Electrification Implementation Plan approved November 2022

Pricing Plans

- TEP offers EV specific rates for both residential and commercial customers focusing on a pricing structure that favors off-peak charging.

Programs

- Rebates for residential customers installing charging stations at their home.
- Rebates and technical assistance for commercial customers for installing charging station at retail, work and multi-family locations.
- Rebates and technical assistance to public transit agencies and schools looking to electrify their fleets.

Website Tools

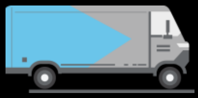
- EV comparison calculator
- EV fleet total cost of ownership calculator
- https://tep.wattplan.com/ev/

TEP EV Adoption and Grid Impact Analysis

Different EV Adoption Forecasts

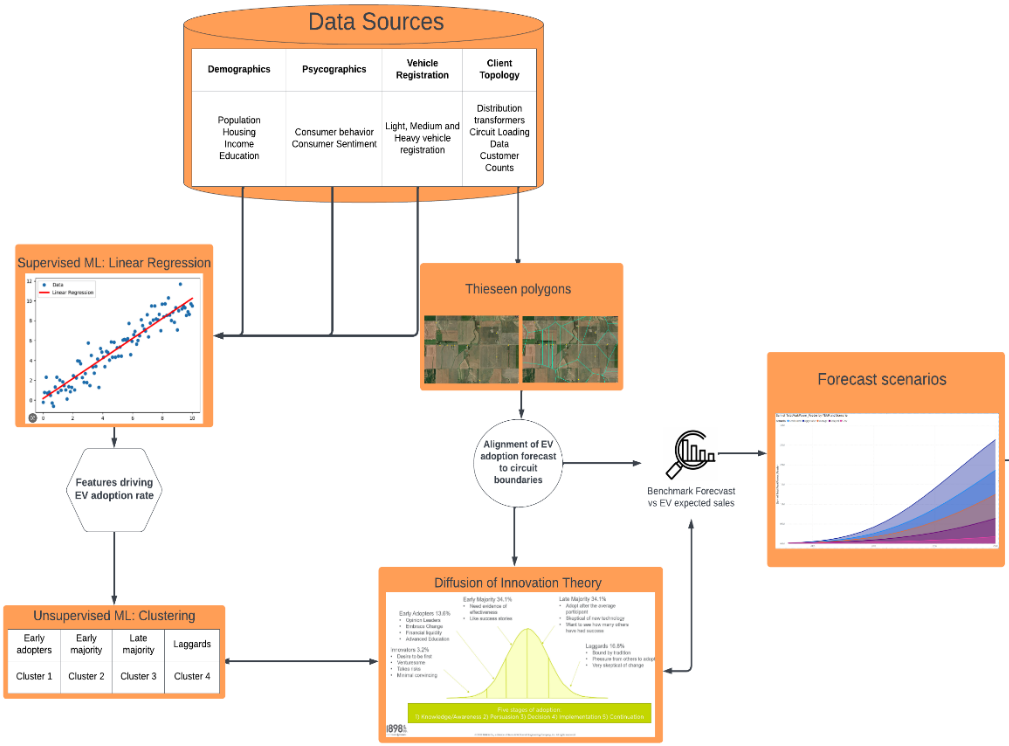
Residential Model: Census Tract analysis of population combined with different forecast scenarios

Public Model: Based on public EV charging today and forecasted out over time to find potential EV locations



Fleet Model: Identify key companies that could electrify fleet and make assumptions around EV adoption

Residential Adoption Model



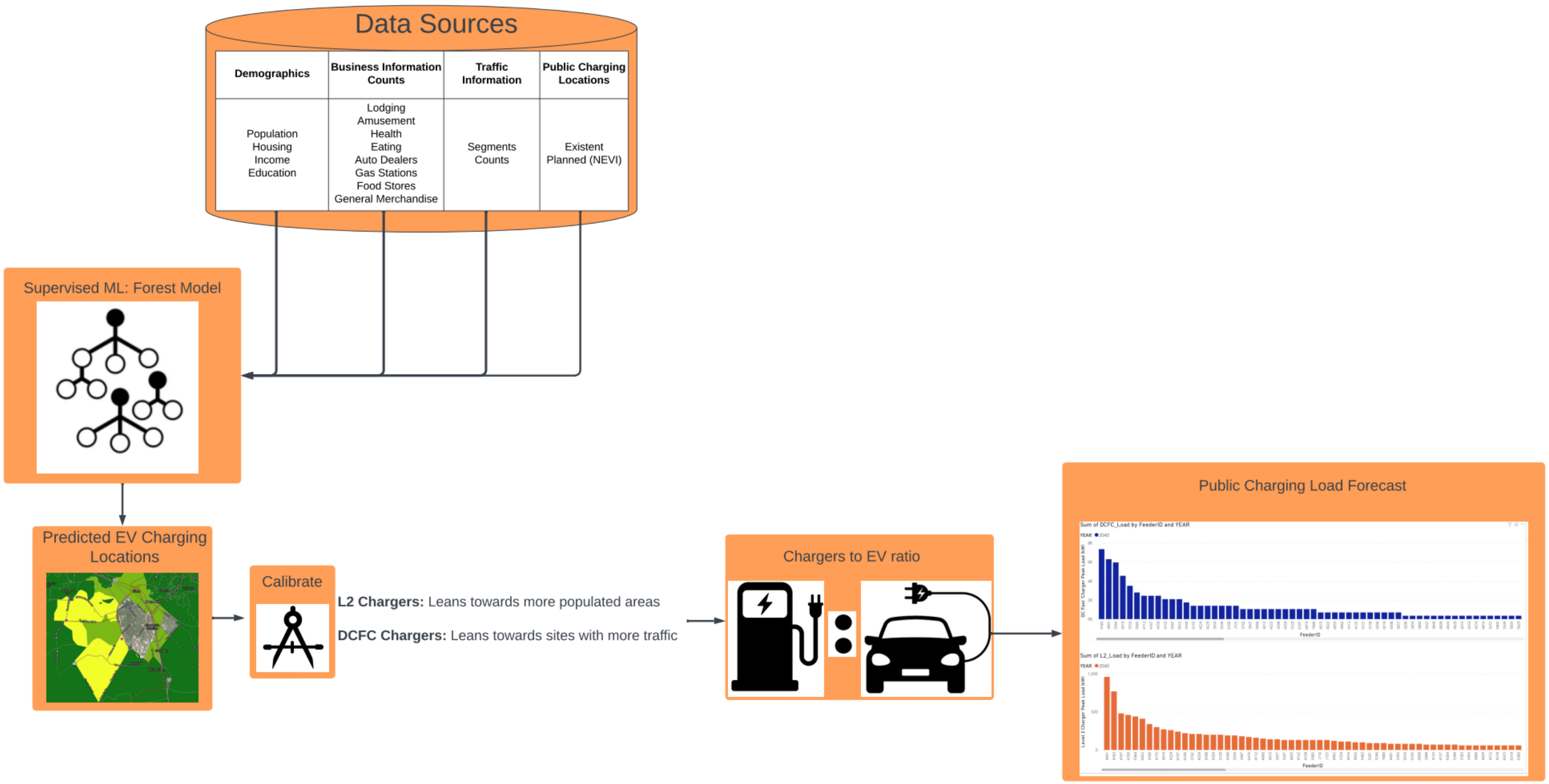
Results

GIS Analysis

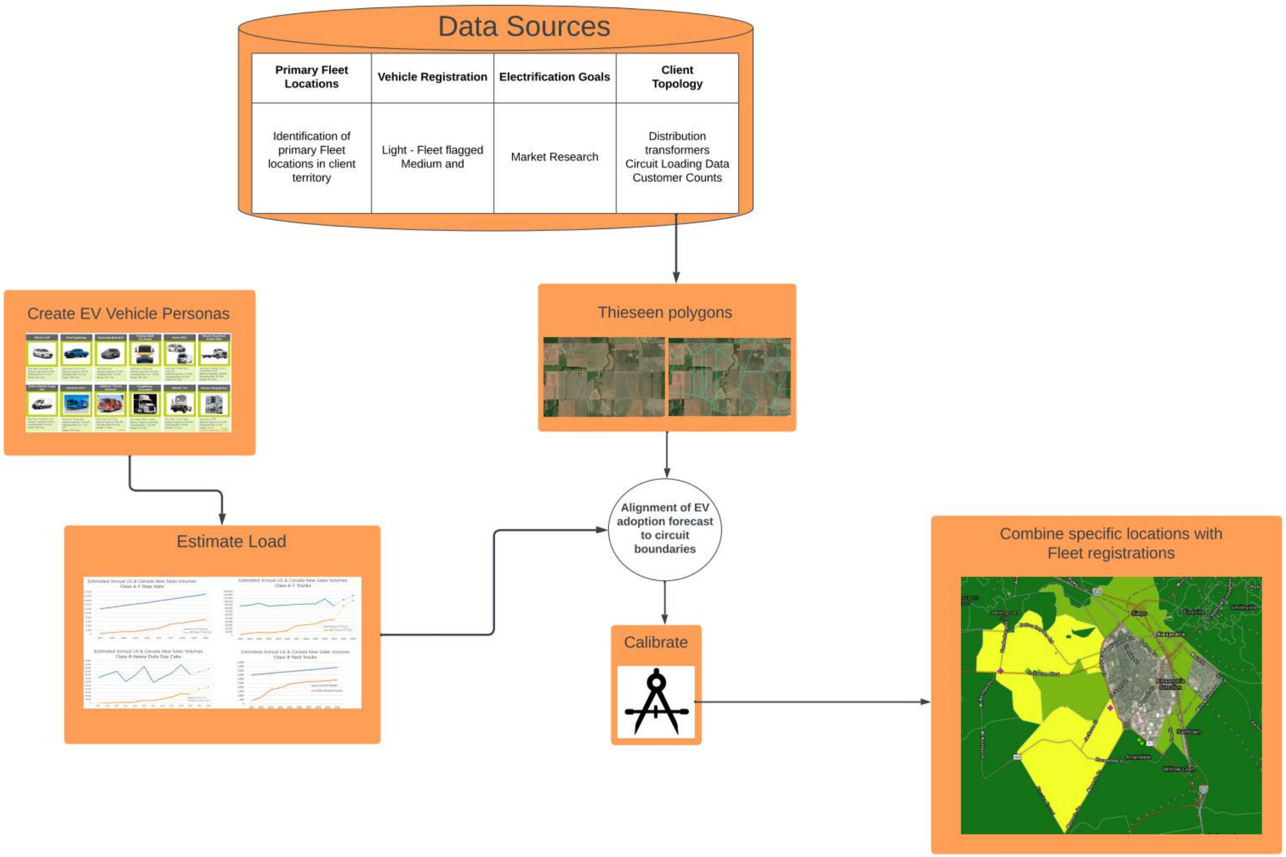
Data Output

Feeder	Adoption	Total Vehicles	Percent EV	Percent Capacity
3975	2022	1	0	44.96
3975	2023	0	0	44.91
3975	2024	2	0	45.08
3975	2025	7	0	45.49
3975	2026	15	0	46.17
3975	2027	26	0	47
3975	2028	48	0	48.84
3975	2029	77	0	51.16
3975	2030	119	0	54.61
3975	2031	176	0	59.14
3975	2032	245	0	64.79
3975	2033	328	0	71.39
3975	2034	426	0	79.36
3975	2035	532	0	87.94
3975	2036	645	0	97.11
3975	2037	764	0	106.69
3975	2038	883	0	116.26
3975	2039	1001	0	125.77
3975	2040	1115	0	135

Public Charging Model



Fleet Model



TEP

Vehicle Market

70 new named EV models in next 3 years

2023

CHEVROLET

Blazer, Silverado, Equinox

NISSAN

8 All-electric models

Audi

A6 e-tron, Q4 e-tron

2024

HONDA

Prologue

RAM

1500

ACURA

ZDX

Electra E5

2025

STELLANTIS

25+ All-electric models

BENTLEY

Bentayga, Flying Spur

HYUNDAI

KIA MOTORS

23 EVs & Hydrogen models

gm

30 All-electric models

TOYOTA

15 All-electric models

...and more coming.

TEP

Light-Duty small cars and SUVs

Summary

There are various options available for small SUVs (aka CUVs), large SUVs, hatchbacks, and 4-door sedans. Both plug-in hybrid and full battery electric vehicles exist from OEMs. OEMs such as Ford and GM are committing to release more models over the next decade; however, specifications and availability are limited.

Weight Classes: Class 1, 2

Commercial Readiness: Market Ready (limited options)

Operational History: Various hybrid, plug-in hybrid and BEVs have been available for a decade.

Battery Size: **PHEV**: 8.8kWh–18.4kWh | **BEV**: 33kWh–100kWh

Range: **PHEV**: 26mi– 42mi | **BEV:** 115mi – 353mi

MSRP[2]: **PHEV**: $28 – $42k | **BEV**: $25k – $65k

Charging Requirements: **PHEV**: Level 2: 3kW - 6.6kW, Time: 2.5 - 3.5hrs
BEV: Level 2: 7 – 11.5kW Time: 7hrs
BEV: DCFC: 50kW - 350kW, Time: 0.5 - 1hrs

Available Models[1]

PHEV

Ford Fusion, Ford Escape, Hyundai Ioniq, Honda Clarity, Kia Niro, Kia Optima, Mini Cooper, Toyota Prius, Toyota RAV4 Prime, Mitsubishi Outlander, Jeep Wrangler, Jeep Grand Cherokee, Subaru Crosstrek and more

BEV

Chevrolet Bolt, Chevrolet Bolt EUV, Ford Mach-E, Tesla Model 3, Tesla Model Y, Hyundai Ioniq, Hyundai Kona, Mini Cooper, Nissan Leaf, Volkswagen ID.4, Volkswagen e-Golf, Kia EV6, Nissan Ariya, Mini Cooper Electric, Toyota bZ4X and more.

(1) Available models quickly evolving because of OEM commitments or planned models.
(2) Estimated; based on OEM announcements, publicly available data, or third-party data.

Light-Duty pickups, SUVs, and vans

Summary

Options emerging for full size SUVs, pickup trucks, and vans. Expected to be available in 2022 to 2023 calendar year. Anticipate more OEM announcements over next 12 months. OEMs (Ford, GM) are moving to BEVs, skipping PHEVs models. Lordstown, GM targeting commercial fleets with their BEV pickup trucks. XL Fleet offers converted PHEV F150s.

Weight Classes: Class 1, 2

Commercial Readiness: Development / Pre-Production (emerging, but not yet available)

Operational History: Limited to Very Limited (Conversion to PHEV or BEV represent majority of operational history)

Battery Size: **Pickup Truck (PHEV)**: 18kWh | **Pickup Truck (BEV)**: 64kWh – 200kWh | **Large SUVs**: 160kWh – 200kWh | **Vans**: 67kWh – 140kWh

Range: **Pickup Truck (PHEV)**: N/A(3) | **Pickup Truck (BEV)**: 100mi – 320mi | **Large SUVs**: ~300mi | **Vans**: 126mi – 155mi

MSRP(2): **Pickup Truck (PHEV)**: ~$62k(4) | **Pickup Truck (BEV)**: $53k - $80k | **Large SUVs**: ~$70k | **Vans**: $45k - $120k

Charging Requirements: PHEV: Level 2 3kW – 6.6kW
BEV: Level 2 7.2kW – 19.2kW
DCFC: 50kW – 150kW

Market Landscape(1)

Likely not a viable option

BEVs(3)

Pickup Trucks: Ford F150 (2022), Chevrolet Silverado (2023), GMC Hummer SUV/SUT (2022/2024), Lordstown Endurance (2021), Rivian R1T (2022), Tesla Cybertruck (~2023), XL Fleet F150, F250 (Available)(3)

Large SUVs: Rivian R1S (2022)

Vans: Ford E-Transit (2022), Chrysler Pacifica Hybrid (Available), Arrival Van (2022), Bollinger Deliver-E (~2023)

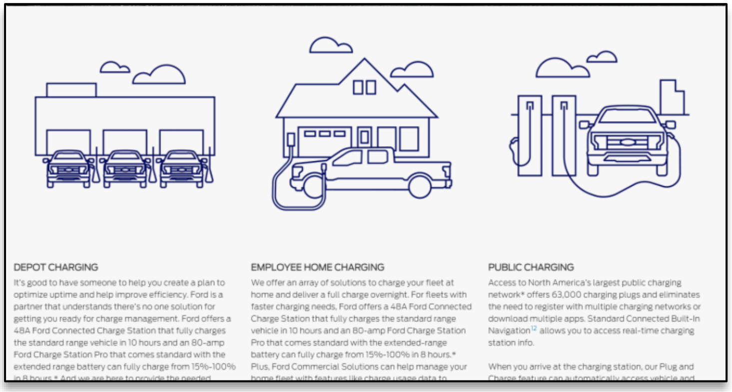
(1) Available models quickly evolving because of OEM commitments or planned models.
(2) Estimated; based on OEM announcements, publicly available data, or third-party data.
(3) Integrated with drive train so it provides assistance but cannot operate under battery only.
(4) This includes both the vehicle and conversion kit at ~$30k per upfit.

F-150 Lightning Pro

All electric F-150

Overview

- Standard and extended range versions
  - **230-mile estimated range: $55,974(starting price)**
  - 320-mile estimated range: $80,974 (starting price)
- **Project more than 40% maintenance savings over 8 years and 100,000 miles assuming scheduled maintenance**
- On-board power capabilities; up to 9.6 kW through 11 outlets (10 – 120 V outlets, 1 – 240 V outlet)
- **Can off-board up to 9.6 kW (V2G) of peak energy to a home with enabled EV charger**
- Intelligent range factors in energy used during various conditions (payload, towing, weather, traffic, grade, etc.)
- FordPass Power My Trip: allows user to plan trips; evaluates SOC and integrates convenient charging locations into the route. Can take into account payload and towing.
- **On-board 80-amp Ford Charge State Pro; allows for peak charging power of 19.2 kW enabled by dual onboard chargers**
- Standard 32-amp Ford Mobile Charger ($500 additional)
- 2,000 lbs. of payload; 10,000 lbs. of towing
- 3-year complimentary access to Ford E-Telematics for Pro version



DEPOT CHARGING

It's good to have someone to help you create a plan to optimize uptime and help improve efficiency. Ford is a partner that understands there's no one solution for getting you ready for charge management. Ford offers a 48A Ford Connected Charge Station that fully charges the standard range vehicle in 10 hours and an 80-amp Ford Charge Station Pro that comes standard with the extended range battery can fully charge from 15%-100%

EMPLOYEE HOME CHARGING

We offer an array of solutions to charge your fleet at home and deliver a full charge overnight. For fleets with faster charging needs, Ford offers a 48A Ford Connected Charge Station that fully charges the standard range vehicle in 10 hours and an 80-amp Ford Charge Station Pro that comes standard with the extended-range battery can fully charge from 15%-100% in 8 hours.* Plus, Ford Commercial Solutions can help manage your

PUBLIC CHARGING

Access to North America's largest public charging network* offers 63,000 charging plugs and eliminates the need to register with multiple charging networks or download multiple apps. Standard Connected Built-In Navigation[12] allows you to access real-time charging station info.

When you arrive at the charging station, our Plug and

Ford charging solutions
(https://www.fleet.ford.com/showroom/trucks/f150/f150-lightning/2022/)

Warranty (key items)

- EV Component: 8 years or 100,000 miles
- Powertrain: 5 years / 60,000 miles
- Bumper to Bumper: 3 years / 36,000 miles
- EV Roadside Assistance: 5 years / 60,000 miles

Medium-Duty Vehicles

Summary

Very limited BEV models available or planned (today) for medium-duty application. Most Class 3 to 6 applications targeting last mile delivery (box trucks, cargo or step vans). Freightliner's eM2 (electric version of M2) is in pre-production (box truck). Ford, Ram, GM have not announced nor appear to be focused on medium-duty vehicles today.

Weight Classes: Class 3 to 6

Commercial Readiness: Not Available (for typical utility functions); Pre-Production for vocational cab/chassis and step vans.

Operational History: Very limited (for typical utility functions)

Battery Size[1]: **Vocational**: 141kWh – 315kW | **Cargo/Step Van**: 70kWh – 100kWh | **Conversions (All)**: 88kWh – 192kWh

Range[1]: **Vocational**: 100mi – 200mi | **Cargo/Step Van**: 100mi – 150mi | **Conversions (All)**: 90mi – 200mi

MSRP[1][6]: **Vocational**: ~$200k | **Cargo/Step Van**: $120k - $150k | **Conversions (All)**: $120k - $220k (vehicle + conversion)

Charging Requirements[1]: Level 2: 11.5-19.2kW
DCFC: 50kW – 150kW (a few up to 250kW)

Market Landscape[2]

BEVs[3]

Freightliner (eM2); BYD (6F); Ram (None Announced); International (eMV); Bollinger (B1, B2, B2 Chass-E Cab); Peterbilt (220EV); Lion Electric[4] (Lion6); Workhorse (C-650, C-1000); Kenworth (K270E); Ford (None Announced); GM (None Announced); Chanje (V8100); Sea Electric[5] (Transit 350, F59 Step Van, F650); Motiv[5] (E450 Cutaway, F59 Step Van); Roush[5] (F650 Cutaway); Lightning[5] (Transit 350, F59 Step Van, E450 Cutaway, F550, Chevrolet 65000XD)

(1) Specifications based on Class 6 vocational/cab chassis and vans
(2) OEMs / Conversions profiled as a part of medium-duty vehicle market landscape.
(3) Most OEM development today is focused Class 6 vocational/cab chassis serving box truck applications. However, future applications likely to be built on same platform (Freightliner eM2) for other applications.
(4) Lion Electric has announced a Class 6 truck (not designed) that may be used in an All-Electric Utility Truck application. Unlikely to be available before late 2022/early 2023.
(5) Sea Electric, Motiv, Roush Cleantech, and Lightning eMotors convert OEM platforms to battery electric by installing electric drivetrain on OEM chassis.
(6) Estimated; based on OEM announcements, publicly available data, or third-party data.

Heavy-Duty vehicles

Summary

Very limited BEV models available or planned (today) for heavy-duty application. Most Class 7 or 8 applications targeting regional haul, drayage, or box truck applications. Freightliner's eM2 (electric version of M2) is in pre-production (box truck). Lion Electric has launched an all-electric bucket truck but won't be in service until late 2021/early 2022 in pilot with ConEd.

Weight Classes: Class 7, 8

Commercial Readiness: Not Available (for typical utility functions); Pre-Production for Class 7/8 tractors and vocational cab/chassis

Operational History: Very limited (for typical utility functions)

Battery Size[1]: **Vocational**: 250kWh – 315kWh | **Tractor**: 250kWh – 500kWh (up to 1,000kWh for Tesla Semi) | **Conversions**: 100kWh – 150kWh

Range[1]: **Vocational**: 170mi – 200mi | **Tractor**: 120mi – 250mi (up to 500mi for Tesla Semi) | **Conversions**: ~200mi

MSRP[1][6]: **Vocational / Tractor**: $200k - $350k | **Conversions**: $170k - $200k (vehicle + conversion)

Charging Requirements[1]: Level 2: 19.2kW
Level 2.5: 24kW
DCFC 50kW – 250kW
Future State: 1MW

Market Landscape[2]

BEVs[3]

Freightliner (eM2, eCascadia); Volvo (VNR Electric); Tesla (Semi); Kenworth (T680E, K370E); Peterbilt (220EV, 579EV); International (eMV); BYD (8TT); Lion Electric (Lion8 Urban, Lion8 Utility[4], Lion8T Tractor); Ford (None Announced); Sea Electric[5] (F-750)

(1) Specifications based on Class 8 tractors and Class 7/8 vocational/cab chassis.
(2) OEMs / Conversions profiled as a part of heavy-duty vehicle market landscape.
(3) Most OEM development today is focused on Cass 8 tractors and Class 7/8 vocational/cab chassis serving drayage, regional haul, and box truck applications. However, future applications likely to be built on same platform (Freightliner eM2) for other applications.
(4) Lion8 All-Electric Utility Truck will be deployed in late 2021 / early 2022 in pilot with Consolidated Edison of New York.
(5) Sea Electric converts OEM platforms to battery electric by installing electric drivetrain on OEM chassis.
(6) Estimated; based on OEM announcements, publicly available data, or third-party data.

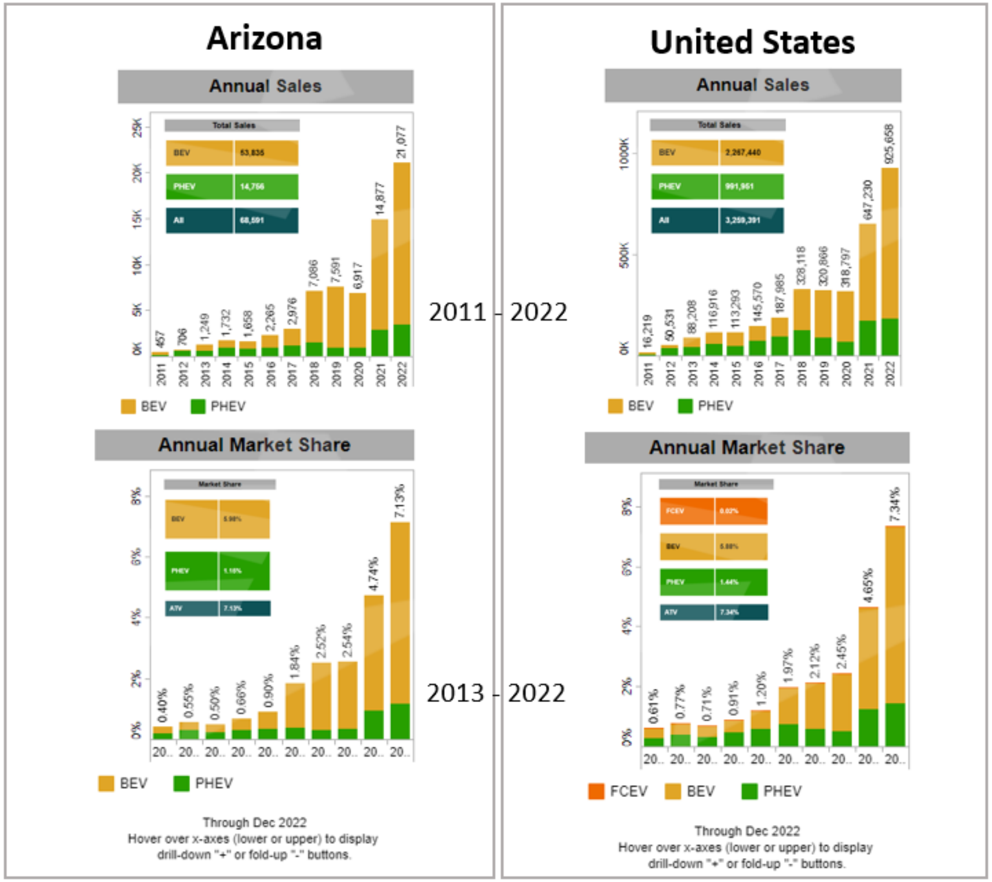
EV Market Share

Arizona & US EV market share

Overview:

- EV market share continues to rapidly increase in both Arizona and the U.S.
- Arizona is currently slightly behind U.S. average EV market share, but the differential is rapidly shrinking
- Arizona's sales growth is outpacing the U.S. average
- Nearly 1/3 of all EV sales since 2011 took place in 2022
- BEV sales growth is substantially outpacing PHEV's

	BEV LD Market Share (2022) Jan - December	Market Share Growth (2020 - 2022)	Sales Growth YoY (2020-2022)
AZ	7.13%	181%	205%
U.S.	7.32%	200%	190%



Alliance for Automotive Innovation (2022). Advanced Technology Vehicle Sales Dashboard. Data compiled by the Alliance for Automotive Innovation using information provided by IHS Markit (2011–2018, Nov 2019–2022) and Hedges & Co. (Jan 2019–Oct 2019). Data last updated 9/15/2022. Retrieved 9/29/2022 from https://www.autosinnovate.org/initiatives/energy-and-environment/electric-drive

Updated EV Market Research

OEM commitments in the next decade are expected to expand the EV market creating more consumer choices. We have compiled a list of OEM commitments below:

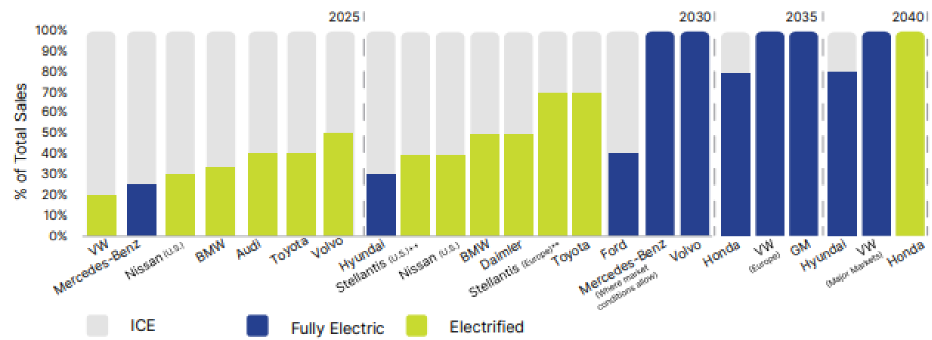
OEM EV Sales 2030:

- **Audi:** 100% BEV by about 2033, last ICE platform to release in 2026
- **Bentley:** PHEV/BEV Only by 2026, BEV only by 2030
- **BMW:** 50% ZEV by 2030
- **Ford:** >600,000 EVs worldwide annually by 2023, 2 million by 2026. Ford expects 40% to 50% of its global vehicle volume to be fully electric by 2030.
- **GM:** 2 million EVs Annually in North America and China by 2025, plans to be BEV only by 2035. dedicate. Will dedicate more than 50% of its factories in North America and China to the production of electric vehicles by 2030.
- **Cadillac:** 100% BEV by 2035
- **Buick:** 100% BEV by 2030
- **Chrysler:** plans to shift to an all-electric feet by 2028.
- **Rolls Royce:** 100% electric by 2030
- **Honda:** 100% BEV by 2040, 80% by 2035, 40% of vehicle sales in NA either hydrogen or BEV by 2030.
- **Hyundai-Kia:** Targeting 1.87 million BEVs sold annually by 2030. Kia aims to sell 1.2 million BEVs by 2030
- **Jaguar/Land Rover:** 100% BEV by 2030
- **Mazda:** By 2030, all models will have "some level of electrification,">25% of sales are EV by 2030
- **Mini:** 100% EV by 2030
- **Daimler/Mercedes-Benz:** 100% BEV by 2030
- **Nissan:** 40% BEV in US by 2030
- **Porsche:** 80% of Unit Sales in 2030 BEV
- **Stellantis:** 40% of Sales Electrified by 2026, 50% BEV by 2030
- **Subaru:** 40% BEV/PHEV by 2030
- **Toyota:** Toyota has a goal to sell 3.5 million EVs per year by 2030 which would be more than a third of its current sales.
- **Volkswagen:** 55% electric in US by 2030, last combustion platform launches in 2026
- **Volvo:** 50% of Global Sales fully electric by 2025, 100% BEV by 2030

US EV Sales 2030:

- By 2030 >47% of all US vehicle sales will be EVs; at least 7.1 million new EVs will be hitting the road in 2030.
- Projections formed via 2021 US vehicle market shares and their commitments as listed above
- All EV only automakers like Tesla, Polestar, Rivian etc. are under-represented in the above projection

Figure 8.
Global Sales Forecast by Manufacturer



Electrified definitions: BMW models will have electrified drive trains (BEV or PHEV), Nissan models will either be pure electric models or e-POWER powertrain models, and Audi does not define electrified, and Volkswagen will have a 100 percent ZEV fleet. Nissan has set a goal for its U.S. sales. Honda announced in March 2019 its ambition of making one hundred percent of its European sales electrified, building upon the brand's 2017 goal of electrifying two-thirds of global sales.

Source: https://blogs.edf.org/climate411/files/2022/04/electric_vehicle_market_report_v6_april2022.pdf

TEP

Vehicle Cost?

Batteries

- EV battery demand is rising quickly, with 2021 shipments 94% higher than in 2020. By 2030, EV battery demand grows to 3,486GWh in the Economic Transition Scenario. Manufacturers have announced plans totaling 4,151GWh of annual capacity due by 2025. China still dominates, but capacity is growing in other regions.
- The timing for achieving battery pack prices below $100/kWh on a volume-weighted average basis has become less certain, as raw material prices have significantly impacted costs over the last 12 months. If raw material prices remain elevated or climb further, this could delay the timeline by a couple of years, out from 2024 in most markets. However, introduction of new cell chemistries and manufacturing equipment and techniques will help to continue to bring costs down. Simplified pack designs for battery-electric vehicle platforms also contribute.
- Automakers have significantly grown their commitment to LFP (lithium iron phosphate)-based chemistries, which we now expect to account for 42% of battery demand by 2023, including through variations such as LMFP (lithium iron manganese phosphate), where the addition of manganese will further improve energy density.
- New EV battery chemistries will continue to be adopted in an effort to provide longer ranges or lighter packs. By the end of the decade new chemistries using more manganese, such as NMCA and NMC (96Ni), will become prevalent to reduce pressure on nickel.

Battery materials

- The supply of lithium, cobalt, manganese and nickel chemicals suitable for lithium-ion batteries could be tight this decade under our Economic Transition Scenario. New refining facilities and investment will be required. Higher prices and new technologies should help the market respond to this need.
- The total demand for lithium surpasses 2.4 million metric tons lithium carbonate equivalent (LCE) in 2030, up 259% from current demand. Companies have invested in the chemical convertors that produce carbonate and hydroxide, while ignoring upstream raw material extraction. This has led to a squeeze in the upstream market driving lithium prices up over the last 18 months. These high prices will lead to the development of new projects, which should lead to prices easing over the next 12 months due to more supply becoming available to meet demand.
- About $5.4 billion is needed to ensure the building of 400,000t LCE in lithium raw material supply, a volume that is currently in the pipeline for 2021-2025 but not yet financed. For the chemical convertors, an additional 100,000t LCE carbonate and 300,000t LCE hydroxide capacity planned by 2025 still needs at least $8.4 billion to be successfully developed.

https://about.bnef.com/electric-vehicle-outlook/

Inflation Reduction Act (IRA) of 2022

- The most significant legislation to accelerate transportation electrification in U.S. history.
  - Signed into law on August 16^{th}, 2022
- Light-duty EV Tax Credit
  - up to $7,500 per vehicle has been extended through 2032.
- Used EV Tax Credit
  - up to $4,000 or 30% of the sales price, whichever is lower.
- Commercial EV Tax Credit
  - up to $7,500 for vehicles under 14,000 pounds and up to $40,000 for all other vehicles.
- EV Charging Equipment Tax Credit
  - For commercial uses, the tax credit Is 6% with a maximum credit of $100,000 per unit (up from $30,000 per property).
- Clean Heavy-duty Vehicles
  - The law allocates $1 billion to states, municipalities, Indian tribes, or non-profit school transportation associations to replace class 6 and 7 heavy-duty vehicles with clean EVs.

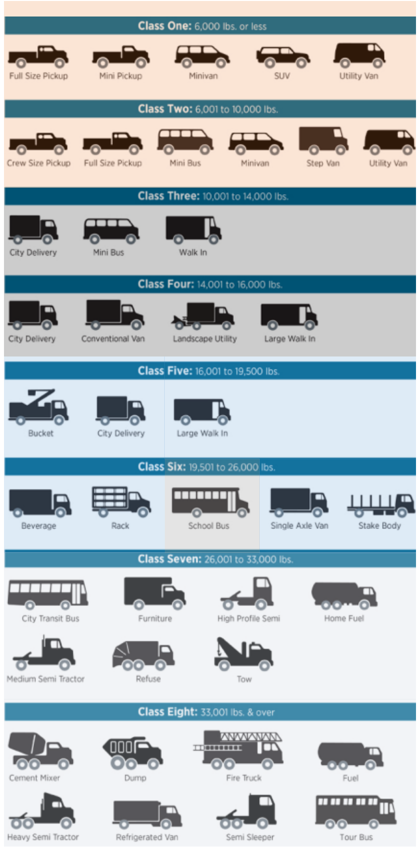
TEP

Vehicle Segment

Vehicle Types and Classifications Reference

Gross Vehicle Weight Rating (lbs)	Federal Highway Administration: Vehicle Class	Federal Highway Administration: GVWR Catagory	US Census Bureau: VIUS Classes
<6,000	Class 1: <6,000 lbs	Light Duty <10,000 lbs	Light Duty <10,000 lbs
10,000	Class 2: 6,001–10,000lbs		
14,000	Class 3: 10,001–14,000 lbs	Medium Duty 10,001–26,000 lbs	Medium Duty 10,001–19,500 lbs
16,000	Class 4: 14,001–16,000 lbs		
19,500	Class 5: 16,001–19,500 lbs		
26,000	Class 6: 19,501–26,000 lbs		Light Heavy Duty: 19,001–26,000 lbs
33,000	Class 7: 26,001–33,000 lbs	Heavy Duty >26,001 lbs	Heavy Duty >26,001 lbs
>33,000	Class 8: >33,001 lbs		

Gross Vehicle Weight Rating (lbs)	EPA Emissions Classification: Heavy Duty Vehicle and Engines: H.D. Trucks	H.D. Engines	General Trucks	Light Duty Vehicles: Passenger Vehicles
<6,000 6,000	Light Duty Truck 1 & 2 <6,000 lbs	Light Light Duty Trucks <6,000 lbs	Light Duty Trucks < 8500 lbs	Light Duty Vehicle < 8500 lbs
8,500	Light Duty Truck 3 & 4 6,001–8,500 lbs	Heavy Light Duty Trucks 6,001-8,500 lbs		
10,000	Heavy Duty Vehicle 2b 8,501–10,000 lbs	Light Heavy Duty Engines 8,501 lbs–19,500 lbs	Heavy Duty Vehicle Heavy Duty Engine >8,500 lbs	Medium Duty Passenger Vehicle 8,501–10,000 lbs
14,000	Heavy Duty Vehicle 3 10,001–14,000 lbs			
16,000	Heavy Duty Vehicle 4 14,001–16,000 lbs			
19,500	Heavy Duty Vehicle 5 16,001–19,500 lbs			
26,000	Heavy Duty Vehicle 6 19,501–26,000 lbs	Medium Heavy Duty Engines 19,501–33,000 lbs		
33,000	Heavy Duty Vehicle 7 26,001–33,000 lbs			
60,000	Heavy Duty Vehicle 8a 33,001–60,000 lbs	Heavy Heavy Duty Engines Urban Bus >33,001		
>60,000	Heavy Duty Vehicle 8b >60,001			



Residential Single-Family Home, MUD, Retail, Workplace, Fleet Passenger Vehicle, Fleet Local Delivery

Fleet Local Delivery, Light Duty Service Vehicles

Fleet MD Service Vehicles

School & Paratransit Buses

Fleet HD Service Vehicles

Consumer Behavior

Behaviors of Consumer EV Buyers: Purchase Trends

A report developed for the Fuels Institute named "EV Consumer Behavior" evaluated EV purchase trends

Source: https://www.fuelsinstitute.org/Research/Reports/EV-Consumer-Behavior/EV-Consumer-Behavior-Report.pdf

- The top demographic of 2019 EV owners are middle-aged white men earning more than $100,000 annually with a college degree or higher and at least one other vehicle in their household.
    - 37% of Democrats and 34% of Republicans appear to view EVs positively, and a guaranteed $7,500 tax rebate could make 78% of Democrats and 71% of Republicans more likely to consider an EV during their next purchase or lease (2019).
    - Younger adults most likely to consider an electric vehicle purchase in the next 10 years as studies have shown Millennials, born between 1981 and 1996, are more open to considering the purchase of an electric vehicle. (source: https://morningconsult.com/2021/12/22/electric-vehicles-consumers-2022/)
- EV sales have grown exponentially over the past 10 years; however, the ownership demographic has remained relatively the same. The average EV owner continues to be male, aged 40-55 years old, with an annual household income of more than $100,000 (2019). Mileage driven, however, has increased from 100 miles to 250 miles a week over the years.
- In the next 10 years, EV sales are expected to constitute between 12% and 40% of all light-duty vehicle sales, implying that:
    - EV buyer age could normalize with the broader new vehicle buying trend
    - EVs could become more affordable
    - Number of EV buyers with no provision to charge at home could increase
    - Driving pattern is expected to be similar to the way internal combustion engine (ICE) vehicles are driven
    - Gender distribution could become more balanced
- EV fleet sales are expected to grow in the upcoming years, driven by state mandates.
- Household income, family size, age, driving distance, geographical location, and type of residence tend to influence EV ownership.
- Total cost of ownership (TCO) and payback period are the key drivers in a business' decision involving adoption of EVs in their commercial fleet.
- Affordability, availability, and familiarity appear to be amongst the key factors influencing likelihood of EV purchases
- EV trips are mostly planned with charging locations in mind, unlike conventional vehicles; however, more daily miles are driven on average in an EV (2020) than in an ICE-powered vehicle

TEP

Behaviors of Consumer EV Buyers: Charging

A report developed for the Fuels Institute named "EV Consumer Behavior" evaluated EV charging trends

Source: https://www.fuelsinstitute.org/Research/Reports/EV-Consumer-Behavior/EV-Consumer-Behavior-Report.pdf

- EV drivers tend to recharge daily or once every two days, typically overnight at home, and overall, about 70-80% of charging occurs at home or at a workplace parking lot.
- Most EV fleet customers today (2020) operate in a hub-and-spoke network and exclusively recharge their vehicles overnight at their home base
- The most used public chargers are those where vehicles are typically parked for long periods (e.g., airport parking lots, grocery store, etc.) (2012-2014).
- Most customers drive within their battery range only, using a public charger when making trips longer than their range would permit.
- Drivers of ICE vehicles fill up based on the cost, necessity, and time of the day; 32% only fill up when they see the fuel warning light in the dashboard (2019).
- Nonavailability of chargers at home and making trips longer than the battery range are two of the various reasons why drivers use public charging stations.
- EV charging stations spaced 70 miles from each other on average could provide convenient access to battery electric vehicle (BEV) drivers across the interstate system (2017).
  - NOTE: NEVI is calling for Alternative Fuel Corridors to have charging every 50 miles, no more then 1 mile from the highway exit with minimum 150kW chargers and 600kW per site.
- Approximately 46% of BEV drivers (2016) feel availability of direct current fast charging (DCFC) as a feature is not a very big influencer in their EV buying decision.
- More than 80% of EV drivers use three charging locations or fewer away from their home, where they do most of their charging (2011-2014).

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Consumer Behavior Demographics

This paper called "Identifying Factors Associated with Consumers' Adoption of e-Mobility", identified factors of adoption as shown in the summary graphic below:

Source: https://www.mdpi.com/2071-1050/13/19/10975

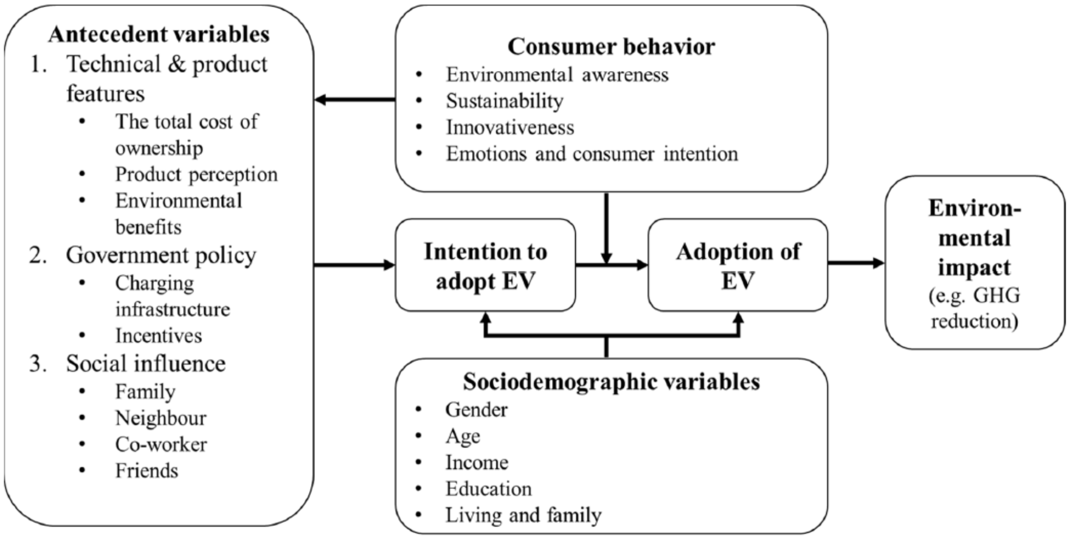


Figure 4. Overview of the context of adoption of EVs adapted and modified from Kumar and Alok (2020).

Residential Forecasting Methodology

The adoption of new technology generally follows the diffusion of innovation theory

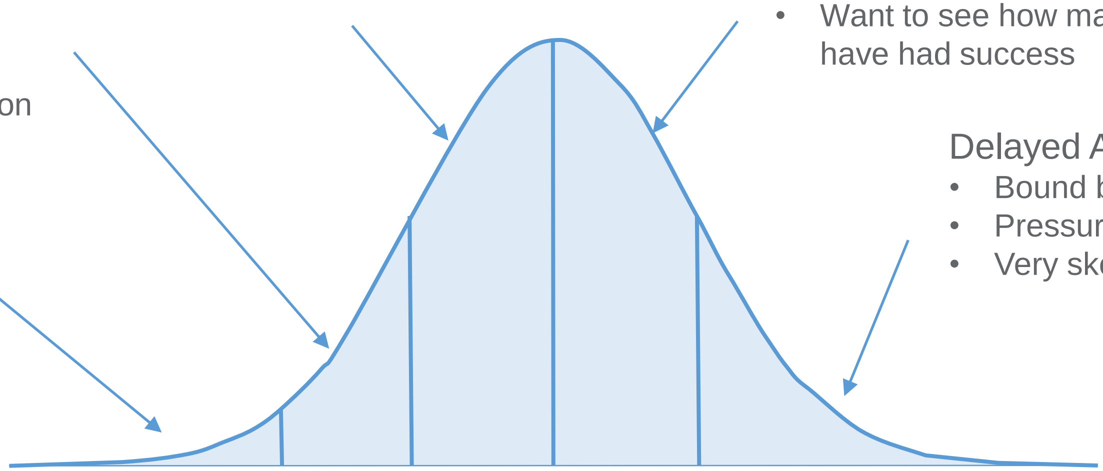
Early Majority 34.1%
- Need evidence of effectiveness
- Like success stories

Late Majority 34.1%
- Adopt after the average participant
- Skeptical of new technology
- Want to see how many others have had success

Early Adopters 13.6%
- Opinion Leaders
- Embrace Change
- Financial liquidity
- Advanced Education

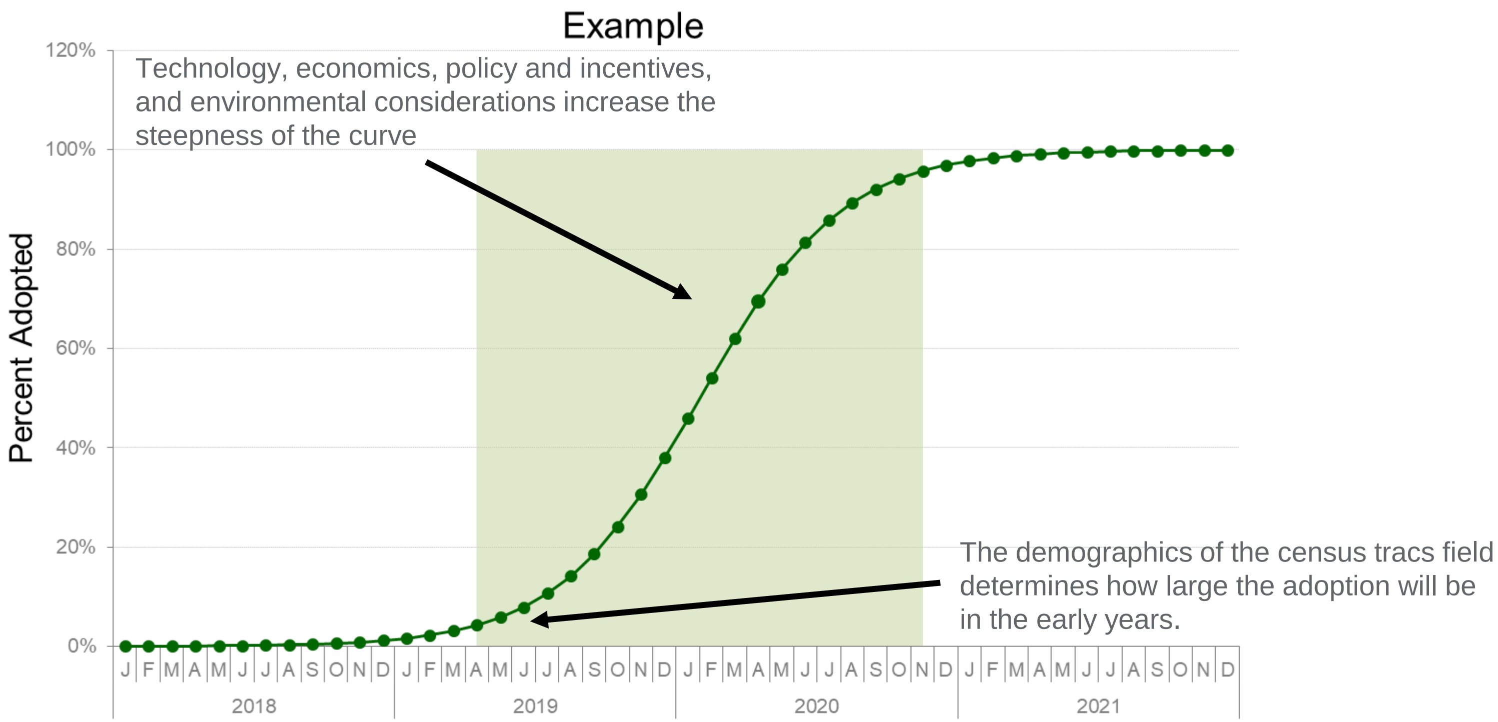
Innovators 3.2%
- Desire to be first
- Venturesome
- Takes risks
- Minimal convincing

Delayed Adopters 16.8%
- Bound by tradition
- Pressure from others to adopt
- Very skeptical of change



Five stages of adoption:
1) Knowledge/Awareness 2) Persuasion 3) Decision 4) Implementation 5) Continuation

From the diffusion of innovation theory, we can develop curves that can model adoption over time



Note: Assumed a start value of 0%. Expected market size accounts for some categories being already adopted. Other categories are at very low adoption levels.

Residential EV Adoption Scenarios

Scenario Name	Scenario Description	Potential Scenario Inputs Assumed to Happen Before 2030
Aggressive	**Optimistic:** Strong Government Investment, Rapid Technological Change	- Solid state batteries increase beyond current Li-ion batteries before 2030, improving durability/range/charging time - OEMs EV model availability and production exceeds expectations - EVs purchase cost the same or less than ICE vehicles - Significant private & public charging infrastructure is built out across the country (post-IIJA). - Chargers reach parity with gas pumps or better - Government increases incentives for EV owners and manufacturers and adopts policies that push EV adoption - Significant Carbon Tax or ICE vehicle tax
Accelerated	**Slightly Optimistic:** Government halts further investment but private sector innovates	- Solid state batteries are in production and can overtake current Li-ion in technology improving durability/range - OEMs EV production increases to meet demand - EVs purchase cost the same as ICE vehicles - Some state governments continue to invest in EV infrastructure (post-IIJA) - Federal government does not invest in further legislation to affect adoption - Federal gas tax (road) altered to include EVs
Average	**Mean Outcome:** Average outcome across all scenarios	- Moderate battery innovation improved chemistry/reduced hazards - Battery production is *sufficient to* meet demand - OEMs EV production increases to meet demand - EVs cost is comparable to ICE vehicles but battery costs do not reduce. - IIJA is completed but only moderate further investment in a national charging infrastructure network is made - ZEV legislation stays on track at the state level - Government maintains benefits for EV drivers and manufacturers - Federal gas (road) tax altered to include EVs
Delayed	**Slightly Pessimistic:** Supply chain constraints, strong government investment, marginal technological improvements	- Battery production does not meet demand - OEMs cannot increase EV production to service demand in near term - Current Li-ion battery technology only marginally improves in performance and lifespan - EVs are more expensive than a comparable ICE vehicle - Federal gas (road) tax is altered to include EVs
Slow	**Pessimistic:** Government halts all further investment, federal gas tax shift, marginal battery innovations	- Current Li-ion battery technology remain the norm and only improve marginally in performance and lifespan - OEMs do not achieve stated electrification goals and production does not continue to increase - Private firms invest in charging infrastructure, but IIJA is only moderately successful and government halts further investment - Production demand is not met but EVs are only slightly reduced in price - EVs adversely affected by federal gas (road) tax shift

Charging Behavior

EV charging equipment standards

Overview of equipment standards and specifications for EV charging

SAE J1772

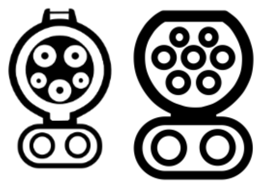
AC Ports
Favored in US & EU

208/240 VAC, 80A (up to 20 kW)

SAE J1772 CCS 1 & 2

DC Power Addition to AC Ports
Favored in US & EU

1,000 VDC, 350A (up to 350 kW)



Tesla NACS

Heavily Present in US and
Emerging as the common standard
AC: 240VAC 48A
DC: 500 or 1000VDC
200A to 400A Max

Most Common in North America

CHAdeMO

DC Power
Favored in Asia

V1.0: 500 VDC, 125A (62.5 kW)
V2.0: 1,000 VDC, 400A (400 kW)

SAE J2954

Emerging
Wireless Charging Standard

3.7kW -11kW

Charger Type	Input Power	Input Voltage	Standards
Level 1 (AC)	1-3kW	1ph 120VAC	n/a
Level 2 (AC)	3-20kW	1ph 208 or 240VAC	J1772/NACS
DC Fast Charging	20kW-500lkW	3ph 480/280VAC	CCS/CHAdeMO/NACS
Emerging DC Fast Charging	1MW+	TBD	CharIN/MCS
Wireless Charging (AC)	3-11kW	1ph 240VAC	SAE J2954
Wireless Charging	500kW+	TBD	TBD

TEP

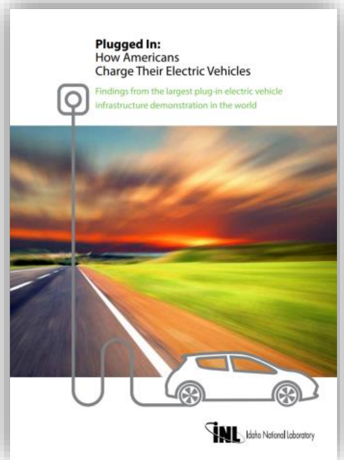
Where is EV charging likely to occur?

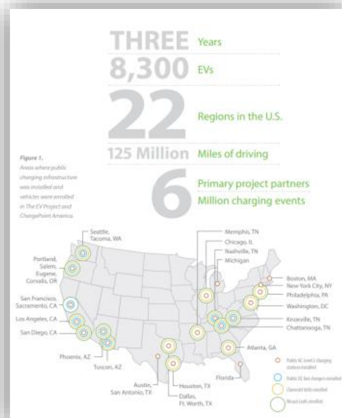
Idaho National Labs conducted a large study from 2011 to 2013 to answer this question:

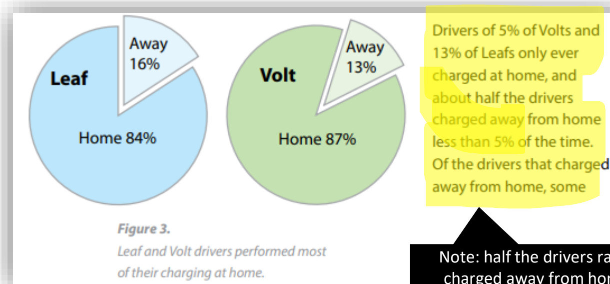
"Barriers to PEV adoption remain, however. One of the most cited barriers is the need for places for PEV drivers to plug in their vehicles. **How many and what kind of charging stations are needed? Where and how often do PEV drivers charge?**

To answer these questions, the U.S. Department of Energy launched The EV Project and the ChargePoint America project. Combined, these projects form the largest PEV infrastructure demonstration in the world. Between Jan. 1, 2011, and Dec. 31, 2013, this combined project installed nearly 17,000 alternating current (AC) Level 2 charging stations for residential and commercial use and over 100 dual-port direct current (DC) fast chargers in 22 regions across the United States."

"**The answer was clear: despite the installation of extensive public charging infrastructure in most of the project areas, the majority of charging was done at home and work**. About half the project participants charged at home almost exclusively. Of those **who charged away from home**, the vast majority favored three or fewer away-from-home charging locations, and one or more of these **locations was at work** for some drivers. **This is not to say that public charging stations are not necessary or desirable.** Many **DC fast chargers (all of which were accessible to the public) experienced heavy use to support both in-town and inter-city driving.** Also, a relatively small number of public AC Level 2 public charging sites saw consistently high use."







Note: half the drivers rarely charged away from home. But they still charged away from home and an another 50% charged away more frequently.

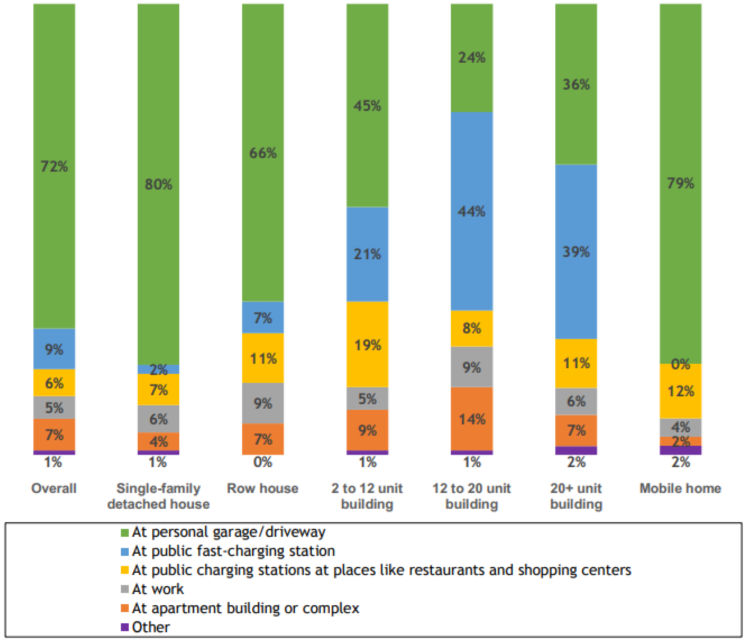
A weak point of the study is the vehicles use. They have less range and slower charge rates. Vehicles such as Tesla's or the F-150 Lightning have longer ranges and charge at higher rates

https://avt.inl.gov/sites/default/files/pdf/arra/PluggedInSummaryReport.pdf

TEP

Updated Load Assumptions

Consumer Reports Survey

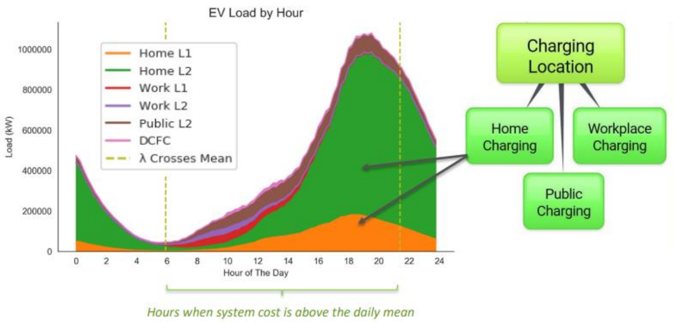


https://advocacy.consumerreports.org/wp-content/uploads/2020/12/CR-National-EV-Survey-December-2020-2.pdf

NREL EV Pro Lite

Most EV charging happens at home

At present, the tendency is for more than 80% of EV charging load (and as much as 93% under some scenarios) to happen at home, mostly in the evening. The rest is divided between public charging and workplace charging.



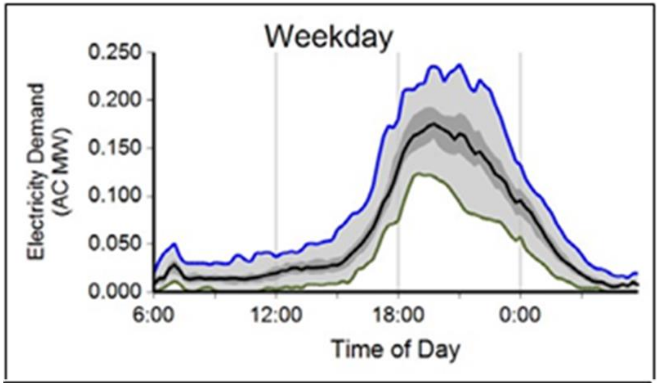
NREL simulation for Colorado using EVI-Pro, with electricity costs from Colorado utility rate books

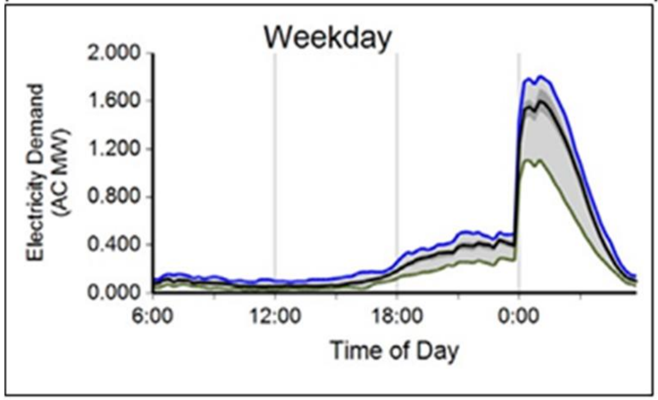
https://afdc.energy.gov/evi-pro-lite

Residential EV Customer Rates and Loads

- **Residential Flat Rates**
  - EV drivers plug in upon arrival
  - No incentive to do anything different
  - Peak increases and volume increase
  - System infrastructure expansion required
  - More new costs and more new revenue

- **Residential TOU Rate Designs**
  - Customers respond by shifting load to low-cost late-night hours (super off-peak)
  - Requires high price differential ratio (3:1)
  - Peak remains the same and volume increases
  - Minimal infrastructure expansion required
  - Minimal new costs and marginal cost recovery



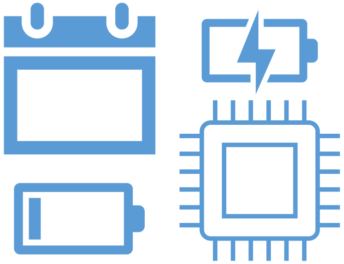


TEP

Diversity factor and charging conditions

The charge diversity is the factor at which we expect all vehicles to charge at the same time. This value allows us to calculate the potential coincident peak load that will be experienced by the system.

Unmanaged charging: The natural occurrence of consumers charging their vehicles at their most convenient time. There are assumed to be no controls or encouragement to manage on peak charging. This could lead to a lower charging diversity.

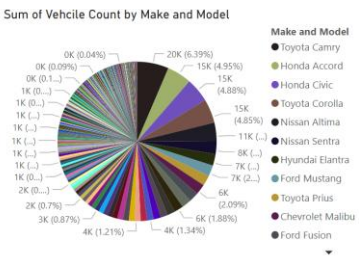


Managed charging: This assumes on-peak charging can be mitigated through passive or active measures such as TOU rates or Demand Load Control (DLC) programs. The potential still exists for on peak charging to occur; however, customers are given suitable benefits to charge at opportune times for the grid.

Residential Charging Scenarios and Assumptions

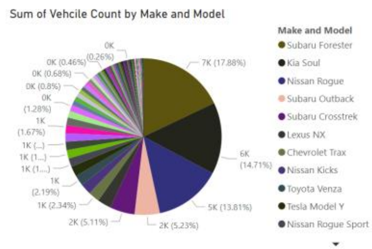
Grouped as LT_1

PC_0 



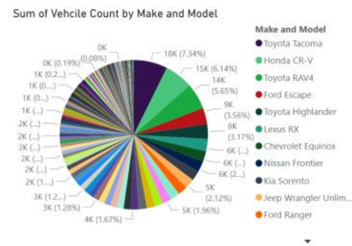
Level 1: 1.92 kW
Level 2: 7.7 kW

LT_0 



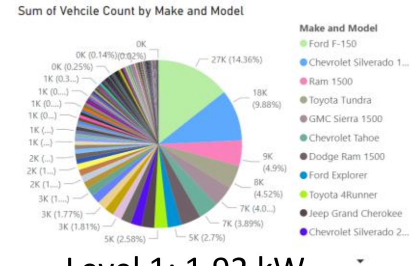
Level 1: 1.92 kW
Level 2: 11.5 kW

LT_1 



Level 1: 1.92 kW
Level 2: 11.5 kW

LT_2 



Level 1: 1.92 kW
Level 2: 19.2 kW

Scenario	Description	Peak Time	Charging Coincident Factor	Charging Split	% Charging at Home	Coincident Charging Demand (kW)
Base Case	No control or mitigation. Customers charge at convenience	4-8pm	30%	Level 1 = 20% Level 2 = 80%	80%	Profile Peak x Charger Power x Diversity Factor
Passive	TOU rates encourage a reduction in on peak charging load at system peaks	12-6am	15%	Level 1 = 20% Level 2 = 80%	80%	Profile Peak x Charger Power x Diversity Factor
Active	Demand control devices activate to mitigate peak load at congested times	8pm-6am	5%	Level 1 = 20% Level 2 = 80%	80%	Profile Peak x Charger Power x Diversity Factor

Appendix H: Environmental Regulations Overview

2023 IRP Environmental Regulations

Overview

The U.S. Environmental Protection Agency (EPA) has the authority to regulate sulfur dioxide (SO_2), nitrogen oxides (NO_x), carbon dioxide (CO_2), particulate matter, mercury, as well as other emissions and byproducts produced by power generation facilities. These power plant emissions and byproducts are regulated by statutory and regulatory programs. As these regulatory programs continue to evolve, they have had, and will continue to have important implications for public health, for the mix of U.S. generating resources, and for 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. All existing and future resources are modeled taking into account the potential impact of environmental regulations.

Regional Haze

The EPA's Clean Air Act Regional Haze Rule[1] establishes a goal to reduce visibility impairment in Class I areas (including national parks, national monuments, and wilderness areas) to natural conditions 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 EPA in relation to that objective. Reasonable Progress is an evaluation on 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 Methodology[2] 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. The ADEQ submitted the revised SIP[3] to the EPA in August 2022. Also in August 2022, the EPA issued a letter to the ADEQ finding Arizona's SIP revision complies with the completeness criteria outlined in the Regional Haze Rule.

Under the Clean Air Act, the EPA has one year from the completeness determination to take action on Arizona's SIP revision. TEP anticipates that compliance measures will likely be required to be implemented one year following EPA approval of ADEQ's revised SIP. TEP cannot predict when or if EPA will take action under the second implementation period for facilities located on the Navajo Nation, that is the Four Corners Power Plant. TEP will work with the operating agent, Arizona Public Service (APS), to develop compliance strategies as needed.

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[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

[3] ADEQ, Air Quality Division, *State Implementation Plan Revision: Regional Haze Program (2018-2028)* (Aug. 2022) https://static.azdeq.gov/aqd/haze/4_factor_screening_approach.pdf

Greenhouse Gas Regulation

On May 23, 2023, the EPA published a proposal to regulate greenhouse gas (GHG) emissions from fossil fuel-fired electric generating units (EGUs) under Section 111 of the Clean Air Act.[4]

EPA's action proposed to repeal the Affordable Clean Energy (ACE) Rule[5] and proposed to establish the following standards and guidelines:

- Revised new source performance standards (NSPS) for new or modified fossil fuel-fired stationary combustion turbine EGUs;
- Emission guidelines for states to develop plans to regulate GHG emissions from existing fossil fuel-fired steam generating EGUs (including both coal-fired and oil/gas-fired); and
- Emission guidelines for states to develop plans to regulate GHG emissions from the largest, most frequently operated existing stationary combustion turbines.

Public comment for the proposal closed on August 8, 2023. A final rule could impact TEP's existing EGUs and any development plans for new EGUs in the future. TEP cannot predict the outcome of this rulemaking, when EPA will take final action, or whether the Agency's final action will be the subject of legal challenge.

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. 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. 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.

The EPA published a proposal to further regulate CCR entitled, Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals from Electric Utilities; Legacy CCR Surface Impoundments, on May 18, 2023.[6] As currently proposed, the rule will cover legacy CCR impoundments at inactive facilities and historical placement of non-containerized CCR on land at either active or inactive facilities, including CCR historically used as structural fill material. Public comment closed July 17, 2023. TEP is analyzing the proposed rule and cannot predict the outcome of this matter 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 degree by which the area is 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

[4] U.S. EPA, Proposed Rules on 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, 88 Fed. Reg. 33,240 (May 23, 2023).

[5] U.S. EPA, Repeal of the Clean Power Plan; Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units; Revisions to Emission Guidelines Implementing Regulations, 84 Fed. Reg. 32,523 (July 8, 2019).

[6] U.S. EPA, Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; Legacy CCR Surface Impoundments, 88 Fed. Reg. 31,982 (May 18, 2023).

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 2008[8] (the 2008 ozone NAAQS). In 2020, the ozone standards were reviewed by EPA and retained, without revision.[9] Recently, in August 2023, EPA announced a new review of the ozone NAAQS, including evaluation of updated air quality criteria and public engagement opportunity.

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. If the Phoenix-Mesa area fails to attain the 2015 Ozone NAAQS by the August 2024 deadline, the area could be reclassified as "serious." A more stringent nonattainment designation could result 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 review the current standard.

Particulate Matter NAAQS

In January 2023 the EPA proposed[10] to revise the primary annual NAAQS for fine particulate matter ($PM_{2.5}$) from its current level of 12 micrograms per cubic meter ($\mu g/m^3$) to within a range of 9-10 $\mu g/m^3$. EPA proposed to retain other particulate matter NAAQS, including the annual secondary $PM_{2.5}$ level of 15.0 $\mu g/m^3$, the primary and secondary 24-hour $PM_{2.5}$ standard of 35 $\mu g/m^3$, and the primary and secondary 24-hour standard of 150 $\mu g/m^3$ for coarse (PM_{10}).

A more stringent standard could result in additional regulatory requirements for existing sources. Pinal County, where North Loop Generating Station is located, does not currently meet the proposed annual fine $PM_{2.5}$ standard of 10.0 $\mu g/m^3$. In addition, Maricopa County, where Gila River Power Station is located, does not meet the proposed level of 9.0 $\mu g/m^3$. TEP will continue to monitor the EPA's efforts to reconsider the current standard.

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 lower water use 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.

TEP's resource diversification strategy replaces generation from higher water use coal-fired resources with a corresponding amount of generation from lower water use technology, such as natural gas-fired combined cycle and internal combustion turbines, and near zero-water use renewable and energy storage resources. See **Figure 1** for average life-cycle water consumption rates for various electricity generation technologies. Based on these life-cycle water consumption rates, TEP's

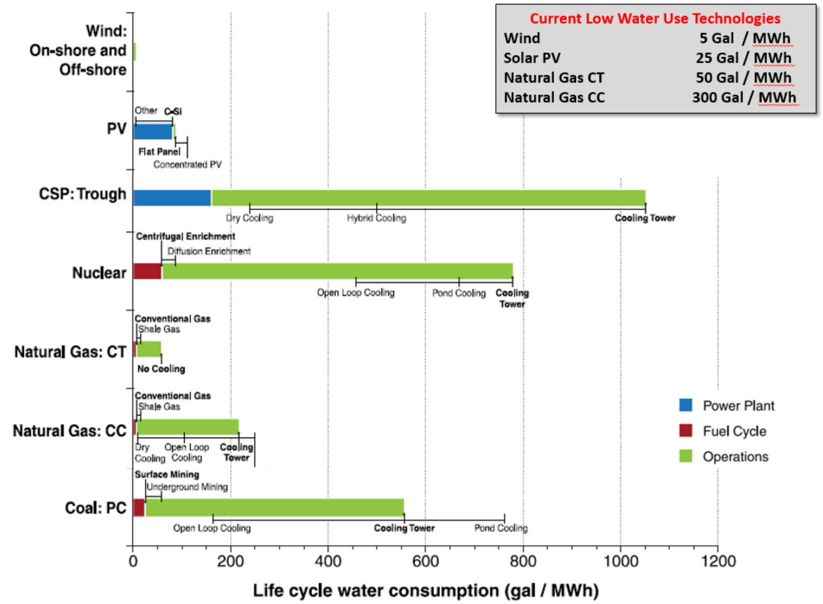
[7] U.S. EPA, National Ambient Air Quality Standards for Ozone, 80 Fed. Reg. 65,291 (Oct. 26, 2015).
[8] U.S. EPA, National Ambient Air Quality Standards for Ozone, 73 Fed. Reg. 16,436 (Mar,12, 2008).
[9] U.S. EPA, Review of the Ozone National Ambient Air Quality Standards, 85 Fed. Reg. 87,256 (Dec. 31, 2020).
[10] U.S. EPA, 8Reconsideration of the National Ambient Air Quality Standards for Particulate Matter, 88 Fed. Reg. 5,560 (Jan. 27, 2023)

resource diversification will result in lower water consumption for power generation overall.[11]

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, as well as the hydrogeological characteristics of the aquifer itself.

Figure 1. Life Cycle Water Use for Power Generation



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. While water conservation BMPs will contribute to TEP's water use reduction across all portfolios, the largest reduction in groundwater use will be through reduced operation at the Springerville plant through seasonal operations and eventually through retirement of the units.

[11] Citation: Evaluating the Technical and Environmental Capabilities of Geothermal Systems through Life Cycle Assessment. Energies 2022, 15, 5673. https://doi.org/10.3390/en15155673.

Appendix I: Wholesale Power and Natural Gas Markets

1 Wholesale Power and Natural Gas Markets

Desert Southwest Wholesale Power and Natural Gas Markets

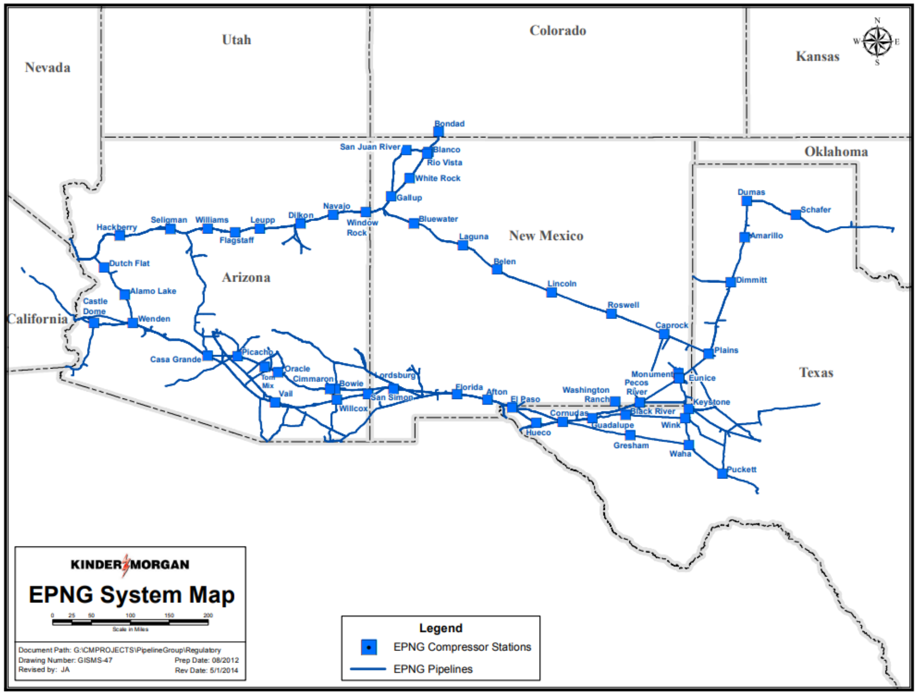
Wholesale power markets in the Desert Southwest historically have provided an efficient mechanism for utilities to buy and sell power as a means to optimize their resource portfolios and reduce costs for customers. However, extreme heat waves and winter weather events over the past three years have resulted in high market volatility and have exposed capacity shortfalls throughout much of the Western Interconnection. This has reduced the reliability and cost-effectiveness of market power to meet load, which is likely to persist until more capacity is brought online.

As more renewable energy is produced in the region, wholesale power prices, already under transformation, are expected to continue changing dramatically. Including this transformation in TEP's portfolio modeling is important to account for how wholesale market opportunities are likely to affect TEP's dispatch and operating costs.

El Paso Natural Gas (EPNG) [1] and Transwestern[2] Pipelines

TEP relies on natural gas from the Permian and San Juan supply basins in West Texas and near the Four Corners area, respectively. They are delivered by the EPNG and Transwestern pipeline networks shown below in Map 5 and Map 6. The basin-specific price forecasts are combined by the relative volume of natural gas available to each plant based on contracted and spot market pipeline capacity.

EPNG Pipeline Network Map[1]



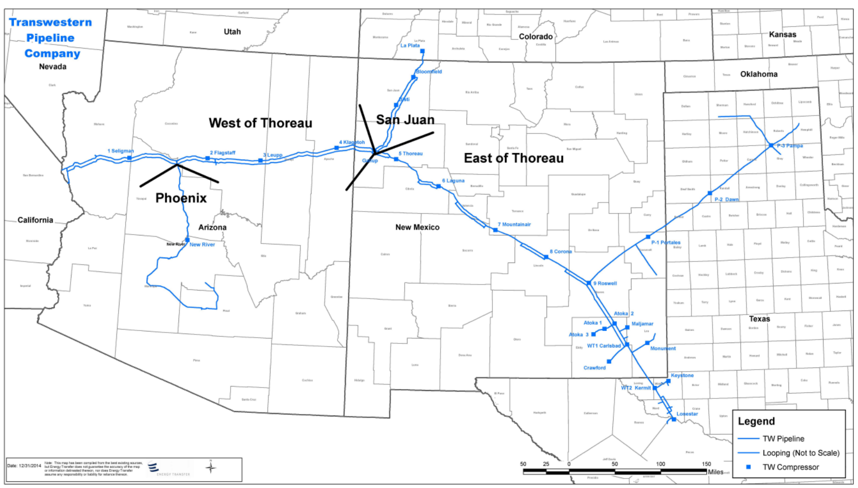
[1] https://pipeline2.kindermorgan.com/Navigation/SiteMap.aspx?code=EPNG

[2] https://twtransfer.energytransfer.com/ipost/TW/maps/system-map

Natural Gas Storage

As TEP reduces its reliance on coal, cleaner, more efficient natural gas will play a bigger role in maintaining the Company's grid operations. Today, TEP relies on the EPNG and Transwestern pipeline networks to deliver natural gas primarily from the San Juan and Permian supply basins to support its long-term, as well as real-time power generation needs. Natural gas storage provides a reliability backstop to a multitude of pipeline operational constraints that can impact the delivery of natural gas. Accordingly, in 2020 TEP contracted a share of the Keystone Gas Storage ("KGS") facility in the Permian Basin of West Texas. With connectivity to both the EPNG and Transwestern pipelines, the KGS facility allows TEP to inject and
withdraw gas to better manage daily and real-time supply.

Transwestern Pipeline Network Map



As part of the Company's future planning strategy, TEP will continue to evaluate natural gas storage as an option to further support its hourly gas balancing and generation ramping requirements. Ultimately, the decision to further invest in natural gas storage will be dependent on statewide participation with other utilities, gas storage economics compared to other energy storage technologies, and the future role of natural gas as a source of fuel within TEP's generation fleet.

Forward Fuel and Power Forecasts

Fuel and power forecasts are prepared by TEP using independent third-party sources. Near-term natural gas prices are based on S&P Global Platts forward curve. The Platts natural gas and power curves are published based upon the use of Intercontinental Exchange (ICE) settlement data. For the first three years 2024 through 2026, TEP applies Platts natural gas forward prices. From 2027-2038, E3's natural gas price forecast assumptions are used. Near-term wholesale power prices are based on a combination of Platts forward power prices and E3's hourly power shape. For the years 2028 through 2038, TEP relies on E3's long term hourly power price forecast assumptions for modeling.

Reduction in Overall Natural Gas Demand and Commodity Prices

Though increased production from renewable resources has reduced demand for natural gas consumption in certain areas, the overall regional capacity deficit has kept natural gas resources an integral part of meeting energy demand. This, coupled with the steady rise in renewable energy production, will continue to drive the displacement of coal resources for the foreseeable future.

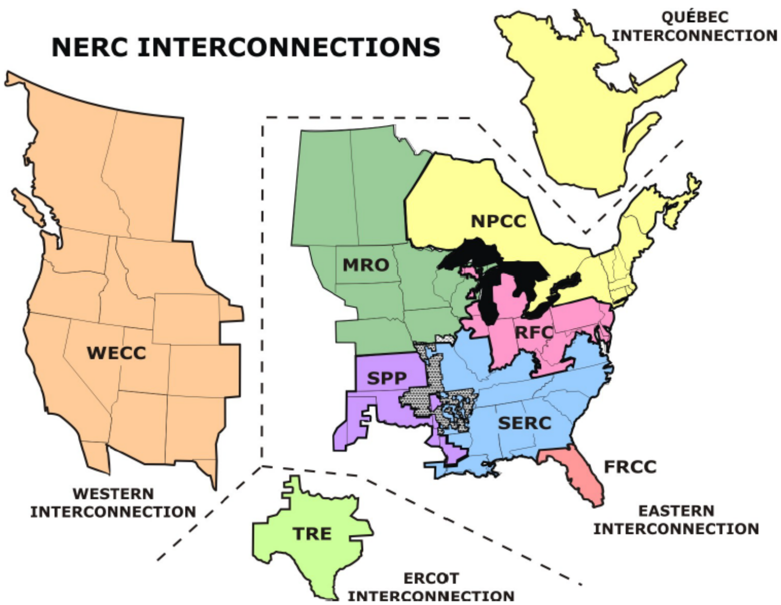
Appendix J: Operations and Transmission

1 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, Quebec, and the Western. These are each part of the North American Electric Reliability Corporation ("NERC"), see **Figure 1**.

Figure 1. NERC Interconnections

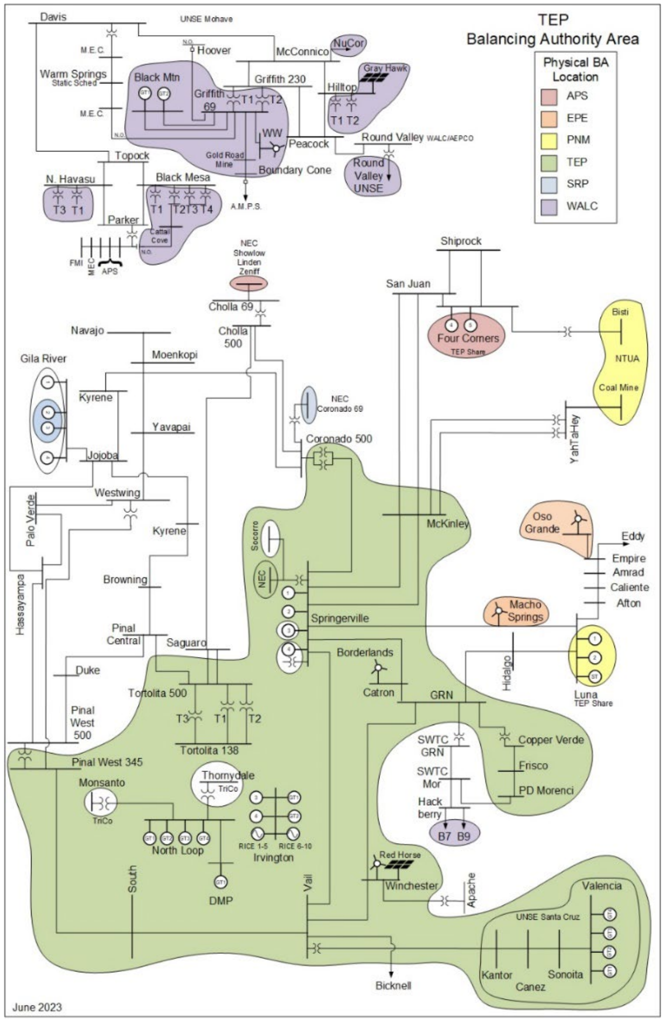


There are over 30 Balancing Authorities within the Western Interconnection. Each BA is responsible for balancing its loads and resources so that the interconnection's alternating current frequency remains at or near 60 Hertz (Hz). This resource balance is important for the safe and reliable operation 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 (CPS)**
  CPS 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 (BAAL)**
  BAAL 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 (DCS)**
  DCS is a measure of a BA's ability to replace its generating resources following the unplanned loss of a resource.
- **Frequency Response Measure (FRM)**
  FRM 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.

1.3 Operating Reserves Versus Planning Reserves

Operating reserves should not be confused with planning reserves. Planning reserves are used by Resource Planners to ensure that adequate capacity will be available to meet demand each year over a long-term planning horizon. TEP targets a planning reserve margin (PRM) of 16.5 percent above forecasted annual peak retail loads. This margin provides the extra resources necessary to account for peak loads that are higher than forecasted, for unplanned outages of generation resources, and to provide operating reserves.

TEP's PRM and its costs to ratepayers would be higher if not for its participation in the Southwest Reserve Sharing Group (SRSG), which is comprised of multiple utilities and power providers in the Southwest. By pooling their resources, members of the SRSG reduce the amount of contingency reserves they would be required to carry individually, which translates into a lower PRM as well. The SRSG, however, does not provide a pool for other operating reserves, such as those needed for frequency response and regulation.

1.4 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 (EMS) that provides Automatic Generation Control (AGC) to manage their load following requirements. However, as more intermittent and variable renewable energy is brought onto the grid, responding to changes in energy supply becomes more challenging than responding to changes in demand. 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.

1.5 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 the initial response in 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.

1.6 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 installation of a foundational communication network, the implementation of an ADMS, AMI, and enhanced systems that improve situational awareness for field personnel.

1.7 Advanced Distribution Management System

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. The 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 impact~~s~~ the distribution Frequency Regulation

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1.11 Automated Metering Infrastructure

The Automated Metering Infrastructure 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, the AMI meters provide the Company with real-time grid information such as of 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.

The AMI meters allow for remote connect and disconnect for our customers. This allows TEP to establish a service remotely instead of sending a technician. This typically reduces the time from days to under an hour.

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, a number of 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 analysis is conducted on an as-needed basis. When voltage or frequency 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.

DG is also closely monitored on a feeder level basis. Customer adoption of DG continues to grow and many of the distribution feeder circuits throughout the service territory are becoming saturated with DG. As DG increases, additional system studies will need to be conducted to identify operational issues.

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.

Project	Description	Other Notes
Sonoran Substation In Service Date [ISD] 2020 (138kV), 2024 (46kV)	New 138 kV substation with two 167 MVA 138/46 kV transformers and two75 MVA 138/13.8 kV transformers, up to eight 13.8 kV circuits and two switchgear lineups	1) Resolves transformer and circuit contingencies at Irvington and South Loop Substations 2) Supports load growth 3) Improves System Reliability 4) Supports integration of large-scale solar PV and energy storage
22nd St Substation T2 (ISD 2023)	New 75 MVA 138/13.8 kV transformer, four 13.8 kV circuits and one switchgear lineup	1) Resolves existing circuit overloads 2) Resolves transformer contingencies at 22nd Street Substation 3) Supports new business 4) Improves System Reliability 5) Supports future retirement of 46 kV Craycroft Substation
Cottonwood Substation (ISD 2024)	New 138 kV substation with 2-75 MVA 138/13.8 kV transformers, up to eight 13.8 kV circuits and two switchgear lineups	1) Provides new looped 138kV source for surrounding area 2) Resolves existing circuit and transformer overloads at Midvale Substation 3) Resolves transformer and circuit contingencies at Midvale and Santa Cruz Substations 4) Supports new business load growth 5) Improves System Reliability 6) Supports future retirement of 46 kV Mission Substation

PROJECT	DESCRIPTION	OTHER NOTES
PATRIOT SUBSTATION (ISD 2023)	New 138 kV substation with two 75 MVA 138/13.8 kV transformers, up to eight 13.8 kV circuits and two switchgear lineups.	1) Provides new looped 138 kV source for surrounding area 2) Resolves existing circuit overloads at Golf Links Substation 3) Resolves transformer and circuit contingencies at Golf Links and Pantano Substations 4) Meets the Department of Defense (DOD) resiliency Goals 5) Improves System Reliability 6) Supports future retirement of 46 kV DM, South Kolb, and Golf Links Substation
HARTT SUBSTATION (ISD 2026)	New 138 kV substation with two 75 MVA 138/13.8 kV transformers, up to eight 13.8 kV circuits and two switchgear lineups.	1) Provides new looped 138kV source for surrounding area 2) Resolves existing circuit overloads at Green Valley and South Loop Substations 3) Resolves transformer and circuit contingencies at Green Valley, South Loop, and Hartt 46kV Substations 4) Improves System Reliability 5) Supports future retirement of the 46kV Hartt and La Vallita skid
MARANA SUBSTATION (ISD 2027)	New 138 kV substation with two 75 MVA 138/13.8 kV transformers, up to eight 13.8 kV circuits and 2 switchgear lineups.	6) Provides new looped 138 kV source for residential and commercial development. 7) Improve transformer contingencies at North Loop Substation 8) Improves System Reliability 9) Support for small and large scale renewable projects 10) Supports future retirement of 46 kV Lateral 7.5 Substation

PROJECT	DESCRIPTION	OTHER NOTES
VINE SUBSTATION (ISD 2027)	New 138 kV substation with three 75 MVA 138/13.8 kV transformers, up to twelve 13.8 kV circuits and three switchgear lineups.	1) Provides new looped 138 kV source for residential and commercial development. 2) Resolves transformer contingencies at Tucson, DMP, Sparkman, Country Club, and Olsen Substations. 3) Improves System Reliability 4) Supports future retirement of 46 kV UA Medical and Winnie Substations 5) Supports delivery of renewable energy
SEARS/WILMOT 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.	1) Provides new looped 138 kV source for residential and commercial development 2) Resolves transformer and circuit contingencies at East Loop, 22nd St, Arcadia, Van Buren, and Craycroft Substations 3) Improves System Reliability 4) Supports future retirement of 46 kV Sears and Wilmot Substations
PORT 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.	1) Provides new looped 138 kV source for residential and commercial development 2) Resolves transformer and circuit contingencies at Robert Bills, Los Reales, and Vail Substations. 3) Improves System Reliability

3 Transmission Planning

3.1 Ten-Year Transmission Plan

TEP's transmission system is planned so that it meets 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 its transmission system, consisting of Extra High Voltage (EHV) and High Voltage (HV) elements, to identify upgrades to the existing system, as well as new facilities, to meet system performance requirements based on load and resource assumptions for the following ten years. The result of 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.

3.2 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 BTA[1] decision that the existing and planned transmission system is adequate to reliably serve the needs of the state during the study period.

3.3 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 7th 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 12th BTA.

3.4 Extreme Contingency Study

TEP conducted power flow analysis of outages involving TEP corridors that include 3 or more lines and TEP substations that include 3 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.

3.5 Regional Planning

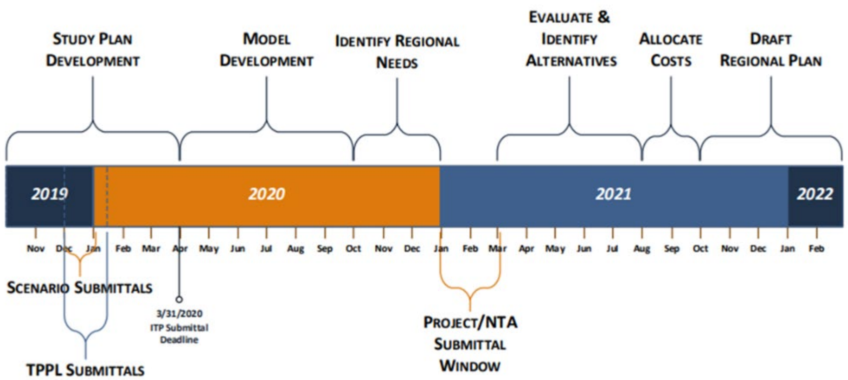
TEP actively participates in the regional transmission planning and cost allocation process of WestConnect as an enrolled member of the Transmission Owners with Load Service Obligations sector in compliance with FERC Order No. 1000 ("FERC Order 1000"). This final rule reformed FERC's electric transmission 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

[1] Arizona Corporation Commission Twelfth Biennial Transmission Assessment for 2022 Through 2031, Docket No. E-99999A-21-0009, May 9, 2023

needs and develop cost-effective enhancements to the western wholesale electricity market.

Preparation for the WestConnect biennial regional transmission planning and cost allocation process covering the period January 1, 2020 through December 31, 2021 began in the fourth quarter of 2019. A schedule for this most recently completed planning cycle is presented in **Figure 3**.

Figure 3. 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, or public policy, (or combination thereof) transmission needs. The 2020-21 planning cycle identified no regional needs within the WestConnect footprint. Therefore, TEP's 2023 IRP does not include an assessment of regional transmission projects that could be developed through the WestConnect process.

3.6 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 activities of 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 1. Regional Transmission Projects

Project Name	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.	Pattern Energy	Pattern Energy purchased the the single circuit dc transmission line from Southwestern Power Group II. According to Pattern Energy's SunZia Fact Sheet[1], construction is starting in 2023 with a commercial operating date in 2025/2026.
Southline	**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 **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	Renewable Energy Transmission Authority of New Mexico ("RETA") and	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

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

Appendix K: Future Resource Technologies

Future Resource Technologies

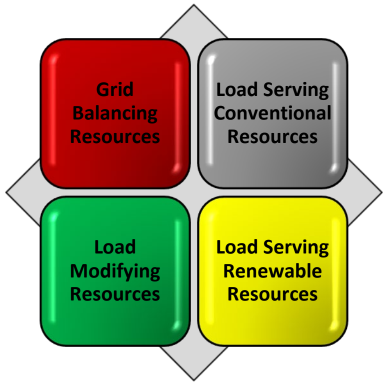
This chapter provides an overview of the future resources considered for development in the Company's resource portfolio. Based on this information and the Company's current resource mix and its commitment to reducing carbon emissions, only combustion turbines, solar, wind, and energy storage were considered as future resources when developing alternative portfolios for analysis. However, if a particular technology was bid into the Company's All-Source Request for Proposal (ASRFP) it was considered equally with all other technologies based on the specific criteria established in the ASRFP.

The TEP 2020 IRP introduced a new approach for categorizing resources in the context of its resource planning. These new resource categories more accurately reflect the changing roles of various resources in meeting our customers' energy needs while maintaining reliability. In this 2023 IRP, we continue to use this framework as we evaluate which resources should be added to our portfolio. The four categories are shown in Figure 1 and are described in more detail below:

Load Modifying Resources - Load modifying resources include Energy Efficiency (EE), Distributed Energy Resources (DER), Distributed Generation (DG), Demand Response (DR), and Time-Of-Use (TOU) tariffs. Although located "behind the meter," load modifying resources have an impact on the Company's grid operations but are typically beyond the view and control of the utility, the exception being DR.

Renewable Load-Serving Resources - Renewable load-serving resources include utility-scale solar, wind, biomass, and geothermal technologies. Solar and wind power are currently the lowest cost energy resources but do not provide the same degree of capacity or dispatchability as conventional load-serving resources to meet customer demand at all times. So while they offer the Company an opportunity to provide low-cost, zero-carbon energy, these technologies must be balanced within a portfolio that includes other resource categories.

Figure 1 – Categories for New Resources



Conventional Load Serving Resources - Conventional load-serving resources include coal, natural gas, hydro, and nuclear-powered technologies that have traditionally been used to provide the vast majority of energy and capacity to meet load.

Grid Balancing Resources - Grid balancing resources include quick-start, fast-response natural gas resources, such as combustion turbines and and energy storage technologies. These grid balancing resources can be used for peak shaving and energy arbitrage and are tools for the Balancing Authorities to maintain grid reliability.

Resources Matrix

Table 1 provides a qualitative summary of each resource type's carbon impact, level of deployment by utilities, potential for local area development, interconnection difficulty, and dispatchability.

Table 1 - New Resource Matrix

Category	Type	Zero or Low Carbon	Level of Deployment by Utilities	Local Area Potential	Interconnection Difficulty	Dispatchability
Load Modifying Resources	Energy Efficiency	Yes	High	Yes	None	None
	Demand Response	Yes	Medium	Yes	None	Medium
	Distributed PV Solar Generation	Yes	Medium	Yes	Low	None
Grid Balancing/ Load Leveling Resources	Reciprocating Engines	No (1)	Low	Yes	Medium	High
	Combustion Turbines	No (1)	High	Yes	Medium	High
	Batteries (Li-ion)	Varies (2)	Low	Yes	Medium	High
	Compressed Air Energy Storage	Varies (2)	Low	No	High	High
	Pumped Hydro	Varies (2)	High	No	High	High
Load Serving Renewable Resources	Wind	Yes	Medium	No	High	Low
	Solar PV	Yes	Low	Yes	Medium	Low
	Solar Thermal	Yes	Low	Yes	Medium	Medium
	Biomass	Yes	High	No	High	Medium
	Geothermal	Yes	High	No	High	Medium
Load Serving Conventional Resources	Natural Gas Combined Cycle	No	High	Yes	Medium	High

(1) Zero or low-carbon emissions are possible with alternative fuels such as biogas and renewable-generated hydrogen. Also, to the extent these resources are used primarily to integrate renewable resources, they can facilitate the implementation of zero carbon resources.

(2) Emissions associated with energy storage can be zero or quite significant depending on which resource is on the margin during the charging. Emissions can also result during generation when using compressed air.

Resource Benchmarking and Source Data

Prior to eliminating any resources from consideration or running any detailed simulation models with candidate technologies, the Company reviewed third-party information to acquire up-to-date cost and performance measures for each technology. Below is a list of the third-party sources. In addition, the Company used information gathered through its ongoing ASRFP competitive bidding processes and reviewed consultant reports provided as part of other utilities' recent IRPs.

- **U.S. Energy Information Administration (EIA)**
  Annual Energy Outlook 2023
  https://www.eia.gov/forecasts/aeo/electricity_generation.cfm

The Company utilized data from the EIA's Annual Energy Outlook (AEO). The EIA is an independent statistical and analytical agency within the U.S. Department of Energy. The AEO is an assessment of energy markets through 2050 and uses up-to-date models and technology information to produce forecasts and to consider alternative scenarios. The AEO includes projections for energy prices by sector and electricity supply, disposition, and emissions. Additionally, the AEO includes scenarios corresponding to "high" and "low" assumptions of oil and gas supply, oil prices, economic growth, and renewable technology costs.

- **National Renewable Energy Laboratory (NREL)**
  Annual Technology Baseline (2023)
  https://atb.nrel.gov/

The Company utilized data from NREL's Annual Technology Baseline (ATB). NREL is a federal laboratory within the U.S. Department of Energy focusing on the science, engineering, and economics of renewable energy, energy efficiency, sustainable transportation, and energy systems integration. The ATB utilizes location-specific resource data for renewable generation plants to estimate their annual energy production and site-specific capital investment. The ATB considers three future cost scenarios: Constant, Mid, and Low Technology.

- **Lazard**
  Levelized Cost of Energy Analysis (April 2023)
  https://www.lazard.com/media/typdgxmm/lazards-lcoeplus-april-2023.pdf

The Company utilized Lazard's levelized cost of energy and storage analyses. Lazard is a preeminent financial advisory and asset management firm whose reports provide levelized costs of technologies, including sensitivities and comparisons of renewable and conventional technologies. Capital, fixed operation and maintenance (O&M), variable O&M, and fuel costs are also included. These analyses are updated annually.

- **Wood Mackenzie**
  North America Power & Renewables Tool (2023)
  https://www.woodmac.com/research/products/power-and-renewables/north-america-power-and-renewables-service/

The Company subscribes to Wood Mackenzie's North America Power and Renewables suite of research products. Wood Mackenzie ("WoodMac") is an industry-leading research, analysis, and consulting firm with expertise in energy related fields, including upstream and downstream natural gas markets, coal pricing, and power markets. The North America Power and Renewables subscription includes a Long-Term Outlook (LTO), which is a comprehensive integrated forecast of energy supply and demand based on WoodMac's independent analysis of key economic drivers. The LTO includes fuel prices by basin and delivery point and the corresponding power market energy and capacity prices at various hubs.

Table 2 – Generation Resources ($2025)

Resource									
Category for Cost Reductions	Resource Category		**Solar**	**Wind**	**Wind**	**Natural Gas**	**Natural Gas**	**Nuclear**
	Technology Type		**Utility-Scale PV**	**New Mexico**	**Four Corners**	**Combined Cycle**	**Combustion Turbine**	**SMRs**
Performance Inputs		**Units**						
Plant Output	Installed Capacity	MW-ac	100	250	250	250	100	100
	Capacity Factor	%	31.0%	43.9%	32.4%	50.0%	20.0%	90.0%
	Degradation	%/yr	0.50%					
Plant Cost Inputs								
Capital Costs	Installed Cost, ($2025)	$/kW-ac	$1,273	$1,591	$1,591	$1,388	$1,186	$7,003
	Interconnection Cost	$Million	$10	$15	$15	$15	$10	$15
Fixed O&M	Annual Fixed O&M	$/kW-yr	$20	$29	$37	$30	$16	$119
	Annual Escalation	%/yr	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
Fuel Costs	Fuel Type					Natural Gas	Natural Gas	Uranium
	Unit Fuel Cost ($2025)	$/MMBtu				$3.46	$3.46	$0.65
	Heat Rate	Btu/kWh				7,250	9,800	10,500
Transmission Wheeling	Transmission ($2025)	$/kW-yr						$50.92
Property Tax	Property Tax	%	0.3%	1.0%	1.0%	0.3%	0.3%	1.0%
Insurance	Insurance	%	0.1%	0.1%	0.1%	0.3%	0.1%	0.1%
IOU Inputs	Financing Lifetime	yrs	30	30	30	22	22	40
	Equity Share	%	54.3%	54.3%	54.3%	54.3%	54.3%	54.3%
	Debt Share	%	45.7%	45.7%	45.7%	45.7%	45.7%	45.7%
	Debt Cost	%	3.8%	3.8%	3.8%	3.8%	3.8%	3.8%
	Equity Return	%	9.6%	9.6%	9.6%	9.6%	9.6%	9.6%
Tax Credits	Enable Tax Credits		Yes	Yes	Yes	No	No	No
ITC	Credit	%						
	Capital Costs Eligible	%						
PTC	Unit Credit	$/MWh	$30.05	$30.05	$30.05			
	Duration	yrs	10	10	10			
MACRS	Term	yrs	5	5	5	20	20	20
	Include Bonus Depreciation		Yes	Yes	Yes	No	No	No

Table 3 – Storage Resources ($2025)

Resource					
Category for Cost Reductions	Resource Category Technology Type		**Battery Storage** **Lithium-ion (4-Hour)**	**Battery Storage** **Lithium-ion (8-Hour)**	**Pumped** **Hydro**
Performance Inputs		**Units**			
Plant Output	Installed Capacity	MW-ac	100	100	100
	Capacity Factor	%	16.7%	33.3%	41.7%
	Degradation	%/yr			
Plant Cost Inputs					
Capital Costs	Installed Cost, ($2025)	$/kW-ac	$1,697	$3,055	$4,157
	Interconnection Cost	$Million	$10	$10	$15
Fixed O&M	Annual Fixed O&M	$/kW-yr	$26	$51	$19
	Annual Escalation	%/yr	3.0%	3.0%	3.0%
Fuel Costs	Fuel Type				
	Unit Fuel Cost ($2025)	$/MMBtu			
	Heat Rate	Btu/kWh			
Transmission Wheeling	Transmission ($2025)	$/kW-yr			$50.92
Property Tax	Property Tax	%	0.3%	0.3%	1.0%
Insurance	Insurance	%	0.1%	0.1%	0.1%
IOU Inputs	Financing Lifetime	yrs	20	20	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%
Tax Credits	Enable Tax Credits		Yes	Yes	No
ITC	Credit	%	30%	30%	
	Capital Costs Eligible	%	95%	95%	
PTC	Unit Credit	$/MWh			
	Duration	yrs			
MACRS	Term	yrs	5	5	20
	Include Bonus Depreciation		No	No	No

Resource Technology Overview

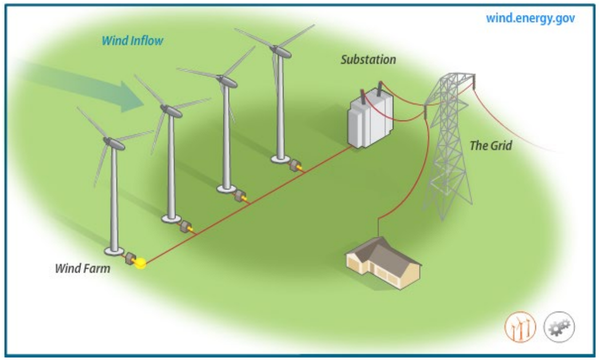
Future energy sources are primarily clean energy generation such as combustion turbines, renewables and nuclear, or storage technologies – batteries, thermal storage, mechanical storage, and hydrogen energy storage. Resources discussed here as potential additions to the portfolio are based on the Company's current resource mix and its long-term commitment to reducing emissions and water consumption. This section highlights a number of established technologies such as wind, solar, natural gas turbines, Small Modular Reactors (SMRs), Advanced Compressed Air Energy Storage (ACAES), Pumped Storage Hydropower (PSH), Carbon Capture and Storage (CCS), iron air batteries, Flow batteries, and Hydrogen Energy. A brief summary of the technology, operational characteristics, economics, and environmental and siting issues are provided below.

Generation Technologies

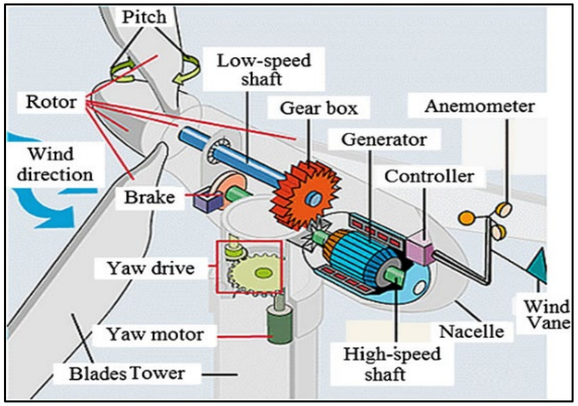
Wind

General Description
Wind power is the process of mechanically harnessing kinetic energy from the wind and converting it into electricity. The most common form of utility-scale wind technology uses a horizontal-axis rotor with turbine blades to turn an electric generator mounted at the top of a tower. For utility-scale wind power production, dozens of wind turbines may be grouped together at a wind farm project.

Yaw motors direct the turbines to face into the wind. The blades are shaped with an airfoil cross section, which causes air to move more quickly over one side than the other. This difference in speed causes a difference in pressure, which in turn causes the blade to move, the rotor to turn, and a rotational force to be generated.



The rotor is connected to a gearbox and generator housed in the nacelle, where the torque is converted into electricity. Electronics within the nacelle convert the electricity into a form that can be synchronized with the grid.



Operational Characteristics
Wind power is generally more intermittent and less predictable than solar power but can produce power at any time of the day or night. Wind velocity and air density determine the power that can be produced.

Small Modular Reactors (SMRs)

General Description

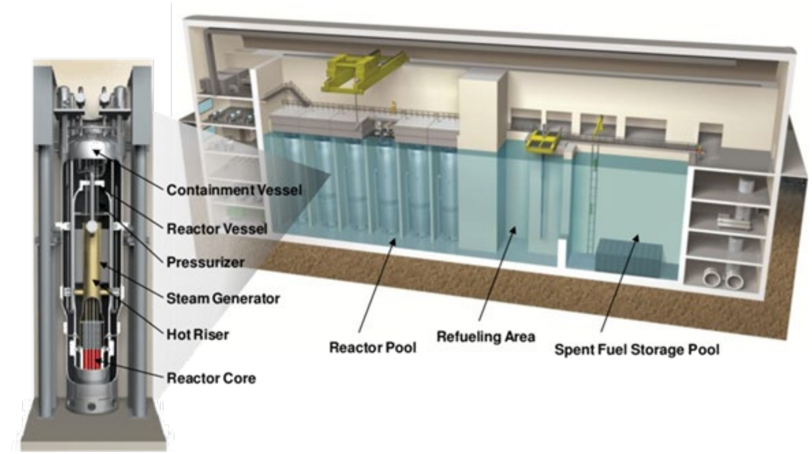
Small modular reactors are nuclear fission reactors that features factory-built-and-assembled modules in a variety of configurations. SMRs are approximately a tenth to a quarter the size of a traditional nuclear energy plant (300 MW or less) and feature compact, simplified designs with advanced safety features. As the name implies, they are scalable and portable: they can be built in one location, then shipped, commissioned, and operated at a separate site. This reduces construction time and capital costs. The design relies on passive concepts, which makes it less reliant on active safety systems, additional pumps, and an external power source for accident mitigation. The modular design and small size also facilitate expedited decommissioning.

Operational Characteristics

SMRs can potentially be located underground or underwater, providing more protection from hazards such as tsunamis and aircraft impacts. The scalability of SMRs allows for small utilities to consider their viability while lessening the financial risk. Although SMRs have high-capacity factors their operating cost is between 15% to 70% higher than electricity produced in a full-sized nuclear power station[1]. SMRs provide flexibility, enabling deployment in diverse settings, including remote areas and industrial complexes. SMRs can operate for longer durations between refueling and can integrate with renewable energy sources, offering a reliable and low-carbon energy supply, making them a promising solution for sustainable electricity generation.

Economics

Size, construction efficiency and passive safety systems (requiring less redundancy) can reduce the construction and financing costs compared to more traditional nuclear power plants.



Market Trends

SMRs are not currently in commercial operation but the U.S. Department of Energy is co-funding efforts to further research, develop, and deploy SMRs, with commercial operation targeted for the late 2020s or early 2030s.[2]

Environmental and Siting

SMRs have zero emissions and lower cooling water requirements than other traditional generation resources, providing more flexibility in siting and opening more opportunities for application, such as mining and desalination. They, however, face challenges related to cost, safety, and public perception. While SMRs are promoted for their potential scalability and reduced construction time, the initial investment remains high, hindering widespread adoption. Safety concerns persist despite their smaller size, necessitating stringent regulatory measures and public trust-building efforts. Standardization and regulatory frameworks are also evolving, impacting their commercial viability. Additionally, managing nuclear waste and decommissioning SMRs raise long-term operational challenges.

[1] US Department of Energy - https://www.energy.gov/ne/articles/4-key-benefits-advanced-small-modular-reactors

[2] https://www.nuscalepower.com/en

Solar Photovoltaic (PV) –Single Axis Tracking (SAT)

General Description

Solar PV cells convert sunlight into direct current electricity. These PV cells are the building blocks of PV modules, or panels, and the modules are the building blocks of PV arrays. Inverters convert the direct current into alternating current, which can then be tied to the electric grid and used by consumers.

Fixed tilt, stationary structures are typically designed with flat-plate systems. These structures tilt the PV array at a fixed angle determined by the latitude of the site, the requirements of the load, and the availability of sunlight. Among the choices for stationary mounting structures, rack mounting may be the most versatile. It can be constructed fairly easily and installed on the ground or on flat or slanted roofs.

The SAT PV systems are designed to track the sun from east to west. They are used with flat-plate systems and sometimes with concentrator systems. These systems track the sun's daily course. Because they can track the sun, SAT PV systems are able to generate more energy per panel than fixed tilt systems. This enables SAT systems to generate electricity at a lower levelized cost than fixed tilt systems, even though they cost more to install and maintain.

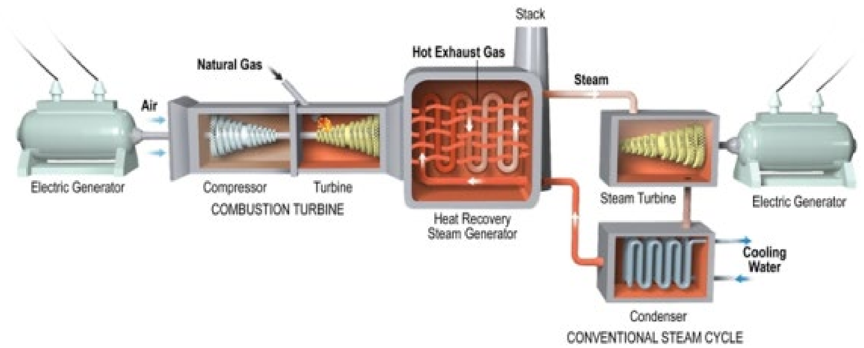
Operational Characteristics

The advantages of fixed arrays are that they lack moving parts, there is virtually no need for extra equipment, and they are relatively lightweight compared to tracking systems. These features make them suitable for many locations, including roofs. Because the panels are fixed in place, their orientation is usually set to produce the maximum amount of power over the course of the year. The advantage of SAT PV is that they generate more electricity because they track the sun.

Natural Gas Combined Cycle (NGCC)

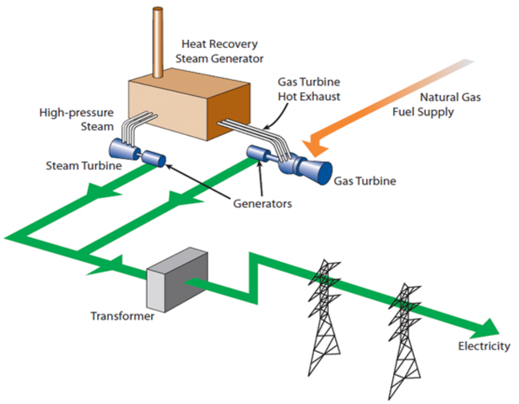
General Description

Natural gas combined cycle technology is the most efficient and cost-effective way of generating electricity from natural gas. NGCC plants use exhaust from combustion turbines to produce steam for an additional turbine and generator, thus extracting more energy from a given amount of fuel.



Operational Characteristics

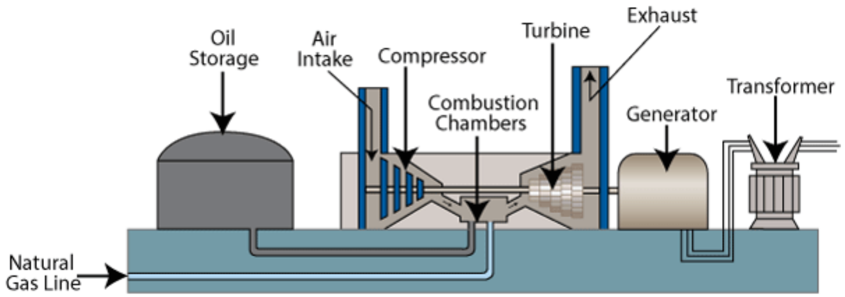
NGCC plants are capable of changing output more rapidly and following load more closely than technologies relying strictly on steam. Output can be enhanced by cooling the air intake with foggers and by adding additional heat to the combustion turbine exhaust.

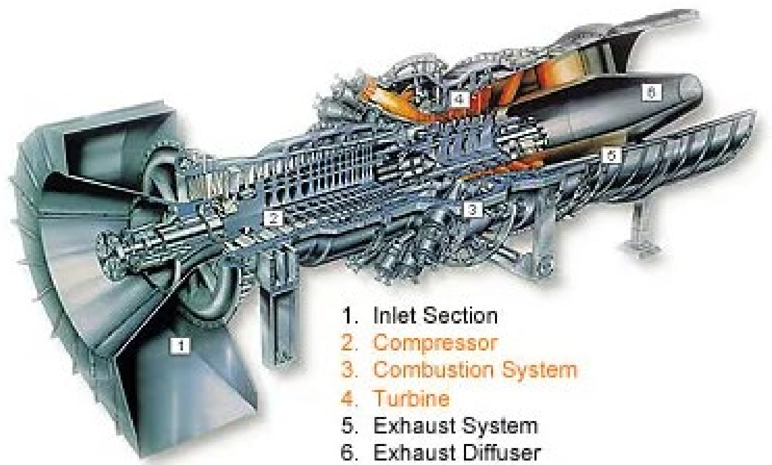


Combustion Turbines

General Description

Combustion turbines (CT) have three main components (compressor, combustion system, and turbine) and are grouped into two classes: aeroderivative and frame. Aeroderivative CTs are based on aircraft jet engine designs. They are more compact, are useful where smaller power outputs are needed, and have increased cycling capabilities. They can also ramp faster than traditional steam turbines, making them well-suited for peaking and load-following applications. Frame CTs are larger and are less efficient but have a lower per kilowatt installation cost and produce higher temperature exhaust, which makes them suitable for combined cycle configurations.





Courtesy of Siemens Westinghouse

Typical start times for frame CTs are longer than aeroderivative CTs, but equipment options from manufacturers can bridge much of that gap. Frame CTs can meet a need for intermediate and base-load applications.

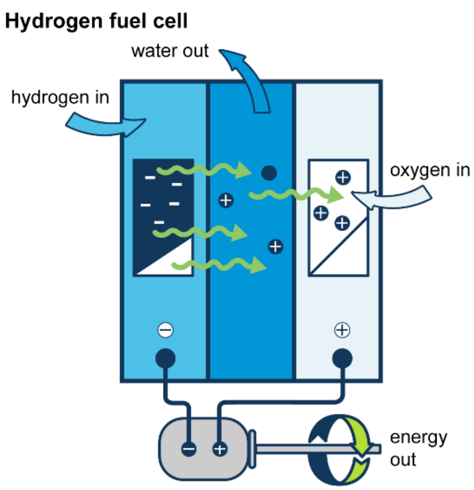
Operational Characteristics

Higher temperatures for a turbine's fuel-to-power efficiency will generally give higher efficiencies. Aeroderivative CTs have faster starts and ramps than frame CTs and meet the need for peaking capacity and load following applications.

Hydrogen (H2)

General Description

Hydrogen is a secondary energy source, storing and transporting energy produced from other resources - fossil fuels, water, biomass. Hydrogen gas is produced by one of four processes: thermal, electrolytic, or solar-driven, or biological processes. Thermal production of hydrogen, through natural gas reforming, accounts for 95 percent of all produced hydrogen. The electrolytic production of hydrogen, the process in which an electrolyzer creates hydrogen from water molecules, accounts for the rest of hydrogen production. Today, natural gas is more energy dense and currently less expensive than hydrogen gas. This affects the viability of hydrogen gas production.



Hydrogen fuel cell Source: *EIA*

The Hydrogen Economy refers to initiatives to improve fuel cell technology and materials for extracting hydrogen, develop cost-effective technologies to make hydrogen gas from renewable resources, and develop efficient and cost-effective hydrogen transport transportation and storage infrastructure. Part of this initiative is the retooling of gas turbines to also use hydrogen as a fuel.

Operational Characteristics

Hydrogen gas is highly versatile and can be used in different sectors such as transportation, industry, and energy storage. Hydrogen systems can also be integrated into existing infrastructures, making it adaptable to diverse applications and energy needs. It is a clean fuel with water vapor as the only by-product and has a high energy-to-weight ratio, making it efficient as a fuel for various applications, especially in fuel cells.

Flow batteries are inherently safe as the active components of the system are stored separately from the reactive point source. They have negligible loss of efficiency over their lifetime and can safely operate over a relatively wide temperature range. Further, they have no standby losses in the event of prolonged gaps in use, which consequently makes them low maintenance. They are modular, lending themselves to be successfully installed in various sites, including underground tanks. While flow batteries have a long lifecycle, they are limited by availability of battery stack components such as vanadium which can be upwards of fifty percent of the system cost.[3]

Market Trends

As of the end of December 2022, the United States had about 205 operating fuel cell electric power generators at 147 facilities with about 350 megawatts (MW) of total nameplate electric generation capacity. The nameplate capacities range from the largest single-fuel cell, with about 17 MW capacity—the Bridgeport Fuel Cell, LLC in Connecticut—to 10 fuel cells each with 0.1 MW capacity at the California Institute of Technology. The majority of all operating fuel cells use pipeline natural gas as the hydrogen source, but one uses landfill gas and four use biogas from wastewater treatment. [4]

[3] Nguyen, T and Savinelli,R.F. Zhaoxiang; Koenig, Gary M. *(12 May 2017).* "Review Article: Flow battery systems with solid electroactive materials". *Journal of Vacuum Science & Technology B, Nanotechnology and Microelectronics: Materials, Processing, Measurement, and Phenomena. 35 (4): 040801.*

[4] Source: EIA.gov

Economics

Hydrogen is considered an alternative vehicle fuel under the Energy Policy Act of 1992. The interest in hydrogen as an alternative transportation fuel stems primarily from its potential to power fuel cells in zero-emission vehicles (vehicles with no emissions of air pollutants). However, the debate is ongoing as to the most viable pathways for scaling up production: thermal versus electrolytic.

Environmental and Siting

Hydrogen gas is highly flammable, requiring careful handling and storage to prevent leaks and ensure safety. There are also GHG concerns from thermal production of hydrogen increasing the amounts of other greenhouse gases such as methane, ozone, and water vapor. Hydrogen storage and transport require the use of high-pressure containers and pipelines, which can be a threat to nearby communities in case of leaks or explosions. Transportation accidents can also lead to explosions and fires. Current methods of hydrogen are also water-intensive which is a concern in regions prone to water scarcity.

Hydrogen fuel cell hybrid vehicle Source: *EIA*

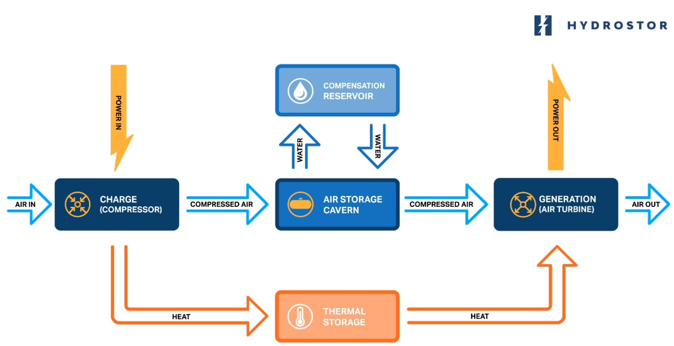
Energy Storage Technologies

Advanced Compressed Air Energy Storage (ACAES)

General Description

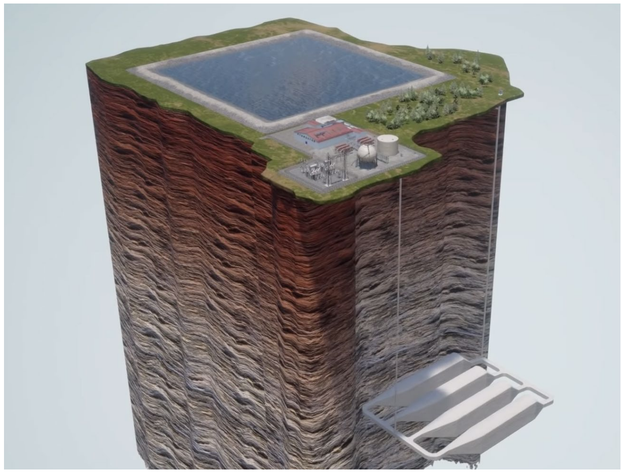
ACAES is an alternative to other forms of bulk, multi-hour energy storage such as pumped hydro, and can potentially offer shorter construction times, greater siting flexibility, lower capital costs, and lower cost per hour of storage than pumped hydro. ACAES is a hybrid generation/storage technology in which electricity is used to inject air at high pressure into underground geologic formations. The compressed air is withdrawn, heated via combustion, and runs through an expansion turbine to drive a generator. ACAES plants can use several types of air-storage reservoirs. In addition to salt caverns, underground storage options include depleted natural gas fields or other types of porous rock formations. Compressed air can also be stored in above-ground pressure vessels or pipelines.[5]

A-CAES Process Flow



Operational Characteristics

CAES can store large amounts of energy for use over many hours at a time. Responding rapidly to load fluctuations, CAES plants can perform ramping services to smooth the intermittent output of renewable generation sources as well as provide spinning reserve and frequency regulation to improve overall grid operations.



Economics

ACAES requires a large up-front capital investment, and there is relatively little commercial operating experience.

Market Trends

ACAES has not seen any growth in applications in the past three years although there is projected growth anticipated in the near future.

Environmental and Siting

EPRI studies show that more than half the United States has geology potentially suitable for ACAES plant construction. Above-ground pressure vessels or pipelines could also be located within rights-of-way along transmission lines.

ACAES faces challenges in energy efficiency and site specificity. Efficiency is hampered by heat generation during compression and cooling during

[5] https://www.hydrostor.ca/technology/

expansion, leading to energy losses. Site requirements, including underground caverns or suitable geological formations, limit its applicability to specific locations, restricting widespread adoption. Moreover, environmental concerns arise from potential air emissions and noise pollution. Additionally, the technology's economic viability and scalability are critical issues, with high initial costs posing barriers to entry.

Lithium-ion Battery Storage

General Description

Batteries can provide many services to support the grid. They can store energy when it is inexpensive or being generated in excess amounts and provide it when it is in higher demand. They can store energy until it is needed for peak demand, avoiding the construction of new "peaker" power plants, and deferring the need for transmission and distribution upgrades. In addition to providing energy and capacity, they can also provide ancillary services, such as operating reserves, voltage support, and backup power. A single battery system can provide all these services depending on when they are most needed. In addition, their size can be easily scaled, and they can be located in a variety of places.

There are various types of batteries that can be used to store energy. Two, are lithium-ion (Li-ion) and flow batteries. Li-ion batteries, originally developed for consumer electronics, are the leading types of batteries in use today. Flow batteries, while more expensive are a promising technology that can provide several more hours of energy before being depleted.

Operational Characteristics

Batteries have a high degree of flexibility in terms of application and scalability. Single systems can serve multiple purposes. While Li-ion batteries are currently the preferred type, flow batteries offer the benefit of having no degradation in the amount of energy they can store. Although batteries of 4-hour duration are currently the most common, longer-duration batteries are achieving lower costs as well.

Pumped Storage Hydropower

General Description

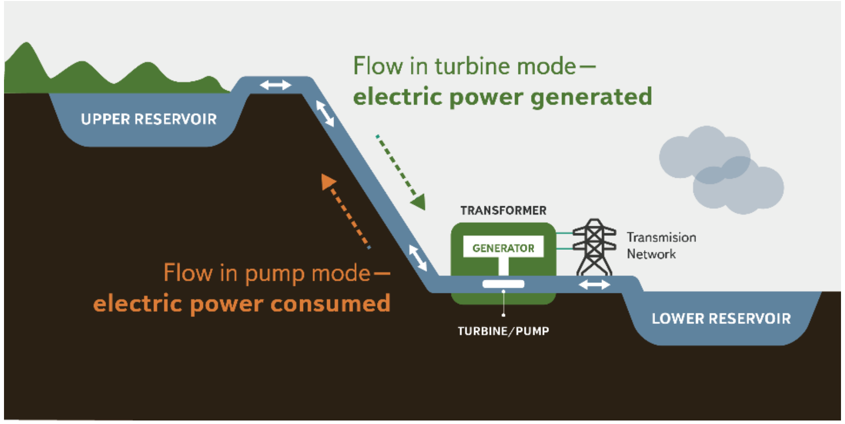
Pumped Storage Hydropower (PSH) is a type of hydroelectric energy storage system that stores energy by using two water reservoirs at different elevations. During periods of excess electricity supply (usually during low-demand hours), the surplus electricity is used to pump water from the lower reservoir to the upper reservoir. During periods of high electricity demand, the stored water is released back to the lower reservoir, passing through turbines to generate electricity.
Pumped hydro is economical only on a large scale (250 MW to 2,000 MW) and can take several years to construct. The technology operates either as open loop, where there is ongoing connection to a body of water, or closed loop, where the reservoirs are not connected to an outside body of water.

Operational Characteristics

Typical pumped hydro facilities are long duration storage technologies, storing enough water for up to 10 or more hours of energy storage. Pumped hydro plants can absorb excess electricity produced during off-peak hours, provide frequency regulation, and help smooth the fluctuating output from other sources. Pumped hydro is a proven technology with high peak use coincidence. The round-trip efficiency of these systems typically exceeds 70 percent.

The Navajo Generating Station in Arizona was one of the country's biggest-emitting power plants. It ceased commercial generation on November 18, 2019, and was demolished in December 2020.

The Navajo Nation Pumped Storage Facility is a 2,230 MW hydro power project planned for the Powell River basin in Utah. The $3.6 billion project would store power by pumping water from Lake Powell. The Navajo Nation Pumped Storage Facility will use the transmission lines to the former Navajo Generating Station.



https://navajopumpedstorage.com/index.html

Economics

Installation costs of these systems tend to be high and permitting and siting requirements pose additional challenges.

Environmental and Siting

Pumped hydro storage offers grid stability, rapid response times, and high efficiency in energy storage and retrieval. It serves as a dependable and cost-effective solution for managing peak electricity demand, integrating renewable energy sources, and ensuring a reliable power supply. However, PHS faces challenges stemming from site specificity, demanding precise geographical conditions. Environmental impact concerns stem from dam construction, with habitat disruption and societal displacement being potential consequences. Further, water scarcity concerns in certain regions, as well as aesthetic conflicts can hinder siting of PHS facilities.

Iron Air Batteries

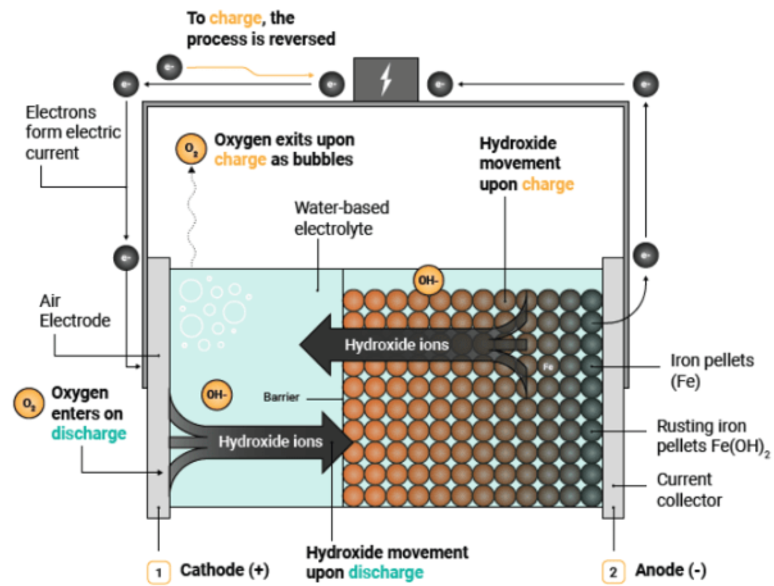
General Description

Iron-air batteries, also known as iron-air cells, are a type of rechargeable metal-air battery that utilizes iron as the anode and air (specifically oxygen) as the cathode. During discharge, iron oxidizes and releases energy, and oxygen from the air reacts with the iron to form iron oxide, generating electricity in the process. Iron Air batteries are not new and have been around since the 1970s[6]. Recent interest in the technology has been driven by incentives to develop low-cost, environmentally friendly energy storage alternatives. They are considered promising for renewable energy storage due to their relatively low cost and the abundance of iron.

They possess high energy density due to the abundance of iron and oxygen, making them suitable for long-duration storage. These batteries offer a long cycle life, enabling multiple charge and discharge cycles. Iron, a low-cost and abundant material, contributes to their affordability. They are considered environmentally friendly and safe due to the non-toxic nature of their components. Iron-air batteries are scalable, adaptable to various sizes for diverse applications.

Operational Characteristics

Iron-air batteries have the potential to store and discharge energy for far longer and at less cost than lithium-ion technology. They are orders of magnitude cheaper than lithium batteries, less flammable, and do not contain heavy metals. They are also resilient to overcharging and partial discharge, supplying over a hundred hours of energy at operating cost. Iron air batteries can also operate over more than 10,000 charge-discharge cycles with reported charge efficiencies of up to 96 percent. A major limitation of these batteries is their weight and speed of charge which makes them a less viable option for portable electronics such as laptops and smartphones.



Source: Form Energy

Market Trends

The market for Iron Air is projected to expand due to increasing adoption of electric vehicles and incentives encouraging clean and locally sourced raw materials for renewable energy. However, currently, most projects in the US are at the research and development phase.

Economics

Iron-air batteries are considered cost-effective compared to other energy storage technologies. According to Form Energy, a company constructing a 10 MW/1 GWh iron-air long-duration energy storage pilot project for Xcel Energy, the all-in capital costs of the system are estimated to be between $1,700 and $2,400 per kW, with operating costs of $19/kW per year[7]. The comparison between the capital costs of

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[6] McKerracher, R.D., Ponce de Leon, C., Wills, R.G.A., Shah, A.A. and Walsh, F.C. (2015), A Review of the Iron–Air Secondary Battery for Energy Storage. ChemPlusChem, 80: 323-335. https://doi.org/10.1002/cplu.201402238

[7] Form Energy. (2023). *Enabling a True 24/7 Carbon-Free Resource Portfolio for Great River Energy with Multi-Day Storage, 2023-2037: Integrated Resource Plan*. Submitted to the Minnesota Public Utilities Commission Docket No. ET-2/RP-22-75. March 31st, 2023.

lithium medium and long duration battery storage to Iron Air batteries is provided in Table 4.

Table 4. Summary of Capital Costs of Lithium Storage and Iron-Air Storage

Pre-ITC All-in Capital Cost ($/kW)				Fixed O&M ($/kW-yr)
Scenario	Low	Moderate	High	All
4-hour Li	$580	$700	$1,065	$25
6-hour Li	$824	$968	$1,485	$35
8-hour Li	$1,067	$1,237	$1,905	$44
Iron-Air	$1,700	$1,900	$2,400	$19

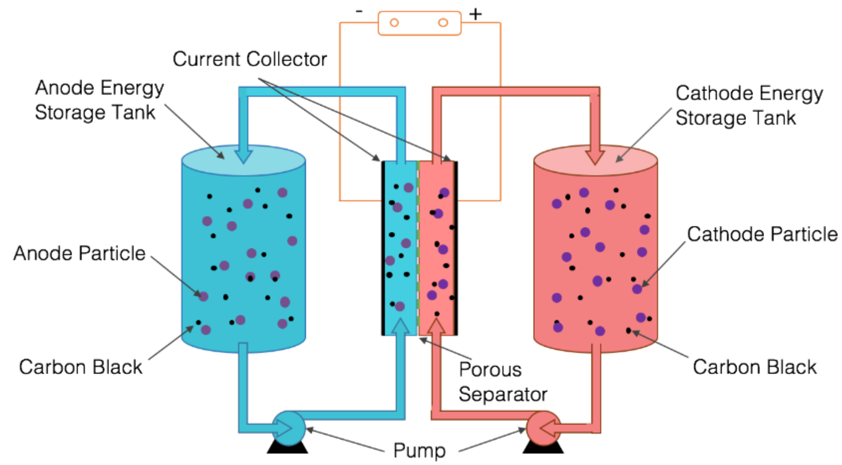
Environmental and Siting

In terms of environmental and siting issues, there do not appear to be specific concerns related to iron-air batteries as they do not contain toxic or hazardous materials. However, the production process for these batteries requires large amounts of water, which could be an issue in areas where water is scarce.

Flow Batteries

General Description

A flow battery is a rechargeable electrical energy storage device that that stores energy in liquid electrolytes contained in external tanks. Unlike traditional batteries, where energy is stored within the cell, flow batteries store energy in the electrolyte solutions and release it through electrochemical reactions when needed. The electrolytes, stored in separate tanks, flow through a cell stack where they react to produce electrical energy. Flow batteries are known for their scalability, long cycle life, and high energy density, making them suitable for renewable energy storage applications[8].



Source: Zaoxiang et al.

Operational Characteristics

Flow batteries are inherently safe as the active components of the system are stored separately from the reactive point source. They have negligible loss of efficiency over their lifetime and can safely operate over a relatively wide temperature range. Further, they have no standby losses in the event of prolonged gaps in use, which consequently makes them low maintenance. They are modular, lending themselves to be successfully installed in various sites, including underground tanks. While flow batteries have a long lifecycle, they are limited by availability of battery stack components such as vanadium which can be upwards of fifty percent of the system cost.[9]

[8] Qi, Zhaoxiang; Koenig, Gary M. *(12 May 2017).* "Review Article: Flow battery systems with solid electroactive materials". *Journal of Vacuum Science & Technology B, Nanotechnology and Microelectronics: Materials, Processing, Measurement, and Phenomena. 35 (4): 040801.*

[9] Nguyen, T and Savinelli,R.F. Zhaoxiang; Koenig, Gary M. *(12 May 2017).* "Review Article: Flow battery systems with solid electroactive materials". *Journal of Vacuum Science & Technology B, Nanotechnology and Microelectronics: Materials, Processing, Measurement, and Phenomena. 35 (4): 040801.*

Market Trends

The market for flow batteries is projected to expand due to the scalability, safety, and reduced environmental impacts of the technology. Similar to Iron-Air batteries, most projects in the US are at the research and development phase.

Economics

Flow batteries require high upfront capital costs. Further, round-trip energy storage efficiency for flow batteries is 70 percent, compared to 84 percent for a Lithium-ion system. Currently, life cycle costs of flow batteries exceed that of Lithium-ion batteries.

Table 5. NPV Results: 20MW/160MWh Net at Point of Interconnection

Description	Li-Ion Battery	Flow Battery
Capital Cost (Million USD)		
Project Capital	$48.770	$95.930
Owner	Excluded	Excluded
Total Installed	**$48.77**	**$95.93**
O&M and Other Annual Costs, NPV (Million USD)		
Battery Charging	**$39.07**	**$43.38**
O&M	**$12.58**	**$4.64**
Total O&M/Charging	**$51.65**	**$48.02**
Life Cycle, NPV	**$100.42**	**$143.95**

Source: Burns & McDonnell

However, they offer economic advantages in the energy sector. Their scalability allows for customized sizing, catering to various applications from grid-level storage to commercial use. Unlike traditional batteries, flow batteries separate power and energy capacity, reducing costs for longer durations. Additionally, their ability to discharge for extended periods without degradation ensures consistent energy supply, enhancing grid stability and reducing the need for expensive backup systems. As technology matures and production scales up, flow battery costs are expected to decline, making them increasingly competitive.

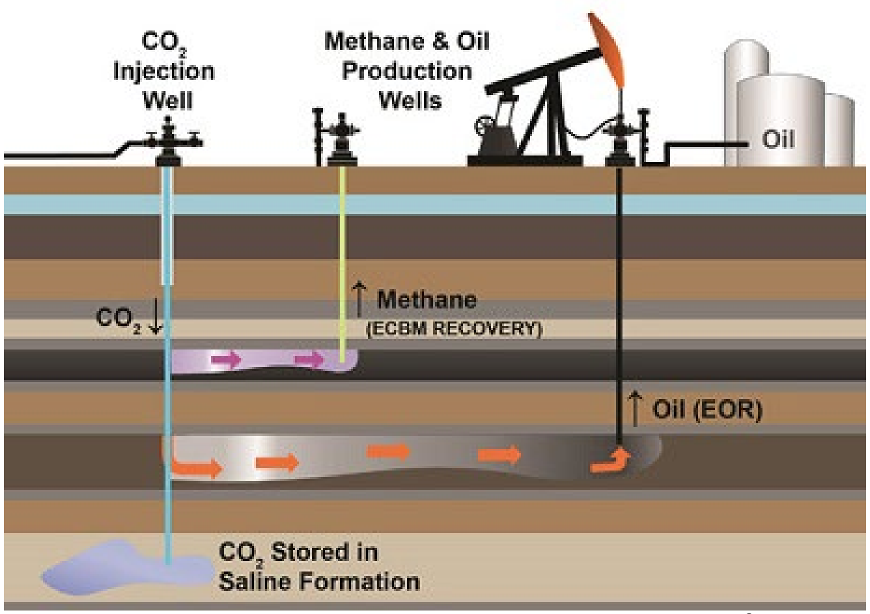
Environmental and Siting

Flow batteries, while promising for renewable energy storage, present environmental and siting challenges. The production and disposal of their chemical components, such as vanadium or zinc, pose environmental risks due to resource extraction and waste disposal. Moreover, flow battery systems demand significant space and specific infrastructure, leading to land-use conflicts, especially in densely populated or ecologically sensitive areas. Siting these batteries near energy sources is essential, raising concerns about habitat disruption and visual impact. Careful planning and rigorous environmental assessments are crucial to mitigate these issues and ensure the sustainable integration of flow batteries into the clean energy landscape.

Carbon Mitigation - CCS Retrofits

General Description

Carbon capture and storage (CCS), also referred to as carbon capture, utilization and storage (CCUS), is a group of technologies that enable the mitigation of carbon dioxide (CO_2) emissions from large point sources such as power plants, refineries and other industrial facilities, or the removal of existing CO_2 from the atmosphere. CCS technologies for carbon capture are post-combustion; pre-combustion; and oxy-fuel combustion.



Source: Department of Energy

Post-combustion capture sends the power plant's emissions through an absorption process where a solvent captures up to 90% of the CO2. The recovered CO2 goes through a regenerator that strips the CO2 from the solvent while the remaining emissions (primarily nitrogen) are vented to the atmosphere.

Pre-combustion turns the fossil fuel into a synthetic gas consisting of relatively pure hydrogen and CO2 before it is burnt. Once the CO2 is separated, the remaining hydrogen-rich mixture can be used as fuel.

With oxy-combustion capture, the fossil fuel is burned in pure oxygen instead of air. The result of this process releases CO2 and steam, with the nearly pure released CO2 subsequently captured. Captured CO2 is pressurized to reduce volume and dried to reduce corrosion. If the storage site is not collocated with the source, CO2 needs to be transported to the storage site and while trucks or ships may be appropriate for smaller CCS operations, industrial-scale CCS operations require pipeline transport. The captured CO2 is then injected into the deep subsurface for permanent storage[10].

Operational Characteristics

CCS enables industry to continue to operate while emitting fewer greenhouse gases (GHGs), making it a powerful tool for addressing mitigation of anthropogenic CO2 in the atmosphere. The captured CO2 may also be utilized as feedstock for industrial processes and to enhance crude oil production.

Economics

The process of CO2 capture and compression is energy-intensive, and current retrofit capture technologies may require up to 30 percent of the power plant initial energy output. The viability of CCS systems is also closely tied to the existence of carbon pricing. Further, the cost of CCS, plus any subsidies, must be less than the expected cost of emitting CO2 for a project to be considered economically favorable.

Market Trends

There is already a commercial market using captured CO2 for enhanced oil recovery (EOR). Further, CCS brings have applicability across a range of economic sectors, from including mining and extraction, energy infrastructure, the manufacture of CCUS equipment, supply chains including component parts and raw materials, to the creation of a new

[10] Source: EIA

CO_2 commodity industry for use in enhanced oil recovery (EOR), bio-refining, and other products[11].

Industrial CCS produces high purity CO_2 and as such is a less capital-intensive source that a power plant. The department of energy has actively pursued projects to demonstrate the commercial viability of CCS via the Regional Carbon Sequestration Partnership (RCSP) Initiative which includes partnerships across over 400 distinct organizations, spanning 43 states and 4 Canadian provinces. This initiative is conducting 19 small-scale field projects building on research and developing the framework needed to validate geologic carbon storage technologies[12].

Environmental and Siting

CCS was initially promoted as a means of capturing CO_2 to mitigate climate change. However, there are environmental and health risks associated with carbon storage facilities, such as the escape of the carbon dioxide from the site, the displacement of groundwater, and seismic activity. CO_2 can also leak through permeable substances or man-made routes like abandoned drilling wells. Further, since liquid amine solutions are used to capture CO_2 in many CCS systems, these types of chemicals can also be released as air pollutants if not adequately controlled. CCS systems also reduce the efficiency of the power plants that use them to control CO_2.

[11] Source: US Department of Energy

[12] Source: National Energy Technology Laboratory

Appendix L: Acronyms

1 Acronyms

ACC – Arizona Corporation Commission
ACE – Area Control Error
ACE – Area Control Error
ADEQ – Arizona Department of Environmental Quality
ADMS – Advanced Distribution Management System
AECC – Arizonans for Electric Choice and Competition
AEO – Annual Energy Outlook
AGC – Automatic Generation Control
AMI – Automated Metering Infrastructure
APS – Arizona Public Service Company
ATB – Annual Technology Baseline
ATC – Available Transfer Capability
AZ WRF – Arizona Weather Research & Forecast
BA – Balancing Authority
BAAL – Balancing Authority ACE Limit
BES – Bulk Electric System
BESS – Battery Energy Storage System
BEV – Battery Electric Vehicles
BTA – Biennial Transmission Assessment
Btu – British Thermal Unit
C&I – Commercial and Industrial
CAES – Compressed Air Energy Storage
CEC – Certificate of Environmental Compatibility
CEM – Capacity Expansion Model
CER – Customer-Sited Energy Resource
CAISO - California Independent System Operator
CO2 – Carbon Dioxide
CPS – Control Performance Standard
CSP – Concentrating Solar Power
CT – Combustion Turbine
DC – Direct Current
DCS – Disturbance Control Standard
DER – Distributed Energy Resources
DG - Distributed Generation
DOE – U.S. Department of Energy (Federal)
DMS – Distribution Management System
DR – Demand Response
DSM – Demand Side Management
E3 – Energy and Environmental Economics
EE – Energy Efficiency
EGU – Electric Generating Unit
EHV – Extra High Voltage
EIA - Energy Information Administration
EIM – Energy Imbalance Market
ELCC – Effective Load Carrying Capability
EMS – Energy Management System
EPA - Environmental Protection Agency
EPNG – El Paso Natural Gas
EPRI – Electric Power Research Institute
EV – Electric Vehicles
FERC – Federal Energy Regulatory Commission
FF – Fabric Filter
FRM – Frequency Response Measure
GHG – Greenhouse Gas
GW – Gigawatt
GWh – Gigawatt-Hour
HEV – Hybrid Electric Vehicle
HRI – Heat Rate Improvement
HRSG – Heat Recovery Steam Generator
HVAC – Heating Ventilation Air Conditioning
Hz – Hertz
IBEW - International Brotherhood of Electrical Workers
ICE – Internal Combustion Engine
IRP – Integrated Resource Plan
ISD – In Service Date
ITC – Investment Tax Credit
kW – Kilowatt
kWh – Kilowatt-Hour

LCOE – Levelized Cost of Energy
LGS – Large General Service
LPS – Large Power Service
LTCE – Long-term Capacity Expansion
LTO – Long Term Outlook
MMBtu – Million British Thermal Units, also shown as MBtu
MBtu – Million British Thermal Units, also shown as MMBtu
MGS – Medium General Service
MVA – Megavolt-ampere
MW – Megawatt
MWh – Megawatt-Hour
NAAQ – National Ambient Air Quality Standards
NEC – Navopache Electric Cooperative
NERC - North American Electric Reliability Corporation
NGCC – Natural Gas Combined Cycle
NOAA – National Oceanic and Atmospheric Administration
NOX – Nitrogen Oxide(s)
NPV – Net Present Value
NPVRR – Net Present Value Revenue Requirement
NREL – National Renewable Energy Laboratory
NTUA – Navajo Tribal Utility Authority
NWP – Numerical Weather Prediction
O&M – Operations and Maintenance
PHEV – Plug-in Hybrid Electric Vehicles
PM - Particulate matter
PNM – Public Service Company of New Mexico
PPA - Purchased Power Agreement
PPFAC – Purchased Power Fuel Adjustment Clause
PRM – Planning Reserve Margin
PTC – Production Tax Credit
PSD – Prevention of Significant Deterioration
PURPA – Public Utility Regulatory Policies Act of 1978
PV – Photovoltaic
QF – Qualifying Facilities
RES – Renewable Energy Standard
RFP – Request for Proposal
RICE – Reciprocating Internal Combustion Engine
RMR – Reliability Must Run
RTP – Real Time Pricing
RUCO - Residential Utility Consumer Office
SAT – Single-Axis Tracking
SCADA – Supervisory Control and Data Acquisition
SCR – Selective Catalytic Reduction
SDA – Spray Dryer Absorber
SGS – Springerville Generating Station (aka Springerville)
SIP – State Implementation Plan
SJCC – San Juan Coal Company
SME – Subject Matter Expert
SMR – Small Modular (Nuclear) Reactor
SNCR – Selective Non-Catalytic Reduction
SO2 – Sulfur Dioxide
SRP – Salt River Project
SRSG – Southwest Reserve Sharing Group
SWAT – Southwest Area Transmission
SWEEP – Southwest Energy Efficiency Project
TEP – Tucson Electric Power Company
TORS – Tucson Electric Power Owned Residential Solar
TOU – Time-of-Use
TOUA - Tohono O'odham Utility Authority
TRICO – Trico Electric Cooperative
TWh – Terawatt-Hour
UA – University of Arizona
UAIE – University of Arizona Institute of the Environment
UES – UniSource Energy Services (Parent Company of UNS Electric)
U.S. – United States
USGS - United States Geological Survey
VAR – Volt-Ampere Reactive; Reactive Power
WAPA – Western Area Power Authority
WECC - Western Electricity Coordinating Council
WRA – Western Resource Advocates