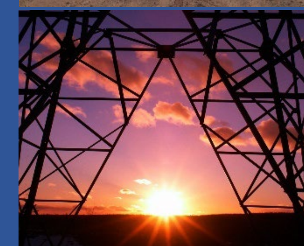
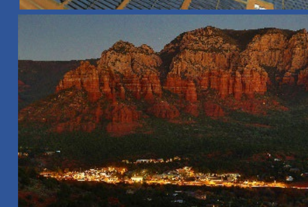
UNS Electric

2023 Integrated Resource Plan

November 1, 2023





UniSourceEnergy SERVICES

Taking Control of our Energy Future

While integrated resource plans are about the future, it helps to start this one with a quick look back.

When UNS Electric was created in 2003 after an acquisition from Citizens Utilities, its entire generating fleet consisted of a few small natural gas-fired turbines located in a Nogales substation – and even those were used mostly for backup. Almost every kilowatt hour delivered to UNSE customers that year was purchased from another Arizona electric company.

That contract, which we inherited, represented a reasonable strategy at the time, as Arizona enjoyed a surplus of wholesale market generation. Much of it had been developed speculatively to serve California customers in a restructured market that didn't develop as planned. That left our state with an assortment of underutilized natural gas-fired power plants that, over time, made for affordable acquisitions for our state's utilities.

In 2014, UNSE joined sister company Tucson Electric Power to purchase Unit 3 at the Gila River Power Station in Gila Bend. For just $55 million, UNSE secured a dependable 140 megawatts (MW) from a modern natural gas combined-cycle unit that satisfies almost a quarter of our peak load. By this time, we had been working for years to expand UNSE's owned generation, understanding that energy might not always be so readily available.

Today, UNSE owns 301 MW of generation, a significant improvement considering our scale and starting position. But we'll need more – much more – over the next 15 years to preserve the reliability and affordability of our service in the face of escalating volatility, growing demand, and significantly reduced resource availability on the southwestern regional grid.

Our 2023 Integrated Resource Plan calls for the addition of 350 MW of solar and wind resources, 200 MW of natural gas turbines and 225 MW of energy storage systems by 2038. These resources will be needed to support the growth of the communities we serve while preserving reliability, particularly during periods of extreme heat.

That particular resource mix – our preferred portfolio, the "Balanced Portfolio" – was determined to be the most cost-effective way to address both near-term needs and long-term goals. It gives us an opportunity to capitalize on federal tax credits for clean energy resources that will limit long-term costs for our customers while reducing greenhouse gas emissions. It also calls for responsive natural gas units that will help us maintain around-the-clock reliability with higher levels of variable wind and solar resources.

We'll develop new resources through all-source requests for proposals, an open-minded approach that invites developers to propose competing technologies that satisfy our performance requirements. If we find an alternate solution would serve customers better than the resource we expected, we'll choose it, and incorporate those updates in our next resource plan.

The goal, as always, is to identify the resources that provide the greatest benefits at the lowest cost for our customers. There was a time, not so long ago, when such solutions could be found just waiting for us in the Arizona desert. But those days are over. If we want to provide a reliable, affordable and sustainable energy future for our customers, we're going to have to build it.

Susan Gray
President and CEO

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1 Executive Summary

The resource plan for UNS Electric (UNSE) put forward in this report establishes an updated roadmap for UNSE's pursuit of a reliable, lower cost, sustainable energy supply. UNSE's 2023 Integrated Resource Plan (IRP) identifies the current and anticipated changes facing UNSE and the utility industry in general. The potential impact of future uncertainties was evaluated through a robust portfolio analysis and risk assessment. This analysis presents a snapshot of current loads and resources and projects future energy and capacity needs through 2038.

The 2023 IRP builds from the 2020 IRP planning cycle and accelerates its plans for developing new energy resources that will support affordable, reliable service while reducing its market exposure to high priced summer capacity purchases. The 2023 IRP adds over 170 MW or 60% more renewable and energy storage capacity by 2030 versus the same capacity amount envisioned in the 2020 IRP. The 2023 IRP also calls for the addition of 200 MW of natural gas combustion turbines to support system reliability during the summer months in Kingman, Lake Havasu and Nogales.

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, UNSE plans to communicate any major change in its anticipated resource plan with the Arizona Corporation Commission (ACC) as part of its ongoing planning activities. UNSE hopes this dialog will engage the Commission on important resource planning issues while providing the Company with greater regulatory certainty with regards to future resource decisions.

1.1 Major Initiatives Executed on from the 2020 IRP Action Plan

As part of the work done in the 2020 IRP, UNSE 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.

Western Energy Imbalance Market

Western Energy Imbalance Market
$5.6 Million Savings
(May 22 - Aug 23)

UNSE joined the real-time Western Energy Imbalance Market in May 2022 – through participation with Tucson Electric Power

All-Source Request for Proposals

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

Status: In negotiations with project developers on solar + storage projects

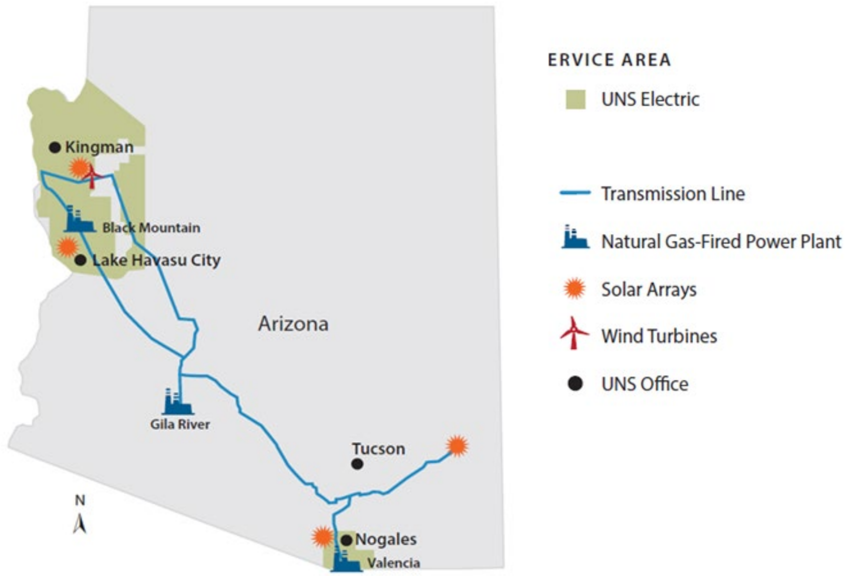
1.2 UNSE's 2023 Preferred Portfolio and Future Action Plans

Section 8 describes UNSE's 2023 Preferred Portfolio and its 2023 Action Plan. While UNSE's 2023 Preferred Portfolio provides a roadmap for UNSE's pursuit of a more sustainable energy supply, circumstances and cost assumptions change over time. As such, UNSE'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 ACC to reflect updated information, technology and market trends.

UNSE service territory along with generation and third-party transmission paths are shown in UNSE's System Map below in **Figure 1.**

Figure 1. UNSE System Map



2 Major Planning Considerations

The following section summarizes the most significant long-term planning challenges and opportunities facing UNSE 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 UNSE's Near-Term Economic Development Opportunities

UNSE'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. UNSE is experiencing accelerated growth that is projected to increase over the next 10 to 15 years. Factors supporting future growth in Mohave County, in addition to continued tourism, include: a strong manufacturing base; assets like the largest industrial park in Northern Arizona that also includes rail service; the newly designated Regional Infrastructure Accelerator, to promote a sustainable logistics corridor along I-40; and logistical advantages of proximity to major markets like Los Angeles,, Inland Empire, Las Vegas, and Phoenix. Santa Cruz County will similarly benefit from its logistical advantages of cross-border manufacturing and distribution with strengths in consumers goods, food processing, and cold storage. Existing foreign trade zones also support the region's competitive position in the transportation and logistics space. The mining sector is also indicating growth potential in Santa Cruz and Mohave counties[1]. UNSE's flexibility in accommodating these trends and new needs will support continued quality economic growth for its communities.

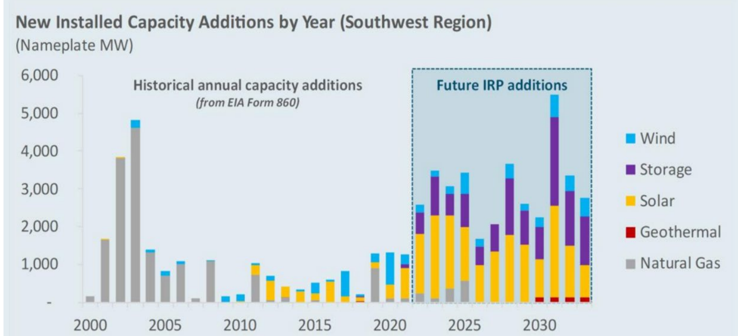
Arizona has positioned itself as a strong competitor in attracting new industry. As such, UNSE is seeing an increase in activity in the economic development pipeline, as well as an increase in the prospective load associated with the potential projects. Not only are there more projects, but the power 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. Should any of these projects come to fruition, UNSE forecasting models would be significantly impacted.

2.2 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.

[1] https://south32hermosa.com/

2.3 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.

2.4 The Future Role for Natural Gas Resources

Over the last decade, the Company has transitioned its energy needs away from the bilateral market 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 at a significant cost discount - to support its expansion of renewable resources.

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]

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

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.

2.4.1 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.

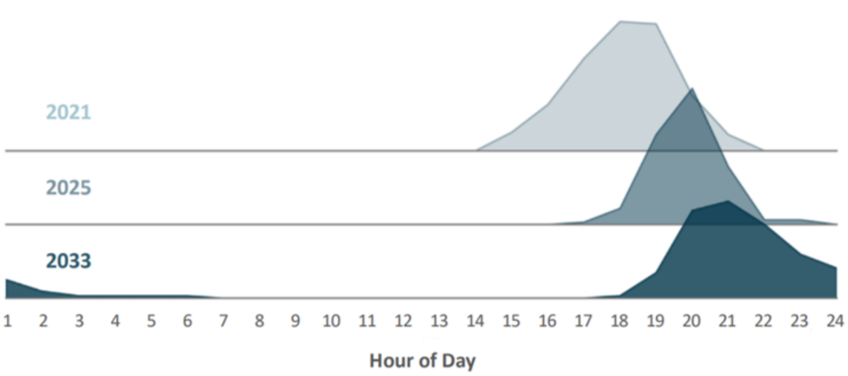
E3 Study – The Changing Profile of Reliability Risk in the Desert Southwest

> *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 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.*

[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

UNSE'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.

2.5 Project Development Timelines and Technology Risks

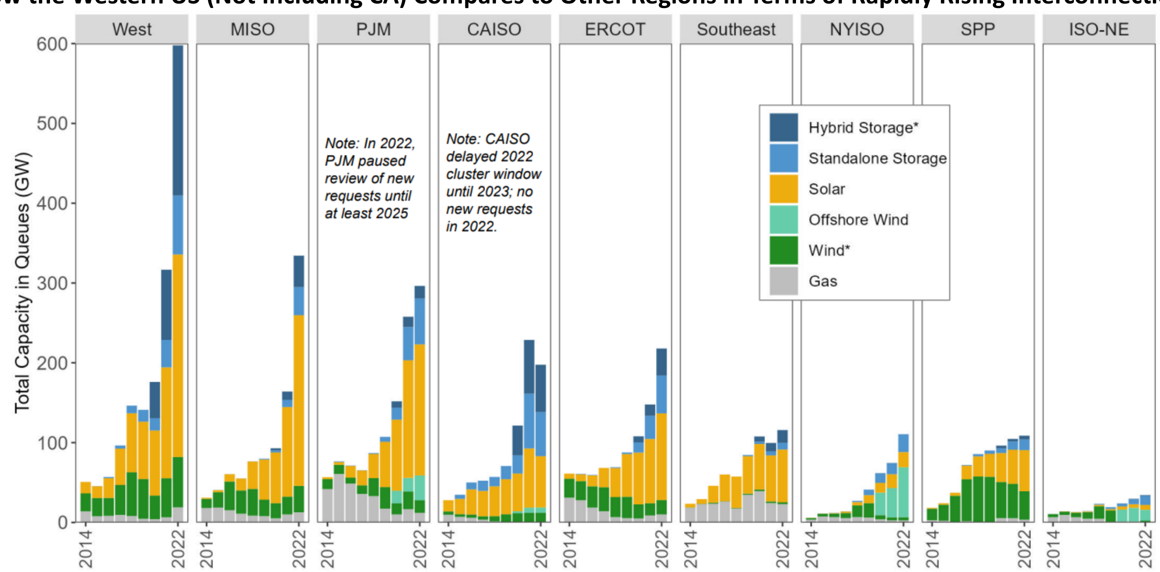
Supply chain issues, in the form of increased cost and prolonged commissioning dates, were evident in proposals received as part of the 2022 ASRFP solicitation. The company was optimistic about receiving proposals with two-to-three-year commissioning dates from notice to proceed to build. Beside the interconnection queue complexity and the potential for project delays discussed in Chapter 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. While lithium remains a dominant material in the production of batteries, the United States will rely mostly on imports for supply[5]. 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 shows the total capacity in interconnection queues by region. Standalone and hybrid storage represent a sizable amount for the west.

Figure 4. A Perspective on How the Western US (Not Including CA) Compares to Other Regions in Terms of Rapidly Rising Interconnection Requests



[5] https://pubs.usgs.gov/periodicals/mcs2021/mcs2021-lithium.pdf

[6] **Source:** *Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection, as of the end of 2021, Lawrence Berkeley National Laboratory.*

2.6 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 portfolios with low-cost energy, the need for new resources with high-capacity contributions such as natural gas and energy storage technologies is the main focus of the 2023 IRP. 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 zero carbon emissions by 2050.

2.7 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 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 qualify for the prevailing wage and apprenticeship requirements in order to quality for additional tax bonus credits under the Investment Recovery Act. **Figure 5** and **Table 1** provide an incremental cost of energy comparison for different resource types.

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

Figure 5. Incremental Cost of Energy by Resource Type, 2025 Install

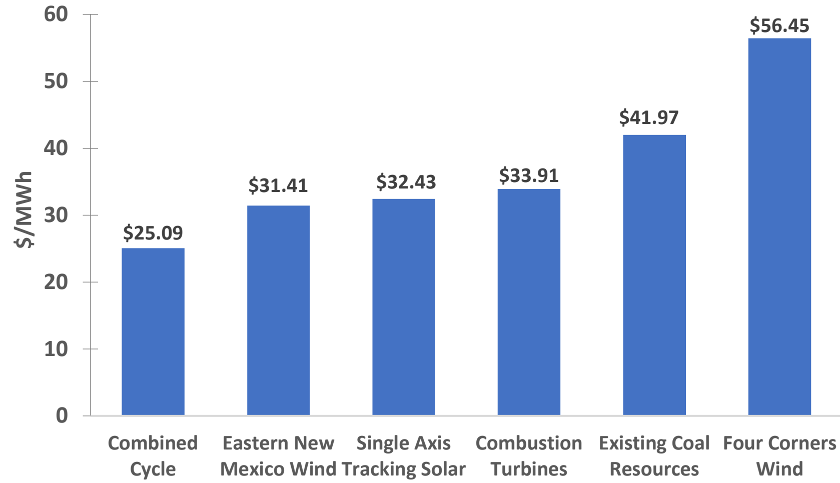
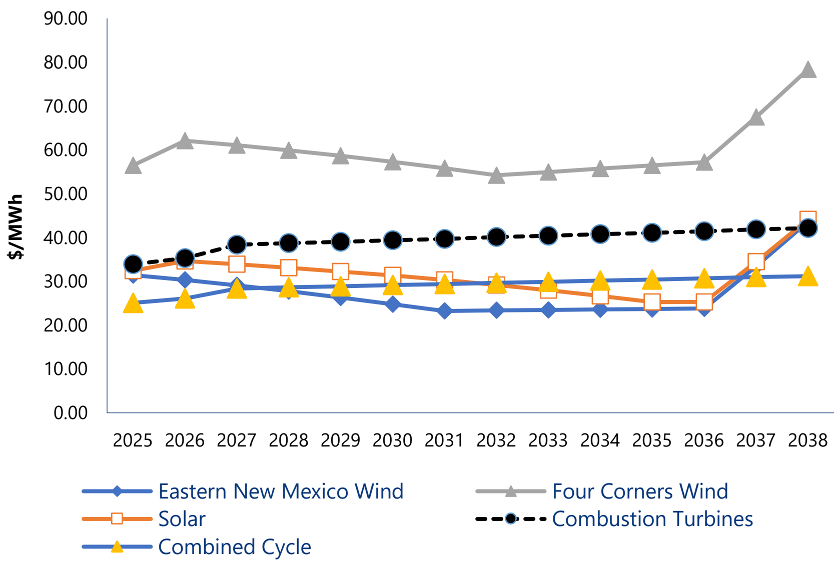


Table 1. Incremental Cost of Energy by Install Year

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

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

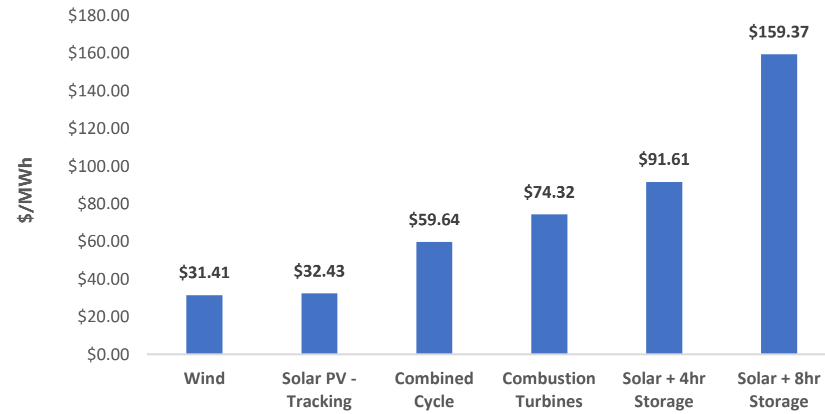
Figure 6. Incremental Cost of Energy by Resource Type and Install Year



2.8 Annual Cost of Operations

While the incremental cost of energy provides insights into 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 included. **Figure 7** below shows the annual operating costs for technologies built in 2025 and exclude any environmental restrictions related to future EPA regulations.

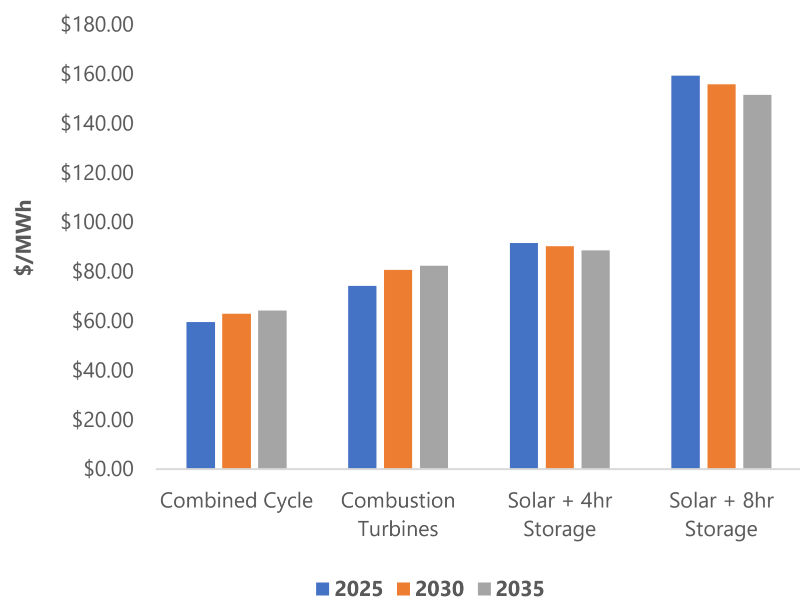
Figure 7. Annual Cost of Operations by Resource Type, 2025 Install



2.9 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** highlights how the annual operating costs for each technology changes as a function of install year. In 2025, new natural gas resources have lower operating costs than solar plus storage resources. However, by 2030, future cost projections show that 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.

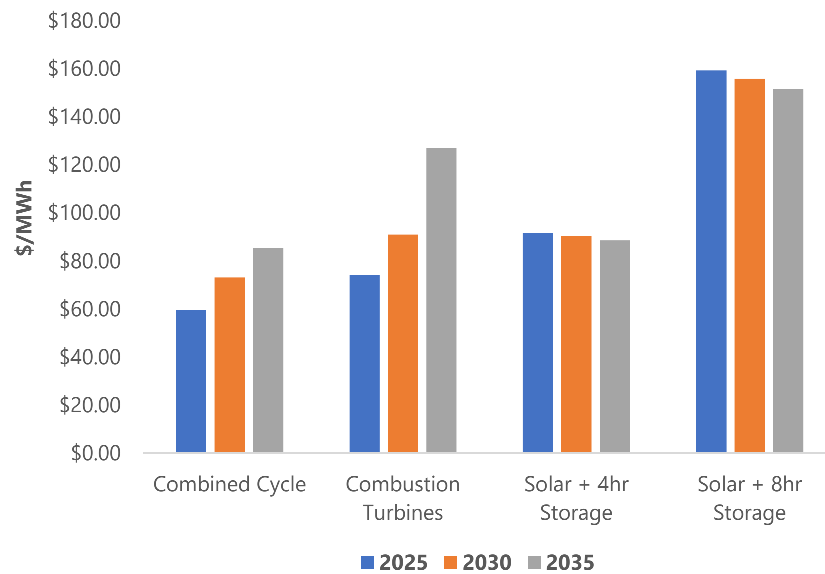
Figure 8. Annual Cost of Operations over the Planning Period



2.10 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 emissions from fossil fuel-fired electric generating units under Section 111 of the Clean Air Act. **Figure 9** 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 UNSE and its resource planning efforts.

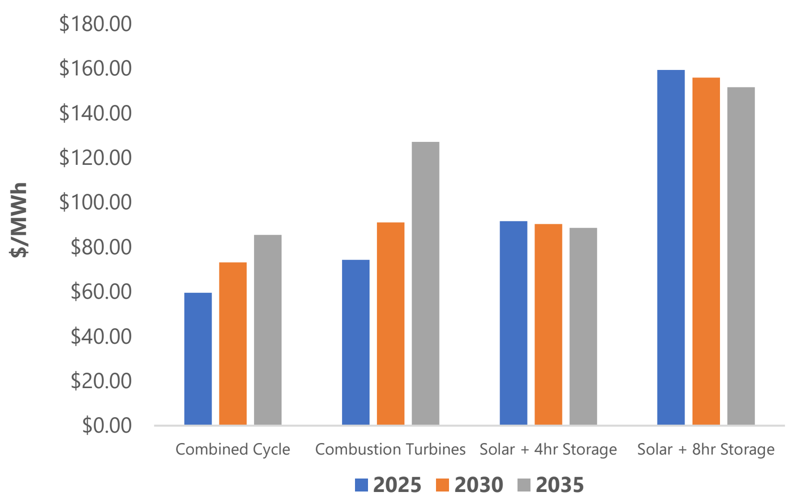
Figure 9. Annual Cost of Operations Under Proposed GHG Regulations



2.11 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 customers. The underlying analysis of the 2023 IRP planning cycle supports a balanced investment in natural gas, solar plus storage, and wind. In the near-term, natural gas resources lower the cost of operations and serve the long-duration capacity needs of the Company. 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**[7]**.**

Figure 10. Costs of Operations for Future Capacity Resources



[7] 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.*

2.12 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 next section examines the potential loss of load risks for UNSE 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 UNSE's 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 result from future load growth.

In a similar comparison that was performed in the E3 Desert Southwest Study described in **Section 2.4.1**, the loss of load risk for UNSE was examined through high-level analysis outside of the IRP modeling for 2028. The 2028 time periods were chosen due to the significant short fall that exists at UNSE. The example also demonstrates how the loss of load hour duration impacts the cost of capacity options when comparing natural gas to solar plus storage. **Table 2** summarizes the loss of load hours and viable replacement capacity options in the time periods shown below.

Table 2. Loss of Load and Replacement Capacity Options

Loss of Load Results	2028
Peak Shortfall, MW	250
Loss of Load Hours / Peak Day	21
Loss of Load Hours, MWh	2,389

Potential Capacity Expansion Options	2028
Natural Gas Combustion Turbines, MW	250
Solar + 4-Hour Storage, MW	400

2.13 Potential Capacity Expansion Options for 2028

Figure 11 below shows a 2028 peak summer day where the total loss of load hours is approximately 2,389 MWh spread across a 21-hour period with a peak shortfall of approximately 250 MW shown in hour ending 18:00. Under this scenario, UNSE could choose to build approximately 250 MW of new natural gas combustion turbines to meet this loss of load requirement. Alternatively, the Company could use approximately 400 MW of solar with 400 MW of 4-hour storage to meet this same loss of load requirement.

Figure 11. Loss of Load Risk Under a 21-Hour Capacity Shortfall Scenario

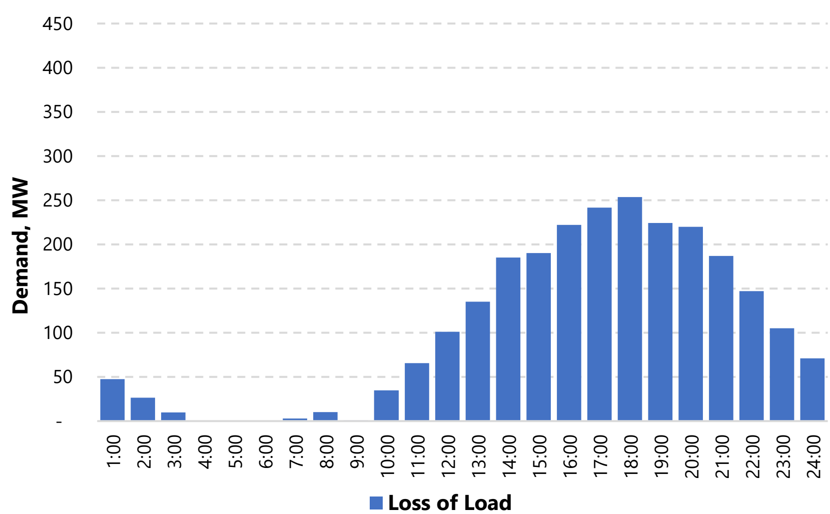


Figure 12 below shows how the use of both solar and 4-hour energy storage would be dispatched to serve these load requirements. The cost comparisons shown in **Table 3** below comparing the costs of both natural gas and solar plus storage resource options, show that the use of solar plus storage to serve these future capacity needs would result in higher capital investments of approximately $283 million and an 85% higher annual revenue requirement of approximately $46 million per year.

Figure 12. 400 MW Solar + 400 MW of 4-Hour Solar Portfolio

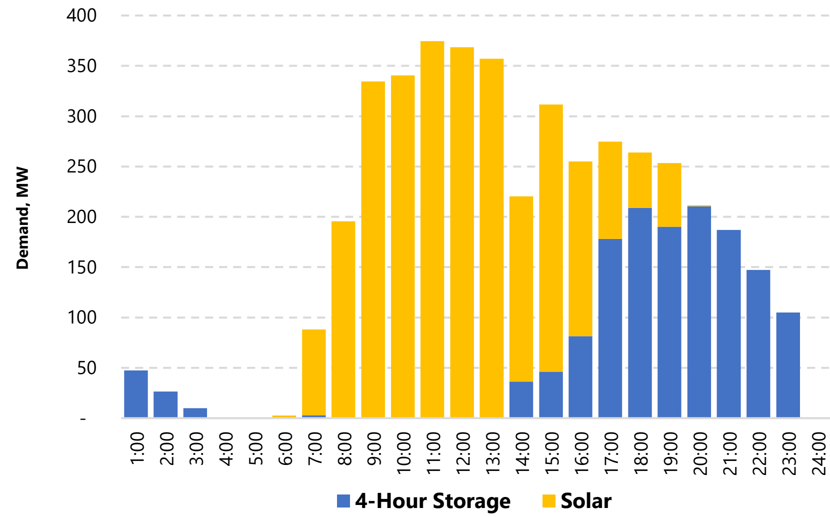


Table 3. 2028 Combustion Turbine – Solar + Storage Cost Comparison

Resource Technologies	Combustion Turbines	Solar + 4hr Storage
Project Cost, $/kW ($2025)	$1,259	$1,494
Capital Investment, $000	**$314,750**	**$597,600**
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	**250**	**400**
Fuel Revenue Requirements, $000	$16,944	
Non-Fuel Revenue Requirements, $000	$36,879	$99,509
Annual Revenue Requirements, $000	**$53,823**	**$99,509**

Capital Investment Difference, $000	**$282,850**
Revenue Requirement Difference, $000	**$45,686**
Revenue Requirement Difference, %	**85%**

2.1 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 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.

2.2 Wholesale Market Reform

2.2.1 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 4.**

While both markets aim to enhance reliability and optimize resource utilization, they differ in terms of their geographic coverage, market structures, and specific objectives. 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 acts as UNSE's Balancing Authority, and 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 4. 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	Same objectives as EDAM with additional focus on managing the variability of renewable energy, particularly wind.

Characteristics	CAISO EDAM	SPP M+
	surplus renewable energy.	
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 participation 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/UNSE 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/UNSE participates in stakeholder meetings and presentations as appropriate.

TEP/UNSE 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.

2.2.2 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.

2.2.3 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.

2.2.4 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[8], 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 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

[8] 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.

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.

2.3 Market and Transmission Considerations

The Company's transition towards cleaner natural gas and renewables must also factor in market and transmission considerations. UNSE relies heavily on market participants and transmission/transport providers for access to electric and natural gas supply.

For electric supply, UNSE is heavily dependent upon transmission service agreements with neighboring utilities to secure access to power markets. Likewise, UNSE heavily depends upon market purchases for resource adequacy. More than half of UNSE's peak load is served by market purchases.

For natural gas, UNSE relies on the El Paso Natural Gas and Transwestern pipeline networks to support power generation. UNSE has sufficient gas transportation contracts for delivering gas to its existing resources. However, UNSE actively competes with Southwest utilities, California, upstream customers and even Liquified Natural Gas exporters for incremental gas supply.

These above-described external dependencies expose UNSE to economic risks of market price fluctuations and supply risks from transmission/transport curtailments. UNSE's resource plan strategy seeks to mitigate these risks by diversifying resources and reducing exposure to third party service providers.

2.4 Environmental Regulations

UNSE 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 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 UNSE and TEP 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, UNSE and sister company TEP 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 5.**

Table 5. 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
	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 6**.

Table 6. 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 Capacity (ELCC) Studies

One of the primary objectives of the Advisory Council engagement was for advisors to provide TEP and UNSE 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 7**. 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.

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.

Table 7. RPAC Modeling Committee Members

RPAC Members	Modeling Consultants
Arizona Corporation Commission	None
ARiSEIA	Rocky Mountain Institute (RMI)
Sierra Club	Synapse Energy Economics
Western Resource Advocates	Energy Strategies
	GridLab
RPAC Members and Affiliates Requesting Data-Only Access	
SWEEP	
Vote Solar	
Arizona Public Interest Research Group	
Interwest Energy Alliance	
Solar United Neighbors	

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.

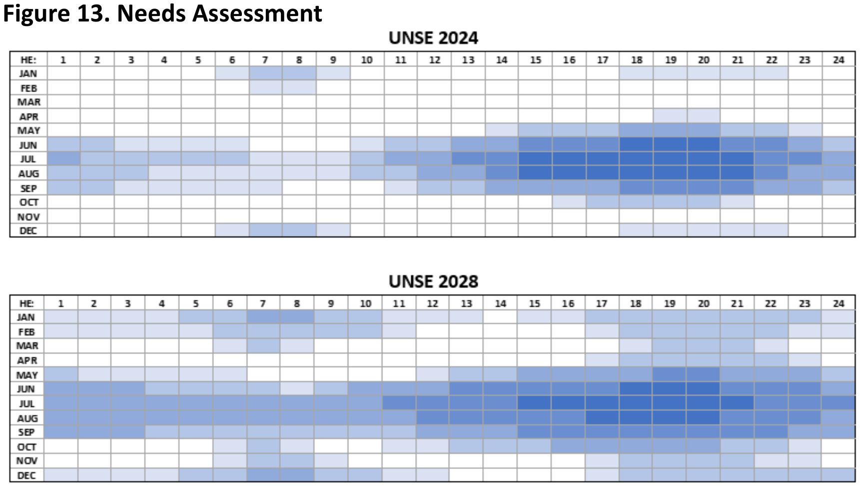
The presentations and minutes of all RPAC meetings and public workshops are posted on the Companies' joint RPAC webpage: https://www.tep.com/irp-advisory-council/.

4 2022 All Source Request for Proposals (ASRFP)

4.1 Resources Requested

UNSE issued an ASRFP to solicit bids for capacity and clean energy resources on April 19, 2022. The in-service dates preferred by UNSE were indicated in the solicitations as May 1, 2024, but no later than May 1, 2025. The need for these resources – originally estimated for UNSE at 160 MW of firm capacity and 170 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 UNSE Needs Assessment is shown in **Figure 13**, 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 13. 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 UNSE retail customers. Projects having obtained or 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 power purchases while transitioning to a cleaner resource portfolio. With these factors in mind, UNSE shortlisted projects and is in discussions with developers to derive viable projects.

UNSE will maintain communication with other developers to keep abreast of near- and mid-term opportunities. UNSE looks forward to their participation and others in the next ASRFP.

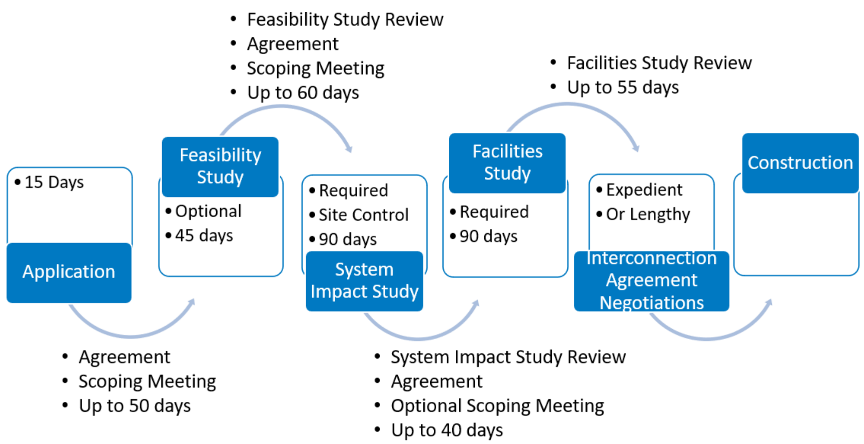
4.3 ASRFP Lessons Learned: Project Development Timelines

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 14 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. The potential for further extending interconnection timelines for UNSE in Mohave County can also occur if the Western Area Power Administration (WAPA) is affected by studied projects. UNSE's electrical system is tied to multiple points on WAPA's 230 kV transmission system but does not tie into any other high voltage systems.

Figure 14. 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 with 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, UNSE 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 and
- One or more portfolios which removes modeling restrictions that limit the amount of energy efficiency that can be selected.

5.2 Modeling Process

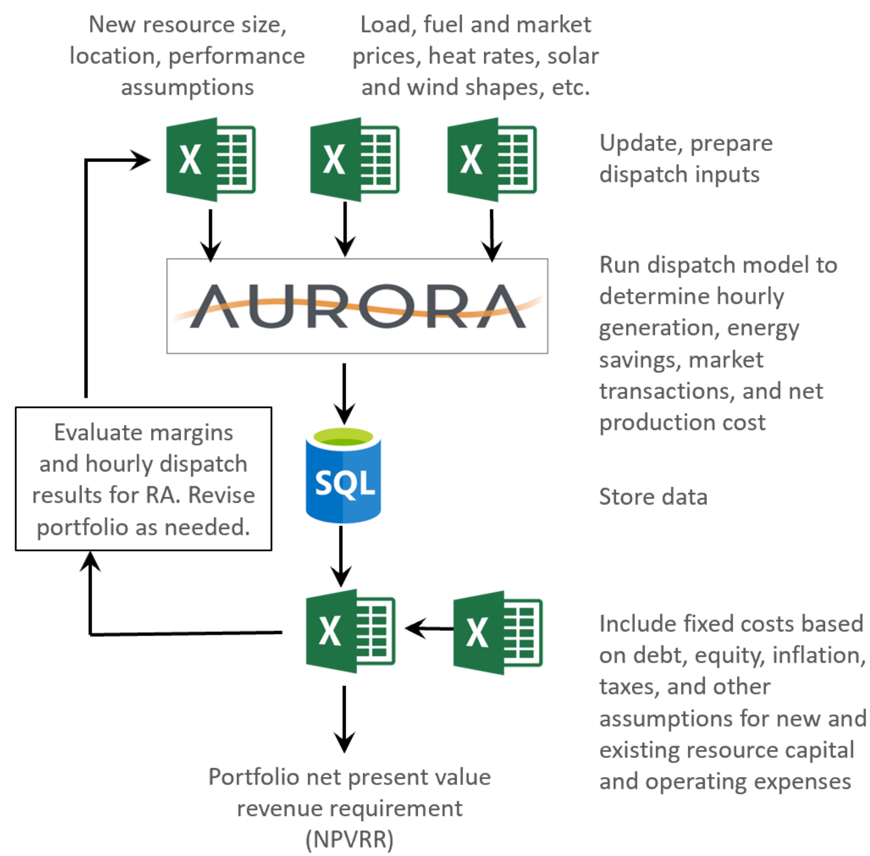
UNSE developed and evaluated 10 portfolios using two different but related modeling approaches: 1) iterations of hand-crafted portfolios and 2) long-term capacity expansion.

5.2.1 Iterations of Hand-Crafted Portfolios

As shown in **Figure 15**, portfolio results are based on two bodies of inputs. The first, shown at the top of **Figure 15**, 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.

The second body of inputs, shown at the bottom of **Figure 15**, 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.

Figure 15. Summary of UNSE Portfolio Modeling Process



The iterative process typically begins with an estimate of the amount of solar and storage needed in addition to the wind power assumptions to reliably and cost-effectively meet firm demand 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, UNSE utilized Aurora's long-term capacity expansion (LTCE) functionality. LTCE modeling selfgenerates 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* [9]

NREL also identifies the complexity that clean energy resource variability and other emerging technologies present for capacity expansion modeling. LTCE case studies performed by UNSE 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.

The least-cost portfolio built by LTCE modeling did not include large natural gas combined cycle (NGCC) plants. Beside the fact that natural gas pipeline capacity in Arizona is limited, NGCC units were determined unfeasible due to their large size. Each LTCE modeling portfolio results for UNSE, included a balance of aeroderivative combustion turbines (CTs), battery storage and renewables.

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 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, UNSE'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.
- Clean energy resources intended to replace large retirements should be implemented over at least a three-year period.
- Replacement resources are generally limited to 200 to 400 MW per year.

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

- Future solar and 4-hour storage resources are added in relatively equal amounts of capacity. This reflects UNSE'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 any resource or contract retirements.

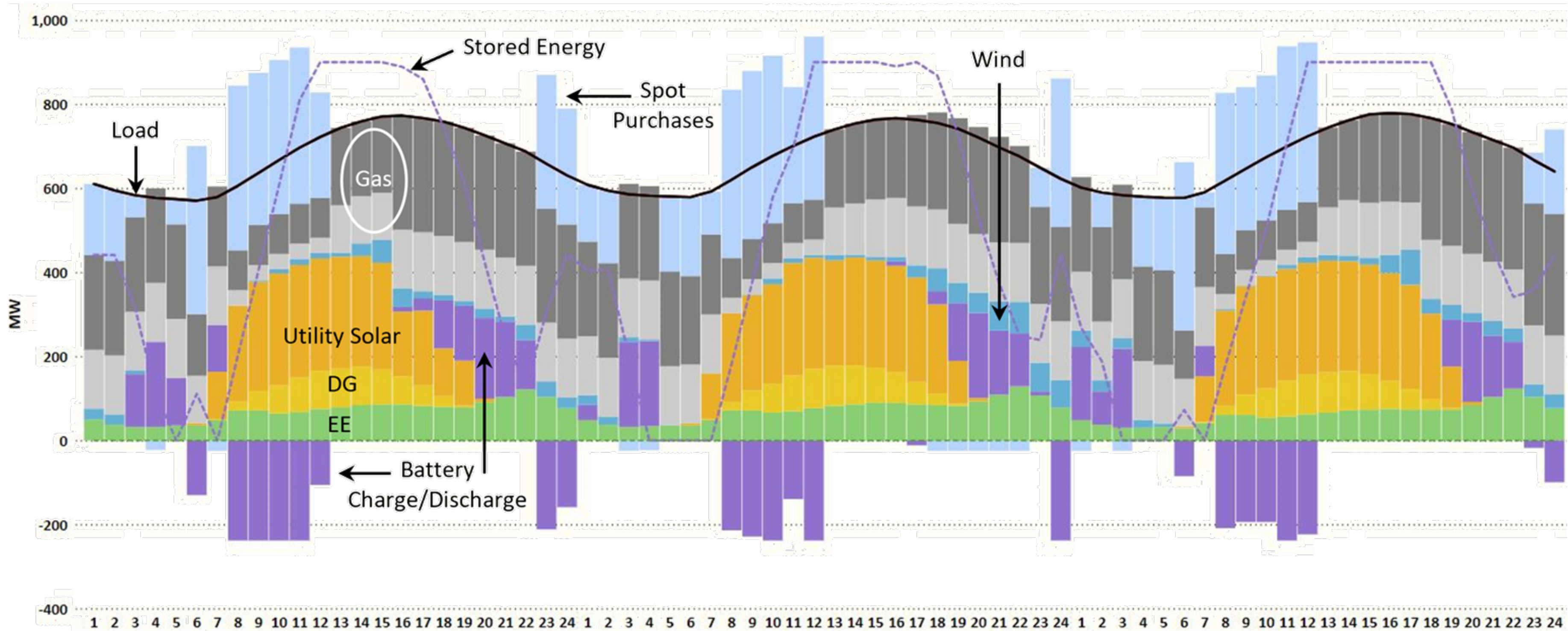
5.3 Resource Adequacy (RA)

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 will become a smaller part of UNSE's portfolio over the long term. 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, UNSE 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 UNSE must meet extended hours of peak loads with only its own resources. Because UNSE 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 16**, 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 replenish energy storage resources. Total stored energy is shown in the dashed purple line. The load and resource stack shown in **Figure 16** are typical of summer days, and the daily charging and discharging of the storage fleet cycles as expected.

Figure 16. Example of Hourly Load and Dispatch Results Used to Ensure Resource Adequacy (July 4-6, 2038)



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 jointly for the TEP/UNSE Balancing Authority Area as described in the E3 study included in **Appendix D**.

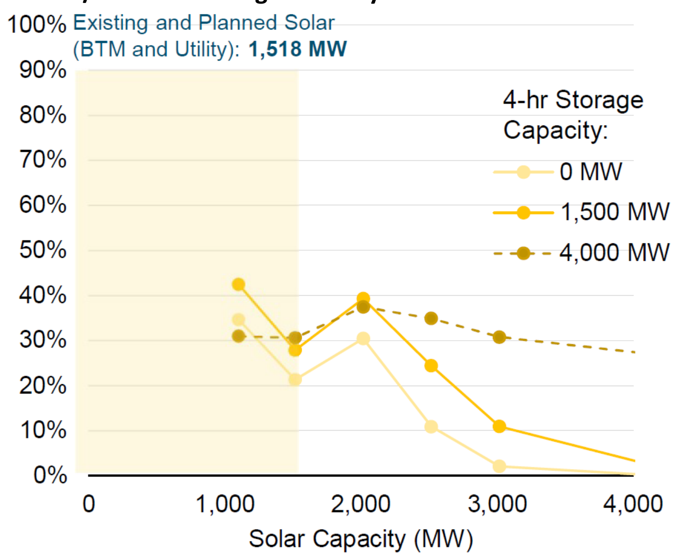
Whereas previous IRPs accredited capacity to renewable resources based on their average output during peak summer hours, ELCCs apply more rigorous, industry-standard methods that account for the decreasing capacity value of renewable resources as their penetration increases, as well as the synergistic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

Each of these effects can be seen in **Figure 17**, 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 the TEP/UNSE 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 on the TEP/UNSE system 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 17** 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 17. Incremental ELCC for Solar Given Alternative Amounts of Storage in the TEP/UNSE Balancing Authority Area



5.5 Load Forecast

This section summares UNSE'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 18 shows UNSE's service territory. UNSE currently provides electricity to approximately 100,000 customers in Santa Cruz and Mohave counties. The number of historic and projected residential customers is shown in **Figure 19**, while the current sales by customer class are shown in **Figure 20**.

Figure 18. UNSE Service Territory

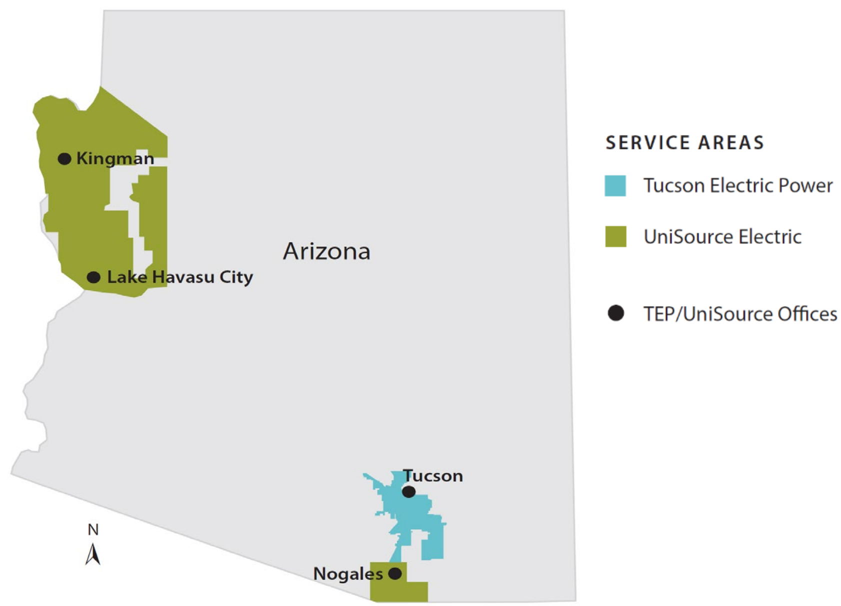


Figure 19. Historic and Projected Number of Residential Customers

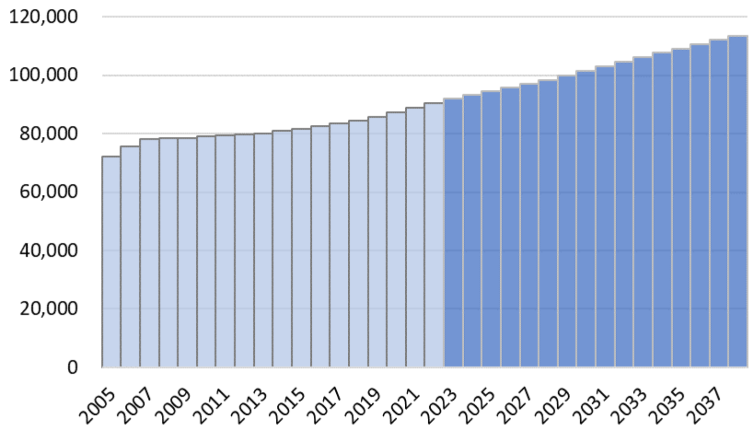
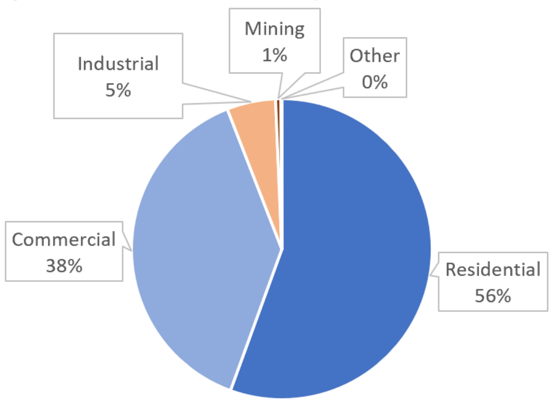


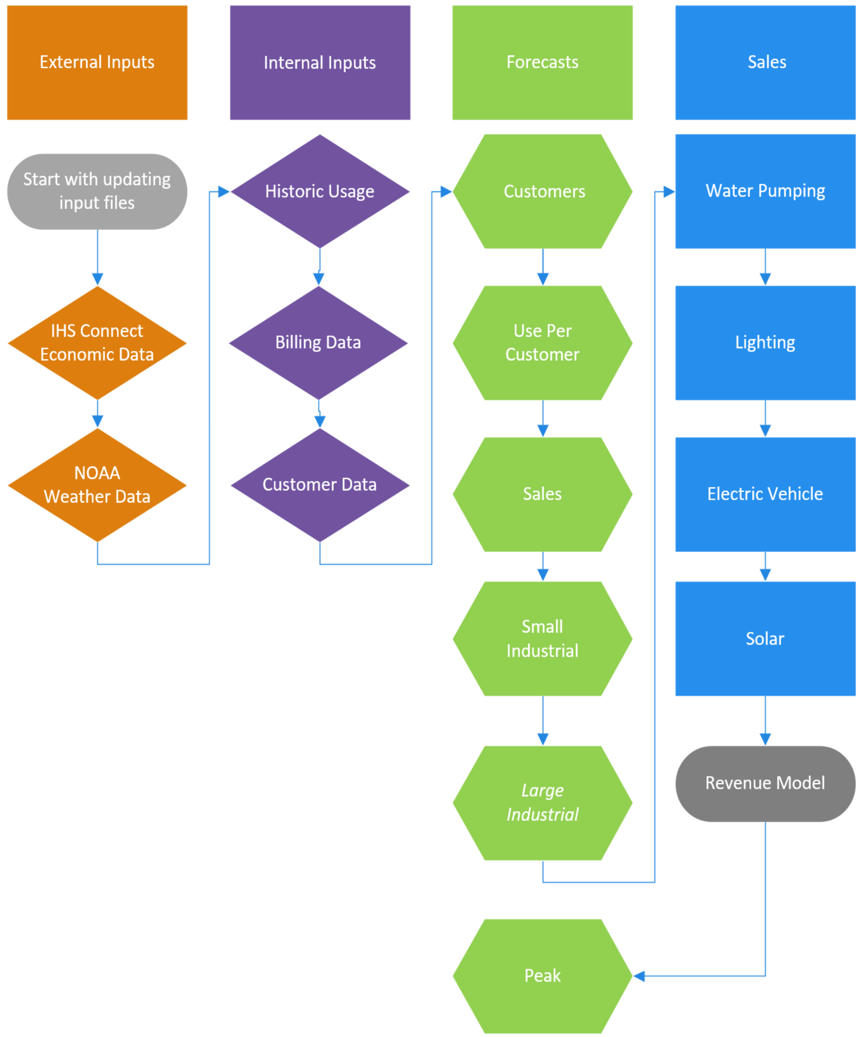
Figure 20. 2022 Retail Sales by Customer Class



5.5.2 Methodology, Data Sources, and Uncertainties

UNSE's load forecast methodology is illustrated in **Figure 21**. 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.

Figure 21. Load Forecast Process



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

Because of the large amount of uncertainty underlying the load forecast, it is crucial to consider the implications to resource planning if UNSE 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 8** provides UNSE's most recent EE savings. Although the state EE standard expired in 2020, UNSE 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 that was approved by the ACC in Decision No. 79096 on September 11, 2023. UNSE submitted an updated DSM Plan to cover implementation years 2024 through 2026. This plan proposed a three-year savings goal of 4.6% of annual retail sales. By having a three-year DSM Plan, UNSE will have greater flexibility in administration of these programs and greater economies of scale to help lower the costs of programs. It allows customers and contractors to have confidence in the programs continuance and viability. The final decision is pending the outcome of the UNSE rate case that is anticipated in February 2024.

The Plan continues UNSE's efforts to redirect DSM programs to achieve both energy and demand savings through cost-effective energy efficiency and load management programs.

Table 8. Recent Annual Energy Savings Through UNSE DSM Programs

Year	Retail Energy Sales (MWh)	Incremental Savings (MWh)	% of Sales	Cumulative Annual Savings (MWh)
2020	1,808,946	31,032	1.8%	309,777
2021	1,840,841	28,654	1.6%	338,431
2022	1,847,495	34,870	1.9%	373,301

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

- Implement cost-effective EE programs
- Target EE programs that meet system needs in order to benefit all customers
- Operate programs that provide opportunities for all customers to participate in
- Transform the market for efficient technologies
- Expand the EE infrastructure in the state
- Inform and educate customers to modify behaviors that enable them to use energy more efficiently
- Provide demand reduction opportunities for system reliability

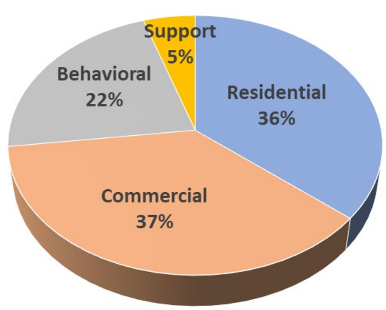
To achieve these objectives, UNSE offers a variety of programs across customer classes as shown in **Table 9** and **Figure 22**. These programs provide customers with information to help manage and control their energy use, making it more efficient and affordable to adopt DSM measures.

Table 9. Summary of UNSE DSM Programs

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

Behavioral Sector	Home Energy Reports
	Behavioral Comprehensive
DSM Initiatives	Load Management Pilot Program
Support Sector	Education & Outreach
	Energy Codes and Standards
	Research & Development/ Innovative Customer Solutions Framework

Figure 22. DSM Energy Savings by Sector, 2024-2026



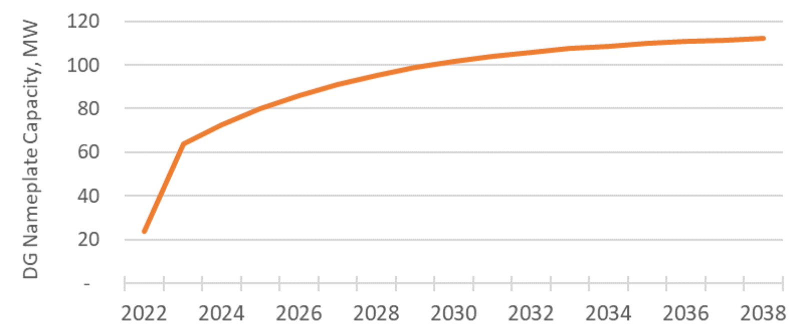
5.5.4 Distributed Generation (DG)

UNSE 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 10** and the forecasted growth in DG adoption is shown in **Figure 23.**

Table 10. Adoption Rates for UNSE DG Programs

	Total All-Time Customers Through 2022	Total MW
3rd Party Residential DG	6,538	63.54
3rd Party Non-Residential DG	219	18.85

Figure 23. UNSE DG Adoption Forecast



5.5.5 Electric Vehicles (EVs)

In February 2023, the ACC approved UNSE's Transportation Electrification Implementation Plan[10], which provides a roadmap for driving the adoption of EVs and building an equitable charging infrastructure in Mohave and Santa Cruz counties.

UNSE's three-year plan lays the foundation for EV readiness through stepped up efforts to educate the community about EV technology and its many benefits while reducing barriers to adoption. It also aligns with the transition to greener resources to reduce carbon emissions for a healthier community.

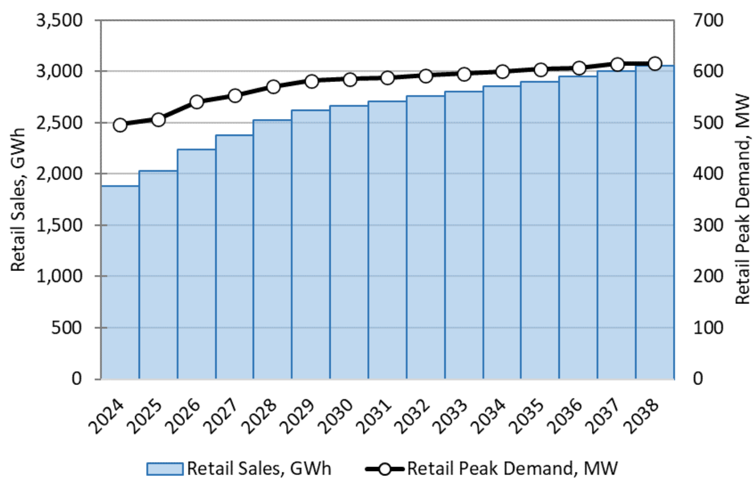
[10] https://docket.images.azcc.gov/E000019493.pdf?i=1671139655897

To help increase awareness, UNSE plans to develop a new page on its website that's dedicated to providing customers with comprehensive information. As part of the outreach efforts, collaboration with local organizations and car dealerships to host ride-and-drive events to give customers hands-on experience driving and charging EVs will be organized. UNSE will also launch residential, commercial and public transit programs which will provide technical and financial assistance to customers interested in deploying EV charging infrastructure at their home, business or agency. Additional information on the EV market can be found in **Appendix G.**

5.5.6 Load Forecast Results

Figure 24 summarizes UNSE's forecasted annual retail sales and peak demand. The average annual growth rate of sales and demand over the planning period is 3.50% and 1.55% respectively. This load forecast was used to develop all portfolios except for the high- and no-load growth sensitivity tests. Detailed forecast results are provided in **Appendix A**.

Figure 24. UNSE Forecasted Annual Retail Sales and Peak Demand



5.6 Resource Costs

UNSE 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 25** through **Figure 29**. 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, UNSE'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 25. Utility-Scale Solar Capital Cost Assumptions, $/kW

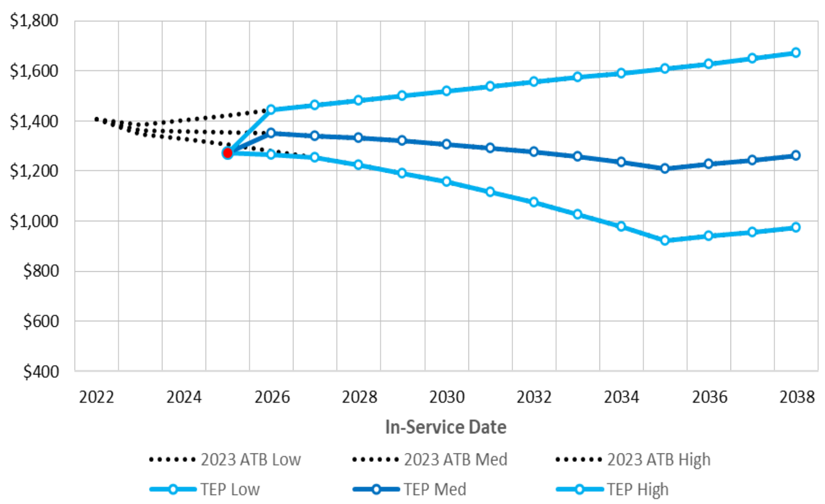


Figure 26. East NM Wind Capital Cost Assumptions, $/kW

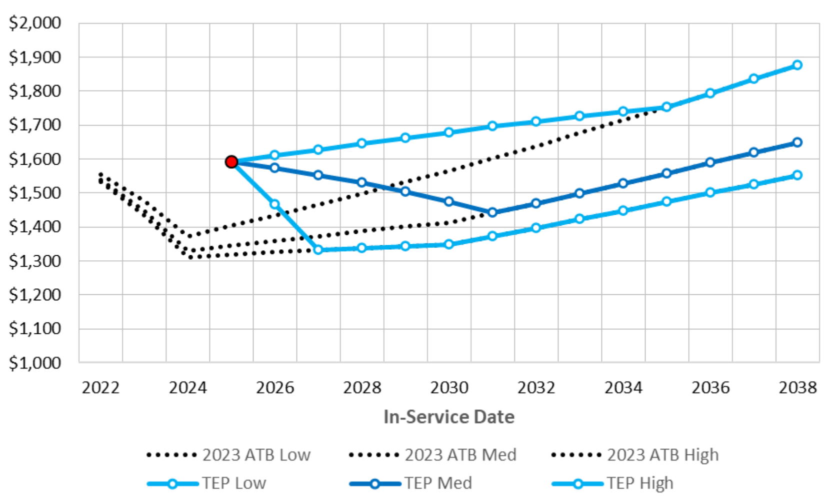


Figure 27. Four Corners Wind Capital Cost Assumptions, $/kW

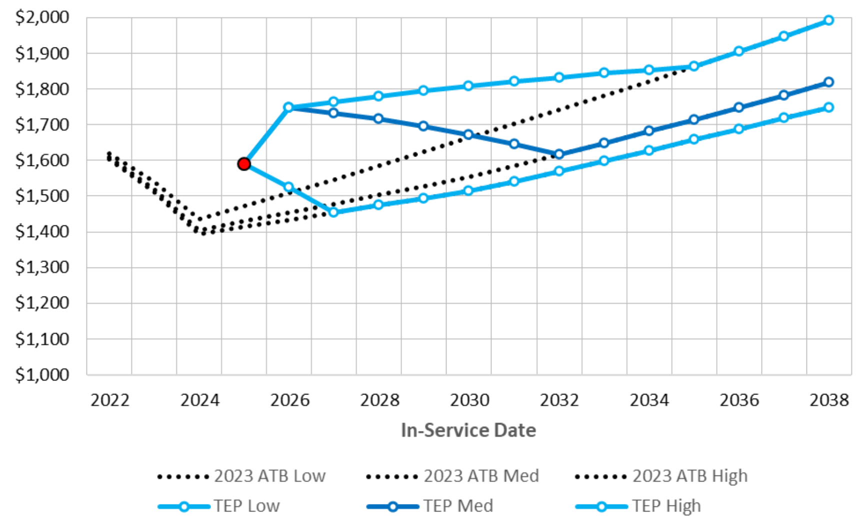


Figure 28. 4h Li-ion Storage Capital Cost Assumptions, $/kW

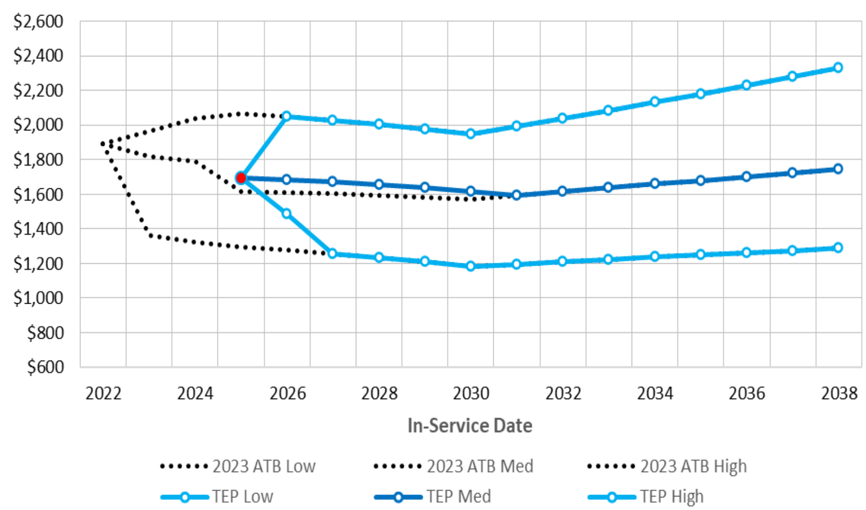
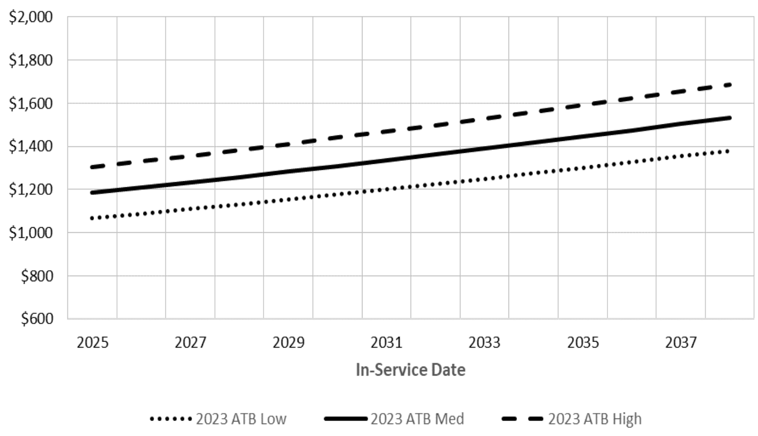


Figure 29. Aeroderivative CT Capital Cost Assumptions, $/kW



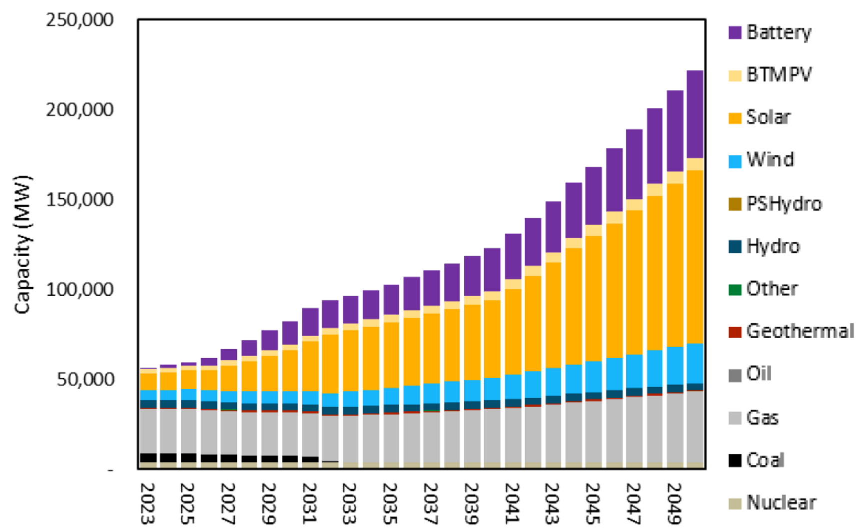
5.7 Market and Fuel Prices

Although UNSE 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 UNSE 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, UNSE 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**.

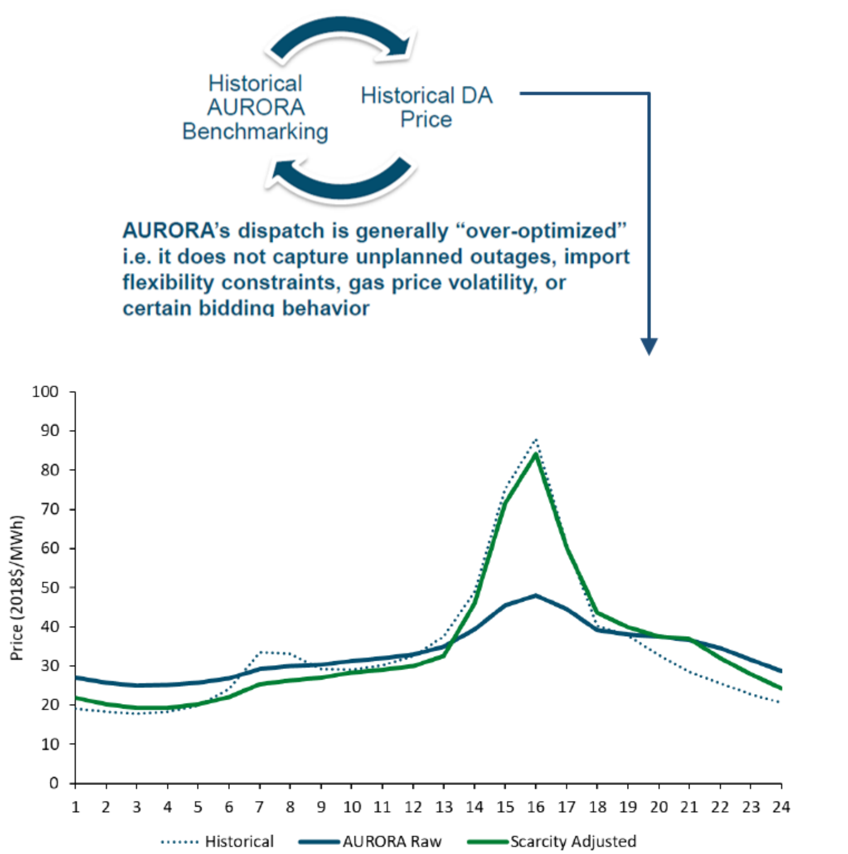
To determine these prices, E3 ran a capacity expansion model for the western United Sates based on planned retirements, expected load changes, federal and state policies affecting the power sector (including the Inflation Reduction Act), transmission limits, new resource cost trends, and future expectations for natural gas prices. **Figure 30** summarizes the capacity expansion results for the Desert Southwest.

Figure 30. Capacity Expansion Results Used as Basis for UNSE'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 UNSE'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 31**.

Figure 31. 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 32**, as more solar power is brought online in the region, average daytime prices are further depressed and peak prices last further into the evening.

Finally, **Figure 33** 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 32. Average Hourly Palo Verde Market Prices for Select Years

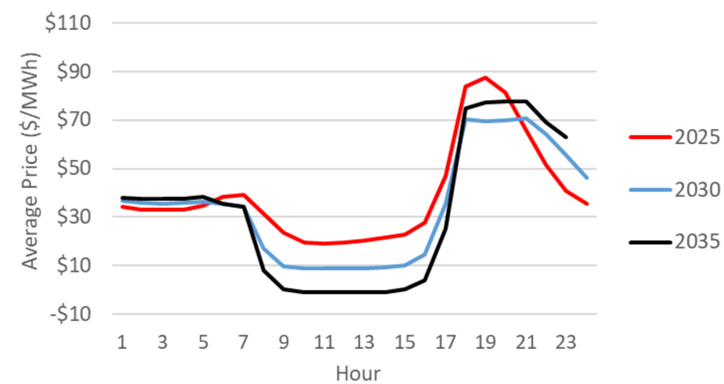


Figure 33. Historic and Forecast Palo Verde Market Prices

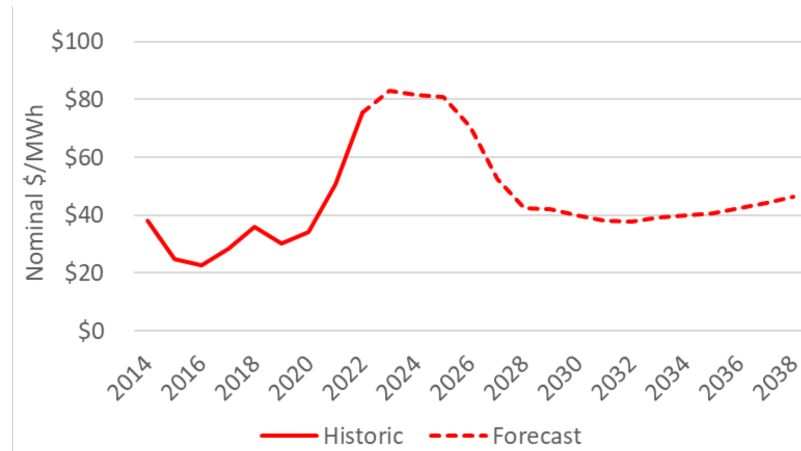
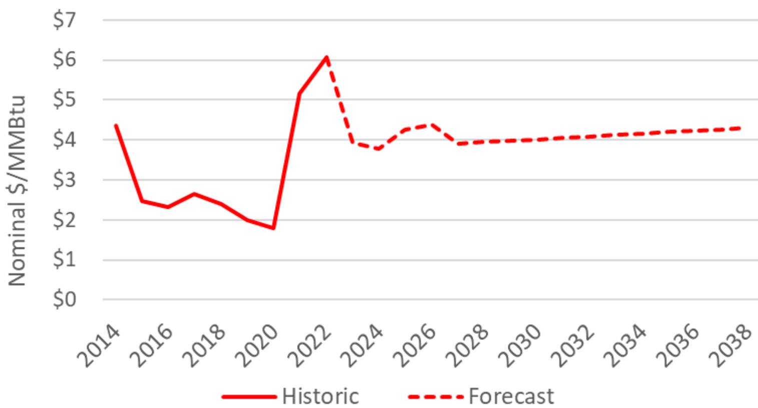


Figure 34 shows historic and forecast natural gas prices. Because UNSE is using the market price forecast developed by E3, it is important that UNSE also use E3's natural gas price forecast, given overlapping assumptions and the fact that gas prices influence power prices. Details on E3's natural gas price forecast can be found in **Appendix E**.

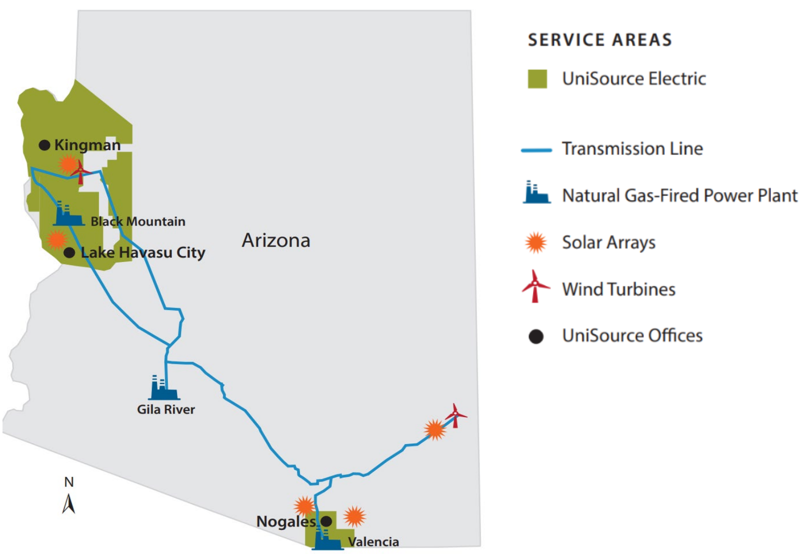
Figure 34. Historic and Forecast San Juan Natural Gas Prices



5.8 Transmission

Figure 35 shows UNSE's generation and transmission assets. For further information on existing generation, transmission, and distribution assets and planning processes, see **Appendix B** and **Appendix J**.

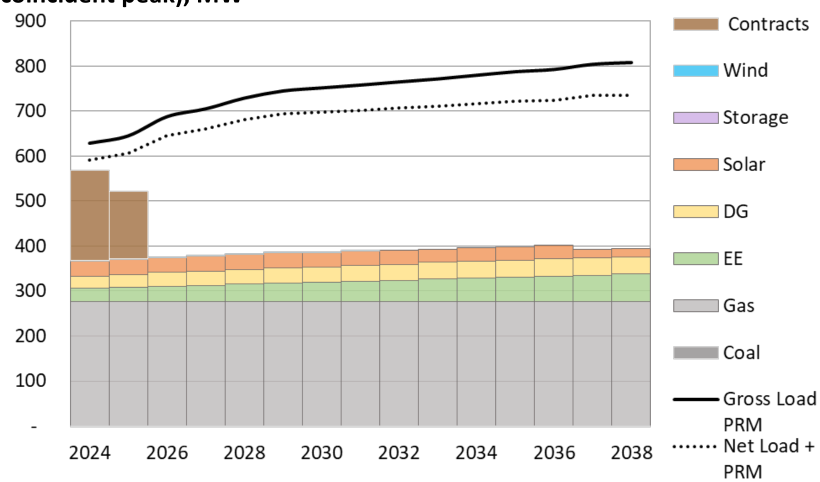
Figure 35. UNSE Transmission and Generation Assets



5.9 Base Case Loads and Resources

Figure 36 shows UNSE'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 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 UNSE customers reliably. **Table 11** 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 36. Annual Loads and Resource with No Future Resources Assumed (coincident peak), MW



5.10 Portfolios Evaluated and Sensitivity Tests

As summarized in **Table 12**, UNSE developed a number of diverse portfolios covering a range of potential future loads, resources, cost, 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, 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 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 3.50 and 2.55% respectively. This is also representative of a scenario in which there is strong customer and economic growth in UNSE's service territory or a greater-than-expected trend in electrification.

Table 11 below summarizes the current loads and resource outlook for UNSE. This table includes all existing resources but no future resources.

Table 11. Base Case Loads and Resources, MW

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Firm Load Obligation	**592**	**606**	**646**	**660**	**682**	**695**	**699**	**702**	**707**	**711**	**717**	**723**	**725**	**735**	**736**
Retail	508	520	555	567	585	597	600	603	607	610	615	620	622	630	632
Retail Reserve Requirement	84	86	92	94	97	98	99	99	100	101	101	102	103	104	104
Firm Resource Capacity*	**512**	**462**	**312**	**312**	**312**	**312**	**310**	**310**	**308**	**306**	**306**	**306**	**306**	**296**	**294**
Gas - Combined Cycle	148	148	148	148	148	148	148	148	148	148	148	148	148	148	148
Gas - Combustion Turbines	129	129	129	129	129	129	129	129	129	129	129	129	129	129	129
Wind	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0
Solar	33	33	33	33	33	33	32	32	32	30	30	30	30	19	18
Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Contracts	200	150	0	0	0	0	0	0	0	0	0	0	0	0	0
Reserve Available for Retail	3	-58	-243	-255	-274	-285	-289	-292	-299	-304	-309	-314	-316	-335	-337
Reserve Margin as Percent of Retail	1%	-11%	-44%	-45%	-47%	-48%	-48%	-49%	-49%	-50%	-50%	-51%	-51%	-53%	-53%
Net Position	-81	-144	-335	-349	-370	-383	-388	-392	-399	-404	-410	-416	-419	-439	-441

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

Table 12. Portfolios Evaluated in UNSE's 2023 IRP

Portfolio Number and Name	Description / Design Objectives	Sensitivity Tests
P01 – 150 MW New Gas	• Re-evaluates USNE's long-term plan acknowledged by the ACC in 2022 given new outlooks in future loads and resource costs and updated modeling capabilities. • Adds 150 MW of four 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
P02 - Balanced Portfolio	• Adds 200 MW of four new, fast-start, fast-ramping aeroderivative CTs brought into service in 2028. • Adds 350 MW of renewables and 225 MW of storage	High/Low Market Prices High/Low Capital Costs High/No Load Growth
P03 – 350 MW New Gas	• Adds 350 MW of seven new, fast-start, fast-ramping aeroderivative CTs brought into service in 2028.	High/Low Market Prices High/Low Capital Costs
P04 – 450 MW New Gas	• Adds 450 MW of seven new, fast-start, fast-ramping aeroderivative CTs brought into service in 2028. • Add no future renewables or storage.	High/Low Market Prices High/Low Capital Costs
P05 – No New Gas	• Adds no new gas. • Adds only renewables and 4 hour storage.	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 115 MW to 50 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 115 MW to 180 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.	High/Low Market Prices
P08 - Mid-Duration Storage / 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 UNSE's ELCC study. • Assumes reservoir would be located in northern AZ with a 100 MW share allocated to UNSE plus a transmission cost of $48/kW-year.	High/Low Market Prices
P09 - Clean Firm Power / 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 37 provides detailed results for four select portfolios. P01 (Reference Case) is based on the 2020 IRP Preferred Portfolio in that it assumes a similar mix of future gas, solar, storage, wind, and unit retirements. However, as a result of an increased load forecast and modeling improvements since 2020, especially the development of ELCCs, P01 contains significantly more solar and storage (600 versus 220 MW) and some additional gas-fired CT capacity (150 vs 100 MW).

Given the large capacity needs shown in **Figure 36**, UNSE modeled subsequent proposals that varied the amount of new gas-fired CTs and adjusted the renewable and storage amounts accordingly to maintain the Company's reliability criteria. P02 (Balanced Portfolio) increases the amount of gas capacity over the Reference Case by 50 MW, whereas P03 and P04 add an additional 200 and 300 MW of new CTs, respectively. Furthermore, P04 does not add any future renewables or storage. By contrast, P05 adds no new natural gas CTs and only adds renewables and storage. The rationales for P06 through P10 are provided in **Table 12**.

The resource schedules and reserve margins for P01, P02, P04, and P05 are shown in **Figure 37** and illustrate the full range of results involving alternative amounts of new or no natural gas CTs. To the right of each chart is the portfolio's total resource additions and retirements by resource type. The red line and percentages shown in **Figure 37** is the reserve margin, which should be at least 16.5% as part of the Company's reliability criteria.

Figure 38 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.

Figure 39 shows the net present value of the revenue requirements for each of the portfolios shown in **Figure 38**, 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. 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. Another explanation is the degree of parity between competing resource types, such as solar versus wind and batteries versus natural gas.

The largest rate impact occurs in the no-load growth scenario beause the reduction needed in new resources is not as great proportionally as the reduction in sales. This is because UNSE, which is relatively dependent on the wholesale market, currently posesses only half of the capacity needed to serve peak demand, so each of the portfolios requires significant new resources, even without any load growth, simply to achieve resource adequacy without relying on the market for the longer term.

Figure 40 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 40** also shows a bit more clearly how the NPVRR compares across Portfolios 1 through 9. Unlike TEP, which tended to be more sensitive to capital cost assumptions, UNSE revenue requirements are more sensitive to market prices assumptions, again because UNSE possesses few resources and is more exposed to prevailing market conditions. An exception to this trend is P05, which adds no new gas and only renewables and storage. Because this portfolio includes the largest amount of future resources in terms of nameplate capacity, it is more sensitive to capital cost assumptions than market price assumptions.

Figure 37. Annual Additions, Retirements & Reserve Margins for Select Portfolios

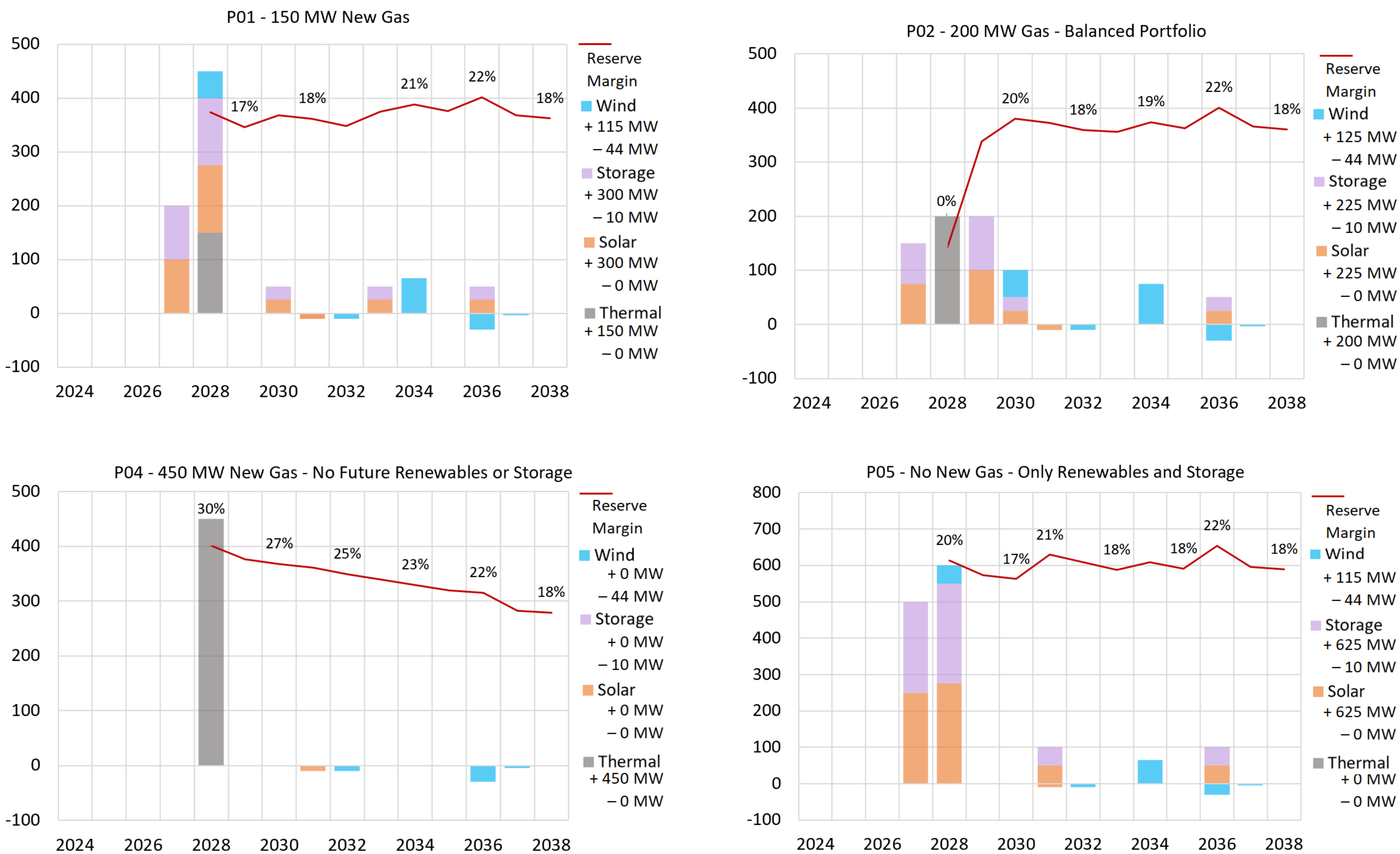


Figure 38. Total Resource Additions for Each Portfolio

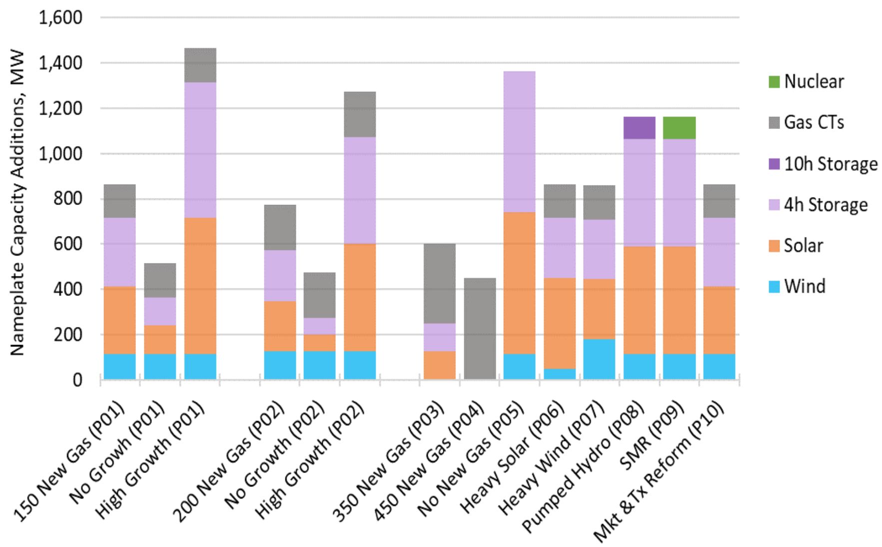


Figure 39. Net Present Value Revenue Requirements (NPVRR) for each Portfolio and Indicative Retail Rates

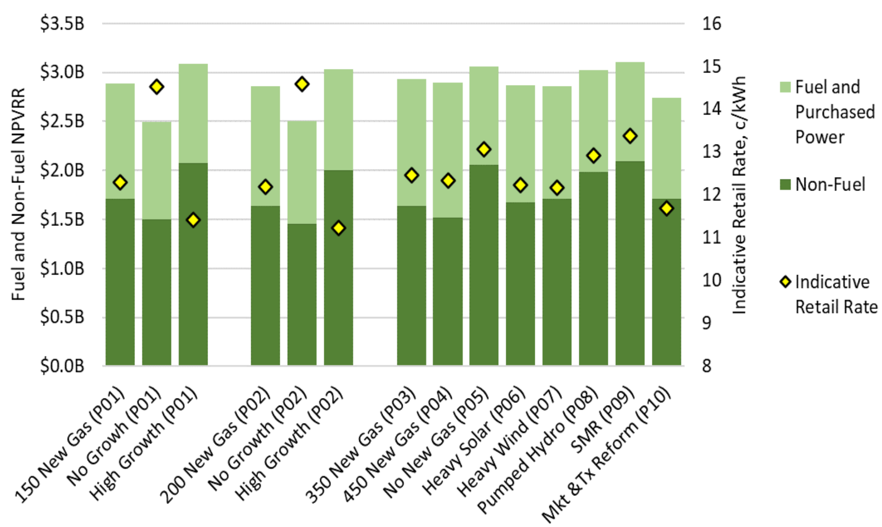
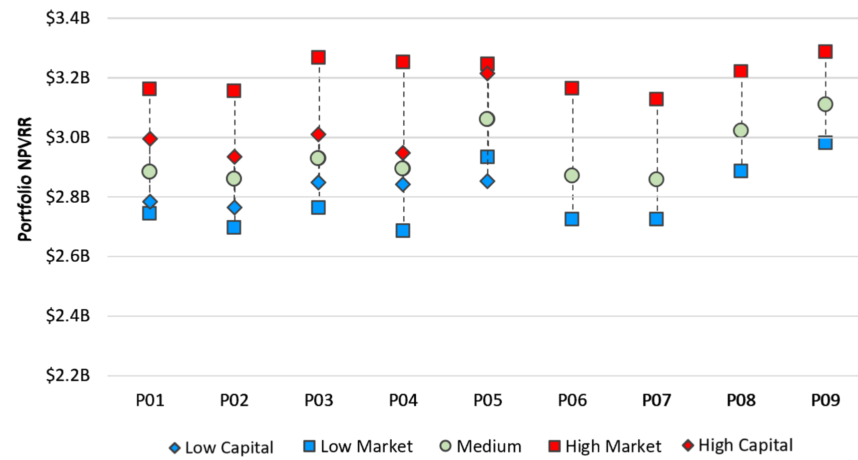


Figure 40. Range of NPVRR Resulting from Sensitivity Tests



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 P07 assumes the low capital cost forecast for just wind. Because of southern Arizona's climate, all portfolios contain substantially more solar than wind, so relative price reductions in solar will have a significant impact on total revenue requirements. The high wind portfolio, however, has virtually the same revenue requirements because not only is wind's cost assumed to be lower in this scenario, but it is assumed UNSE will have access to high-quality wind in eastern New Mexico that produces more energy per MW than solar in the UNSE area. There are also no assumptions for transmission costs for the 180 MW of wind in this portfolio. Regardless, neither P06 nor P07 have lower revenue requirements than the Balanced Portfolio, and the results suggest that the wind assumed in this portfolio is probably an upper bound on what is optimal for UNSE, at least given the current status of the interstate transmission network. The ultimate mix, of course, will depend on economics, system needs (e.g., for night-time power from wind), transmission availability, and interconnection status at the time of procurement.

Portfolios P08 and P09 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 Fortis's 2050 net zero goal.

Portfolio P10, which is the same as P01 but assumes greater market depth and lower prices, reduces revenue requirements by approximately $0.15B and is an indicator of the benefits that might be realized through future transmission investments and market reform.

Figure 41 through **Figure 43** compare the environmental attributes of each portfolio. The Balanced Portfolio (P02) is shown in a thick blue line with yellow circles. The portfolios with additional gas (P03 and P04) are shown in yellow and orange dotted lines. Although the emissions shown are relatively small because of UNSE's efficient use of natural gas and increasing use of renewable energy, these figures show how precisely emissions can vary depending on resource mix. P05, along with P08 and P09, has the lowest emissions because it assumes no new natural gas and only future renewables and 4h storage. P08 and P09 have similar emissions because they too assume no new natural gas. Generally speaking, the PSH and SMR technologies included in these portfolios are considered most appropriate under very high renewable or zero carbon scenarios, so they make the same base assumptions as P05 about no new natural gas.

Figure 41. CO_2 Emissions

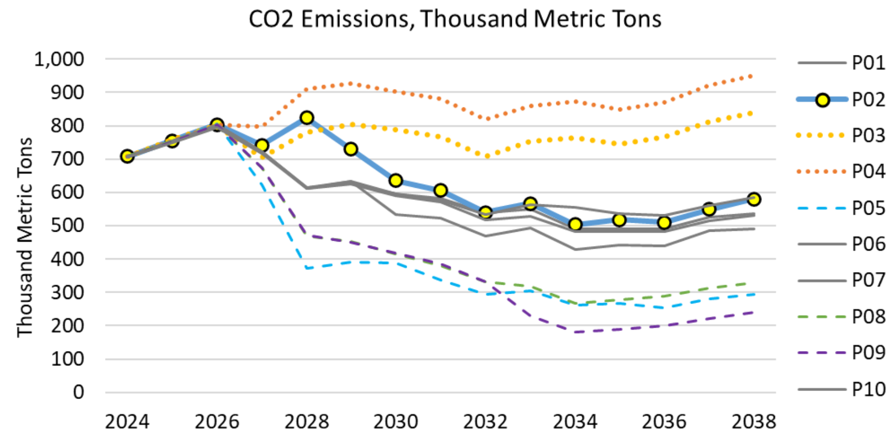


Figure 42. NOx Emissions

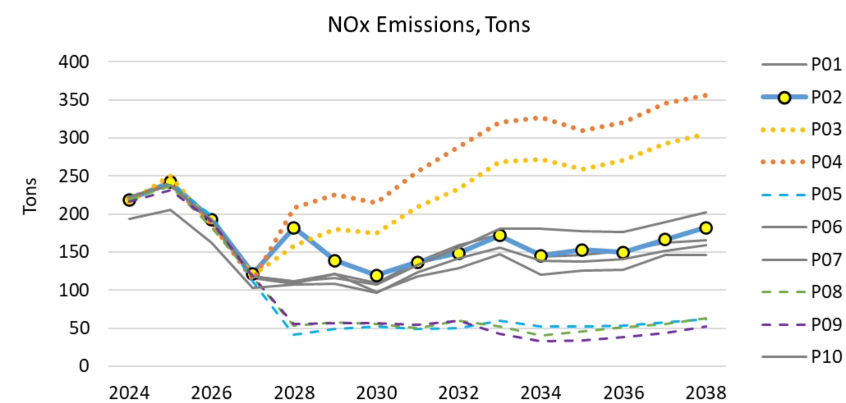


Figure 43. Water Use

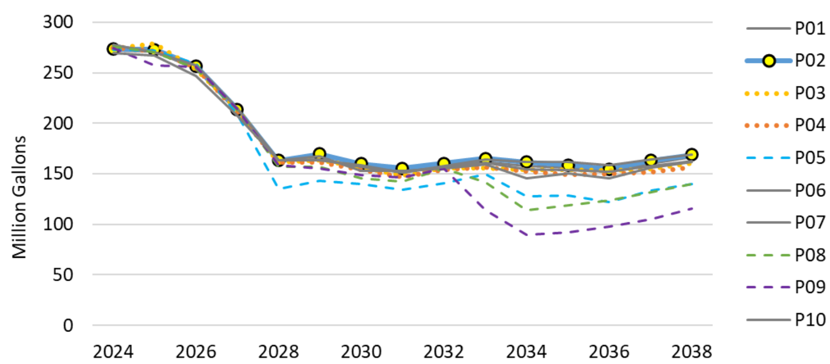


Figure 44 shows the capacity-weighted, fleet-wide capacity factor for UNSE's gas-fired generators. Each portfolio, almost irrespective of the amount of gas capacity or gas use, has a decreasing, then flat capacity factor. Broadly speaking, this suggests that additional gas capacity does not translate into a disproportionate amount of gas use, but rather used as intended to complement UNSE's clean resource portfolio while also meeting peak demand.

Figure 44. Gas Fleet Capacity Factor

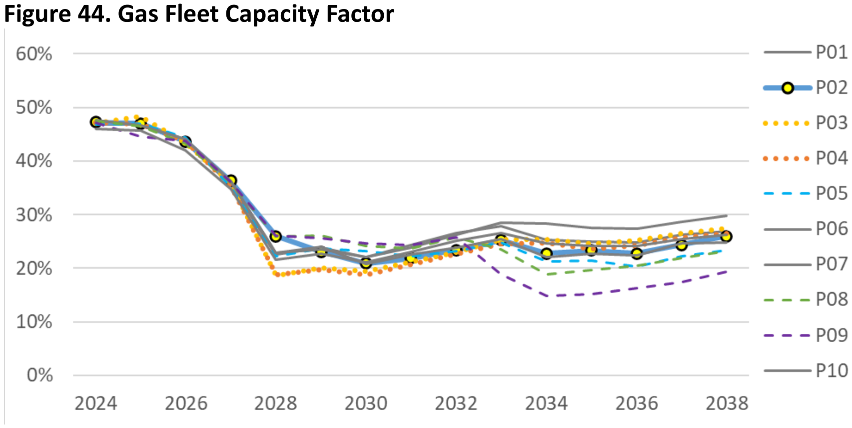
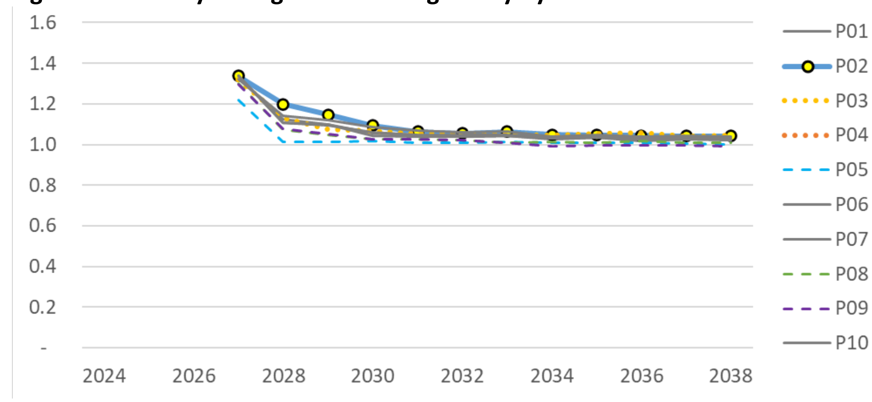


Figure 45 shows the capacity-weighted, average daily cycling of each portfolio's battery storage fleet. Although the size of the battery storage fleet is driven largely by the need for capacity, it serves an important and related function of storing excess renewable generation for later use, during non-peak hours. This energy shifting maximizes the use of solar and wind power and reduces the amount of natural gas generation, as well as market purchases. Unless otherwise needed for capacity, UNSE 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 underutilized or over cycled, as battery warranties often have limits on the number of annual cycles.

Figure 45. Battery Storage Fleet Average Daily Cycle



Based on the portfolio analysis done in this 2023 IRP and other implementation and risk management considerations, the Company expects P02 (the Balanced Portfolio) to be the most likely outcome of its planning and resource acquisition activities.

UNSE developed and analyzed ten different resource portfolios as part of the 2023 IRP. A summary of the 15-year net present value and cumulative capacity additions are shown in **Table 13** below.

Table 13. Portfolio Case Matrix Details

					Cumulative Additions (2024-2038)				
Portfolio #	**Portfolio Name**	**NPV ($000)**	**Fuel NPV ($000)**	**Non-Fuel NPV ($000)**	**Solar (MW)**	**Storage (MW)**	**Wind (MW)**	**Gas (MW)**	**Other (MW)**
UNSE P01	**150 MW New Gas**	$2,884	$1,172	$1,713	300	300	115	150	0
UNSE P02	**Balanced Portfolio**	$2,861	$1,227	$1,633	225	225	125	200	0
UNSE P03	**350 MW New Gas**	$2,930	$1,297	$1,633	125	125	0	350	0
UNSE P04	**450 MW New Gas**	$2,895	$1,382	$1,514	0	0	0	450	0
UNSE P05	**No New Gas**	$3,061	$1,007	$2,054	625	625	115	0	0
UNSE P06	**Heavy Solar**	$2,870	$1,199	$1,671	400	265	50	150	0
UNSE P07	**Heavy Wind**	$2,858	$1,144	$1,714	265	265	180	150	0
UNSE P08	**Pumped Hydro**	$3,021	$1,034	$1,988	475	475	115	0	100
UNSE P09	**Small Modular Reactors**	$3,110	$1,017	$2,093	475	475	115	0	100
UNSE P10	**Market and Transmission Reform**	$2,739	$1,026	$1,713	300	300	115	150	0

Notes:

1. P08 assumes that 100 MW of pumped hydro capacity is included in the portfolio.
2. P09 assumes that 100 MW of small modular reactors are included in the portfolio.
3. P10 is a sensitivity analysis utilizing the P01 portfolio and reflects a cost savings of approximately $145M 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 14** below provides a load and resource forecast for the Balance Portfolio (P02).

Table 14. 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	**592**	**606**	**646**	**660**	**682**	**695**	**699**	**702**	**707**	**711**	**717**	**723**	**725**	**735**	**736**
Retail	508	520	555	567	585	597	600	603	607	610	615	620	622	630	632
Retail Reserve Requirement	84	86	92	94	97	98	99	99	100	101	101	102	103	104	104
Firm Resource Capacity*	**512**	**462**	**312**	**387**	**587**	**695**	**720**	**720**	**718**	**720**	**735**	**735**	**757**	**749**	**747**
Gas - Combined Cycle	148	148	148	148	148	148	148	148	148	148	148	148	148	148	148
Gas - Combustion Turbines	129	129	129	129	329	329	329	329	329	329	329	329	329	329	329
Wind	2	2	2	2	2	2	12	12	10	10	25	25	25	25	25
Solar	33	33	33	75	75	132	138	138	138	137	137	137	148	137	135
Storage	0	0	0	33	33	85	93	93	93	96	96	96	107	110	110
Contracts	200	150	0	0	0	0	0	0	0	0	0	0	0	0	0
Reserve Available for Retail	3	-58	-243	-180	1	99	120	117	111	110	120	115	135	119	116
Reserve Margin as Percent of Retail	1%	-11%	-44%	-32%	0%	17%	20%	19%	18%	18%	19%	19%	22%	19%	18%
Net Position	-81	-144	-335	-274	-95	0	21	18	11	9	18	12	32	15	12

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

7 Risk Management Plan

7.1 Analysis of UNSE 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, UNSE employs several strategies including:

1. **Diversifying Energy Sources:** UNSE 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. UNSE 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 UNSE's service area.

2. **Coordination Between Plant and Gas Supply Operators:** UNSE 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 covers UNSE and 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. UNSE 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:** UNSE 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:** UNSE 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.

   UNSE's tools for system operations have complete 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 delivery electricity, increased grid resilience, increased voltage support on the distribution network, and perhaps 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 distribution generation as opposed to large scale systems. More importantly, customer adoptability of installing distribution generation is largely unknown in both quantity and location. Without this key input, the quantification of these benefits and other factors is 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 UNSE's 2023 Preferred Portfolio

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

UNSE's 2023 Preferred Portfolio (P02 - Balanced Portfolio) establishes an updated roadmap for UNSE's pursuit of a reliable, lower cost, sustainable energy supply. The 2023 IRP builds from the 2020 IRP planning cycle and accelerates its current plans for developing new energy resources that will support affordable, reliable service while reducing its over-reliance on summer market capacity.

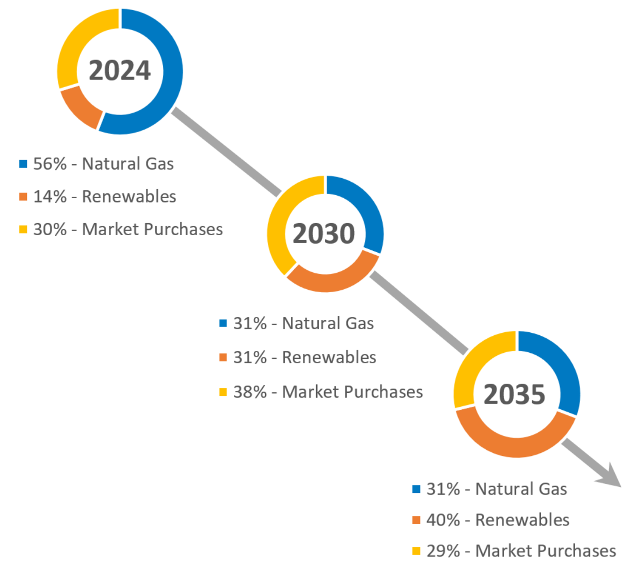
UNSE presents the 2023 Preferred Portfolio based on the best of the portfolios evaluated while ultimately deferring future resource acquisitions to outcomes determined through All-Source Request for Proposals (ASRFP). It is in this context that UNSE selects P02 - Balanced Portfolio as the Preferred Portfolio. The resource mix in the Balanced Portfolio establishes an updated roadmap for UNSE's pursuit of a reliable, lower cost, sustainable energy supply.

UNSE believes that defining the UNSE Preferred Portfolio through the results of ASRFPs has several advantages. An ASRFP will provide the most complete and contemporaneous set of cost and performance data on which to base firm resource decisions. This is particularly important given the rapid changes that are occurring in technology advancements, resource economics and regional market development.

Future ASRFPs will enable UNSE to competitively acquire resources in a strategic manner that maintains reliability, affordability, and environmental performance while adequately mitigating cost and performance risks. Moreover, given UNSE's small size and its two geographically distinct service areas, UNSE will need to rely on firm market capacity in the interim to mitigate large single year rate impacts associated with resource acquisition.

As shown in **Figure 46** the Balanced Portfolio is the most cost-effective way to maintain reliable, affordable service while achieving UNSE's environmental objectives.

Figure 46. Balanced Portfolio Energy Mix



The Balanced Portfolio is expected to have a lower impact on customers' rates than other portfolios that were considered.

8.2 Future Resource Additions

To meet anticipated load growth, UNSE plans to secure 550 MW of new generating capacity and 225 MW of new energy storage over the next 15 years. As shown in **Figure 47,** while 74% of the new resource capacity will be sourced from renewable and energy storage projects, UNSE
anticipates a need to develop 200 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

options 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 225 MW of new energy storage. In general, the energy storage additions are paired with solar and coincide with 225 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. A 15-year timeline of the Balanced Portfolio is shown in **Figure 57** on **Page 53**.

As shown in **Figure 48** through **Figure 50** the Balanced Portfolio accelerates UNSE's buildout of clean energy resources, with 575 MW of new renewables and storage coming online over the next 15 years compared to the 335 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 portfolios that were considered.

Figure 47. Future Capacity Additions

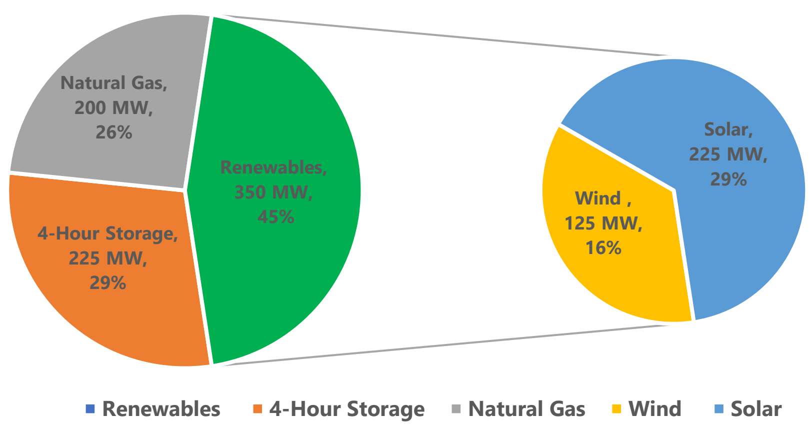


Figure 48. New Resource Differences between the 2020 and 2023 IRPs

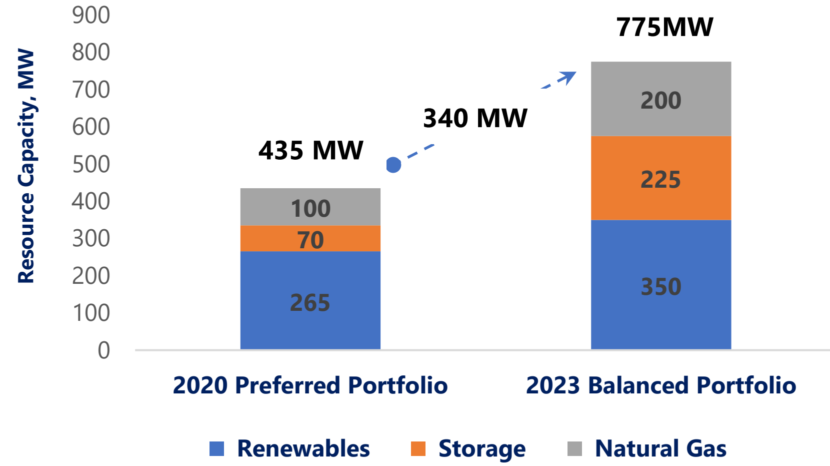
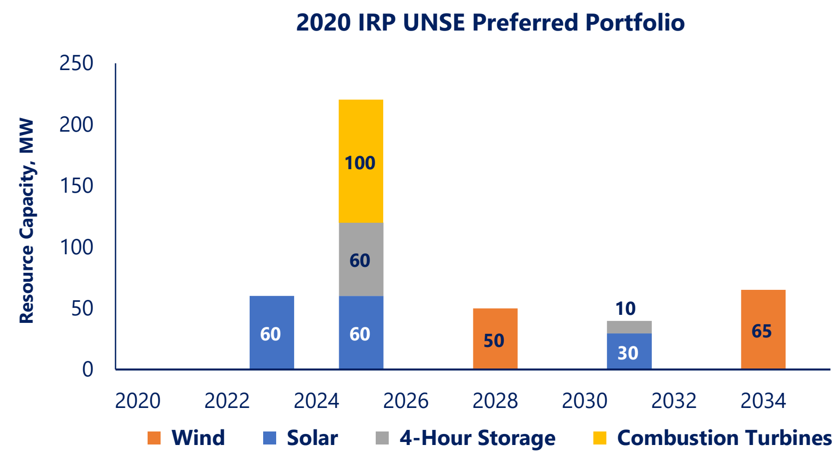
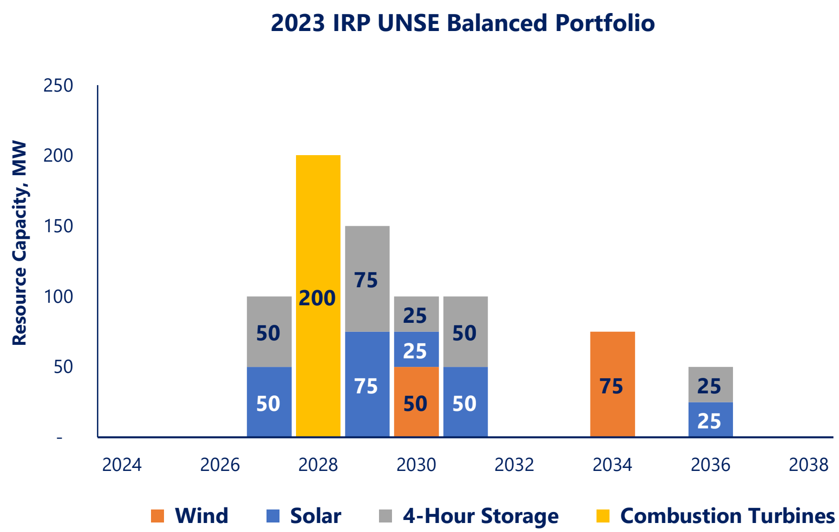


Figure 49. 2020 IRP Renewable and Storage Capacity Additions



[12] *See Hydrogen - Carbon-Free Fuel Blending as a Transition Fuel to the Future on* **Page 54**

Figure 50. 2023 IRP Renewable and Storage Capacity Additions



8.3 Balanced Portfolio Environmental Attributes

Figure 51 through **Figure 53** show the expected levels of CO_2 and NO_X emissions and water use over the next 15-years based on UNSE's Balanced Portfolio.

Figure 51 - Balanced Portfolio - CO2 Emissions

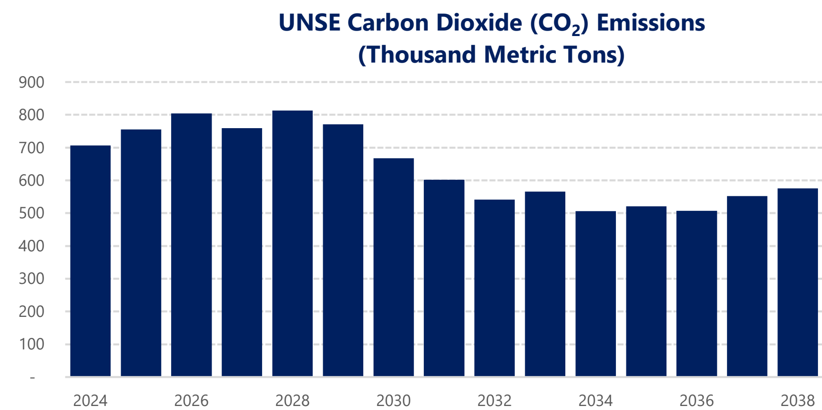


Figure 52. Balanced Portfolio – NO_X Emissions

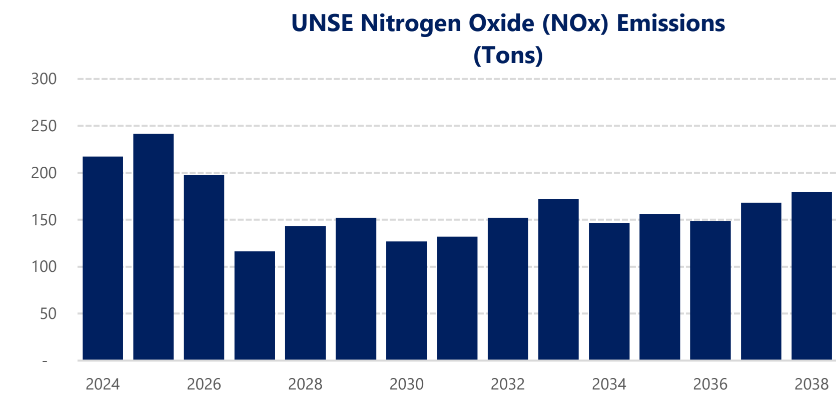
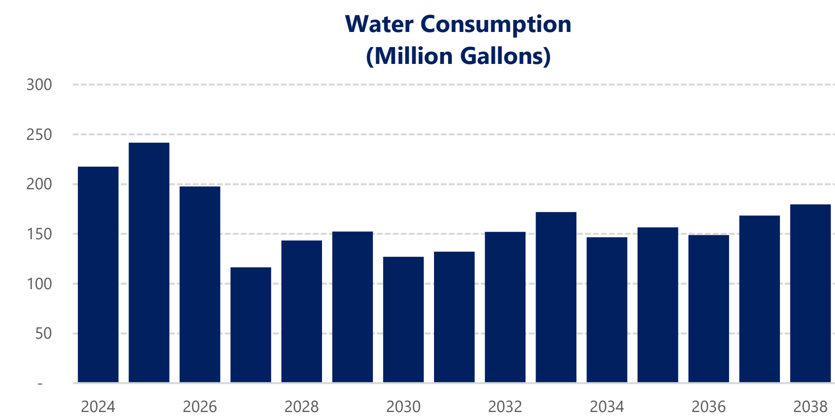


Figure 53. Balanced Portfolio – Water Usage



8.4 Future Energy Efficiency

UNSE's Balanced Portfolio will continue to incorporate EE based on the Company's on-going implementation plan process. UNSE filed its 2022 EE Implementation Plan on June 1, 2021, for approval that would cover implementation years 2022 and 2023. This plan was approved on September 11, 2023 in Decision No 79096. As part of the Company's current rate case, UNSE submitted an updated EE plan to cover implementation years 2024 through 2026.[13] This plan proposed a three-year savings goal of 4.6% and will apply to 2024 and will run through 2026. By having a three-year DSM Plan, UNSE will have greater flexibility in administration of these programs and greater economies of scale to help lower the costs of our programs. It allows our customers and contractors to have confidence in the programs' continuance and viability. The final decision on this is pending the outcome of the UNSE rate case that is anticipated to be decided in February 2024.

This updated DSM Plan continues UNSE's efforts to redirect DSM programs to achieve both energy and demand savings through cost-effective energy efficiency and load management programs. UNSE believes that incorporating EE at levels consistent with recent historical years 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.

8.5 Demand Response

UNSE currently implements a voluntary load control program for larger commercial and industrial customers in UNSE's service territory. The program is designed to manage peak demand and mitigate system emergencies through a commercial and industrial load curtailment program. The UNSE customers on the interruptible rate had equipment installed that provides the Company control of their entire electric load. Customers are placed on UNSE's Interruptible Power Service tariff in lieu of any cash incentive for participation.

8.6 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. UNSE'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 54** 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 54. Balanced Portfolio – Net Additions and Retirements (2024-2038)

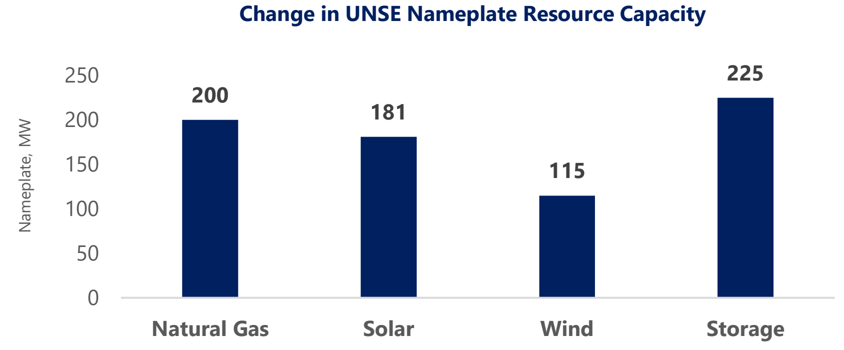
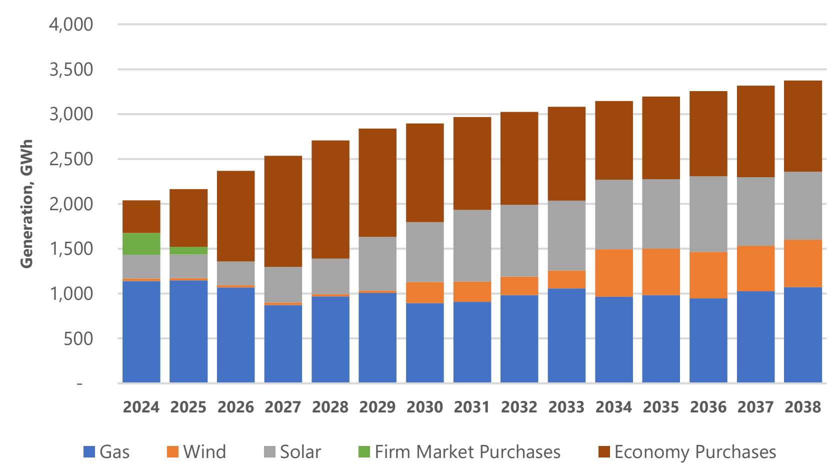


Figure 55 below shows the shift in energy mix over the planning period.

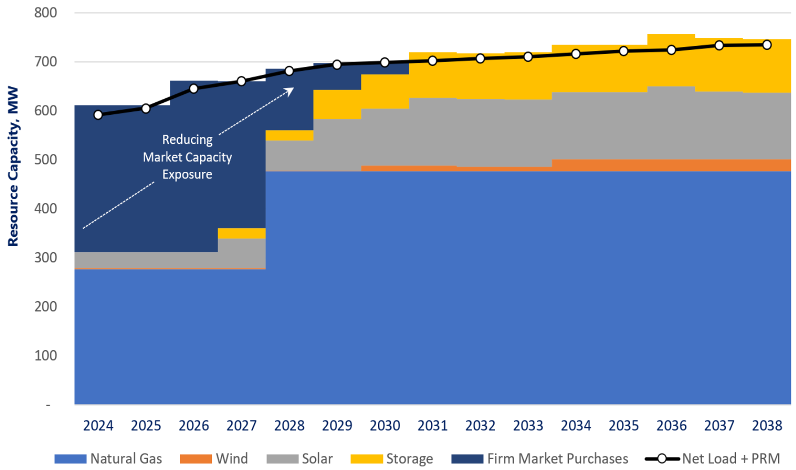
Figure 55. Balanced Portfolio – Annual Energy by Resource Type



[13] This plan was submitted as Rejoinder testimony of Dallas J. Dukes in the UNSE rate case in Exhibit-DJD-RJ1 on September 15, 2023.

Figure 56 below shows final Load and Resources assessment of the Preferred Portfolio.

Figure 56. Balanced Portfolio – Loads and Resources



8.7 Future ASRFPs

The Balanced Portfolio will be developed through future needs analyses and ongoing 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.

UNSE'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.

8.8 2023 IRP Action Plan

UNSE has developed a 2023 Action Plan based on the Company's forward-looking customer growth and cost assumptions that are detailed in Section 1. Under this action plan, additional All-Source Request for Proposal (ASRFP) solicitations will be conducted to validate all technical and financial assumptions prior to any acquisition decisions. UNSE's action plan includes the following:

UNSE continues to negotiate with developers on new solar and storage project solicitations that were received through the Company's 2022 ASRFP. The Company expects that these negotiations may lead to the acquisition of new solar plus storage projects in the 2026 and 2027 timeframes.

UNSE will continue to implement cost-effective energy efficiency programs. Through future implementation plans developed in coordination with the Commission, UNSE will target a three-year savings goal of 4.6% and will apply to 2024 and will run through 2026. Moreover, UNSE will continue to solicit new demand response programs that are mutually beneficial to the Company and its customers.

UNSE 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.

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

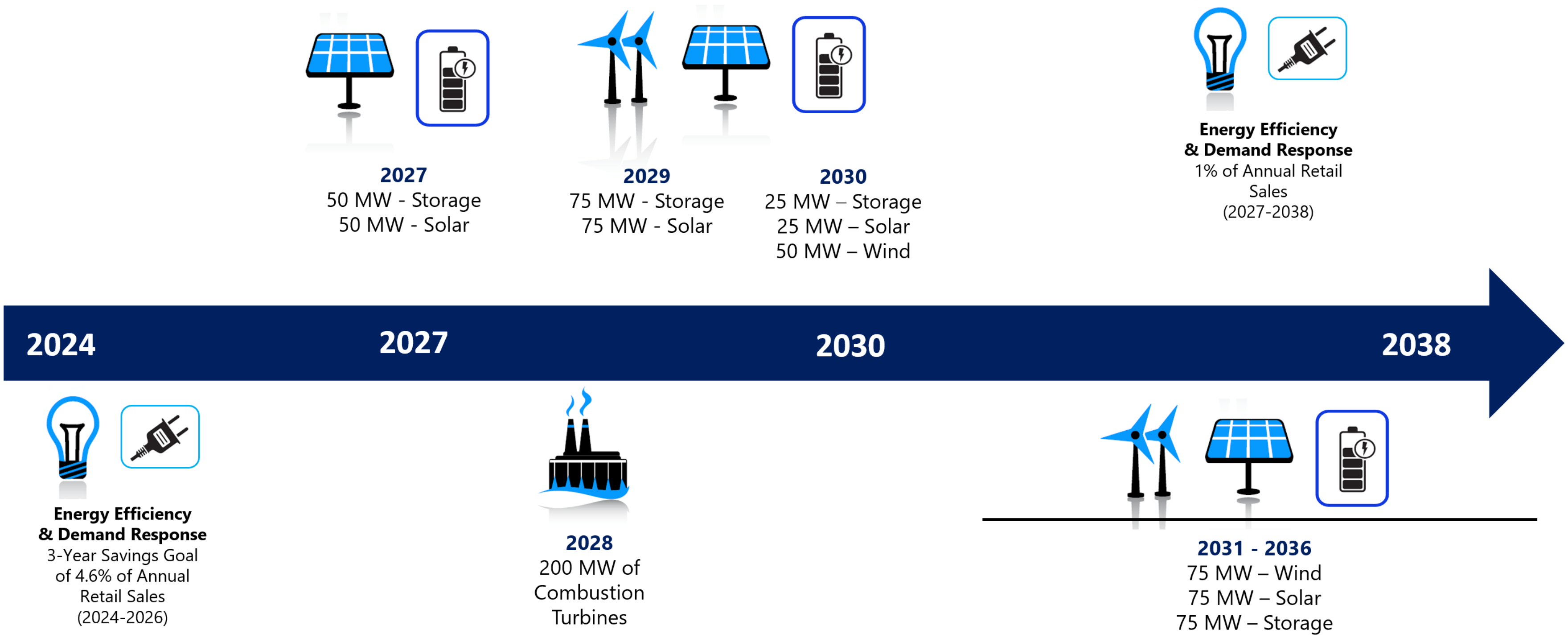
The Preferred Portfolio will ultimately be defined by future All-Source Request for Proposals

Figure 57. Balanced Portfolio Project Timeline

2023 IRP UNSE Balanced Portfolio

2024-2038 Capacity Expansion Plan – 775 MW

2024-2038	Expansion Plan
Renewables	350
Storage	225
Natural Gas	200
Total Expansion Plan	775



Note: *UNSE retires 10 MW of wind and 44 MW of solar 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 UNSE Integrated Resource Plan: Appendices

Appendix A: Load Forecast

Table A1. UNSE Monthly Energy Forecast, MWh

Month	Residential	Commercial	Industrial	Mining	Other	System Losses	Total
1/1/2024	76,956	52,850	7,856	6,621	182	11,101	155,565
2/1/2024	64,248	48,536	7,719	6,610	146	9,203	136,462
3/1/2024	60,170	53,293	8,102	6,605	155	9,584	137,909
4/1/2024	57,166	54,067	7,612	6,643	144	8,834	134,465
5/1/2024	78,432	63,838	7,784	6,662	126	12,947	169,790
6/1/2024	109,344	71,609	7,796	6,564	119	12,568	208,000
7/1/2024	135,257	75,451	7,483	6,600	129	18,509	243,429
8/1/2024	128,756	73,392	7,571	6,619	143	18,093	234,575
9/1/2024	99,446	64,055	7,725	7,088	153	15,927	194,393
10/1/2024	66,210	56,777	7,900	7,104	166	11,642	149,799
11/1/2024	59,365	51,894	7,790	6,851	174	8,781	134,856
12/1/2024	78,150	53,297	7,461	6,708	186	11,493	157,295
1/1/2025	78,440	53,549	7,985	9,823	182	11,577	161,556
2/1/2025	66,087	49,122	7,683	9,253	146	9,395	141,686
3/1/2025	61,859	53,847	8,212	12,459	155	10,085	146,616
4/1/2025	58,918	54,500	7,921	12,404	144	9,560	143,447
5/1/2025	79,518	64,595	8,045	12,223	126	14,530	179,037
6/1/2025	110,122	72,176	8,071	12,372	119	15,265	218,126
7/1/2025	136,627	76,248	7,691	12,503	129	20,709	253,907
8/1/2025	130,757	73,949	7,812	21,931	143	20,561	255,152
9/1/2025	101,733	64,725	7,872	21,304	153	17,476	213,262
10/1/2025	68,025	57,430	8,054	22,275	166	13,013	168,963
11/1/2025	61,181	52,446	7,958	20,682	174	9,917	152,358
12/1/2025	80,168	54,148	7,617	21,936	186	12,473	176,528
1/1/2026	80,373	54,556	7,929	31,719	182	12,988	187,747
2/1/2026	68,040	50,099	7,580	28,834	146	10,507	165,206
3/1/2026	63,732	54,379	8,170	31,004	155	11,632	169,072
4/1/2026	60,906	54,910	7,778	30,586	144	11,252	165,577
5/1/2026	81,464	65,327	7,930	29,749	126	16,584	201,180
6/1/2026	110,998	72,312	7,941	30,831	119	19,712	241,914
7/1/2026	138,176	76,801	7,594	31,252	129	24,483	278,436
8/1/2026	133,413	74,449	7,698	31,195	143	22,081	268,979
9/1/2026	104,492	65,334	7,805	29,983	153	18,297	226,064
10/1/2026	70,326	57,947	7,984	31,552	166	13,704	181,680
11/1/2026	63,481	52,702	7,880	29,150	174	10,599	163,985
12/1/2026	82,686	54,666	7,547	31,272	186	12,938	189,296
1/1/2027	82,375	55,067	7,955	41,236	182	13,972	200,787
2/1/2027	70,072	50,571	7,630	37,348	146	11,429	177,196
3/1/2027	65,700	54,851	8,189	40,255	155	12,636	181,786
4/1/2027	62,974	55,396	7,847	39,666	144	12,312	178,340
5/1/2027	83,875	65,824	7,984	38,505	126	17,861	214,175
6/1/2027	113,899	72,795	8,003	40,032	119	21,178	256,025
7/1/2027	141,371	77,550	7,641	40,598	129	25,783	293,072
8/1/2027	136,489	74,988	7,753	40,513	143	23,440	283,325
9/1/2027	107,192	65,817	7,838	38,659	153	19,509	239,167
10/1/2027	72,493	58,565	8,017	40,816	166	14,554	194,612
11/1/2027	65,578	53,157	7,918	37,599	174	11,336	175,761
12/1/2027	84,990	55,369	7,580	40,579	186	13,491	202,194
1/1/2028	84,500	55,748	7,938	50,723	182	14,728	213,819
2/1/2028	72,206	51,232	7,873	47,470	146	12,282	191,209
3/1/2028	67,779	55,536	8,176	49,478	155	13,441	194,565
4/1/2028	65,142	55,706	7,809	48,711	144	13,590	191,102
5/1/2028	86,411	66,633	7,954	47,224	126	18,901	227,248
6/1/2028	116,953	73,304	7,968	49,210	119	22,707	270,262
7/1/2028	144,750	78,524	7,614	49,920	129	26,973	307,910
8/1/2028	139,743	75,734	7,722	49,804	143	24,717	297,862
9/1/2028	110,024	66,483	7,817	47,336	153	20,665	252,479
10/1/2028	74,750	59,351	7,996	50,087	166	15,361	207,712
11/1/2028	67,743	53,916	7,895	46,057	174	11,882	187,667
12/1/2028	87,377	56,121	7,560	49,901	186	14,107	215,252
1/1/2029	87,095	56,546	7,949	55,691	182	14,714	222,177

Table A1. UNSE Monthly Energy Forecast, MWh

Month	Residential	Commercial	Industrial	Mining	Other	System Losses	Total
2/1/2029	74,788	52,001	7,619	50,277	146	12,175	197,006
3/1/2029	70,275	56,329	8,185	54,307	155	13,550	202,802
4/1/2029	67,700	56,518	7,831	53,450	144	13,833	199,476
5/1/2029	89,335	67,555	7,972	51,792	126	19,308	236,089
6/1/2029	120,412	73,919	7,988	54,013	119	23,602	280,054
7/1/2029	148,556	79,613	7,630	54,800	129	27,513	318,242
8/1/2029	143,392	76,791	7,740	54,668	143	25,180	307,913
9/1/2029	113,181	67,441	7,830	51,870	153	21,029	261,503
10/1/2029	77,251	60,217	8,010	54,929	166	15,583	216,156
11/1/2029	70,120	54,739	7,909	50,474	174	11,914	195,329
12/1/2029	90,008	56,971	7,573	54,767	186	14,107	223,611
1/1/2030	89,797	57,412	7,943	55,689	182	14,205	225,228
2/1/2030	77,467	52,830	7,610	50,274	146	11,838	200,166
3/1/2030	72,890	57,196	8,180	54,305	155	13,238	205,964
4/1/2030	70,412	57,406	7,819	53,447	144	13,645	202,872
5/1/2030	92,481	68,566	7,962	51,789	126	19,246	240,170
6/1/2030	124,156	75,031	7,978	54,012	119	23,631	284,926
7/1/2030	152,699	80,816	7,621	54,798	129	27,588	323,651
8/1/2030	147,362	77,953	7,731	54,666	143	25,243	313,097
9/1/2030	116,646	68,484	7,823	51,871	153	21,029	266,006
10/1/2030	80,058	61,157	8,002	54,930	166	15,375	219,689
11/1/2030	72,841	55,613	7,901	50,475	174	11,515	198,518
12/1/2030	93,020	57,859	7,566	54,768	186	13,577	226,976
1/1/2031	92,710	58,340	7,946	55,690	182	13,773	228,641
2/1/2031	80,343	53,722	7,614	50,276	146	11,627	203,728
3/1/2031	75,677	58,148	8,182	54,306	155	13,092	209,561
4/1/2031	73,272	58,384	7,825	53,448	144	13,682	206,754
5/1/2031	95,755	69,686	7,967	51,791	126	19,426	244,751
6/1/2031	128,023	76,243	7,983	54,013	119	23,832	290,213
7/1/2031	156,944	82,076	7,625	54,799	129	27,765	329,338
8/1/2031	151,460	79,151	7,735	54,667	143	25,273	318,429
9/1/2031	120,207	69,558	7,826	51,871	153	20,942	270,556
10/1/2031	82,911	62,132	8,005	54,929	166	15,118	223,262
11/1/2031	75,537	56,526	7,904	50,474	174	11,127	201,742
12/1/2031	95,964	58,778	7,569	54,767	186	13,077	230,341
1/1/2032	95,712	59,281	7,945	55,689	182	13,227	232,036
2/1/2032	83,302	54,630	7,884	52,071	146	11,524	209,557
3/1/2032	78,560	59,128	8,182	54,305	155	12,914	213,245
4/1/2032	76,223	59,403	7,823	53,447	144	13,732	210,771
5/1/2032	99,096	70,808	7,965	51,790	126	19,682	249,467
6/1/2032	131,941	77,432	7,981	54,012	119	24,149	295,634
7/1/2032	161,208	83,325	7,624	54,798	129	28,121	335,206
8/1/2032	155,532	80,337	7,733	54,666	143	25,588	324,000
9/1/2032	123,765	70,627	7,825	51,871	153	21,199	275,440
10/1/2032	85,791	63,119	8,004	54,929	166	15,179	227,190
11/1/2032	78,319	57,448	7,903	50,474	174	10,967	205,285
12/1/2032	99,022	59,692	7,568	54,768	186	12,738	233,975
1/1/2033	98,366	60,219	7,945	55,689	182	13,289	235,690
2/1/2033	85,955	55,546	7,613	50,275	146	11,667	211,203
3/1/2033	81,143	60,117	8,182	54,305	155	13,232	217,134
4/1/2033	78,912	60,447	7,823	53,448	144	14,220	214,993
5/1/2033	102,214	71,958	7,966	51,790	126	20,253	254,308
6/1/2033	135,655	78,651	7,981	54,012	119	24,709	301,128
7/1/2033	165,319	84,590	7,624	54,798	129	28,621	341,082
8/1/2033	159,505	81,557	7,734	54,667	143	25,929	329,534
9/1/2033	127,229	71,724	7,825	51,871	153	21,350	280,151
10/1/2033	88,583	64,115	8,005	54,929	166	15,079	230,878
11/1/2033	80,952	58,409	7,904	50,474	174	10,684	208,596
12/1/2033	101,914	60,680	7,568	54,768	186	12,277	237,393
1/1/2034	101,270	61,244	7,945	55,689	182	12,822	239,152
2/1/2034	88,873	56,549	7,612	50,275	146	11,465	214,920

Table A1. UNSE Monthly Energy Forecast, MWh

Month	Residential	Commercial	Industrial	Mining	Other	System Losses	Total
3/1/2034	84,017	61,195	8,182	54,305	155	13,040	220,894
4/1/2034	81,893	61,565	7,823	53,448	144	14,207	219,079
5/1/2034	105,608	73,197	7,965	51,790	126	20,378	259,064
6/1/2034	139,628	79,981	7,981	54,012	119	24,862	306,583
7/1/2034	169,664	85,971	7,624	54,798	129	28,741	346,928
8/1/2034	163,687	82,884	7,733	54,667	143	25,924	335,038
9/1/2034	130,880	72,927	7,825	51,871	153	21,236	284,891
10/1/2034	91,556	65,227	8,005	54,929	166	14,718	234,601
11/1/2034	83,785	59,430	7,904	50,474	174	10,122	211,889
12/1/2034	104,995	61,703	7,568	54,768	186	11,554	240,773
1/1/2035	104,502	62,170	7,945	55,689	182	12,068	242,556
2/1/2035	92,109	57,478	7,613	50,275	146	11,019	218,639
3/1/2035	87,155	62,191	8,182	54,305	155	12,671	224,659
4/1/2035	85,130	62,598	7,823	53,448	144	14,078	223,222
5/1/2035	109,232	74,353	7,966	51,790	126	20,419	263,886
6/1/2035	143,812	81,217	7,981	54,012	119	24,940	312,082
7/1/2035	174,169	87,271	7,624	54,798	129	28,770	352,762
8/1/2035	167,989	84,139	7,734	54,667	143	25,850	340,522
9/1/2035	134,676	74,058	7,825	51,871	153	21,047	289,629
10/1/2035	94,651	66,265	8,005	54,929	166	14,314	238,331
11/1/2035	86,789	60,408	7,904	50,474	174	9,444	215,192
12/1/2035	108,238	62,691	7,568	54,768	186	10,638	244,089
1/1/2036	107,889	63,297	7,945	55,689	182	10,885	245,888
2/1/2036	95,493	58,548	7,884	52,071	146	10,445	224,588
3/1/2036	90,428	63,328	8,182	54,305	155	12,038	228,437
4/1/2036	88,483	63,774	7,823	53,448	144	13,786	227,457
5/1/2036	112,953	75,642	7,965	51,790	126	20,329	268,806
6/1/2036	148,091	82,575	7,981	54,012	119	24,855	317,634
7/1/2036	178,736	88,677	7,624	54,798	129	28,640	358,604
8/1/2036	172,350	85,494	7,734	54,667	143	25,622	346,009
9/1/2036	138,557	75,288	7,825	51,871	153	20,708	294,402
10/1/2036	97,862	67,404	8,005	54,929	166	13,747	242,114
11/1/2036	89,911	61,485	7,904	50,474	174	8,631	218,579
12/1/2036	111,590	63,783	7,568	54,768	186	9,599	247,493
1/1/2037	111,116	64,361	7,945	55,689	182	10,056	249,349
2/1/2037	98,747	59,594	7,613	50,275	146	9,920	226,295
3/1/2037	93,522	64,433	8,182	54,305	155	11,814	232,412
4/1/2037	91,696	64,915	7,823	53,448	144	13,891	231,918
5/1/2037	116,530	76,896	7,966	51,790	126	20,661	273,969
6/1/2037	152,217	83,905	7,981	54,012	119	25,209	323,444
7/1/2037	183,132	90,055	7,624	54,798	129	28,884	364,623
8/1/2037	176,523	86,828	7,734	54,667	143	25,793	351,687
9/1/2037	142,327	76,513	7,825	51,871	153	20,756	299,444
10/1/2037	100,999	68,549	8,005	54,929	166	13,522	246,171
11/1/2037	93,051	62,577	7,904	50,474	174	8,044	222,225
12/1/2037	114,999	64,889	7,568	54,768	186	8,726	251,136
1/1/2038	114,365	65,518	7,945	55,689	182	9,319	253,019
2/1/2038	102,040	60,737	7,613	50,275	146	9,711	230,522
3/1/2038	96,676	65,633	8,182	54,305	155	11,753	236,705
4/1/2038	94,980	66,157	7,823	53,448	144	14,188	236,740
5/1/2038	120,198	78,251	7,965	51,790	126	21,123	279,453
6/1/2038	156,471	85,330	7,981	54,012	119	25,611	329,524
7/1/2038	187,643	91,526	7,624	54,798	129	29,147	370,868
8/1/2038	180,879	88,251	7,734	54,667	143	25,832	357,504
9/1/2038	146,310	77,814	7,825	51,871	153	20,561	304,533
10/1/2038	104,333	69,763	8,005	54,929	166	13,003	250,199
11/1/2038	96,334	63,728	7,904	50,474	174	7,190	225,804
12/1/2038	118,545	66,053	7,568	54,768	186	7,514	254,633

Table A2. UNSE Monthly Coincident Peak Demand Forecast, MW

Month	Retail	EHV Losses	Total
1/1/2024	279	8	287
2/1/2024	253	6	260
3/1/2024	235	7	242
4/1/2024	272	6	278
5/1/2024	344	9	352
6/1/2024	429	11	439
7/1/2024	497	12	508
8/1/2024	449	11	460
9/1/2024	390	11	401
10/1/2024	296	9	305
11/1/2024	236	7	243
12/1/2024	279	7	287
1/1/2025	283	8	291
2/1/2025	260	7	267
3/1/2025	244	7	251
4/1/2025	280	6	287
5/1/2025	351	8	360
6/1/2025	439	12	451
7/1/2025	508	12	520
8/1/2025	473	11	485
9/1/2025	419	11	429
10/1/2025	320	10	330
11/1/2025	257	7	263
12/1/2025	302	7	309
1/1/2026	317	10	326
2/1/2026	294	8	302
3/1/2026	277	8	285
4/1/2026	314	7	320
5/1/2026	379	10	389
6/1/2026	471	12	483
7/1/2026	541	14	555
8/1/2026	490	12	502
9/1/2026	433	12	445
10/1/2026	336	10	346
11/1/2026	275	7	282
12/1/2026	318	7	325
1/1/2027	331	9	341
2/1/2027	312	8	320
3/1/2027	291	8	300
4/1/2027	330	8	339
5/1/2027	402	9	411
6/1/2027	493	13	506
7/1/2027	553	14	567
8/1/2027	509	12	521
9/1/2027	448	13	461
10/1/2027	347	10	357
11/1/2027	296	8	304
12/1/2027	337	8	345
1/1/2028	350	11	360
2/1/2028	328	9	337
3/1/2028	308	9	317
4/1/2028	344	8	352
5/1/2028	417	10	427
6/1/2028	509	13	522
7/1/2028	571	15	585
8/1/2028	527	13	540
9/1/2028	461	13	474
10/1/2028	362	11	373
11/1/2028	307	8	315
12/1/2028	351	8	359
1/1/2029	359	11	369

Table A2. UNSE Monthly Coincident Peak Demand Forecast, MW

Month	Retail	EHV Losses	Total
2/1/2029	332	9	341
3/1/2029	314	9	323
4/1/2029	356	9	364
5/1/2029	427	10	438
6/1/2029	519	14	533
7/1/2029	582	15	597
8/1/2029	536	14	550
9/1/2029	474	13	487
10/1/2029	377	11	388
11/1/2029	315	8	323
12/1/2029	356	8	364
1/1/2030	360	11	370
2/1/2030	334	10	344
3/1/2030	317	9	325
4/1/2030	355	8	363
5/1/2030	429	11	441
6/1/2030	518	14	532
7/1/2030	585	14	600
8/1/2030	538	14	551
9/1/2030	479	14	492
10/1/2030	380	12	391
11/1/2030	315	8	323
12/1/2030	359	8	367
1/1/2031	361	10	371
2/1/2031	336	10	346
3/1/2031	318	10	327
4/1/2031	355	8	363
5/1/2031	429	11	440
6/1/2031	521	14	535
7/1/2031	588	15	603
8/1/2031	541	14	554
9/1/2031	489	14	503
10/1/2031	381	12	393
11/1/2031	316	7	323
12/1/2031	361	9	369
1/1/2032	362	11	372
2/1/2032	340	9	349
3/1/2032	323	10	333
4/1/2032	363	8	371
5/1/2032	437	10	448
6/1/2032	531	14	545
7/1/2032	592	15	607
8/1/2032	547	14	561
9/1/2032	487	13	500
10/1/2032	381	12	392
11/1/2032	324	9	333
12/1/2032	366	8	374
1/1/2033	366	11	378
2/1/2033	344	9	353
3/1/2033	324	10	334
4/1/2033	365	8	373
5/1/2033	440	11	451
6/1/2033	534	14	548
7/1/2033	596	14	610
8/1/2033	552	14	566
9/1/2033	490	13	503
10/1/2033	381	12	392
11/1/2033	324	7	331
12/1/2033	368	8	376
1/1/2034	369	10	379
2/1/2034	344	10	353

Table A2. UNSE Monthly Coincident Peak Demand Forecast, MW

Month	Retail	EHV Losses	Total
3/1/2034	329	10	339
4/1/2034	367	8	375
5/1/2034	444	11	455
6/1/2034	538	14	551
7/1/2034	600	15	615
8/1/2034	556	14	570
9/1/2034	493	13	507
10/1/2034	385	12	397
11/1/2034	326	8	334
12/1/2034	368	8	377
1/1/2035	369	10	380
2/1/2035	344	8	352
3/1/2035	328	10	338
4/1/2035	372	9	381
5/1/2035	446	11	457
6/1/2035	542	14	556
7/1/2035	605	15	620
8/1/2035	559	13	572
9/1/2035	499	14	513
10/1/2035	393	12	405
11/1/2035	326	8	334
12/1/2035	367	8	375
1/1/2036	372	11	383
2/1/2036	346	10	356
3/1/2036	329	10	339
4/1/2036	369	8	378
5/1/2036	445	11	456
6/1/2036	539	14	553
7/1/2036	607	15	622
8/1/2036	559	15	574
9/1/2036	512	14	526
10/1/2036	395	11	406
11/1/2036	326	9	335
12/1/2036	369	9	379
1/1/2037	372	11	383
2/1/2037	350	9	359
3/1/2037	336	10	346
4/1/2037	377	9	386
5/1/2037	448	11	459
6/1/2037	544	14	558
7/1/2037	615	16	630
8/1/2037	564	15	579
9/1/2037	508	14	522
10/1/2037	397	11	409
11/1/2037	331	8	339
12/1/2037	372	9	381
1/1/2038	373	11	385
2/1/2038	355	9	363
3/1/2038	337	11	348
4/1/2038	379	9	388
5/1/2038	458	12	469
6/1/2038	553	15	568
7/1/2038	616	15	632
8/1/2038	569	15	584
9/1/2038	513	14	527
10/1/2038	397	12	409
11/1/2038	333	8	341
12/1/2038	375	10	385

Appendix B: Existing Resources

Existing Resources

This section provides an overview of UNSE's existing thermal generation, renewable generation, energy storage, and transmission resources. This chapter provides details on each 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 UNSE's existing transmission system is also detailed below.

UNSE's Existing Resource Portfolio

UNSE's existing thermal resource capacity is 289 MW. In addition, the Company also relies on the wholesale market for firm capacity PPAs to meet its summer peak demand obligations. **Table 1** provides a summary of UNSE's existing thermal resources.

Table 1 - UNSE Thermal Resources

Generating Station	Unit	Fuel Type	Net Nominal Capability (MW)	Commercial Operation Year	Operating Agent	UNSE's Ownership Share (%)	UNSE Planning Capacity (MW)
Valencia	1	Gas	14	1989	UNSE	100	14
Valencia	2	Gas	14	1989	UNSE	100	14
Valencia	3	Gas	14	1989	UNSE	100	14
Valencia	4	Gas	19	2006	UNSE	100	19
Black Mountain	1	Gas	45	2008	UNSE	100	45
Black Mountain	2	Gas	45	2008	UNSE	100	45
Gila River	3	Gas	550	2003	SRP	25	137.5
Total Planning Capacity							**288.5**

Valencia Power Plant

The Valencia Power Plant ("Valencia") is located in Nogales, Arizona and provides UNSE with 61 MW of combustion turbine capacity. All four of the Valencia units are owned by UNSE. Units 1 through 3 were acquired with the purchase from Citizens Utilities in 2003. They are rated at 14 MW each. Valencia Unit 4 is rated at 19 MW and was constructed in 2006.

Valencia Unit Profiles

Units	Capacity (MW)	In-Service Date	Planned Retirement
Unit 1	14	1989	Not Planned
Unit 2	14	1989	Not Planned
Unit 3	14	1989	Not Planned
Unit 4	19	2006	Not Planned

Valencia Fuel Supply

UNSE purchases natural gas on the spot market and through hedging contracts that are consistent with the Company's hedging policy. Natural gas is sourced from the Permian basin and is delivered through Kinder Morgan's El Paso interstate natural gas pipeline to the facility.

Valencia Pollution Controls

Valencia's combustion turbine Units 1-4 burn natural gas and diesel fuel, and each unit is equipped with water spray injection for control of oxides of nitrogen ("NOx"). Plant-wide emission limits of 250 tons per year for Sulfur Dioxide ("SO2") and NOx were incorporated into the Title V permit in order to maintain below "major source" thresholds. Each of the units is required to meet NSPS for NOx and SO2. However, each of these units is less than 25MW capacity; therefore, they are not subject to Acid Rain provisions.

Valencia Operational Outlook

The Valencia units are an added layer of reliability for UNSE's customers in Nogales. The service area's power needs are primarily met by market purchases and transmitted via the Vail to Valencia 138 KV line which went into service in 2014.

Black Mountain Generating Station

The Black Mountain Generating Station ("Black Mountain") is located approximately five miles south of Kingman, Arizona and provides UNSE with 90 MW of combustion turbine capacity from two units.

Black Mountain is wholly owned by UNSE.

Black Mountain Unit Profiles

Units	Capacity (MW)	In-Service Date	**Planned Retirement**
Unit 1	45	2008	Not Planned
Unit 2	45	2008	Not Planned

Black Mountain Fuel Supply

UNSE purchases natural gas on the spot market and through hedging contracts that are consistent with the Company's hedging policy. Natural gas is sourced from the San Juan basin and is delivered through Transwestern's interstate natural gas pipeline to the facility.

Black Mountain Pollution Controls

The Black Mountain units are natural gas-fired combustion turbines with dry Low NOx Burners for NOx control. As a greenfield site, a Prevention of Significant Deterioration (PSD) permit was obtained prior to construction. A PSD permit requires that Best Available Control Technology (BACT) be applied for control of SO2 and NOx, and the facility must comply with the Acid Rain program limits for SO2 and NOx.

Black Mountain Operational Outlook

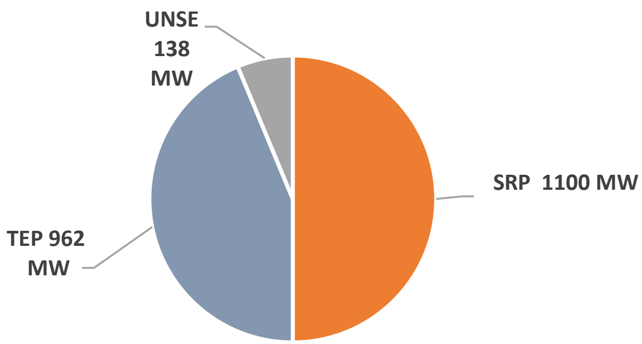
The Black Mountain units provide peaking capacity and reliability services to UNSE's Kingman and Lake Havasu Districts.

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 purchases natural gas on the spot market and through hedging contracts that are 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. Both Blocks will undergo upgrades with the potential to provide more capacity in the near future. 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.

Existing Renewable Resources

Over the last several years, UNSE has developed and constructed its own renewable energy resources as well as worked with third-party contractors to develop renewable resource projects within UNSE's service territory. The adjacent table provides UNSE's existing solar and wind renewable resources.

UNSE Solar Facilities Located at the Rio Rico High School

UNSE's Existing Solar and Wind Renewable Resources

Resource-Counterparty	Owned/ PPA	Technology	Location	Operator-Manufacturer	Capacity MWac
Western Wind	PPA	Wind	Kingman, AZ	Brookfield Renewable	10
La Senita School	Owned	SAT PV	Kingman, AZ	UNSE	1
Black Mountain	PPA	SAT PV	Kingman, AZ	Black Mountain, LLC	7
Rio Rico	Owned	Fixed PV	Rio Rico, AZ	UNSE	6
Red Horse Solar 3	PPA	SAT PV	Willcox, AZ	D. E. Shaw & Co., L.P. dba Red Horse III Solar	30
Jacobson Solar	Owned	Fixed PV	Kingman, AZ	UNSE	4
Grayhawk Solar	PPA	SAT PV	Kingman, AZ	D. E. Shaw & Co., L.P. dba Grayhawk Solar	46

Notes: PPA – Purchased Power Agreement - Energy is purchased from a third-party provider
Fixed PV – Fixed Photovoltaic – Stationary Solar Panel Technology
SAT PV – Single Axis Tracking Photovoltaic

UNSE Transmission Resources

Existing Transmission Resources

UNSE's existing transmission system as constructed is contained within two service areas in Arizona, Mohave and Santa Cruz Counties.

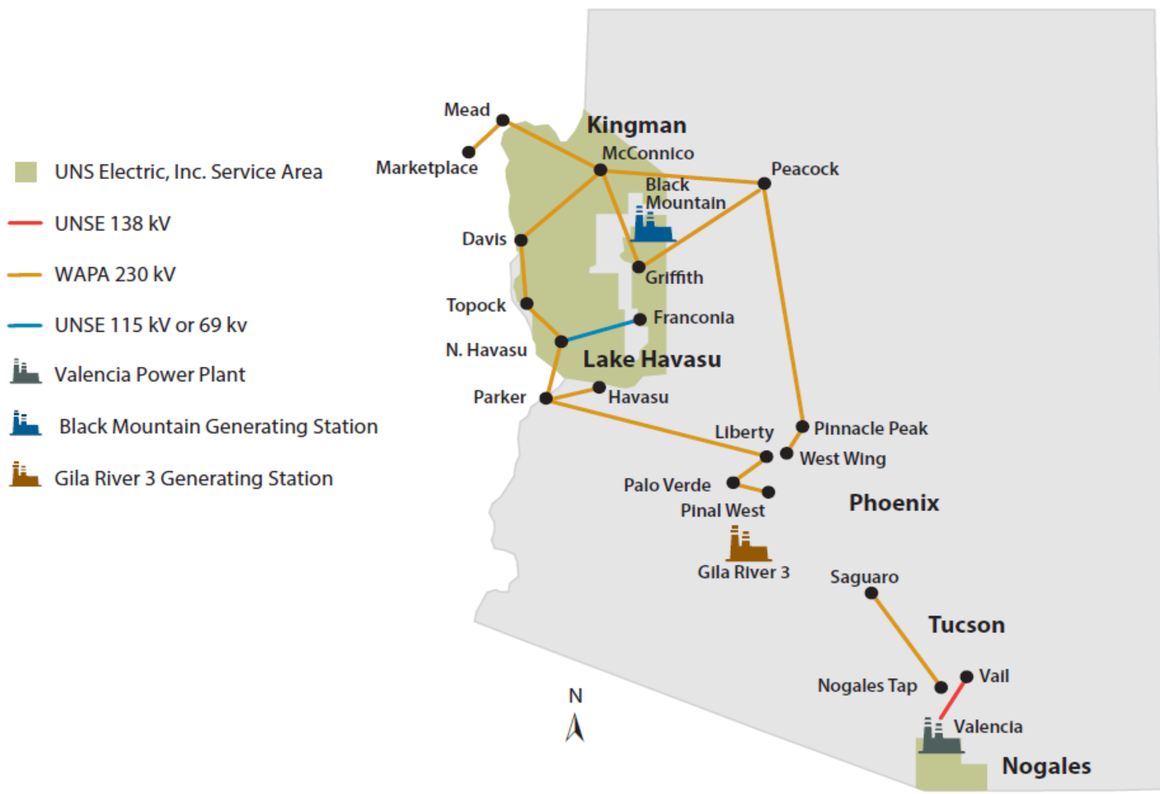
Mohave County Transmission Overview

The UNSE-Mohave service territory is supplied by WAPA's 230 kV network which is interconnected to the Extra High Voltage (EHV) transmission system via three substations: Mead, Liberty and Peacock. Firm system purchases designated as Network Resources are delivered to the Pinnacle Peak and Liberty substations. UNSE-Mohave receives Network Integration Transmission Service (NITS) from WAPA at several 230 kV points of delivery including Hilltop, McConnico, Black Mesa, North Havasu, and Griffith. These substations interconnect and supply energy to the local system. UNSE also purchases point-to-point transmission from WAPA and other providers in the region as needed.

Santa Cruz County Transmission Overview

UNSE delivers power to TEP's Vail Substation via NITS to serve the Santa Cruz load. UNSE owns the 60 miles of 138 kV transmission line between the Vail Substation, located southeast of Tucson, and the Valencia Substation in Nogales, Arizona. The 138 kV line serves the local distribution grid located in Santa Cruz County which includes the City of Nogales.

Overview of UNSE Resources

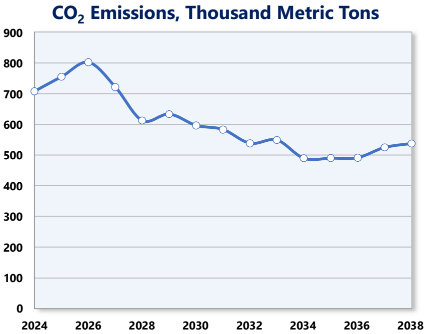


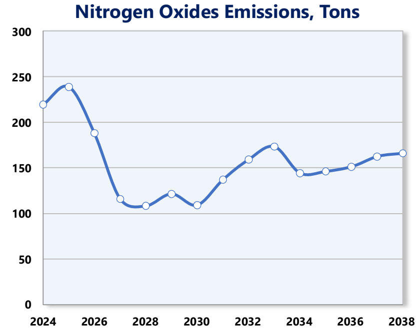
Appendix C: Portfolio Summaries

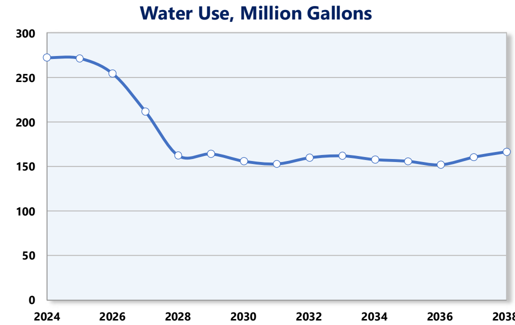
Portfolio ID - P01

Portfolio Description - Solar + Storage Portfolio

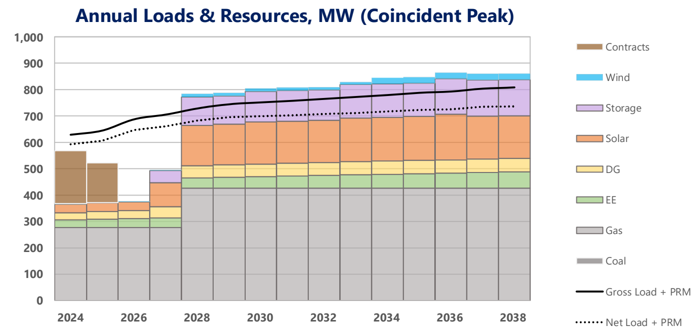
Environmental Dashboard

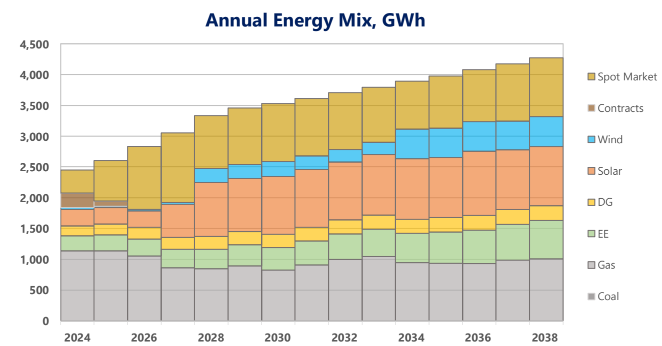


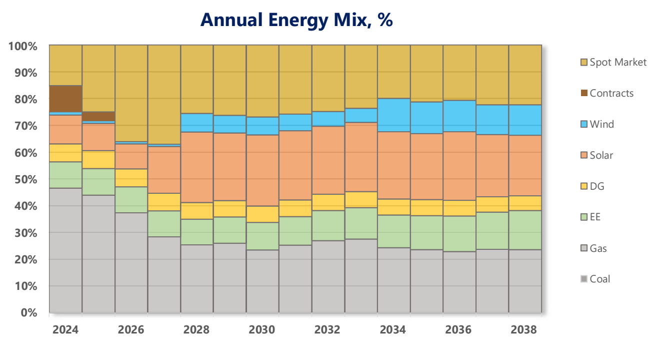


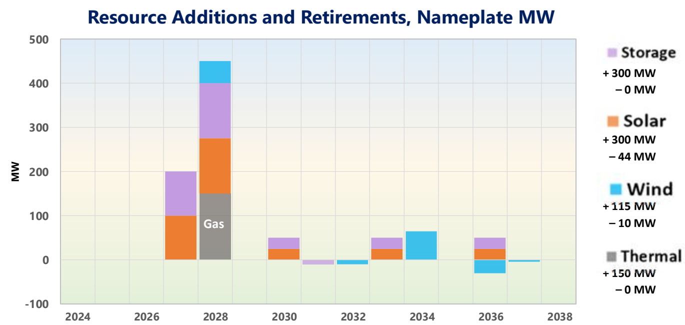


Loads & Resources Dashboard



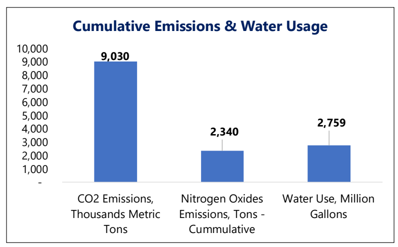






Annual Loads & Resources, MW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Gross Load + PRM	628	644	687	704	728	744	751	757	764	771	779	787	792	804	807
Net Load + PRM	592	606	646	660	682	695	699	702	707	711	717	723	725	735	736
Coal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas	277	277	277	277	427	427	427	427	427	427	427	427	427	427	427
Wind	2	2	2	2	12	12	12	12	10	10	23	23	23	23	23
Solar	33	33	33	91	153	153	160	160	160	166	166	166	173	163	161
Storage	-	-	-	46	107	107	115	115	115	126	126	126	135	137	137
DG	27	29	31	43	46	48	48	48	49	50	50	51	50	51	51
EE	30	32	34	36	38	41	43	45	48	50	52	54	57	59	61

Total NPVRR:	$2,884,398
Fuel NPVRR:	$1,171,570
Non-Fuel NP'	$1,712,828

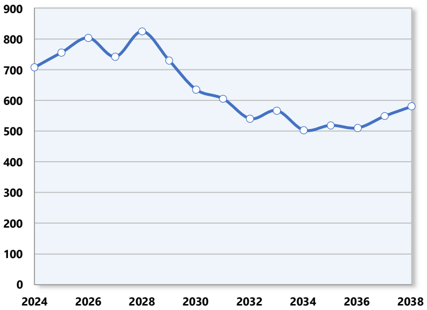


Annual Loads & Resources, GWh	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Gross Energy	2,447	2,597	2,832	3,048	3,329	3,452	3,531	3,610	3,703	3,795	3,890	3,972	4,077	4,171	4,269
Coal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas	1,137	1,139	1,056	865	846	896	828	910	998	1,045	946	935	930	987	1,007
Wind	27	26	27	27	232	229	237	223	206	201	485	475	475	463	484
Solar	266	263	263	534	875	871	939	935	937	980	978	978	1,047	970	961
DG	163	176	189	198	207	213	218	223	228	230	232	234	237	237	238
EE	242	258	276	295	317	338	362	387	416	444	475	508	545	582	623

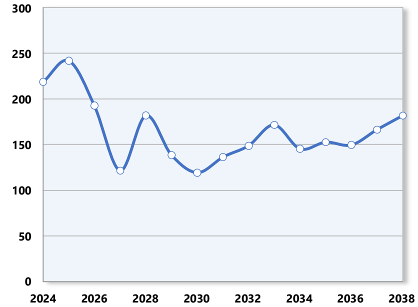
Portfolio ID - P02
Portfolio Description - Balanced Portfolio

Environmental Dashboard

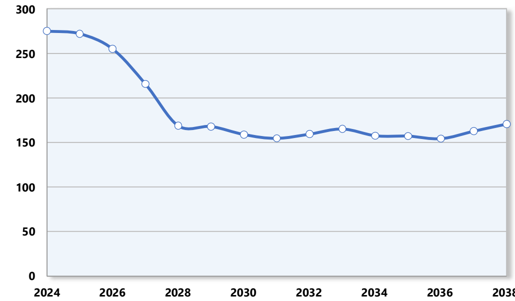
CO_2 Emissions, Thousand Metric Tons



Nitrogen Oxides Emissions, Tons

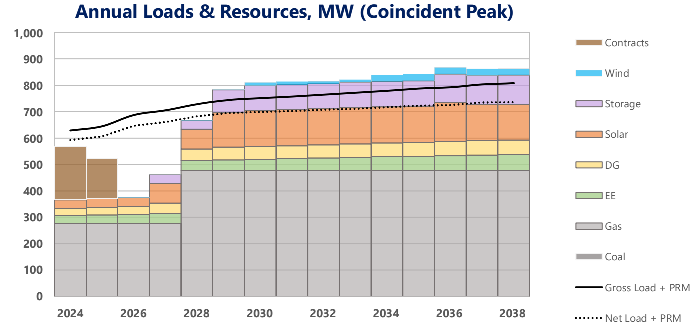


Water Use, Million Gallons

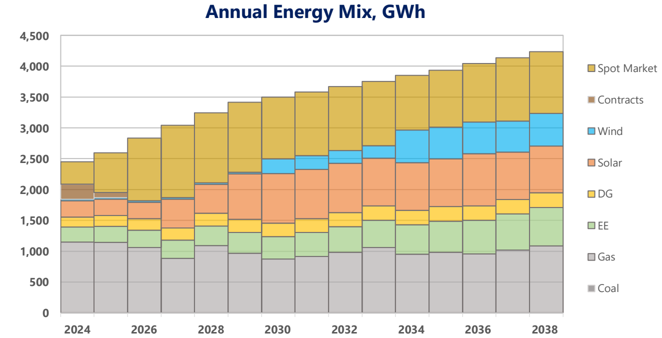


Loads & Resources Dashboard

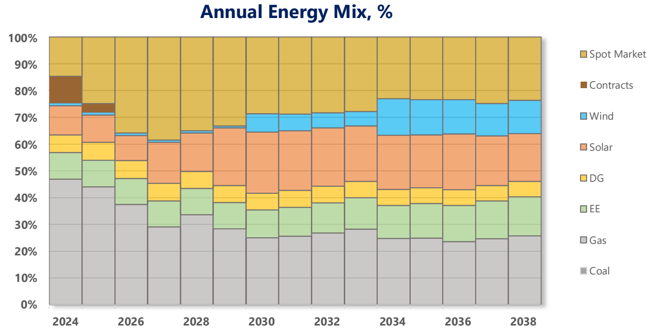
Annual Loads & Resources, MW (Coincident Peak)



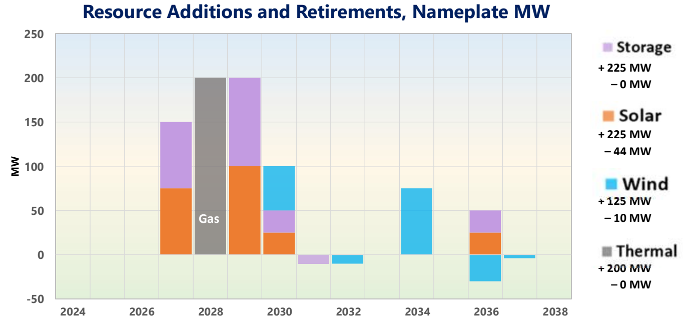
Annual Energy Mix, GWh



Annual Energy Mix, %



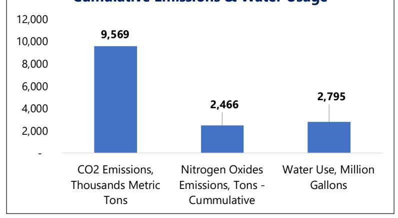
Resource Additions and Retirements, Nameplate MW



Annual Loads & Resources, MW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Gross Load + PRM	628	644	687	704	728	744	751	757	764	771	779	787	792	804	807
Net Load + PRM	592	606	646	660	682	695	699	702	707	711	717	723	725	735	736
Coal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas	277	277	277	277	477	477	477	477	477	477	477	477	477	477	477
Wind	2	2	2	2	2	2	12	12	10	10	25	25	25	25	25
Solar	33	33	33	75	75	132	138	138	138	137	137	137	148	137	135
Storage	-	-	-	33	33	85	93	93	93	96	96	96	107	110	110
DG	27	29	31	41	43	49	48	49	50	52	52	53	53	54	55
EE	30	32	34	36	38	41	43	45	48	50	52	54	57	59	61

Total NPVRR:	**$2,860,842**
Fuel NPVRR:	$1,227,484
Non-Fuel NP'	$1,633,358

Cumulative Emissions & Water Usage



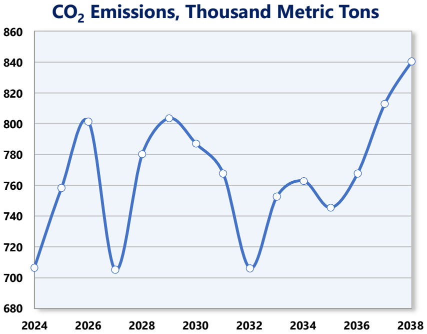
Annual Loads & Resources, GWh	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Gross Energy	2,448	2,596	2,832	3,037	3,244	3,412	3,500	3,580	3,668	3,752	3,849	3,934	4,041	4,135	4,233
Coal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas	1,148	1,143	1,061	883	1,092	966	875	917	981	1,058	954	979	955	1,021	1,087
Wind	27	26	27	27	26	27	237	223	206	201	527	516	516	504	526
Solar	266	263	263	466	466	736	802	799	800	776	775	774	842	766	757
DG	163	176	189	198	207	213	218	223	228	230	232	234	237	237	238
EE	242	258	276	295	317	338	362	387	416	444	475	508	545	582	623

Portfolio ID - P03

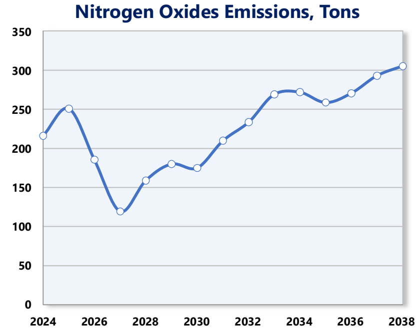
Portfolio Description - 350 MW Gas Portfolio

Environmental Dashboard

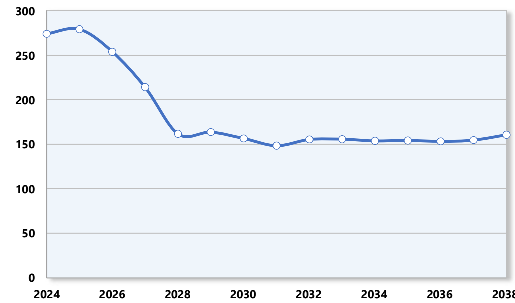
CO_2 Emissions, Thousand Metric Tons



Nitrogen Oxides Emissions, Tons

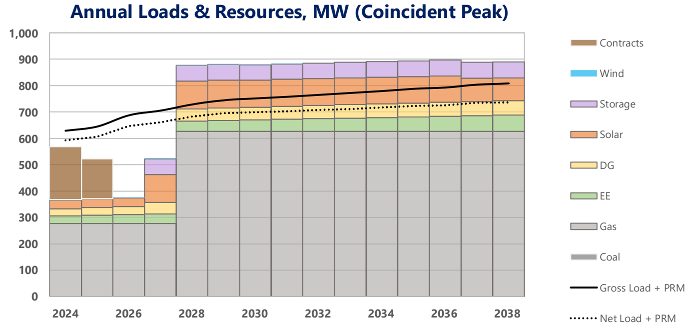


Water Use, Million Gallons

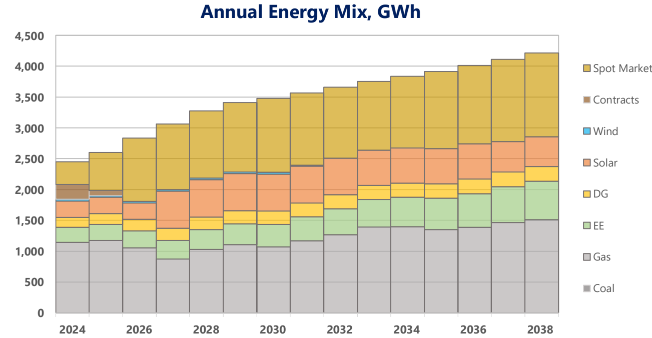


Loads & Resources Dashboard

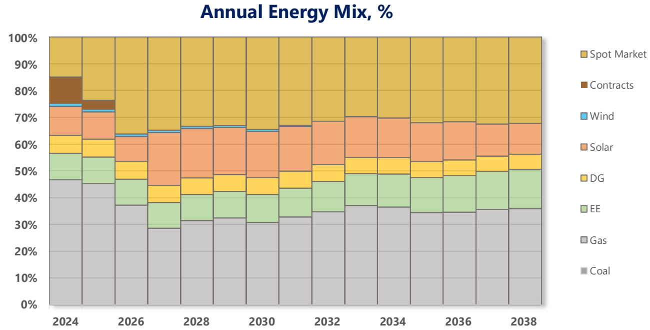
Annual Loads & Resources, MW (Coincident Peak)



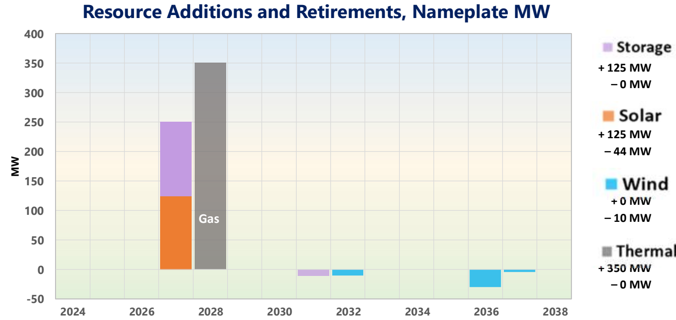
Annual Energy Mix, GWh



Annual Energy Mix, %



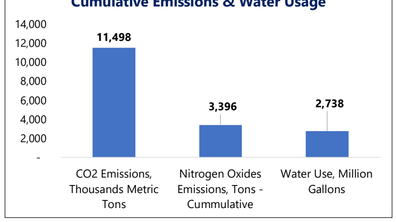
Resource Additions and Retirements, Nameplate MW



Annual Loads & Resources, MW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Gross Load + PRM	628	644	687	704	728	744	751	757	764	771	779	787	792	804	807
Net Load + PRM	592	606	646	660	682	695	699	702	707	711	717	723	725	735	736
Coal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas	277	277	277	277	627	627	627	627	627	627	627	627	627	627	627
Wind	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-
Solar	33	33	33	105	105	105	103	103	103	100	100	100	100	88	86
Storage	-	-	-	60	60	60	58	58	58	60	60	60	60	61	61
DG	27	29	31	44	46	48	48	49	50	51	52	52	53	54	55
EE	30	32	34	36	38	41	43	45	48	50	52	54	57	59	61

Total NPVRR:	**$2,929,589**
Fuel NPVRR:	$1,296,590
Non-Fuel NP'	$1,632,999

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	2,447	2,597	2,832	3,064	3,275	3,411	3,476	3,567	3,656	3,751	3,834	3,914	4,009	4,110	4,213
Coal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas	1,142	1,174	1,053	876	1,030	1,106	1,071	1,169	1,270	1,391	1,397	1,351	1,388	1,463	1,509
Wind	27	26	27	27	26	27	27	18	-	-	-	-	-	-	-
Solar	266	263	263	602	602	598	598	595	596	572	571	570	570	494	484
DG	163	176	189	198	207	213	218	223	228	230	232	234	237	237	238
EE	242	258	276	295	317	338	362	387	416	444	475	508	545	582	623

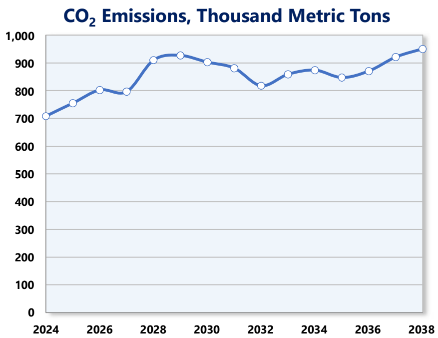
2023 Integrated Resource Plan

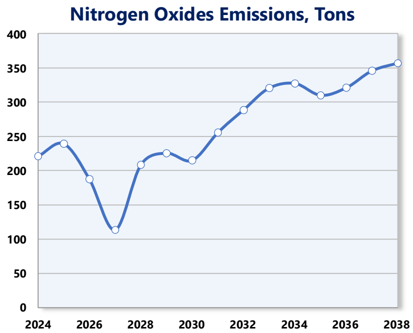
UniSource Energy SERVICES

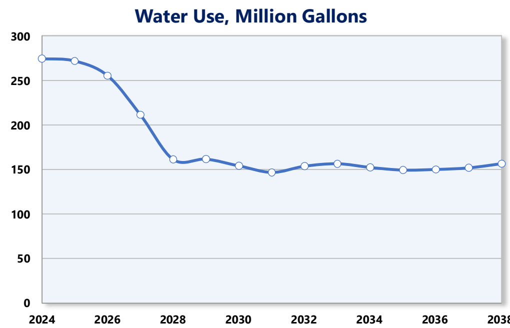
Portfolio ID - P04

Portfolio Description - 450MW Gas Portfolio

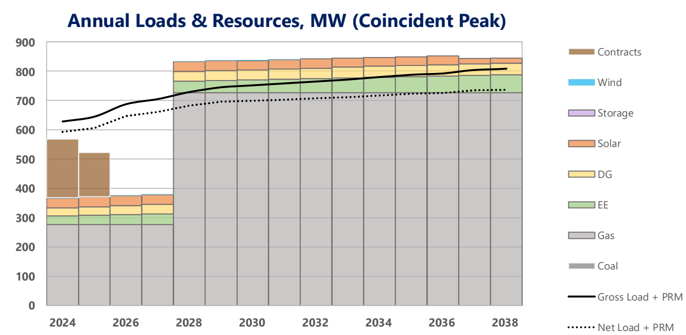
Environmental Dashboard

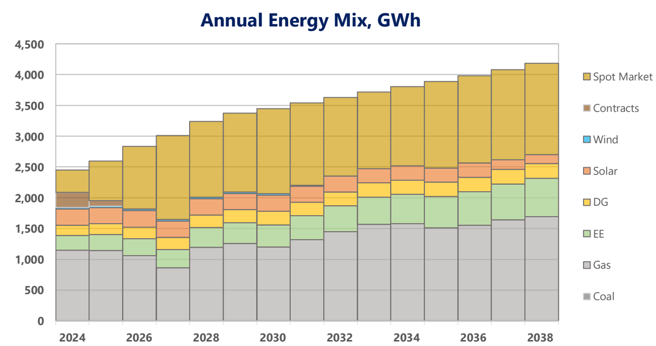


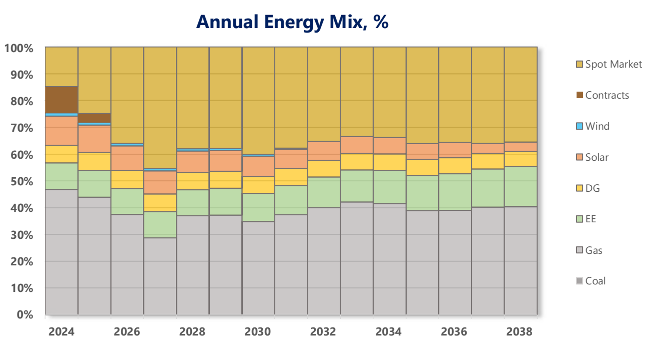


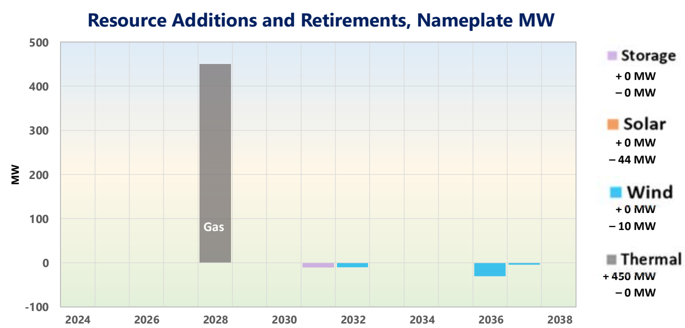


Loads & Resources Dashboard



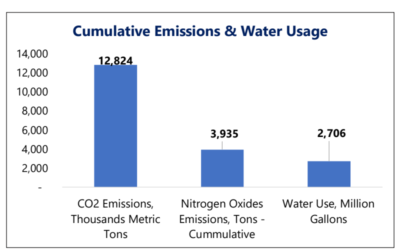






Annual Loads & Resources, MW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Gross Load + PRM	628	644	687	704	728	744	751	757	764	771	779	787	792	804	807
Net Load + PRM	592	606	646	660	682	695	699	702	707	711	717	723	725	735	736
Coal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas	277	277	277	277	727	727	727	727	727	727	727	727	727	727	727
Wind	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-
Solar	33	33	33	33	33	33	32	32	32	30	30	30	30	19	18
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DG	27	29	31	32	33	34	34	35	35	37	38	38	38	38	39
EE	30	32	34	36	38	41	43	45	48	50	52	54	57	59	61

Total NPVRR:	$2,895,276
Fuel NPVRR:	$1,381,648
Non-Fuel NP'	$1,513,628



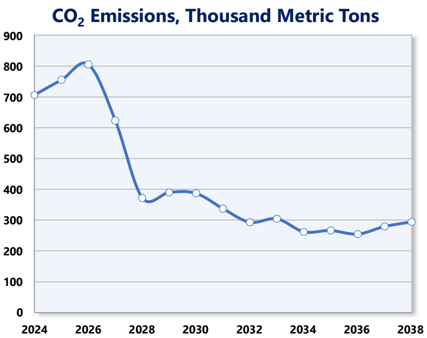
Annual Loads & Resources, GWh	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Gross Energy	2,449	2,596	2,832	3,010	3,238	3,373	3,442	3,537	3,629	3,715	3,804	3,883	3,977	4,079	4,180
Coal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas	1,146	1,142	1,060	864	1,196	1,257	1,199	1,319	1,451	1,566	1,580	1,512	1,551	1,641	1,691
Wind	27	26	27	27	26	27	27	18	-	-	-	-	-	-	-
Solar	266	263	263	262	261	259	258	255	255	232	230	229	229	154	144
DG	163	176	189	198	207	213	218	223	228	230	232	234	237	237	238
EE	242	258	276	295	317	338	362	387	416	444	475	508	545	582	623

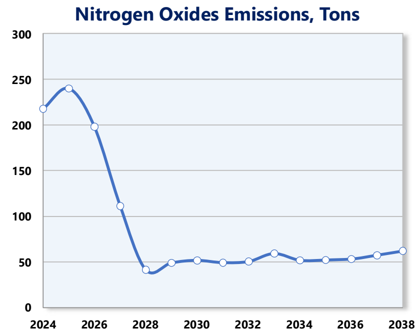
2023 Integrated Resource Plan

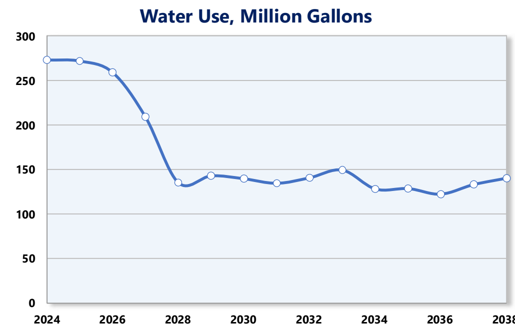
Portfolio ID - P05

Portfolio Description - No New Gas Portfolio

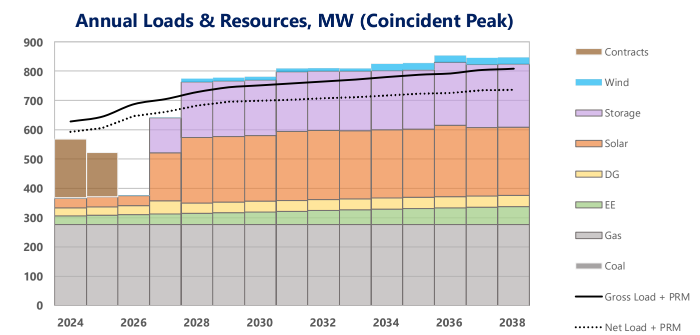
Environmental Dashboard

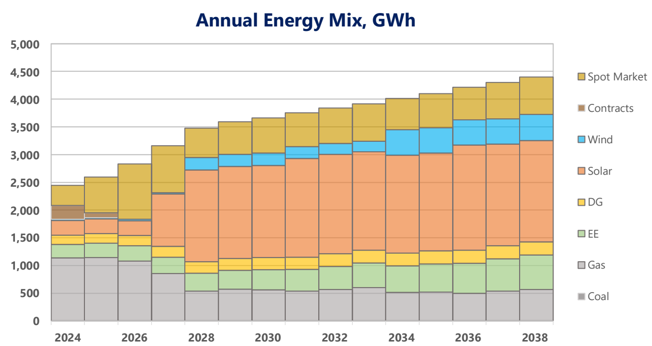


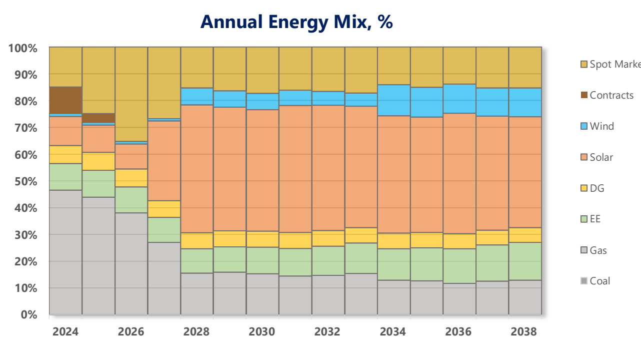


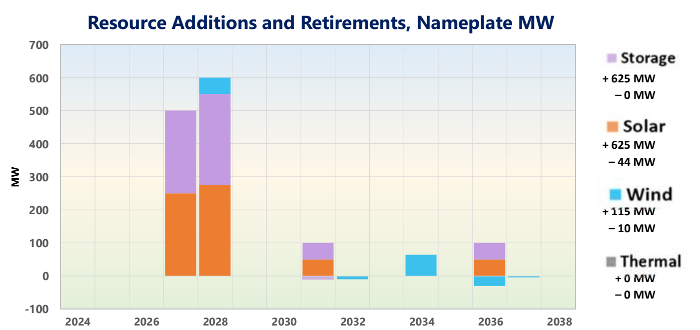


Loads & Resources Dashboard



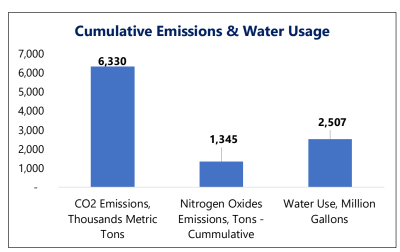






Annual Loads & Resources, MW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Gross Load + PRM	628	644	687	704	728	744	751	757	764	771	779	787	792	804	807
Net Load + PRM	592	606	646	660	682	695	699	702	707	711	717	723	725	735	736
Coal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas	277	277	277	277	277	277	277	277	277	277	277	277	277	277	277
Wind	2	2	2	2	12	12	12	12	10	10	23	23	23	23	23
Solar	33	33	33	164	223	223	223	236	236	232	232	232	244	234	232
Storage	-	-	-	119	189	189	189	202	202	202	202	202	215	215	215
DG	27	29	31	44	35	36	37	37	38	38	38	39	38	38	38
EE	30	32	34	36	38	41	43	45	48	50	52	54	57	59	61

Total NPVRR:	$3,060,665
Fuel NPVRR:	$1,007,035
Non-Fuel NP'	$2,053,629

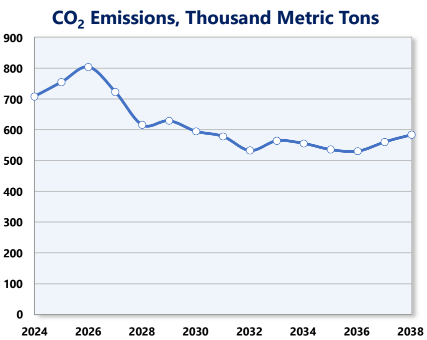


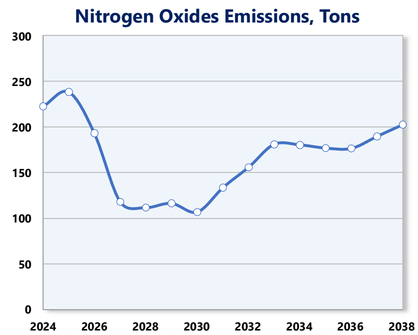
Annual Loads & Resources, GWh	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Gross Energy	2,445	2,597	2,832	3,161	3,474	3,592	3,660	3,752	3,837	3,915	4,014	4,096	4,212	4,300	4,400
Coal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas	1,139	1,142	1,078	854	541	574	562	541	566	602	517	519	495	539	568
Wind	27	26	27	27	223	219	226	214	198	194	464	455	460	452	473
Solar	266	263	263	942	1,658	1,660	1,659	1,779	1,793	1,771	1,762	1,766	1,892	1,831	1,824
DG	163	176	189	198	207	213	218	223	228	230	232	234	237	237	238
EE	242	258	276	295	317	338	362	387	416	444	475	508	545	582	623

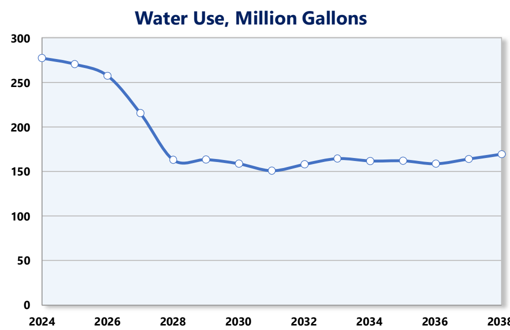
Portfolio ID - P06

Portfolio Description - Heavy Solar Portfolio

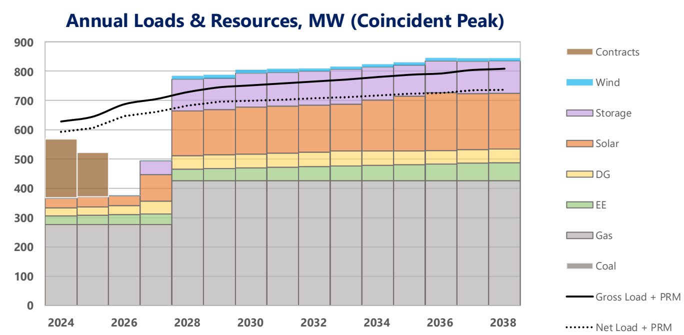
Environmental Dashboard

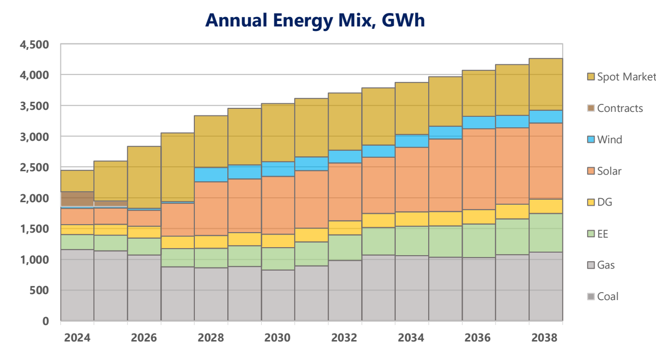


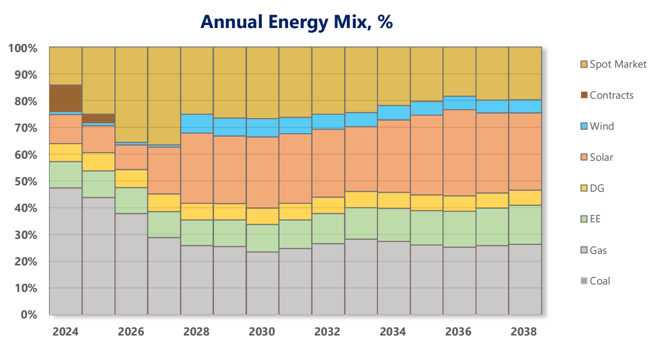


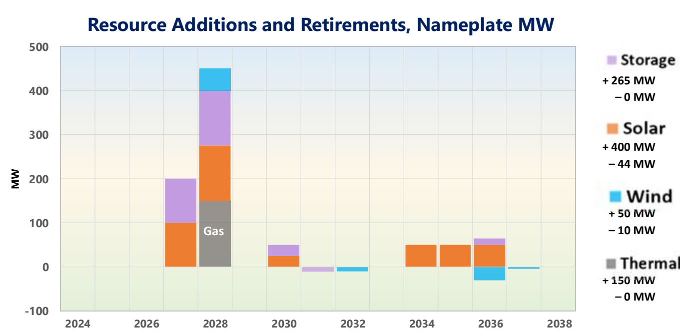


Loads & Resources Dashboard



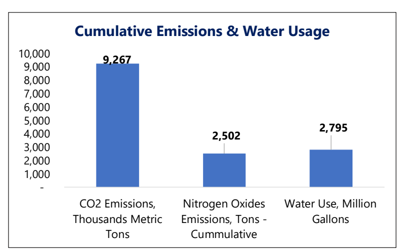






Annual Loads & Resources, MW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Gross Load + PRM	628	644	687	704	728	744	751	757	764	771	779	787	792	804	807
Net Load + PRM	592	606	646	660	682	695	699	702	707	711	717	723	725	735	736
Coal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas	277	277	277	277	427	427	427	427	427	427	427	427	427	427	427
Wind	2	2	2	2	12	12	12	12	10	10	10	10	10	10	10
Solar	33	33	33	91	153	153	160	160	160	159	173	186	198	191	189
Storage	-	-	-	46	107	107	115	115	115	119	112	107	108	111	111
DG	27	29	31	43	46	48	48	48	49	51	49	47	45	46	47
EE	30	32	34	36	38	41	43	45	48	50	52	54	57	59	61

Total NPVRR:	**$2,869,974**
Fuel NPVRR:	$1,199,026
Non-Fuel NP'	$1,670,948



Annual Loads & Resources, GWh	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Gross Energy	2,447	2,596	2,832	3,049	3,330	3,451	3,529	3,608	3,699	3,784	3,869	3,963	4,070	4,159	4,259
Coal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas	1,158	1,136	1,070	881	861	882	827	893	983	1,070	1,061	1,032	1,028	1,074	1,119
Wind	27	26	27	27	232	229	237	223	206	201	211	205	202	200	210
Solar	266	263	263	534	875	872	939	935	937	912	1,047	1,179	1,309	1,240	1,231
DG	163	176	189	198	207	213	218	223	228	230	232	234	237	237	238
EE	242	258	276	295	317	338	362	387	416	444	475	508	545	582	623

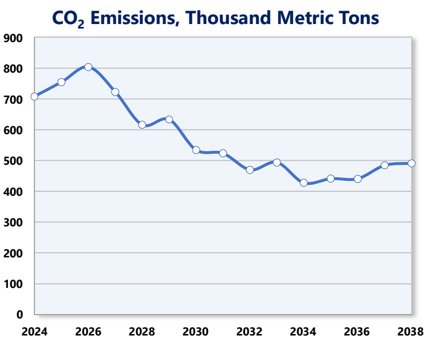
UniSource Energy SERVICES

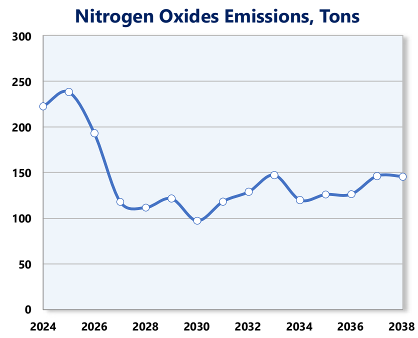
2023 Integrated Resource Plan

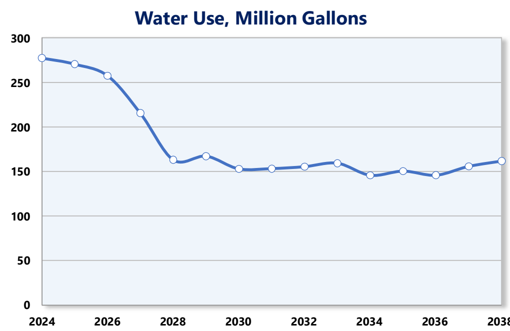
Portfolio ID - P07

Portfolio Description - Heavy Wind Portfolio

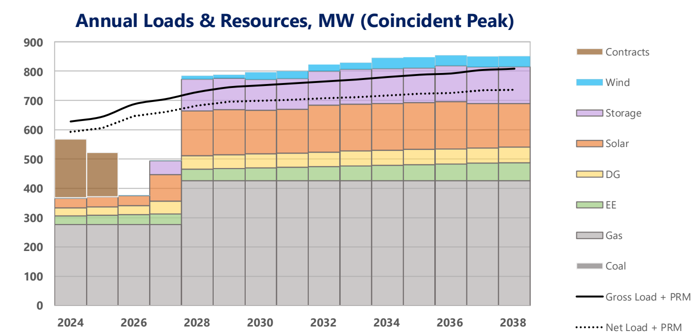
Environmental Dashboard

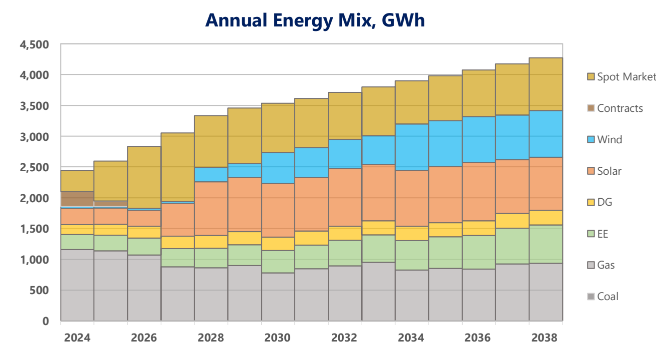


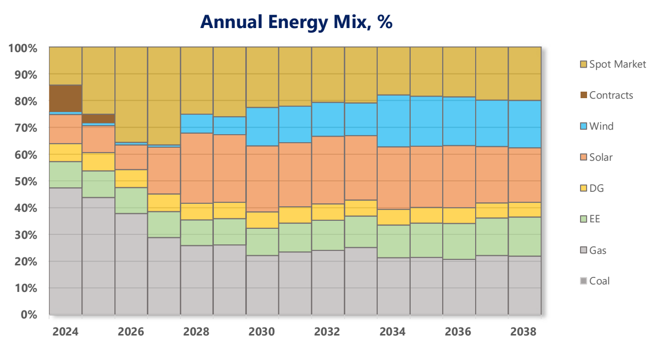


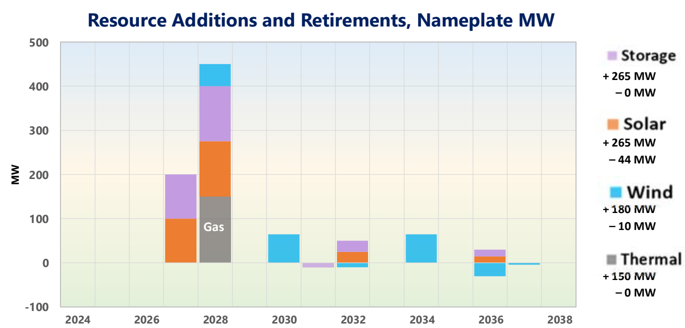


Loads & Resources Dashboard





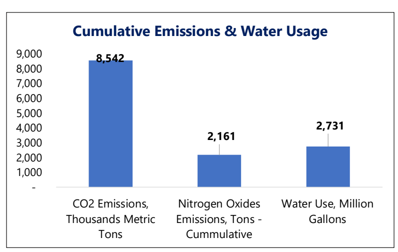




Annual Loads & Resources, MW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Gross Load + PRM	628	644	687	704	728	744	751	757	764	771	779	787	792	804	807
Net Load + PRM	592	606	646	660	682	695	699	702	707	711	717	723	725	735	736
Coal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas	277	277	277	277	427	427	427	427	427	427	427	427	427	427	427
Wind	2	2	2	2	12	12	25	25	23	23	36	36	36	36	36
Solar	33	33	33	91	153	153	149	149	160	159	159	159	161	151	149
Storage	-	-	-	46	107	107	104	104	115	119	119	119	122	125	125
DG	27	29	31	43	46	48	48	49	49	51	52	52	51	52	53
EE	30	32	34	36	38	41	43	45	48	50	52	54	57	59	61

Total NPVRR:	$2,857,557
Fuel NPVRR:	$1,143,589
Non-Fuel NP'	$1,713,968

Annual Loads & Resources, GWh	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Gross Energy	2,447	2,596	2,832	3,049	3,330	3,452	3,534	3,611	3,712	3,796	3,896	3,978	4,074	4,168	4,267
Coal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas	1,158	1,136	1,070	881	861	901	780	846	893	954	829	855	844	923	933
Wind	27	26	27	27	232	229	508	490	473	463	755	741	742	725	758
Solar	266	263	263	534	875	872	870	867	937	912	908	909	950	874	865
DG	163	176	189	198	207	213	218	223	228	230	232	234	237	237	238
EE	242	258	276	295	317	338	362	387	416	444	475	508	545	582	623

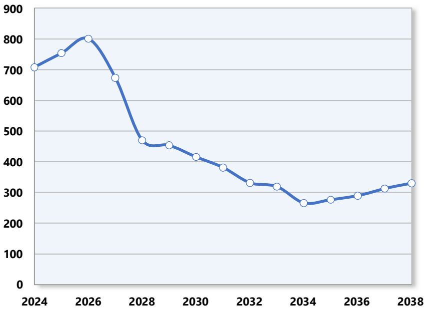


2023 Integrated Resource Plan

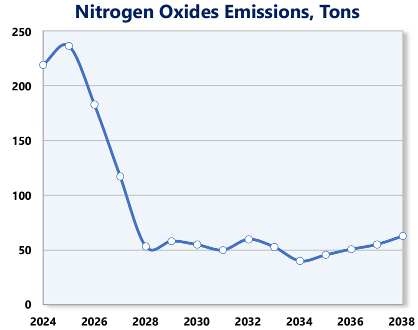
Portfolio ID - P08
Portfolio Description - Pumped Hydro Portfolio

Environmental Dashboard

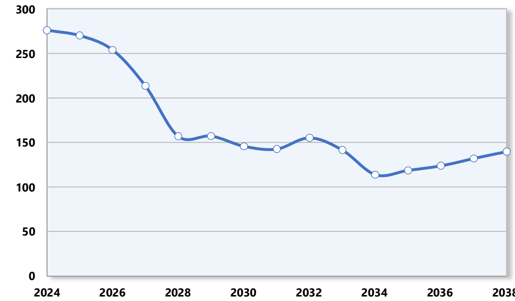
CO_2 Emissions, Thousand Metric Tons



Nitrogen Oxides Emissions, Tons

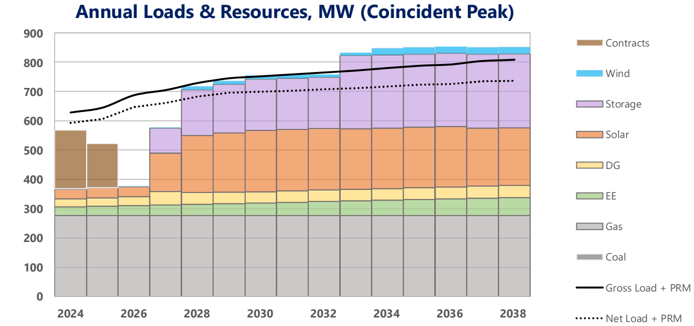


Water Use, Million Gallons

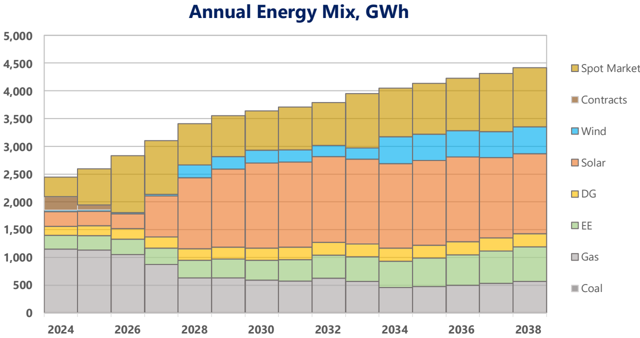


Loads & Resources Dashboard

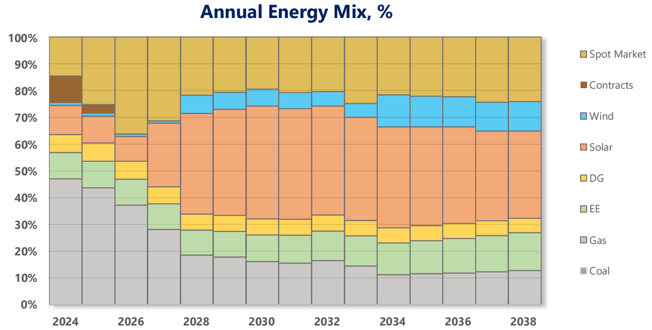
Annual Loads & Resources, MW (Coincident Peak)



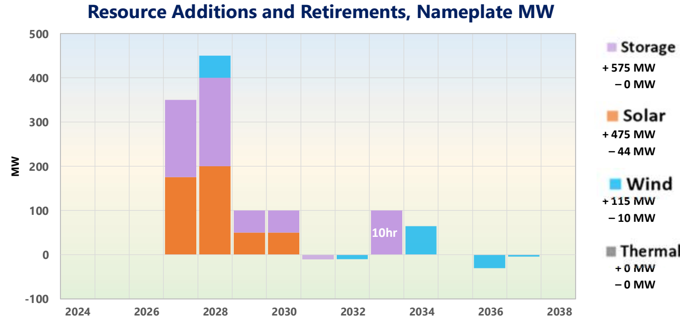
Annual Energy Mix, GWh



Annual Energy Mix, %



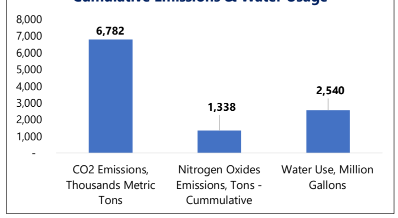
Resource Additions and Retirements, Nameplate MW



Annual Loads & Resources, MW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Gross Load + PRM	628	644	687	704	728	744	751	757	764	771	779	787	792	804	807
Net Load + PRM	592	606	646	660	682	695	699	702	707	711	717	723	725	735	736
Coal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas	277	277	277	277	277	277	277	277	277	277	277	277	277	277	277
Wind	2	2	2	2	12	12	12	12	10	10	23	23	23	23	23
Solar	33	33	33	132	195	202	210	210	210	206	206	206	206	198	196
Storage	-	-	-	85	155	165	175	175	175	250	250	250	250	252	252
DG	27	29	31	45	40	39	38	39	39	40	40	40	41	41	42
EE	30	32	34	36	38	41	43	45	48	50	52	54	57	59	61

Total NPVRR:	**$3,021,326**
Fuel NPVRR:	$1,033,680
Non-Fuel NP'	$1,987,646

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	2,449	2,596	2,832	3,103	3,405	3,548	3,638	3,705	3,788	3,876	3,973	4,056	4,149	4,239	4,340
Coal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas	1,151	1,134	1,053	873	630	633	587	573	626	570	457	478	500	533	566
Wind	27	26	27	27	230	225	230	218	202	201	484	475	475	463	484
Solar	266	263	263	738	1,280	1,406	1,534	1,531	1,542	1,525	1,523	1,523	1,525	1,447	1,437
DG	163	176	189	198	207	213	218	223	228	230	232	234	237	237	238
EE	242	258	276	295	317	338	362	387	416	444	475	508	545	582	623

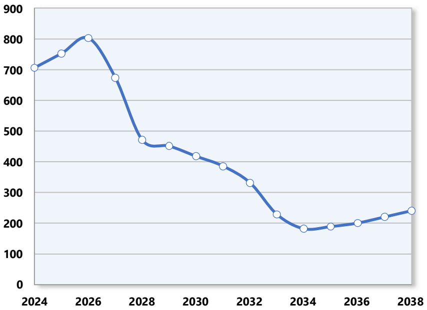
2023 Integrated Resource Plan

UniSource Energy SERVICES

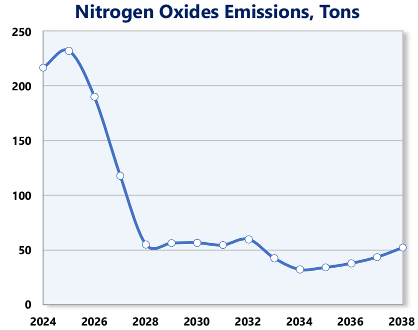
Portfolio ID - P09
Portfolio Description - Small Modular Reactors Portfolio

Environmental Dashboard

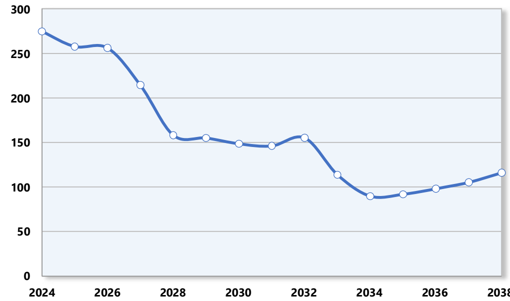
CO_2 Emissions, Thousand Metric Tons



Nitrogen Oxides Emissions, Tons

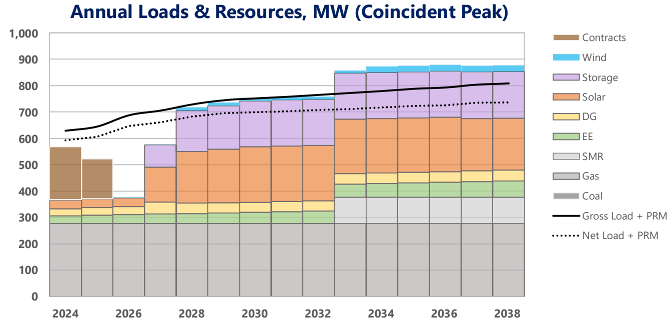


Water Use, Million Gallons

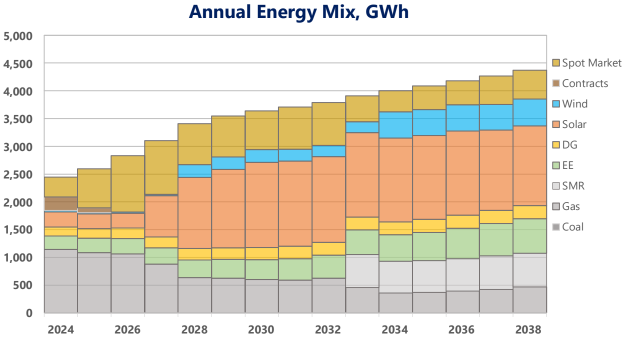


Loads & Resources Dashboard

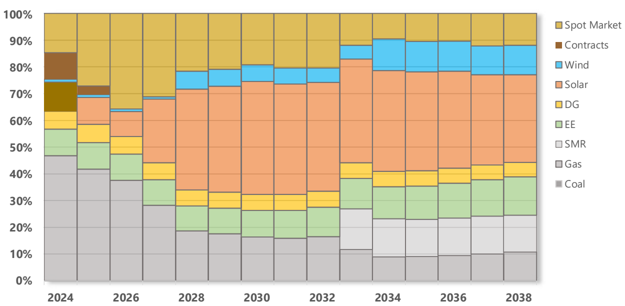
Annual Loads & Resources, MW (Coincident Peak)



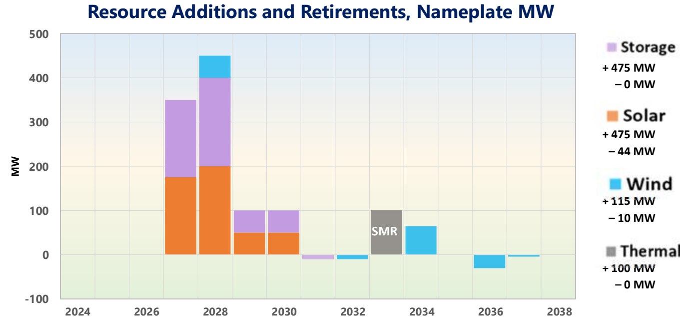
Annual Energy Mix, GWh



Annual Energy Mix, %



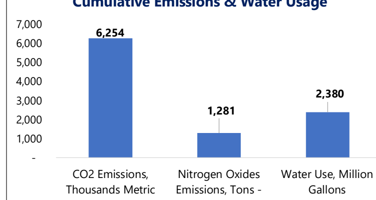
Resource Additions and Retirements, Nameplate MW



Annual Loads & Resources, MW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Gross Load + PRM	628	644	687	704	728	744	751	757	764	771	779	787	792	804	807
Net Load + PRM	592	606	646	660	682	695	699	702	707	711	717	723	725	735	736
Coal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas	277	277	277	277	277	277	277	277	277	277	277	277	277	277	277
Wind	2	2	2	2	12	12	12	12	10	10	23	23	23	23	23
Solar	33	33	33	132	195	202	210	210	210	206	206	206	206	198	196
Storage	-	-	-	85	155	165	175	175	175	175	175	175	175	177	177
DG	27	29	31	45	40	39	38	39	39	40	40	40	41	41	42
EE	30	32	34	36	38	41	43	45	48	50	52	54	57	59	61

Total NPVRR:	$3,109,688
Fuel NPVRR:	$1,016,685
Non-Fuel NP'	$2,093,003

Cumulative Emissions & Water Usage



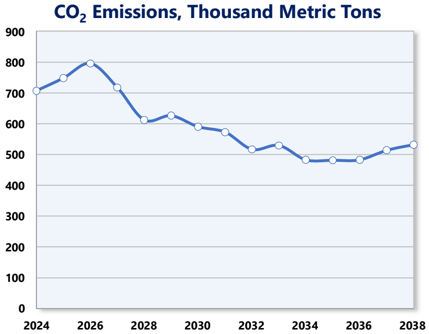
Annual Loads & Resources, GWh	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Gross Energy	2,446	2,596	2,832	3,102	3,406	3,547	3,639	3,706	3,788	3,908	4,004	4,085	4,179	4,266	4,367
Coal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas	1,145	1,084	1,064	877	636	624	598	589	626	458	360	369	395	425	470
Wind	27	26	27	27	230	225	230	218	202	199	476	466	469	460	481
Solar	266	263	263	738	1,280	1,406	1,534	1,531	1,542	1,518	1,508	1,510	1,516	1,443	1,434
DG	163	176	189	198	207	213	218	223	228	230	232	234	237	237	238
EE	242	258	276	295	317	338	362	387	416	444	475	508	545	582	623

Portfolio ID - P10

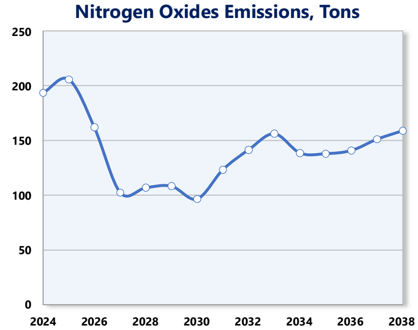
Portfolio Description - Market and Transmission Remission Portfolio

Environmental Dashboard

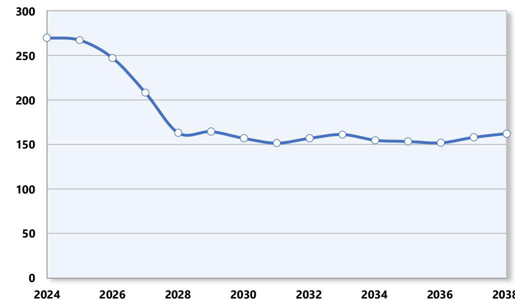
CO_2 Emissions, Thousand Metric Tons



Nitrogen Oxides Emissions, Tons

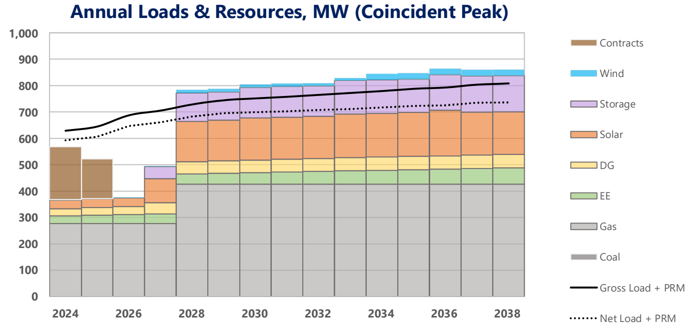


Water Use, Million Gallons

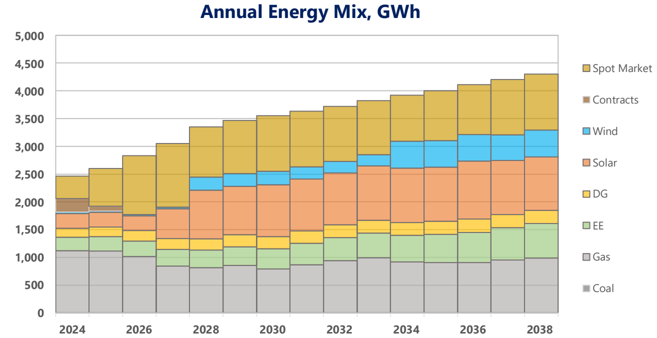


Loads & Resources Dashboard

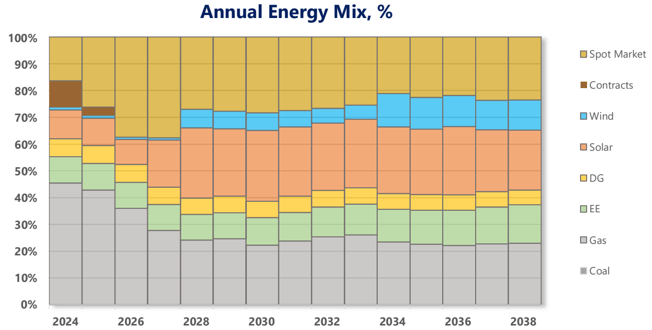
Annual Loads & Resources, MW (Coincident Peak)



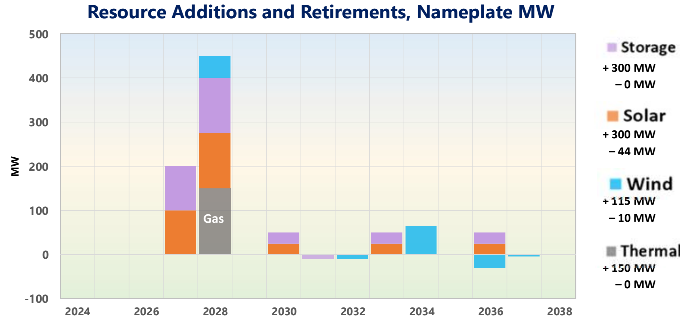
Annual Energy Mix, GWh



Annual Energy Mix, %



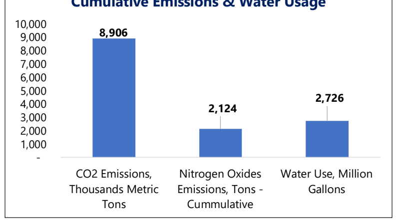
Resource Additions and Retirements, Nameplate MW



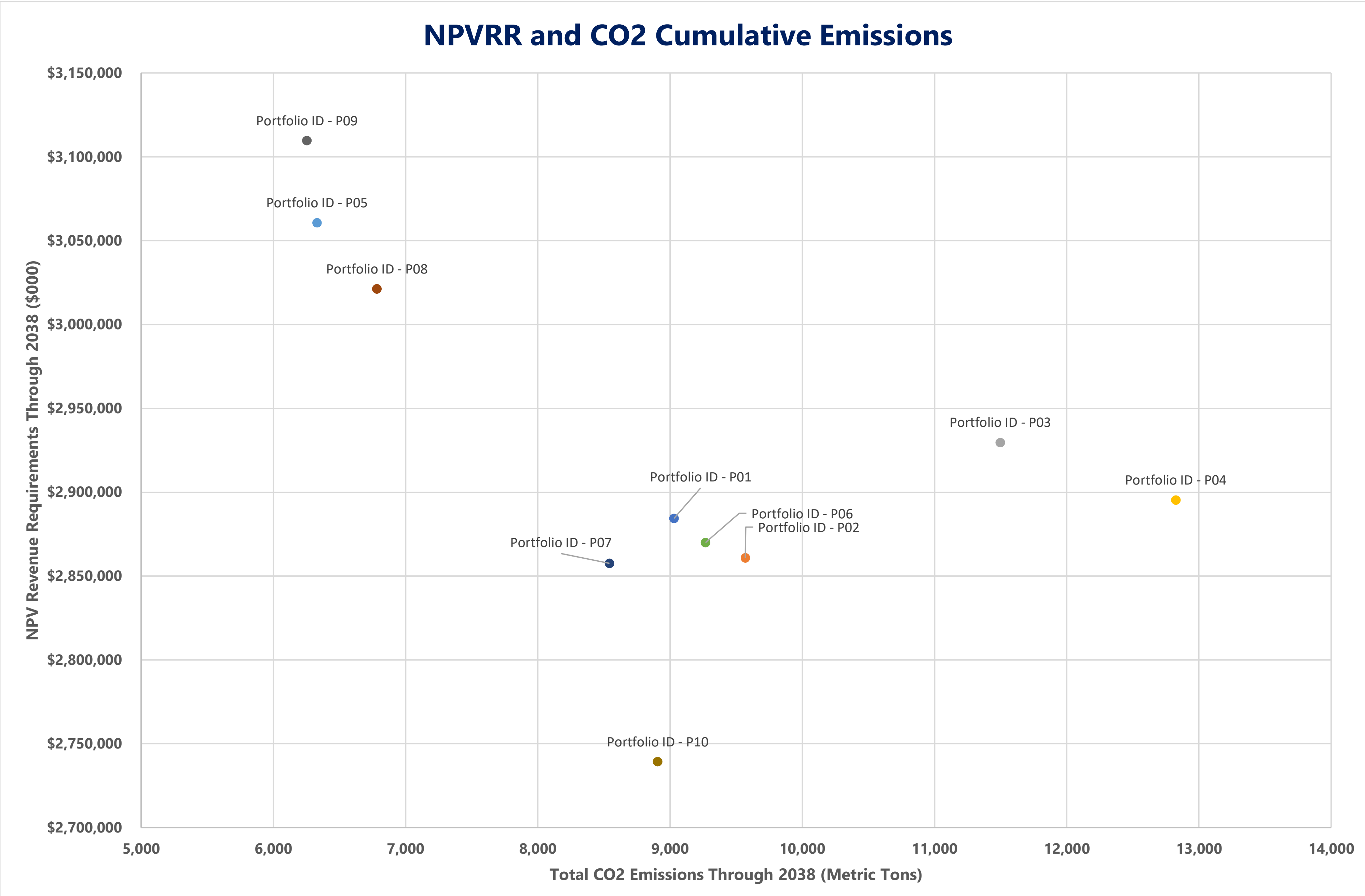
Annual Loads & Resources, MW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Gross Load + PRM	628	644	687	704	728	744	751	757	764	771	779	787	792	804	807
Net Load + PRM	592	606	646	660	682	695	699	702	707	711	717	723	725	735	736
Coal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas	277	277	277	277	427	427	427	427	427	427	427	427	427	427	427
Wind	2	2	2	2	12	12	12	12	10	10	23	23	23	23	23
Solar	33	33	33	91	153	153	160	160	160	166	166	166	173	163	161
Storage	-	-	-	46	107	107	115	115	115	126	126	126	135	137	137
DG	27	29	31	43	46	48	48	48	49	50	50	51	50	51	51
EE	30	32	34	36	38	41	43	45	48	50	52	54	57	59	61

Total NPVRR:	$2,739,245
Fuel NPVRR:	$1,026,417
Non-Fuel NP'	$1,712,828

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	2,461	2,599	2,832	3,049	3,349	3,467	3,548	3,630	3,717	3,820	3,921	4,003	4,110	4,202	4,303
Coal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas	1,118	1,112	1,019	847	812	855	791	864	942	994	921	907	906	955	985
Wind	27	26	27	27	232	229	237	223	206	201	485	475	475	463	484
Solar	266	263	263	534	875	872	939	935	937	980	979	978	1,047	970	961
DG	163	176	189	198	207	213	218	223	228	230	232	234	237	237	238
EE	242	258	276	295	317	338	362	387	416	444	475	508	545	582	623


NPVRR and CO2 Cumulative Emissions
NPV Revenue Requirements Through 2038 ($000)
$3,150,000
$3,100,000
$3,050,000
$3,000,000
$2,950,000
$2,900,000
$2,850,000
$2,800,000
$2,750,000
$2,700,000
Portfolio ID - P09
Portfolio ID - P05
Portfolio ID - P08
Portfolio ID - P03
Portfolio ID - P01
Portfolio ID - P04
Portfolio ID - P06
Portfolio ID - P02
Portfolio ID - P07
Portfolio ID - P10
5,000
6,000
7,000
8,000
9,000
10,000
11,000
12,000
13,000
14,000
Total CO2 Emissions Through 2038 (Metric Tons)

Appendix D: Effective Load Carrying Capability

Tucson Electric Power ELCC Study

Final Report

03/23/2023

Energy+Environmental Economics

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

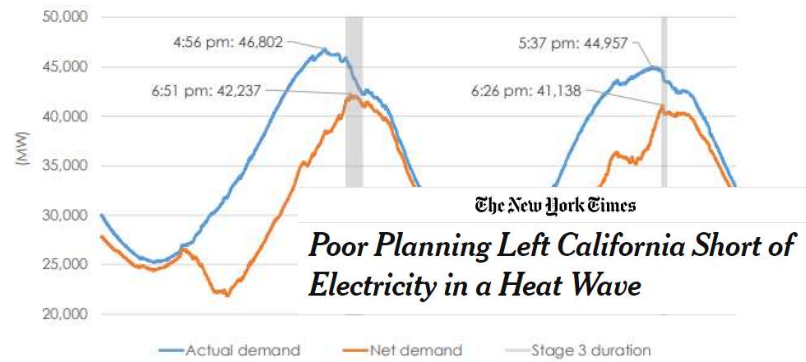
List of contents

Background

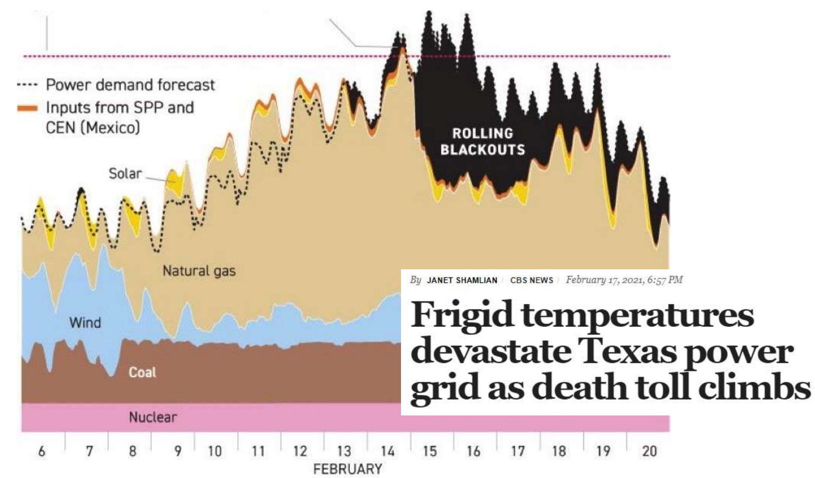
Energy+Environmental Economics

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

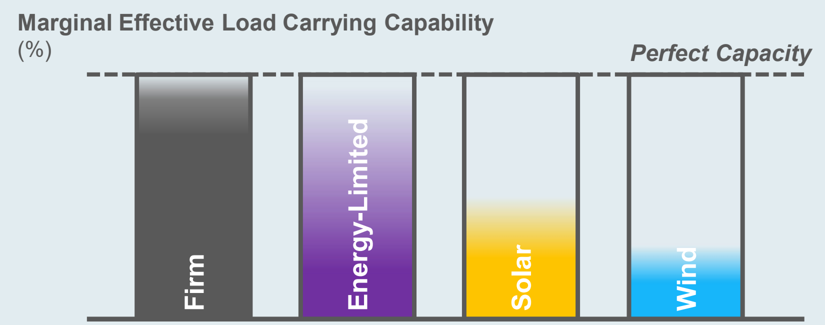


Graph source: https://twitter.com/bcshaffer/status/1364635609214586882

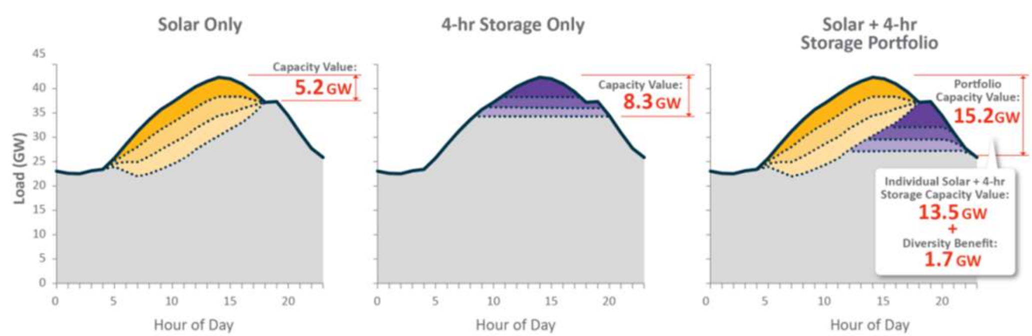
Accurately accounting for resources' reliability contribution is necessary to ensure reliable electric service

+ **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

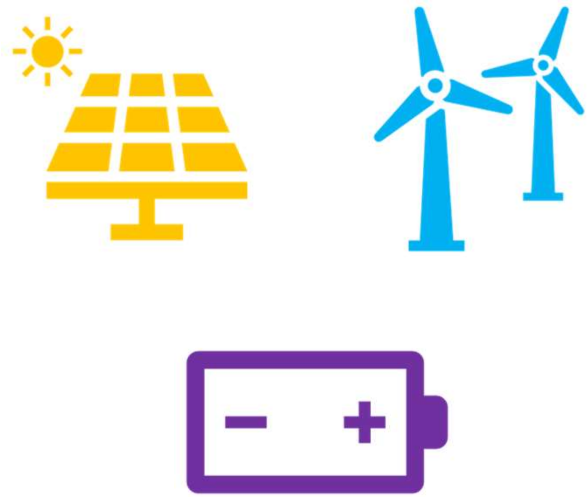


Saturation effect with increasing penetration **Interactive effect**



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

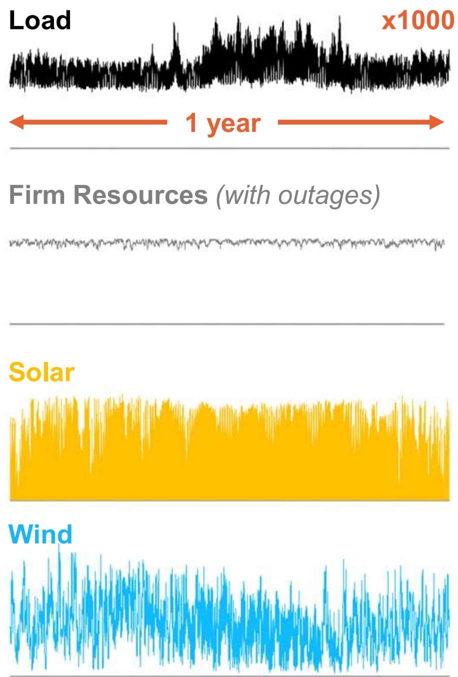
Task 1. Develop model inputs

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

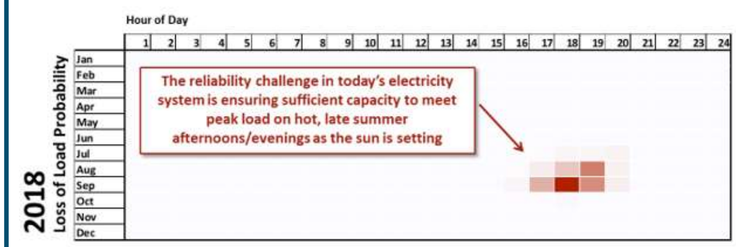
Task 2. Setting up E3's RECAP model

- **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**

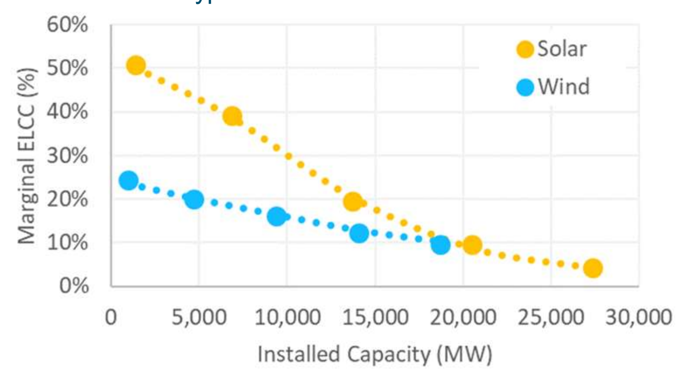
Monte Carlo simulation of loads, renewable profiles, and generator outages used to simulate 1,000 years of plausible system conditions



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



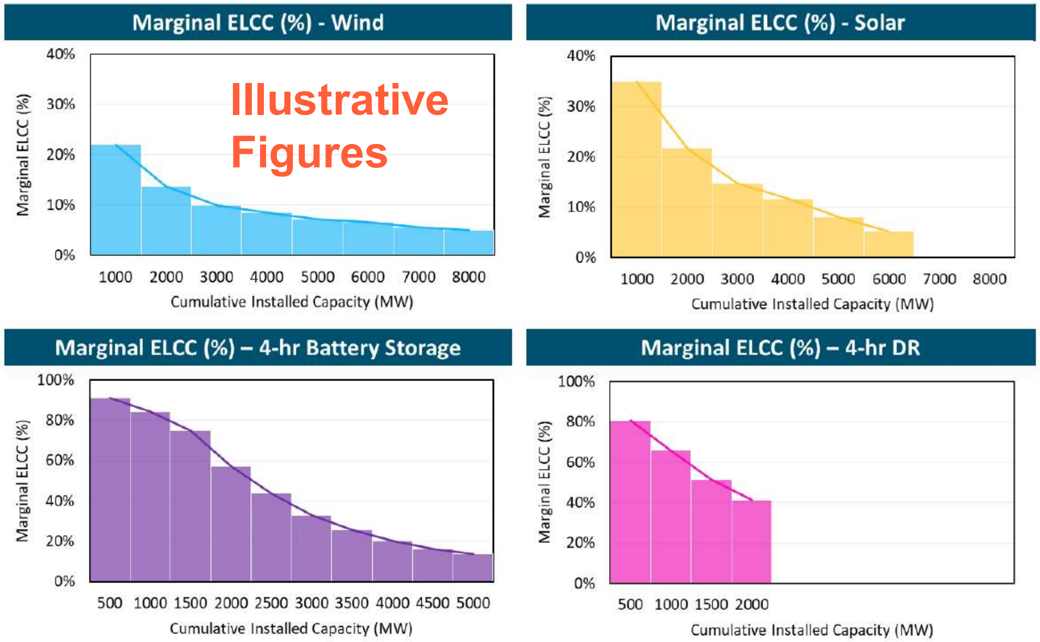
Example RECAP result from *Long-Run Resource Adequacy under Deep Decarbonization Pathways for California* (Calpine, 2019)

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**

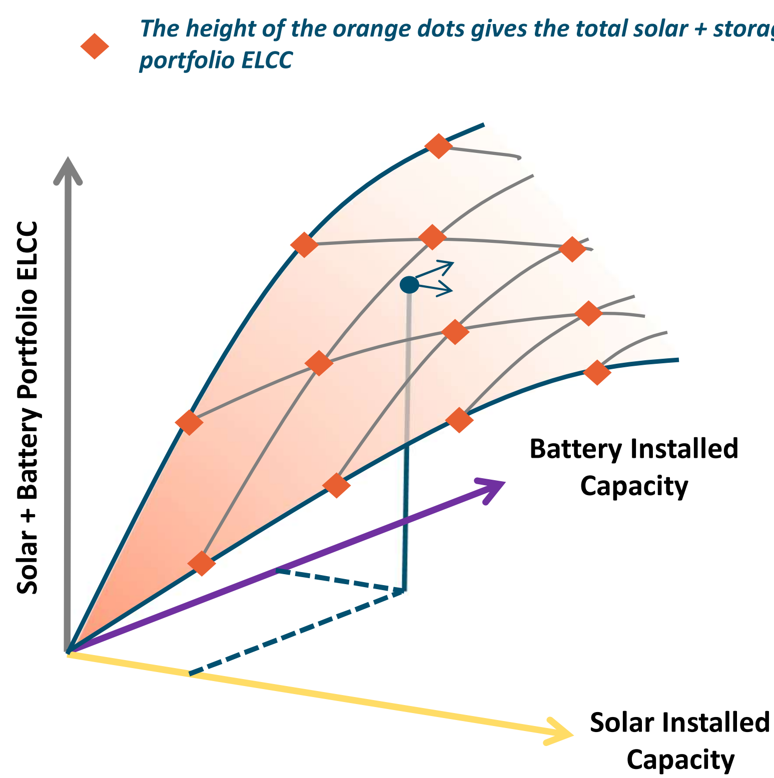


Task 3. Calculate ELCCs

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**

Inputs

Load
- *Hourly load for multiple weather years*

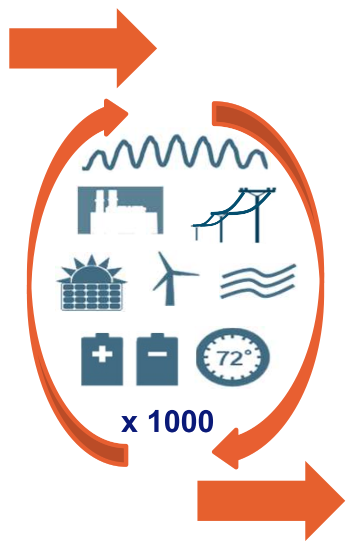
Key data to update for the full LOLP study

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*

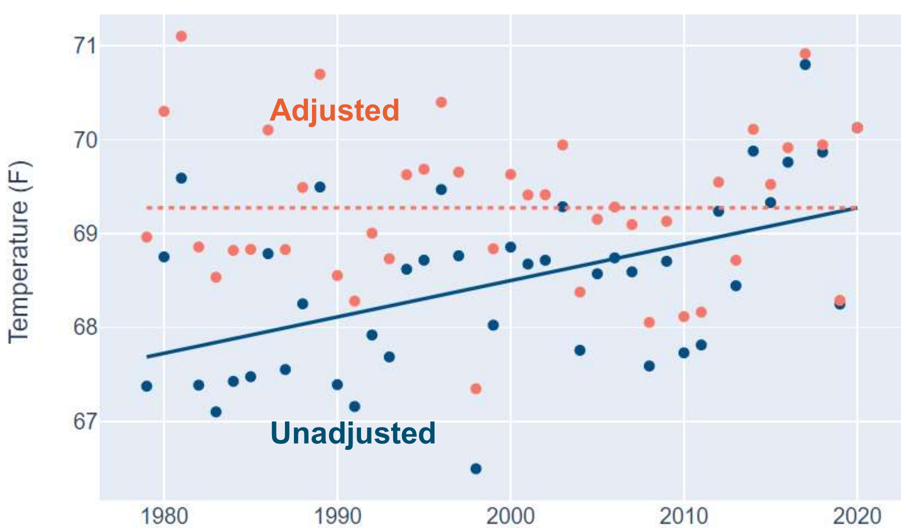
Capacity Shortfall / Excess
- *Amount of perfect capacity required / excess in the system to achieve the reliability threshold*

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

Inputs and Assumptions

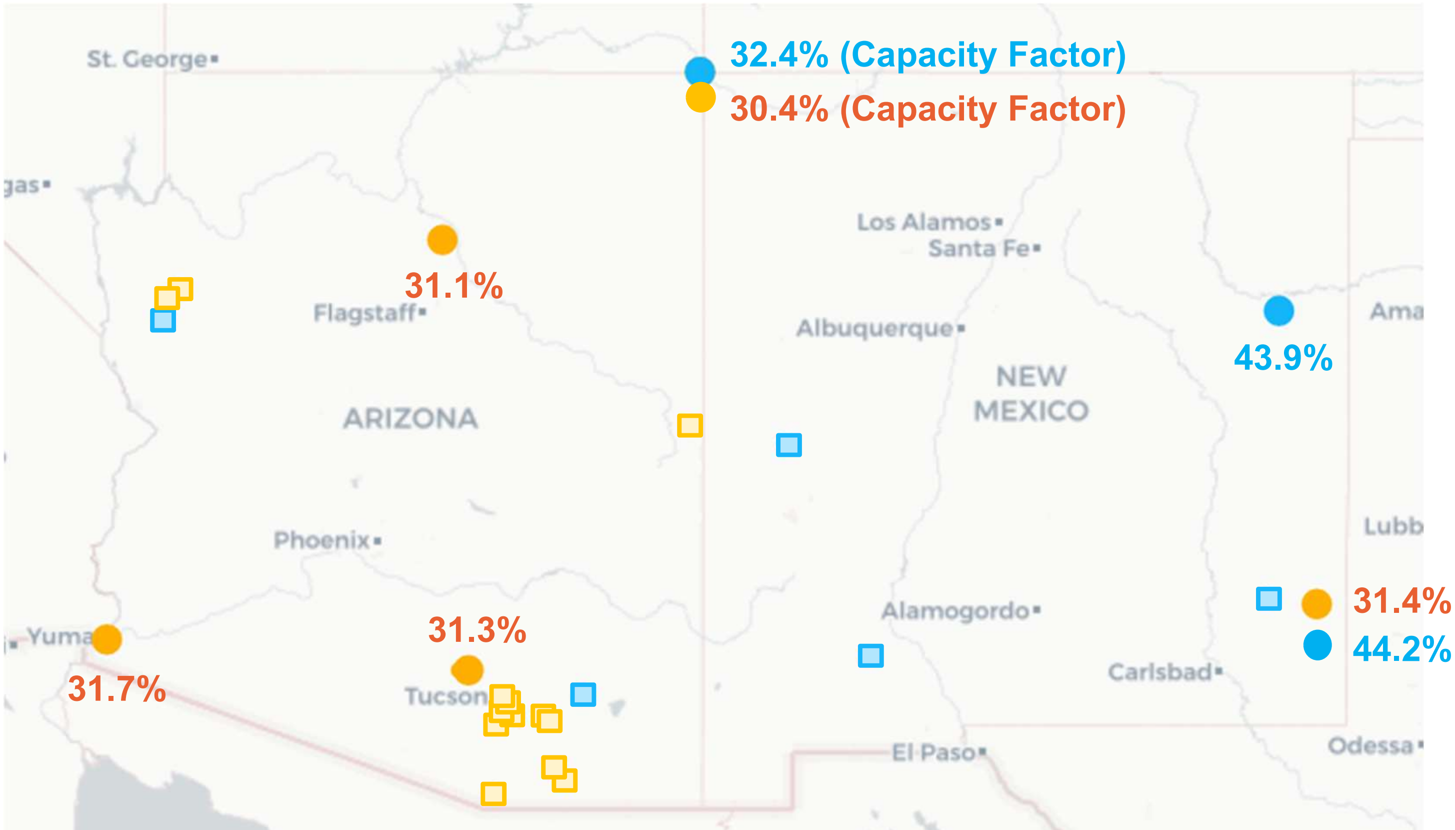
Temperature detrending

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

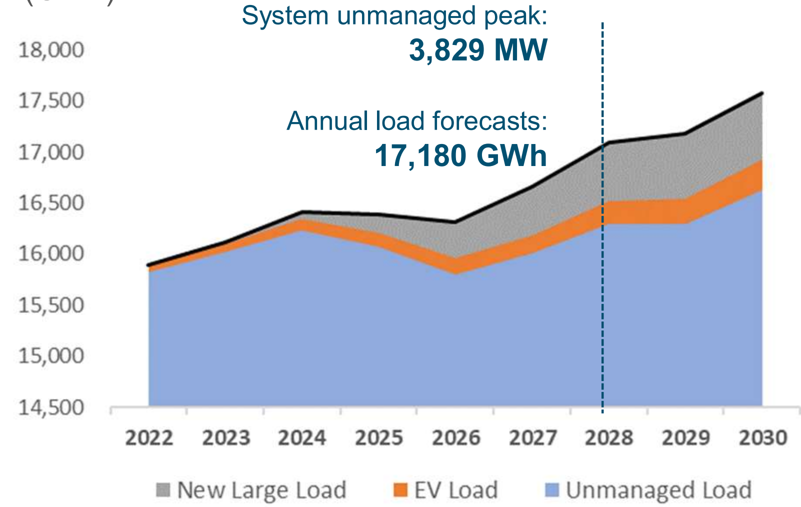
Profile simulation methodology

+ **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

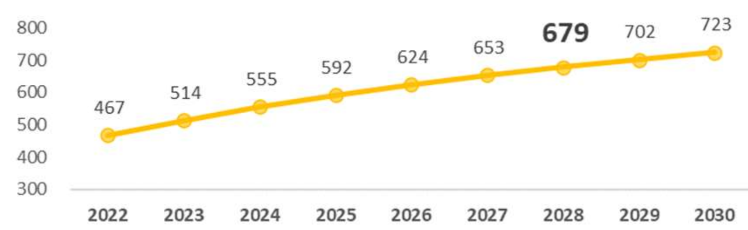
Other inputs and assumptions

- **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	

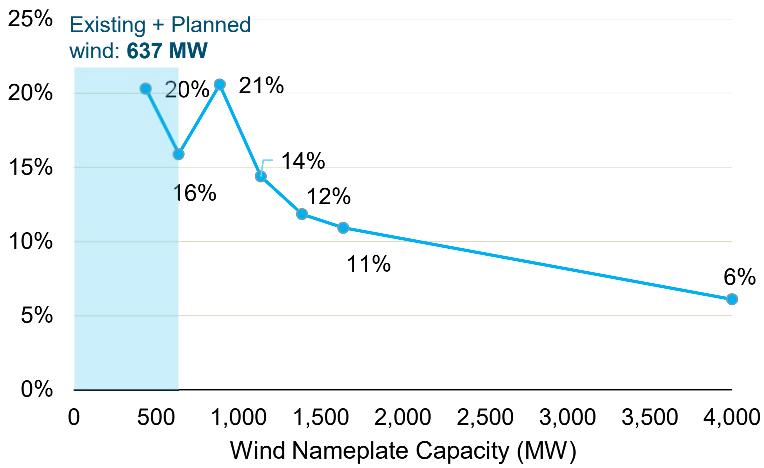
- **Wind ELCC curve was calculated without any solar or storage in the base system**
- **Solar-4-hr storage ELCC surface was built for a base portfolio containing 1637 MW of wind**
- **Each combination of solar and storage penetration in these tables was modeled to construct the full solar-storage ELCC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

Results

Energy+Environmental Economics

Wind ELCCs

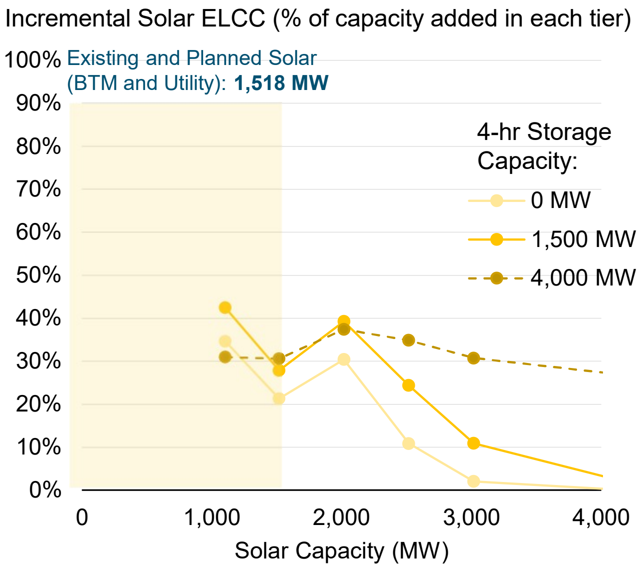
Incremental Wind ELCC (% of capacity added in each tier)

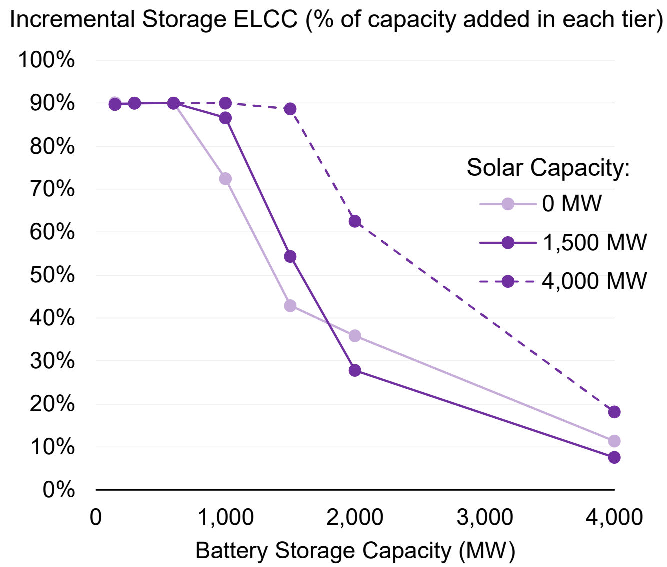


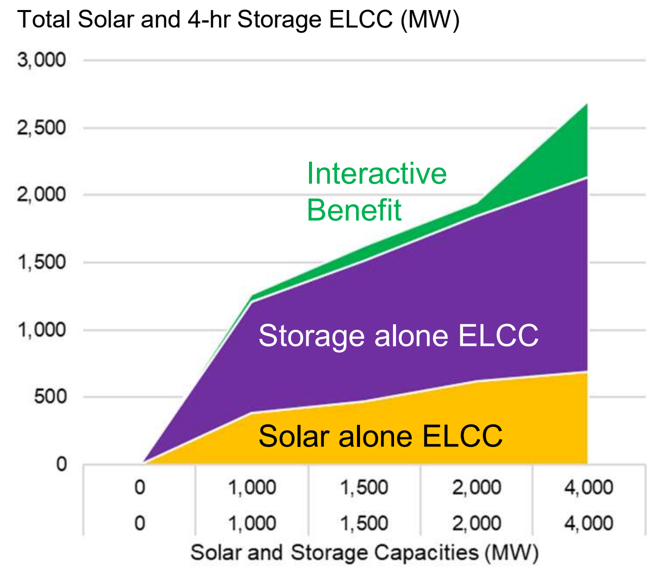
Wind Capacity (MW)	Incremental ELCC (MW)	Average ELCC (MW)	Incremental ELCC (%)	Average ELCC (%)
437	89	89	20%	20%
637	32	120	16%	19%
887	51	172	21%	19%
1,137	36	208	14%	18%
1,387	30	237	12%	17%
1,637	27	265	11%	16%
4,000	144	408	6%	10%

- **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

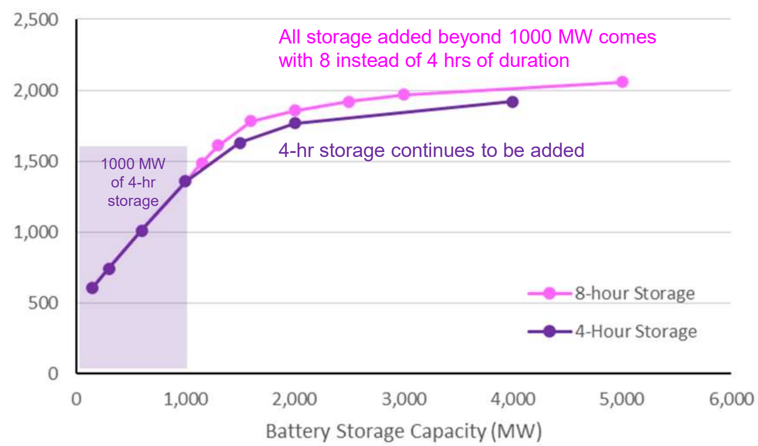
4-hr Storage Nameplate Capacity (MW)

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**

Deliverables

+ **In addition to this PowerPoint report, TEP will also be provided with 2 workbooks containing-**
  - Simulated solar and wind profiles
  - Detailed ELCC results

Thank You

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Appendix E: Wholesale Power Price Forecast

Southwest
Market Price Forecast
E3 Core Case

March 2023 edition

Energy+Environmental Economics

marketprices@ethree.com

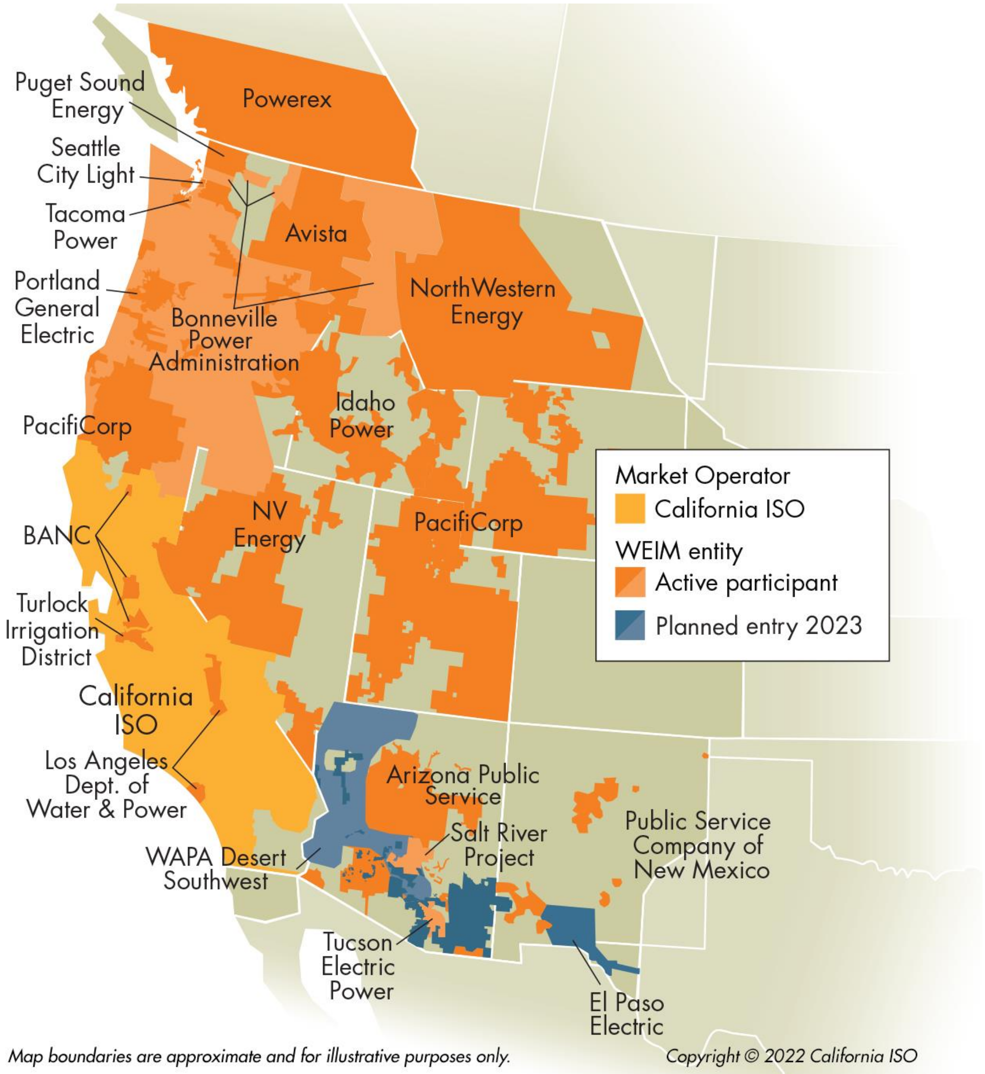
Disclaimer

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



Energy Markets in the West: Bilateral Trading

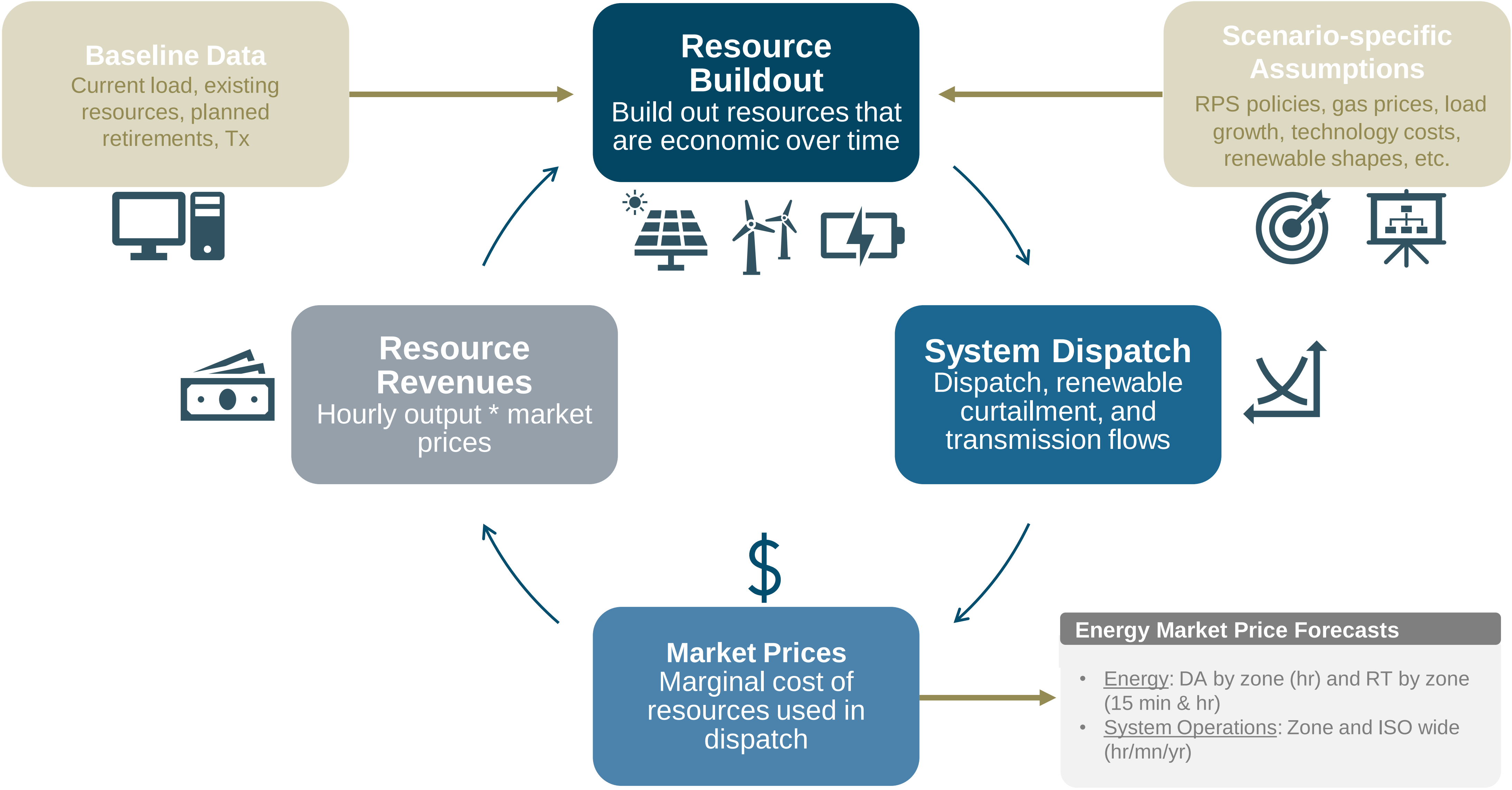
- Outside of the CAISO wholesale market, energy trading is done bilaterally in the West through exchanges which match buyers and sellers (for example, the Intercontinental Exchange or ICE)
- Two major trading hubs exist:
  - Mid-Columbia (“Mid-C”) in Washington
  - Palo Verde in Arizona
- Energy is traded 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?

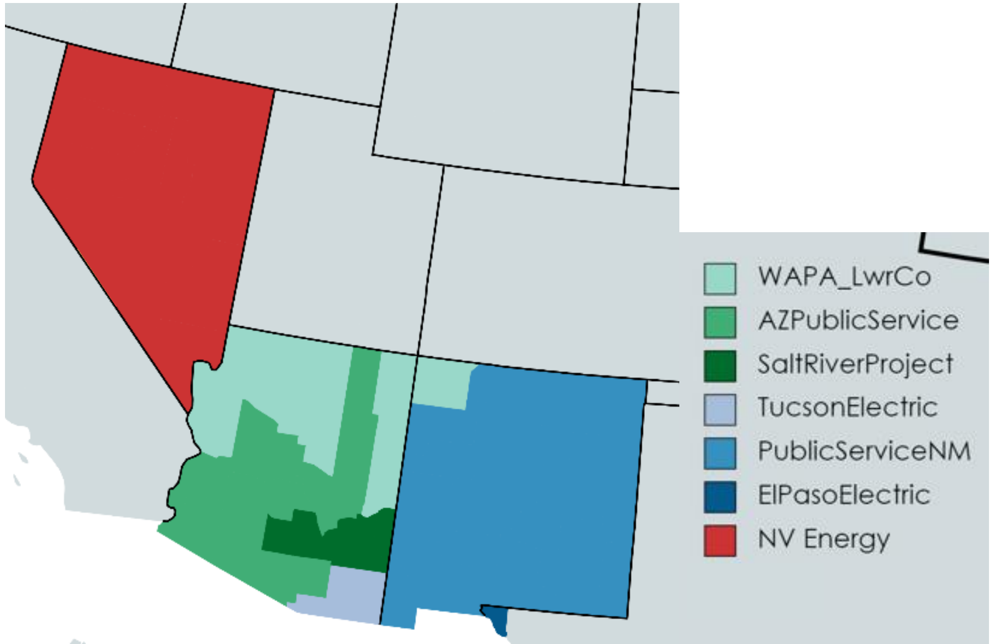
+ **E3 provides an <u>hourly price forecast</u> that reflects the market premiums and bidding behavior expected in future Day-Ahead On-Peak/Off-Peak trades at Palo Verde**
+ **These "future day-ahead prices" are different from month-ahead forward prices at Palo Verde**
  - For example, forward prices (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



Southwest Region: Model Footprint

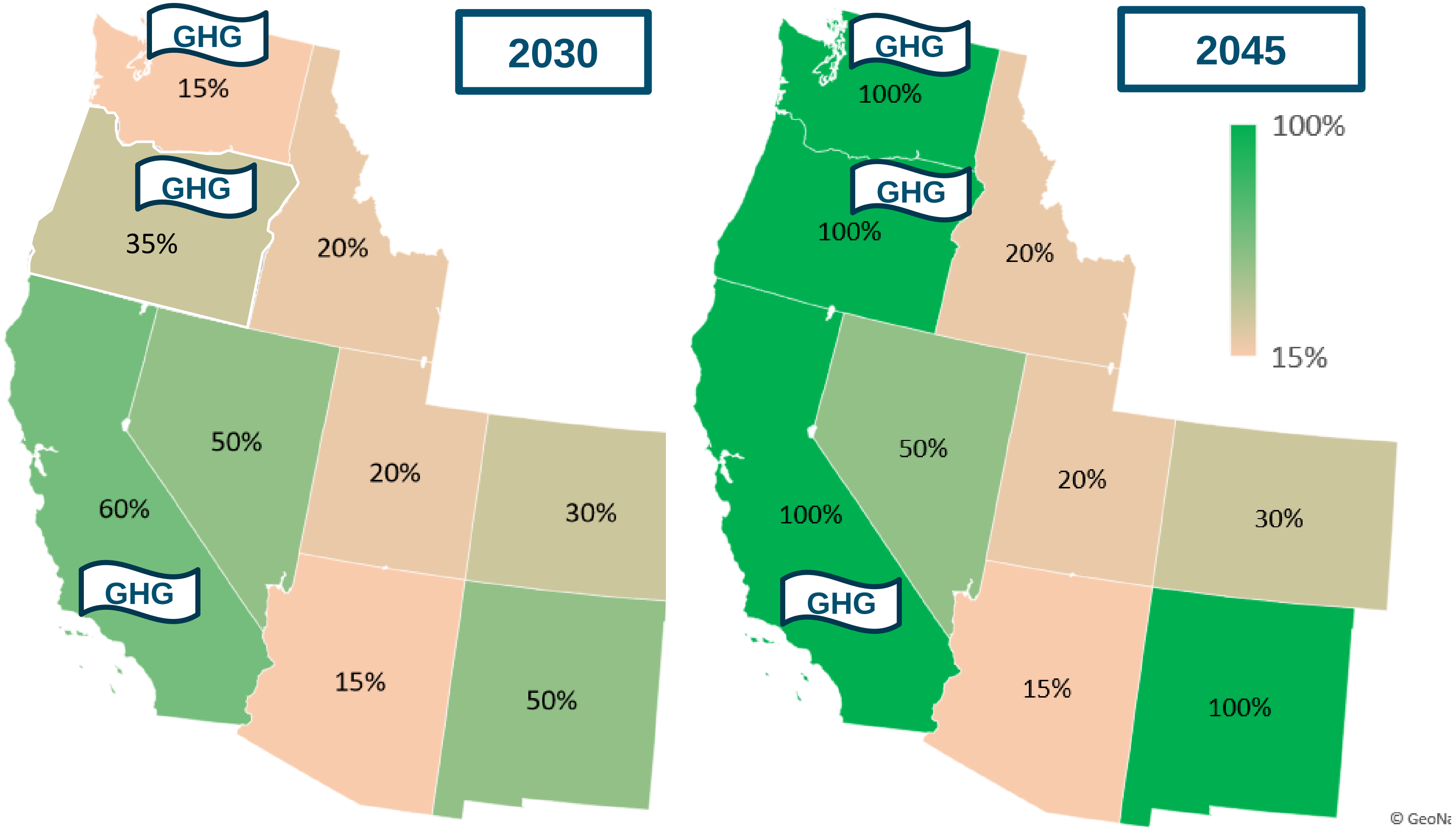
- **E3's market forecasts of the Southwest region include 6 Balancing Authorities across 3 states:**
  - Arizona: APS, SRP, TEP, WAPA Lower Colorado
  - Nevada: Nevada Energy
  - New Mexico: PNM, ElPasoElectric
- **Energy prices are forecasted as marginal costs of generation by Balancing Authority region**



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

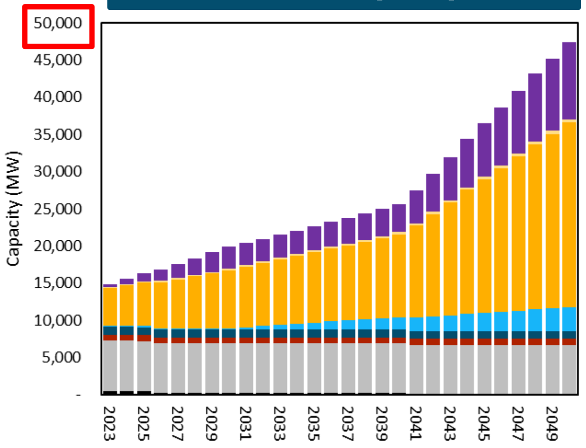
Region	Utility	2030	2045	2050
SW	SRP		GHG Target	
	APS	65%	65%	100%
	TEP		GHG Target	
	EPE		100%	100%
	PNM*		100%	100%
	NV Energy			100%
RMT	Black Hills		GHG Target	
	Xcel CO*			100%
	Tri-State*	50%	50%	50%
Basin	Idaho Power		100%	100%
	PacifiCorp East		GHG Target	
PNW	NW Energy			
	Portland General			
	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			

*Utility has CES and GHG target

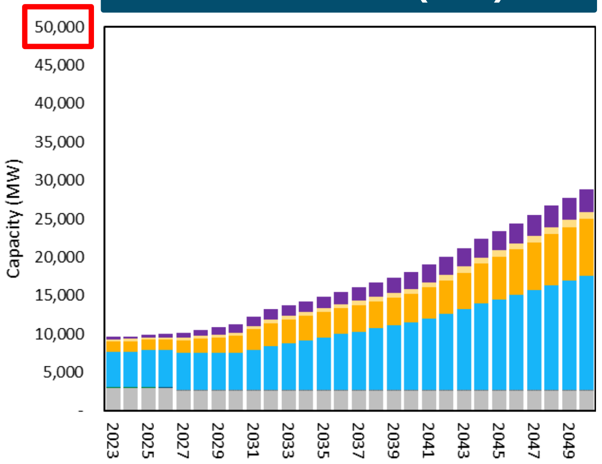
Installed Generation Capacity (MW)

*Note the difference in y-axes

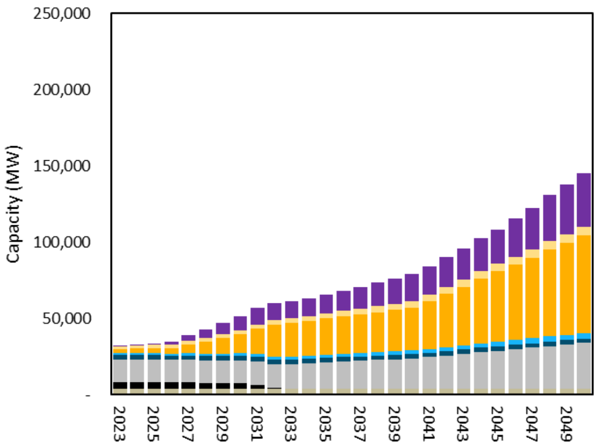
Nevada (MW)



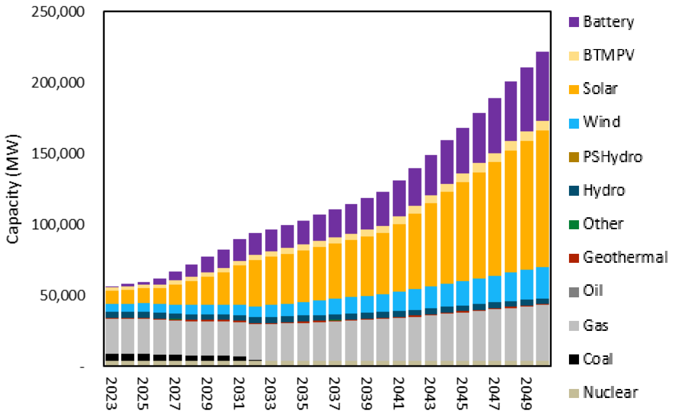
New Mexico (MW)



Arizona (MW)



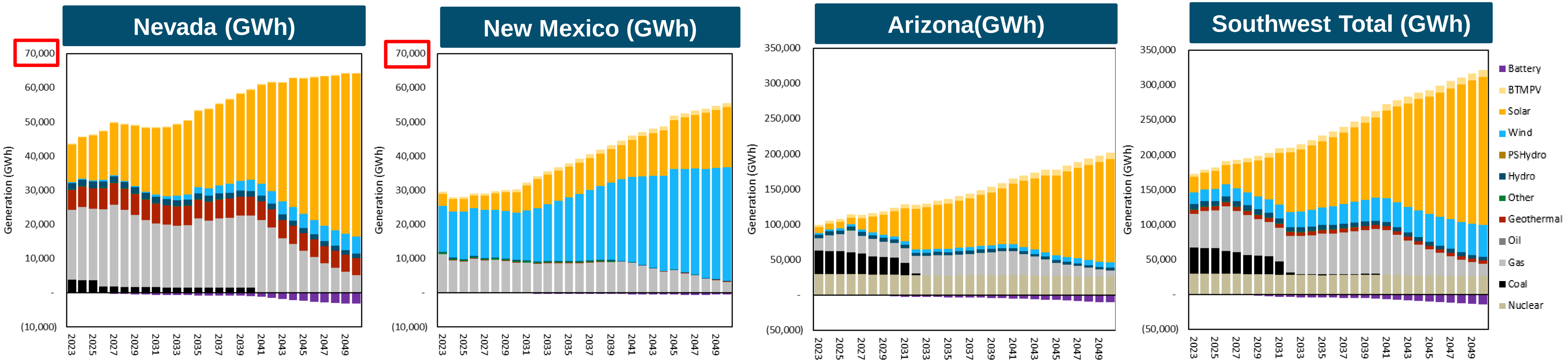
Southwest Total (MW)



- 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)

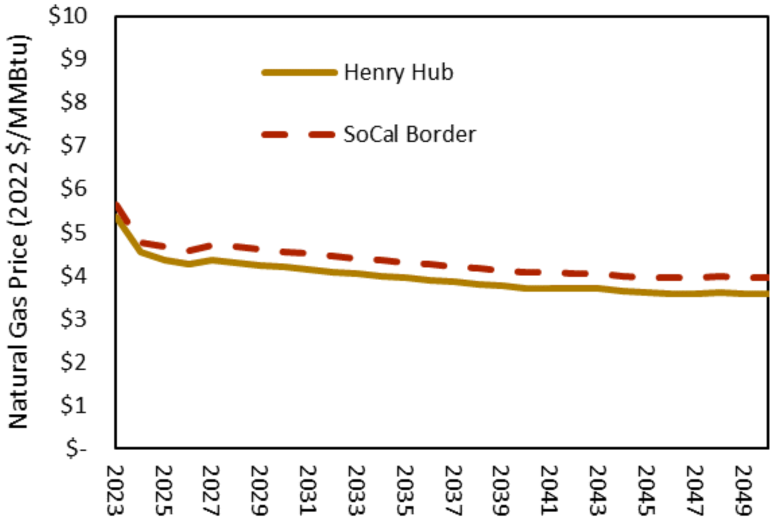
*Note the difference in y-axes



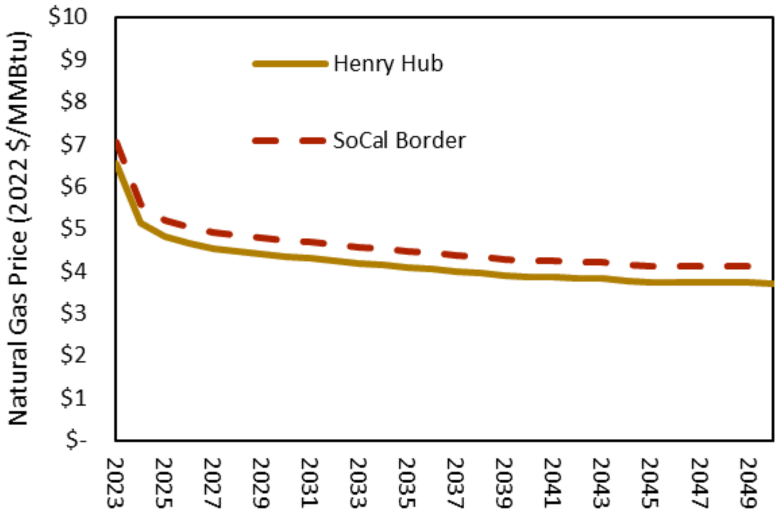
- **Solar generation is the dominant new renewable resource in Nevada and Arizona, while wind is the most significant resource in New Mexico**
- **Thermal generation decreases significantly over time and is replaced by solar and wind generation**
  - Most coal generation phases out by 2032 and the last 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)

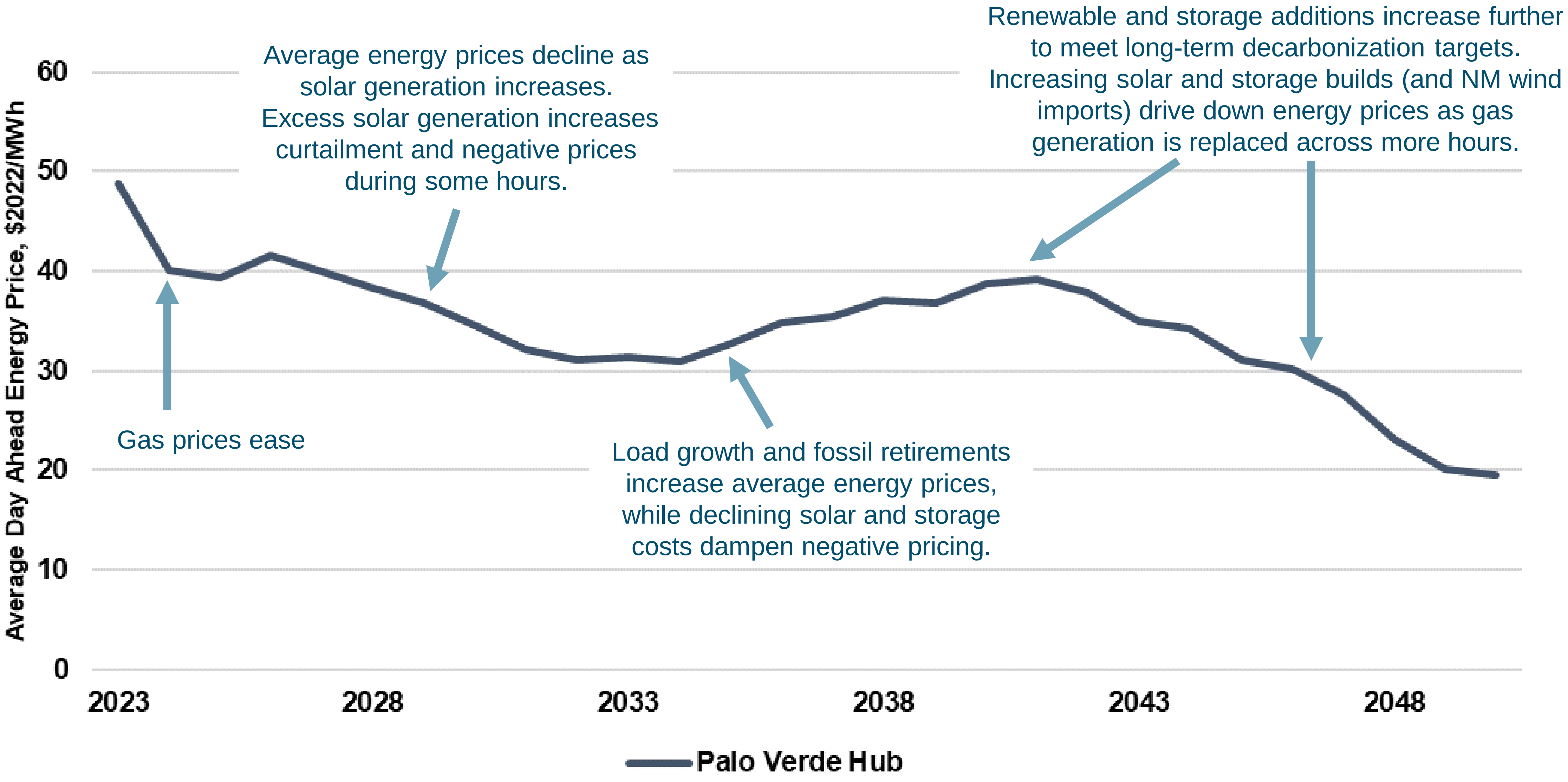


Winter Gas Price (2022 $/MMBtu)



+ **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

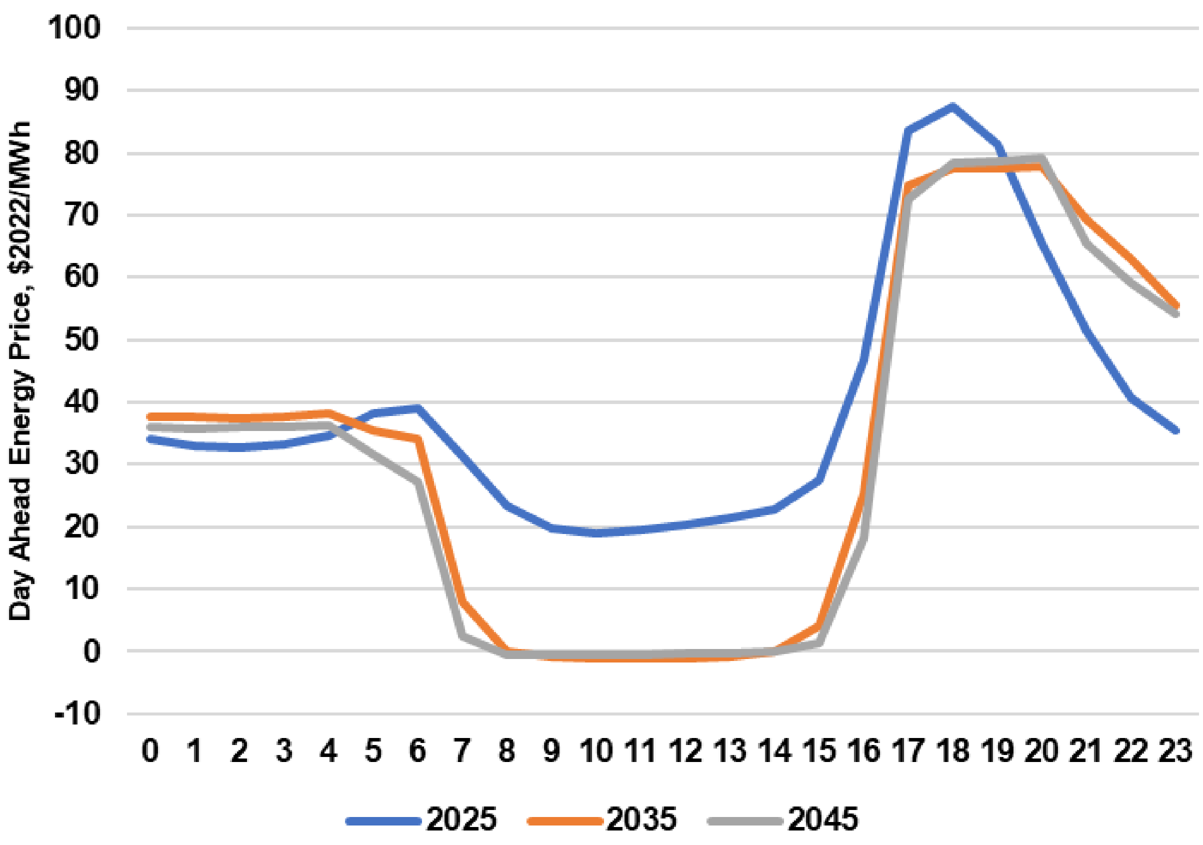
Avg. Annual Day Ahead Energy Prices ($2022/MWh)



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**

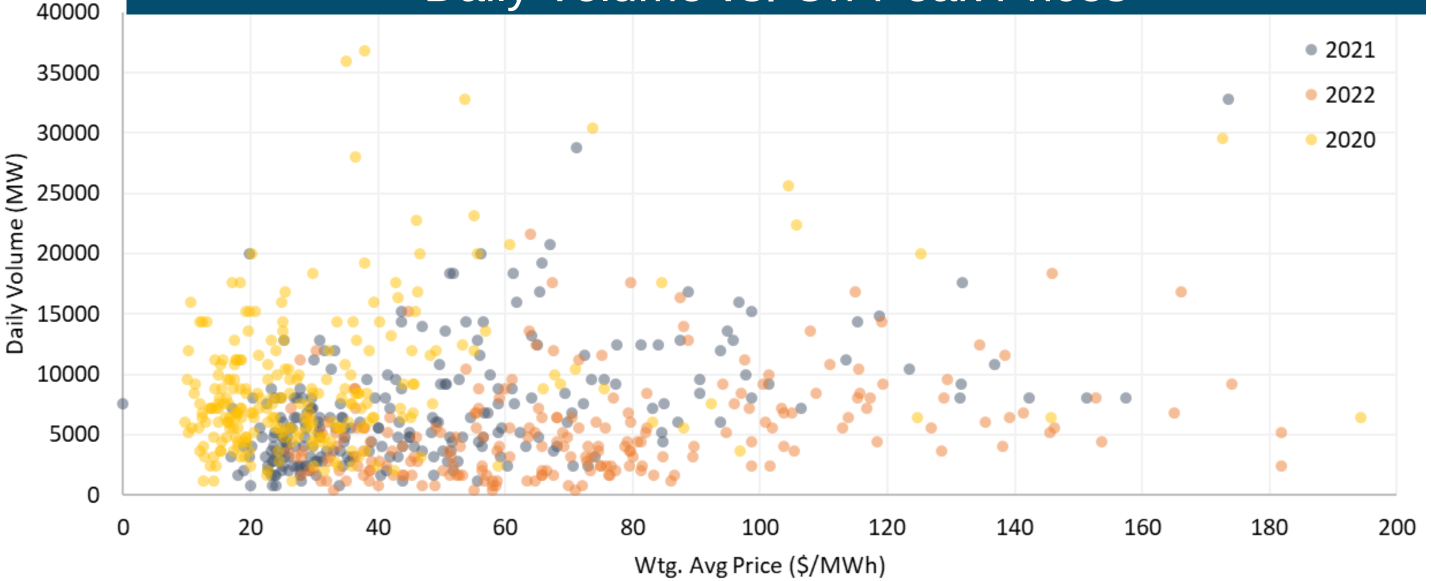
Palo Verde Hub



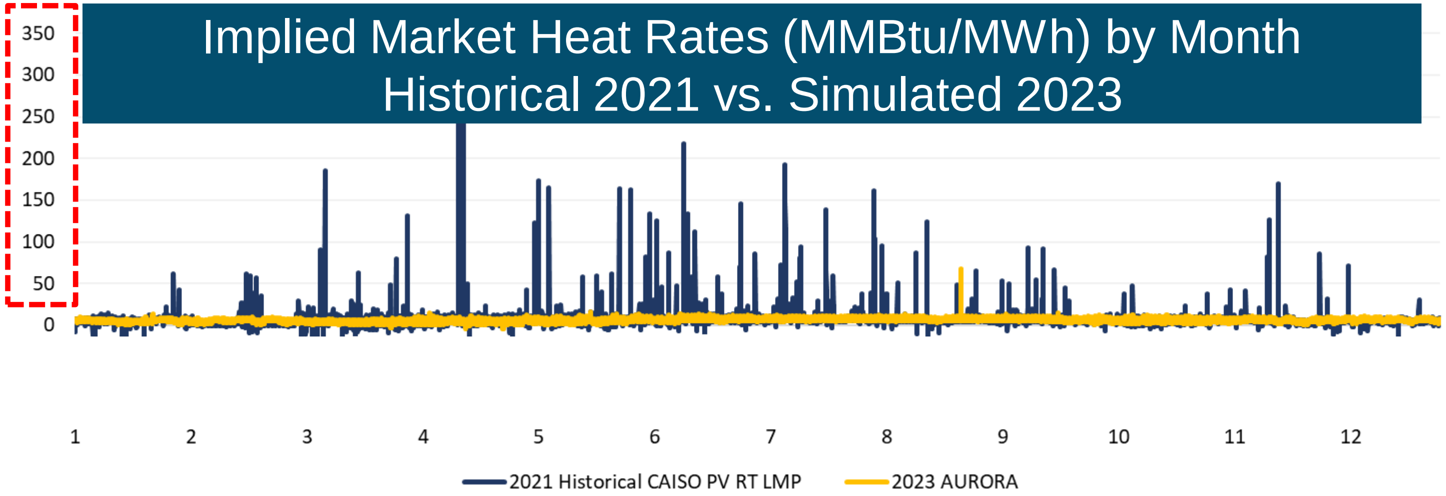
Historical Palo Verde Price Trends

- **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

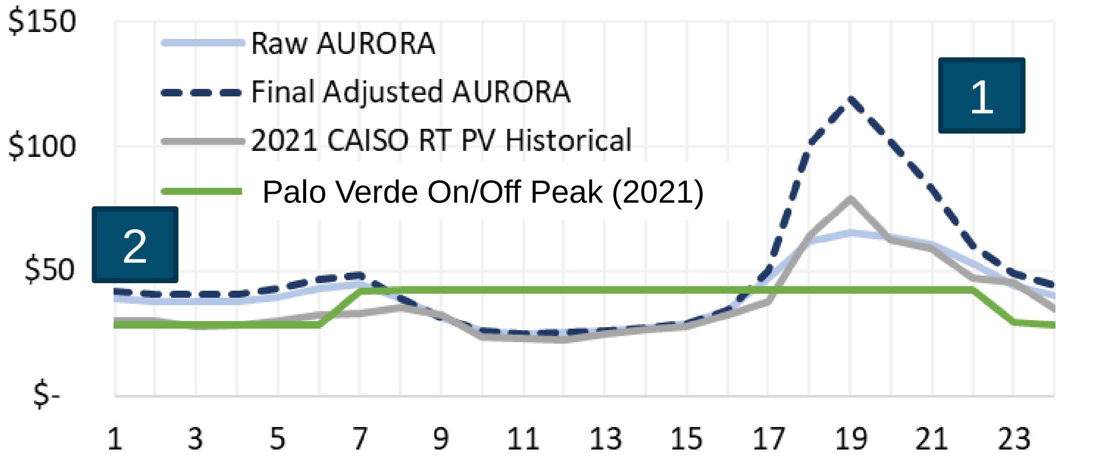


*On-peak hours are defined as hours ending 7am through 10pm, Monday through Saturday (16x6)

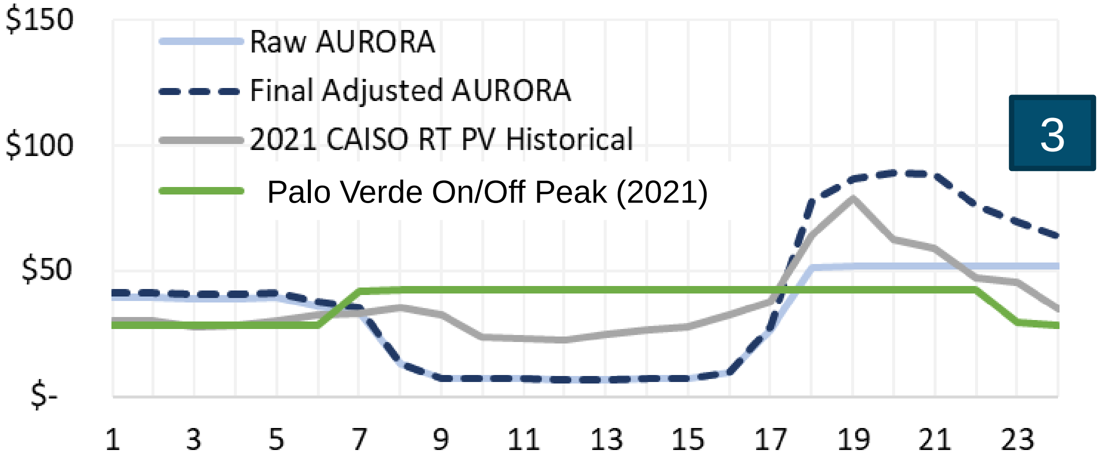
Capturing Historical Price Premiums and Bidding Behavior in E3's Price Forecast

+ **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.

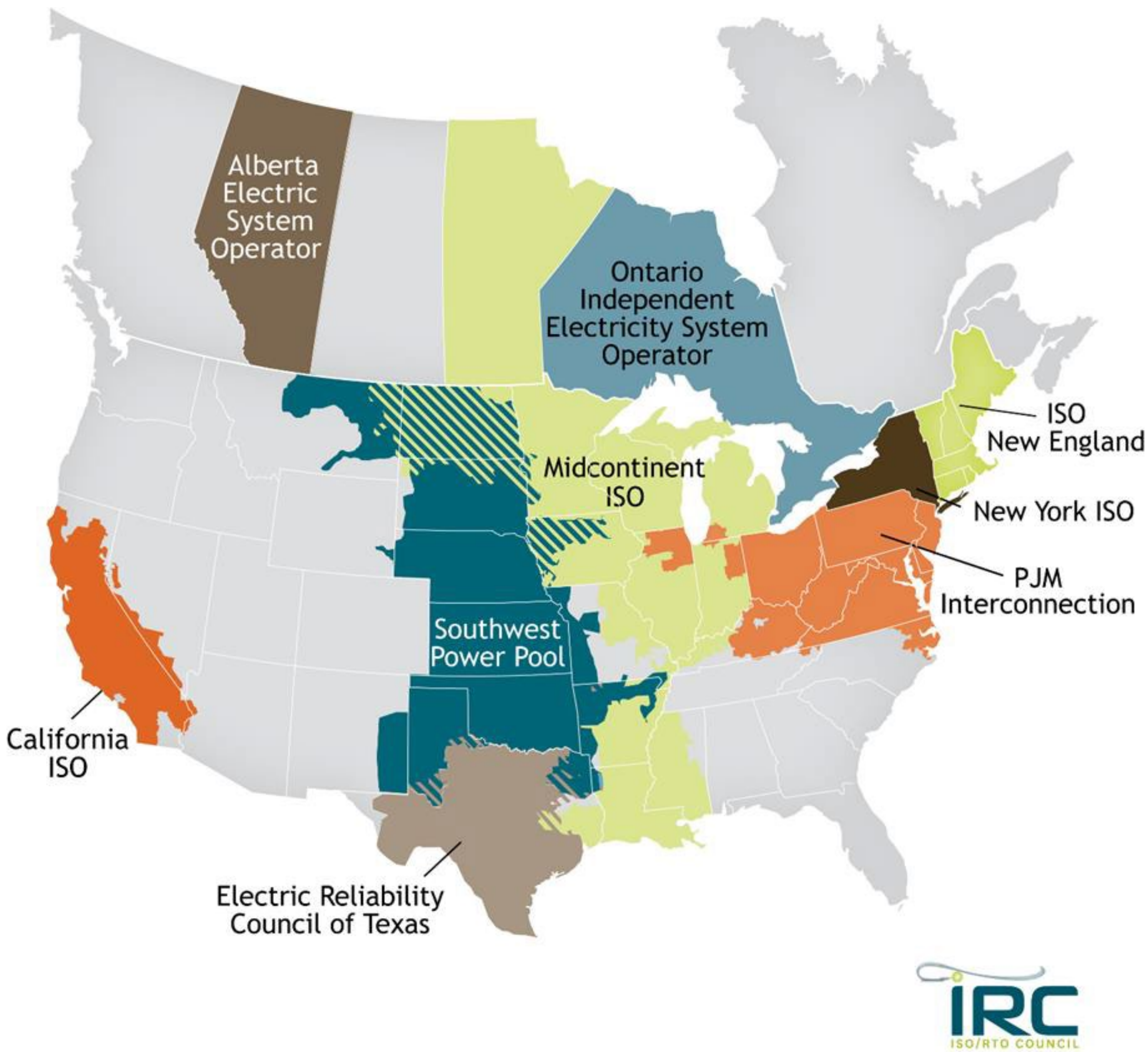


Figure 1. Current Organized Markets in North America.

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.

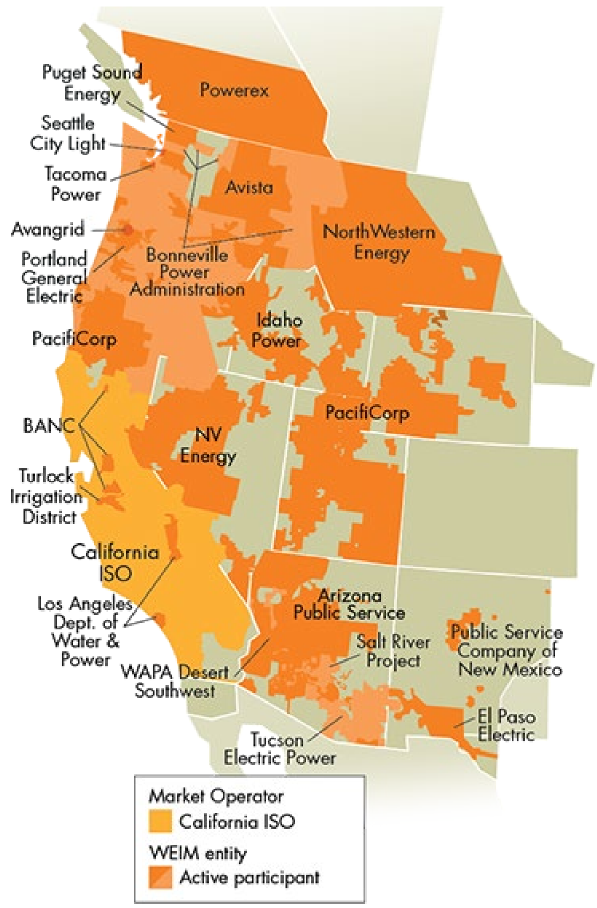


Figure 2. WEIM Participants

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.

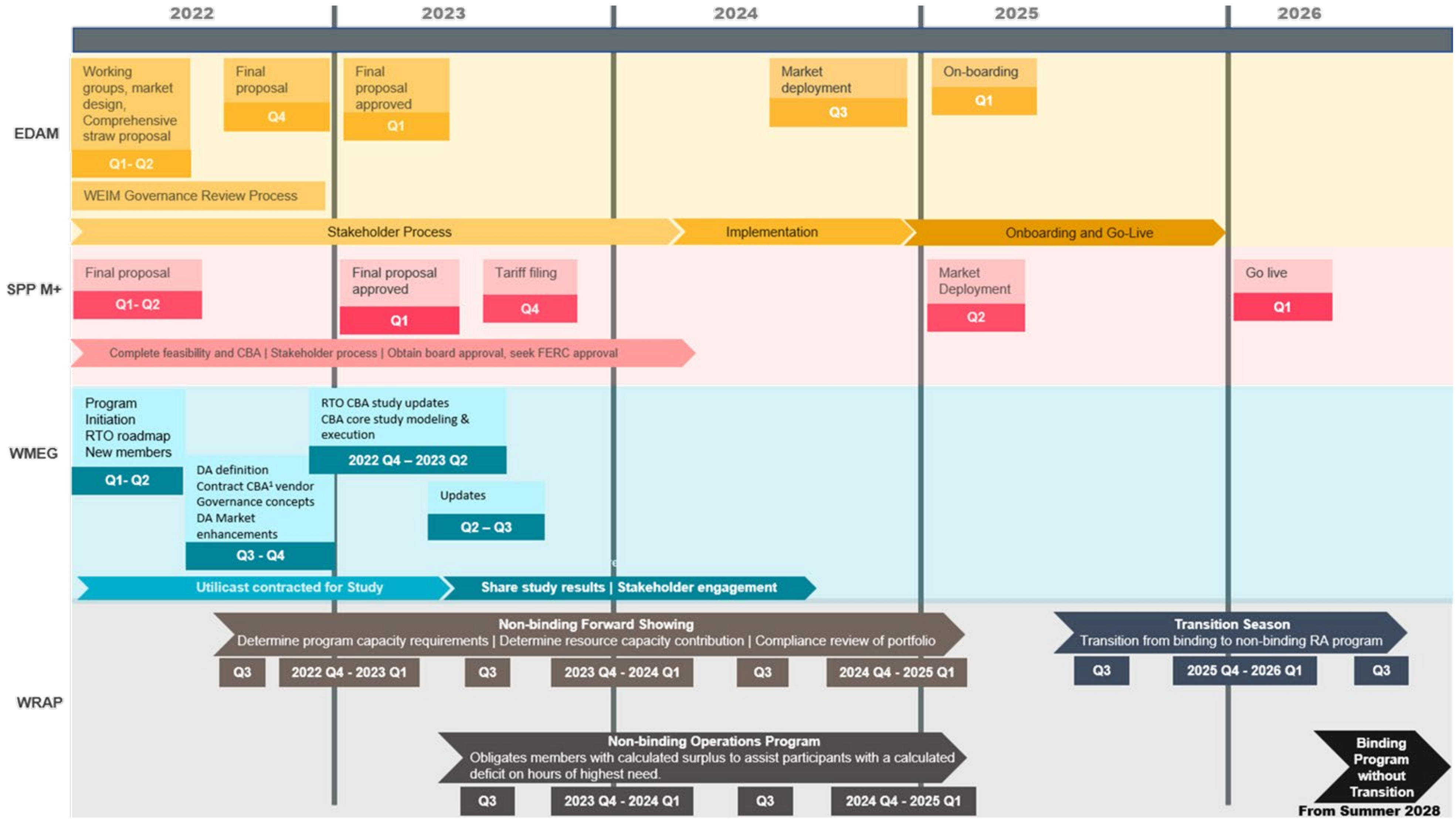


Figure 3. Timelines and Decision Points for Markets and Resource Adequacy Initiatives under Development

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.

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[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

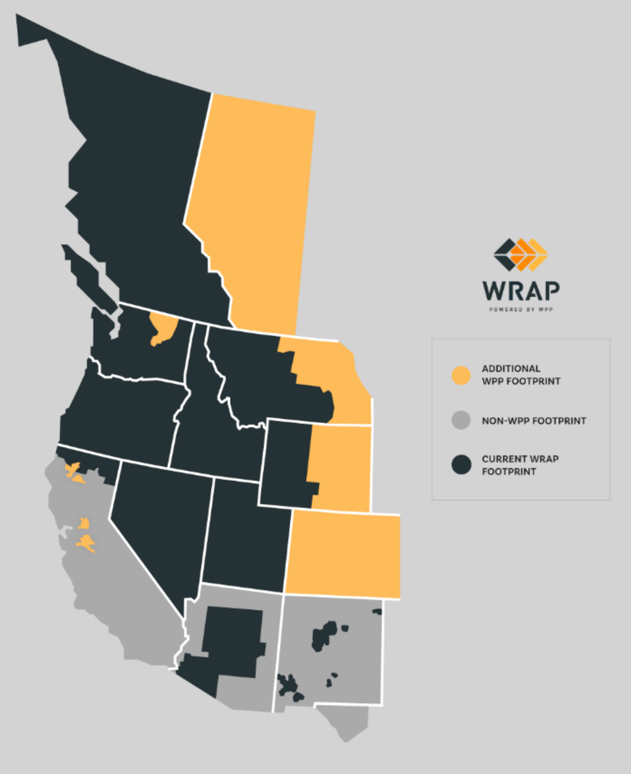
Recall APS's goals

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)

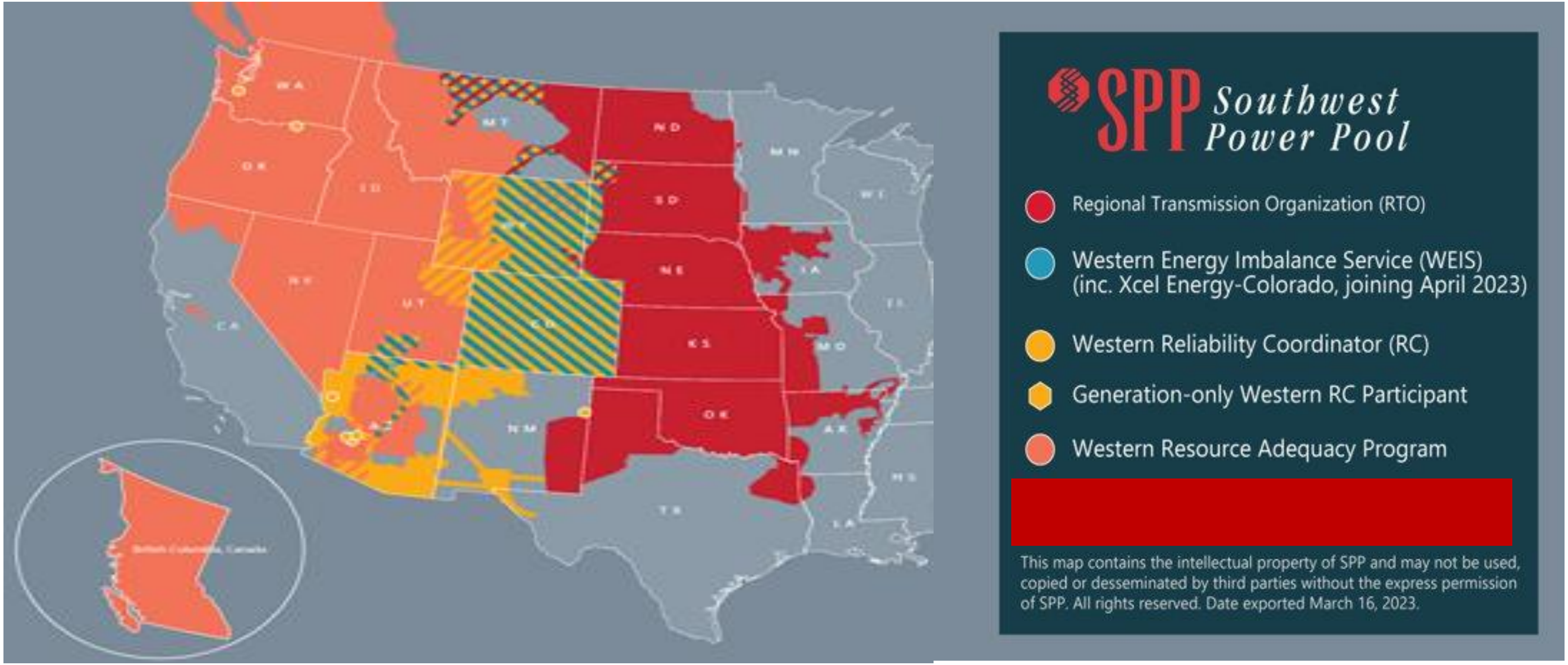


1. Arizona Public Service
2. Avista
3. Bonneville Power Administration
4. Calpine
5. Chelan County PUD
6. Clatskanie PUD
7. Eugene Water & Electric Board
8. Grant PUD
9. Idaho Power
10. Northwestern Energy
11. NVEnergy
12. PacifiCorp
13. Portland General Electric
14. Powerex
15. Public Service Company 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

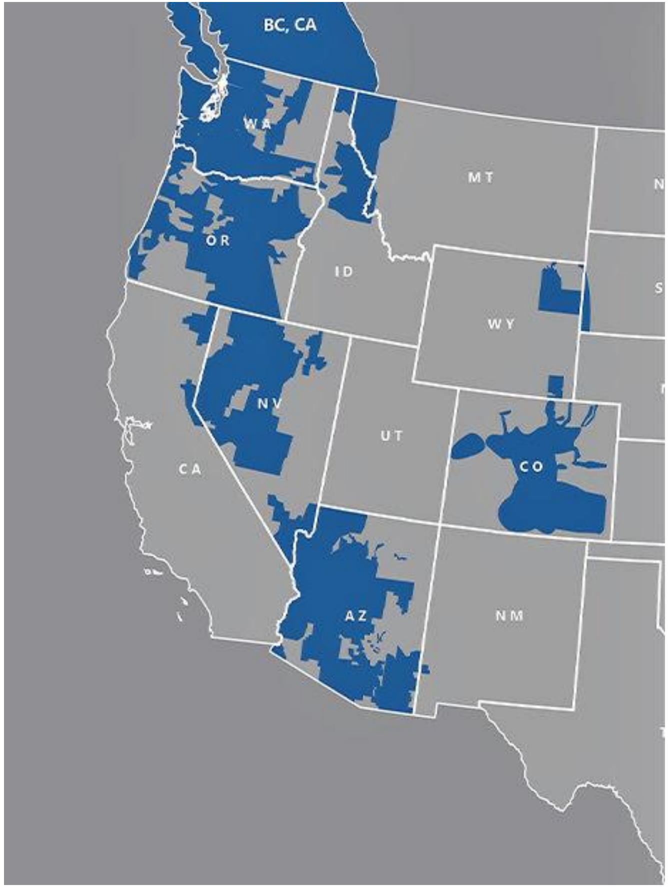
Western Energy Imbalance Market (WEIM)

Southwest Power Pool (SPP) in the West

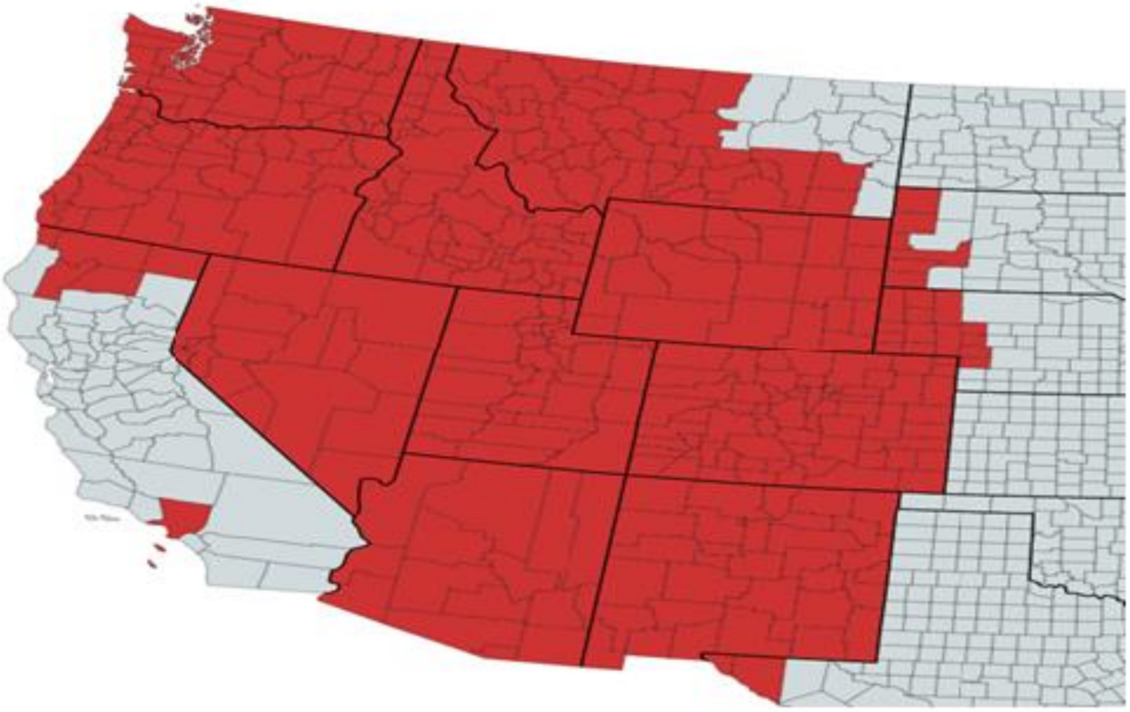


SPP Markets+ Phase 1

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

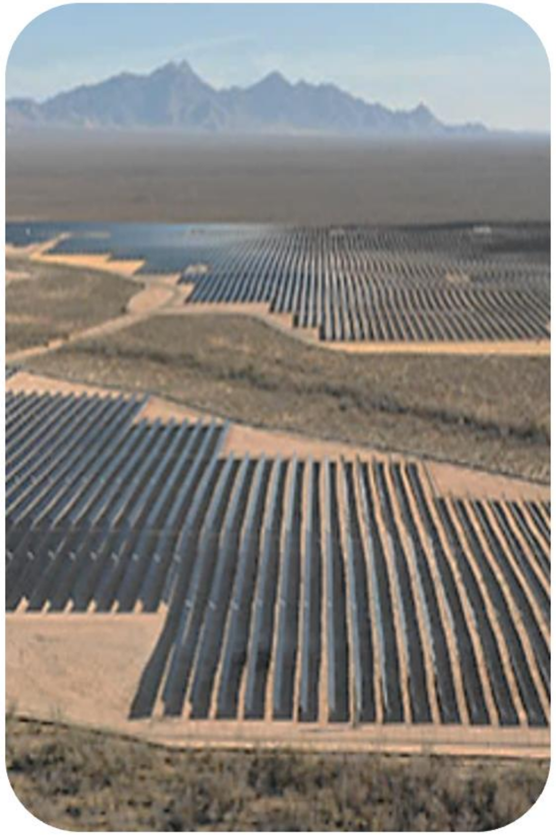
A Fortis Company

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

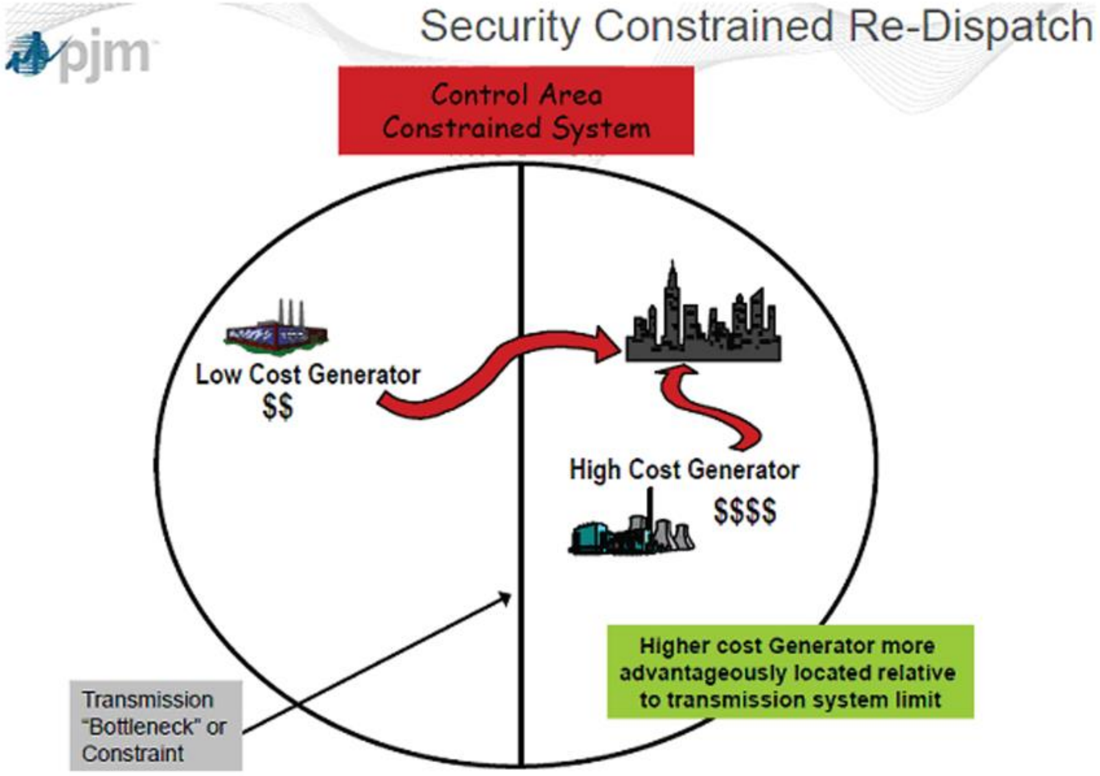
Day Ahead & Real Time Optimization

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)

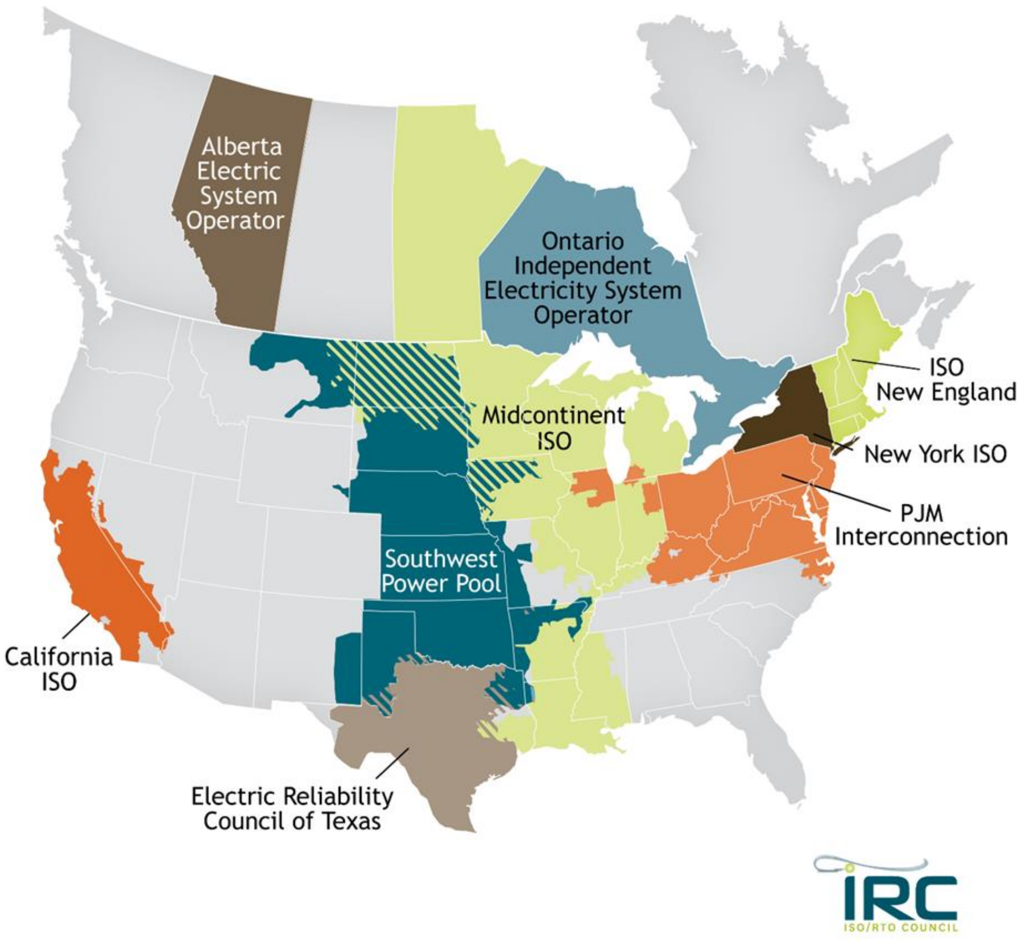
Security-Constrained Economic Dispatch (SCED)

- 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



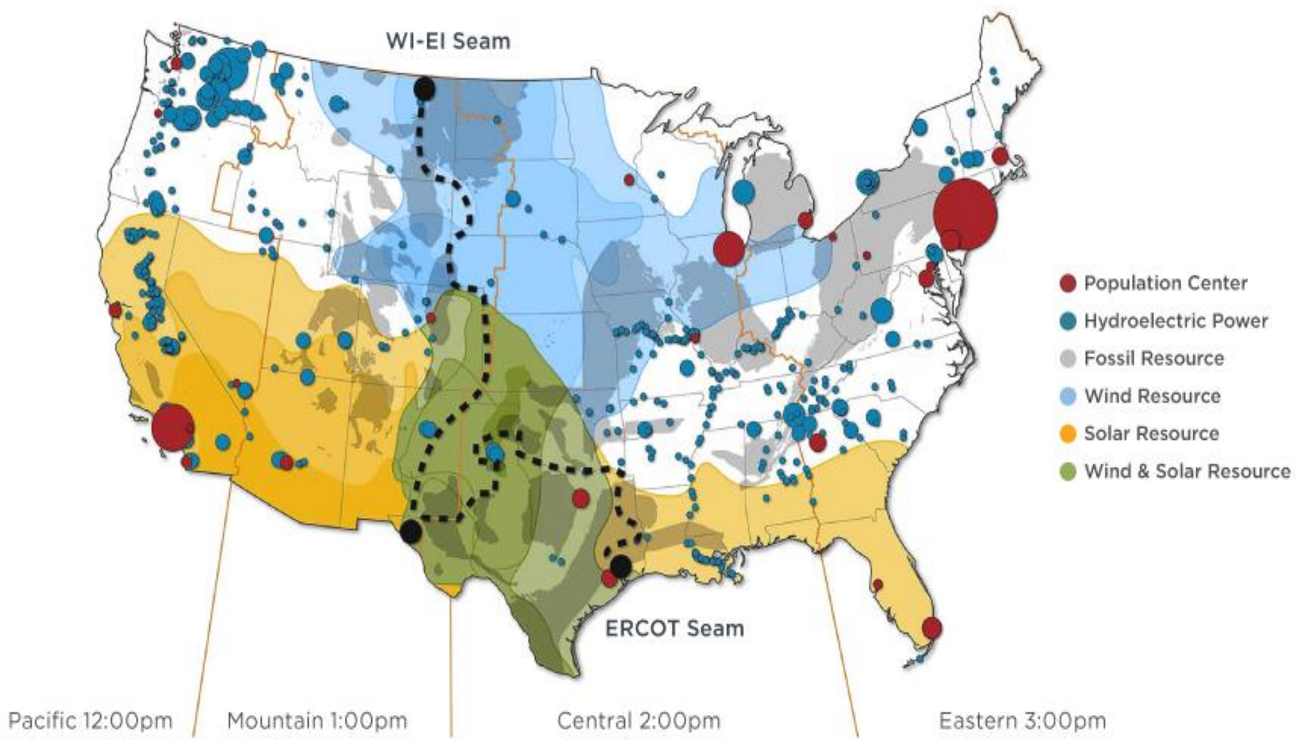
Existing Structured Markets



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

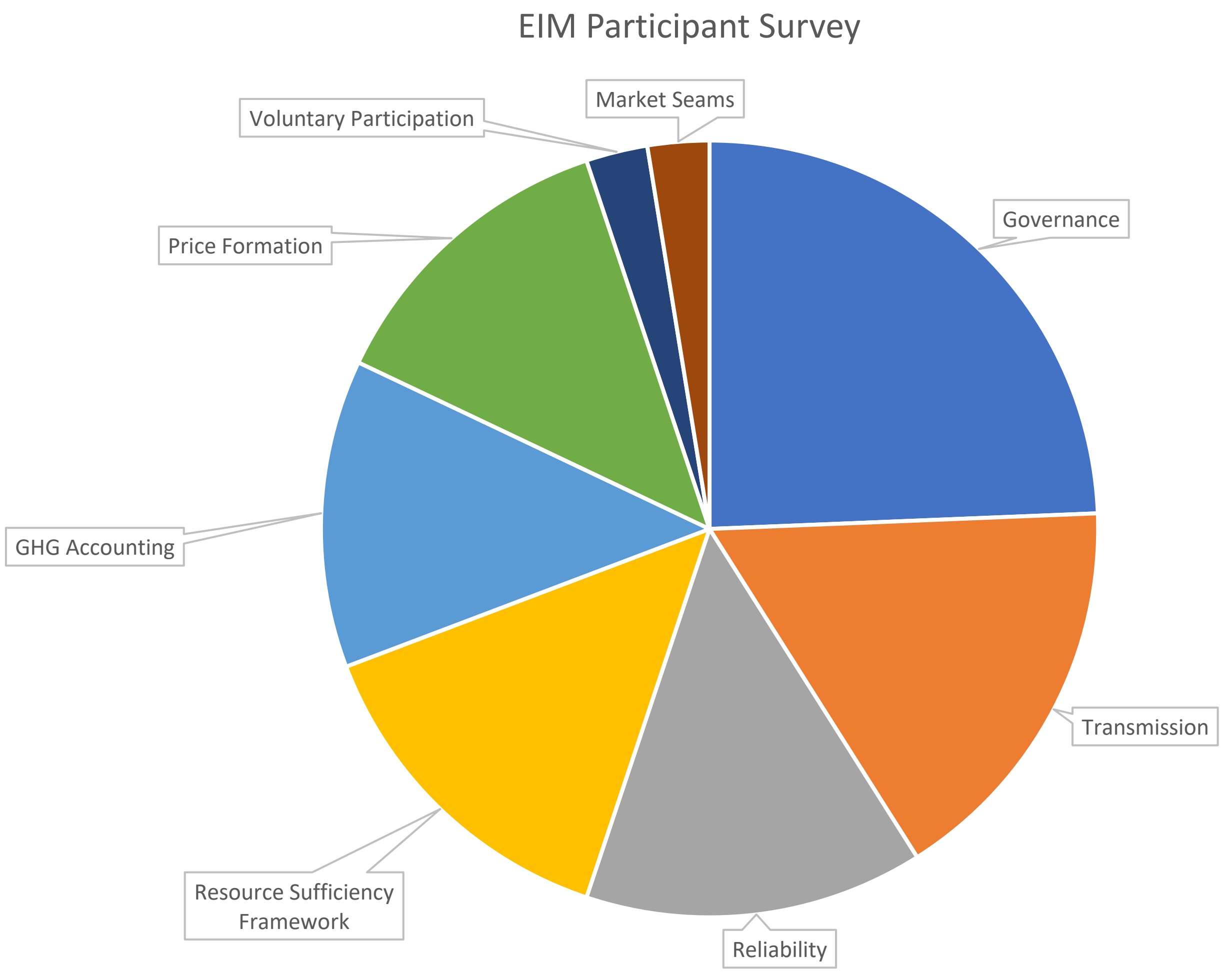
Not Offered

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.

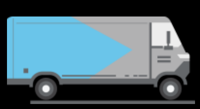
Appendix G: Electric Vehicle Market Overview

TEP EV Adoption and Grid Impact Analysis

Different EV Adoption Forecasts

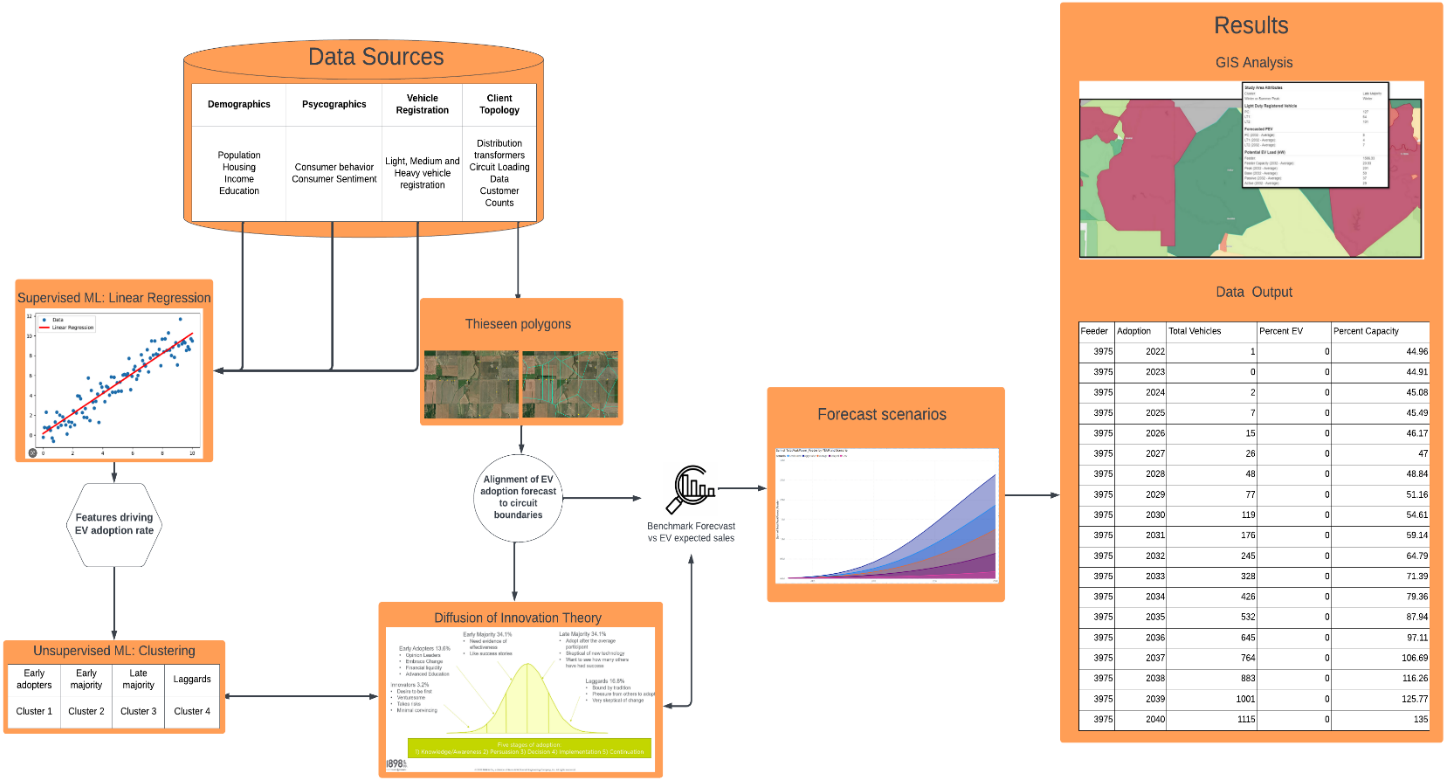
Residential Model: Census Tract analysis of population combined with different forecast scenarios

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



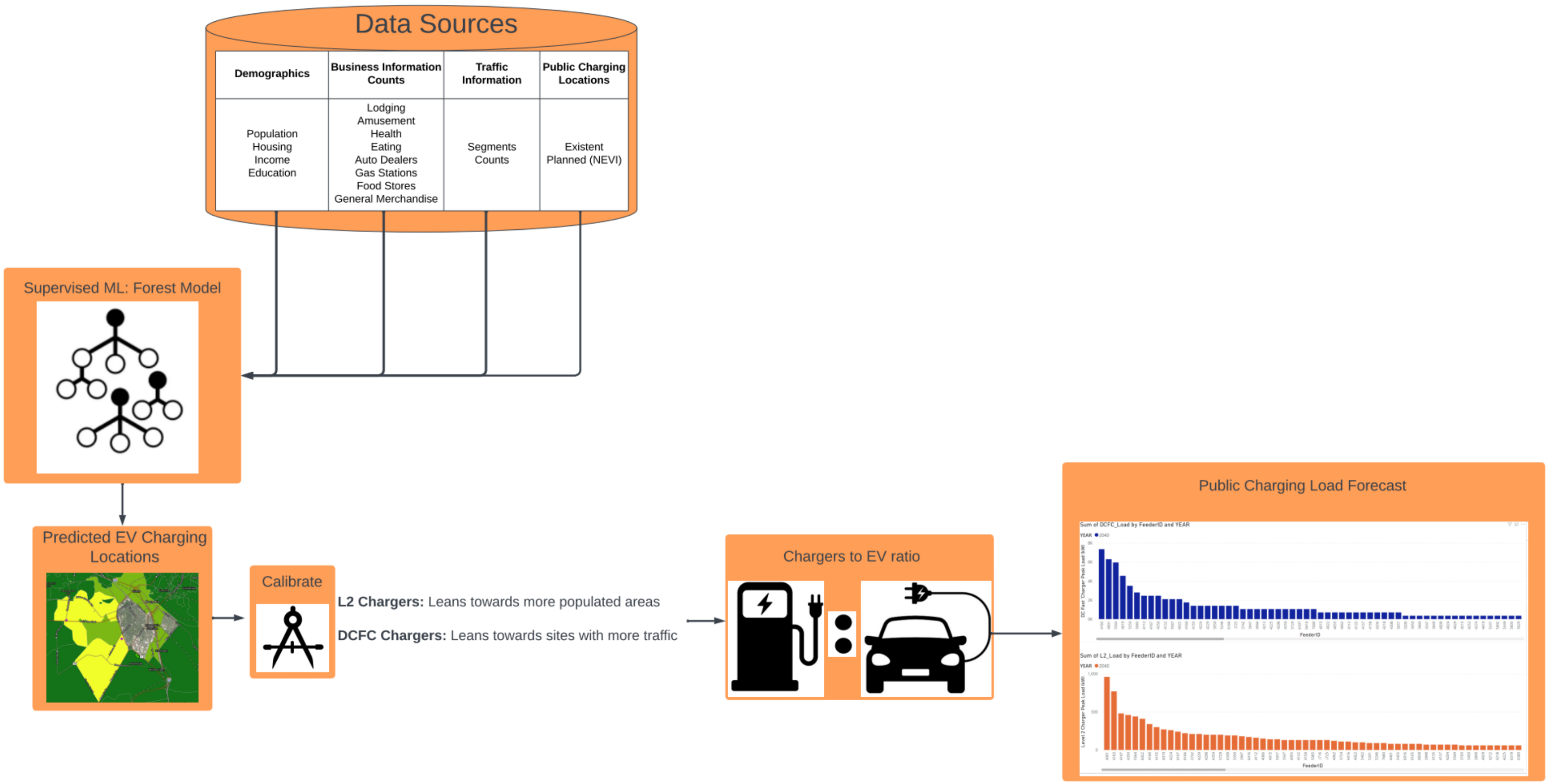
Fleet Model: Identify key companies that could electrify fleet and make assumptions around EV adoption

Residential Adoption Model

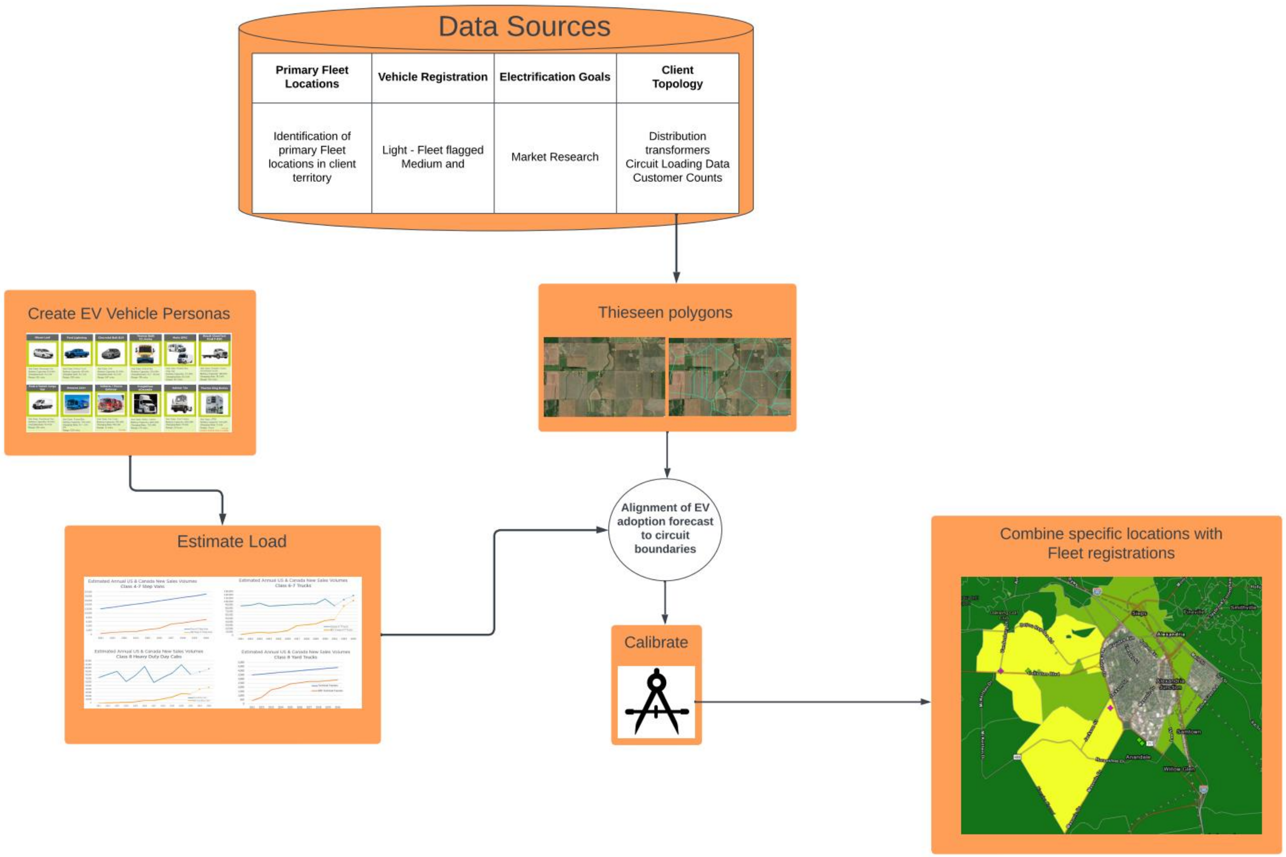


Feeder	Adoption	Total Vehicles	Percent EV	Percent Capacity
3975	2022	1	0	44.96
3975	2023	0	0	44.91
3975	2024	2	0	45.08
3975	2025	7	0	45.49
3975	2026	15	0	46.17
3975	2027	26	0	47
3975	2028	48	0	48.84
3975	2029	77	0	51.16
3975	2030	119	0	54.61
3975	2031	176	0	59.14
3975	2032	245	0	64.79
3975	2033	328	0	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


Data Sources
Primary Fleet Locations
Vehicle Registration
Electrification Goals
Client Topology
Identification of primary Fleet locations in client territory
Light - Fleet flagged Medium and
Market Research
Distribution transformers
Circuit Loading Data
Customer Counts
Create EV Vehicle Personas
Thieseen polygons
Estimate Load
Alignment of EV adoption forecast to circuit boundaries
Calibrate
Combine specific locations with Fleet registrations

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.

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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]

Ford, Chevrolet, Arrival, Hummer EV, Rivian, Lordstown, Tesla, XLFleet

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.

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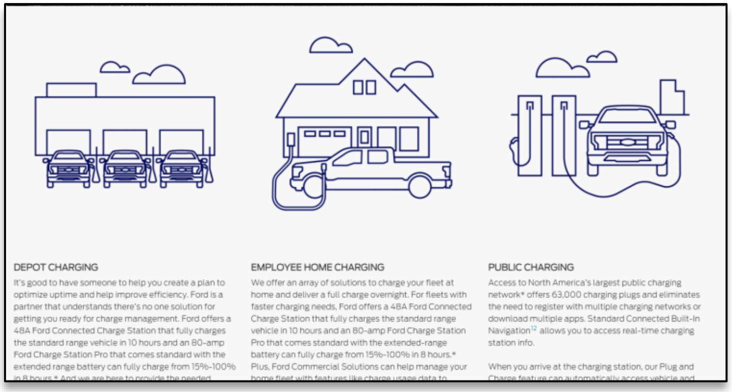
F-150 Lightning Pro

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



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.

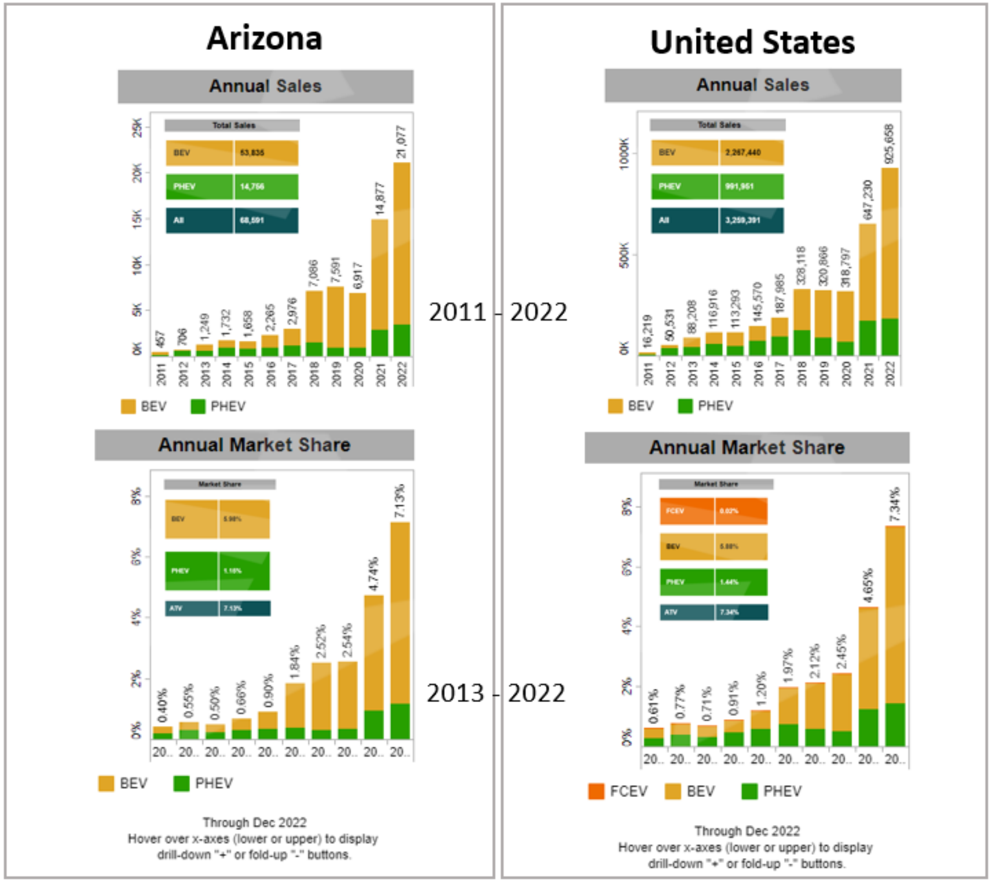
EV Market Share

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

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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:

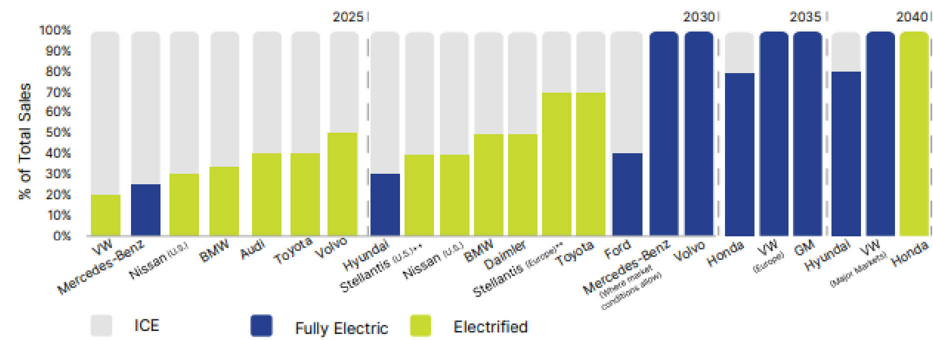
OEM EV Sales 2030:

- **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

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Vehicle Cost?

Contents

BloombergNEF

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 16th, 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.

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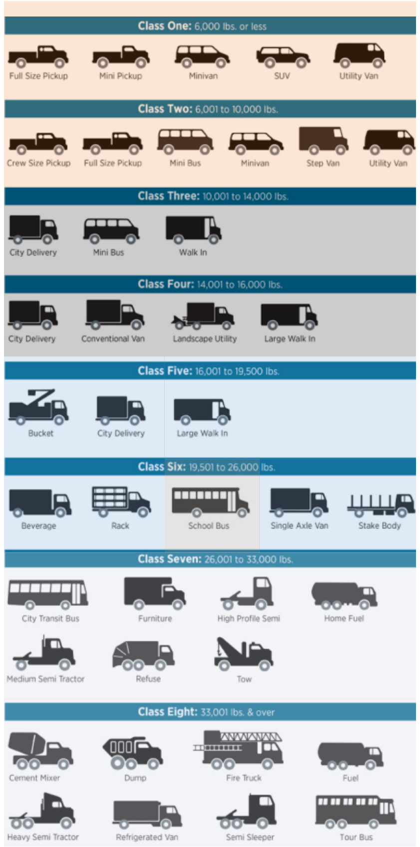
Vehicle Segment

Vehicle Types and Classifications Reference

Gross Vehicle Weight Rating (lbs)	Federal Highway Administration		US Census Bureau
	Vehicle Class	GVWR Catagory	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			Light Duty Vehicles
	H.D. Trucks	H.D. Engines	General Trucks	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

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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

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).

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

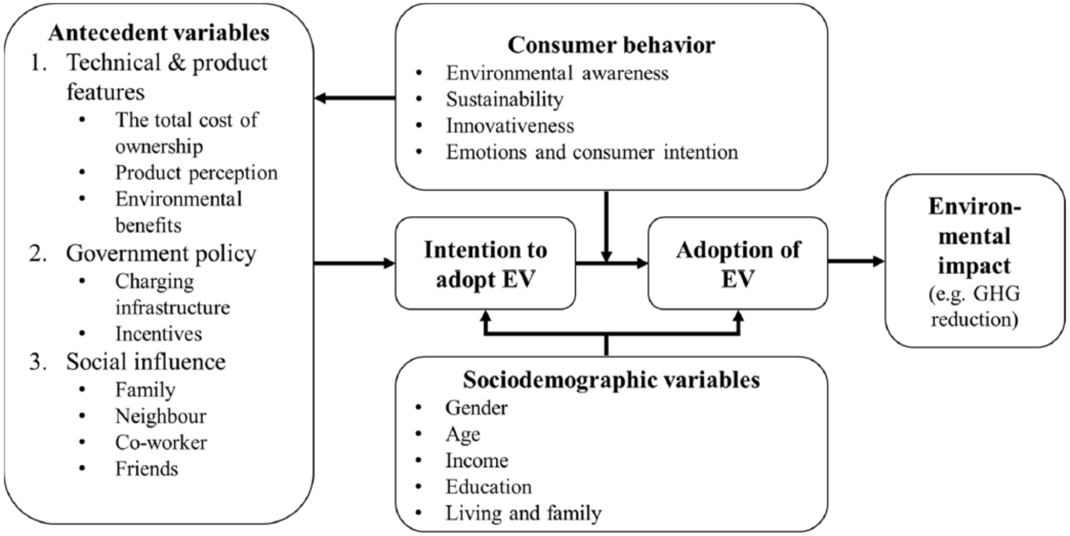


Figure 4. Overview of the context of adoption of EVs adapted and modified from Kumar and Alok (2020).

Residential Forecasting Methodology

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

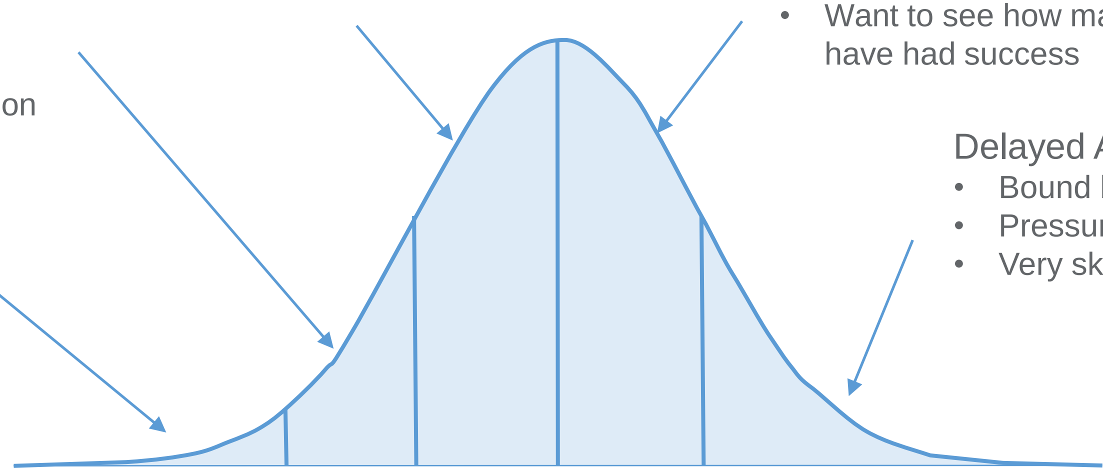
Innovators 3.2%
- Desire to be first
- Venturesome
- Takes risks
- Minimal convincing

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

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

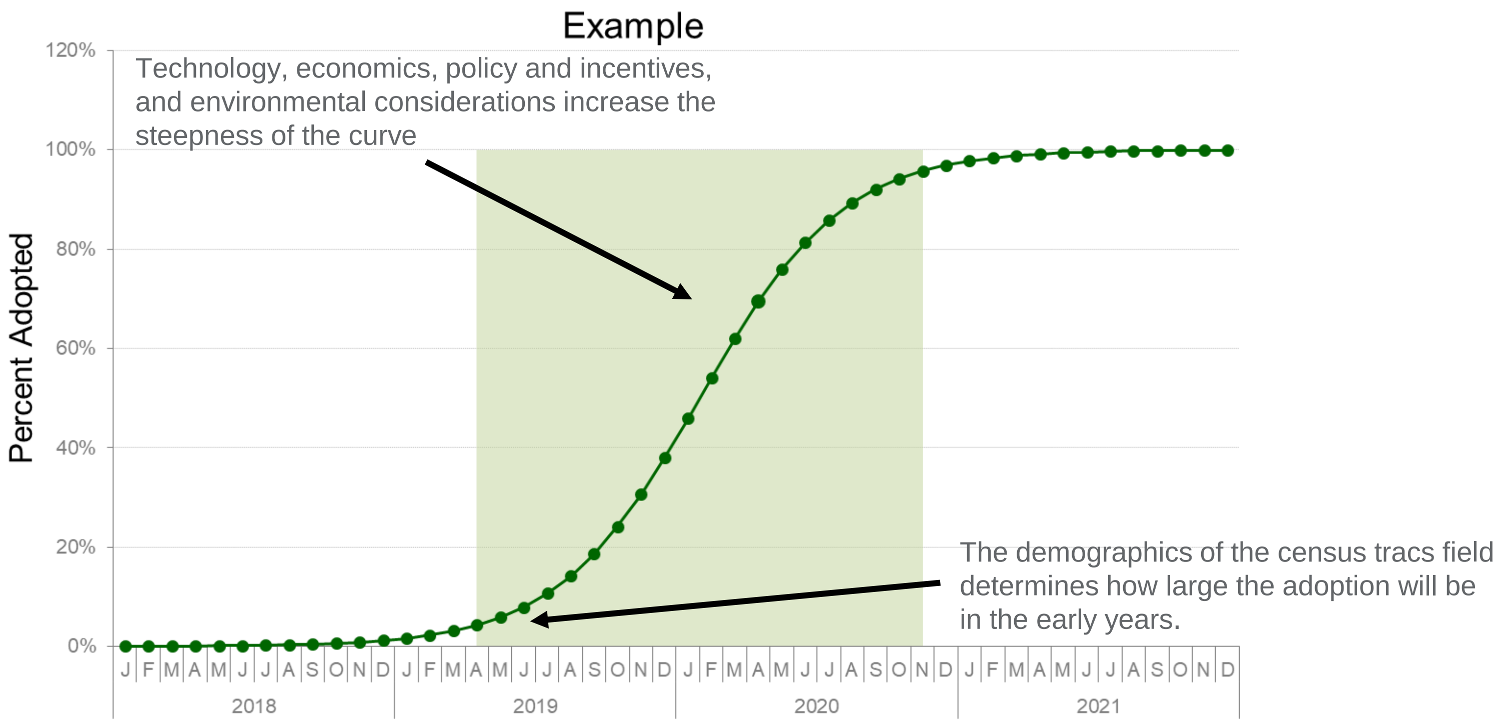
Late Majority 34.1%
- Adopt after the average participant
- Skeptical of new technology
- Want to see how many others have had success

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

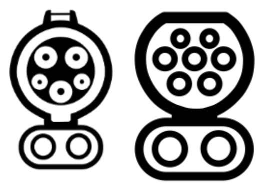
AC Ports
Favored in US & EU

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

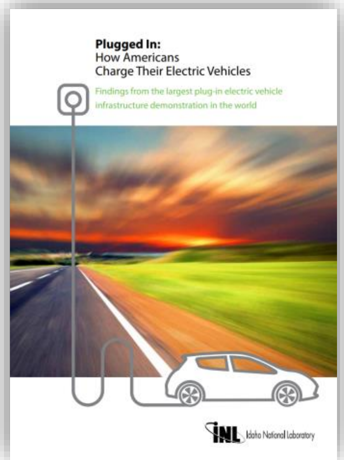
Where is EV charging likely to occur?

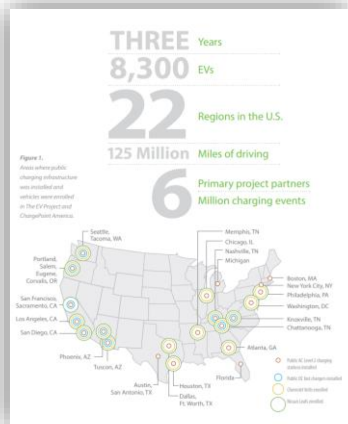
Idaho National Labs conducted a large study from 2011 to 2013 to answer this question:

"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."





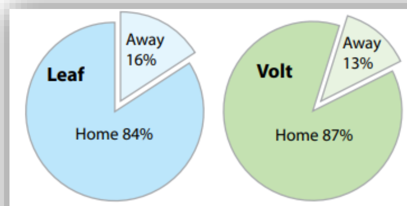


Figure 3.
Leaf and Volt drivers performed most of their charging at home.

Drivers of 5% of Volts and 13% of Leafs only ever charged at home, and about half the drivers charged away from home less than 5% of the time. Of the drivers that charged away from home, some

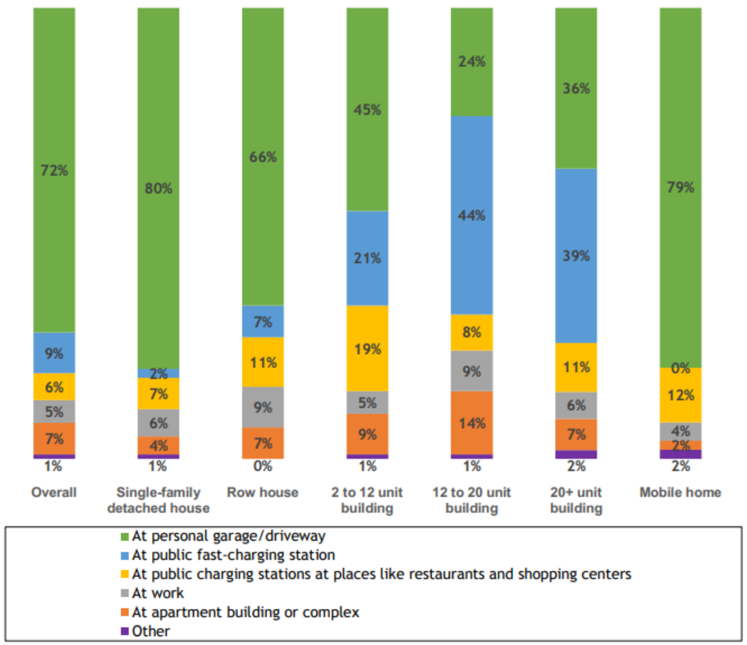
Note: half the drivers rarely charged away from home. But they still charged away from home and an another 50% charged away more frequently.

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

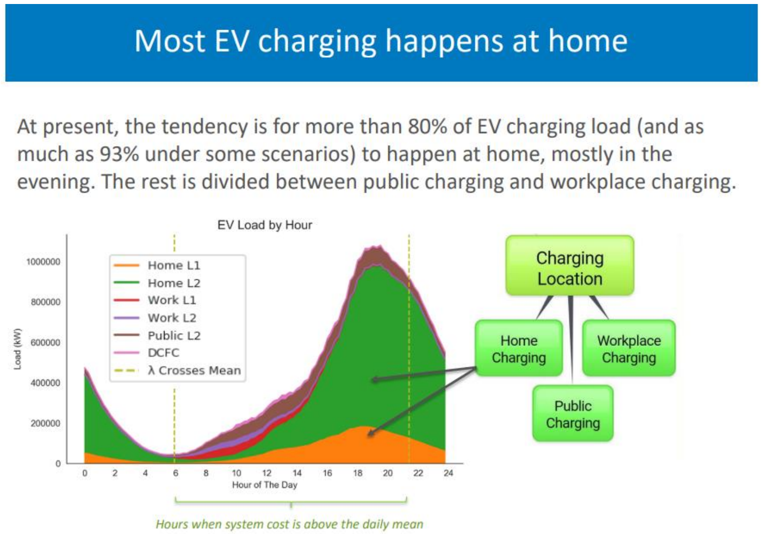
Updated Load Assumptions

Consumer Reports Survey



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

NREL EV Pro Lite



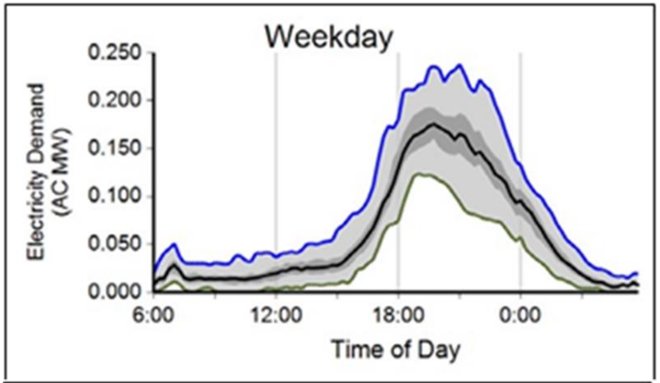
NREL simulation for Colorado using EVI-Pro, with electricity costs from Colorado utility rate books

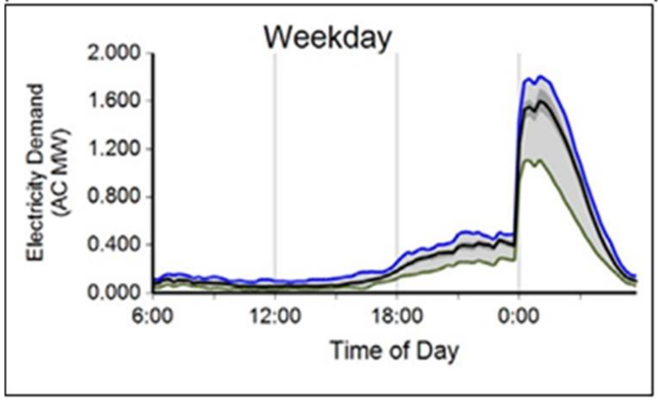
https://afdc.energy.gov/evi-pro-lite

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



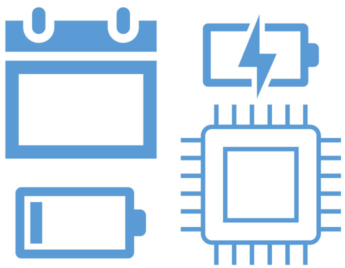


TEP

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.

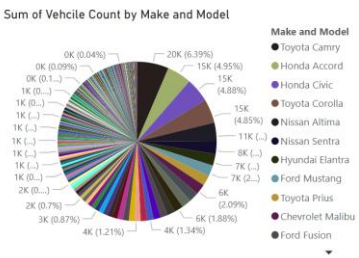


Managed charging: This assumes on-peak charging can be mitigated through passive or active measures such as TOU rates or Demand Load Control (DLC) programs. The potential still exists for on peak charging to occur; however, customers are given suitable benefits to charge at opportune times for the grid.

Residential Charging Scenarios and Assumptions

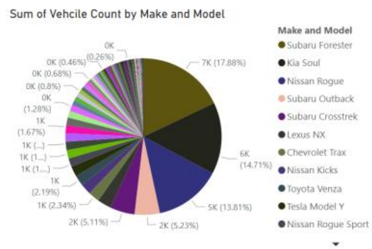
Grouped as LT_1

PC_0 



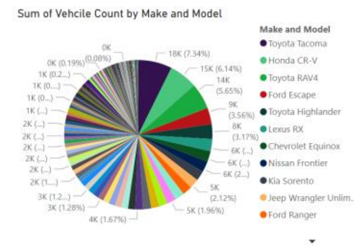
Level 1: 1.92 kW
Level 2: 7.7 kW

LT_0 



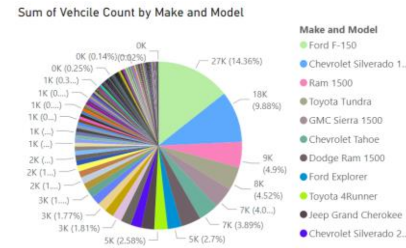
Level 1: 1.92 kW
Level 2: 11.5 kW

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

1 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, as well as other emissions and by-products produced by generation facilities. These power plant emissions and by-products 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 UNSE and its resource planning efforts. All existing and future resources are modeled taking into account the potential impact of environmental regulations.

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.[1]

EPA's action proposed to repeal the Affordable Clean Energy (ACE) Rule[2] 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 UNSE's existing EGUs and any development plans for new EGUs in the future. UNSE 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.

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 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)[3] (the 2015 ozone NAAQS), lowering the 75 ppb standard set in 2008[4] (the 2008 ozone NAAQS). In 2020, the ozone standards were reviewed by EPA and retained, without revision.[5]

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[1] 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).

[2] 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).

[3] U.S. EPA, National Ambient Air Quality Standards for Ozone, 80 Fed. Reg. 65,291 (Oct. 26, 2015).

[4] U.S. EPA, National Ambient Air Quality Standards for Ozone, 73 Fed. Reg. 16,436 (Mar,12, 2008).

[5] U.S. EPA, Review of the Ozone National Ambient Air Quality Standards, 85 Fed. Reg. 87,256 (Dec. 31, 2020).

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. UNSE 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[6] 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 NAAQSs, 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. Current $PM_{2.5}$ design values in Maricopa and Santa Cruz counties, where Gila River Power Station and Valencia Power Plant are located, respectively, sit above the proposed annual fine $PM_{2.5}$ standard of 9.0 $\mu g/m^3$. UNSE will continue to monitor the EPA's efforts to reconsider the current standard.

In addition to the regulatory programs and proposals highlighted above, Arizona's plan to limit the interstate transport of ozone, as it relates to the 2015 ozone NAAQS, is under EPA review. The State's updated plan to achieve reasonable progress toward the national goal to reduce visibility impairment in Class I areas, under the Regional Haze program, is also under EPA review. These and other state and federal air quality program developments may impact the operation of UNSE's generation resources and present broad implications to regional grid reliability, the mix of U.S. generating resources and economic growth.

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. This section provides an overview of UNSE's water use at its existing generating facilities and discusses its strategy to minimize overall water consumption.

Water consumption can have a localized environmental impact. The availability of water that is withdrawn from groundwater aquifers, as in the case of Gila River, Black Mountain and Valencia power plants, is dependent on the recharge to and other withdrawals from the aquifer, as well as the hydrogeological characteristics of the aquifer itself.

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, UNSE 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.

[6] U.S. EPA, 8Reconsideration of the National Ambient Air Quality Standards for Particulate Matter, 88 Fed. Reg. 5,560 (Jan. 27, 2023)

For the 2023 IRP, UNSE includes for each portfolio the change in water consumption over the planning period. For the Preferred Portfolio, the IRP will chart the annual amount of water consumed for power generation. Increasing water consumption within either of these source categories will be weighed as a risk factor for that portfolio.

Appendix I: Wholesale Power and Natural Gas Markets

1 Wholesale Power and Natural Gas Markets

Desert Southwest Wholesale Power and Natural Gas Markets

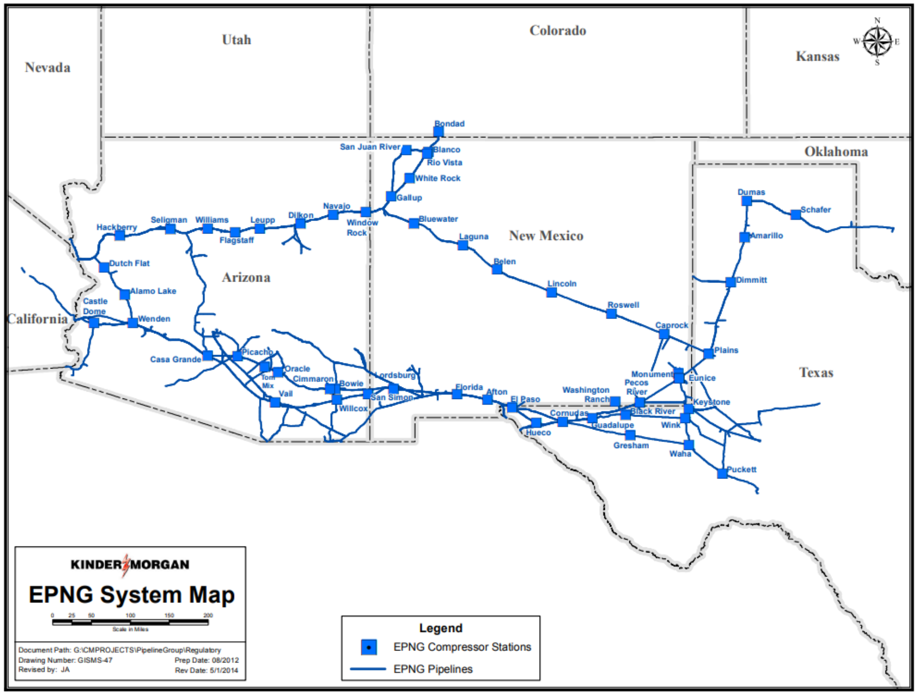
Wholesale power markets in the Desert Southwest historically have provided an efficient mechanism for utilities to buy and sell power as a means to optimize their resource portfolios and reduce costs for customers. However, extreme heat waves and winter weather events over the past three years have resulted 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 UNSE's portfolio modeling is important to account for how wholesale market opportunities are likely to affect UNSE's dispatch and operating costs.

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

UNSE 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]



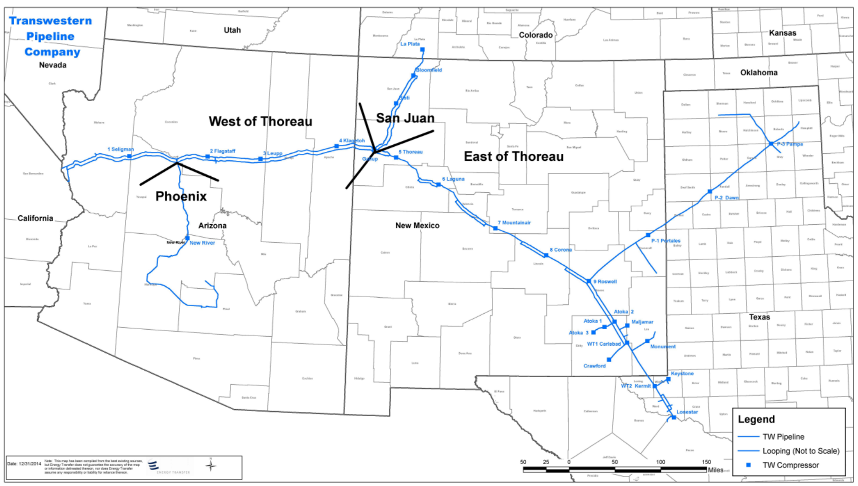
[1] https://pipeline2.kindermorgan.com/Navigation/SiteMap.aspx?code=EPNG

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

Natural Gas Storage

As part of the Company's future planning strategy, UNSE 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 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 UNSE's generation fleet.

Transwestern Pipeline Network Map



Forward Fuel and Power Forecasts

Fuel and power forecasts are prepared by UNSE 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, UNSE 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, UNSE 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, Distribution and Transmission Planning

1 Operations

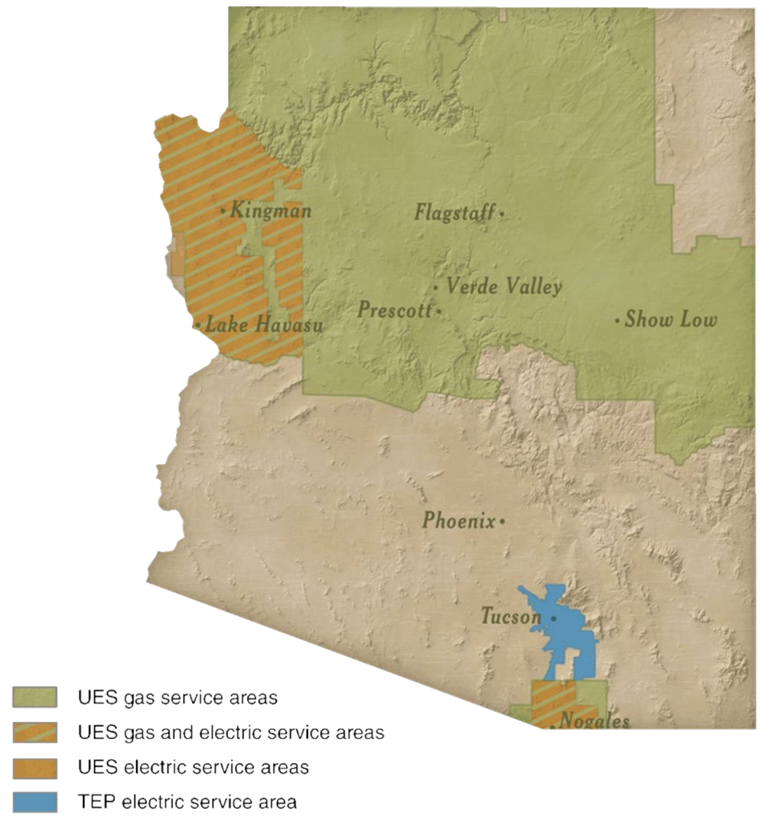
Balancing Authority Operations

UNSE has a Control Area Service Agreement (CASA) with TEP. Pursuant to the CASA, TEP provides services necessary for balancing UNSE's load and resources for safe and reliable operations. Additionally, the CASA enables UNSE to comply with the North American Electric Council's performance standards needed to support reliability across the Western interconnection. See TEP 2024 IRP, Appendix J for a detailed description on balancing authority operations and reliability performance standards.

Distribution Operations and ADMS

An Advanced Distribution Management System (ADMS) is the central software application that will provide distribution supervisory control and data acquisition, outage management and geographical information in a single interface providing improved visibility to UNSE operations personnel. By combining the information from these systems into a single 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 (i.e., solar and storage, charging electric vehicles, etc.), which can be used to evaluate how customers' load profiles impact supply-side resource decisions. UNSE began implementation of ADMS in 2020 and will continue to expand on the capabilities of the system as additional ADMS functionality is integrated and field devices are deployed.

Figure 1 - Map of UNSE and TEP Service Areas



2 Distribution Planning

2.1 Overview

Distribution facilities are critical resources that enable UNSE to provide safe and reliable service to its customers. Sufficient distribution capacity must exist throughout the system to meet UNSE's existing and future load forecasts. UNSE's distribution engineer coordinates with TEP's distribution and transmission planning group to ensure the most cost effective and beneficial system upgrades are planned and implemented to meet customer demand.

2.2 Distribution Planning Analysis

UNSE's distribution system is studied and to accommodate load growth from existing customers as well as new customers. 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, 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.

For the Santa Cruz County area, Distribution Planning 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.

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

Table 1. Major Planned Distribution System Additions

PROJECT	DESCRIPTION	OTHER NOTES
Feeder Tie EA5022-5024 **In Service Date [ISD] 2025**	Install tie switch between circuits 5022 and 5024 out of Eastern Substation.	1) Supports new business 2) Improves System Reliability
Cheyenne Substation **(ISD 2025)**	New 69-12.47 kV substation	1) Supports new business 2) Permits future looping opportunities
East Mohave Feeder Upgrade **Phased project thru 2029**	Replace 4/0 primary with 559 AAAC conductor and re-route portions of the line to improve accessibility	1) Increases capacity 2) Improves voltage 3) Improves protective coordination
Circuit 6013 Extension (LHC) **In Service Date 2023**	Three phase extension, London Bridge Road	1) Supports load growth

2.3 Distribution Modernization

UNSE is in the early stages of exploring smart grid technologies. The district engineer evaluates prospective smart grid equipment vendors and identifies areas of the grid that will reap the greatest reliability benefits from this emerging technology. Although UNSE expects to collaborate with TEP in some of these efforts, it is anticipated that some UNSE-specific vendors and projects will be identified due to the uniqueness of the Mohave County demographics and load structure.

3 Transmission Planning

UNSE shares Transmission Planning functions with TEP. See the TEP 2023 IRP, Appendix J.

Appendix K: Future Resource Technologies

Future Resource Technologies

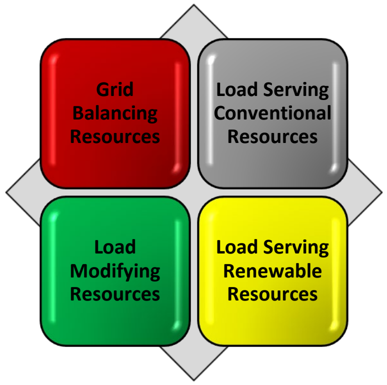
This chapter provides an overview of the future resources considered for development in the Company's resource portfolio. Based on this information and the Company's current resource mix and its commitment to reducing carbon emissions, only combustion turbines, solar, wind, and energy storage were considered 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 UNSE 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

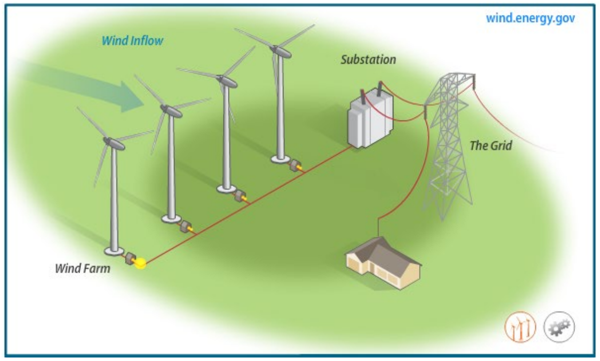
Future energy sources are primarily clean energy generation such as combustion turbines, renewables and nuclear, or storage technologies – batteries, thermal storage, mechanical storage, and hydrogen energy storage. Resources discussed here as potential additions to the portfolio are based on the Company's 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

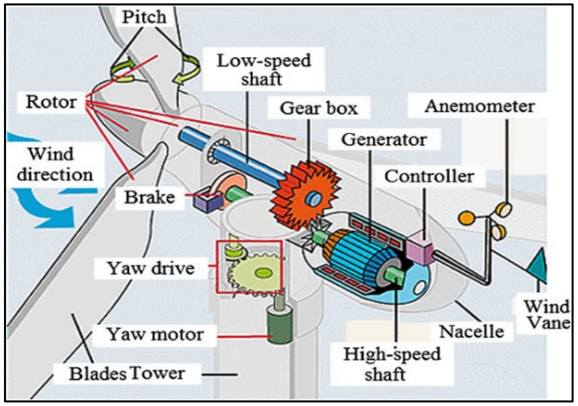
Wind

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

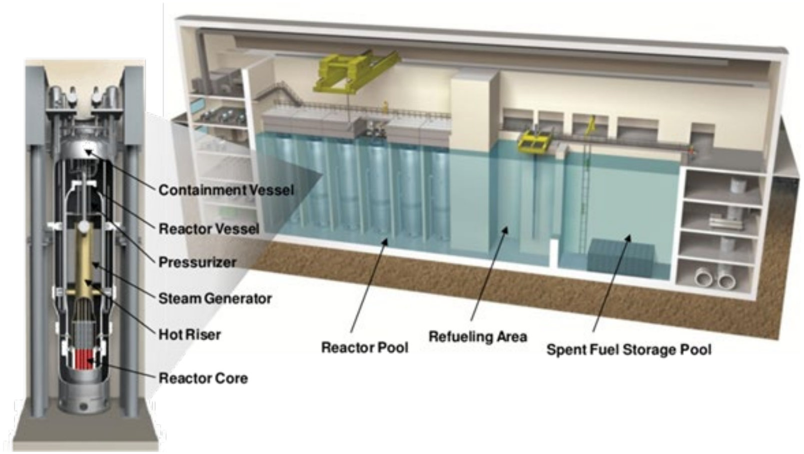
Small modular reactors are nuclear fission reactors that features factory-built-and-assembled modules in a variety of configurations. SMRs are approximately a tenth to a quarter the size of a traditional nuclear energy plant (300 MW or less) and feature compact, simplified designs with advanced safety 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.

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[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.

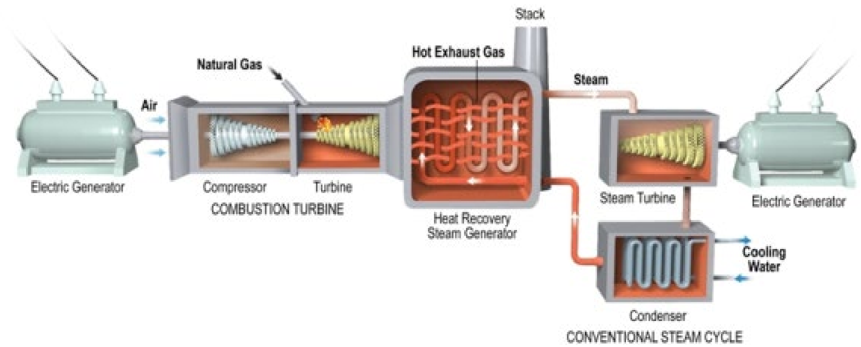
Operational Characteristics

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)

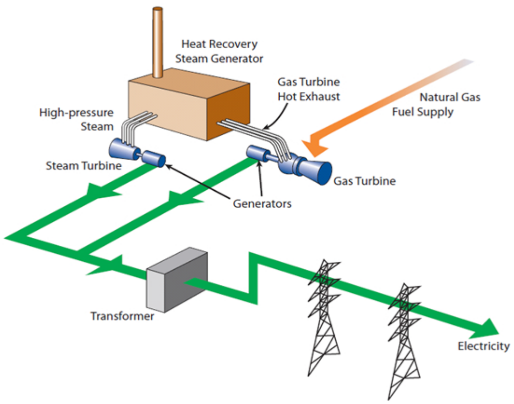
General Description

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

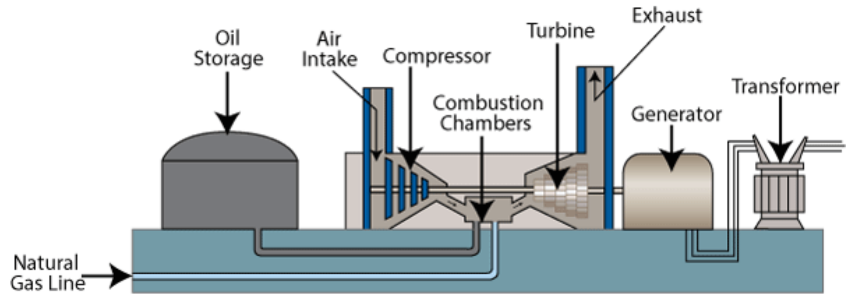
NGCC plants are capable of changing output more rapidly and following load more closely than technologies relying strictly on steam. Output can be enhanced by cooling the air intake with foggers and by adding additional heat to the combustion turbine exhaust.

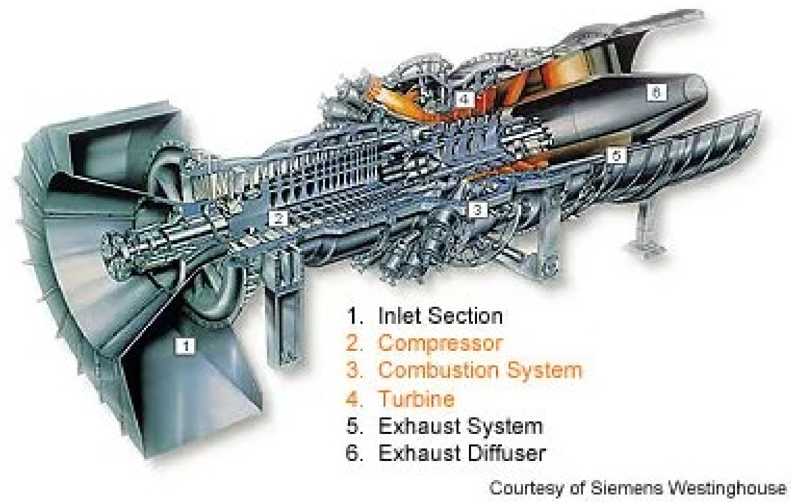


Combustion Turbines

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.





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.

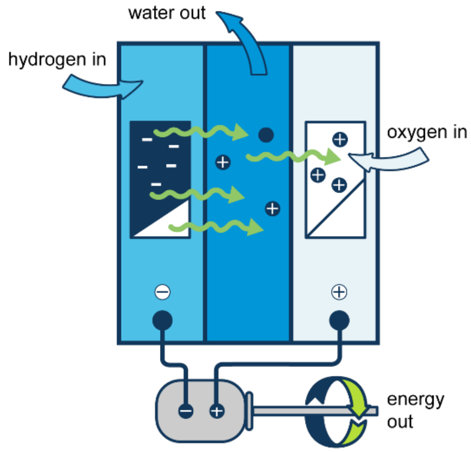
Operational Characteristics

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*

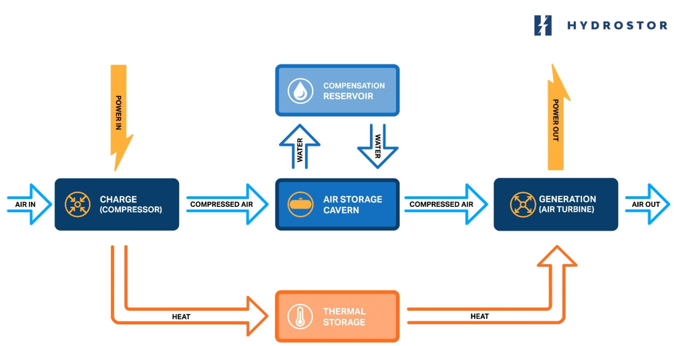
Energy Storage Technologies

Advanced Compressed Air Energy Storage (ACAES)

General Description

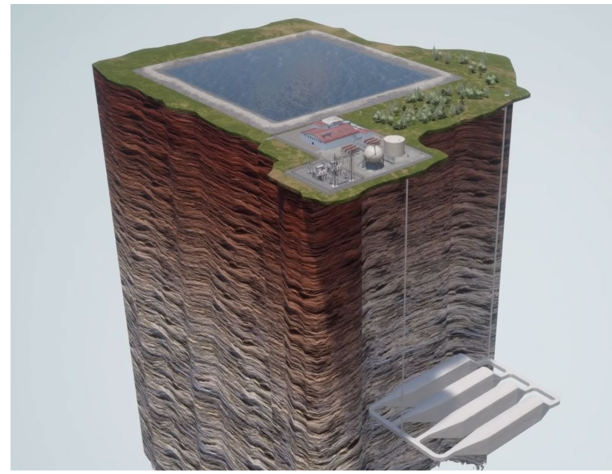
ACAES is an alternative to other forms of bulk, multi-hour energy storage such as pumped hydro, and can potentially offer shorter construction times, greater siting flexibility, lower capital costs, and lower cost per hour of storage than pumped hydro. ACAES is a hybrid generation/storage technology 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

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[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

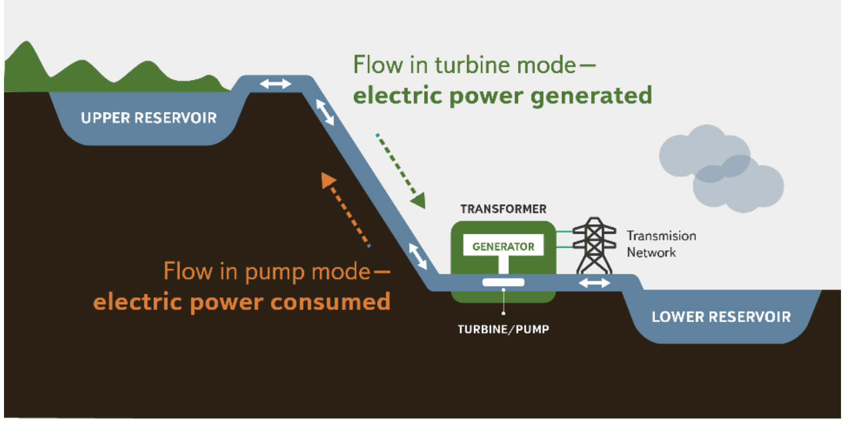
Pumped Storage Hydropower (PSH) is a type of hydroelectric energy storage system that stores energy by using two water reservoirs at different elevations. During periods of excess electricity supply (usually during low-demand hours), the surplus electricity is used to pump water from the lower reservoir 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

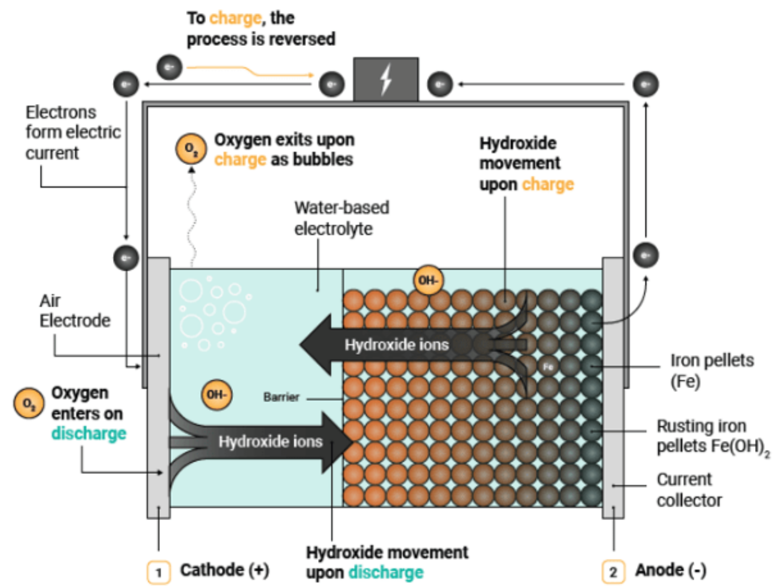
General Description

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

[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

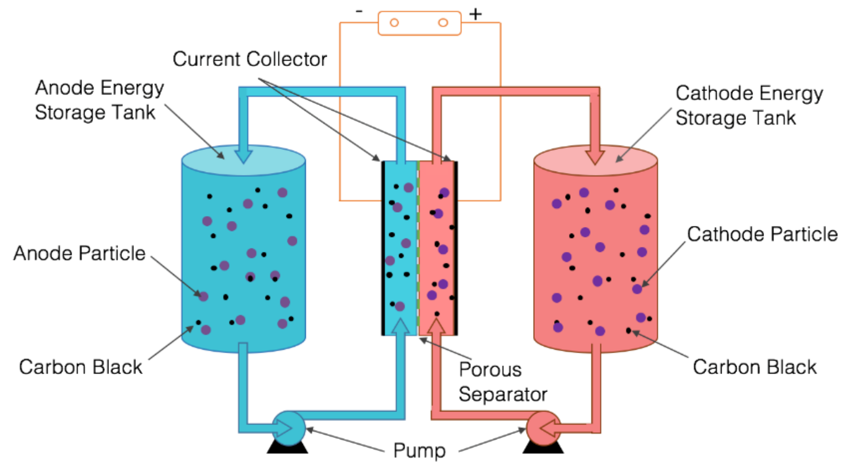
Environmental and Siting

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.

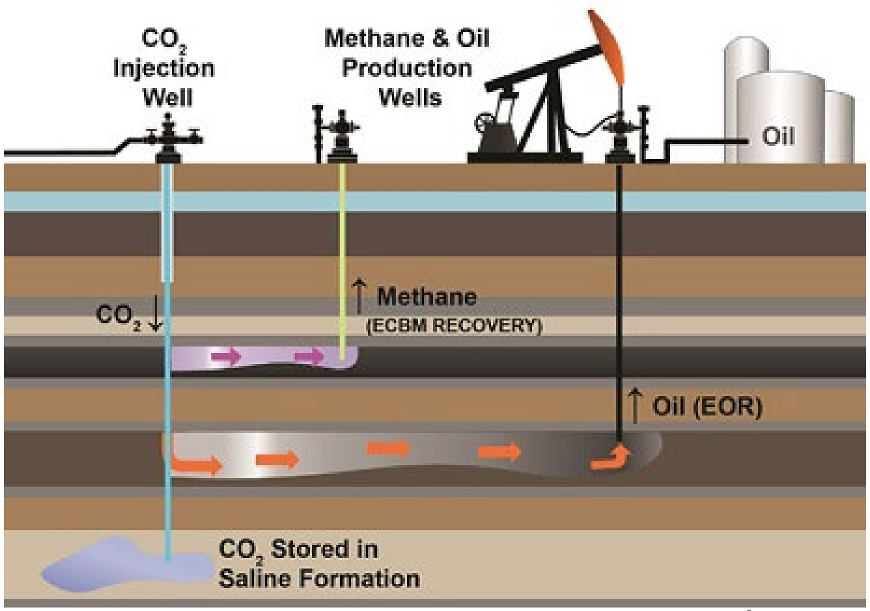
Environmental and Siting

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

CO2 commodity industry for use in enhanced oil recovery (EOR), bio-refining, and other products[11].
Industrial CCS produces high purity CO2 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 CO2 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. CO2 can also leak through permeable substances or man-made routes like abandoned drilling wells. Further, since liquid amine solutions are used to capture CO2 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 CO2.

[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