UNS ELECTRIC INC.

2020 Integrated Resource Plan

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List of Acronyms

ACRONYMS

ACC – Arizona Corporation Commission
ADMS – Advanced Distribution Management System
AEO – Annual Energy Outlook
AMI – Automated Metering Infrastructure
ASRFP – All-Source Request for Proposal
ATB – Annual Technology Baseline
BA – Balancing Authority
Btu – British Thermal Unit
C&I – Commercial and Industrial
CAISO - California Independent System Operator
CO_2 – Carbon Dioxide
DC – Direct Current
DER – Distributed Energy Resources
DG - Distributed Generation
DMS – Distribution Management System
DR – Demand Response
DSM – Demand Side Management
E3 – Energy and Environmental Economics
EE – Energy Efficiency
EHV – Extra High Voltage
EIA - Energy Information Administration
EIM – Energy Imbalance Market
EPNG – El Paso Natural Gas
EPRI – Electric Power Research Institute
EV – Electric Vehicles
FERC – Federal Energy Regulatory Commission
GW – Gigawatt,
GWh – Gigawatt-Hour
HVAC – Heating Ventilation Air Conditioning
ICE – Intercontinental Exchange index
IRP – Integrated Resource Plan
ITC – Investment Tax Credit
kW – Kilowatt
kWh – Kilowatt-Hour
LCOE – Levelized Cost of Energy
LGS – Large General Service
LPS – Large Power Service
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
MW – Megawatt
MWh – Megawatt-Hour
NGCC – Natural Gas Combined Cycle
NOAA – National Oceanic and Atmospheric Administration
NO_X – Nitrogen Oxide(s)
NPV – Net Present Value
NPVRR – Net Present Value Revenue Requirement
NREL – National Renewable Energy Laboratory
O&M – Operations and Maintenance
PPA - Purchased Power Agreement
PTC – Production Tax Credit
PSD – Prevention of Significant Deterioration
PV – Photovoltaic
RES – Renewable Energy Standard
RICE – Reciprocating Internal Combustion Engine
RTP – Real Time Pricing
SAT – Single-Axis Tracking
SCADA – Supervisory Control and Data Acquisition
SCR – Selective Catalytic Reduction
SGS – Small General Service
SO_2 – Sulfur Dioxide
SRP – Salt River Project
TEP – Tucson Electric Power Company
TOU – Time-of-Use
UES – UniSource Energy Services (Parent Company of UNS Electric)
UNSE –UNS Electric, Inc.
U.S. – United States
WAPA – Western Area Power Authority

Forward

Sustainable, Reliable, Affordable Energy for the Future

Although the evolution of technology is rapidly reshaping how we provide energy, one thing remains constant: Our commitment to delivering reliable, affordable service to the communities we serve.

Our 2020 Integrated Resource Plan (IRP), which was informed by input from customers and other stakeholders during workshops, continues our ongoing shift away from a dependence on purchased power to greater self-reliance with our own cleaner generating assets. Although UNS Electric will continue to make capacity purchases, we're pleased that market purchases have been reduced to slightly more than a third of our retail energy mix, providing greater certainty for our customers and ensuring a stronger, more flexible resource portfolio.

A robust mix of resources that includes an expanding portfolio of cost-effective renewable resources and efficient natural gas generation will be necessary to achieve our goals during this period of energy transition. We'll also offer customers new opportunities for energy efficiency and managing peak energy demands. All of these resources will play key roles in ensuring sustainable, responsive service.

We're excited about our steady march toward a cleaner energy future. UNS Electric has already surpassed the state's Renewable Energy Standard and continues to work toward a goal of supplying 50 percent of its energy to retail customers from renewable resources by 2035, taking advantage of anticipated rapid changes in price and technological advancements while advancing our commitment to decreasing our carbon emissions.

Those rapid changes, however, also introduce some uncertainty, which is why we will rely on flexible, measured and thoughtful evaluation of the available options to meet our future needs. This approach will allow us to take advantage of reductions in the cost and improvements in reliability for wind, solar and storage technologies.

We are committed to a thorough exploration of how these technologies will best fit with our existing infrastructure and unique operating conditions. Our goal is simple: to develop the most cost-effective resource portfolio that provides safe, reliable and affordable service and to support continued growth in Arizona.

David G. Hutchens
CEO

CHAPTER 1

EXECUTIVE SUMMARY

Introduction

Since UNS Energy Corporation acquired UNS Electric Inc., (UNSE or "Company") (formerly Citizens Arizona Electric) in 2003, UNSE has added approximately 250 megawatts (MW) of new generating resources to enhance reliability and reduce its reliance on the wholesale power market to meet the majority of customers' energy needs. These additions include the construction of 115 MW of combustion turbine capacity and the acquisition of 138 MW in Block 3 at the Gila River Generating Station ("Gila River"), UNSE's first baseload and intermediate generating resource.

In addition, UNSE has added 104 MW of renewable resources since 2011, resulting in the Company surpassing the Arizona Corporation Commission's (ACC or "Commission") Renewable Energy Standard (RES)[1] 2025 goal of serving 15 percent of retail sales from renewables, six years ahead of schedule. The Company currently serves 20 percent of retail sales from renewable resources using solar and wind technologies procured through a combination of self-build facilities and long-term purchased power agreements (PPAs).

Notwithstanding these system improvements as well as the continuation of energy efficiency programs, additional resources will be required to meet anticipated load growth and to further reduce reliance on market power and capacity. UNSE is at a crossroads. The cost of solar and wind resources have declined drastically over the past three years making these resources the lowest cost forms of energy, and further declines are anticipated. However, significant shortfalls in near-term capacity point to a need for conventional resources, particularly for maintaining reliability to address capacity shortages lasting several hours.

During stakeholder workshops held in December 2019 in Lake Havasu City and Kingman, participants expressed support for increasing the amount of renewable resources serving UNSE customers, if it could be done without negatively impacting affordability. In addition, the workshop participants recognized the uncertainty in the long-term cost effectiveness of certain resources. They expressed hesitancy in investing in nascent storage technologies that are projected to cost less in future years, and in investing in natural gas-fired resources that could see steep increases in fuel prices. In short, the participants preferred to avoid "big bets" on long-term assets with uncertain futures.

UNSE's 2020 Integrated Resource Plan (IRP) identifies the current and anticipated changes facing the utility industry, and UNSE specifically. The potential impact of these uncertainties is evaluated through a robust portfolio analysis and risk assessment. This analysis presents a snap shot of current loads and resources and projects future energy and capacity needs through 2035. UNSE presents the 2020 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). 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.

[1] Arizona Administrative Code R14-2-1801 et. seq.

UNSE shares several business functions with its sister company, Tucson Electric Power Company ("TEP"), including but not limited to:

- Resource Planning and Acquisition
- Balancing Services
- Transmission Planning
- Corporate Environmental Compliance
- Energy Efficiency Coordination and Implementation
- Management of Gila River

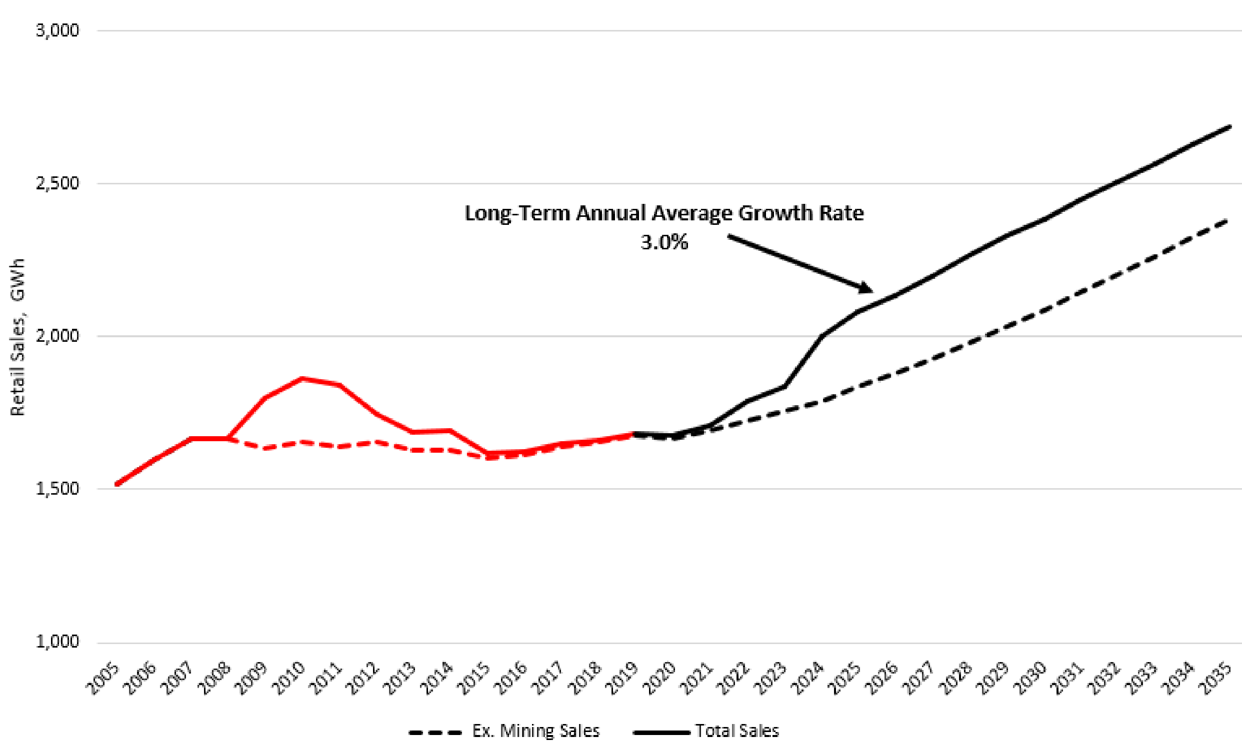
Therefore, in order to avoid unnecessary duplication of vastly similar information, this IRP refers to and incorporates by reference the following sections of the Tucson Electric Power 2020 Integrated Resource Plan. TEP's IRP can be found at: https://www.tep.com/wp-content/uploads/TEP-2020-Integrated-Resource-Plan-Lo-Res.pdf.

- Balancing Authority Operations and Standards – Chapter 3, Page 46.
- Electric Vehicles – Chapter 4, Page 76.
- The Future of Customer-Sited Energy Resources – Chapter 4, Page 80.
- Distribution Planning Analysis – Chapter 5, Page 83.
- Transmission Planning Overview – Chapter 5, Page 87.
- Environmental Requirements– Chapter 6, Page 100.
- Load Serving Resources – Chapter 6, Page 125.
- Grid Balancing and Load Leveling Resources – Chapter 7, Page 169.
- Regional Transmission Planning – Chapter 8, Page 185.
- Siemens Resource Adequacy Study – Appendix A
- Future Resource Technology Summaries – Appendix B

Load Forecast and Reserve Margin Requirement

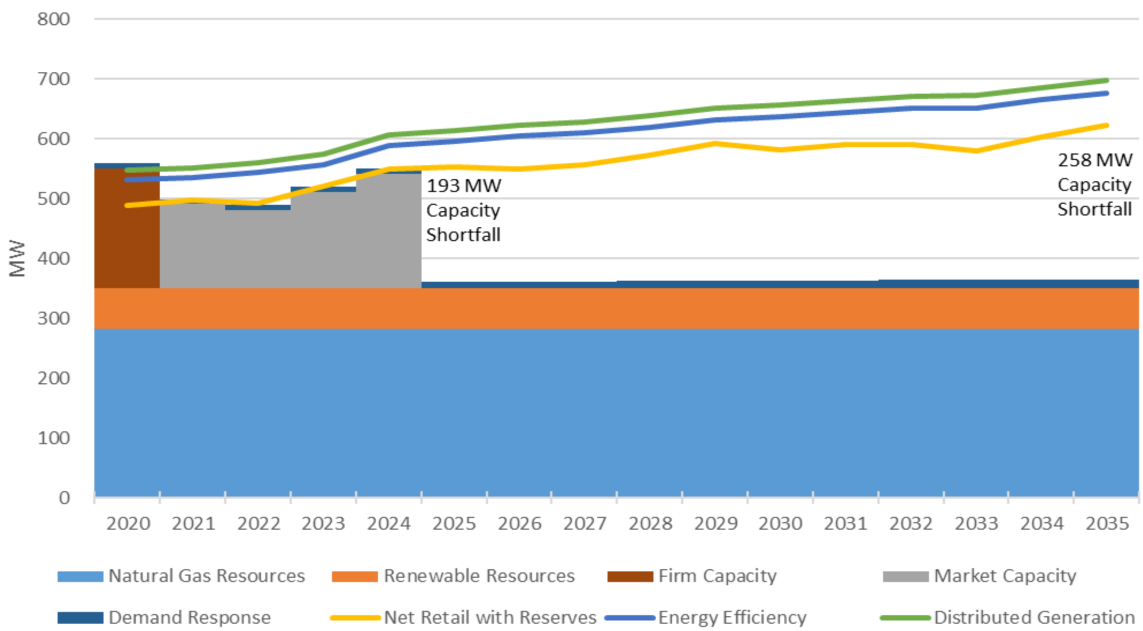
UNSE's the underlying sales forecast excluding mining is showing an expected annual growth rate of 2.3 percent in the 2020-2035 period. In the near future, UNSE is expecting mining load to return to UNSE's service territory. Including this mining load brings the expected annual growth rate to 3.0 percent.

UNSE's Historical and Forecast Retail Sales (2008-2035)



UNSE targets a 15 percent planning reserve margin during the months of May through September in order to maintain sufficient resource capacity to meet its firm load obligations. The chart below shows UNSE's net retail load requirements including minimum reserves based on the retail load forecast presented on the prior page. The chart below shows UNSE's 2020 firm wholesale purchased power commitments along with the Company's plan to acquire future market capacity through 2024. The Company's capacity shortfalls and the need for additional firm resources are apparent from 2025 through 2035.

UNSE's Current Load and Resources Outlook (2020-2035)



Resource Adequacy

In addition to meeting peak load, UNSE's system must have the flexibility to balance short-term and multi-hour ramps in net load and to manage over generation. These operational issues will become much more significant as UNSE brings more renewable energy onto its system. This inherently involves consideration of TEP's loads and resources since UNSE is included in TEP's Balancing Authority area. This IRP evaluates the flexibility requirements of UNSE under different renewable penetration scenarios and whether those requirements can be met with existing resources.

The increases in UNSE's flexibility requirements are well within the planned capabilities if the TEP Balancing Authority area. All of the UNSE portfolios being considered in this IRP include 35 to 175 MW of battery-based energy storage, and all but one include the addition of fast-start, fast-ramping gas-fired resources. Thus, for the renewable energy penetration scenarios considered in this study, no additional resources appear necessary for the purposes of integrating and balancing renewable energy supplies

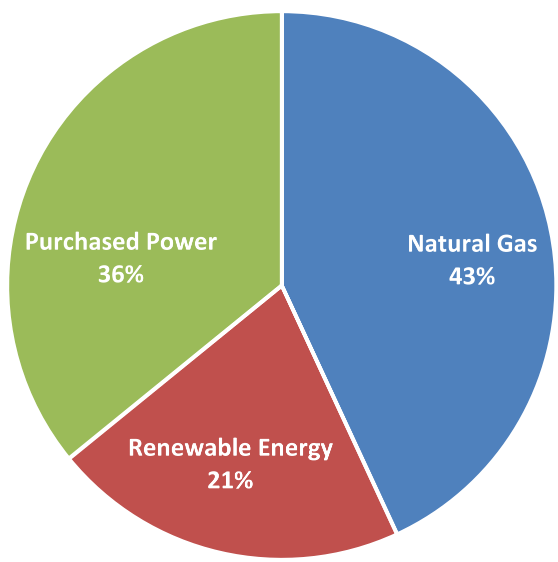
Customer-Sited Resources and Distribution Modernization

UNSE is continually modernizing the distribution grid in order to operate the grid more safely, efficiently, and reliably while integrating customer–sited energy resources and other new energy technologies. Current modernization programs include: the installation of a foundational communication network, the implementation of an Advanced Distribution Management System (ADMS), an Automated Metering Infrastructure (AMI), and enhanced systems that improve situational awareness for field personnel.

UNSE Existing Resources

UNSE currently owns 291 MW of thermal resource capacity. In addition, the Company relies on the wholesale power market for firm capacity PPAs to meet its summer peak demand obligations. Between 2011 and 2018, the Company added 104 MW of renewable resources including owned facilities and long-term PPAs. The chart below presents UNSE's 2019 retail energy mix.

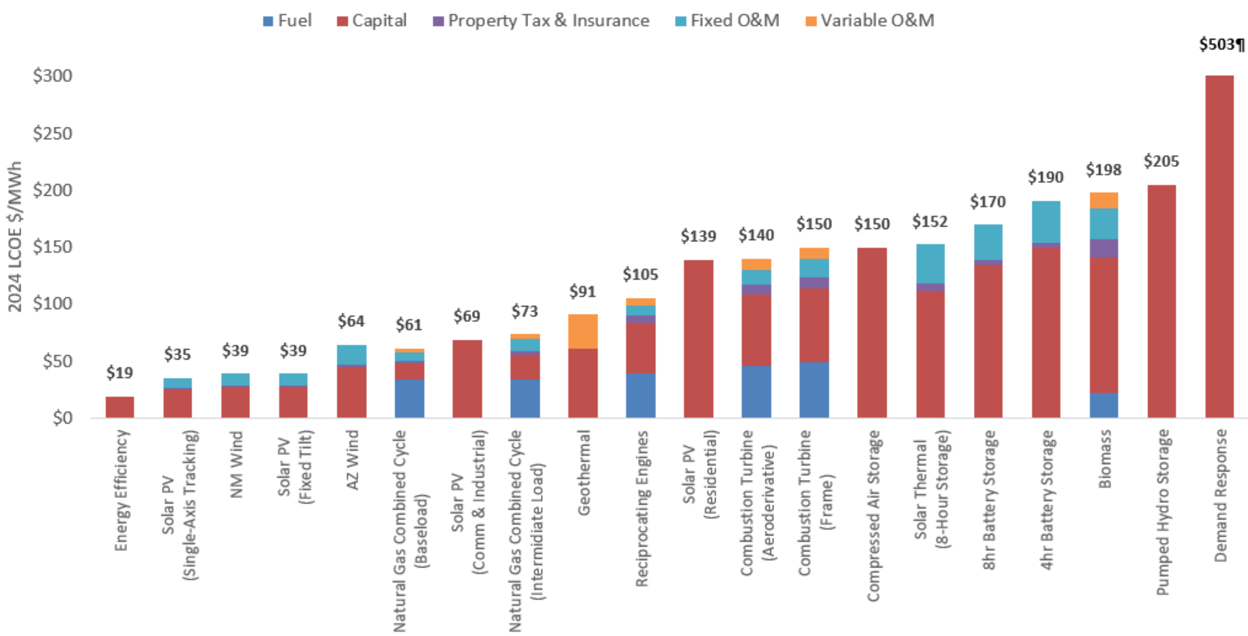
UNSE 2019 Retail Energy Mix



Future Resource Alternatives

UNSE evaluated a wide range of resource as potential additions to the UNSE system. Resources are evaluated based on key characteristics including environmental performance, level of deployment, location and any related interconnection difficulty, dispatchability and cost. The chart below presents the Levelized Cost of Energy for various resource options.

Levelized Cost of Energy Resources



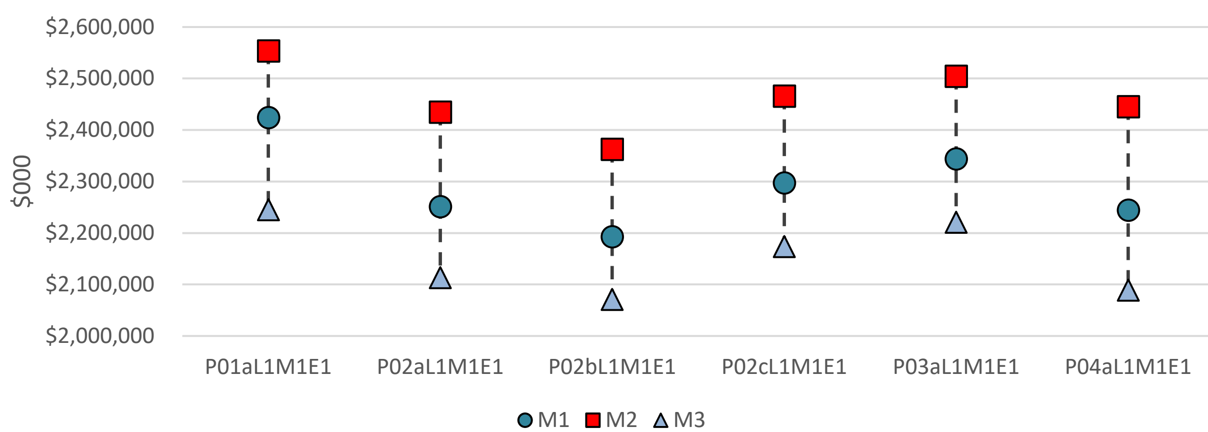
The Development of UNSE's Preferred Portfolio

UNSE evaluated a range of resource portfolios based on key planning metrics, such as total cost to customers, water consumption, and Carbon Dioxide ("CO_2") emissions. In addition to a portfolio required by the ACC, the portfolios evaluated span a range of moderate to aggressive renewable energy and energy efficiency targets as presented in the table below.

Portfolio Requirements	
Portfolio 1	Required by the ACC; 50% clean energy by 2035; Storage equal to 20% of demand; 25 MW of biomass; and at least 20% demand side management
Portfolio 2	50% renewables by 2035; with varying levels of energy efficiency
Portfolio 3	50% clean energy by 2030; No fossil fuel additions
Portfolio4	30% renewables by 2030

The chart below summarizes the Net Present Value Revenue Requirement (NPVRR) of each portfolio under base, high, and low market scenarios.

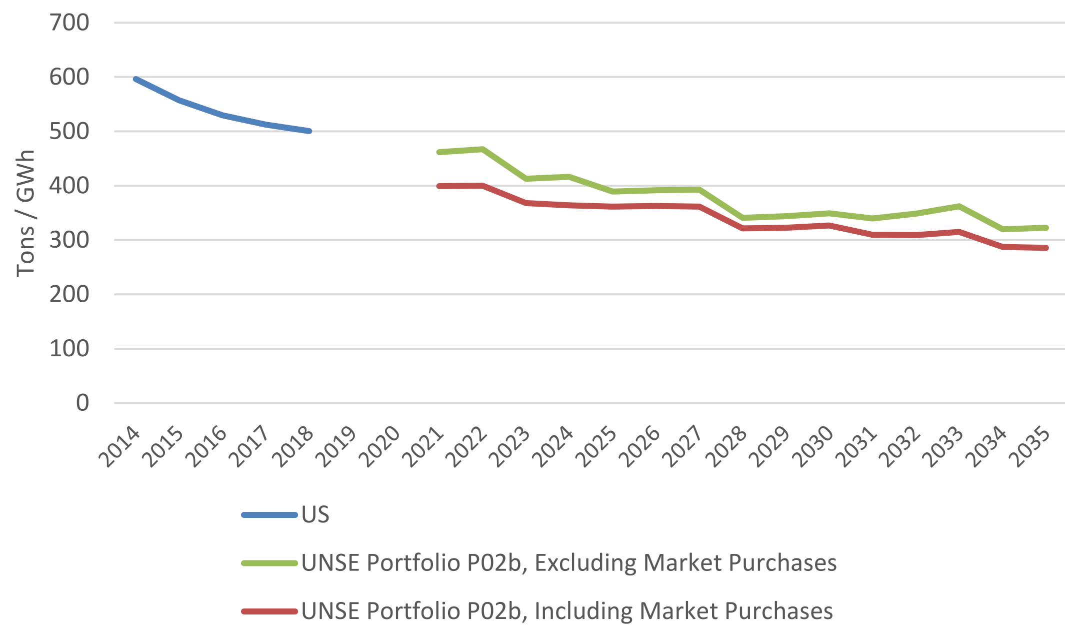
NPVRR for Each Portfolio and Scenario



UNSE's 2020 IRP continues the Company's transition from a high dependence on purchased power to meet customer demand, toward greater self-reliance on owned generating assets and the stability and predictability this provides to customer rates. This transition must take into account uncertainty in the overall cost and performance of various resources due to rapid changes in price and technical advancements. Therefore, the mix of future resources needed to meet UNSE's needs will be determined through strategic, market-based, ASRFPs. While the Preferred Portfolio will be based on the results of ASRFPs, Portfolio P02b will be used as the "**Reference Portfolio"** for evaluating and selecting resources from the ASRFP that will constitute the Preferred Portfolio.

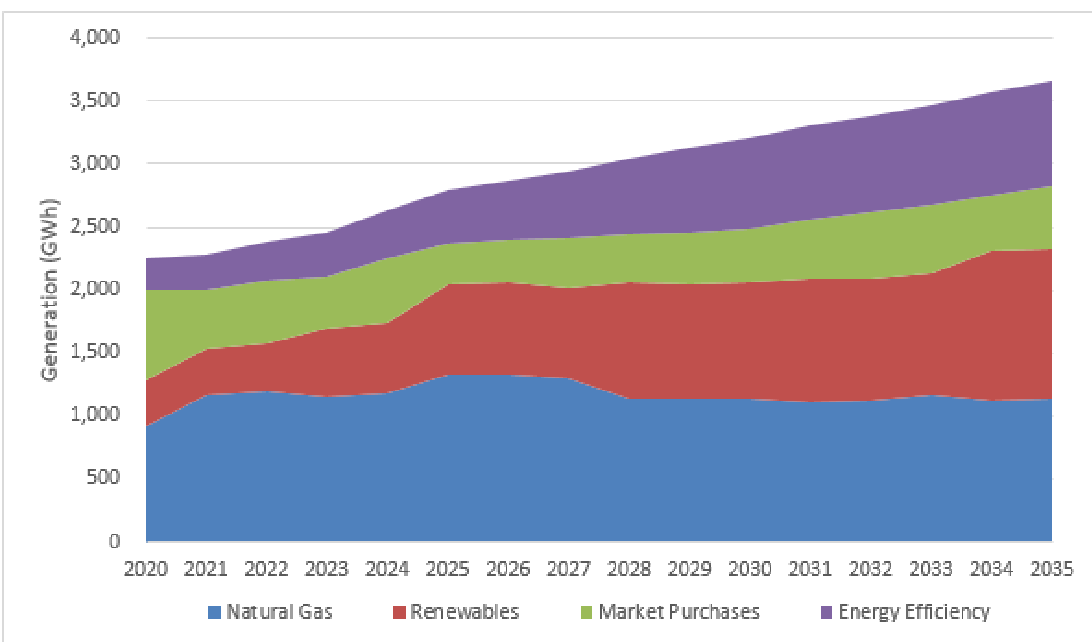
The figure below shows the trend in emission rates for the Reference Portfolio with and without consideration of purchased power emissions and also compares UNSE emission rates to the national average for 2014-2018, the most recent five years for which such data are available.

National and UNSE CO_2 Emission Rates



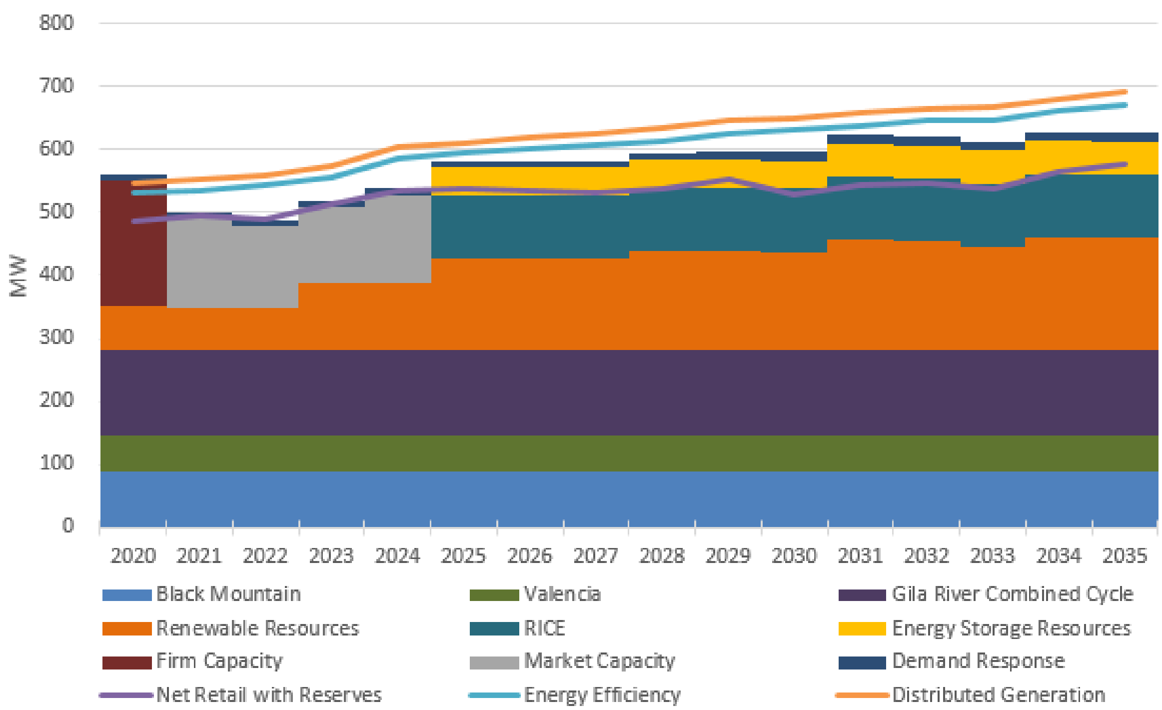
The Reference Portfolio energy mix is presented on the chart below.

Reference Portfolio, Annual Energy by Resource Type



The Reference Portfolio Load and Resources is presented on the chart below.

Reference Portfolio, Load and Resources



To gauge the potential risk of under- or over-purchasing generation resources, the resource additions in the Reference Portfolio were amended to serve three alternative load scenarios while maintaining the same level of reserves and renewable energy penetration as the Reference Portfolio. The results of this work demonstrated that the risk associated with under or over investing is low because purchasing plans can be adjusted to accommodate changes in anticipated load growth. This is because the Reference Portfolio would add resources incrementally over the planning horizon. This is true for both the renewable and dispatchable resources considered in this portfolio, as they are both very scalable.

UNSE's 2020 IRP Preferred Portfolio

UNSE believes that defining the UNSE Preferred Portfolio through the results of ASRFPs will provide the most complete and contemporaneous set of cost and performance data on which to base firm resource decisions. UNSE intends to design its ASRFPs based on the results of a rigorous needs assessment and in consultation with stakeholders and the Commission. ASRFPs will be technology neutral, including supply- and demand-side resources. Criteria for the evaluation of proposals will be determined as part of the development of the ASRFP, and will not unduly exclude any commercially available resource that can demonstrate adequate performance and cost-effectiveness.

Five-Year Action Plan

UNSE has developed a five-year action plan (2020-2024) based on the resource decisions that are contemplated in this IRP.

- UNSE will continue to implement cost-effective Energy Efficiency programs consistent with historical levels targeting 1.5 percent incremental energy savings over the prior year's retail load in each year through 2024.

- UNSE will continue to procure market-based resources to meet its short-term capacity needs through 2024. In the interim, the Company will explore other options through its future ASRFP's to acquire alternative resources through these solicitations if they are proven to be more cost-effective.

- The Company is committed to procuring future resources through ASRFPs based on specific, identified system needs. UNSE anticipates issuing an ASRFP in 2022 or 2023.

- UNSE is conducting studies relating to the costs and benefits of actively participating in the California Independent System Operator ("CAISO") Western Energy Imbalance Market (EIM), and anticipates making a decision in 2021.

CHAPTER 2

ENERGY DEMAND AND USE PATTERNS

Load Forecast

In the IRP process, it is crucial to estimate the load obligations that existing and future resources will be required to meet for both short- and long-term planning horizons. As a first step in the development of the resource plan, a long-term load forecast is produced. This chapter will provide an overview of the anticipated long-term load obligations at UNSE, a discussion of the methodology and data sources used in the forecasting process, and a summary of the tools used to deal with the inherent uncertainty surrounding a number of key forecast inputs.

The specific load and demand projections presented in this chapter represent UNSE's 2020 annual planning forecast made at the end of 2019.

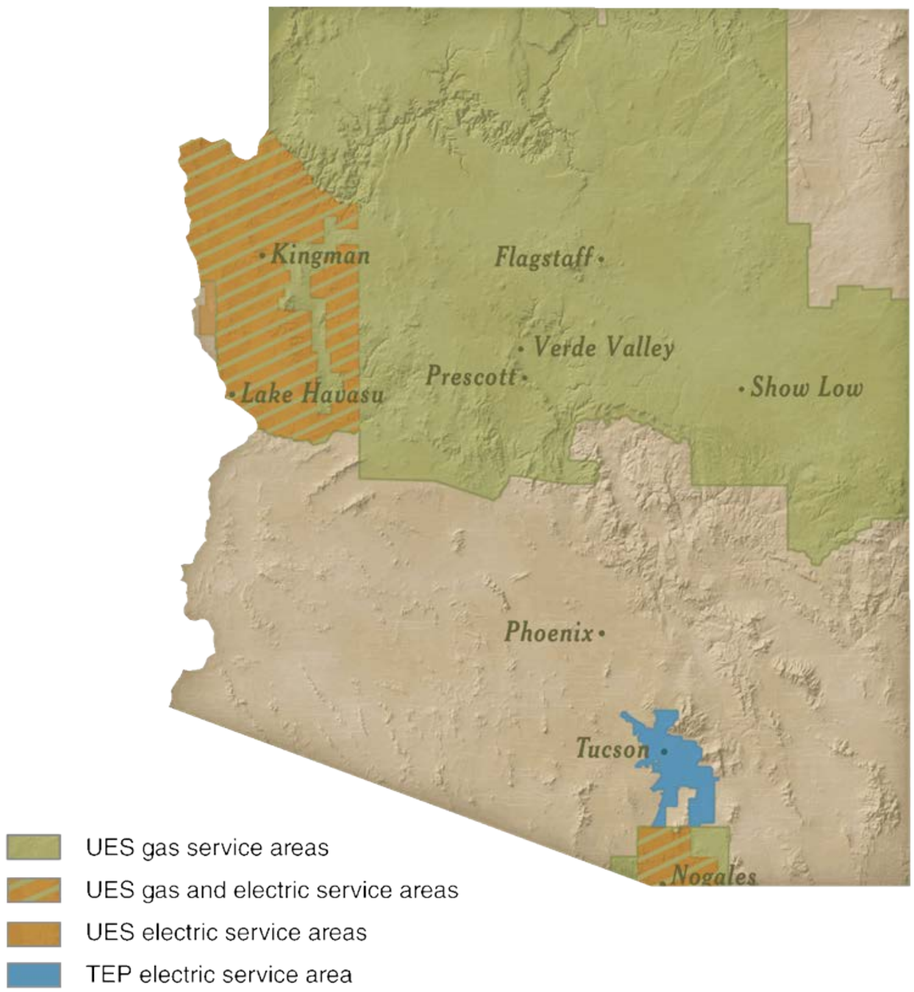
The sections in this chapter include:

- **Company Overview:** UNSE geographical service territory, customer base, and energy consumption by rate class
- **Reference Case Plan Forecast:** An overview of the Reference Case Plan forecast of energy and peak demand used in the planning process.
- **Summary:** Compilation of results from this analysis.
- **Rate Design:** An overview rate design and its role in long-term planning.

Geographical Location and Customer Base

UNSE currently provides electricity to roughly 100,000 customers in Mohave and Santa Cruz Counties. Mohave and Santa Cruz Counties have experienced growth over the last decade and are estimated to have a combined population of approximately 260,000 people.

Map 1 - Service Area of Unisource Energy Services (UES) and Tucson Electric Power[2] Utilities

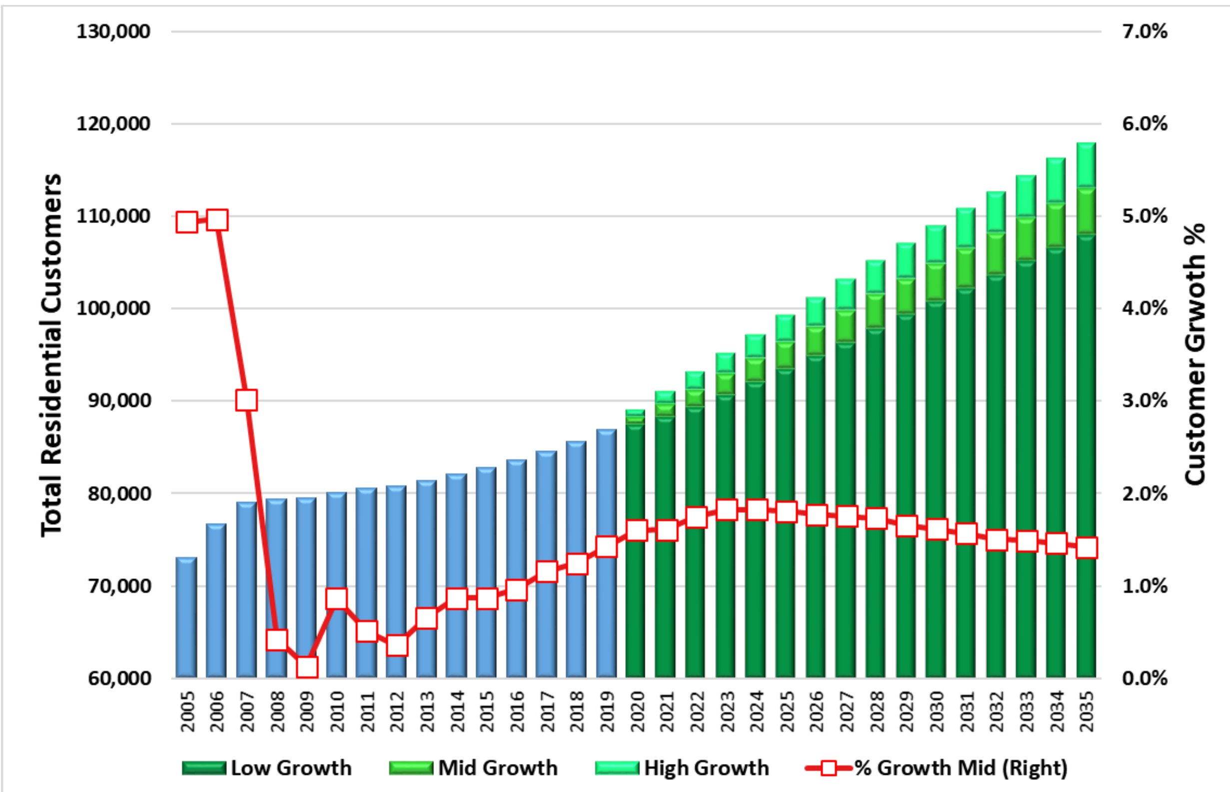


[2] UniSource Energy Services is the parent company of UNS Electric, Inc., and UNS Gas, Inc. Tucson Electric Power is a regulated utility providing electric services in Arizona and is a sister company to UniSource Energy Services.

Customer Growth

In recent years, population growth in Mohave and Santa Cruz Counties and customer growth at UNSE have slowed dramatically compared to periods before 2008 because of the severe recession and subsequent economic weakness. While customer growth has rebounded somewhat from its recessionary lows for Mohave County, it is not expected to return to its pre-recession level within the forecast period. Santa Cruz County continues to see low population growth. Chart 1 outlines the historical (in blue) and expected (in green) customer growth in the residential rate class from 2005-2035. As customer growth is a significant factor behind growth in UNSE's load, the continuing customer growth will necessitate additional resources to serve the increased load in the medium- to long-term.

Chart 1 - UNSE Residential Customer Growth Including Estimates for 2020-2035

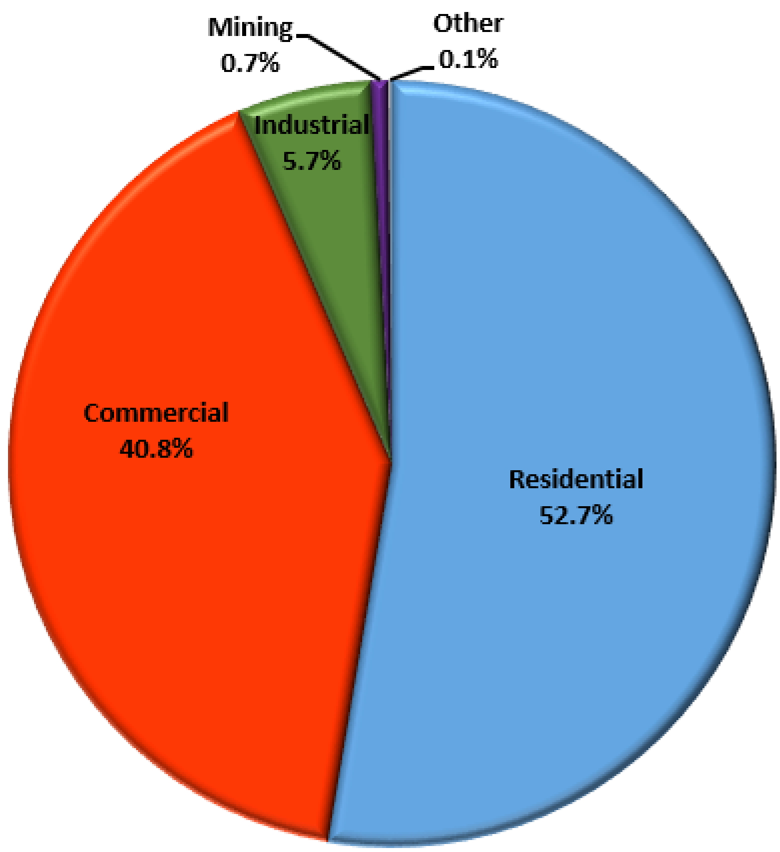


Retail Sales by Rate Class

In 2019, UNSE experienced a coincident peak demand of approximately 453 MW for the combined load in Mohave and Santa Cruz Counties with approximately 1,700 gigawatt-hours (GWh) of retail sales. Approximately 94 percent of 2019 retail energy was sold to residential and commercial customers, with approximately 6 percent sold to industrial and mining customers. Customer classes such as municipal street lighting and other public authority uses accounted for the remaining sales.

Chart 2 gives a detailed breakdown of the estimated 2020 retail sales by rate class.

Chart 2 – Estimated 2020 Retail Sales % by Rate Class



Reference Case Forecast Methodology

The load forecast used in the UNSE IRP process is produced using a "bottom up" approach. A separate monthly energy forecast is prepared for each of the major rate classes (residential, commercial, industrial, and mining) for each of the major load pockets (Kingman, Lake Havasu City, and Santa Cruz County). As the factors affecting usage in each of the rate classes and load pockets vary significantly, the methodology used to produce the individual rate class forecasts also varies. However, the individual methodologies fall into two broad categories:

1) For the residential and commercial classes, forecasts are produced using statistical models. Inputs include factors such as historical usage, normal weather conditions (e.g. average temperature and dew point), demographic forecasts (e.g. population growth), and economic conditions (e.g. real gross county product and real per capita personal income).

2) For the industrial and mining classes, forecasts are produced for each individual customer. Inputs include historical usage patterns, information from the customers themselves (e.g. timing and scope of expanded operations), and information from internal Company resources working closely with the mining and industrial customers.

After the individual monthly forecasts are produced, they are aggregated (along with any remaining miscellaneous consumption falling outside the major categories) to produce a monthly energy forecast for the Company. Following this aggregation, the retail load is reduced by the amount of customer Energy Efficiency (EE) and Distributed Generation (DG) anticipated in each year.

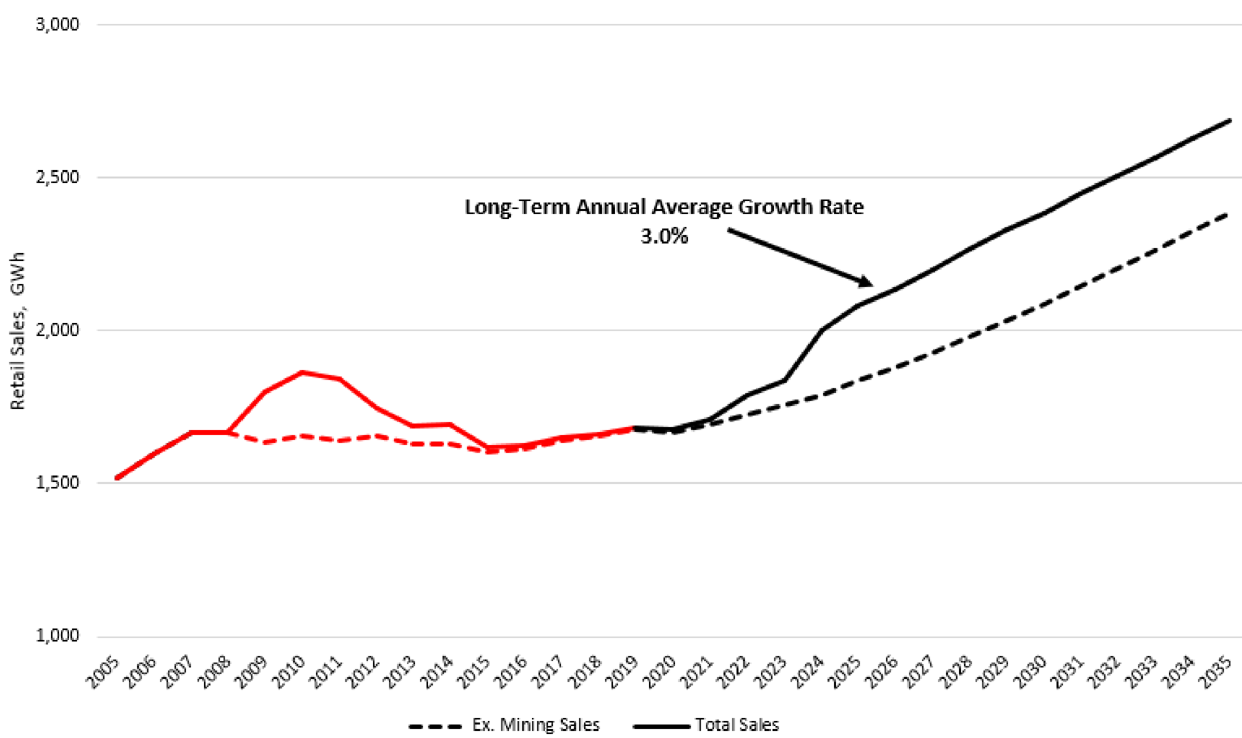
Special assumptions were also made for forecasting DG resources and Electric Vehicle (EV) uptake as these have significant impacts on load projections. Using an econometric model, DG growth is projected to slow, a reflection of the maturation of the DG market, from an average annual rate of 48.2 percent for the 2009-2019 period to 2.4 percent for the 2019-2029 period. In 2008, the DG market was based on nascent technology whereas in 2019, DG resources are well-established. The current market for EVs resembles the DG market of 2009 in that the future is still largely uncertain. To estimate the market penetration of EVs, UNSE used an ensemble of EV forecasts for the United States and made a few assumptions to more closely relate the forecasts to Santa Cruz and Mohave counties. The primary assumption is that these counties are not as economically affluent as most of the country and that vehicles last longer in these counties due to a variety of climatological reasons. Both of these factors suggest that vehicle turnover rates are slower in Santa Cruz and Mohave Counties, so the Company is using an average vehicle age of 18 years instead of the 12 year average in the US.

After the monthly energy forecast for the Company is produced, the anticipated monthly energy consumption is used as an input to estimate the peak demand. The peak demand model is based on historical relationships between hourly load and weather, calendar effects, and sales growth. Once these relationships are estimated, 30 years of historical weather scenarios are simulated to generate a probabilistic peak load forecast.

Reference Case Retail Energy Forecast

UNSE's weather normalized retail energy sales fell significantly from their peak in 2010 and remained below this peak nearly every year through 2015. Starting in 2010, the Great Recession took a significant toll on the industrial and mining businesses in Mohave County, closing numerous businesses and causing the mines to go into a mothballed state. The reduced employment opportunities and the effects of EE and DG kept residential and commercial sales from growing through this period. Beginning in 2015, customer growth picked up and sales began to increase again in UNSE's service territory and this trend is expected to continue. As shown on Chart 3, the underlying sales forecast excluding mining is showing an expected annual growth rate of 2.3 percent in the 2020-2035 period. In the near future, UNSE is expecting mining load to return to UNSE's service territory. Including this mining load brings the expected annual growth rate to 3.0 percent.

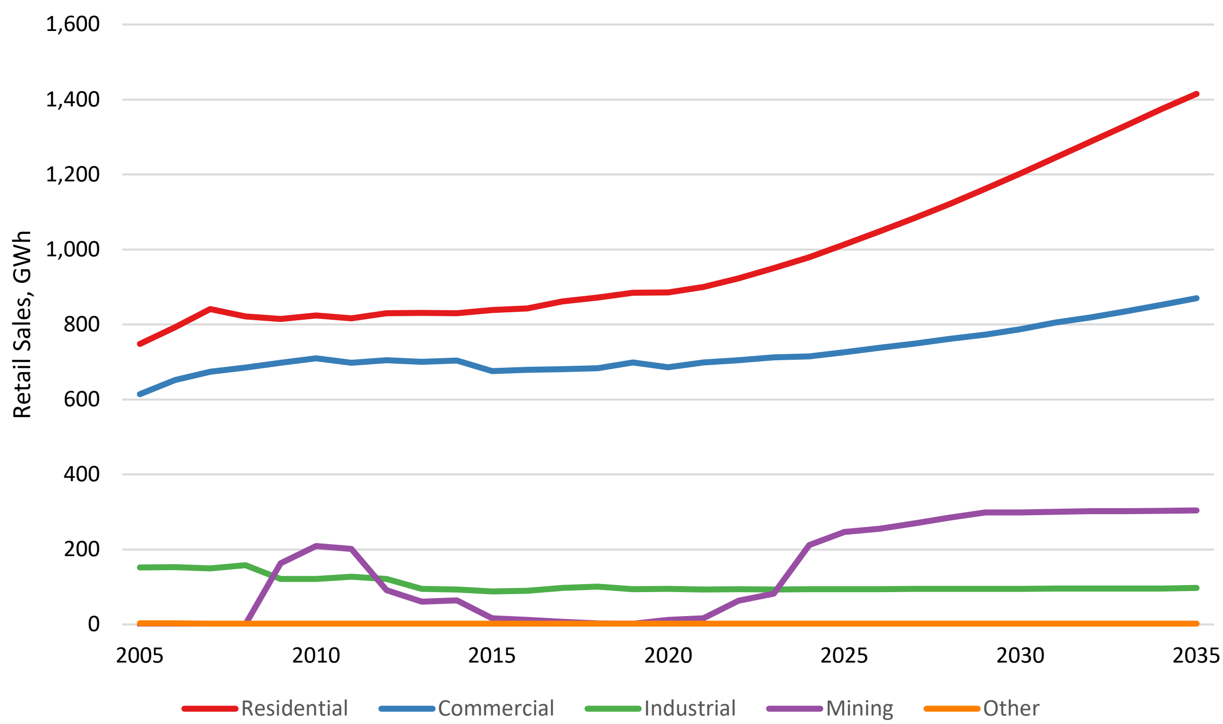
Chart 3 - Reference Case Plan Retail Energy Sales, Weather Normalized



Reference Case Retail Energy Forecast by Rate Class

As illustrated in Chart 4, the Reference Case Plan forecast assumes significant short-term changes to mining load for the next few years while other categories exhibit a more steady and gradual growth. However, the growth rates vary significantly by rate class. The energy sales trends for each major rate class are detailed in Chart 4.

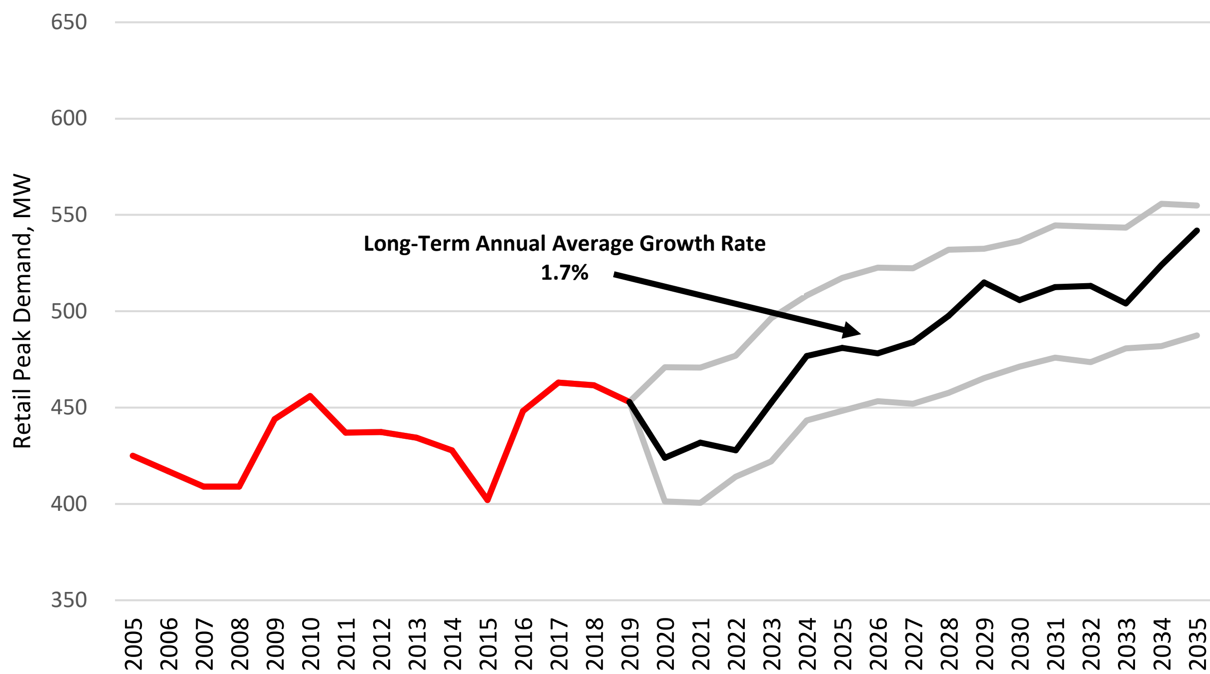
Chart 4 - Reference Case Plan Retail Energy Sales by Rate Class



Reference Case Peak Demand Forecast

As shown in Chart 5 below, peak demand (historical in red, forecast in black) is expected to drop in 2020 based on the assumption of a return to normal weather, although the upper confidence band (grey) shows it could remain relatively unchanged compared to the prior three years. Similar to the energy sales forecast, as the mining class expands the retail peak demand is expected to grow.

Chart 5 - Reference Case Plan Peak Demand



Data Sources Used in Forecasting Process

As outlined above, the Reference Case forecast requires a broad range of inputs (demographic, economic, weather, etc.). For internal forecasting processes, UNSE utilizes a number of data sources:

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

Risks to Reference Case Forecast and Risk Modeling

As always, there is a large amount of uncertainty regarding projected load growth. Some of the key risks to the current forecast include:

- Local and regional general economic conditions
- Structural changes to customer behavior
- Volatility in industrial metal prices and associated shifts in mining consumption
- Efficacy of EE programs (i.e. percentage of load growth offset by demand side management programs)
- Technological innovations (e.g. electric vehicle penetration)
- Volatility in demographic assumptions (e.g. higher or lower population growth)
- Regulatory changes (e.g. changes to the price on carbon emissions)

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. Specifically, the performance of each potential resource portfolio is assessed through the simulation of 50 different iterations of potential load growth scenarios (along with correlated gas and power prices in each case).

Summary of Reference Case Load Forecast

Table 1 below includes the effects of distributed generation and energy efficiency.

Table 1 - UNSE Reference Case Forecast Summary

Retail Sales (GWh)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Residential	885	900	923	950	979	1,013	1,048	1,084	1,122	1,162	1,203	1,245	1,288	1,331	1,374	1,415
Commercial	686	699	705	712	715	726	738	749	762	773	787	805	819	835	852	870
Industrial	95	93	94	93	94	94	94	95	95	95	95	96	96	96	96	97
Mining	12	16	63	82	212	247	255	270	285	299	299	300	302	302	303	304
Other	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Total Retail	1,680	1,710	1,787	1,839	2,002	2,082	2,137	2,200	2,266	2,331	2,386	2,448	2,507	2,566	2,627	2,688
Residential Sales Growth %	0.1%	1.7%	2.6%	2.9%	3.1%	3.5%	3.5%	3.4%	3.5%	3.6%	3.5%	3.5%	3.5%	3.3%	3.2%	3.0%
Commercial Sales Growth %	-1.9%	1.9%	0.9%	1.0%	0.4%	1.5%	1.7%	1.5%	1.7%	1.4%	1.8%	2.3%	1.7%	2.0%	2.0%	2.1%
Industrial Sales Growth %	1.1%	-2.1%	1.1%	-1.1%	1.1%	0.0%	0.0%	1.1%	0.0%	0.0%	0.0%	1.1%	0.0%	0.0%	0.0%	1.0%
Mining Sales Growth %	500.0%	33.3%	293.8%	30.2%	158.5%	16.5%	3.2%	5.9%	5.6%	4.9%	0.0%	0.3%	0.7%	0.0%	0.3%	0.3%
Other Sales Growth %	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total Retail Sales Growth %	-0.1%	1.8%	4.5%	2.9%	8.9%	4.0%	2.6%	2.9%	3.0%	2.9%	2.4%	2.6%	2.4%	2.4%	2.4%	2.3%
Customer Count (000)	98	100	101	103	105	107	109	111	113	114	116	118	120	121	123	125

Retail Peak Demand (MW)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Retail Peak Demand	424	432	428	453	477	481	478	484	498	515	506	513	513	504	524	542
Retail Demand Growth %	-6.4%	1.9%	-0.9%	5.8%	5.3%	0.9%	-0.6%	1.2%	2.8%	3.5%	-1.8%	1.3%	0.1%	-1.8%	4.0%	3.4%

Rate Design Influence on the Long-Term Load Forecast

UNSE supports an evolution in rate design to offer customers more options and choices. Customers may want to have access to time-varying rate tariffs in order to minimize their energy usage during high cost periods. Other customers may want to sign up for clean energy tariffs that incentivize the use of zero-emission resources such as renewables, Demand Response (DR), and EE. Other customers may want a demand- and energy-based rate that would enable them to take advantage of distributed energy resources and storage technologies. In any case, the ability to collect and manage real-time grid data will be a critical milestone for utilities to achieve in order to provide these types of services for customers in the future.

This next section discusses some of these rate design strategies and how they could be included as part of the on-going IRP planning process.

Rate Design

One element of the provision of electric utility services that affects customer usage patterns and, therefore, impacts future capacity needs is retail rate design. This section provides an overview of approaches to retail rate design that may affect future resource needs and should be considered as components of the IRP process. The two broad rate design categories discussed in this section are demand rates and time-varying rates. That is followed by a brief discussion of UNSE's current rate design and potential alternative rate designs and programs including programs designed to address higher use of solar generation.

Volumetric Rates

The most basic electric utility rate design is the two-part rate, which consists of a fixed basic service charge and volumetric energy charges assessed on each kilowatt-hour (kWh) consumed during a billing period. Most residential and small commercial customers receive service on a two-part rate structure.

Demand Rates

Demand rates, or three-part rates, assess charges on a customer's peak demand during a billing period in addition to a fixed charge and volumetric energy charges. The peak demand upon which the customer is billed may be measured as the customer's maximum kilowatt (kW) demand over time intervals ranging from instantaneous to one-hour. Billing demand may be defined as the maximum demand over the entire billing period or only during designated on-peak periods. Either of those approaches to billing demand may incorporate a demand ratchet. A demand ratchet further defines billing demand as the greater of measured demand during the billing period and some percentage of maximum billing demand for a set number of prior billing periods. Because system peak demand is a major driver in the need for additional generating capacity, charging customers directly for their contribution to system peak provides an incentive to reduce peak demand and therefore results in delaying the need for future capacity additions. Medium and large commercial customers and industrial customers usually take service on some variation of a three-part demand rate.

Time-Varying Rates

Time-varying rates, if designed properly, may be used to induce load shifting from peak to off-peak periods by providing a price signal that results in higher prices during peak periods and lower prices during off-peak periods. Shifting loads may reduce the need for additional capacity by reducing the need for energy supply at peak times. Time-varying rates may also be used in a three-part demand rate structure and both the demand and energy components of the rate design can have time-varying elements.

Time-varying electric rates include time-of-use (TOU) rates, critical peak pricing, and real-time pricing (RTP). TOU is the most basic and by far the most commonly used of time-varying approaches to retail electric pricing and consists of pre-defined peak and off-peak periods with differentiated pricing for each. RTP is the most sophisticated and variable approach, with hourly prices determined by day-ahead market prices or real-time spot market prices for electricity. Critical peak pricing rates are fixed rates where customers are charged higher prices during peak demand events that are announced in advance. A variation of critical peak pricing is a pricing regime where customers receive a rebate for reducing usage during a pre-announced peak demand event.

UNSE Rate Design

Currently, UNSE offers optional TOU rates to all retail customer classes except Lighting Service. Residential and Small General Service (SGS) customers may take service on either two- or three-part rates, while Medium General Service (MGS), Large General Service (LGS), and Large Power Service (LPS) customers take service under three-part demand rate structures. While Residential and SGS customers have historically taken service on two-part rates, UNSE expanded its rate plans for these rate classes to include three-part demand rate options. These Residential and SGS demand rate options have either flat or TOU variants for energy charges and define billing demand as the maximum one-hour measured kW demand during on-peak periods.

More information can be found at UNSE's website: https://www.uesaz.com/rates/

Alternative Rate Plans and Programs

UNSE understands the needs of its diverse customer base and is continuously exploring different programs and products to help customers achieve their energy goals. The maturation of new technology further unlocks potential for new programs and products to provide potentially cost-effective system benefits. The use of alternative rate plans could enhance UNSE's ability to obtain additional benefits from customer-sited and new grid technologies.

The trend of declining costs for renewable technologies has led to new challenges and opportunities. Both UNSE and its customers recognize that the economics of new technologies present opportunities for products and partnerships that were not previously available. Voluntary clean energy products provide customers with energy choices that can help achieve their energy and sustainability objectives. There are many different voluntary renewable products and programs offered in the utility industry and UNSE will continue to review which products make the most sense for its service territory and balance the interests of all stakeholders. UNSE recognizes that new products and programs provide an opportunity for increased economic development and closer connections with its customers. As technology develops and becomes cost effective, the diversity of the products and programs UNSE offers could expand.

Rate Design and Increased Solar Generation

The increased penetration of generation from solar resources on UNSE's system, both DG and utility-scale, creates integration challenges for system operations and system capacity planning. Therefore, the Company recognizes the need to adapt its rate design to address these challenges. The peak period for solar production occurs during midday and does not coincide with UNSE's system peak, which occurs in the late afternoon during the summer, and in the morning and early evening during the winter. Due to this mismatch, increasing solar generation has only a minor impact on reducing net system peak demand. Therefore, future rate designs should focus more on shifting consumption away from the system peak periods into the periods of peak solar production, which has the benefit of improving system load factor and operations and alleviates the need for future capacity additions to serve peak demand. From a rate design perspective, combining TOU rates with demand rates and expanding off-peak hours to include more hours with abundant solar energy will serve to modernize utility rate design and address the challenges put forth by increased solar development.

CHAPTER 3

RESOURCE ADEQUACY

Peak Demand

A critical component of the IRP planning process is the assessment of firm load obligations and available firm resource capacity to meet those obligations. This section summarizes UNSE's expected firm load and firm capacity at the time of its annual peak loads. Included in the firm load obligation is a 15 percent planning reserve margin, which is necessary to ensure that UNSE will have adequate capacity in the event that peak load is higher than forecasted or an unplanned outage occurs with its generation and transmission resources. Any shortfall in capacity or planning reserve margin resulting from load growth or resource retirements must be addressed by resource additions in the alternative resource plans considered in this IRP.

Figure 1 combines data from Table 2 and Table 3 on the following pages to show how the Company's firm load obligations compare to its firm resources. In this IRP, the Company is relying upon market purchases to help meet peak demand through 2024. Beginning in 2025, all portfolios considered in this IRP will be capable of meeting peak demand plus a 15 percent reserve margin through the remainder of the planning period without having to rely upon market purchases.

Table 2 shows UNSE's annual firm load obligations based on its December 2019 forecast. The obligations are equal to the gross retail peak demand minus the expected reductions from distributed generation and energy efficiency programs coincident with peak demand plus the planning reserve requirements. Table 3 summarizes UNSE's firm resource capacity based on its initial planning assumptions. All capacities are based on their expected contribution at the time of peak retail demand.

Figure 1 - UNSE Loads and Resources

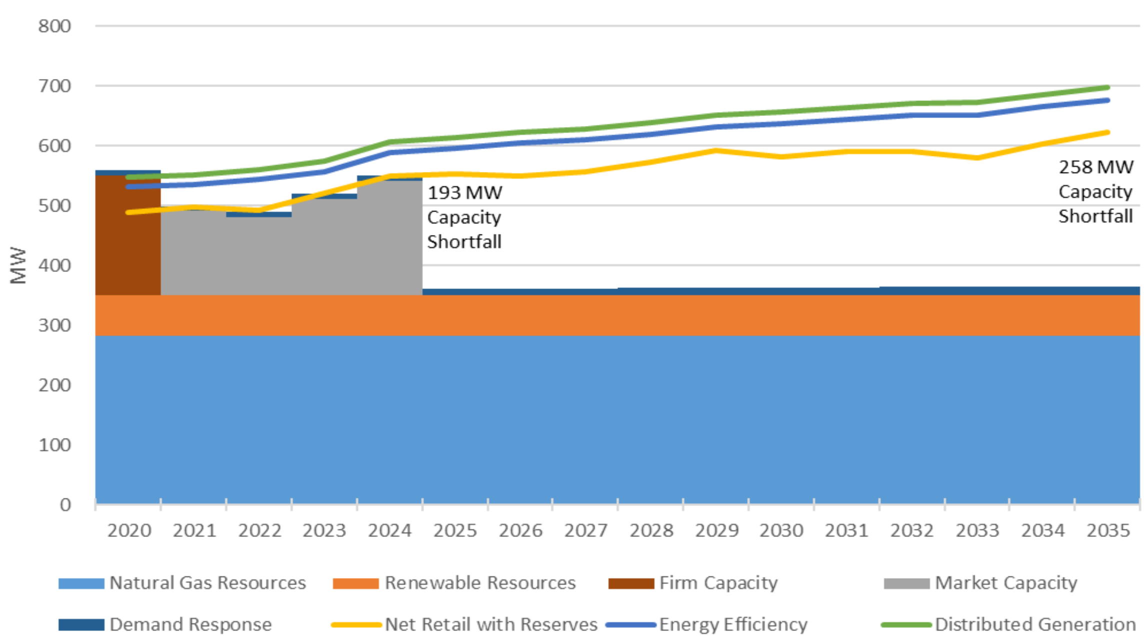


Table 2 - Firm Load Obligations, System Peak Demand (MW)

Firm Load Obligations (MW)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Residential	311	313	314	322	324	329	336	341	346	354	361	367	374	378	387	394
Commercial	154	155	153	155	151	152	153	152	152	153	154	155	156	155	157	159
Industrial	16	16	16	15	15	15	15	15	15	14	14	14	14	14	14	14
Mining	2	3	13	13	44	45	46	48	50	52	51	50	50	49	49	49
Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retail Peak Demand	484	487	496	506	534	541	550	556	563	573	580	587	594	596	607	615
Less Energy Efficiency	(44)	(39)	(52)	(36)	(40)	(42)	(54)	(53)	(47)	(39)	(55)	(55)	(61)	(72)	(63)	(53)
Less Distributed Generation	(16)	(16)	(17)	(17)	(18)	(18)	(18)	(19)	(19)	(19)	(19)	(20)	(20)	(20)	(20)	(21)
Net Retail Demand	424	432	428	453	477	481	478	484	498	515	506	513	513	504	524	542

Reserve Requirements	64	65	64	68	72	72	72	73	75	77	76	77	77	76	79	81
Total Firm Load Obligations	488	497	492	520	548	553	550	557	572	592	582	589	590	580	603	623

Table 3 – Capacity Resources in Initial Planning Assumptions, System Peak Demand (MW)

Firm Resource Capacity (MW)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Black Mountain	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
Valencia	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
Gila River Combined Cycle	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138
Natural Gas Resources	283	283	283	283	283	283	283	283	283	283	283	283	283	283	283	283
Utility Scale Renewables	67	67	67	67	67	67	67	67	67	67	67	67	67	67	67	67
Energy Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Demand Response	8	9	9	10	10	10	11	11	12	12	12	13	13	14	14	15
Total Coincident Peak Capacity	359	359	359	360	360	360	361	361	362	362	363	363	364	364	364	365
Firm Purchases	130	140	135	160	190	0	0	0	0	0	0	0	0	0	0	0
Total Resources	489	499	494	520	550	360	361	361	362	362	363	363	364	364	364	365
Reserve Margin	65	67	66	67	73	(193)	(189)	(195)	(211)	(230)	(219)	(226)	(227)	(216)	(238)	(258)
Reserve Margin %	15%	16%	16%	15%	15%	-40%	-40%	-40%	-42%	-45%	-43%	-44%	-44%	-43%	-45%	-48%

Renewable Integration and Flexibility of Portfolio Resources

All portfolios considered in this IRP significantly increase the amount of renewable energy in UNSE's resource mix. In 2020, renewable energy is expected to serve approximately 22 percent of retail sales. In the portfolios being considered, this contribution will increase to at least 30 to 50 percent of retail sales prior to the end of the planning period, depending on the portfolio.

Integrating this amount of renewable energy presents many challenges, such as site-specific issues regarding the siting of renewable facilities and transmission lines, the safety and disposal of large-scale battery systems, the ability of renewable facilities to "ride through" voltage dips, and the potential for "islanding" portions of the distribution system. The purpose of this IRP, however, is to ensure that adequate resources will be in place to satisfy UNSE's load requirements during all hours of the year. This includes the peak load, as discussed above, as well as load during non-peak hours. This can be a challenge in high-renewable portfolios because the availability of renewable energy in any given hour can be highly variable and difficult to predict. The non-renewable resources in UNSE's portfolio, therefore, must have the flexibility to respond to rapid and large changes in renewable output, since load must be met on a continuous basis. Additional detail on these flexibility requirements can be found in Chapter 3 of the TEP IRP.

The remainder of this chapter evaluates the flexibility requirements of UNSE under different renewable penetration scenarios and whether those requirements can be met with existing resources. This inherently involves consideration of TEP's loads and resources since each utility is part of the same Balancing Authority (BA) area. For example, in isolation, UNSE may require a certain amount of flexibility, but when sharing a BA with TEP, the flexibility requirements of each utility can be reduced. This expansion of a utility's operational footprint is a widely recognized method for reducing flexibility requirements (and associated costs) and occurs because large changes in the renewable output of one utility's resources is unlikely to occur at the same time and in the same direction as another's.[3] Changes in the second utility's renewable energy and load, in fact, may be in the opposite direction and help balance or "net out" changes in the first utility. In sum, UNSE currently procures balancing services from TEP, so it is important to understand if integrating more renewable energy into UNSE's energy supply will require additional balancing resources to be procured by UNSE either directly or indirectly through its service contract with TEP.

Table 4 shows the six renewable energy penetration scenarios (or "cases") considered in the flexibility requirements analysis. Case 1 assumes no additional renewable resources are added beyond the solar and wind resources already in UNSE's portfolio. The subsequent cases assume 35 and 50 percent renewable energy with the majority of new renewable energy coming primarily from wind or solar power. Case 6 is identical to Case 5 except that most of the new solar capacity is assumed to be located at only a couple sites, as opposed to a more geographically dispersed scenario. This case is included to account for the increase in ramping requirements that can result from siting large amounts of capacity in the same area and subject it to the same cloud cover and coincident variability. All cases assume distributed generation increases to 32 MW by 2024, from approximately 29 in 2020.

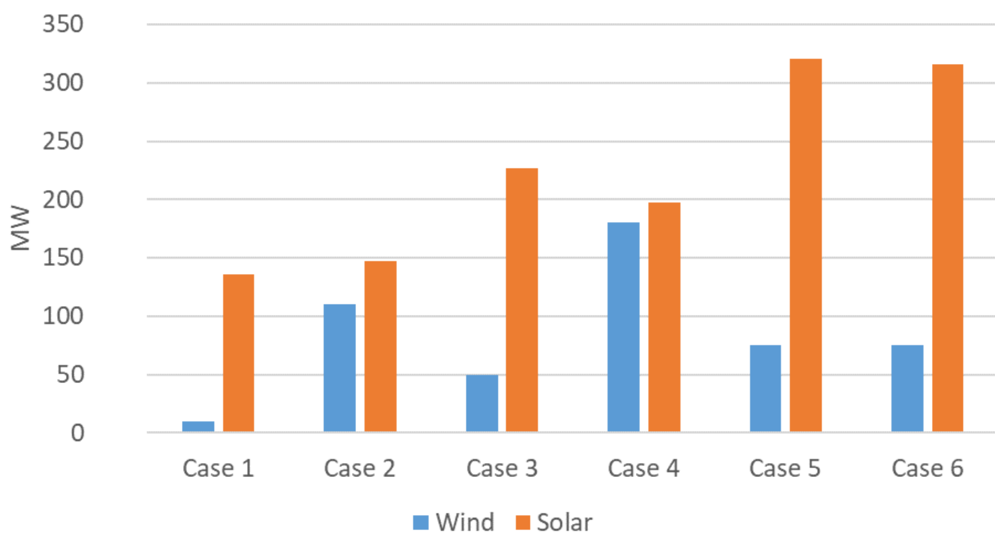
[3] Even when this occurs, the flexibility requirements of the utilities are no greater than what would be required of them in isolation.

Figure 2 shows the amount of renewable energy capacity assumed in each case to achieve the renewable energy penetration shown in Table 4.

Table 4 - Renewable Energy Penetration Cases Considered in UNSE Flexibility Study

Case	Renewable Energy as a Percent of 2024 Retail Sales	Resources Beyond Case 1
1	18%	Not Applicable
2	35%	Majority Wind
3	35%	Majority Solar
4	50%	Majority Wind
5	50%	Majority Solar
6	50%	Majority Solar Geographically Concentrated

Figure 2 - Renewable Energy Capacity Assumed in Each Case



Siemens Industry, Inc. was hired to evaluate the impact of these scenarios when combined with similar scenarios for TEP. Any increases in the BA's flexibility requirements can then be attributed to UNSE's renewable cases. The study evaluated these cases in the context of the resource portfolio and customer demand expected in 2024. This time frame was chosen because it represents a mid-2020s snapshot of the TEP BA operating conditions following the retirement of 508 MW of coal-fired capacity and the addition of 456 MW of renewable capacity currently under development. It is also the time frame in which UNSE would likely begin adding more renewable resources to its portfolio. The analysis uses one-minute, quality-assured load and renewable generation data from July 2017 through June 2019. Detail on the methodology and results is provided in Chapter 3 and Appendix A of the TEP IRP.

Table 5 shows the maximum 10-minute ramps in net load for each case. These tend to occur in the summer afternoons. The TEP column shows the maximum ramps resulting only from TEP's renewable penetration cases. The TEP+UNSE column shows the maximum ramps when UNSE renewable assumptions are added to TEP renewable assumptions. As shown in the difference column, the addition of UNSE renewable resources increases the BA's 10-minute net load ramps by 20 to 33 MW. Net load is defined as the load that must be served by the Companies after subtracting the energy generated by renewable resources – i.e., the remaining load that non-renewable resources must be able to serve.

Table 5 - Maximum 10-Minute Ramps in Net Load

Case	TEP	TEP + UNSE	Difference
1	299	329	30
2	307	333	26
3	307	340	33
4	322	342	20
5	327	359	32
6	333	366	33

Table 6 shows the maximum 3-hour ramps in net load for each case. These tend to occur outside the summer months during the sunrise and sunset hours.

Table 6 - Maximum 3-Hour Ramps in Net Load

Case	TEP	TEP + UNSE	Difference
1	517	672	155
2	604	799	195
3	751	1000	249
4	702	1020	318
5	1029	1160	131
6	1027	1158	131

As shown in Appendix A of TEP's IRP, these increases of 33 MW in 10-minute net load ramps and 318 MW in 3-hour net load ramps are well within the BA's planned capabilities. Moreover, TEP is expected to join the Western EIM in 2022, which should further increase the area's renewable energy integration capacity. Finally, all of the UNSE portfolios being considered in this IRP include 35 to 175 MW of battery-based energy storage, and all but one include the addition of fast-start, fast-ramping gas-fired resources.[4] Thus, for the renewable energy penetration scenarios considered in this study, no additional resources appear necessary for the purposes of integrating and balancing renewable energy supplies. Nonetheless, this is UNSE's first in-depth analysis of renewable integration and no major utility in the U.S. has yet achieved 50 percent renewable penetration on an annual basis, so the Company will continue to evaluate the challenges of high renewable penetrations, the methodologies available for determining "flex capacity" requirements, and the means for obtaining such capacity, including but not limited to:

- Energy storage, including electric vehicles and customer-sited batteries
- Upgrading the ramping and turndown capabilities of existing thermal generators
- Daily cycling of gas-fired combined cycle plants
- Quick-start and fast-response generation technology
- Load shape modification through rate design
- Participation in the Western EIM and other innovative market mechanisms
- Routine curtailment of renewable resources to maintain headroom for mitigating ramps
- Geographic and technological diversification of renewable resources (e.g., between solar, wind, and other non-emitting resources)

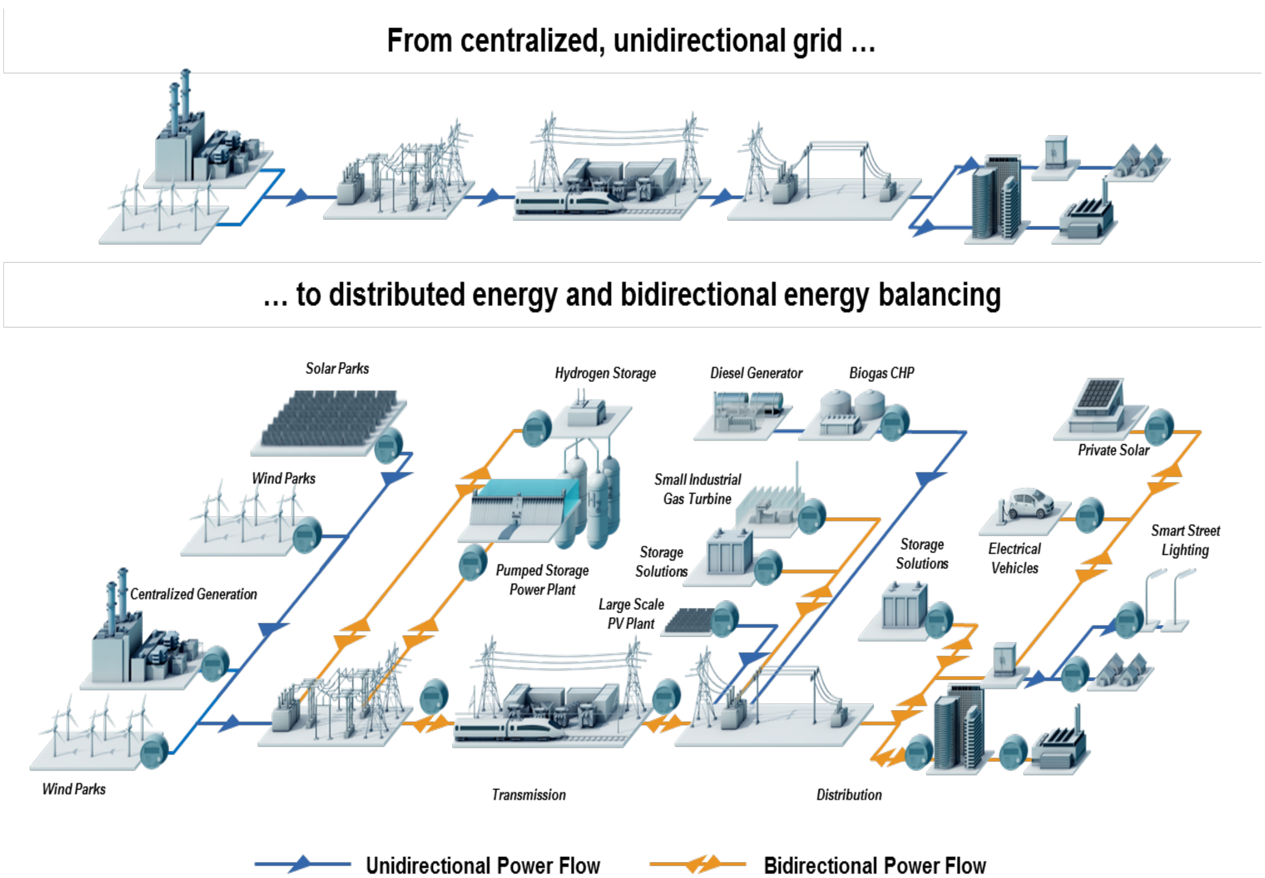
[4] These storage resources are included primarily for meeting peak loads, reducing renewable energy curtailment, and meeting renewable energy targets, but they can also provide energy balancing and ramping services.

PREPARING FOR AN INTEGRATED GRID

The Future of the Distribution Grid

Changes in the supply, demand, and delivery of electricity are transforming electric distribution systems at most North American utilities. Distributed Energy Resources (DERs) are leading many of these changes.

UNSE envisions a future that will accommodate DERs and other innovations into the existing network while transitioning to a digital network. To accommodate DERs and other innovations, electric utilities need to do more than make their distribution systems bigger. Instead, utilities need to make their distribution systems smarter. Smart distribution systems provide flexibility, capability, speed, and resilience. These smart distribution systems include new types of software, networks, sensors, devices, equipment, and resources. To achieve new levels of economic value, these smart distribution systems will need to operate according to new strategies and metrics. With more DERs being deployed on UNSE's distribution system, higher demands and lower per capita energy consumption is occurring today. This puts demand on the transmission and distribution systems that were not contemplated in the original designs and requirements of the system.



With increased demand and lower per capita energy consumption, new techniques and strategies need to be developed and implemented to effectively manage costs. By adding additional measurement and sensing capabilities, the situational awareness of the distribution system will be increased. The increased situational awareness allows for real time operations and planning opportunities for efficiency and productivity changes. To utilize the existing distribution system more efficiently, UNSE is investigating the use of DERs, energy storage, energy efficiency, and targeted load shaping and load management capabilities in conjunction with optimization software. These technology improvements may reduce future infrastructure additions as customer demand increases. This strategy is much different than how the distribution system has been managed in the past. It requires the use of a bottom up planning and design process that needs to be integrated with the IRP.

At the core of these changes, is the need for a communications network that allows for intelligent electronic devices to be installed on the distribution system. The communications network allows for the backhaul of information from the intelligent electronic devices to centralized software and control applications. Simply collecting and displaying more sensing and measurement information will not provide the needed benefits. An integrated approach to the installation of field devices, software applications, and historical data management will be needed. A Distribution Management System (DMS) is the central software application that provides distribution Supervisory Control and Data Acquisition (SCADA), outage management, and geographical information into a single operations view. By combining the information from all three of these systems into one centralized system, an electrical distribution system model can be created for both real time applications and planning needs. Moreover, this centralized DMS provides real-time situational awareness of the distribution system that has not been possible in the past. It also creates a platform from which additional applications can be launched to continue to provide value and new opportunities for customers. The historical information also creates a new opportunity to drive value and decisions based on system performance and dynamic simulations.

With the potential development of multiple distribution microgrid feeders and DER systems, the challenge of resource dispatching will become more complex. A solution to dispatch across a fleet of resources of existing centralized generation, purchased power from the market, and the intermittency of DER systems to customer demand will be required. The speed with which the resource pool will need to change and optimize for efficiency and cost will require the system to be developed into a fully automated resource. The distribution microgrid feeder concept is intended to help manage distribution-level intermittency but would need to be monitored and managed by the automated system for resource management. To manage such a large and dynamic system as outlined is a substantial challenge. This type of automated system is not currently available within the utility industry.

Distributed Energy Resources

Distributed energy resources include DG, which are small-scale, renewable resources often sited on utility customer premises. The Arizona RES requires that a portion of the load serving entity's renewable energy be obtained from residential and commercial DG systems. The required percentage of DG in the Arizona RES is 30 percent of the total annual renewable energy requirement.

Picture 1 – Typical Residential Distributed PV Systems

UNSE has been interconnecting solar DG for the past two decades. By the end of 2019, UNSE had approximately 47 MW_{DC} of rooftop solar photovoltaic ("PV") systems. DG is expected to supply approximately 92 GWh of energy in 2020. UNSE offers different programs for customers to utilize DG.

3rd-Party Solar Photovoltaic

Both residential and commercial customers are able to interconnect to UNSE's grid to install solar PV systems at their premises. These systems are either purchased by the customer; leased by the customer from a 3rd party; or procured through a PPA or solar service agreement. These systems are typically sized with capacity that will offset nearly all of the energy needs at a customer's premises over the course of a year.

Bright Arizona Community Solar

For nearly 10 years, UNSE has offered its customers the opportunity to offset some or all of their annual energy usage from the Company's Bright Arizona Community Solar program. Customers can elect to purchase 150 kWh blocks for a $0.02/kWh premium. The cost of shares remains fixed for 20 years and remains exempt from renewable energy and fuel and purchased power surcharges.

Table 7 shows the rates of adoption for the various programs available to customers.

Table 7 - Current Adoption of UNSE DG Programs

	Total All-Time Customers Through 2019	Total MW
3rd-Party Residential DG	3,584	33.75
3rd-party Non-Residential DG	180	13

Energy Efficiency Resources

UNSE recognizes that energy efficiency and demand response can provide cost-effective benefits. UNSE offers a variety of incentives to both residential and commercial & industrial (C&I) customers, encouraging them to invest in EE upgrades through Demand Side Management (DSM) programs.

Compliance with the 2020 Energy Efficiency Standard

The Commission's Energy Efficiency Standard ("EE Standard") requires UNSE and other affected utilities to achieve a cumulative annual energy savings through its DSM programs by the end of each calendar year.[5] This EE Standard requires affected electric utilities in Arizona to increase the kilowatt-hour savings realized through customer ratepayer-funded EE programs each year until the cumulative reduction in energy reaches 22 percent of the previous year's retail sales by 2020.

UNSE is implementing programs with the intent to meet the 2020 EE Standard directly through its program offerings, along with certain allowable savings credits. A portion of the energy savings required by the EE standard were achieved by implementing efficiency measures resulting in a direct reduction of demand and energy use. The remainder is attributable to credits: the Direct Load Control Credit, Energy and Building Codes Credit, and Pre-Rule Credit.

2021 Implementation Plan, Goals, and Objectives

UNSE remains committed to helping customers reduce energy use and demand through its DSM programs. UNSE is filing an Implementation Plan covering the 2021 and 2022 program years, consistent with ACC rules.[6] This Plan proposes continued DSM program operation in the residential, and C&I sectors.

UNSE's high-level EE-related goals and objectives include:

- 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

Program Portfolio Overview

UNSE has been implementing programs approved on October 27, 2015 in ACC Decision No. 75297 with the ACC (Docket No. E-04204A-14-0178).

[5] Arizona Administrative Code R14-2-2401 et seq.
[6] Arizona Administrative Code R14-2-2405

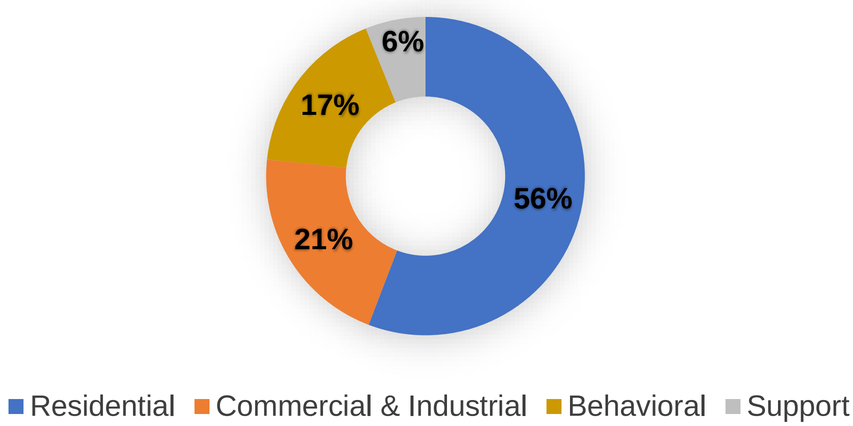
UNSE programs are divided between residential, C&I, behavioral, and support sectors with administrative functions providing support across all program areas.

Table 8 - Current UNSE DSM Programs

Residential Sector	Efficient Products
	Existing Homes
	Low-Income Weatherization
	Multi-Family
	Residential New Construction
	Shade Tree
Commercial & Industrial Sector	C&I Facilities/Schools
	C&I Demand Response
Behavioral Sector	Behavioral Comprehensive
	Home Energy Reports
Support Sector	Consumer Education and Outreach
	Energy Codes and Standards

Chart 6 shows the actual segmentation of energy savings across sectors resulting from the implementation of these programs during 2019.

Chart 6 – 2019 DSM Portfolio Composition by Sector



Resource Planning Integration

Potential Differences between Targeted Savings and Actual Load Reduction

The 2020 IRP includes cumulative energy savings to meet the 2020 EE Standard, and a forecast for cumulative energy savings from future DSM initiatives annually over the 15-year IRP planning period. UNSE's DSM programs reduced energy demand and consumption. However, the energy savings claimed against the EE Standard do not necessarily align with actual reduction in load, which introduces potential uncertainty for resource planning. There are three main causes for these differences.

First, the 2020 EE Standard allowed certain energy credits to achieve savings targets: Direct Load Control Credit, Energy and Building Codes Credit, and the Pre-Rule Credit. The savings attributed through these energy credits correctly reward past, present, and potential (e.g., Direct Load Control) energy or demand reductions, but by design they might not align with the actual load reductions in the year the credits are granted. UNSE's forecast savings builds upon the estimated cumulative reductions in load attributable to the DSM programs. Applied credits are not included in the DSM forecast.

The second source of difference is the notion of DSM program persistence, which assumes that claimed savings are permanent. A customer participating in a DSM program typically receives an incentive to purchase a more efficient product. When eventually faced with that purchasing decision again, DSM programs assume that customers will not buy inefficient products after they've experienced the benefits of increased efficiency. This assumption of persistence is generally accepted, but some level of non-persistence likely exists. In this sense, any actual deviation from assumed persistence mildly degrades the ability of claimed DSM savings to forecast future load.

Finally, the third cause of difference is the blend of efficiency measures offered in UNSE's DSM program portfolio. Certain factors, such as changes in technology costs and baseline efficiencies (stemming from Federal equipment EE standards becoming more stringent) change both the cost effectiveness and gross savings of certain measures over time. Forecasting the measure blend over a multi-year period is challenging to perform with any degree of confidence. Since UNSE's forecast of DSM savings are fixed, and since some measures cost more per kWh saved to implement, the blend of measures strongly affects the budget required to achieve the EE standard. Additionally, different measure blends deliver different system-wide hourly demand reduction profiles, meaning that a lighting-heavy blend will do less to reduce demand during peak system load than an Heating, Ventilation, and Air Conditioning (HVAC)-heavy blend.

DSM Energy Savings

Development of Measure Group Assumptions in Energy Efficiency Forecasts

For past IRPs, UNSE has prepared a single monthly energy and peak reduction forecast for all years in the IRP planning period. For this IRP, UNSE built three of these forecasts, each based around a distinct scenario that assumes a different blend of efficiency measures. UNSE is using these three scenarios, rather than just one, in planning models for this IRP to understand the possible boundary conditions that could exist depending on the blend of future efficiency measures.

UNSE forecasts EE savings for different measure group assumptions:

1. **Scenario A: EPRI Projection**
   Based on report published by the Electric Power Research Institute (EPRI) titled, "U.S. Energy Efficiency Potential Through 2035." Assumes that UNSE's DSM savings target is achieved using the existing blend of measures.[7]

2. **Scenario B: Existing Measure Mix**
   Based on a level of energy savings needed to achieve 31 percent to 35 percent energy savings by 2030 (dependent on the amount of allowed credits). UNSE assumes that the DSM savings target is achieved using the existing mix of measures.

[7] Electric Power Research Institute, *U.S. Energy Efficiency Potential Through 2035*, Palo Alto, CA: 2014. 1025477

3. **Scenario C: Existing Measure Blend with Lighting Measures Removed**
   Based on the level of energy savings in Scenario B. Assumes all lighting measures are discontinued. Represents the scenario where Federal standards for lighting are made more stringent.

The blend of measures implemented across the DSM portfolio affects the cost required to achieve a certain amount of first year savings, as described in further detail later in this section. For example, lighting measures provide a relatively high level of energy savings at a low incremental cost. By contrast, HVAC measures are implemented at a moderately high incremental cost and provide relatively modest energy savings. In this way, a portfolio that emphasizes lighting measures will provide first year savings at a lower cost than a portfolio that focuses more on HVAC measures.

Each scenario not only presents a different cost of meeting UNSE's DSM savings target, but also the effects of demand reduction, coincident with peak system load, differently. Although lighting measures provide energy savings at a low incremental cost, they are not typically associated with a peak coincident demand reduction. HVAC measures, on the other hand, do provide a relatively large reduction in coincident demand. In this way, the value provided by demand reduction is considered alongside the cost required to meet UNSE's DSM target using a certain measure blend.

Estimation of First Year Energy Savings

UNSE's forecasted DSM savings builds upon the 2020 EE Standard, which uses cumulative first year annual energy savings as a core comparison metric. First year annual energy savings are calculated for each approved (and proposed) DSM measure using algorithms, input assumptions, baseline conditions, and other relevant engineering considerations. This data is gathered from trusted industry sources and often enhanced using existing UNSE program tracking data. It should be noted that these engineering workbooks calculate energy savings at the meter, but the savings are translated to generated energy savings using a fixed line-loss factor when reported at a program-level.

The first year energy savings for measures and programs, are currently evaluated and verified by Guidehouse, Inc. ("Guidehouse"), formerly Navigant Consulting, Inc., a third-party evaluation contractor. Guidehouse verifies savings for programs using industry evaluation standards and protocols outlined by the International Performance Measurement and Verification Protocol, Federal Energy Management Plan, and the Uniform Methods Project of the National Renewable Energy Laboratory (NREL).

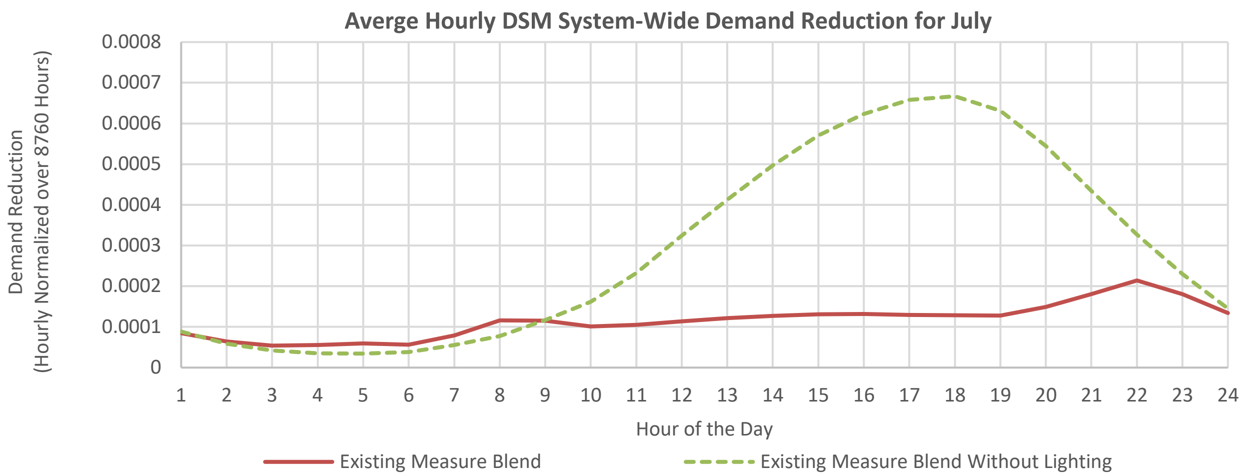
Determining Cost of First Year Energy Savings ($/MWh)

The EE Standard required the cumulative first-year savings from UNSE's DSM programs to exceed a certain percentage of the previous year's energy sales. UNSE will continue to use this metric to measure its own DSM savings, which compares the 1) cumulative first-year savings; and 2) previous year's energy sales. UNSE's DSM savings target therefore places an inherent significance on first year savings, as well as the cost of these savings.

The cost of first year savings can be calculated at program, sector, and portfolio level by comparing verified first year energy savings against the corresponding costs to manage, implement, and evaluate those savings accounting for annual inflation and program cost escalation. The annual cost required for UNSE to meet its DSM savings forecast can be estimated by multiplying the calculated portfolio-level cost of first year savings by the energy savings forecast for the given year. Each of the three scenarios carries a different annual savings and annual cost.

In addition to the cost per first year savings, different measure blend scenarios also provide different load reduction shapes. Further discussion of load shape development is presented later in this chapter. In this way, even though a lighting-heavy measure blend might require a lower DSM program budget to achieve equivalent savings, it will not reduce demand coincident with a system-wide peak as effectively as an HVAC-heavy lighting blend. Chart 7 shows this difference by comparing the forecasted average normalized hourly load reduction in July for the existing DSM measure blend against the same blend with all lighting measures removed. The former represents a continuation of the current DSM offerings ("Scenarios A and B"), while the latter aligns with the aforementioned "Scenario C" that removes lighting measures.

Chart 7 - Load Reduction Comparison for Potential Measure Blends



The removal of lighting measures (i.e., 2023-2030 for "Scenario C") increases the cost of meeting UNSE's DSM savings target by increasing reliance on HVAC measures to meet this target. However, Chart 7 shows this would also provide a greater demand reduction during system load peaks. This demonstrates the importance of load shapes in resource planning. DSM measures not only provide energy savings to meet savings targets, but they also provide value by reducing demand during system load peaks. Additional information relating to the development of DSM load shapes is available in the UNSE 2017 Integrated Resource Plan.[8]

Peak Coincident Capacity Contribution

Energy savings for measures in each program are aggregated to develop the cumulative reduction to load for each hour. Since peak demand in UNSE's service territory occurs during the summer months of June through August, these are months where DSM programs provide the most capacity value. During summer for example, the forecasted demand reduction from UNSE's DSM programs is greatest between 8:00 PM and midnight. However, UNSE's forecasted system load during the summer is greatest between 4:00 PM and 5:00 PM. Rather than simply reducing energy consumption, DSM measure blends are prioritized to reduce demand coincident with the system peak.

The interaction between the measure-level savings load shape and UNSE's system load shape, specifically with regard to load during peak periods, informs the coincident and non-coincident peak demand reduction. The system peak demand (prior to any reductions from DSM and DG), as well as the demand reduction from DSM and DG coincident with that system peak are determined in Aurora. The coincident demand savings factor associated with DSM programs is calculated as the difference between the modeled peak demand with and without accounting for reductions from DSM and DG, less the coincident peak contribution from DG alone. The

[8] https://www.uesaz.com/wp-content/uploads/2016/04/UNSE-2017-Integrated-Resource-FINAL_reduced.pdf, pp. 55-57

coincident peak contribution from DG alone is the average capacity factor of a fixed-tilt system operating from 3 to 4 PM in the month of July. This is the month and hour in which the UNSE peak routinely occurs.

Each measure's hourly load shape is incorporated with the predicted DSM measure blend to model the annual hourly system-wide demand load reduction resulting from DSM programs. This allows UNSE to evaluate DSM as a resource for replacement of generation. This modeling of DSM measures as a resource in UNSE's cost production model indicates their potential cost savings by displacing energy and capacity from conventional resources. This analysis allows UNSE to focus on measures that coincide with high cost resources or the system peaks, even if the cost of their first-year savings is slightly higher.

Demand Response

Demand Response refers to a class of programs offered by the utility to incentivize customers, generally C&I customers with high energy demand, based on UNSE's system needs. DR programs can be used to avoid the build out of firm capacity resources required to meet reserve requirements, reduce market power purchases during periods of high energy prices, and provide greater grid stability and reduction in transmission and distribution outages due to reduced grid demand. Although DR has traditionally been focused on providing "capacity" through curtailment in customer demand during peak periods, it is increasingly being considered for additional services such as ramping or load leveling, wherein energy demand is "rescheduled" versus curtailed.

The UNSE C&I Demand Response Program is designed to manage peak demand and mitigate system emergencies through a commercial and industrial load curtailment program. The program is delivered in-house by engaging the interruptible rate customers. The UNSE customers on the interruptible rate had equipment installed that provides the Company control of their entire electric load.

UNSE installed metering equipment for participants to enable automated load curtailment and proper tracking of load data to evaluate customer participation levels in an event and provide data for post event analysis. In addition, participants agreed to be placed on UNSE's Interruptible Power Service tariff in lieu of any cash incentive for participation.

Distribution Modernization

UNSE is continually modernizing the distribution grid in order to operate the grid more safely, efficiently, and reliably while integrating new energy technologies. Current modernization programs include: the installation of a foundational communication network, the implementation of an ADMS, a two-way metering system (i.e. AMI), and an enhanced asset management program.

Advanced Distribution Management System

An ADMS is the central software application that will provide distribution supervisory control and data acquisition, outage management and geographical information in a single interface 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 implemented ADMS in the spring of this year, in parallel operation with its legacy outage management system and energy management system applications. It will cut over to the primary system in the fourth quarter of 2020, and will continue to expand on the capabilities of the system as additional ADMS functionality is integrated and field devices are deployed.

Automated Metering Infrastructure

AMI is in the "mesh network building" stage at UNSE with deployment of 5,000+ AMI meters. This stage will be completed by the third quarter of 2020. Deployment of the remaining AMI meters in UNSE service territory will continue through 2026.

CHAPTER 5

DISTRIBUTION AND TRANSMISSION PLANNING

Distribution Planning

Overview

UNSE is in the early stages of exploring smart grid technologies. The formation of a UNSE Distribution Automation Task Force is planned for 2021-2022. This team will evaluate prospective smart grid equipment vendors and identify 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.

Customers continue to have high expectations for electric service reliability. To this end, UNSE recently created a new Mohave County Distribution Planning Engineer position. This will enable functions such as distribution system modeling and detailed load and fault studies – previously outsourced to TEP planning engineers due to local resource constraints – to be performed “in house” at UNSE. With proper analysis, the necessity for capital improvement projects will be identified, proposed and budgeted.

A study on harmonics and the impacts of harmonics on the system is currently underway at UNSE and will be ongoing. Meanwhile, different vendor products are being evaluated for possible installation at various large industrial customer locations.

Table 9 outlines major future system additions that have been identified through the distribution planning analysis.

Table 9 - Proposed UNSE Distribution Project Enhancements

Project	Description	Other Notes
Feeder Tie SU5001-5003 **In Service Date 2021**	Install tie switch between circuits 5001 and 5003 out of Sunrise Substation.	1) Supports load growth 2) Improves System Reliability
Feeder Tie EA5022-5024 **In Service Date 2024**	Install tie switch between circuits 5022 and 5024 out of Eastern Substation.	1) Supports new business 2) Improves System Reliability
S. Kingman-Hilltop Dist. Rebuild **In Service Date 2021-22**	Rebuild and reconductor	1) Increases capacity 2) Improves System Reliability
Cheyenne Substation **In Service Date 2024**	New 69-12.47 kV substation	1) Supports new business 2) Permits future looping opportunities
Mulberry Feeder Addition (LHC) **In Service Date 2022**	Add a new feeder position at Mulberry Substation.	1) Supports load growth
Circuit 6013 Extension (LHC) **In Service Date 2023**	Three phase extension, London Bridge Road	1) Supports load growth
East Mohave Feeder Upgrade **Phased project thru 2025**	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
Meadview Substation **In Service Date 2022**	New 69-12.47 kV substation	1) Improves voltage 2) Supports future irrigation wells for large tree farming operations 3) Provides additional capacity for residential load growth in Meadview

Transmission Planning

UNSE shares Transmission Planning functions with TEP. See the TEP 2020 IRP, Chapter 5.

CHAPTER 6

UNSE EXISTING RESOURCES

UNSE's Existing Resource Portfolio

This section provides an overview of UNSE's existing thermal generation, renewable generation, and transmission resources. For the thermal generation resources it provides details on each station's ownership structure, fuel supply, environmental controls, and a brief future outlook. For the renewable generation resources, it provides capacity and technology information as well as certain details on the construction of the facilities. Information on connections to the bulk electric system is provided in the transmission section.

UNSE's existing thermal resource capacity currently owned by the Company is 291 MW. In addition, the Company also relies on the wholesale market for firm capacity PPAs to meet its summer peak demand obligations. Table 10 below provides a summary of UNSE's existing thermal resources.

Table 10 - UNSE Existing Thermal Resources

Generating Station	Unit	Primary Fuel Type	Net Nominal Capability MW	Commercial Operation Year	Operating Agent	UNSE's Share %	UNSE Planning Capacity
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	21.5	2006	UNSE	100	21.5
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							**291**

SRP = Salt River Project

Map 2 - UNSE System Map

Valencia Power Plant

Valencia Power Plant

The Valencia Power Plant ("Valencia") is located in Nogales, Arizona and provides UNSE with 64 MW of combustion turbine capacity.

Ownership:

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 21.5 MW and was constructed in 2006.

In-Service Date:

Valencia Unit 1	1989
Valencia Unit 2	1989
Valencia Unit 3	1989
Valencia Unit 4	2006

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.

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 ("SO_2") 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 SO_2. However, each of these units is less than 25MW capacity; therefore, they are not subject to Acid Rain provisions.

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

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.

Ownership:

Black Mountain is wholly owned by UNSE.

In-Service Date:

Black Mountain Unit 1	2008
Black Mountain Unit 2	2008

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.

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 SO_2 and NOx, and the facility must comply with the Acid Rain program limits for SO_2 and NOx.

Outlook:

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

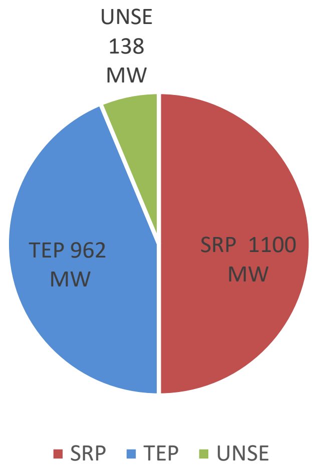
Gila River Generating Station

Gila River Generating Station

Gila River Generating Station ("Gila River") is a 2,200 MW natural gas-fired combined cycle facility located three miles north of the town of Gila Bend, in Maricopa County, Arizona. The plant is operated by SRP.

Ownership:

Units 1 and 4 are owned by SRP. 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

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 Company's hedging policy. Gila River is connected to the El Paso Natural Gas and Transwestern pipelines and can be supplied from either pipeline.

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

Outlook:

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

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. Table 11 below provides an overview of UNSE's renewable energy portfolio.

Table 11 – UNSE's Renewable Resources

Resource-Counterparty	Owned/PPA	Technology	Location	Operator-Manufacturer	Completion Date	Capacity MWac
Western Wind	PPA	Wind	Kingman, AZ	Brookfield Renewable	Sept 2011	10
La Senita School	Owned	SAT PV	Kingman, AZ	UNSE	Nov 2011	1
Black Mountain	PPA	SAT PV	Kingman, AZ	Black Mountain, LLC	Dec 2012	7
Rio Rico	Owned	Fixed PV	Rio Rico, AZ	UNSE	Mar 2014	6
Red Horse Solar 3	PPA	SAT PV	Willcox, AZ	D. E. Shaw & Co., L.P. dba Red Horse III Solar	Jun 2016	30
Jacobson Solar	Owned	Fixed PV	Kingman, AZ	UNSE	Mar 2017	4
Grayhawk Solar	PPA	SAT PV	Kingman, AZ	D. E. Shaw & Co., L.P. dba Grayhawk Solar	Jun-2018	46

Notes: PPA – Purchased Power Agreement
SAT PV – Single Axis Tracking Photovoltaic
Fixed PV – Fixed-Tilt Panel Photovoltaic

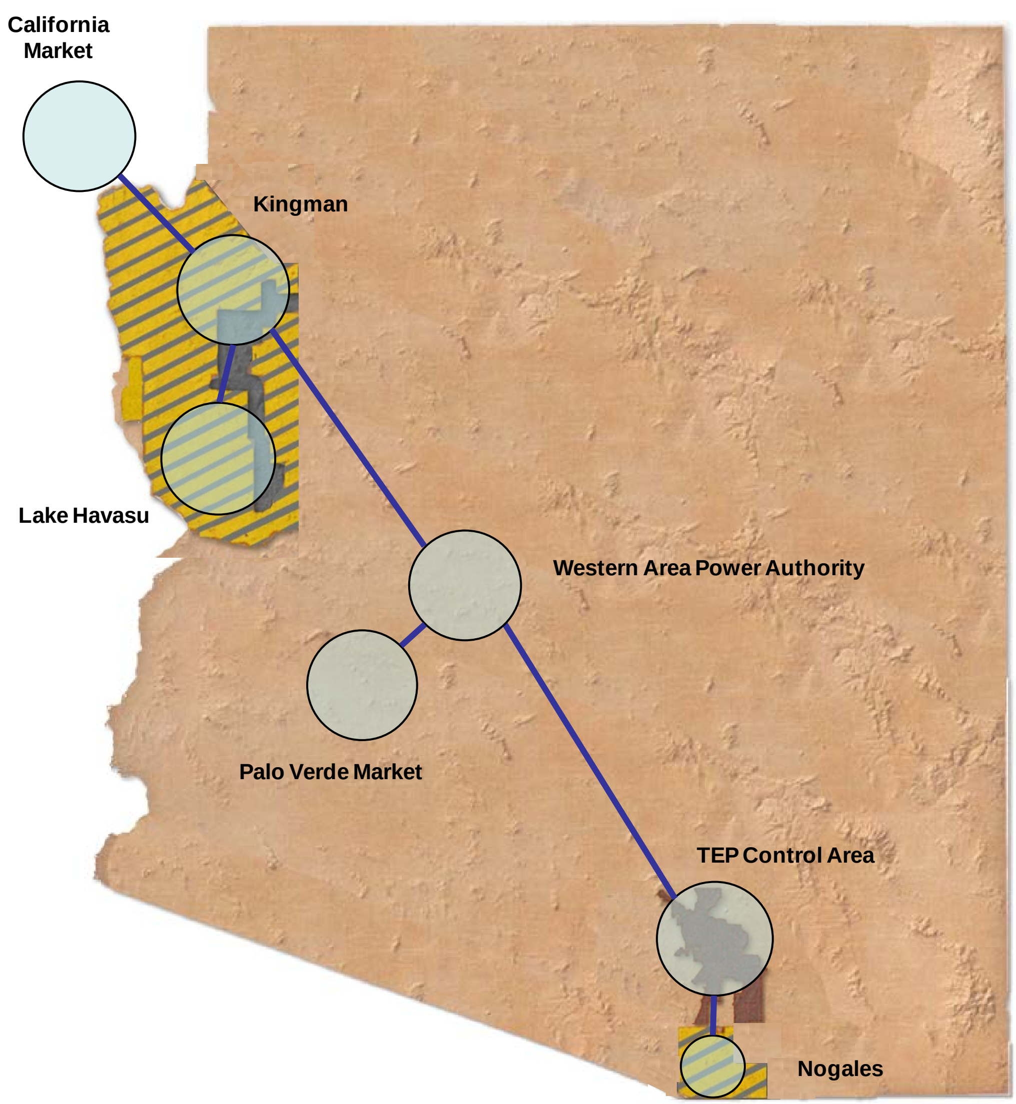
Picture 2 - UNSE Solar Facilities Located at the Rio Rico High School

Transmission

UNSE Transmission Resources

UNSE's transmission resources include approximately 339 miles of transmission lines owned by UNSE, long-term transmission rights (Point to Point and Network service) purchased from Western Area Power Administration (WAPA) and TEP, and Point-to-Point transmission purchased from other transmission providers on an ad hoc basis. Given UNSE's dependence on third-party transmission providers, UNSE works closely with WAPA's and TEP's transmission planning groups to ensure adequate long-term transmission capacity is available to serve the Mohave service territories. UNSE load and market delivery points are shown on Map 3, below.

Map 3 – UNSE Load and Market Delivery Points



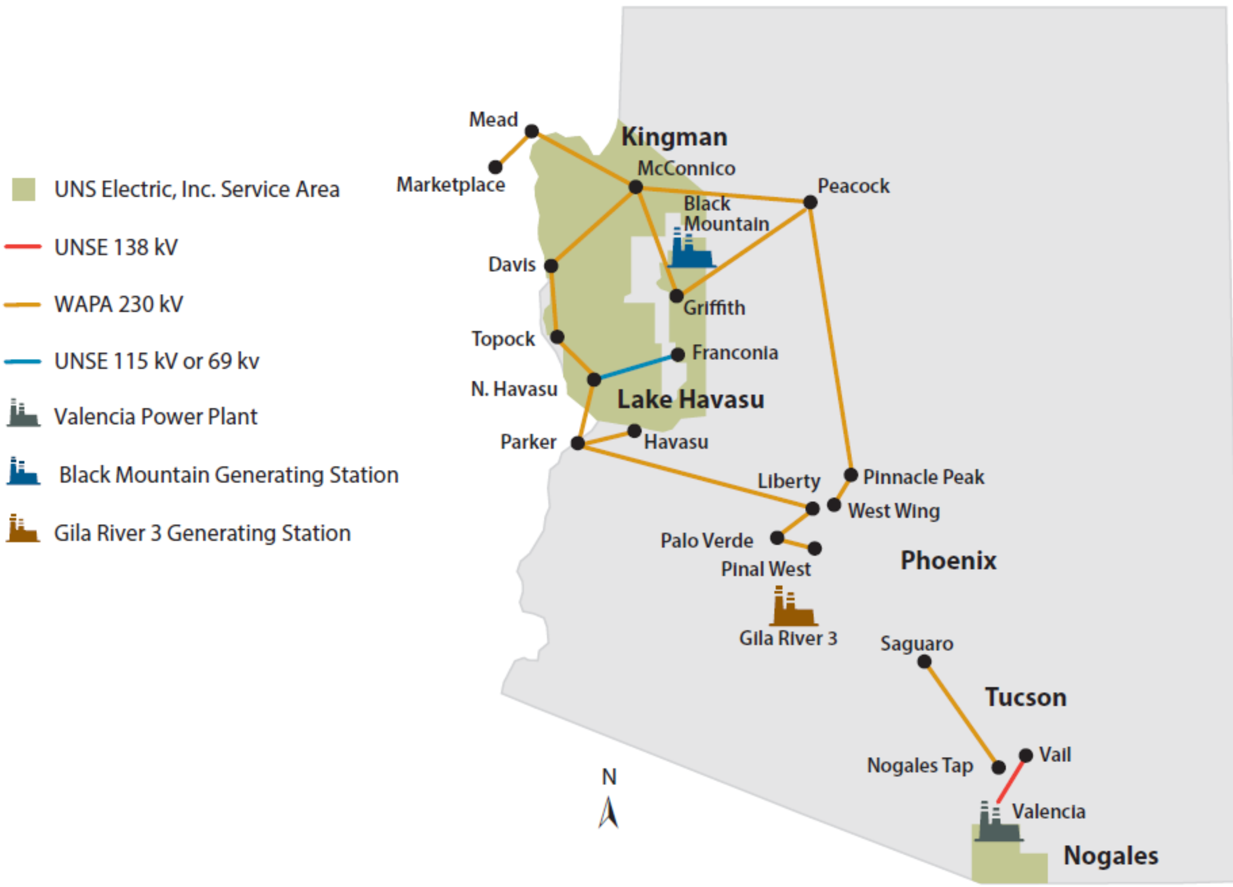
Control Area Services Agreement

Beginning in June 2008, UNSE entered into a long-term Control Area Services Agreement with TEP. At that time UNSE became part of the TEP Balancing Authority under which TEP provided for a fee, the required Balancing or Ancillary Services. These services include: Control Area Administration, Reactive Supply and Voltage Control, Regulation and Frequency Response, Energy Imbalance, Spinning Reserve and Supplemental Reserves. The Services and charges under this Control Area Services Agreement are approved by and on file with the Federal Energy Regulatory Commission (FERC).

Existing Transmission Resources

UNSE's existing transmission system as constructed is contained within two service areas in Arizona, being Mohave and Santa Cruz counties. As shown on Map 4, 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 345 kV substations: Mead, Liberty and Peacock. Firm system purchases designated as Network Resources are delivered to Pinnacle Peak substation. UNSE-Mohave receives Network Integration Transmission Service 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. With the completion of the Vail to Valencia 138 kV line, the UNSE Santa Cruz service territory is served by TEP's system. UNSE owns approximately 2,796 miles of 69 kV transmission lines in Mohave County and 60 miles of 138 kV transmission lines in Santa Cruz County.

Map 4 - UNSE Transmission Delivery Points

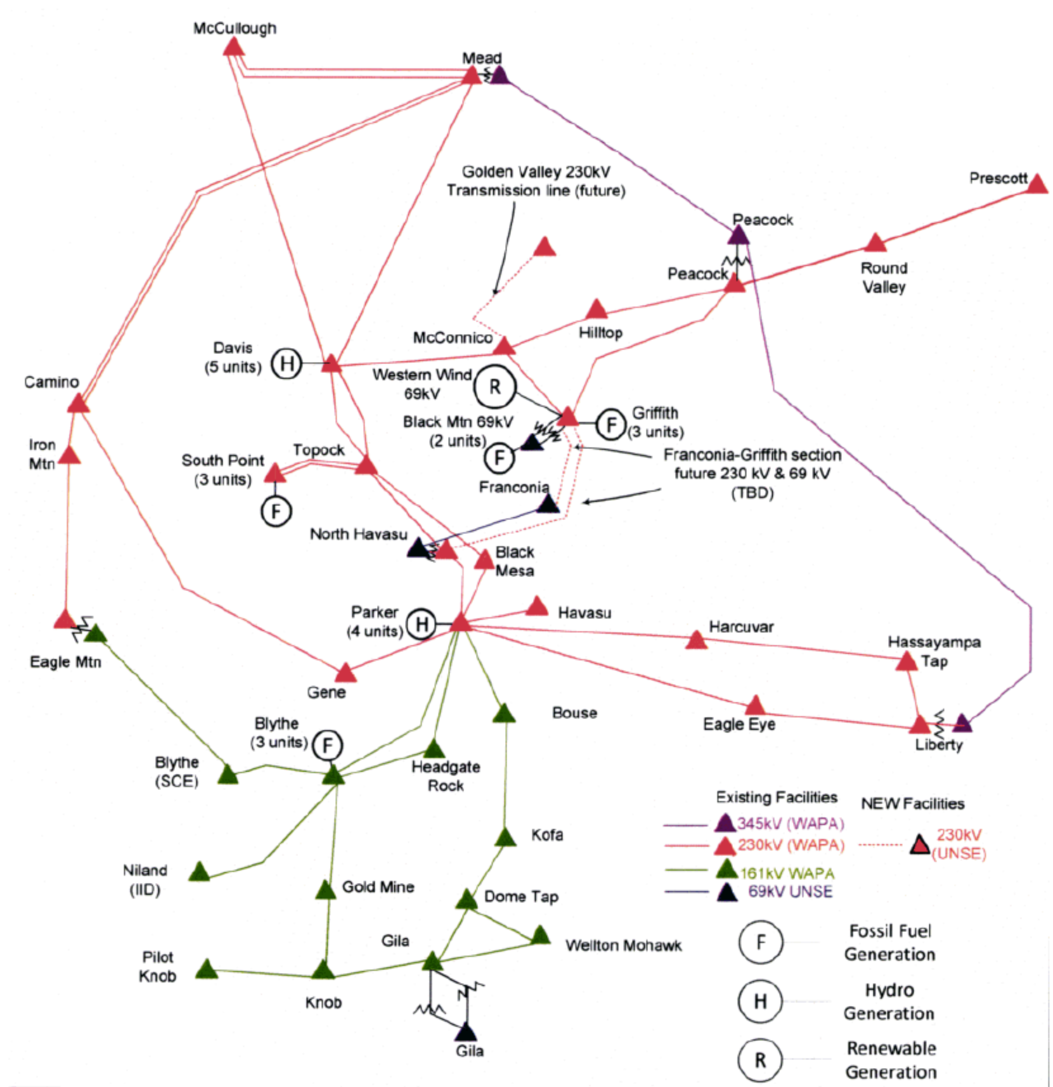


Mohave County Transmission Overview

UNSE has current transmission contracts with WAPA totaling approximately 480 MW, which includes network service on WAPA's system. The network service currently has Pinnacle Peak as a receipt point and Hilltop, Duval-Warm Springs, Planet Ranch, McConnico and North Havasu as delivery points in Mohave County.

In addition, UNSE has point to point service on both WAPA's Parker Davis System and its Central Arizona Power System and a separate point to point service on WAPA's Intertie Power System and on its Central Arizona Power System. UNSE also buys point to point transmission over WAPA's Open Access Same-Time Information System (OASIS), on an ad hoc basis. UNSE is able to purchase access on transmission systems of other providers in the region as needed.

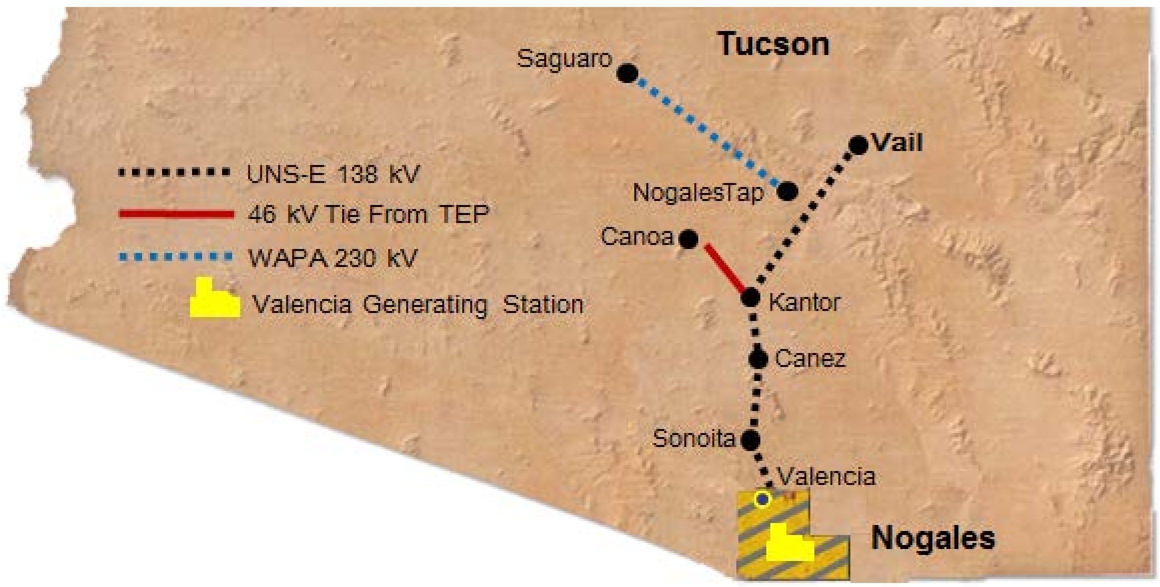
Map 5 - Mohave County Transmission Delivery Points



Santa Cruz County Transmission Overview

Santa Cruz County relies on a single 138 kV transmission line to serve the local distribution grid located in the City of Nogales as shown on Map 6. The Vail to Valencia project upgraded an existing 115 kV transmission line with a 138 kV transmission line between the Vail Substation, located southeast of Tucson, and the Valencia Substation in Nogales, Arizona. The existing transmission line is the primary source of electrical service for customers in Nogales, Arizona and surrounding communities.

Map 6 - Santa Cruz County Transmission Delivery Points



Energy Imbalance Markets

Energy Imbalance Markets are specialized wholesale power markets designed to help BA areas balance the sub-hourly intermittent characteristics of wind and solar power. An EIM monitors the variability of loads and resources across the footprints of its participating BA areas and dispatches resources to achieve the least-cost balance of electric demand and supply in real time (e.g., 5- to 15-minute intervals).

Participants in the EIM expect to realize at least three benefits:

- Economic savings to customers through lower production costs
- Improve visibility and situational awareness for system operations in the Western Interconnection
- Better and more cost-effective integration of renewable resources

CAISO Western EIM

TEP signed an agreement with the CAISO in May 2019 to join the Western EIM beginning in April 2022. TEP's decision to join the Western EIM was based in part on the results of a study completed by Energy and Environmental Economics ("E3") in November 2018 showing estimated annual benefits of participation in the Western EIM at $13.6 million. In August 2020, UNSE retained E3 to evaluate the potential economic benefits of UNSE's participation in the Western EIM. As UNSE operates within TEP's BA area, the current E3 study will involve updating the November 2018 study completed for TEP with UNSE's generators, transmission, and loads to assess the economic benefit to the combined TEP-UNSE system. The benefit specific to UNSE will be estimated by subtracting the "TEP only" benefit from the combined benefits.

CHAPTER 7

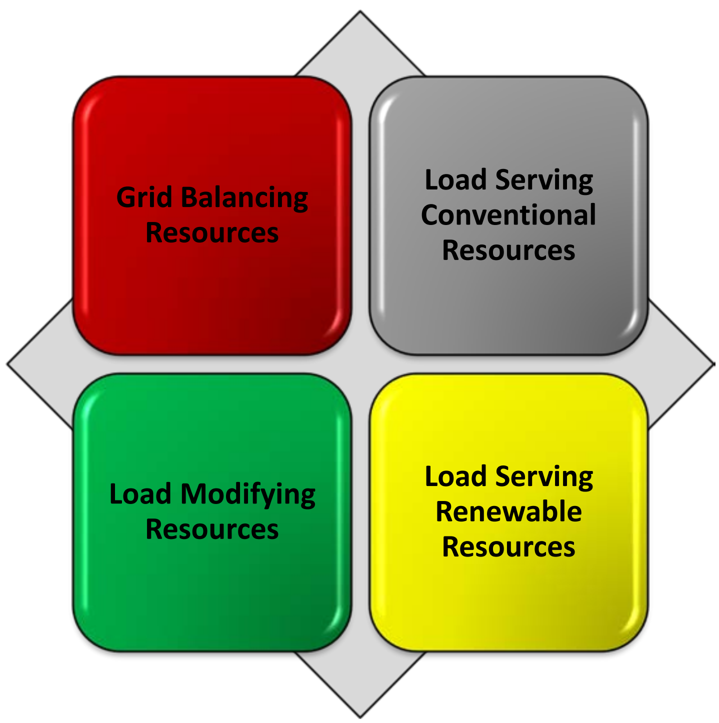
FUTURE RESOURCE ALTERNATIVES

This chapter provides an overview of the future resources considered for deployment and the key economic and operational metrics considered. After a brief description of resource categories, this chapter provides 1) a resource matrix that qualitatively summarizes each resource type and 2) a levelized cost comparison of each resource type. Conventional hydro-, coal- and nuclear-powered resources were not considered and are not included in this chapter because of their cost and environmental impacts. However, if a particular technology is bid into an ASRFP issued by UNSE, it would be considered equally with all other technologies based on the specific criteria established in the ASRFP.

Resource Categories

The UNSE 2017 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 UNSE's 2020 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 3 and are described in more detail below:

Figure 3 – Categories for New Resources



Load Modifying Resources. Load modifying resources include EE, DERs, including DG, DR, and time of use 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. The role of load modifying resources is addressed in Chapter 4 – Preparing for an Integrated Grid.

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 UNSE an opportunity to provide low-cost, zero-carbon energy, these technologies must be balanced within a portfolio that includes other resource categories.

Conventional Load Serving Resources. Conventional load serving resources include coal, natural gas, hydro, nuclear powered technologies that have traditionally been used to provide the vast majority of energy and capacity to meet load. For the 2020 IRP, UNSE is not considering adding any future conventional load serving resources to any of its proposed portfolios.

Grid Balancing Resources. Grid balancing resources include quick-start, fast-response natural gas resources, such as combustion turbines and Reciprocating Internal Combustion Engine (RICE) generators; 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 12 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 12 – 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)	(2)	Low	Yes	Medium	High
	Compressed Air Energy Storage	(2)	Low	No	High	High
	Pumped Hydro	(2)	High	No	High	High
Load Serving Renewable Resources	Wind	Yes	Medium	Yes	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, UNSE 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, UNSE used information gathered through its ongoing competitive bidding processes and reviewed consultant reports provided as part of other utilities' recent IRPs.

- **U.S. Energy Information Administration (EIA)**
  Annual Energy Outlook 2020
  https://www.eia.gov/forecasts/aeo/electricity_generation.cfm

  UNSE utilizes 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. This AEO is revised annually.

  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. UNSE utilizes the AEO to benchmark resource costs and natural gas prices.

- **National Renewable Energy Laboratory (NREL)**
  Annual Technology Baseline (2019)
  https://atb.nrel.gov/

  UNSE utilizes 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. UNSE utilizes the Mid Technology Cost Scenario, which accounts for likely technology advancements and market conditions.

- **Lazard**
  Levelized Cost of Energy Analysis 13.0 (November 2019)
  https://www.lazard.com/media/451086/lazards-levelized-cost-of-energy-version-130-vf.pdf

- **Lazard**
  Levelized Cost of Storage Analysis 5.0 (November 2019)
  https://www.lazard.com/media/451087/lazards-levelized-cost-of-storage-version-50-vf.pdf

  UNSE utilizes 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 (2019)
  https://www.woodmac.com/research/products/power-and-renewables/north-america-power-and-renewables-service/

  UNSE 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. In addition, the LTO includes scenarios corresponding to "high" and "low" natural gas prices. Decision No. 76632 requires the IRP to consider a "wide variety of natural gas priced scenarios."

  The LTO includes forecasts for CO_2 emission prices for jurisdictions where emission pricing applies (e.g. California). In addition, the LTO includes a scenario in which future Federal regulations result in emission prices for CO_2 emitted from electric generating units outside of California.[9]

Forecast Outlook on the Cost of Fuel for Conventional Load-Serving Resources

Natural gas prices are forecasted to remain low in upcoming years. Prices are expected to reach $3/MMBtu in 2030 and not rise above $4/MMBtu until 2038. Permian Basin prices are expected to remain even lower. Therefore, natural gas will continue to increase its share of the total U.S. energy mix. A Natural Gas Combined Cycle (NGCC) generator can produce energy at a marginal cost of $15/MWh, given a heat rate of 7,500 Btu/kWh and a natural gas price of $2/MMBtu. This, and the low price of renewable energy, has put pressure on coal and nuclear resources, resulting in the frequent announcements of coal plant retirements.[10]

Forecast Outlook on Conventional Renewable Resources

Renewable energy costs continue to decline, competing with conventional resource technologies.[11] On an energy-only basis, renewable resources continue to be the lowest-cost resource; thus, their share of the total energy mix will continue to increase. Considerable amounts of wind power is currently being built to take advantage of the Production Tax Credit before it begins to phase out. Utility-scale solar continues to be cost-effective, primarily due to economies of scale, in comparison to residential, and to a lesser extent, commercial-sited solar. Many renewable cost analyses do not take into account potential social and environmental externalities or reliability- or intermittency-related considerations.

Forecast Outlook on Grid Balancing Resources

The pronounced cost decrease in certain renewable energy technologies, combined with the high penetration of intermittent renewables, has significantly increased demand for grid-balancing technologies. Lithium-ion battery storage is experiencing the most pronounced cost declines and represents 99 percent of recent

[9] The Wood Mackenzie 2019 H1 LTO includes a "Federal Carbon Case", which implements a $2.40/short ton price on CO_2 emitted from power plants beginning in 2028 and escalating about $2.50 per year thereafter.
[10] https://www.eia.gov/todayinenergy/detail.php?id=37817
[11] Within the last 10 years, the costs of onshore wind and utility-scale solar have decreased by 70 percent and 89 percent respectively. Lazard LCOE v13.

energy storage deployments.[12] Pairing solar and storage has been cost-effective for energy and short-term capacity since it can take advantage of the Investment Tax Credit. The ratio of solar to battery power at new solar plus storage facilities has decreased from 4:1 to as low to 1:1 in some cases, indicating an increasing reliance on storage for capacity purposes.[13] Most storage systems paired with solar have a discharge duration of 4 hours at maximum capacity. Where this duration is not sufficient to cover peak loads, gas-fired generation will continue to be a cost-effective alternative to energy storage technologies.

Forecast Outlook on Resource Capital Costs

The red lines in Chart 8 through Chart 11 show the nominal capital cost forecasts used by UNSE in developing the cost estimates within its portfolio analyses. The 2019 costs for solar and wind are from Lazard, and the 2019 cost for 4-hour batteries is from the ATB.[14] Their cost forecasts, however, are based on WoodMac's forecast of future year costs relative to WoodMac's 2019 cost. Although the addition of natural gas combined cycle plants was not considered in any portfolios, its cost projection is shown for reference, since its trend is indicative of other gas-based technologies and since gas-based resources have been the most common resource recently chosen by utilities in addition to solar and wind. Details on these and other technologies can be found in Appendix B of the 2020 TEP IRP.

[12] Lazard's LCOS v5.0
[13] https://media.srpnet.com/srp-to-cut-emissions-through-major-solar--battery-energy-purchase/
https://www.greentechmedia.com/articles/read/southern-california-edison-picks-770mw-of-energy-storage-projects-to-be-built-by-next-year#:~:text=Southern%20California%20Edison%20Contracts%20Huge,tough%20deadline%20in%20August%202021.
[14] 8-hour batteries were assumed to have a capital cost 1.8 times greater than 4-hour batteries of the same power rating.

Chart 8 - UNSE Capital Cost Forecast for Solar PV Single-Axis Tracking

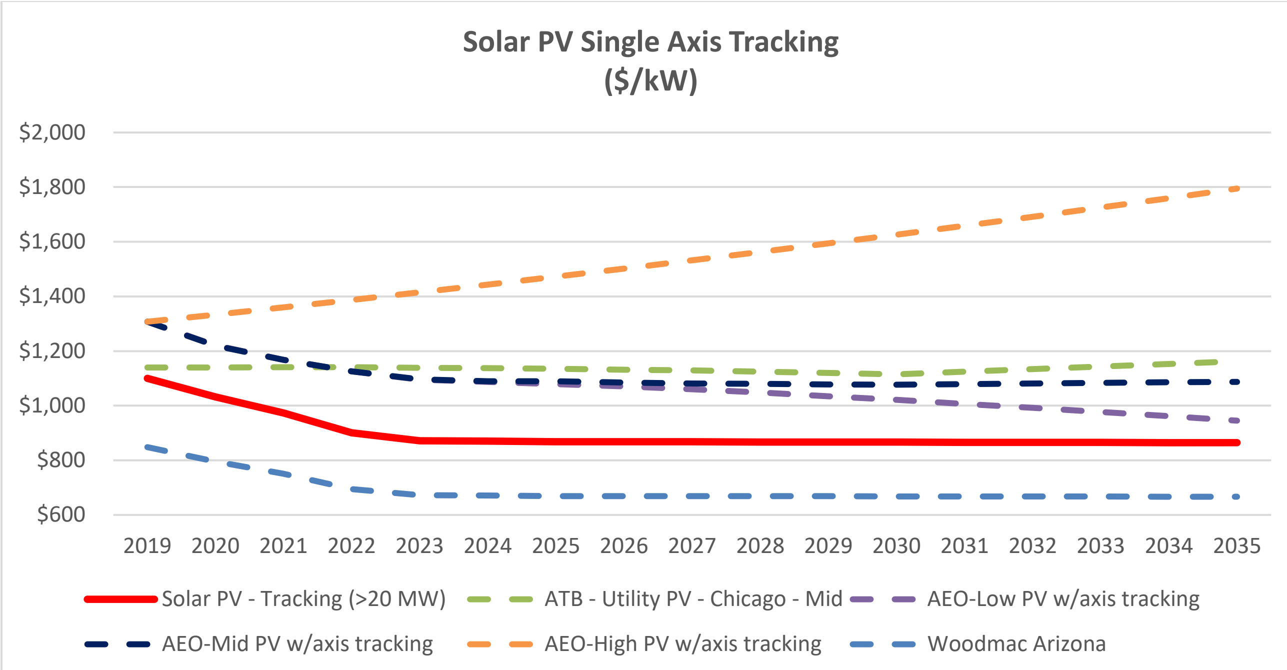


Chart 9 - UNSE Capital Cost Forecast for Onshore Wind

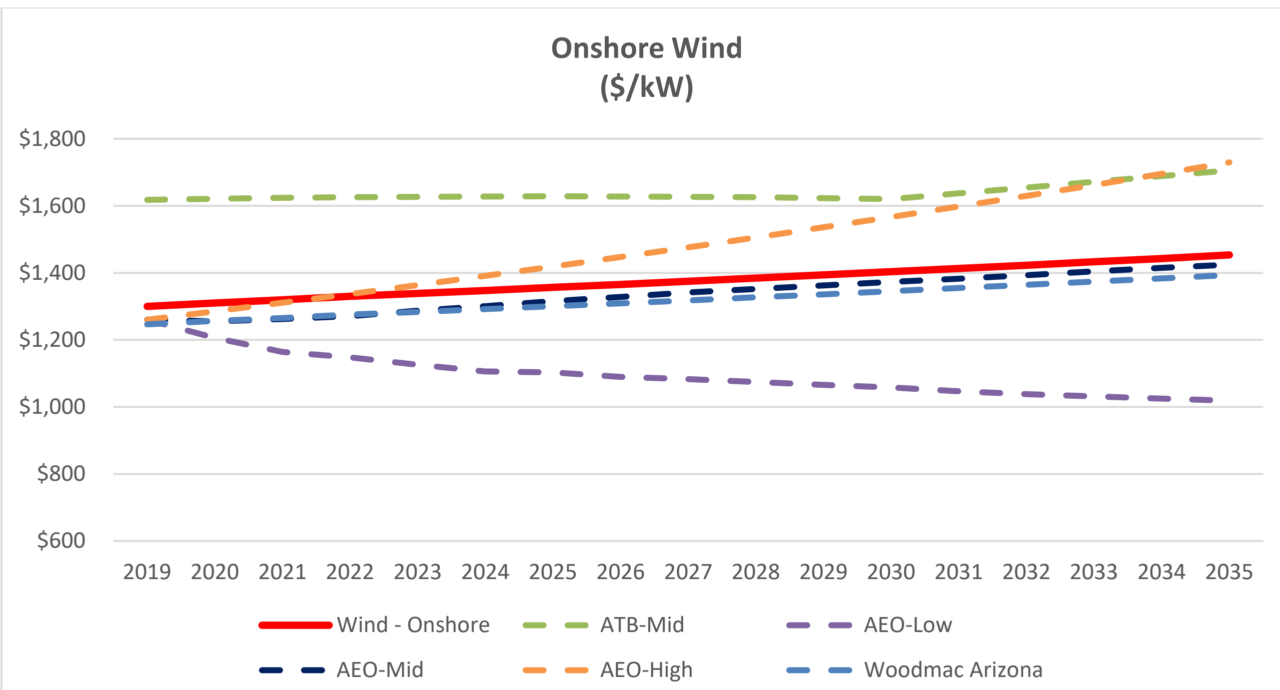


Chart 10 - UNSE Capital Cost Forecast for 4-Hour Battery Storage

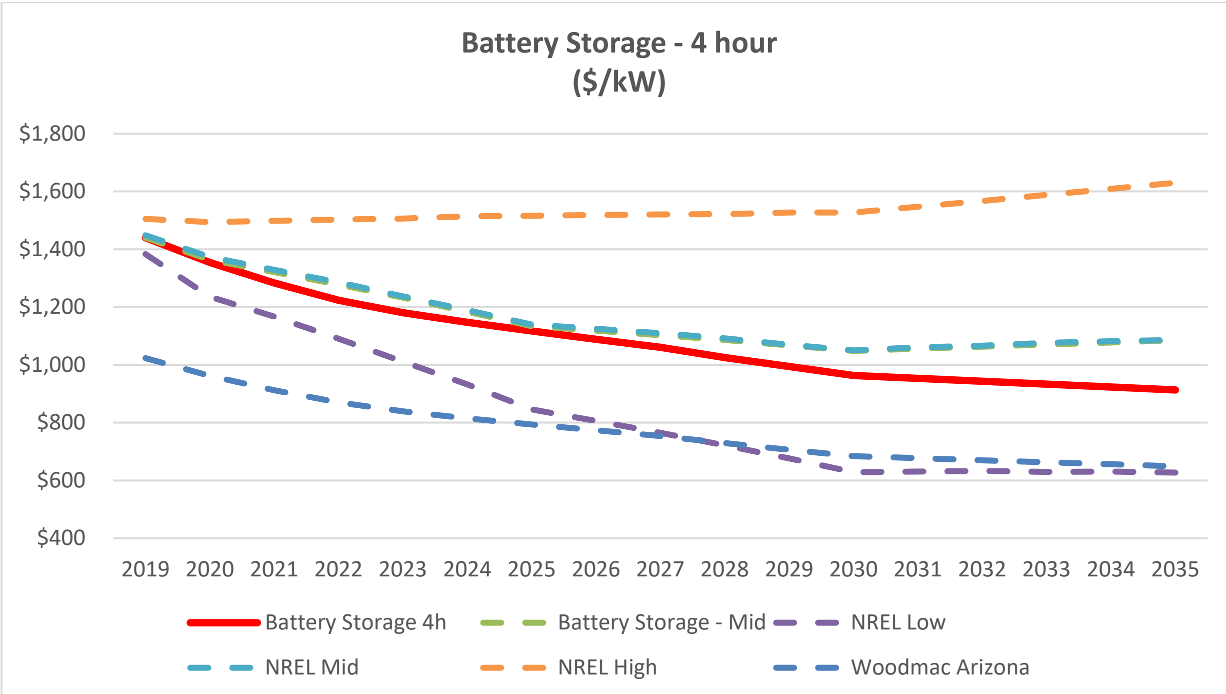
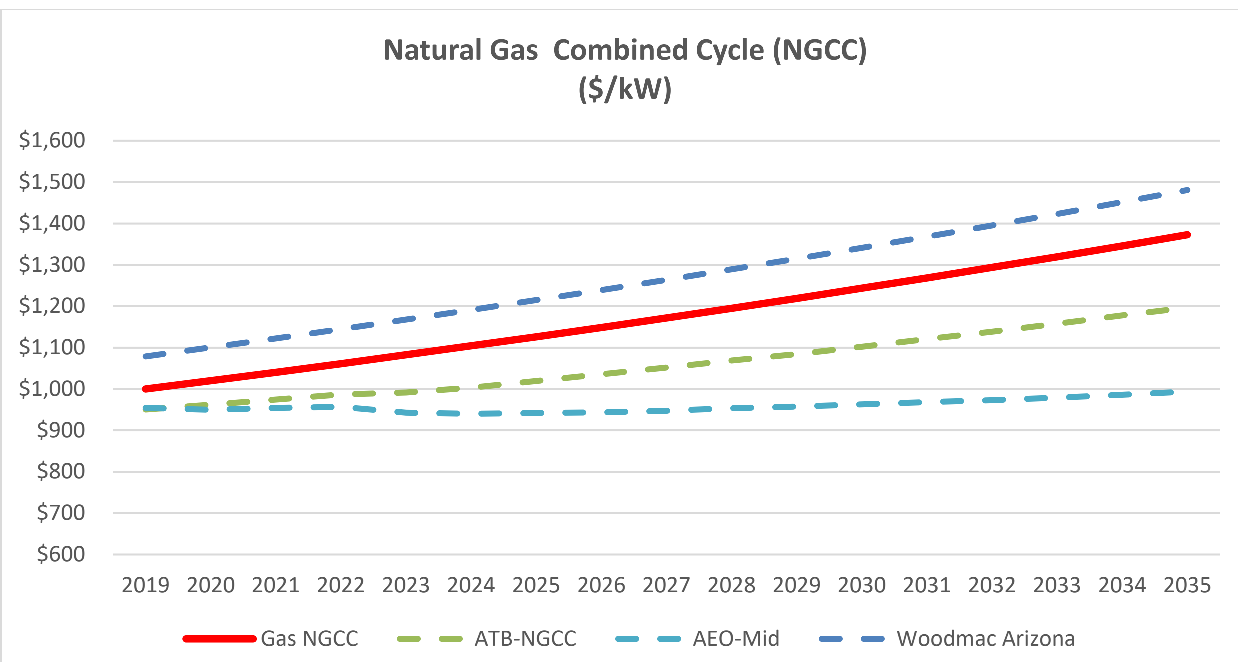


Chart 11 - UNSE Capital Cost Forecast for Natural Gas Combined Cycle



2020 Integrated Resource Plan Levelized Cost Comparisons

The levelized cost of energy (LCOE) provides a means of comparing the lifetime cost of energy across different demand and supply-side options. The LCOE is the net present value of a project's cost over its lifetime divided by the net present value of the energy produced over its lifetime ($/MWh). Costs include construction, financing, fuel, and operation and maintenance. Costs that depend significantly on specific project attributes or locations are typically not included in the LCOE, such as capacity value, environmental impacts, tax credits, permitting, and interconnection and transmission costs. The LCOE also does not take into account risk factors such as fuel price and regulatory risks.

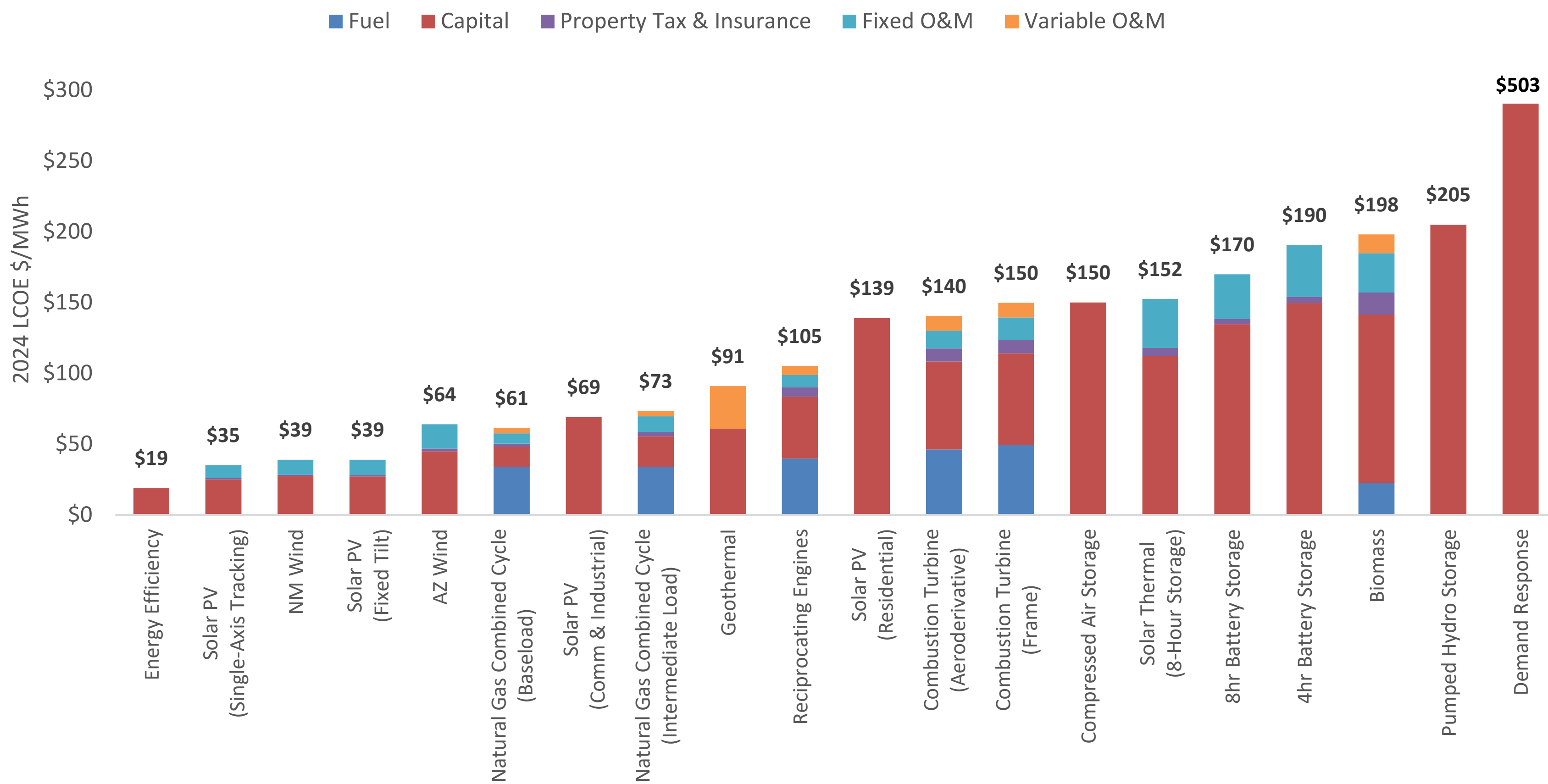
Cost Assumptions for All Resources

Below are the assumptions applicable to all LCOE calculations in this section:

- Costs are in 2024 dollars and assume installations in 2024, which is near the time frame in which many portfolios considered by UNSE begin adding new resources.
- Integration costs are not included, such as those that might be required for conventional and grid balancing resources to balance the intermittency of solar and wind energy.
- Interconnection, transmission, and decommissioning costs are not included.
- An average long-term delivered natural gas price of $4.68/MMBtu is assumed for natural gas resources.

Chart 12 below provides a comparison of the levelized costs of a variety of resources.

Chart 12 - Levelized Costs of All Resources



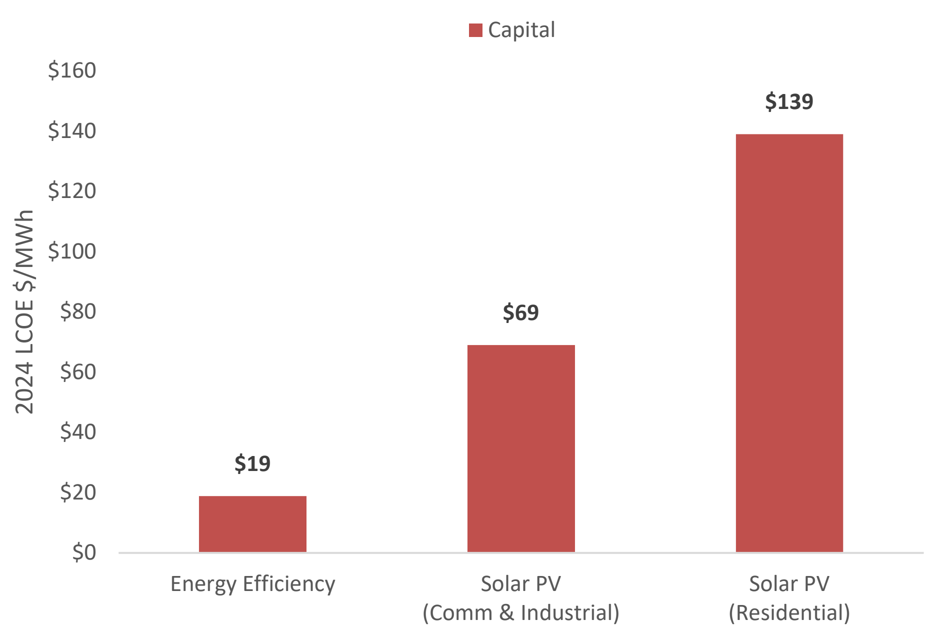
Cost Assumptions for Load Modifying Resources

Table 13 includes the load modifying resource costs for the 2020 IRP.

Table 13 – Cost Assumptions for Load Modifying Resources

Energy Efficiency	Solar PV – Commercial and Industrial	Solar PV – Residential	Rate Design
Customer Efficiency Programs	Commercial & Industrial DG Programs	Residential DG Programs	Targeted Load Usage / Reductions By Time of Use
Based on various customer demand side programs	Based on various commercial & industrial DG programs	Based on various residential DG programs	Based on various rate tariff by customer class
$19	$69	$139	Depends on Tariff

Chart 13 - LCOE for Load Modifying Resources



LCOE Assumptions for Load Modifying Resources:

- Energy efficiency is based on UNSE's projected program costs for 2020 based on the average lifetime of the programs.
- Solar PV – Residential is based on Lazard's LCOE Analysis – Version 13.
- Solar PV – Commercial & Industrial is based on Lazard's LCOE Analysis – Version 13.

Cost Assumptions for Renewable Load Serving Resources

Table 14 includes the load serving renewable resource costs for the 2020 IRP. The levelized costs for biomass and geothermal energy were obtained directly from Lazard. As a result, their component costs are not included in Table 14.

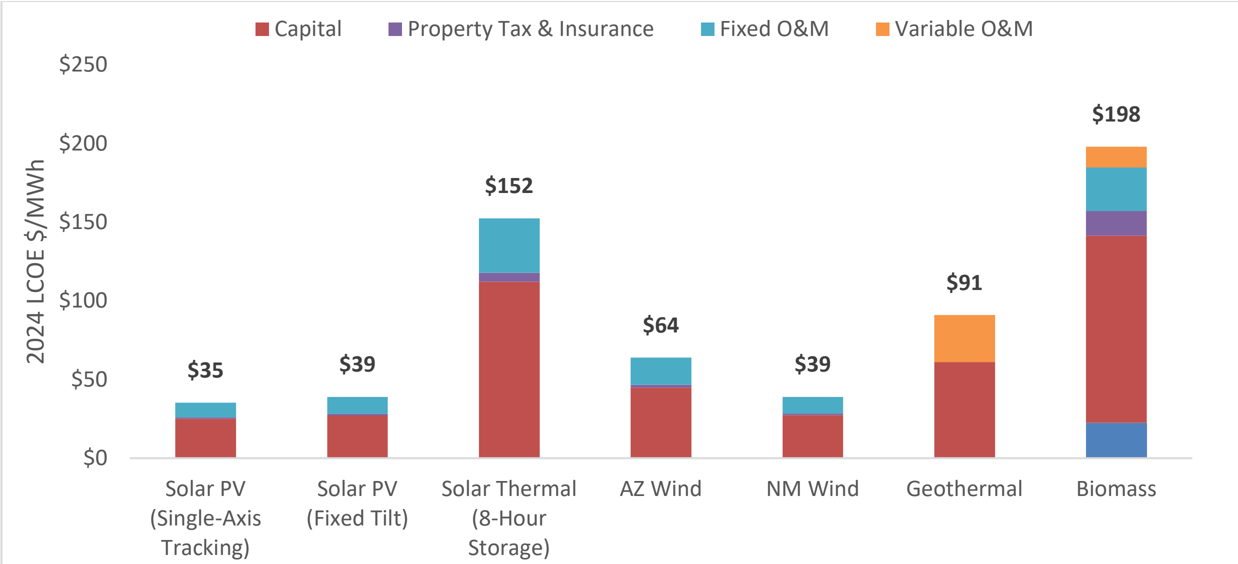
Table 14 – Cost Assumptions for Renewable Load Serving Resources

Resource Characteristics	Units	Solar Thermal – 8-Hour Storage	Solar PV – Fixed Tilt	Solar PV – Tracking	AZ Wind Resources	NM Wind Resources
Project Lead Time	Years	4	2	2	3	3
Installation Year	First Year	2024	2024	2024	2024	2024
Resource Life	Years	35	20	20	30	30
Peak Capacity, MW	MW	100	100	100	200	200
Construction Cost	2024 $/kW	$4,991	$668	$817	$1,317	$1,335
Fixed O&M	2024 $/kW	$82.19	$19.41	$21.56	$32.36	$32.81
Annual Capacity Factor	%	39%	25%	33%	27%	45%
Annual Output	GWh	342	219	289	473	788
Net Coincident Peak	%	100%	37%	65%	23%	25%
Water Usage	Gal/MWh	700[15]	-	-	-	-

Levelized Cost of Energy	$/MWh	$152	$39	$35	$64	$39

[15] Mid-point of https://www.seia.org/initiatives/water-use-management plus wash water for mirrors and makeup water for steam cycle process from the https://www.nrel.gov/docs/fy15osti/61376.pdf

Chart 14 - LCOE for Renewable Load Serving Resources



LCOE Assumptions for Renewable Load Serving Resources:

- Solar resources assume high solar insulation for projects sited in the Desert Southwest.
- AZ wind resources assume capacity factors reflective of projects sited in eastern Arizona.
- NM wind resources assume capacity factors reflective of projects sited in southeast New Mexico.

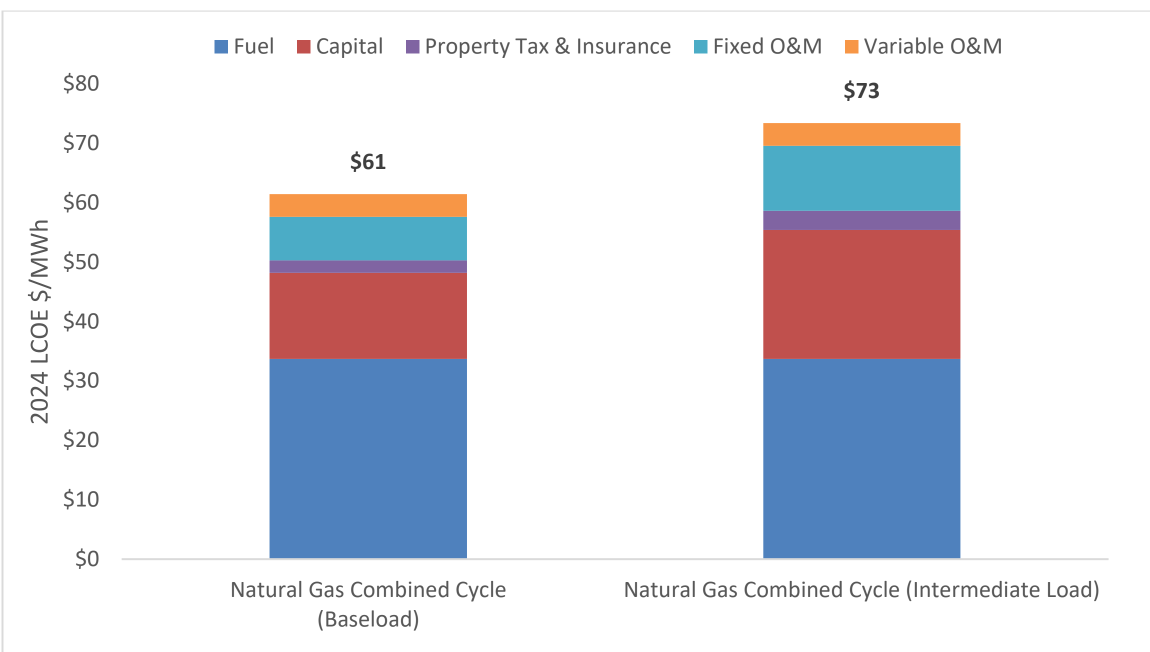
Cost Assumptions for Conventional Load Serving Resources

Table 15 includes the load serving conventional resource cost assumptions for the 2020 IRP.

Table 15 – Cost Assumptions for Conventional Load Serving Resources

Resource Characteristics	Units	Baseload NGCC	Intermediate NGCC
Project Lead Time	Years	4	4
Installation Years	First Year	2024	2024
Resource Life	Years	30	30
Peak Capacity	MW	550	550
Plant Construction Cost	2024 $/kW	$1,085	$1,085
Fixed O&M	2024 $/kW	$37.96	$37.96
Variable O&M	2024 $/MWh	$3.06	$3.06
Gas Transportation	2024 $/kW	$16.80	$16.80
Heat Rate	Btu/kWh	7,200	7,200
Annual Capacity Factor	%	75%	50%
Expected Annual Output	GWh	3,614	2,409
Fuel Source	Fuel Source	Natural Gas	Natural Gas
Unit Fuel Cost	$/MMBtu	$4.68	$4.68
Net Coincident Peak	%	100%	100%
Water Usage	Gal/MWh	250	250
Levelized Cost of Energy	$/MWh	$61	$73

Chart 15 - LCOE for Conventional Load Serving Resources



Cost Assumptions for Grid Balancing Resources

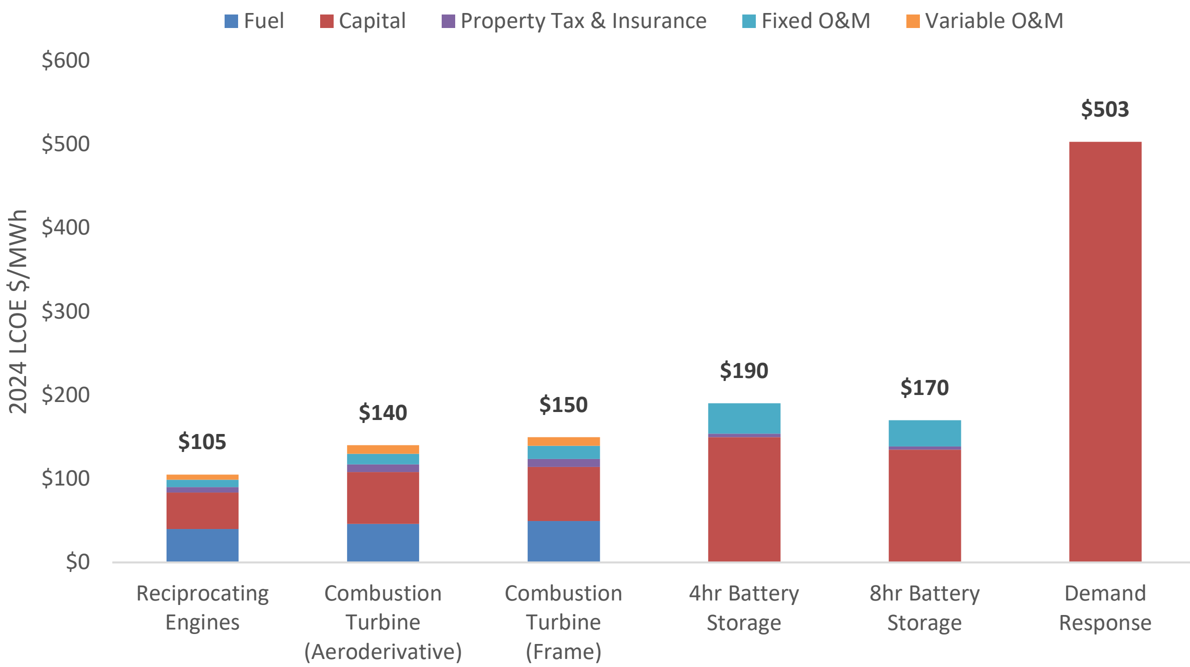
Table 16 includes the grid balancing resource cost assumptions for the 2020 IRP.

Table 16 – Cost Assumptions for Grid Balancing Resources

Resource Characteristics	Units	Combustion Turbine (Aeroderivative)	Combustion Turbine (Frame)	Reciprocating Engines (RICE)	4-hr Battery Storage	8-hr Battery Storage	Demand Response
Project Lead Time	Years	4	4	3	2	2	Customer Load Control Programs
Installation Years	Year Available	2024	2024	2024	2024	2024	
Resource Life	Years	30	30	30	20	20	
Peak Capacity, MW	MW	45	75	100	40	40	
Construction Cost	2024 $/kW	$925	$771	$874	$1,081	$1,945	
Fixed O&M	2024 $/kW	$13.08	$13.08	$12.34	$32.31	$55.39	
Variable O&M	2024 $/MWh	$8.20	$8.20	$4.97	$0.00	$0.00	Based on Various Direct Load Control Programs
Gas Transportation	2024 $/kW	$16.80	$16.80	$16.80	-	-	
Heat Rate	Btu/kWh	9,800	10,500	8,500	-	-	
Capacity Factor	%	15%	15%	15%	10%	20%	
Annual Output	GWh	59	99	175	35	70	
Fuel Source	Fuel Source	Natural Gas	Natural Gas	Natural Gas	(1)	(1)	
Unit Fuel Cost	$/MMBtu	$4.68	$4.68	$4.68	-	-	
Net Coincident Peak	%	100%	100%	100%	100%	100%	
Water Usage	Gal/MWh	150	150	<10	(1)	(1)	
Levelized Cost of Energy	$/MWh	$140	$132	$125	$190	$170	$503

(1) Fuel source and water usage of batteries depends on the resources used to charge the batteries.

Chart 16 - LCOE for Grid Balancing Resources



LCOE Assumptions for Grid Balancing Resources:

- Reciprocating engines and combustion turbines serve a similar purpose and are assumed to operate at a capacity factor of 15 percent.
- Demand response costs are based on average estimated program cost. Annual capacity factors based on limited customer interrupt ability. These programs assume a limit of 80 hours per year, with a typical load control event lasting 3 to 4 hours (or 1 percent capacity factor).

Production Tax Credit (PTC)

The LCOE for a given project depends on several factors specific to that project, including eligibility for tax credits. Wind power projects typically benefit from the federal PTC, which is an inflation-adjusted per-kilowatt-hour credit for electricity generated by qualified energy resources and sold by the taxpayer to an unrelated person during the taxable year. The duration of the credit is for 10 years after the date the facility is placed in service. The credit is reduced by 20, 40, or 60 percent, respectively, for projects commencing construction in 2017, 2018, or 2019, with no credit for projects commencing construction after 2019. The Internal Revenue Service recently issued Notice 2020-41, which grants a one-year extension of the Safe Harbor period for projects that began construction in 2016 (or 2017). As long as all assets are placed in service by December 31, 2021, full value of PTCs produced can be realized.

Investment Tax Credit (ITC)

Solar projects (and storage projects powered primarily by renewable energy) typically benefit from the federal ITC, which, for solar projects, is worth 30 percent of the cost of the solar system. This credit is reduced to 26, 22, or 10 percent, respectively, for projects commencing construction in 2020, 2021, or after 2022. Residential projects commencing construction after 2021, however, receive no ITC.

CHAPTER 8

ALTERNATIVE FUTURE SCENARIOS AND FORECAST SENSITIVITIES

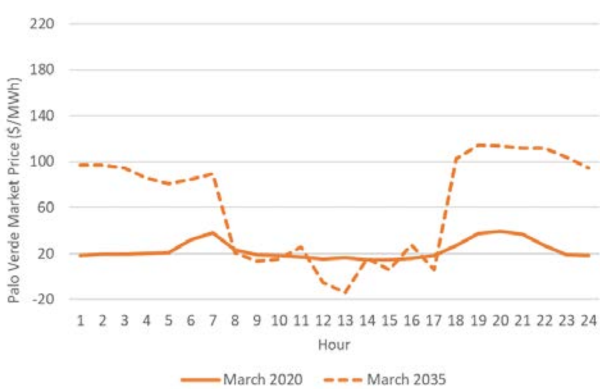
Desert Southwest Wholesale Power and Natural Gas Markets

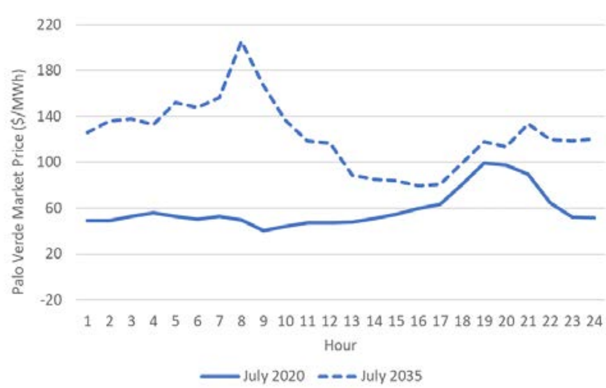
Wholesale power markets in the Desert Southwest provide an efficient mechanism for utilities to buy and sell power as a means to optimize their resource portfolios and reduce costs for customers. To execute wholesale power transactions, UNSE uses the Palo Verde hub as its primary transfer point.

As more renewable energy is produced in the region, wholesale power prices, already under transformation, are expected to change 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.

To capture this effect, TEP, on behalf of itself and UNSE, contracted E3 to develop an hourly market price forecast for the Palo Verde trading hub through the end of the IRP planning period. The forecast takes into account regional trends in power demand, fuel prices, resource retirements, and resource additions (including energy storage) that are driven by state clean energy policies and resource economics. Chart 17 shows how average market prices for the months of March and July are forecasted to change between 2020 and 2035. As expected, the average monthly price increases over the years, but the change in price over the course of the day is even more profound, largely due to the effect that solar power has on depressing daytime prices.

Chart 17 - Palo Verde Wholesale Market Price Forecasts

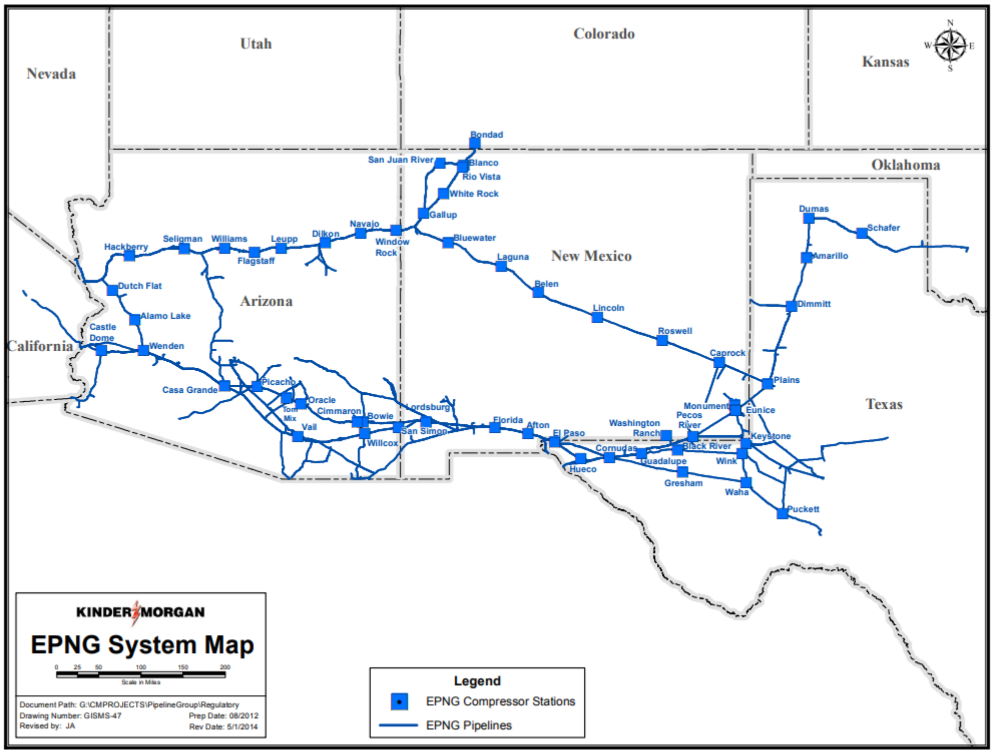




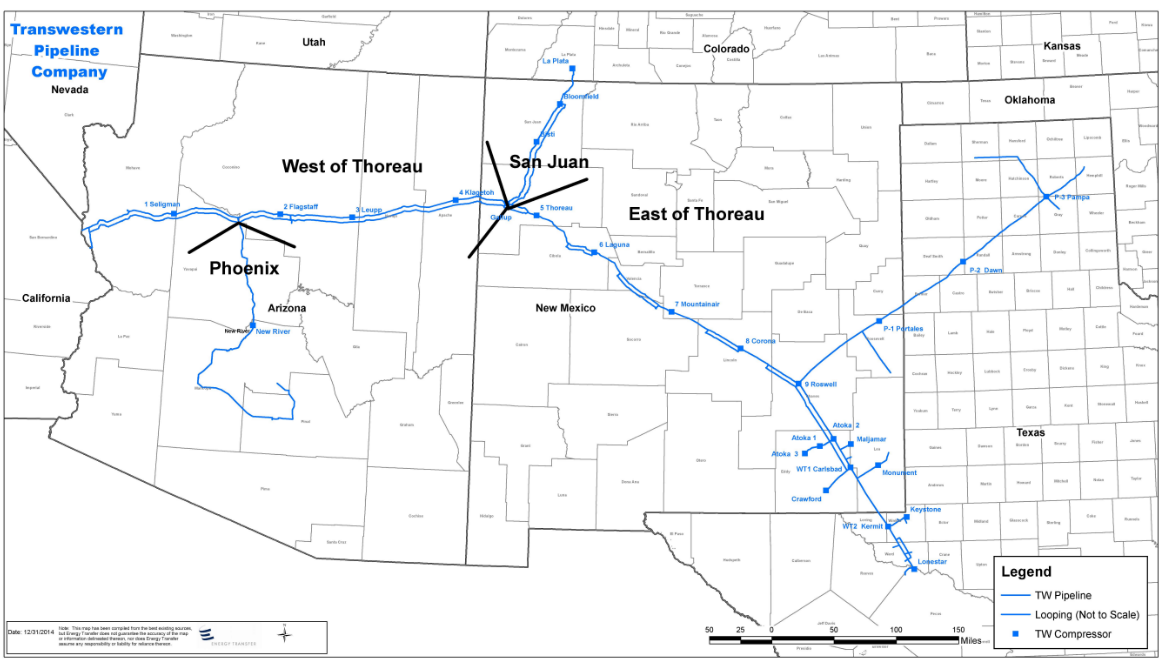
El Paso Natural Gas (EPNG) and Transwestern Pipelines

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 network shown below in Map 7 and Map 8. 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.

Map 7 – EPNG Pipeline Network Map[16]



Map 8– Transwestern Pipeline Network Map[17]



[16] https://pipeline2.kindermorgan.com/Navigation/SiteMap.aspx?code=EPNG
[17] https://twtransfer.energytransfer.com/ipost/TW/maps/system-map

Arizona Natural Gas Storage

Today, UNSE relies on the EPNG and Transwestern pipeline network to deliver natural gas primarily from the San Juan and Permian supply basins to support its real-time power generation needs. In other regions of the country, natural gas storage provides a reliability backstop to a multitude of pipeline operational constraints that can impact the delivery of natural gas. However, in Arizona there are currently no natural gas storage facilities. 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 expected phase out of natural gas as a source of fuel within UNSE's generation fleet.

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 the Intercontinental Exchange index ("ICE index") index. The ICE index is a financial services and information company who own the New York Stock Exchange among other entities. UNSE receives updated ICE index data every business day. The ICE index forecast for Permian for the first five years, 2020 through 2024, is derived by calculating the monthly cash settled Exchange Futures Contracts.[18] From 2025-2035 the data is extrapolated by using the growth rates of Wood MacKenzie's Henry Hub gas prices.[19] Near-term wholesale power prices are based on the Tullet Prebon index, one of the world's leading interdealer brokers that provides independent and unbiased market pricing.[20] Market information is updated every business day and UNSE uses the monthly data from Palo Verde's on and off-peak to develop its long-term forecast assumptions through 2035. Beyond 2035, UNSE relies on Wood MacKenzie's long-term Permian natural gas growth rates to escalate these prices out to 2050.

Long-term outlooks from Wood MacKenzie are used to develop the Company's base case, high, and low forecast scenarios. The base case forecast uses two years of the near-term data from 2020 and 2021, then extrapolates the remaining years by using the growth rates of Wood MacKenzie's natural gas and wholesale power prices from the 2019H1FederalCarbonCase. To develop the high and low forecasts, the 2020 and 2021 prices are calculated by taking the relative difference between the base case scenario and the high and low carbon case scenarios from Wood MacKenzie and applying those proportionally to the respective year. Then the growth rates of Wood MacKenzie 's natural gas and wholesale power prices from the 2019H1HighFederalCarbonCase and 2019H1LowNoFederalCarbonCase are used to extrapolate the data for the high and low forecasts respectively.

Reduction in Overall Natural Gas Demand and Commodity Prices

In addition to the market changes listed above, renewable resources are dramatically reducing the power sector's overall demand for natural gas consumption.[21] Low load growth coupled with a higher penetration of renewable energy and historically low natural gas prices, have resulted in low wholesale power prices during the last two years. This trend is likely to continue for some time due to the increased efficiencies in shale production and the declining cost of renewable energy resources, which are below the cost of traditional fossil

[18] The price of the last scheduled trading day of the NYMEX Henry Hub Natural Gas Futures Contract is subtracted from the price of the first publication date of El Paso's Permian Basin Inside FERC; then, the price of the penultimate scheduled trading day of the NYMEX Henry Hub Natural Gas Futures Contract is added in. https://www.theice.com/products/6590149/EP-Permian-Basis-Future

[19] North America power & renewables long-term outlook H1 2019: Who's the greenest? Accelerated state plans for renewables pressure prices, August 2019, attachment: naprs_lto_base-case_delivered_fuel_prices_nominal_7_31_2019

[20] https://www.tullettprebon.com/

[21] NREL Study: A Retrospective Analysis of the Benefits and Impacts of U.S. Renewable Portfolio Standards. https://emp.lbl.gov/sites/all/files/lbnl-1003961.pdf

fuel resources on a long-term levelized basis. As noted in the Wood MacKenzie Base Case, despite uncertainty regarding U.S. energy policy changes, recent analysis suggests low natural gas prices are one of the biggest disruptors of the power sector, forecasting prices to remain below $4/MMBtu until 2035.[22] This low price trajectory has caused natural gas to increasingly displace coal resources resulting in a number of recent near-term closure announcements.

Sensitivity Analysis

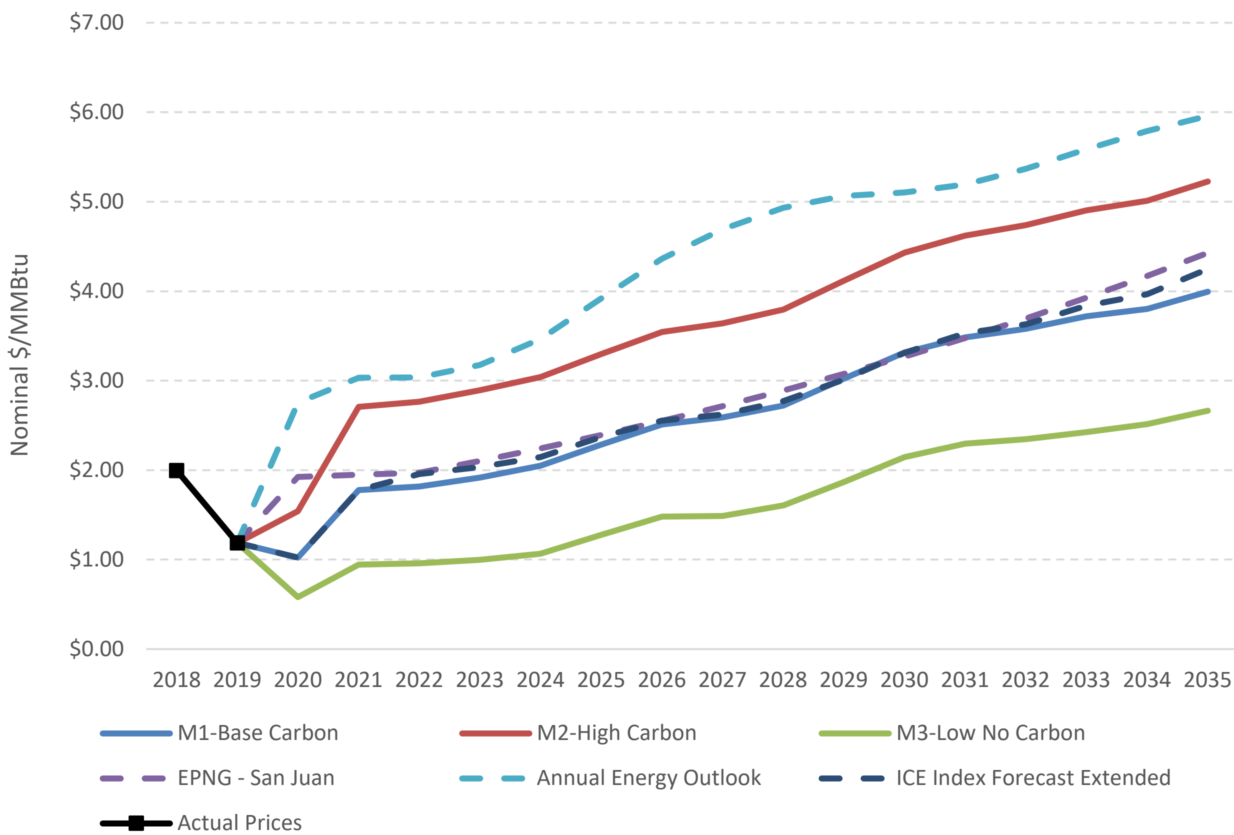
Modeling the performance of a resource portfolio involves making assumptions about future conditions such as economic growth, fuel and wholesale power markets, regulatory conditions (e.g. emission prices), and the pace of technological development. UNSE seeks to identify a reference case portfolio that provides solid performance under the assumptions selected while maintaining optionality to make course adjustments in response to actual emerging conditions. Due to the inherent uncertainty about these future assumptions, it is necessary to test the performance of each resource portfolio against a range of future conditions to better assess whether a portfolio is robust under varying conditions. Because certain market conditions do not move independently of each other, alternative future scenarios must be identified capturing a range of future conditions, yet represent plausible outcomes in terms of the relative movement of different market forces.

[22] Wood Mackenzie North America power markets long-term outlook H2 2019: The view to 2050 as the transition accelerates December 2019.

Natural Gas Price Sensitivities

Chart 18 shows the full range of natural gas price sensitivities considered in the 2020 IRP.

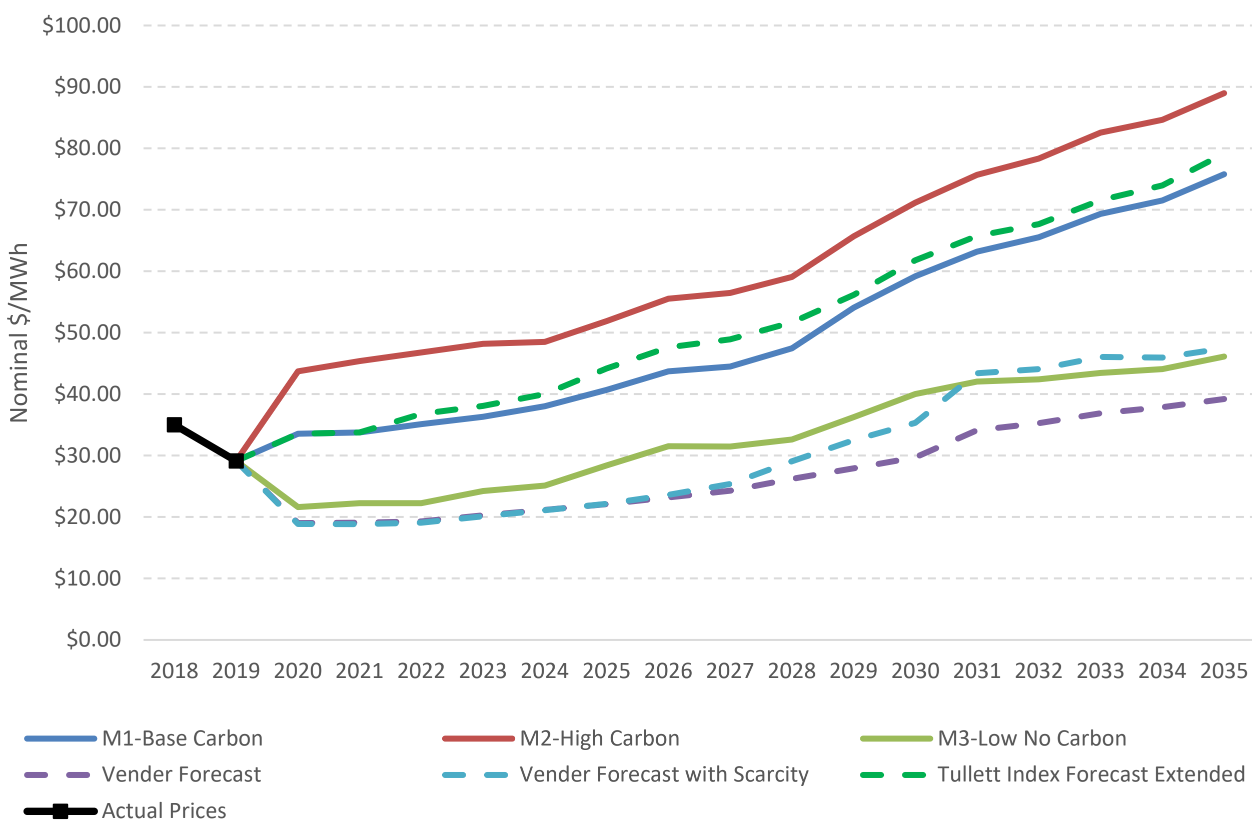
Chart 18 - Natural Gas Price Sensitivities



Palo Verde (7x24) Wholesale Market Prices

Chart 19 shows the Palo Verde market price sensitivities considered in the 2020 IRP.

Chart 19 - Palo Verde (7x24) Market Price Sensitivities



Load Growth Scenarios

UNSE developed alternative load forecasts to evaluate the impact that customer load could have on the level of resource additions needed to serve that load. An initial list of four load forecasts were identified as presented in Table 17 below.

Table 17 - Load Growth Scenarios

Load Scenario	Description
L1	Base load forecast described in Chapter 2.
L2	Low (<1%) load growth as required by Decision 76632.[23]
L3	No load growth as required by Decision 76632.[24] For this scenario, the 2020 net retail load was held constant for the duration of the planning period.
L4	High load growth.

Due to the need for comparability between alternative portfolios, the Base load forecast (L1) assumptions are used for all alternative portfolios. Varying assumptions on load growth is analyzed against the Reference Portfolio only. Results of this scenario analysis along with changes that would be required in the Reference Portfolio are summarized in Chapter 10.

Fuel, Market and Demand Risk Analysis

UNSE developed explicit market risk analytics for each portfolio through the use of Monte Carlo computer simulations using Aurora[25]. Specifically a stochastic based dispatch simulation was used to develop a view on future trends related to fuel prices, wholesale market prices, and peak retail demand. The results of this modeling was employed to quantify the risk of uncertainty and evaluate the cost performance of each portfolio. This type of analysis ensures that the selected portfolio not only has a low expected cost, but is also robust enough to perform well against a wide range of future load and market conditions.

As part of the Company's 2020 resource plan, UNSE conducted risk simulations around the following key variables:

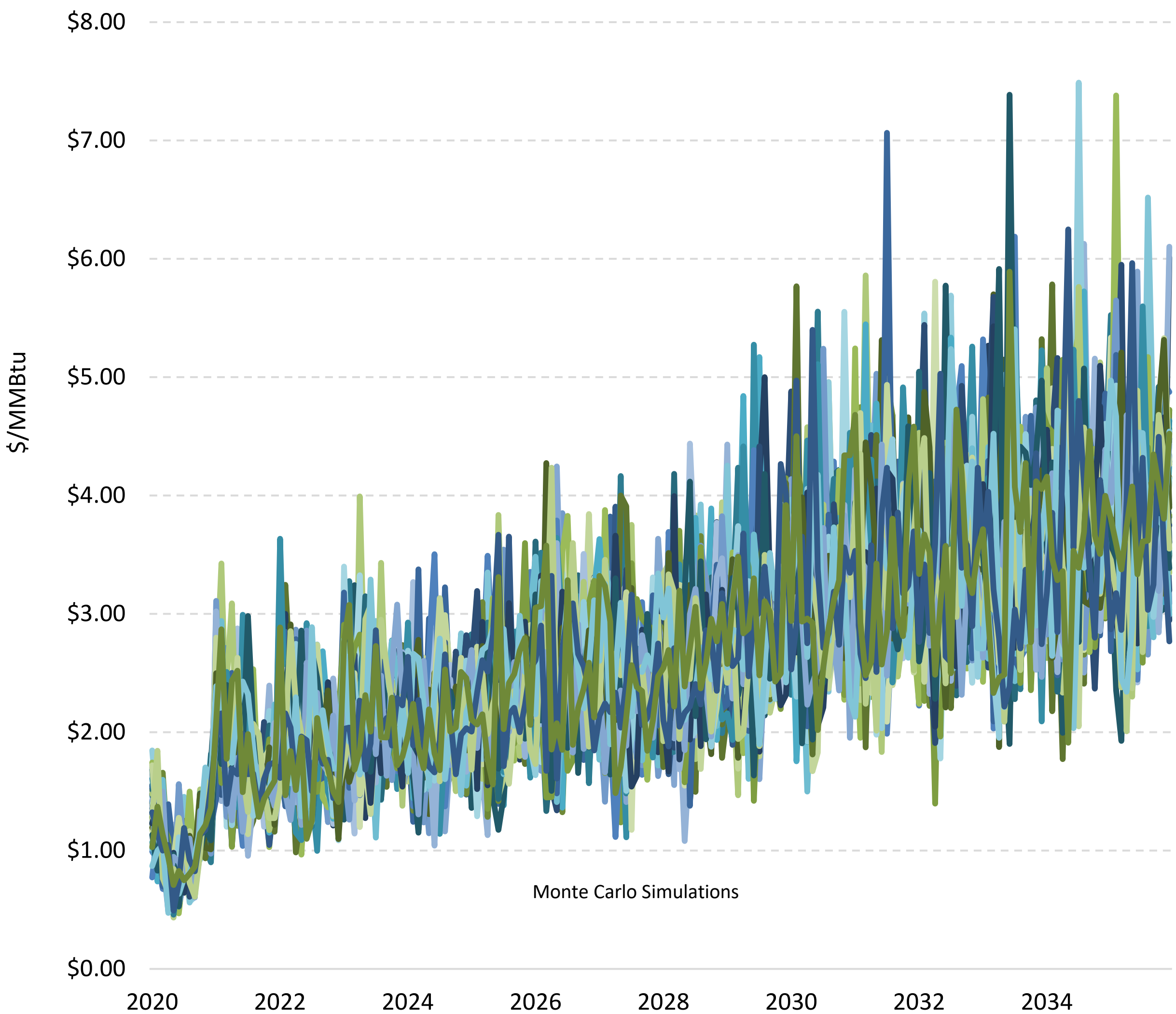
- Natural Gas Prices
- Wholesale Market Prices
- Retail Load and Demand

[23] https://docket.images.azcc.gov/0000186964.pdf; see p. 51, Lines 9-11
[24] ibid
[25] AURORA is a stochastic based dispatch simulation model used for resource planning production cost modeling. Additional information about AURORA can be found at https://energyexemplar.com/solutions/aurora/

Permian Basin Natural Gas Prices

As part of the 2020 IRP analysis, UNSE ran fifty individual risk simulations to quantify the risk of uncertainty related to Permian Basin natural gas prices. Chart 20 below details the natural gas price simulations against which the portfolios were evaluated.

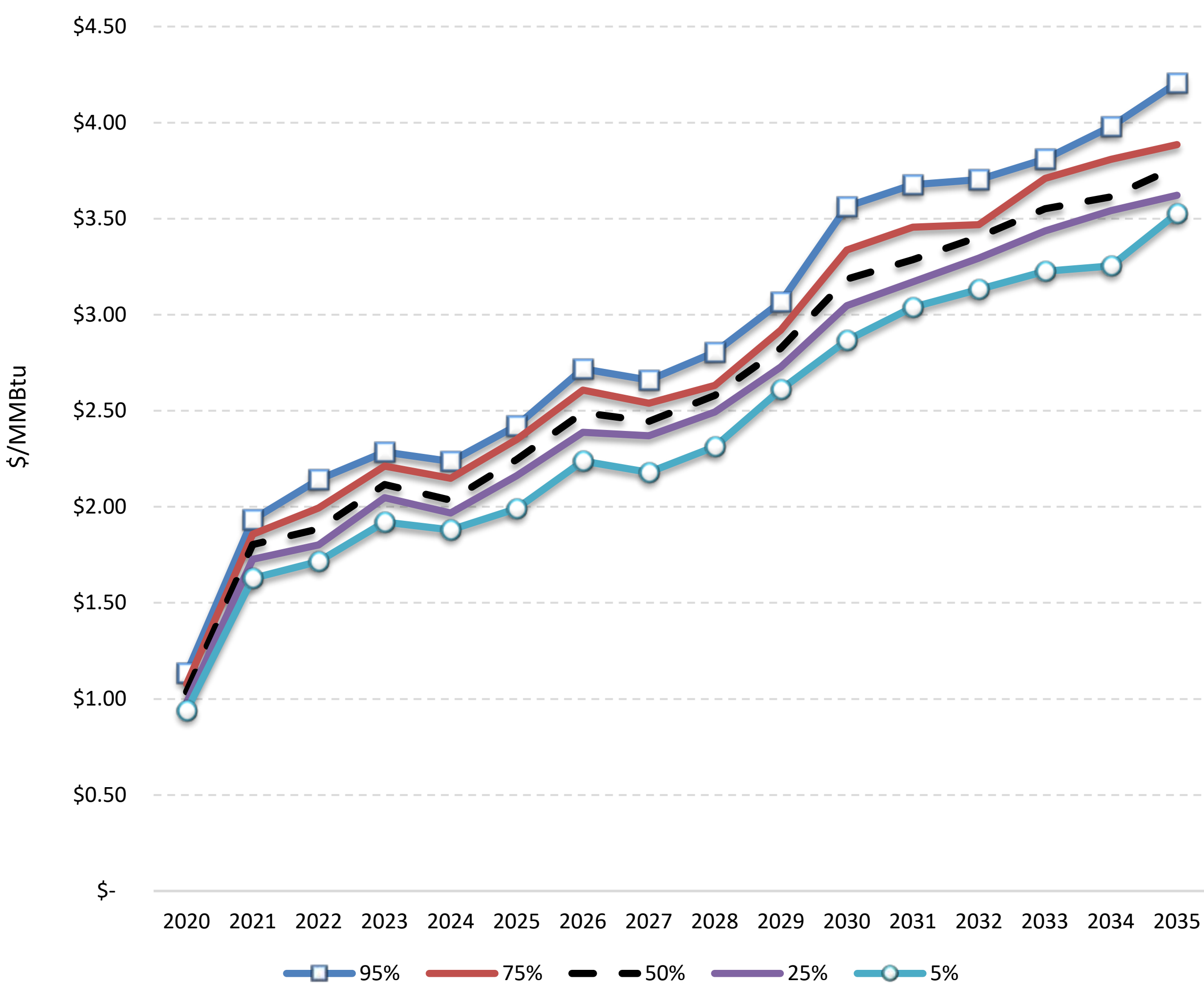
Chart 20 - Permian Basin Natural Gas Price Simulations



Permian Basin Natural Gas Price Distributions

Chart 21 shows the expected annual price distributions for natural gas sourced from the Permian Basin. High and low gas prices scenarios are above and below the 95th and 5th percentiles respectively. These distributions are based on the stochastic data simulations shown in Chart 20 on the prior page.

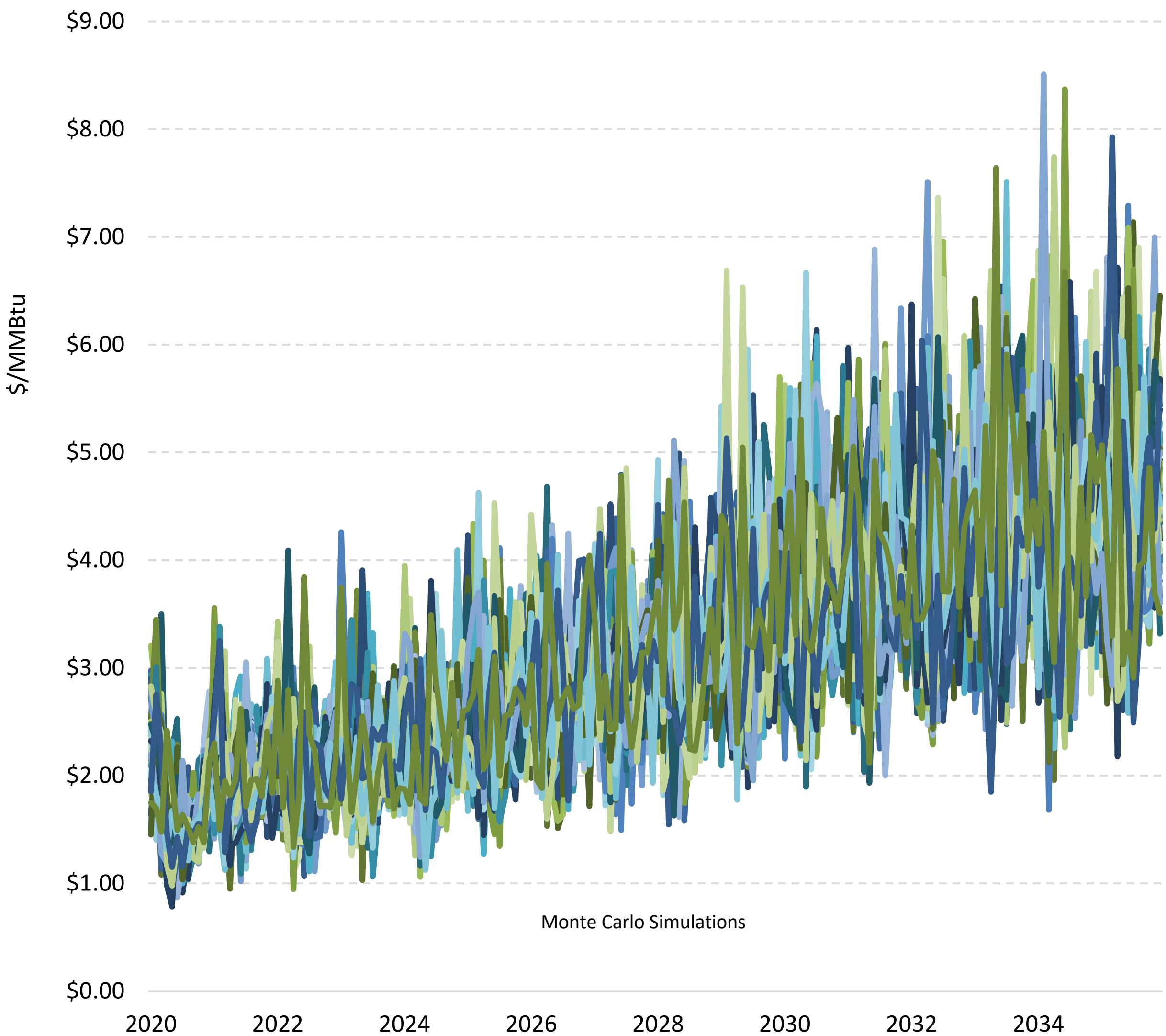
Chart 21 - Permian Basin Natural Gas Price Distributions



San Juan Basin Natural Gas Prices

As part of the 2020 IRP analysis, TEP ran fifty risk simulations to quantify the risk of uncertainty related to San Juan Basin natural gas prices. Chart 22 below details the natural gas price simulations against which the portfolios were evaluated.

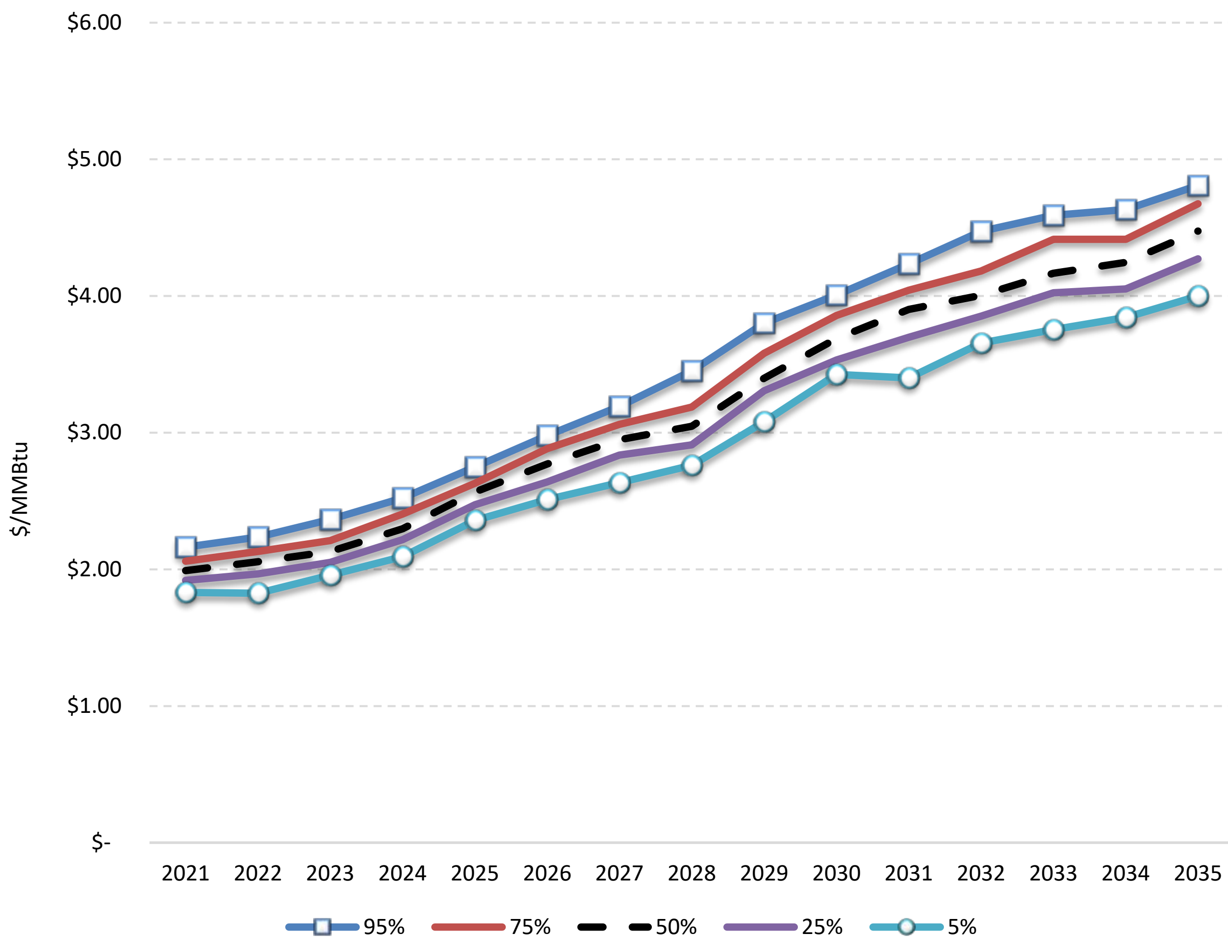
Chart 22 - San Juan Basin Natural Gas Price Simulations



San Juan Basin Natural Gas Price Distributions

Chart 23 shows the expected annual price distributions for natural gas sourced from the San Juan Basin. High and low gas prices scenarios are above and below the 95th and 5th percentiles respectively. These distributions are based on the stochastic data simulations shown in Chart 22 on the prior page.

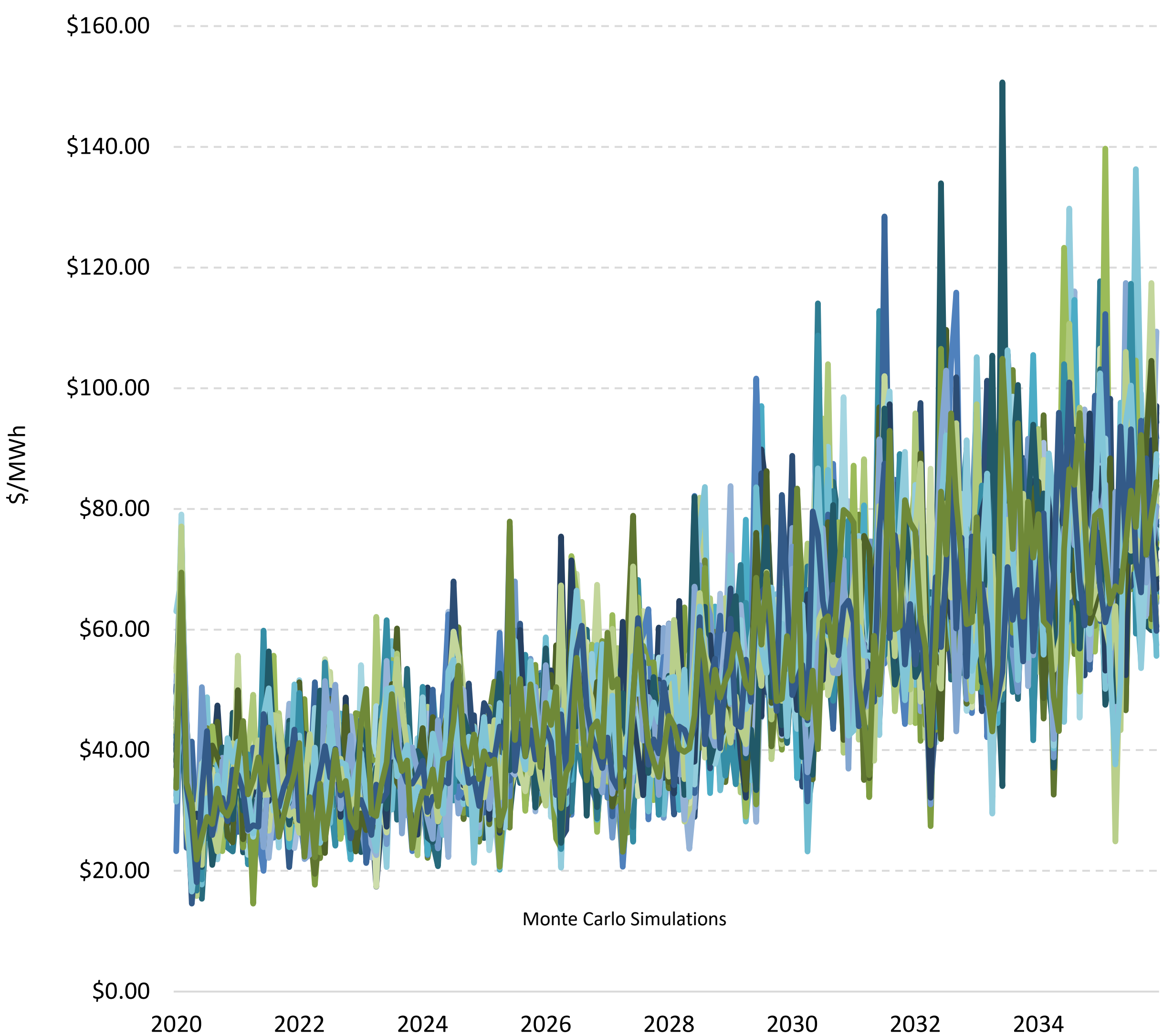
Chart 23 - San Juan Basin Natural Gas Price Distributions



Palo Verde (7x24) Wholesale Power Prices

As part of the 2020 IRP analysis, UNSE ran 50 risk simulations to quantify the risk of uncertainty related to wholesale power prices. Chart 24 below details the wholesale power price simulations against which the portfolios were evaluated.

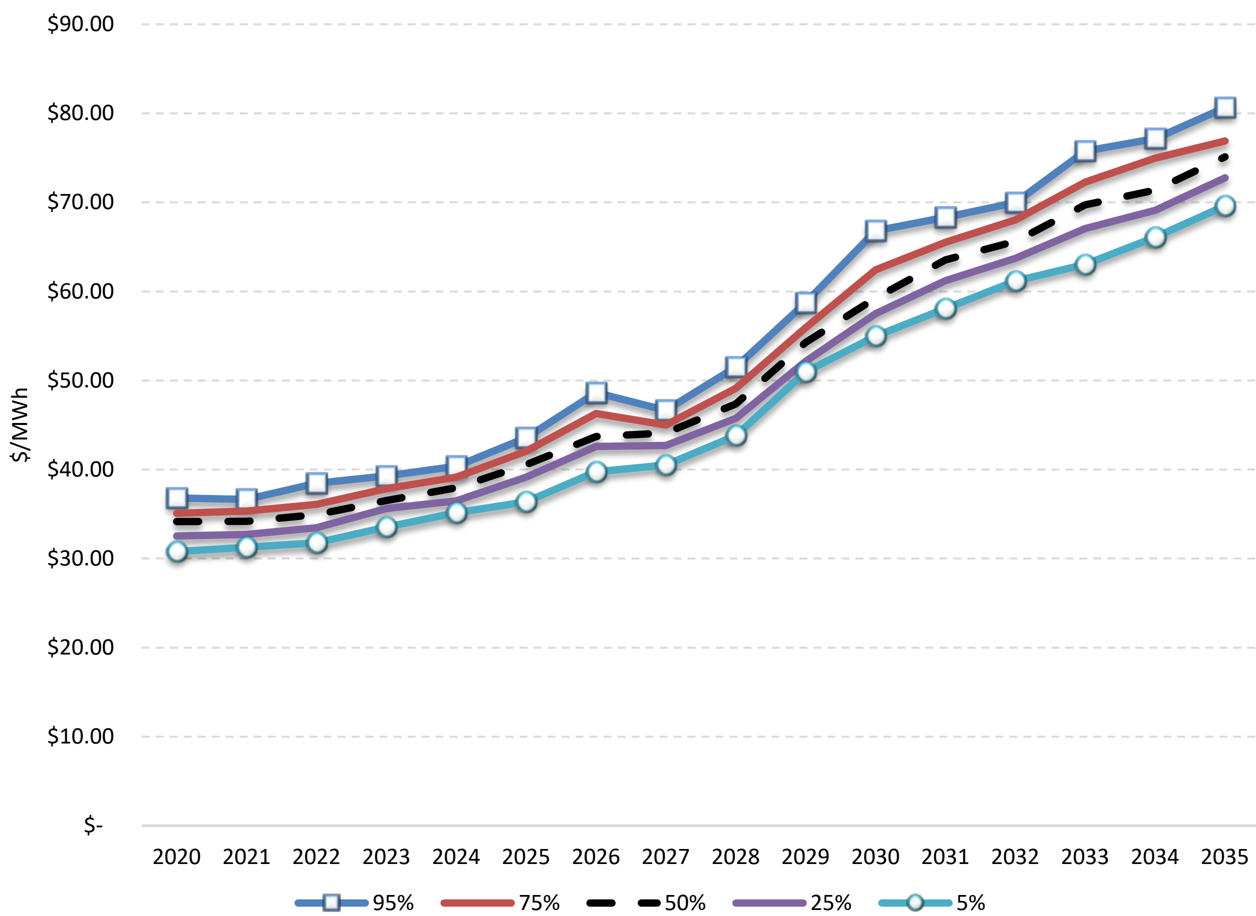
Chart 24 - Palo Verde Wholesale Power Price Simulations



Palo Verde (7x24) Market Price Distributions

Chart 25 shows the expected price distributions for wholesale power sourced from the Palo Verde market. High and low gas prices scenarios are above and below the 95th and 5th percentiles respectively. These distributions are based on the stochastic data simulations shown in Chart 24 on the page above.

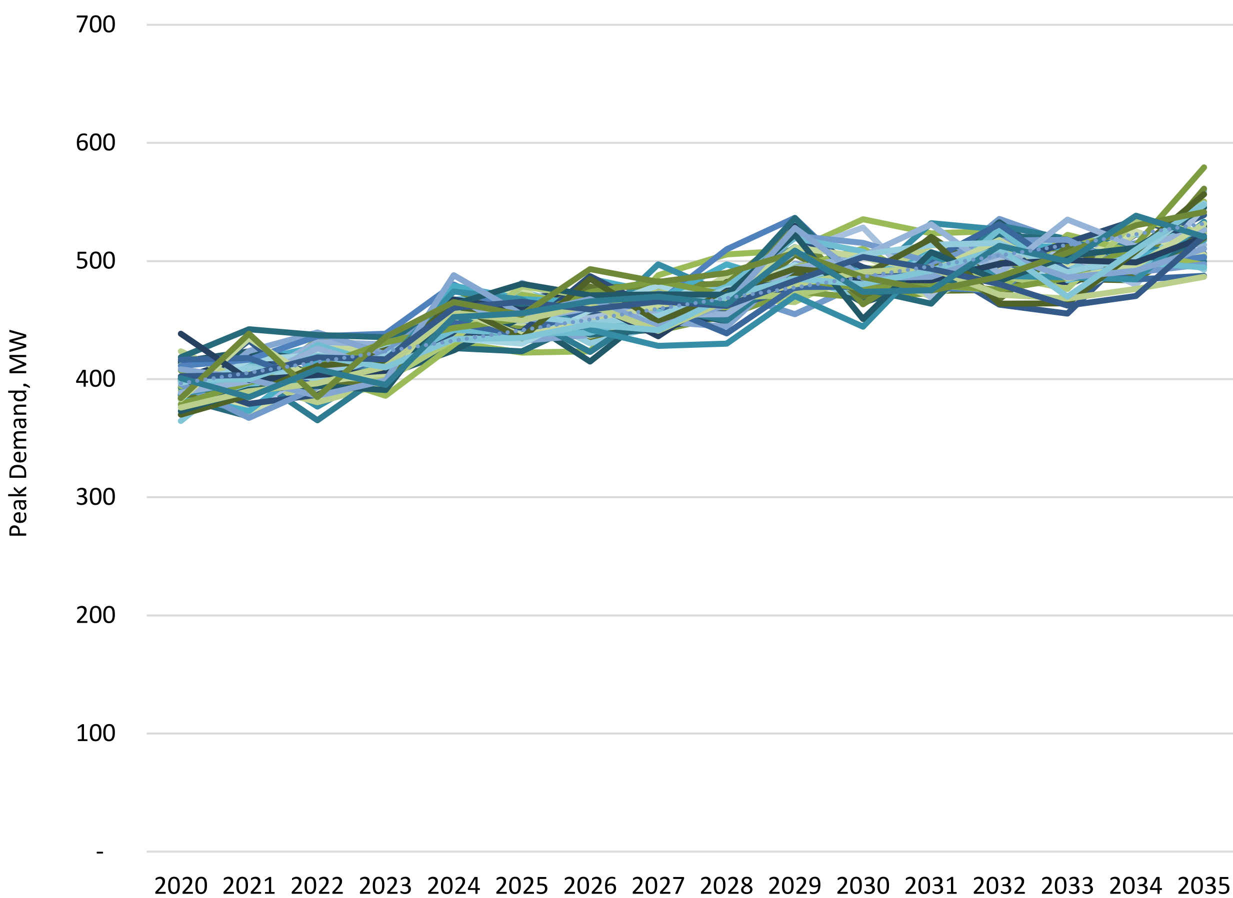
Chart 25 - Palo Verde (7x24) Market Price Distributions



Load Variability and Risk

As outlined in the previous sections, load is also varied within each of the Monte Carlo simulations and correlated with the movement of natural gas and wholesale power prices. In this way, a wide variety of possible load growth scenarios are also considered in the simulation analysis and are therefore inherent in the resulting risk profiles.

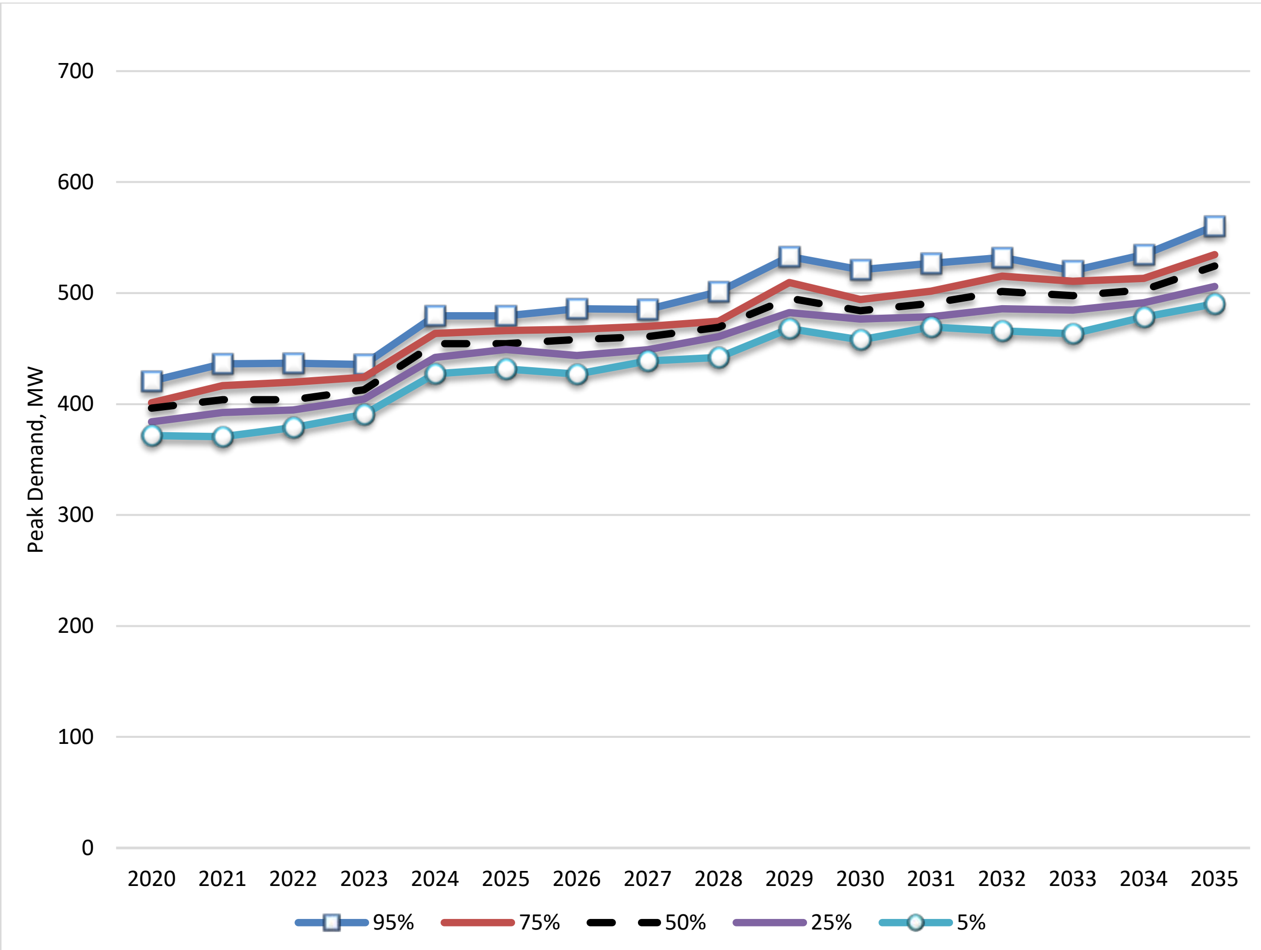
Chart 26 - UNSE Peak Retail Demand Simulations



Load Variability and Peak Demand Distributions

Chart 27 shows the expected demand distributions for UNSE's peak demand forecast. These distributions are based on the stochastic data simulations shown in Chart 26 on the page above. The High load growth scenario generally falls at or above the 95th percentile. The no load growth scenario generally falls below the 5th percentile, particularly in the latter years of the forecast. The load growth scenarios used for this comparison are based on the Reference Portfolio (see Chapter 10), which incorporates higher levels of EE.

Chart 27 - UNSE Peak Retail Demand Distributions



CHAPTER 9

PORTFOLIO ANALYSIS

Overview

This chapter evaluates a range of resource portfolios based on key planning metrics, such as total cost to customers, water consumption, and CO_2 emissions. In addition, ACC Decision 76632 requires Load Serving Entities to model a single resource portfolio with the following attributes; 1) the portfolio musts include the lesser of 1,000 MW of energy storage capacity or an amount of energy storage capacity equivalent to 20 percent of system demand; 2) the portfolio must serve 50 percent of the load with clean energy resources; 3) the portfolio must have at least 25 MW of renewable biomass capacity operating at no less than an annual capacity factor of 60 percent; 4) the portfolio must have a 20 percent DSM target.[26]

Three additional portfolios were evaluated by UNSE, spanning a range of moderate to aggressive renewable energy and energy efficiency targets. The first portfolio is based on the ACC Staff's fourth draft revisions to the ACC's proposed energy rules.[27] The second portfolio represents the most aggressive portfolio considered, which would achieve a 50 percent renewable energy target by 2030 and would not add any fossil fuel-fired resources. This portfolio also satisfies the requirement in Decision 76632 that at least one portfolio be analyzed where the addition of fossil fuel resources is no more than 20 percent of all resource additions. The final portfolio represents the least aggressive of those considered and would achieve 30 percent renewable energy by 2030, relying more on natural gas resources.

Portfolio Requirements	
Portfolio 1	Required by the ACC; 50% clean energy by 2035; Storage equal to 20% of demand; 25 MW of biomass; and at least 20% demand side management
Portfolio 2	50% renewables by 2035; with varying levels of energy efficiency
Portfolio 3	50% clean energy by 2030; No fossil fuel additions
Portfolio4	30% renewables by 2030

All portfolios include enough capacity to satisfy UNSE's peak retail demand without having to rely on market capacity purchases after 2024. No existing resources are retired in any of the portfolios except for 16 MW of solar capacity and 10 MW of wind capacity with PPA expiration dates or useful-end-of-life dates prior to 2035.

Technology Considerations for Future Resource Additions

As expected with the current technology cost declines, current tax incentive policies, and solar irradiance values in Arizona, utility-scale PV single-axis tracking solar is the least cost supply-side resource on an energy-only

[26] Resource Planning and Procurement in 2015 and 2016, Arizona Corporation Commission Docket ID E-00000V-15-0094, March 29, 2018
[27] http://docket.images.azcc.gov/E000007680.pdf

basis, followed closely by higher-capacity factor wind resources located in the eastern region of New Mexico. These are the renewable resource additions evaluated in the UNSE portfolios.

Currently, battery energy storage systems, particularly those utilizing Li-ion chemistries, represent 99 percent of the utility-scale energy storage market for new storage capacity. Therefore, these are the energy storage additions modeled in the UNSE IRP portfolios. However, the Company views the dominance of Li-ion energy storage technology as a risk to diversity in the grid balancing resource category. As part of UNSE's deployment of energy storage technologies, the Company plans to explore newer fast-acting storage technologies to mitigate system variability due to intermittent resources. The integration of new energy storage resources through sequential, competitive ASRFPs is intended to allow the energy storage market to mature, not just in terms of low cost, but also in terms of the variety of technologies available.

The combination of renewables and storage alone, even when combined with demand side options, may not be the most cost effective means to address UNSE's significant energy and capacity needs. This is particularly the case in the near term and at times when the capacity need extends for several hours. Therefore, natural gas-fired resources must all so be considered as future UNSE resources. For modeling purposes, UNSE evaluated RICE technology based on its combination of efficiency, flexibility, and scalability, however, their use in these portfolio evaluations is intended as a proxy for any fast-start, fast-ramping gas-fired resource.

Portfolio Development

Resource additions were selected based on hourly variations in coincident load and renewable output. This helped to identify the solar, wind, and storage capacities necessary to achieve the design elements in the various portfolios. Generally speaking, more solar capacity was added than wind capacity based on their relative costs and the ability to locate solar resources closer to load. Because solar power has a higher **capacity value** than wind, especially when paired with energy storage, and because wind power has a higher **capacity factor** than solar power, adjustments were made to the solar-to-wind ratio depending on whether it was more difficult to achieve the portfolio's renewable energy target (which could call for a greater portion of wind power) or to maintain reliability (which could call for a greater portion of solar power). RICE, geothermal power, or additional storage capacity was then identified as necessary to meet peak demand and maintain reliable service.

These initial capacities were modeled with Aurora and adjusted as necessary to ensure the renewable targets were met in a security-constrained, economic-dispatch simulation and that a 15 percent reserve margin was maintained in each year. Resource additions were made incrementally, approximately every three years in recognition of the time frames necessary to procure new resources and allow for further maturation and cost reductions in renewable and energy storage technologies. While this approach provides a sound basis for estimating UNSE's required resources and comparing alternative resource plans, the precise amount and types of resources and their implementation dates will depend on the outcome of competitive technology-neutral resource solicitations designed to meet UNSE's service requirements and environmental objectives.

Portfolio Definitions

Table 18 provides additional detail on the objectives and assumptions of the portfolios evaluated in this IRP. The first column is a portfolio identifier. The second column identifies portfolio variations based on EE assumptions. The "a", "b", and "c" in the Var column of Table 18 correspond respectively to EE Scenarios A, B, and C as described in Chapter 4. The Source column identifies the basis for designing the portfolio. The remaining columns identify the amount of additional capacity by 2035 assumed in the portfolio for each resource technology.

The six portfolios in Table 18 were evaluated against alternative load forecasts, market conditions, and CO_2 emission prices to ascertain how their costs might deviate from UNSE's base assumptions, resulting in a wider range of potential outcomes. For this reason, a naming convention was established to help define and distinguish each portfolio analysis in the results provided further below. Table 19 explains the naming convention and also defines the different scenarios applied against the portfolios. For example, results for P01aL1M1E1 are for portfolio 01, variation "a", with the base load forecast (L1), base market conditions (M1), and a base carbon emission price (E1). Additional details on fuel and market sensitivities is presented in Chapter 8.

Table 18 - Summary of Portfolios Evaluated for This IRP

ID	Var	Source	Design Elements	Resource Additions by 2035, MW Fossil	Solar	Wind	Storage	Biomass	Geothermal
P01	a	2017 IRP Order	50% clean energy by 2035; Storage equal to 20% of demand; 25 MW of biomass; and At least 20% DSM	80	150	100	100	25	
P02	a	ACC Draft Energy Rules	50% renewables by 2035	100	180	130	90		
P02	b	ACC Draft Energy Rules	50% renewables by 2035; Higher EE (low cost)	100	150	115	70		
P02	c	ACC Draft Energy Rules	50% renewables by 2035; Higher EE (high cost)	80	150	130	60		
P03	a	UNSE Most Aggressive	50% clean energy by 2030; No fossil fuel additions	0	175	70	175		32
P04	a	UNSE Least Aggressive	30% renewables by 2030	180	105	40	35		

Table 19 – Definition and Naming Conventions for Portfolios and Scenarios Analyzed in the IRP

Portfolios		Scenarios		
ID	**Variation**	**Load Forecast (L)**	**Market Conditions (M)**	**Carbon Emission Price (E)**
01-04	a = 22% EE	L1 = Base forecast	M1 = Base conditions	E1 = Base price
	b = 35% EE (low cost)	L2 = Less than 1% annual growth	M2 = High natural gas and power market prices	E2 = No price (for use only with M3)
	c = 35% EE (high cost)	L3 = No growth	M3 = Low natural gas and power market prices	
		L4 = High growth		

Comparison of Environmental Attributes

CO_2 emissions are a primary metric for evaluating the environmental performance of alternative portfolios. These emissions are directly proportional to the combustion of fossil fuels, which are also responsible for emissions of hazardous air pollutants and criteria air pollutants. Thus, in addition to their direct impact on climate change, CO_2 emissions are also an indicator of other environmental impacts.

Chart 28 shows the annual CO_2 emissions from each portfolio. As expected, emissions are highest in the least aggressive portfolio (P04a) and lowest in the most aggressive (P03a). Because UNSE's modeling of these portfolios suggest that all of them will continue to make significant market purchases throughout the planning period, Chart 28 includes emissions associated with market purchases. These emissions are calculated as the product of market purchase energy and annual emission factors derived from regional electricity market modeling that accounts for current clean energy policies in the Southwest.

Chart 28 - Annual CO_2 Emissions by Portfolio

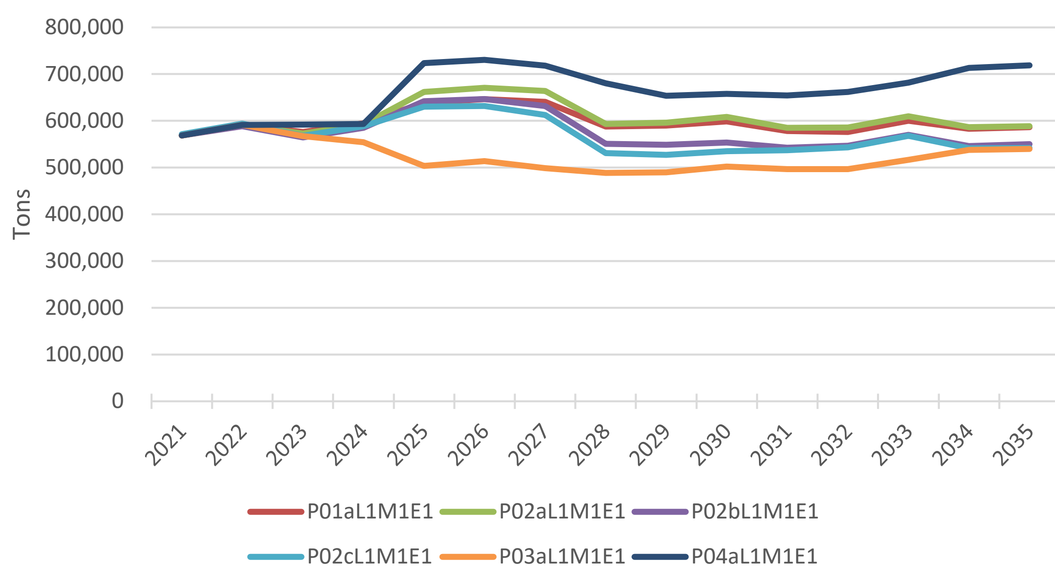


Chart 29 shows the annual NOx emissions for each portfolio. NOx emissions contribute to the formation of ozone, with the impact largely limited to the air-shed in which those emissions occur. As with CO_2, NOx emissions are directly proportional to fossil fuel combustion but also depend heavily on the type of emission control systems installed on each generating unit. Since each portfolio increases the amount of renewable energy in UNSE's resource mix, there is a decrease in NOx emissions across portfolios through 2028, followed by a gradual increase. This increase is greatest in portfolios P04a and P03a. P04a increases after 2029 because no renewable resources are added after that point. P03a, although the cleanest portfolio in terms of CO_2, has the highest NOx emissions by the end of the planning period because existing natural gas-fired resources are increasingly dispatched as retail sales and peak demand increase. By contrast, the other portfolios include new, flexible gas-fired generation that would be equipped with modern NOx control technology, and these resources would be dispatched in lieu of increasing generation from existing resources, particularly the combustion turbines at Black Mountain and Valencia. The NOx emissions associated with market purchases is not relevant to this analysis as the geographical location of the emissions cannot be reliably determined and the impact of those emissions is a function of multiple local factors.

Chart 29 - Nitrogen Oxides Emissions

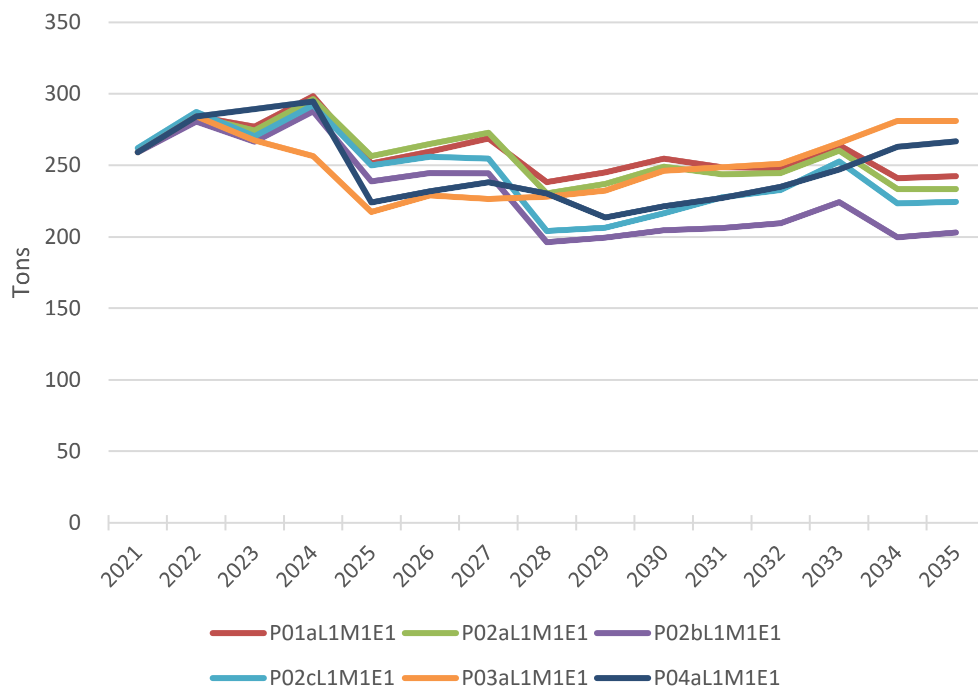
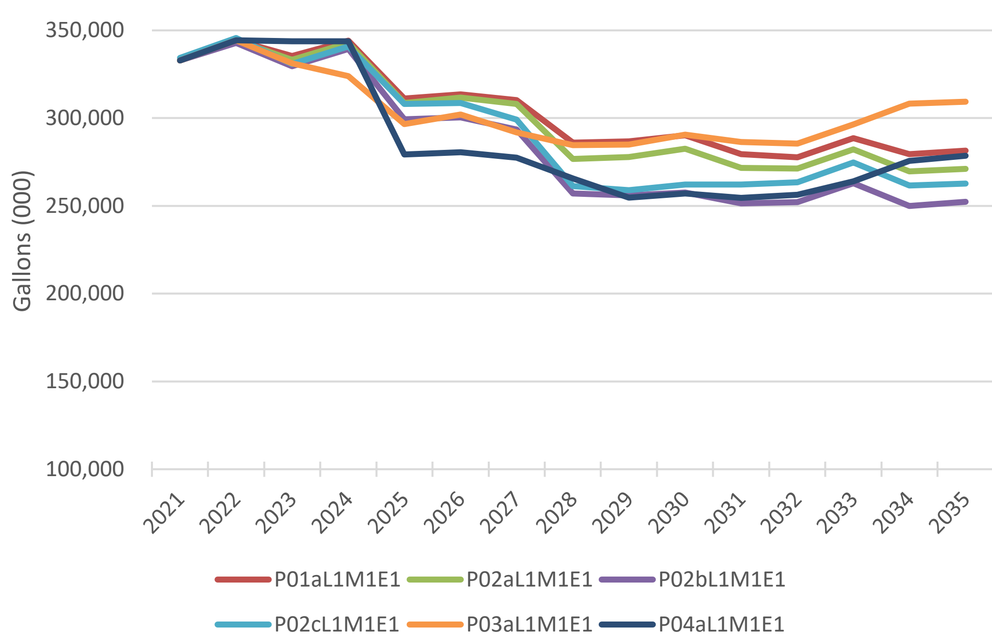


Chart 30 shows the water consumption for each portfolio. The consumption follows a similar trend to NOx emissions, and largely for the same reasons, although water usage only increases in the later years for portfolios P03a and P04a. P03a increases in the later years because its renewable capacity additions are complete by 2031, and much of the increased energy demand after that point is met with existing resources, whereas other portfolios rely on RICEs to meet much of the increased energy demand, and RICEs require minimal water for power generation. P04a, even though it has RICEs in its portfolio, increases in later years because it simply has fewer renewable resources and must rely more on existing assets.

Chart 30 - Water Consumption



Comparison of Cost Attributes

Chart 31 summarizes the NPVRR of each portfolio under the base, high, and low market scenarios. Details for each portfolio and scenario are provided in Table 20 through Table 22. The impact of alternative load scenarios is evaluated in the next chapter.

Chart 31 - NPVRR for Each Portfolio and Scenario

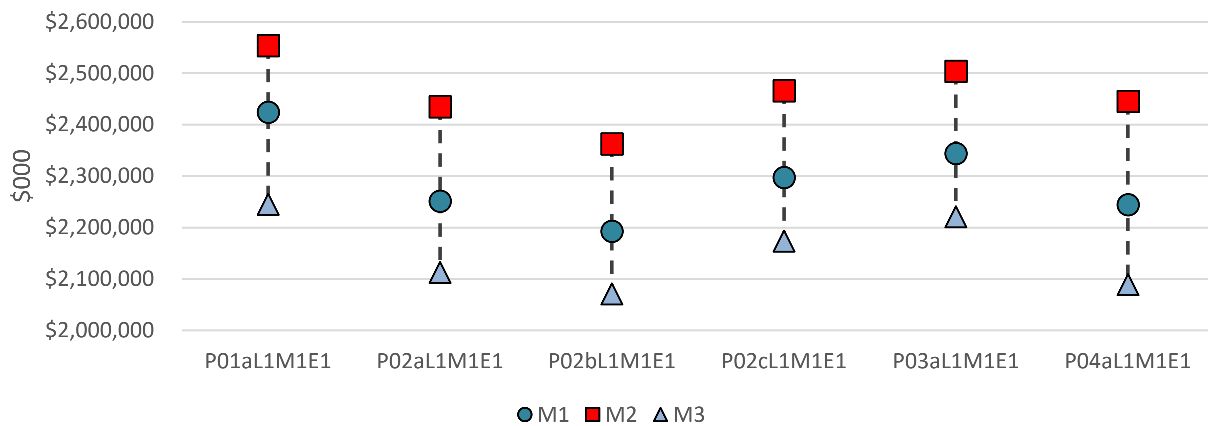


Table 20 - NPVRR Details - Base Market Scenario

Non Fuel Revenue Requirements, $000	P01aL1M1E1	P02aL1M1E1	P02bL1M1E1	P02cL1M1E1	P03aL1M1E1	P04aL1M1E1
Existing T&D Resources	$632,841	$632,841	$632,841	$632,841	$632,841	$632,841
Existing Thermal Resources	$273,461	$273,282	$272,836	$272,965	$273,355	$272,908
New Thermal Resources	$73,011	$80,711	$80,549	$64,164	$0	$155,592
Storage Resources	$91,893	$88,360	$67,153	$56,550	$174,072	$40,251
New Renewable Resources	$311,686	$165,722	$147,864	$157,312	$194,911	$78,906
New Transmission Resources	$0	$0	$0	$0	$0	$0
Existing Transmission Expenses	$61,014	$61,014	$61,014	$61,014	$61,014	$61,014
Total Non-Fuel Revenue Requirements	$1,443,906	$1,301,930	$1,262,258	$1,244,846	$1,336,193	$1,241,513

Fuel & Purchased Power, $000	P01aL1M1E1	P02aL1M1E1	P02bL1M1E1	P02cL1M1E1	P03aL1M1E1	P04aL1M1E1
Total Fuel and Market Purchases	$875,308	$844,544	$788,506	$791,794	$868,495	$897,780

Energy Efficiency and Renewables, $000	P01aL1M1E1	P02aL1M1E1	P02bL1M1E1	P02cL1M1E1	P03aL1M1E1	P04aL1M1E1
Energy Efficiency	$33,557	$33,557	$70,735	$188,910	$33,557	$33,557
Demand Response	$1,980	$1,980	$1,980	$1,980	$1,980	$1,980
Total Energy Efficiency	$35,537	$35,537	$72,715	$190,890	$35,537	$35,537

Total Renewable Purchased Power	$69,661	$69,661	$69,661	$69,642	$103,672	$69,661

Total Energy Efficiency and Renewables	$105,198	$105,198	$142,376	$260,533	$139,209	$105,198

Total System Revenue Requirements	**$2,424,411**	**$2,251,672**	**$2,193,140**	**$2,297,173**	**$2,343,897**	**$2,244,490**

Table 21 - NPVRR Details - High Market Scenario

Non Fuel Revenue Requirements, $000	P01aL1M2E1	P02aL1M2E1	P02bL1M2E1	P02cL1M2E1	P03aL1M2E1	P04aL1M2E1
Existing T&D Resources	$632,841	$632,841	$632,841	$632,841	$632,841	$632,841
Existing Thermal Resources	$272,256	$272,157	$271,740	$271,916	$272,298	$271,722
New Thermal Resources	$73,754	$80,371	$80,249	$63,933	$0	$154,889
Storage Resources	$91,893	$88,360	$67,153	$56,550	$174,072	$40,251
New Renewable Resources	$311,686	$165,722	$147,864	$157,312	$194,911	$78,906
New Transmission Resources	$0	$0	$0	$0	$0	$0
Existing Transmission Expenses	$61,014	$61,014	$61,014	$61,014	$61,014	$61,014
Total Non-Fuel Revenue Requirements	$1,443,444	$1,300,466	$1,260,862	$1,243,566	$1,335,137	$1,239,623

Fuel & Purchased Power, $000	P01aL1M2E1	P02aL1M2E1	P02bL1M2E1	P02cL1M2E1	P03aL1M2E1	P04aL1M2E1
Total Fuel and Market Purchases	$1,005,041	$1,029,304	$959,615	$961,924	$1,029,949	$1,100,848

Energy Efficiency and Renewables, $000	P01aL1M2E1	P02aL1M2E1	P02bL1M2E1	P02cL1M2E1	P03aL1M2E1	P04aL1M2E1
Energy Efficiency	$33,557	$33,557	$70,735	$188,910	$33,557	$33,557
Demand Response	$1,980	$1,980	$1,980	$1,980	$1,980	$1,980
Total Energy Efficiency	$35,537	$35,537	$72,715	$190,890	$35,537	$35,537

Total Renewable Purchased Power	$69,661	$69,661	$69,661	$69,643	$103,672	$69,661

Total Energy Efficiency and Renewables	$105,198	$105,198	$142,376	$260,533	$139,209	$105,198

Total System Revenue Requirements	**$2,553,683**	**$2,434,968**	**$2,362,853**	**$2,466,023**	**$2,504,295**	**$2,445,669**

Table 22 - NPVRR Details - Low Market Scenario

Non Fuel Revenue Requirements, $000	P01aL1M3E2	P02aL1M3E2	P02bL1M3E2	P02cL1M3E2	P03aL1M3E2	P04aL1M3E2
Existing T&D Resources	$632,841	$632,841	$632,841	$632,841	$632,841	$632,841
Existing Thermal Resources	$271,990	$271,810	$271,449	$271,518	$271,872	$271,510
New Thermal Resources	$71,743	$80,067	$79,872	$63,683	$0	$154,335
Storage Resources	$91,893	$88,360	$67,153	$56,550	$174,072	$40,251
New Renewable Resources	$311,686	$165,722	$147,864	$157,312	$194,911	$78,906
New Transmission Resources	$0	$0	$0	$0	$0	$0
Existing Transmission Expenses	$61,014	$61,014	$61,014	$61,014	$61,014	$61,014
Total Non-Fuel Revenue Requirements	$1,441,167	$1,299,815	$1,260,193	$1,242,918	$1,334,711	$1,238,858

Fuel & Purchased Power, $000	P01aL1M3E2	P02aL1M3E2	P02bL1M3E2	P02cL1M3E2	P03aL1M3E2	P04aL1M3E2
Total Fuel and Market Purchases	$698,629	$707,962	$668,204	$670,367	$747,059	$744,946

Energy Efficiency and Renewables, $000	P01aL1M3E2	P02aL1M3E2	P02bL1M3E2	P02cL1M3E2	P03aL1M3E2	P04aL1M3E2
Energy Efficiency	$33,557	$33,557	$70,735	$188,910	$33,557	$33,557
Demand Response	$1,980	$1,980	$1,980	$1,980	$1,980	$1,980
Total Energy Efficiency	$35,537	$35,537	$72,715	$190,890	$35,537	$35,537

Total Renewable Purchased Power	$69,661	$69,661	$69,661	$69,643	$103,672	$69,661

Total Energy Efficiency and Renewables	$105,198	$105,198	$142,376	$260,533	$139,209	$105,198

Total System Revenue Requirements	**$2,244,994**	**$2,112,975**	**$2,070,773**	**$2,173,819**	**$2,220,979**	**$2,089,002**

NPVRR Mean and Worst Case Risk

The degree to which each portfolio is able to adequately meet future load serving requirements at a reasonable cost is measured by examining the distribution of its NPVRR outcomes for each portfolio across multiple stochastic iterations. The performance of each portfolios is summarized in Appendix A.

Energy Efficiency Insights

Energy efficiency programs have the potential to reduce costs for customers in two ways: by reducing their energy consumption and consequently their bills, and, if enough savings are realized throughout the customer base, by reducing or deferring Company investments in generation and transmission resources. Portfolios P02b and P02c were specifically designed to estimate these cost savings, albeit from the perspective of the Company's NPVRR.

As shown in Table 20, Portfolio P02b would reduce the Company's NPVRR by $58M relative to P02a. P02c, however, would increase the Company's NPVRR by $46M relative to P02a because to achieve the same annual energy savings as P02b without lighting measures would be more expensive. In the high market scenario (M2), in which fuel prices are higher, the savings are greater and P02b would reduce the NPVRR by $72M. In the low market scenario (M3), the savings of P02b would be $43M. In the M2 and M3 scenarios, like the M1 scenario, P02c would cost $31M to $61M more than P02a respectively.

From an environmental perspective, the CO_2 emissions of P02b and P02c are practically identical and somewhat lower than P02a because of less fossil fuel combustion. Their NOx emissions, for the same reason, are also lower, although P02b emits even less than P02c. This results from the different times of year and day during which the P02c efficiency measures would have an impact, which causes some shift in unit dispatch and market purchases, both of which can reduce NOx emissions. The same trend can be seen in the water consumption of P02a, P02b, and P02c, and for the same reasons.

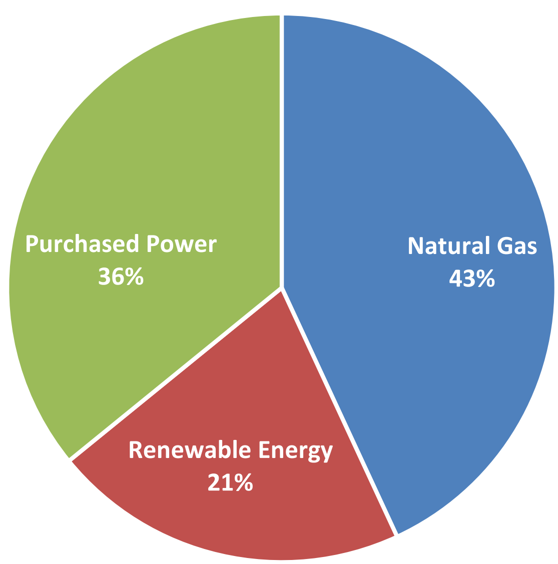
CHAPTER 10

PREFERRED PORTFOLIO

Overview

When UNS Energy Corporation gained control of UNSE through the acquisition of the former Citizens Arizona Electric, the Company relied almost entirely on long-term purchased power agreements for its energy supply. Since that time, the Company has reduced its dependence on purchased power through the construction and acquisition of natural gas assets and the integration of renewable energy systems. In 2006, UNSE completed construction of Unit 4 at the Valencia Power Plant, a 22 MW aeroderivative combustion turbine. In 2008, the Company completed construction of Black Mountain Generating Station, which consists of two 45 MW aeroderivative combustion turbines. In 2014, UNSE acquired a 25 percent share of Power Block 3 at the Gila River Generating Station. Gila River Unit 3 is a 550 MW combined-cycle natural gas generator, which adds 138 MW of efficient, low cost energy and capacity to the UNSE portfolio. Between 2011 and 2018, the Company added 104 MW of renewable resources including owned facilities and long-term PPAs. As of 2019, market purchases (not including renewable energy PPAs) have been reduced to 36 percent of UNSE retail energy mix, as presented in Chart 32.

Chart 32 - UNSE 2019 Retail Energy Mix



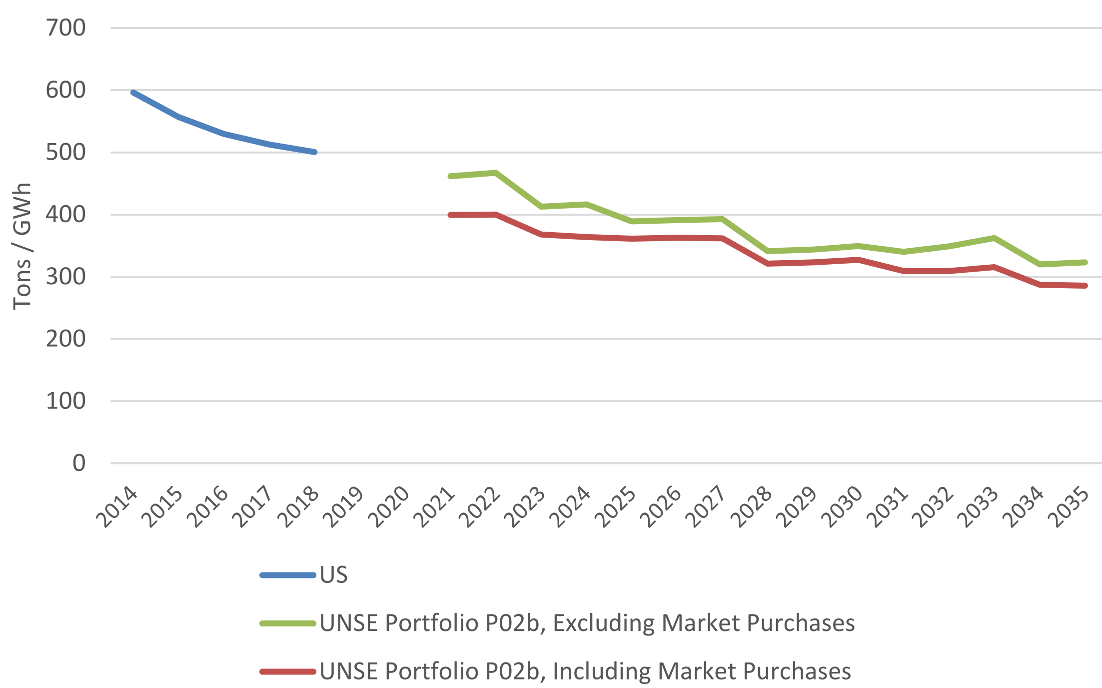
UNSE's 2020 IRP continues the Company's transition from high dependence on purchased power to meet generation requirements, toward greater self-reliance on owned generating assets. This transition must take into account the high degree of uncertainty in the overall performance of various resources due to rapid changes in price and technical advancements. Therefore, the mix of future resources needed to meet UNSE's needs will be determined through strategic, market-based, ASRFPs.

Reference Portfolio

While the Preferred Portfolio will be based on the results of ASRFPs, Portfolio P02b will be used as the "**Reference Portfolio**" for evaluating and selecting resources from the ASRFP that will constitute the Preferred Portfolio. Of all the portfolios evaluated in Chapter 9, Portfolio P02b represents the lowest overall cost. Portfolio P02b achieves this lowest cost while maintaining a diverse mix of energy as renewable resources are added to reach the goal of supplying 50 percent of retail load from renewable energy by 2035. Portfolio P02b also achieves the highest level of energy efficiency savings of all the portfolios evaluated.

While total UNSE CO_2 emissions remain relatively constant across the planning period, this occurs as electricity sales are expected to increase 3.4 percent on an annual average basis, so the emission rate in terms of tons per gigawatt-hours of sales actually decreases significantly, as shown in Chart 33. This chart shows the trend in emission rates with and without consideration of purchased power emissions and also compares UNSE emission rates to the national average for 2014-2018, the most recent five years for which such data are available.

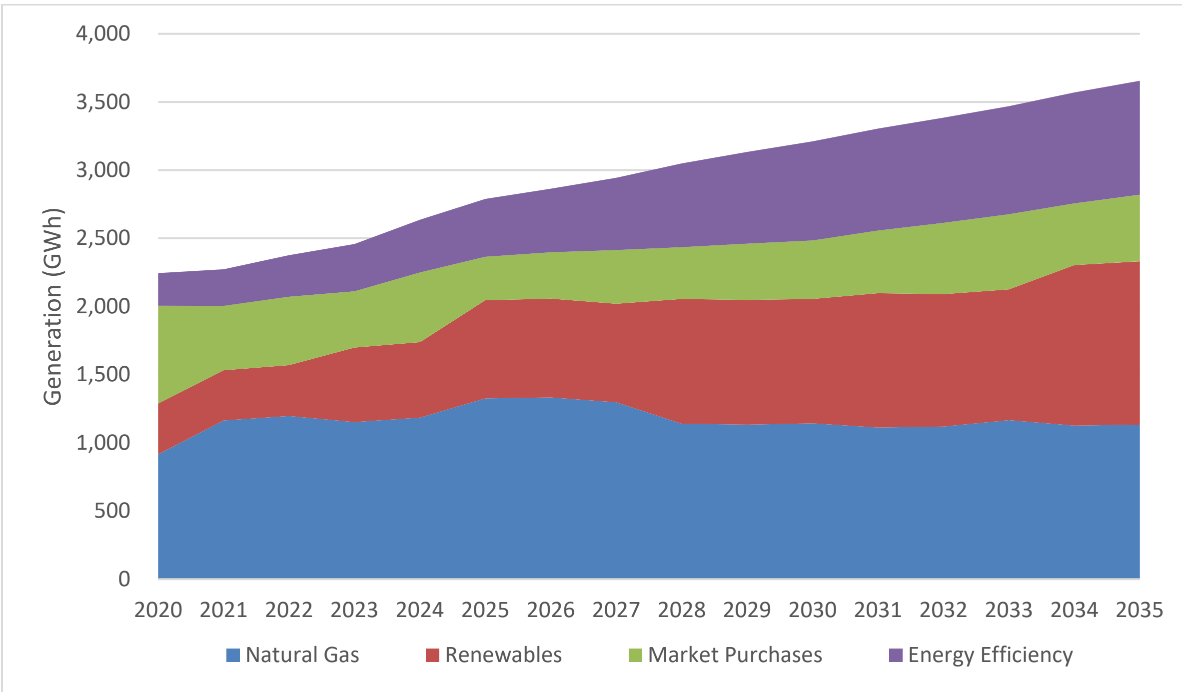
Chart 33 - National and UNSE CO_2 Emission Rates



Reference Portfolio Energy Mix

Chart 34 below shows the Reference Portfolio energy mix over the planning period, with renewable energy reaching 50 percent of retail sales by 2025.

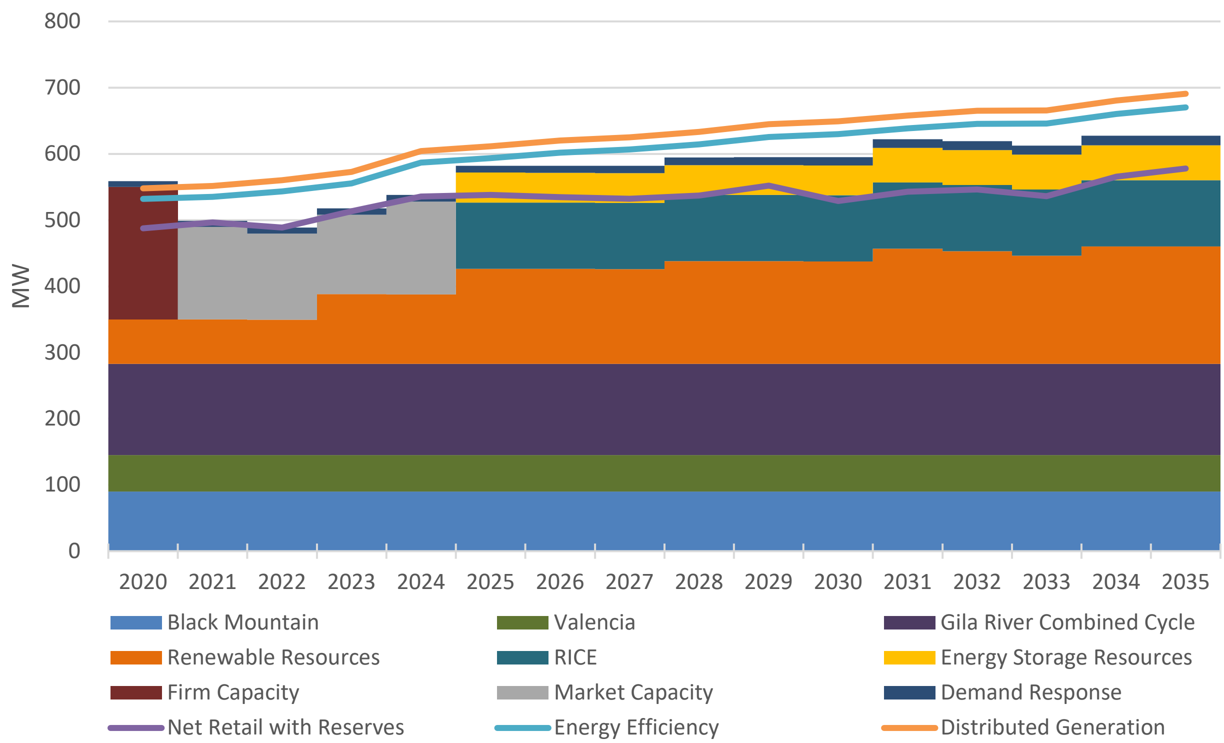
Chart 34 - Reference Portfolio, Annual Energy by Resource Type



Loads and Resources

Chart 35 below shows the Load and Resources assessment for the Reference Portfolio.

Chart 35 - Reference Portfolio, Load and Resources



Preferred Portfolio Energy Efficiency

UNSE's Preferred Portfolio will continue to incorporate high levels of EE. Based on the results of the portfolio analysis in Chapter 9, UNSE believes that incorporating EE at levels consistent with the Reference Portfolio is cost-effective for both participating customers as well as non-participating customers, provided that a full suite of EE programs and measures are available. As federal, state, and local energy efficiency standards and codes evolve and become more stringent, the ability of UNSE's DSM programs to effectuate incremental savings above and beyond these standards will diminish. While customers are still benefiting from these efficiency improvements, UNSE may no longer be able to "claim" energy savings associated with these measures.

Preferred Portfolio Demand Response

UNSE currently implements a voluntary load control program for larger commercial and industrial customers in UNSE's service territory. Participating customers voluntarily reduce their electricity consumption during times of peak electricity demand or as otherwise needed to optimize resource utilization (when alerted by UNSE). Customers are compensated with incentives for their participation at negotiated levels that will vary depending on multiple factors including the size of the facility, amount of load that can be curtailed, and the frequency with which the resource can be utilized.

The UNSE Preferred Portfolio assumes approximately 4 percent annual growth in DR capacity after 2021 resulting in 15 MW available in 2035 with a 4 percent annual increase in fees needed to achieve that level of growth.

Preferred Portfolio All-Source Request for Proposal

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 and resource economics. An ASRFP allows the full suite of resources to compete on a level playing field. Finally, there is strong support among stakeholders and our regulators for a robust ASRFP process as the basis for the Preferred Portfolio of resources.

UNSE intends to design its ASRFPs based on the results of a rigorous needs assessment and in consultation with stakeholders and the Commission. The Company continues to evaluate on an on-going basis, the most cost-effective energy, capacity, and grid balancing options currently available. This evaluation includes the most current market costs of renewable technology such as wind and solar, developments in system integration and associated energy storage technologies to facilitate greater renewable penetration, as well as existing and planned transmission availability for regions located outside the Company's service territory.

ASRFPs will be technology neutral, including supply- and demand-side resources. Criteria for the evaluation of proposals will be determined as part of the development of the ASRFP, and will not unduly exclude any commercially available resource that can demonstrate adequate performance and cost-effectiveness. Examples of likely evaluation criteria include:

- Demonstrated performance relative to the specific needs identified in the Company's needs assessment;
- Total cost of resources including capital, operation and maintenance, and fuel;
- Commercial availability within the utility sector and considering factors unique to UNSE's system;
- Environmental attributes including emissions, water use, and waste generation;
- Resource diversity.

In order to balance these criteria in the selection of resources, it is possible that the ASRFP process will result in a combination of multiple proposals and/or technologies being selected for each solicitation.

Load Growth Scenario Analysis

UNSE evaluated the Reference Portfolio under varying forecasts of future load growth. As required in Decision 76632, the Company evaluated two low load growth scenarios.

- Less than 1 percent Load Growth (L2)
- No Load Growth (L3)

In addition, UNSE evaluated one high load growth scenario (L4) in which EV sales are assumed to be higher than expected.

The financial risk of the Reference Portfolio to alternative load growth scenarios is related to the non-fuel NPVRR. If load grows more slowly than expected, then UNSE's capital investments in generation resources in the Reference Portfolio could be larger (or could occur sooner) than what would be ideal if the slower load growth were known at the time of the investments. Likewise, if load grows faster than expected, then UNSE will be required to buy capacity on the wholesale market or invest in additional generation resources. These expenditures may or may not cost more than if additional capacity were procured earlier. Although fuel and market purchases would also vary based on the load scenarios, these expenses are less dependent on the amount of owned capacity in the Reference Portfolio.

To gauge the potential risk of under- or over-purchasing generation resources, the resource additions in the Reference Portfolio were amended to serve the three alternative load scenarios while maintaining the same level of reserves and renewable energy penetration as the base load scenario. The resulting resource additions for the various load scenarios are presented in Table 23.

Table 23 - Changes in Resource Capacity Associated with Load Growth Scenarios

Capacity By 2035 (MW)	Base Case (L1)	Less Than 1% Load Growth (L2)	No Load Growth (L3)	High Load Growth (L4)
RICE	100	80	70	120
Solar	150	100	80	170
Wind	115	70	50	150
Storage	70	50	50	110

UNSE will adjust its procurement plans and the use of market purchases on an on-going basis to match up with actual load growth. This is possible because both the renewable and dispatchable resources considered in these portfolios are very scalable such that the Reference Portfolio would add resources incrementally over the planning horizon. This results in a low risk of over or under investing due to uncertainty in load growth.

CHAPTER 11

FIVE-YEAR ACTION PLAN

The 2020 Preferred Portfolio is based on current forecasts and assumptions. UNSE has developed a five-year action plan (2020-2024) based on the resource decisions that are contemplated in this IRP. Under this action plan, additional detailed study work will be conducted to validate all technical and financial assumptions prior to any final implementation decisions. UNSE's action plan includes the following:

- UNSE will continue to implement cost-effective EE programs consistent with historical levels. Through Implementation Plans developed in coordination with the Commission, UNSE will target 1.5 percent incremental energy savings over the prior year's retail load in each year through 2024. UNSE will continue to monitor closely and implement DR programs that are mutually beneficial to the Company and its customers.

- UNSE will continue to procure market-based resources to meet its short-term capacity needs through 2024. This market-based procurement strategy is currently the least cost option to cover the Company's summer capacity shortfalls. In the interim, the Company will explore other options through its future ASRFP's to acquire alternative resources through these solicitations if they are proven to be more cost-effective.

- UNSE is optimistic about the potential for an open market to provide cost-effective, sustainable solutions to the Company's future energy and capacity needs. Therefore, the Company is committed to procuring future resources through ASRFPs based on specific, identified system needs. UNSE anticipates issuing an ASRFP in 2022 or 2023.

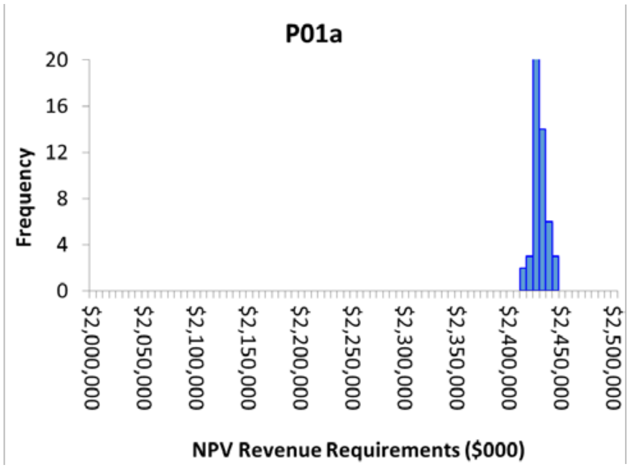
- UNSE is conducting studies relating to the costs and benefits of actively participating in the CAISO EIM, and anticipates making a decision in 2021.

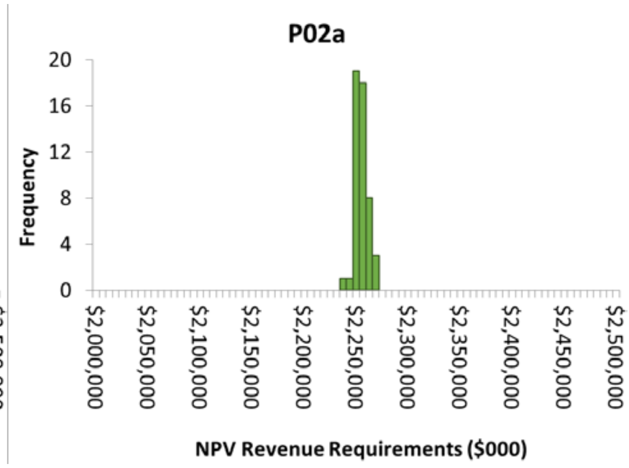
As with any planning analysis, the 2020 IRP represents a snapshot in time based on known and reasonable planning assumptions. The implementation of specific actions involves complex issues surrounding operating agreements, resource procurement contracts, land leases, economic analysis and environmental 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 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. UNSE requests that the Commission approve its 2020 Integrated Resource Plan as provided in A.A.C. R14-2-704.B. and the associated actions herein.

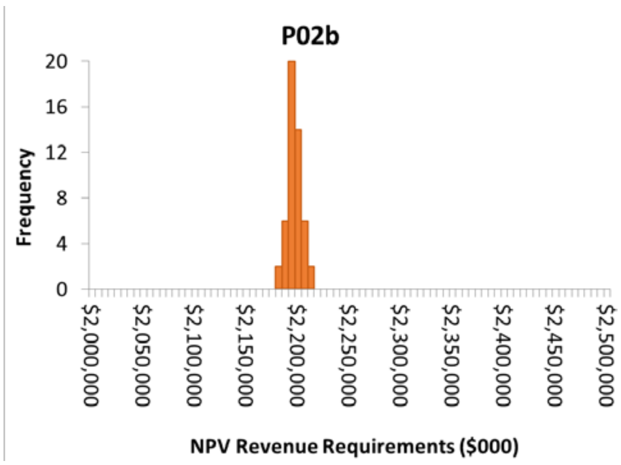
APPENDIX A

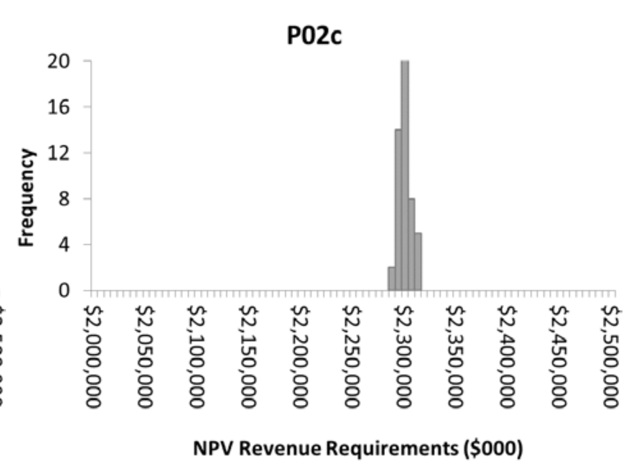
DISTRIBUTION OF NPV REVENUE REQUIREMENT RISK RESULTS

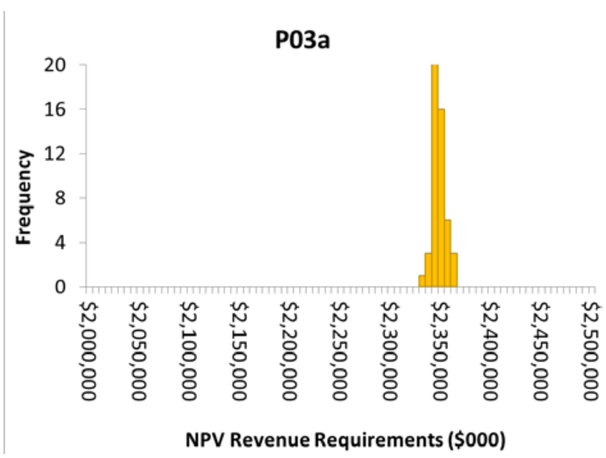
The following charts show the results of a Monte Carlo risk analysis performed on the net present value revenue requirements of the portfolios considered in the 2020 UNSE IRP. In this analysis, 50 iterations were performed on each portfolio, in which retail demand, natural gas prices, and Palo Verde market prices were randomly varied while preserving a high degree of correlation between gas and market prices. The chart on the following page combines the results of each portfolio analysis. The peak of the curves indicate the most frequent revenue requirement outcomes, while the width of the curves reflect the potential range (i.e., risk) of outcomes.

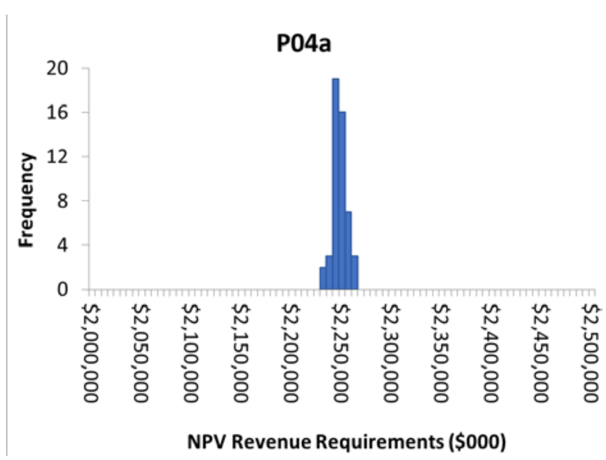


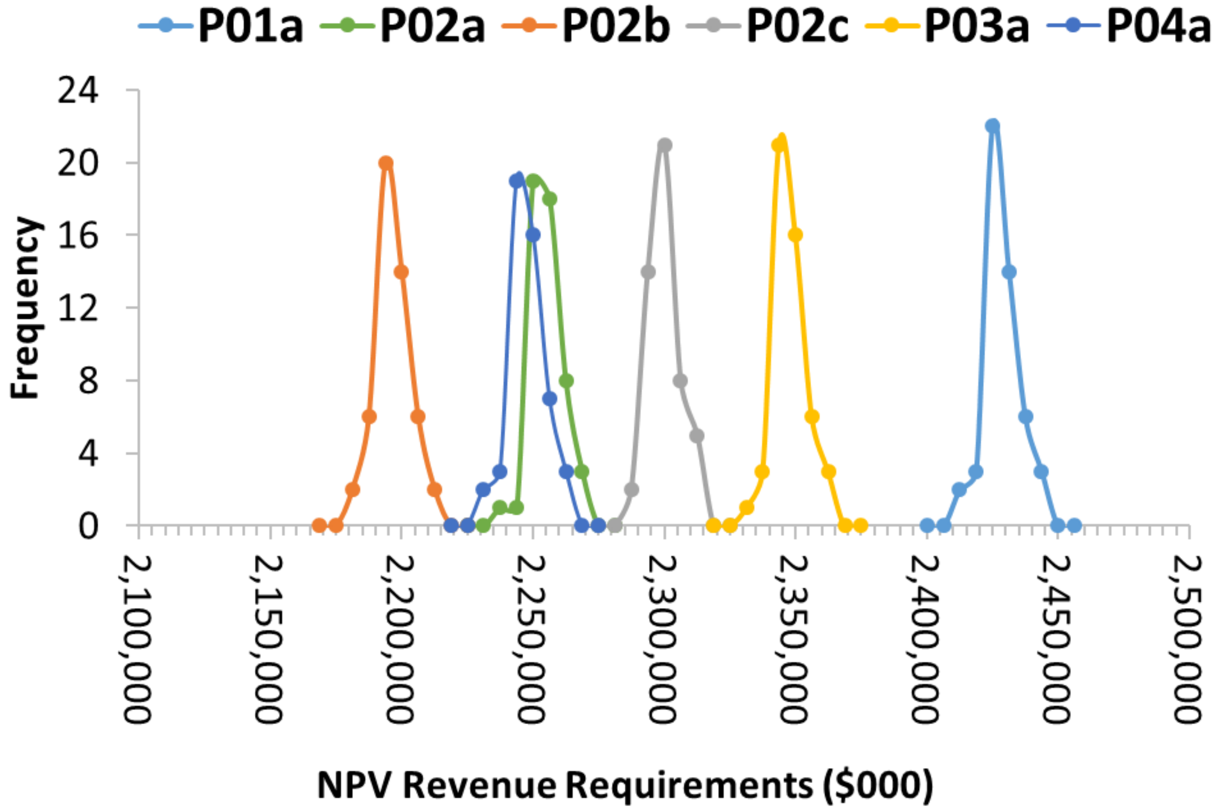











P01a
P02a
P02b
P02c
P03a
P04a
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16
12
8
4
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Frequency
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NPV Revenue Requirements ($000)