



UNS ELECTRIC INC.

2019 Preliminary Integrated Resource Plan

• AUGUST 1, 2019 •




Forward

Our Preliminary Integrated Resource Plan describes the opportunities and challenges that UNS Electric will consider while developing modern, cost-effective and increasingly sustainable resources to serve our customers' future energy needs.

For our 2020 IRP, UNSE plans to develop balanced, meaningful and measurable planning objectives to guide our planning decisions. Although customer affordability is crucial, we will also consider service reliability, risk and greenhouse gas emissions reductions. The resource options we develop in the Final 2020 IRP will include assessments of total system emissions, allowing us to identify low-emission portfolios that allow UNSE to provide affordable, reliable energy.

UNSE serves about 20 percent of its retail load using renewable resources, more than twice the current requirement under Arizona's Renewable Energy Standard and Tariff (REST) rules. With more wind and solar, UNSE will need to consider all available options to compensate for increased intermittency on our grid.

We've enlisted Siemens Industry, Inc. to help us study how our system would support the possible expansion of wind and solar energy resources to levels as high as 50 percent of our retail sales. We will analyze potential future resource needs, including the best ways to deploy energy storage systems. Battery systems, for example, are expected to experience steep cost declines in the coming years. UNSE can significantly reduce costs by delaying investment in these systems until they are actually needed to provide load shifting, peak capacity and other services. Based on the Siemens study, UNSE will evaluate various energy storage systems and deployment timelines for the Final 2020 IRP.

We're also introducing a new, more rigorous and efficient method for evaluating resource adequacy based on the combined loads and resources of UNSE and its sister company, Tucson Electric Power, which provides balancing and ancillary services for UNSE. This allows more thorough long-term planning that considers summer peak loads, over-generation, system regulation and ramping needs.

This plan expresses support for consolidation of Arizona's renewable energy and energy efficiency standards with other Arizona Corporation Commission (ACC) proceedings into an IRP docket that allows utilities to consider all potential resource options in a more useful and appropriate context. We support the premise of the Arizona Energy Rules docket for assessing baseload security, forest biomass energy, electric vehicles and other resource issues in a single proceeding. This comprehensive review would allow utilities greater flexibility to improve environmental performance while satisfying our unique, long-term energy requirements.

We plan to hold public workshops in Mohave and Santa Cruz counties to share our resource planning goals with customers and other stakeholders. Public input gathered at these meetings will inform our planning decisions as we participate in ACC IRP proceedings.

We appreciate your interest in UNSE's IRP and look forward to working with regulators, customers and the communities we serve throughout the planning process. Although our methods for meeting customers' needs will change, we remain focused on providing them with safe, reliable, affordable and sustainable energy service.

David G. Hutchens
President and CEO

Acknowledgements

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List of Acronyms

ACRONYMS

ACC – Arizona Corporation Commission
ADMS – Advanced Distribution Management System
ATB – Annual Technology Baseline
BESS – Battery Energy Storage System
BTA – Biennial Transmission Assessment
CAISO - California Independent System Operator
CO_2 – Carbon Dioxide
CT – Combustion Turbine
DG - Distributed Generation
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
EPRI – Electric Power Research Institute
EV – Electric Vehicle
FERC – Federal Energy Regulatory Commission
GHG – Greenhouse Gas
GW – Gigawatt
GWh – Gigawatt-Hour
HV – High Voltage
IGCC – Integrated Gasification Combined Cycle
IRP – Integrated Resource Plan
ITC – Investment Tax Credit
kW – Kilowatt
kWh – Kilowatt-Hour
kW-yr – Kilowatt-Year
LACE – Levelized Avoided Cost of Energy
LCOE – Levelized Cost of Electricity
LTO – Long-Term Outlook
LSE – Load Serving Entity
MMBtu – Million British Thermal Units, also shown as MBtu
MW – Megawatt
MWh – Megawatt-Hour
NERC - North American Electric Reliability Corporation
NGCC – Natural Gas Combined Cycle

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
PCM – Production Cost Model
PNM – Public Service Company of New Mexico
PPA - Power Purchase Agreement
PIRP – Preliminary Integrated Resource Plan
PTC – Production Tax Credit
REST – Renewable Energy Standard and Tariff
RICE – Reciprocating Internal Combustion Engine
RFP – Request for Proposal
RUCO - Residential Utility Consumer Office
SAT – Single-Axis Tracking
SCT – Societal Cost Test
SMR – Small Modular (Nuclear) Reactor
SRP – Salt River Project Agricultural and Improvement District
SO_2 – Sulfur Dioxide
SWEEP – Southwest Energy Efficiency Project
TEP – Tucson Electric Power Company
UNSE – UNS Electric, Inc.
UES – UniSource Energy Services
WECC - Western Electricity Coordinating Council

Chapter 1

OVERVIEW

Introduction

UNS Electric Inc.'s ("UNSE" or "Company") 2019 Preliminary Integrated Resource Plan (PIRP) introduces and discusses the issues that UNSE plans to analyze in detail as it develops the Final 2020 Integrated Resource Plan (IRP) due to be filed with the Arizona Corporation Commission (ACC or "Commission") on April 1, 2020. The purpose of this PIRP is to increase transparency into, and improve understanding of the IRP, and to provide the Commission, customers and other stakeholders with the background needed to offer meaningful feedback on the Company's future resource plans. UNSE will consider stakeholder feedback it receives in developing the Final 2020 IRP.

In addition to providing a snapshot of UNSE's current loads and resources, this PIRP provides an overview of the tools, methods, sources and assumptions UNSE will use in developing the Final 2020 IRP. This PIRP also provides an update on near-term initiatives identified in the UNSE 2017 IRP's Five-Year Action Plan[1].

An important consideration in evaluating UNSE's ability to meet its customers' energy needs is the fact that UNSE is within the Control Area[2] of Tucson Electric Power Company ("TEP"), and contracts with TEP for balancing and ancillary services. Therefore, it would not be accurate to assess UNSE's resource adequacy based solely on a comparison of UNSE's loads to UNSE's resources. In this IRP cycle, we are introducing a new and more rigorous method for evaluating the Company's resource adequacy based on the combined loads and resources of UNSE and TEP. This more comprehensive view will also go beyond capacity planning for summer peak to include issues around over-generation, system regulation, and ramping needs.

Modernization of Arizona's Energy Rules

Arizona utility IRPs are developed in accordance with rules established by the Commission[3] and are heavily influenced by other Commission rules relating to the procurement of renewable energy, the implementation of energy efficiency (EE) and demand side management (DSM) programs, and other initiatives. In August 2018, the Commission opened a rulemaking docket[4] to explore modifications to the Commission's energy rules ("Arizona Energy Rules").

UNSE currently serves approximately 20% of its retail load using renewable resources, double the current requirement under the Renewable Energy Standard and Tariff (REST) rules. The Company supports a re-examination of the REST rules and we agree with the premise behind the Arizona Energy Rules docket[5] that any

[1] UNSE 2017 Integrated Resource Plan, April 3, 2017, p 123; https://www.uesaz.com/wp-content/uploads/2016/04/UNSE-2017-Integrated-Resource-FINAL_reduced.pdf

[2] A Control Area is an electric power system or combination of electric power systems to which a common automatic control scheme is applied in order to instantaneously match all loads and resources at all times.

[3] Arizona Administrative Code R14-2-701 et. Seq. *Resource Planning and Procurement*

[4] In the matter of possible modification to the Arizona Corporation Commission's Energy Rules, August 17, 2018, RU-00000A-18-0284

[5] Memorandum to Docket Control from Elijah O. Abinah, Director, Utilities Division; RE: Request for New Docket, dated August 17, 2018 *lists specific subjects to be considered in the rulemaking*

such re-examination should be comprehensive, including all energy policies before the Commission, both existing and proposed. It would be counterproductive to continue assessing related energy initiatives such as EE, baseload security, forest biomass energy, and electric vehicles (EVs) in separate dockets and proceedings. These policy choices should be better aligned.

Arizona needs a coordinated, integrated energy policy that incorporates resiliency, affordability, reliability, sustainability, innovation, economic development and resource diversity. Once finalized, each utility should develop its unique contribution to Arizona's overall policy objectives. The policy itself should not pick winners and losers, rather, utilities need the flexibility to select the resources that fit best within their existing portfolio. Achieving an appropriate balance between these objectives is a challenge and it only becomes more difficult when utilities lose flexibility through narrowly crafted mandates. If given a clear vision of Arizona's desired energy future, utilities, through their IRPs, can formulate a balanced path toward that future.

Planning Objectives

For a long-term plan to be credible to customers and regulators, and useful to the utility as a guide for decision-making, it needs to be focused on meaningful planning objectives. However, planning objectives are often times competing, therefore, the final plan needs to strike a balance between these objectives which involves trade-offs as one optimizes a final plan that represents the best overall outcome. For the Final 2020 IRP, UNSE proposes to develop its plan based on the following key planning objectives.

- **Affordability for our customers must be our primary planning objective** – This objective will be measured based on the change in total net present value (NPV) revenue requirement and an estimate of the corresponding aggregated rate impact.
- **Reliability of Service** – All portfolios presented in the Final 2020 IRP will be capable of meeting anticipated customer demand in every hour during the planning horizon without load curtailment through a stochastic assessment of peak load, minimum load, 3-hour ramping, and 10-minute regulation.
- **Risk** – Portfolios will be evaluated against a wide range of future conditions to assess the impact on cost associated with unforeseen circumstances.
- **Greenhouse Gas ("GHG") Emission Reductions** – Rather than a renewable energy target, this objective, more directly focused on the sustainability challenge of climate change, will be measured by total system GHG emissions.

Stakeholder Involvement

We recognize the need for greater stakeholder involvement in the IRP process and the evolving energy needs of our customers. The roles that certain resources play within a utility's portfolio are changing.[6] Certain resources can serve multiple roles, and the overall model that utilities have traditionally relied on (central power stations serving load through transmission to a distribution grid) is no longer the only model available to serve customers' energy needs.

UNSE will lead and/or participate in public workshops and Commission proceedings to present our plans for the IRP and to solicit feedback from interested community members. A list of public workshops and

[6] TEP 2017 IRP, p83. *A New Integration Approach to Resource Planning*

Commission proceedings required by Decision No. 76632[7], along with the overall schedule for the 2020 IRP cycle, is presented in Table 1. In addition to or in combination with these workshops, UNSE will hold public workshops in each of the Mohave and Santa Cruz districts to encourage more active participation by community members.

Table 1 - 2020 IRP Public Workshops and Commission Proceedings

Topic	Responsibility	Timing
LSEs file PIRPs	LSEs	August 1, 2019
Portfolio Selection Workshop	LSEs / ACC Staff	Within 60 days after filing the PIRP
PIRP Review	ACC Staff and Stakeholders	August 1, 2019 – September 1, 2019
Energy Efficiency post 2020 Workshop	ACC Staff	Not specified
PIRP Workshop	LSEs / ACC Staff	September 2019
ACC Open Meeting – Review PIRP	ACC	October 1, 2019 – November 15, 2019
Pre-filing Workshop – Final IRP	LSEs / ACC Staff	December 1, 2019 – January 15, 2020
Final IRPs Filed	LSEs	April 1, 2020
Comments due on Final IRPs	Stakeholders	July 1, 2020
LSE response to Stakeholder comments due	LSEs	August 15, 2020
ACC Staff Assessment and Proposed Order due	ACC Staff	November 2, 2020
ACC Open Meeting and Final Order	ACC	February 15, 2021

[7] Dates reflected as modified by Decision No. 77176 (May 15, 2019).

Chapter 2

ACTION PLAN UPDATE

UNSE continually evaluates adjustments to the projects addressed in its Five-Year Action Plan to respond to changing conditions and new opportunities. This section provides an update on specific projects and documents any changes to their implementation.

Expansion of Community Scale Renewable Energy

UNSE's 2017 Five-Year Action Plan described the Company's plans to serve 20% of its retail load with renewable energy by 2020, exceeding the state requirement of 15% renewable energy by 2025. In June 2018, UNSE brought into operation its largest renewable resource – Gray Hawk Solar. This single-axis tracking (SAT) plant is 46 megawatt (MW) and located six miles Northeast of Kingman, Arizona. Power from the plant is acquired through a power purchase agreement (PPA) with D. E. Shaw Renewable Investments.

Grid Balancing Resources

UNSE continues to evaluate the need for additional flexible resources. At certain times, UNSE's renewable energy output accounts for 80% of its retail load. With such a high penetration of renewable resources at particular times, we would normally expect issues relating to regulation or ramping. However, the arrangement with TEP providing balancing services has allowed UNSE to manage the increased intermittency associated with renewable energy currently on its system.

The potential need for additional flexible resources will be based on the Resource Adequacy Study, discussed below.

Energy Efficiency

UNSE continues to implement cost effective EE programs based on the Arizona Energy Efficiency Standard ("EE Standard"). Following the sunset of the EE Standard, programs and measures will continue to be evaluated for cost-effectiveness using industry-accepted metrics, then those programs and measures will be modeled as demand-side resources within Aurora[8] such that the costs and benefits of the programs include their impacts on peak demand and overall portfolio dispatch economics. See Chapter 5 for more details on UNSE's assumptions for EE.

Load Serving Resource Additions and Wholesale Markets

The 2017 Five-Year Action Plan recommended the addition of 137 MW of Natural Gas Combined Cycle (NGCC) capacity by 2022. UNSE continues to evaluate the need for additional load serving resources to reduce the Company's high reliance on short- and medium-term market resources. Given UNSE's potential capacity need

[8] Aurora is an electric modeling simulation platform used for energy portfolio analysis and long-term resource planning optimization. Chapter 5 provides an in-depth overview of the Aurora software. https://energyexemplar.com/

(less than 150 MW) relative to typical NGCC generator capacities, the Company would likely need to partner with other load serving entities if it were to build or acquire a NGCC generator. Therefore, the Company envisions a PPA for new resource capacity as a more likely resource alternative.

Resource Adequacy Study

In past IRPs, UNSE demonstrated resource adequacy by identifying resource portfolios that provide at least a 15% peak load planning reserve margin in each year.

In order to gauge the system needs associated with higher penetrations of renewable energy, UNSE hired Siemens Industry, Inc. ("Siemens") to help the Company enhance its methodology for assessing resource adequacy in terms of both capacity and flexibility for its Final 2020 IRP. The expected outcome of this work is to develop a resource adequacy methodology that determines at which point UNSE's planned capacity and flexibility resources may be inadequate to serve retail load with high saturation levels of renewable resources. This will be done by examining various combinations of solar and wind power expansion scenarios, resulting in renewable energy penetration of up to 50% of retail sales. Because UNSE is located in TEP's Control Area, Siemens will use the combined historic load and renewable energy variability of TEP and UNSE to determine stochastically the amount of capacity and flexibility needed under such scenarios.

For each scenario, Siemens will identify the (i) peak net load[9], (ii) minimum net load, (iii) maximum 3-hour net load ramps (e.g., during sunrise and sunset), and (iv) maximum 10-minute net load ramps (e.g., during periods of rapid wind change and/or cloud cover). For each of these four criteria, the resource adequacy requirements will be compared to the resource capabilities of TEP's and UNSE's combined portfolios under six distinct scenarios during the year 2024. TEP is conducting the same study based solely on its loads and resources, so the results of the combined TEP/UNSE study will be compared to those of the TEP only study to evaluate the needs directly associated with the renewable energy expansions at UNSE. Any shortfalls in resources will be assumed to be provided through additional energy storage.

Natural Gas Storage

UNSE continues to evaluate and support the development of large scale, underground natural gas storage in Arizona. Natural gas storage within the state would improve the reliability of natural gas fired generation in responding to rapidly changing loads as a result of the intermittency caused by renewable resources. Moreover, due to the distance between Arizona's largest load pockets (Phoenix and Tucson) and the San Juan and Permian natural gas production basins, a state sourced natural gas storage facility would boost system resiliency. The boost is achieved by supplying natural gas during periods of shortfalls such as when the natural gas mainlines experience operational issues and storing excess natural gas during periods when the natural gas mainlines have no operational limitations. Natural gas storage in Arizona is feasible technically and economically if the project includes participation by all the major Arizona electric and natural gas utilities and with appropriate support from local and state government. UNSE will continue to assess the need for, costs of, and benefits of natural gas storage in Arizona in relation to the specific portfolio options evaluated in the Final 2020 IRP[10].

[9] Net load is the retail and firm wholesale energy demand in a given period less the total renewable energy production during that same period.

[10] Decision No. 76632 dated March 29, 2018 (Docket No. E-00000V-15-0094) ordered UNSE and other load serving entities to *"address natural gas storage in greater detail in future IRPs, including a discussion of efforts to develop natural gas storage, the costs and benefits of natural gas storage, and risks resulting from a lack of market area natural gas storage in Arizona."*

Chapter 3

LOAD FORECAST

Introduction

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 2019 annual planning forecast. The Final 2020 IRP will be based on UNSE's 2020 annual planning forecast.

The sections in this chapter include:

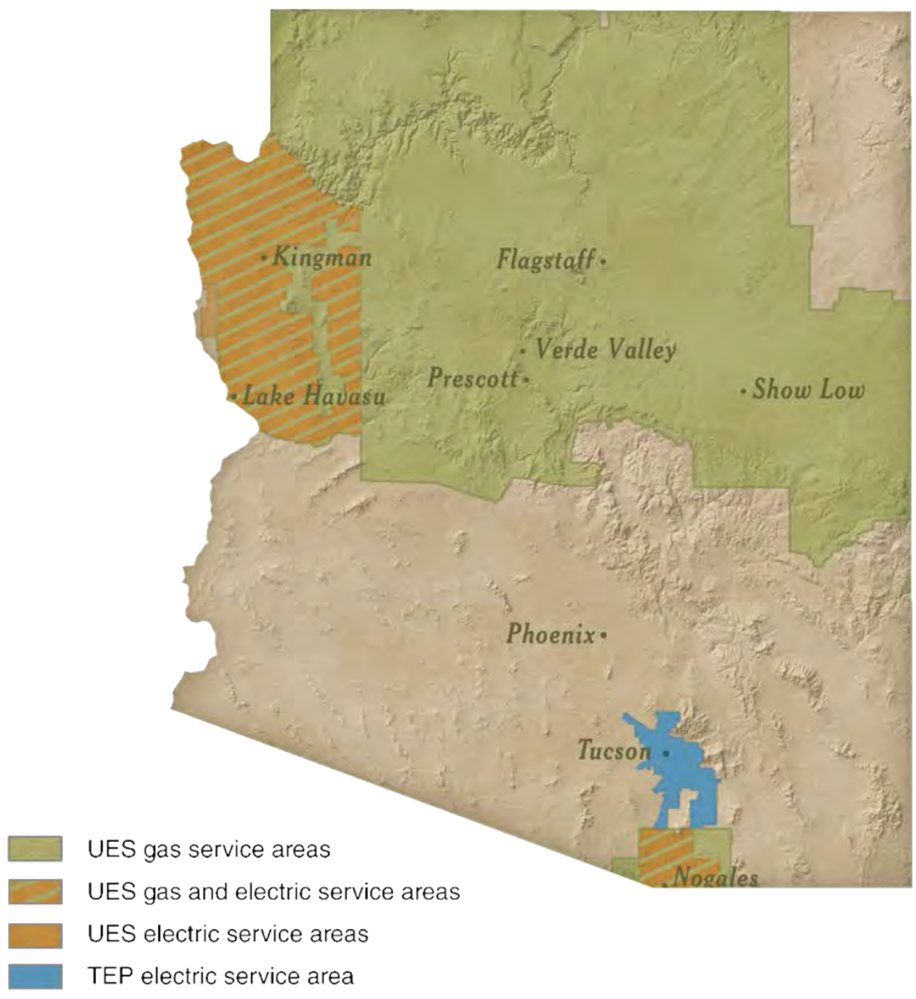
- **Company Overview:** UNSE geographical service territory, customer base, and energy consumption by rate class,
- **Reference Case Plan Forecast:** An overview of the Reference Case Plan forecast of energy and peak demand used in the planning process,
- **Summary:** Data sources and risks to the forecast.

Company Overview

Geographical Location and Customer Base

UNSE currently provides electricity to more than 86,000 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 255,000 people.

Map 1 - Service Area of Unisource Energy Services (UES) and Tucson Electric Power[11] Utilities

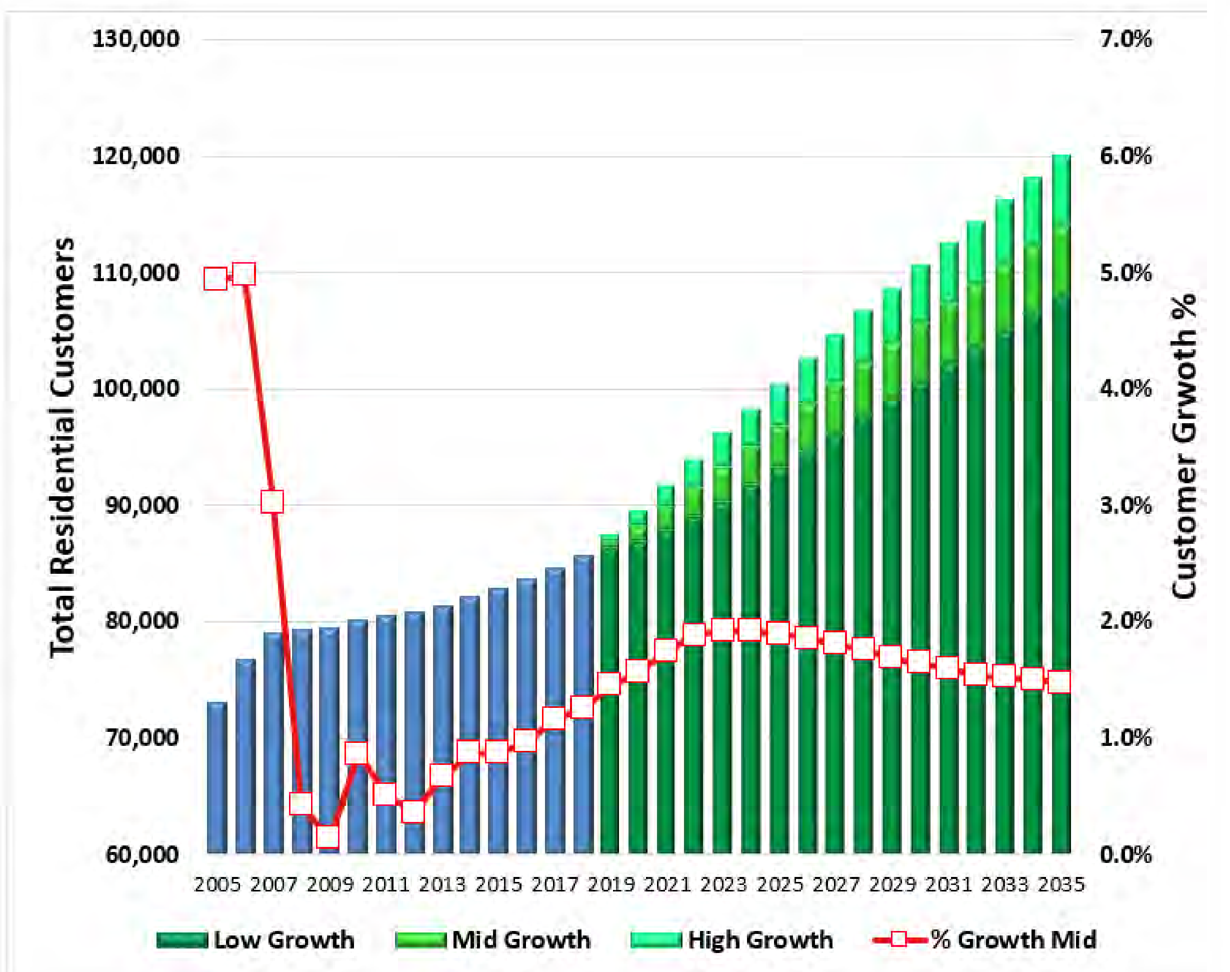


[11] UniSource Energy Services is the parent company of UNS Electric, Inc., and UNS Gas, Inc. Tucson Electric Power is a regulated utility providing electric services in Arizona and is a sister company to UniSource Energy Services.

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 and expected 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 term.

Chart 1 - UNSE Residential Customer Growth Including Estimates for 2019-2035

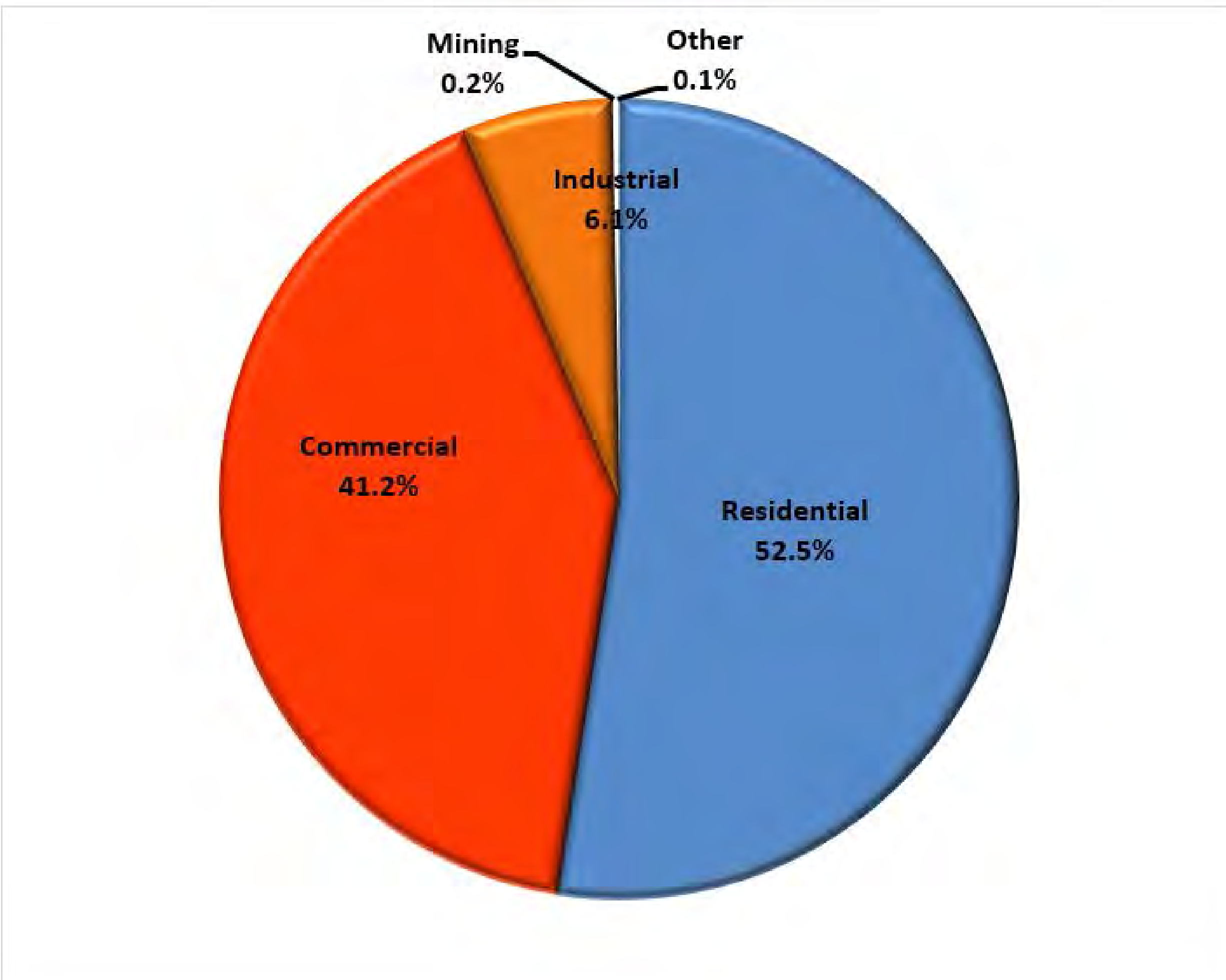


Retail Sales by Rate Class

In 2018, UNSE experienced a coincident peak demand of approximately 462 MW for the combined load in Mohave and Santa Cruz with approximately 1,700 gigawatt-hours (GWh) of retail sales. Approximately 94% of 2018 retail energy was sold to residential and commercial customers, with approximately 6% 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 2019 retail sales by rate class.

Chart 2 – Estimated 2019 Retail Sales % by Rate Class



Reference Case Plan 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 Nogales). 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 EE and Distributed Generation (DG) anticipated in each year.

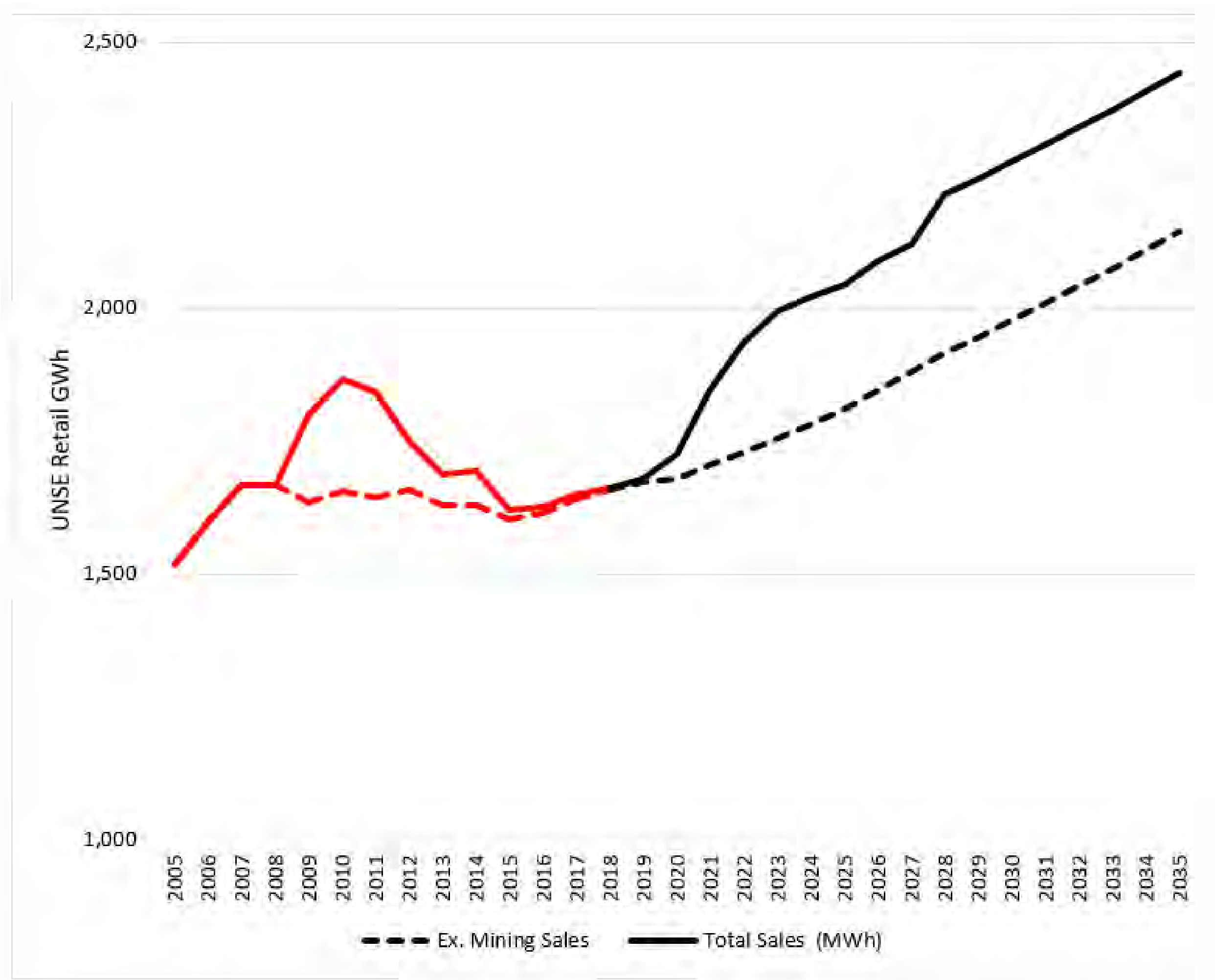
UNSE used a different approach in forecasting DG resources, as these have significant impacts on load projections. Using an econometric model, DG growth is projected to slow from an average annual rate of 26.9% for the 2012-2018 period to 2.9% for the 2018-2028 period. This is largely a reflection of the maturation of the DG market and adjustments to the mechanism for reimbursing DG owners for excess energy transferred to the grid.

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 Plan Retail Energy Forecast

UNSE's weather normalized retail energy sales fell significantly from their peak in 2010 nearly every year through 2018. 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. As shown on Chart 3, the underlying sales forecast (historical in red, forecast in black) excluding mining is showing an expected annual growth rate of 1.6% 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 2.3%.

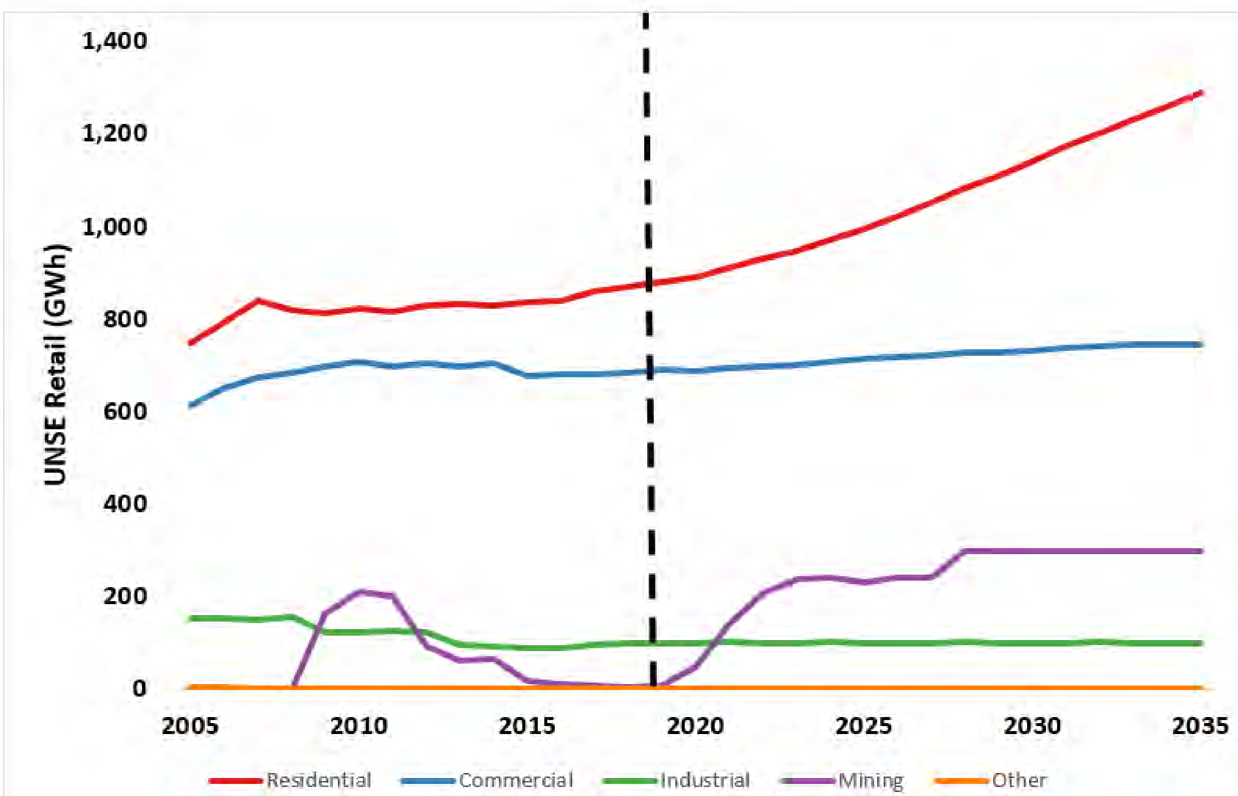
Chart 3 - Reference Case Plan Retail Energy Sales, Weather Normalized Historical



Reference Case Plan 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 regular slow steady 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

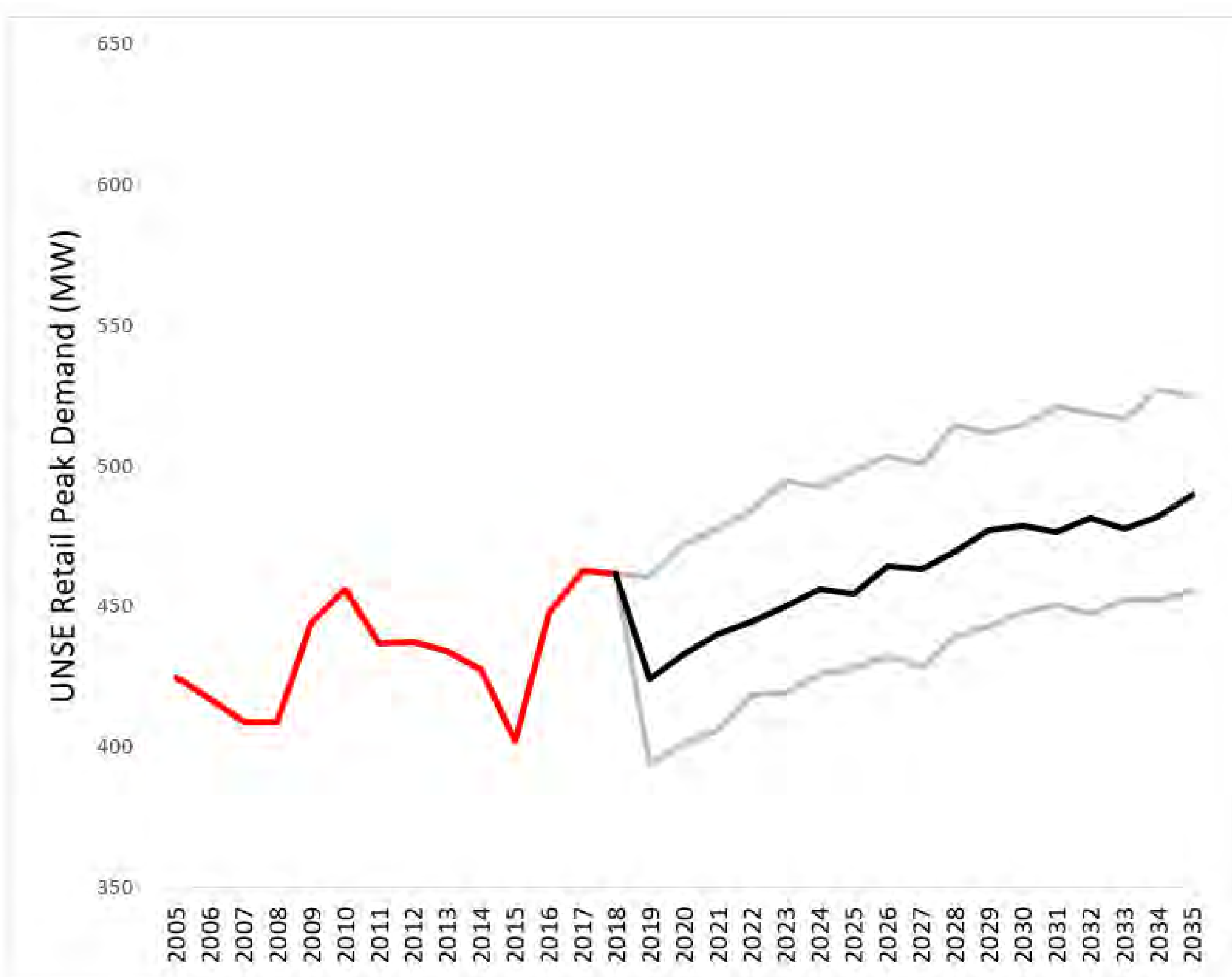


After experiencing consistent year over year growth throughout the past, residential and commercial energy demand remained nearly flat from 2008 through 2018. Both are assumed in the Reference Case Plan to increase steadily after 2019. Mining sales are assumed to expand.

Reference Case Plan Peak Demand Forecast

As show in Chart 5 below, peak demand (historical in red, forecast in black) is expected to drop in 2019 based on the assumption of a return to normal weather, although the upper confidence band (grey) shows it could remain relatively unchanged. 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 the Forecasting Process

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

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

Risks to Reference Case Plan 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 DSM programs)
- Technological innovations (e.g. EV penetration)
- Volatility in demographic assumptions (e.g. higher or lower population growth)
- Regulatory changes (e.g. introduction of a 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 that will be undertaken as part of the Final 2020 IRP. Specifically, the performance of each potential resource portfolio will be assessed through the simulation of over 100 different iterations of potential load growth scenarios (along with correlated gas and power prices in each case).

Chapter 4

PRELIMINARY LOADS AND RESOURCES

A critical component to the IRP planning process is the assessment of firm load obligations compared to a utility's firm resource capacity. This chapter presents a preliminary summary of the Company's future load obligations and the resources available to meet that obligation. The preliminary assessment of resource capacity includes capacity purchased from the market for up to five years. This preliminary assessment targets a 15% reserve margin in order to cover any unforeseen increases in demand and system contingencies related to unplanned outages on its generation and transmission system.

Renewable Resource Contribution to Meeting Peak Demands

UNSE's peak demand historically occurs between 4 and 6 PM in the summer. To estimate the contribution of UNSE's current and future variable renewable energy sources to meeting peak demand, UNSE examined the capacity factors of its renewable resources during these hours in the months of June through August. UNSE plans to reevaluate the net coincident peak demand and the incremental contribution of new renewable resources to UNSE's system as part of the Final 2020 IRP planning cycle.

Energy Efficiency and Demand Response

UNSE's EE program development through 2020 will continue to target compliance with the Arizona EE Standard of a cumulative energy savings of 22%. From 2021 through the end of the planning period, the preliminary load and resource assessment assumes annual energy savings based on an assessment of "achievable potential" in energy savings from EE programs conducted by the Electric Power Research Institute (EPRI).[12] By 2035, this offset to future retail load growth represents a reduction in UNSE's system peak demand of 60 MW. UNSE's Final 2020 IRP will replace this assumption of EE growth with an evaluation of specific EE measures or groups of measures as demand-side resources within our production cost-modeling platform Aurora (see Chapter 5, Energy Efficiency Assumptions).

UNSE Loads and Resources

Table 2 summarizes UNSE's gross retail peak demands by year based on its 2019 annual forecast projections. These demands are broken down by customer class and the Company's assumptions on coincident peak load reductions from DG and EE.

[12] Electric Power Research Institute, *U.S. Energy Efficiency Potential Through 2035*, dated April 2014. http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001025477

Table 3 summarizes UNSE's firm resource capacity based on its current planning assumptions related to its natural gas and renewable resources. Additional resources such as demand response (DR) programs and short-term market purchases are also shown in the UNSE resource portfolio. In addition, Table 3 summarizes the Company's reserve margin positions based on the Net Retail Demand shown in Table 2.

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

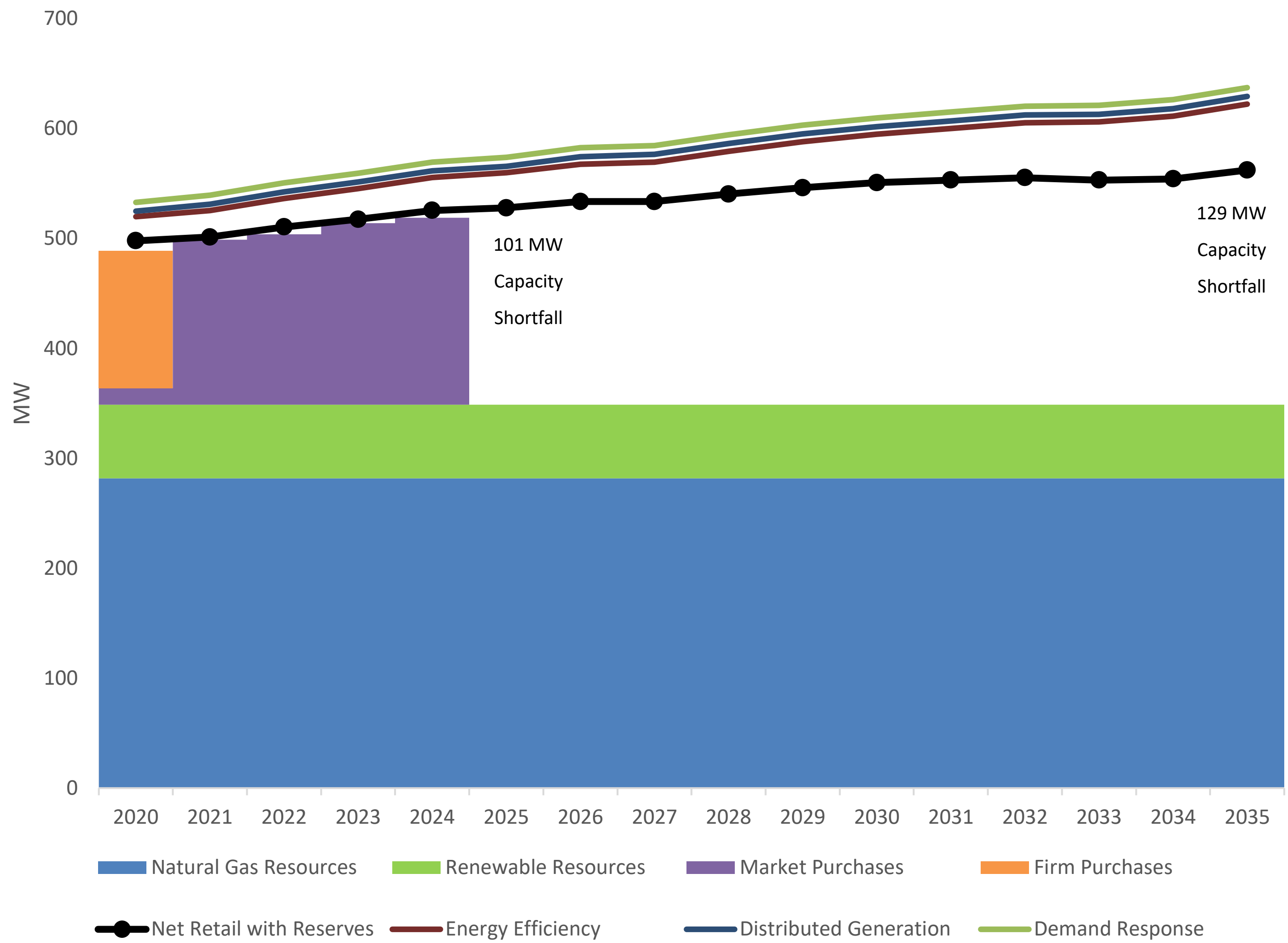
Firm Load Obligations (MW)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Residential	291	295	301	307	312	315	320	321	327	332	336	339	342	343	346	352
Commercial	138	140	143	145	148	149	151	152	155	157	159	160	162	162	164	167
Industrial	29	29	30	30	31	31	32	32	32	33	33	34	34	34	34	35
Mining	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retail Peak Demand	460	466	476	484	493	497	505	507	516	524	530	535	540	541	546	556
Less Energy Efficiency	-22	-24	-26	-28	-30	-32	-34	-36	-39	-42	-44	-47	-50	-53	-57	-60
Less Distributed Generation	-5	-6	-6	-6	-6	-6	-7	-7	-7	-7	-7	-7	-7	-7	-7	-7
Net Retail Demand	433	436	444	450	457	459	464	464	470	475	479	481	483	481	482	489
Reserve Requirement	65	65	67	68	69	69	70	70	71	71	72	72	72	72	72	73
Total Firm Load Obligations	498	501	511	518	526	528	534	534	541	546	551	553	555	553	554	562

Table 3 – Capacity Resources, 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	89	89	89	89	89	89	89	89	89	89	89	89	89	89	89	89
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	282	282	282	282	282	282	282	282	282	282	282	282	282	282	282	282
Utility Scale Renewables	67	67	67	66	66	66	65	65	65	64	64	64	63	63	63	63
Demand Response	8	9	9	10	10	10	11	11	12	12	12	13	13	14	14	15
Total Coincident Peak Capacity	357	358	358	358	358	358	358	358	359	358	358	359	358	359	359	360
Short Term Market Purchases	15	150	155	165	170	0	0	0	0	0	0	0	0	0	0	0
Firm Purchases	125	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Purchases	140	150	155	165	170	0	0	0	0	0	0	0	0	0	0	0
Total Resources	497	508	513	523	528	358	358	358	359	358	358	359	358	359	359	360
Reserve Margin	64	72	69	73	71	-101	-106	-106	-111	-117	-121	-122	-125	-122	-123	-129
Reserve Margin %	15%	17%	16%	16%	16%	-22%	-23%	-23%	-24%	-25%	-25%	-25%	-26%	-25%	-26%	-26%

Chart 6 combines the data from Table 2 and Table 3 to show graphically how our firm resources compare to our current firm obligations.

Chart 6 – UNSE 2020 Preliminary Loads and Resource Assessment



Chapter 5

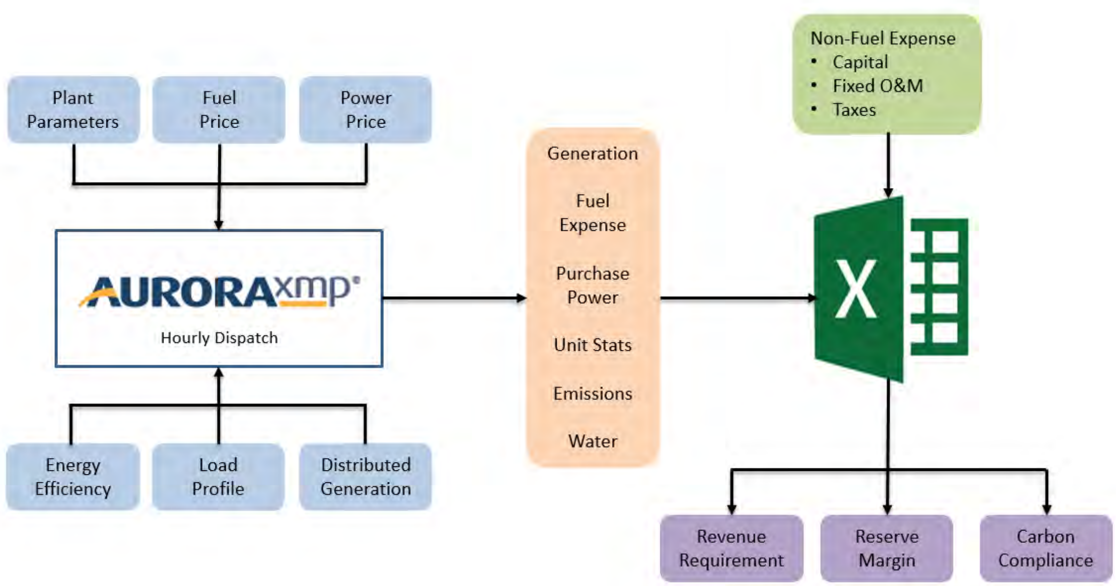
RESOURCE MODELING ASSUMPTIONS

Chapter 5 presents a description of the modeling inputs, framework and tools UNSE will use to develop its Final 2020 IRP. Input assumptions for parameters external to UNSE's system are based on independent third-party sources as available. Internal parameters are based on a combination of independent third-party sources and historical operations.

Production Cost Modeling

UNSE uses Aurora[13] for its resource planning production cost modeling. Aurora is a chronological economic dispatch simulation model that is used to represent the behavior and performance of a portfolio of resources under a set of operating and market conditions specified by the user. Inputs include hourly and peak load, plant design and operating parameters, and commodity prices. The model outputs include generation levels and the resulting costs of various resources as well as the overall production cost of the portfolio. These production costs are combined with capital and other fixed (i.e., non-fuel) expenses to determine the total revenue requirement of the portfolio (see Figure 1).

Figure 1 - Production Cost Modeling Platform



[13] https://energyexemplar.com/products/aurora-electric-modeling-forecasting-software/

Historically, the revenue requirements of a portfolio could be adequately determined by considering how customer load, and the least-cost resources dispatched to serve that load, change from hour to hour over the course of the year and the planning horizon. However, increasing amounts of renewable energy creates a variability in supply that greatly exceeds the variability in customer load. This variability occurs at a time scale of minutes, as well as hours. Thus, to quantify the operational and revenue requirement impacts of renewable energy, as well as the technologies and procedures needed to integrate this energy, it is becoming increasingly important to conduct resource dispatch analyses at the sub-hourly level. This has become well recognized in utility resource planning.[14] [15]

While IRP models, including Aurora, have been recently upgraded to perform sub-hourly analyses, using them at this scale is more resource-intensive and time-consuming. With this in mind, planning experts have recommended 1) determining where greater modeling complexity is meaningful and 2) the continued use of simpler screening tools in parallel with more complicated models.[16]

Based on its prior modeling efforts with TEP[17], it was determined that 10-minute intervals provide the best balance between capturing the dispatch effects of fast-response resources, such as batteries, and limiting database sizes and computer run times to manageable levels.

UNSE is also in the process of evaluating its flexible capacity needs under high renewable energy penetration scenarios using sub-hourly analysis of its net load and sub-hourly dispatch modeling with Aurora (see Resource Adequacy Study, Chapter 2).

As with any modeling exercise, the results are dependent on the inputs to the model. Appendix A lists several key model inputs for UNSE's existing resources. While it is not practical or even useful to list each of the thousands of individual input values the model uses, UNSE intends to provide as much transparency as can reasonably be afforded to stakeholders in our IRP process.

Greenhouse Gas Emissions

The first step in determining meaningful GHG emission reductions is to directly measure the emissions of resource portfolios. UNSE currently has one of the lowest GHG emission intensities (emissions per unit of energy) in the desert southwest. Each portfolio developed for the Final 2020 IRP will include an assessment of the total system GHG emissions associated with that portfolio. The various portfolios will be compared based on their total emissions and emissions intensity, targeting as low emission profile as possible while maintaining affordable, reliable energy to customers.

[14] In June 2018, the National Association of Regulatory Utility Commissioners issued a resolution that planning frameworks and modeling tools should model the full spectrum of services that energy storage and flexible resources are capable of providing, including sub-hourly services; https://pubs.naruc.org/pub.cfm?id=BF35538B-B75F-6495-0F61-9D9BBA61D76F

[15] The Washington State Utilities and Transportation Commission issued guidance that the benefits of storage and other flexible resources be evaluated on a sub-hourly basis using an external model, such as EPRI's StorageVet tool, then deducted from the resource's cost in the IRP to obtain a net cost; https://www.utc.wa.gov/docs/Pages/DocketLookup.aspx?FilingID=UE-151069

[16] https://emp.lbl.gov/sites/all/files/lbnl-1006269.pdf

[17] Tucson Electric Power Company, *2019 Preliminary Integrated Resource Plan*, July 1, 2019; p.38

Energy Efficiency Assumptions

Since 2011, UNSE's focus on EE has been to provide cost effective programs to meet the targets established in the EE Standard. UNSE's portfolio of programs incorporates elements of the most successful EE programs across North America and is designed in consideration of local markets. A substantial amount of information including evaluations, program plans and studies were used to develop specific programs for UNSE. With input from Navigant, the Residential Utility Consumer Office (RUCO) and the Southwest Energy Efficiency Project (SWEEP), UNSE also used a benchmarking process to review the most successful EE programs from across the country, with a focus on successful desert southwest programs to help shape the portfolio.

UNSE develops a suite of programs and presents those programs to the Commission for approval in the form of an Implementation Plan. The Implementation Plans include an analysis of EE and DSM cost-effectiveness focused primarily on the calculation of specific EE metrics, using the Societal Cost Test (SCT), which is the cost test identified in the EE Standard as the key measure for determining the cost-effectiveness of EE measures and programs. In the past, the programs approved through the EE Implementation Plans were incorporated into the IRP without significant consideration of how those programs intersected with electricity demand patterns, electricity market transactions, and UNSE's resource portfolio.

UNSE's Final 2020 IRP will include an explicit evaluation of EE programs and measures within this broader context. Programs and measures will continue to be evaluated for cost-effectiveness using the SCT and other applicable metrics. Then those programs and measures will be modelled as demand-side resources within Aurora such that the costs and benefits of the programs include their impacts on peak demand and overall portfolio dispatch economics.

There are a number of options for evaluating EE programs as demand-side resources within the IRP. One option is to calculate the difference between the Levelized Avoided Cost of Energy (LACE) and the Levelized Cost of Energy (LCOE) for the program or measure. The LACE is determined by conducting two simulations of the portfolio where one contains the EE program and one does not, then dividing the NPV of production costs savings by the NPV of total energy avoided by the EE program. The LCOE is simply the NPV of the cost of the program over the NPV of the lifetime energy saved. If the LACE is greater than the LCOE, the program is cost effective within the portfolio. Another option would be to evaluate the EE programs in a capacity expansion simulation, where the model selects resources to add to the portfolio based on their long-term value.

ACC Decision No. 76632 requires ACC Staff to "conduct one or more EE workshops to allow stakeholders to provide input regarding the future of EE beyond the 2020 expiration date" of the EE Standard. UNSE will work with Staff and stakeholders through these workshops to determine a method of evaluating EE that provides the best outcome for customers in terms of affordability, reliability and environmental performance.

Renewable Integration

As discussed in its prior IRP, there are a number of integration issues related to high penetrations of renewable energy. From a resource planning perspective (e.g., not including transmission and distribution issues), these include:

- **Meeting Peak Demand**

  While it is reasonable to expect some solar and wind power during hours of peak demand, it is impossible to know precisely how much they will contribute during those peaks, unless backed up by considerable amounts of energy storage or firm capacity. In addition, as more solar power is brought onto the system, the peak "net load" – i.e., load net of renewable resources – will shift to later hours, when solar power is no longer available. This will reduce the ability of future solar resources to contribute to the peak net load, unless the peak net load is shifted earlier by wind power, demand side programs, or energy storage.

- **Managing Renewable Resource Over Generation**

  During certain times of the day and year, under high renewable energy penetration scenarios, the amount of renewable energy being generated can exceed UNSE's ability to accept that power. This happens because the amount of renewable energy plus the amount of "must run" energy exceeds the demand for power. Must run energy is the minimum level of energy that must be supplied from certain generating units to meet reliability requirements relating to voltage control or for meeting ramping requirements during sunset when solar energy drops off.

- **Following Load During Sunrise and Sunset**

  In portfolios with large amounts of solar power, UNSE must have the flexibility to reduce generation from non-solar resources by large amounts during sunrise, and to increase them by large amounts during sunset.

- **Balancing Intra-Hour Variations in Renewable Power**

  In any portfolio with large amounts of intermittent renewable power, UNSE must have the flexibility to rapidly increase or decrease output from other resources on a sub-hourly basis in order to maintain a balance between energy demand and energy supply.

In its Final 2020 IRP, UNSE will examine these issues stochastically, using the variability observed in load and renewable energy at several renewable sites to estimate the likelihood of exceeding the above four flexibility criteria under different renewable penetration assumptions. (See Resource Adequacy Study, Chapter 2). This resource adequacy study will indicate the points at which UNSE may need to add more flexible capacity to its system. In the Final 2020 IRP, we will evaluate strategies to meet these flexibility needs, such as:

- Enhance operating capabilities of existing thermal resources
- Add energy storage resources as they become cost effective
- Add new, fast-starting, fast-ramping thermal resources
- Curtail renewable energy output during times of over generation
- Enhance operating capabilities of existing and new renewable energy plants to provide ancillary services
- Diversify renewable energy resources, both geographically and technologically
- Using an energy imbalance market to manage intra-hour variations, and use other market transactions to help manage other flexibility issues
- Improve renewable energy forecasting
- Implement rates and demand side programs that enhance the flexibility of UNSE's system

Energy Storage

UNSE is actively evaluating multiple potential uses for energy storage in our system. As required by Decision No. 76632, UNSE must evaluate energy storage as a potential solution for distribution and transmission needs in our system. The Company is also following the technology advances in large-scale (>10 MW) energy storage, specifically as it relates to the development of long duration (4 hours or greater), energy storage systems that can provide load shifting, peak capacity and other services.

As described in Chapter 2, UNSE is contracting Siemens to conduct a resource adequacy study that will provide insights into the timing and specific need for energy storage systems. Based on the results of that study, UNSE will model energy storage systems with various configurations for the Final 2020 IRP. The evaluation of energy storage will require modeling these systems at sub-hourly intervals due to the very short durations for which these resources are committed.

The timing for introducing energy storage systems is a critical planning determinant as it has a significant impact on the cost of the resource. Battery Energy Storage Systems (BESS) have experienced significant reductions in cost over the past several years and are expected to see additional cost reductions going forward. Table 4 shows the forecast capital cost reductions for a BESS.

Considering these declining costs and the time value of money, UNSE can significantly reduce the NPV cost of BESSs by delaying the purchase of those system until such time that they are needed in the system. As an example of these potential savings, Table 4 presents NPV costs of otherwise identical BESSs but with different deployment dates.

Table 4 - Comparison of Net Present Value Cost Based on Year of Installation[18]

Year Installed	CapEx ($/kW)	Fixed O&M ($/MW-yr)	Variable O&M ($/MWh)	NPV (2020$)
2020	$2,866	$8,645	$2.50	$88,657,303
2025	$2,331	$8,113	$2.20	$72,653,500
2030	$2,109	$7,581	$1.91	$65,727,485

Representative system is 30 MW, 8-hour duration, 350 cycles per year, 90% round-trip efficiency

[18] National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB), 2018, Storage Calculations

Energy Imbalance Market

Energy Imbalance Markets (EIMs) are specialized wholesale power markets designed to help Control Areas, such as TEP's (UNSE is within TEP's Control Area), to balance the sub-hourly intermittent characteristics of wind and solar power. An EIM aggregates the variability of loads and resources across the footprints of its participating balancing authority 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).

In December 2016, Energy and Environmental Economics ("E3") completed a study for TEP, which estimated that joining the California Independent System Operator ("CAISO") Western EIM[19] could have benefits for TEP of approximately $6 million per year (lower bound). Since then, Public Service Company of New Mexico ("PNM") and Salt River Project Agricultural and Improvement District ("SRP"), which have significant transmission connections with TEP, have announced their intention to join the Western EIM.[20] The expansion of the Western EIM, including parties connected to TEP's system, could improve both TEP's and UNSE's access to EIM market opportunities and at the same time non-EIM bilateral trading opportunities are being reduced as others enter the EIM market. Thus, an updated analysis was completed in November 2018, which estimated annual benefits of $13.6 million to TEP. Based on these considerations, TEP signed an agreement with the CAISO in May 2019 to join the Western EIM beginning in April 2022. As TEP develops its EIM implementation plans, UNSE plans to study the feasibility of joining the CAISO Western EIM as a stand-alone entity. Alternatively, UNSE may consider other opportunities through its current Balancing Authority arrangements or through other bilateral trading agreements to expand its options to balance the variability of its future loads and resources.

[19] https://www.westerneim.com/pages/default.aspx

[20] Arizona Public Service Company, which also has transmission connections with TEP, began participating in the Western EIM in October 2016.

Chapter 6

MARKET AND FUEL ASSUMPTIONS

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. 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 scenarios 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 that capture a range of future conditions yet represent plausible outcomes in terms of the relative movement of different market forces.

For the Final 2020 IRP, UNSE will develop a base case set of market assumptions and two alternative future scenarios for modeling the performance of each resource portfolio. Discrete and varying economic drivers that represent three separate forecasts of forward market conditions characterize these three scenarios.

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, as well as power markets. The North America Power and Renewables subscription includes a Long-Term Outlook (LTO), which is a comprehensive integrated forecast of energy demand and supply based on their 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. UNSE intends to use an updated version of the WoodMac LTO as the primary input for future fuel and market prices. Decision No. 76632 requires the IRP to consider a "wide variety of natural gas priced scenarios," therefore, depending on the range between the "high" and "low" scenarios, UNSE may consider additional scenarios, to test more extreme conditions.

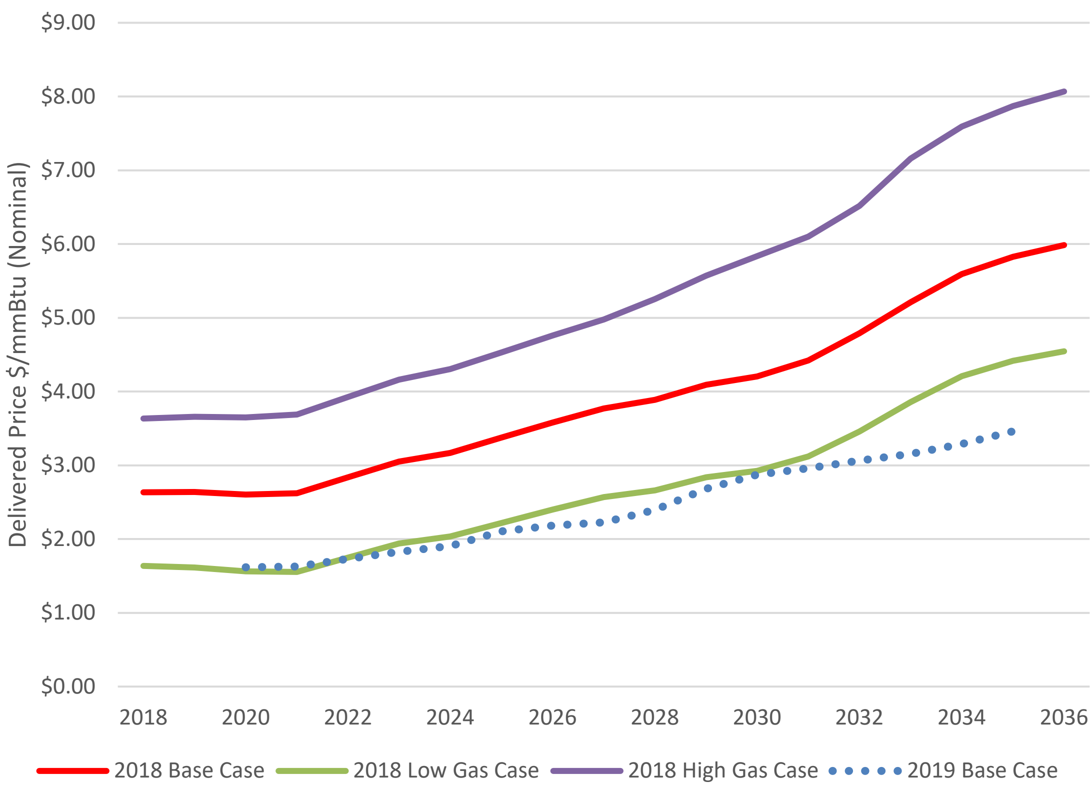
The LTO includes forecasts for carbon dioxide ("CO_2") emission prices for jurisdictions where emission pricing applies (e.g. California). In addition, the LTO includes a scenario[21] in which future Federal regulations result in emission prices for CO_2 emitted from electric generating units. UNSE's Final 2020 IRP will include scenarios with and without a Federal program resulting in emission prices for CO_2.

[21] The Wood Mackenzie 2018 H1 LTO includes a "Federal Carbon Case", which implements a $2/short ton price on CO_2 emitted from power plants beginning in 2028, escalating $2/short ton each year thereafter.

Natural Gas Price Forecast

Chart 7 shows WoodMac's 2018 LTO[22] forward price forecast for Arizona delivered natural gas under base case, high case, and low case scenarios along with the 2019 base case LTO[23]

Chart 7 – Natural Gas Price Forecast for Arizona Delivery

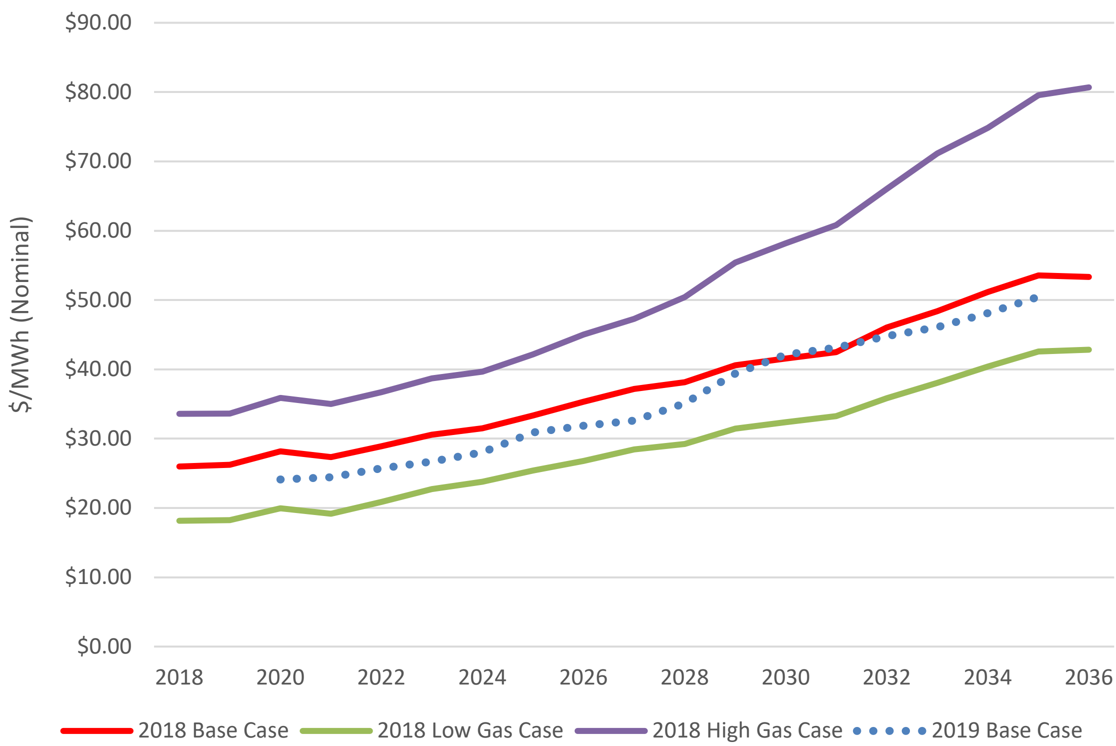


[22] Wood Mackenzie H1 2018 No Federal Carbon Case Long Term Outlook
[23] Wood Mackenzie H1 2019 Long Term Outlook

Palo Verde (7x24) Market Prices

WoodMac's 2018 LTO forward price forecast for 7x24 Palo Verde wholesale market prices is presented in Chart 8 under base case, high case, and low case scenarios along with the 2019 base case LTO.

Chart 8 - Palo Verde (7x24) Market Prices



Chapter 7

RESOURCE OPTIONS AND ECONOMIC ASSUMPTIONS

The starting point for any portfolio analysis is the utility's existing suite of resources. As a vertically integrated utility, UNSE is required to have sufficient generation, transmission, and distribution assets to (i) serve customer load, and (ii) for planning purposes, meet load from five years out through the end of the planning period with firm resources (as opposed to relying on short-term market purchases). The vast majority of these assets have long economic lives, and the degree of amortization varies widely.

The treatment of existing resources in the IRP requires close attention to their remaining useful lives to limit the economic impact of simultaneously paying for a resource and its replacement. The Final 2020 IRP will include an evaluation of all existing resources including an assessment of how those resources may be used differently to extract the maximum value out of them until they are no longer needed. A list of the current existing resources, including key modeling assumptions is included in Appendix A.

There is a broad spectrum of potential future resources that could be deployed to meet a specific utility need. For purposes of the Final 2020 IRP, UNSE will use the following criteria to identify resources that will be considered as future additions to the portfolio:

- Resources are similar to those that have been successfully deployed at UNSE;
- Resources are similar to those that that have been successfully deployed by utilities with characteristics similar to UNSE's and for services similar to those needed by UNSE; or
- Resources are of particular interest to regulators or stakeholders to evaluate a specific policy objective.

Table 5 provides a brief overview of the types of generating resources that will be considered for evaluation in the resource planning process for the Final 2020 IRP. For each technology type a brief summary of potential risks and benefits are listed. In addition, attributes such as costs, siting requirements, dispatchability, transmission requirements and environmental potential are summarized.

Table 5 - Resource Matrix

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

(1) Emissions associated with storage can vary from zero to levels greater than conventional fossil depending on what resource is on the margin during charging and discharging.

(2) Natural gas hybridization or thermal storage could allow resource to be dispatched to meet utility peak load requirements.

To keep the list of potential future resources manageable, UNSE has eliminated certain resources from consideration as future portfolio additions due to the low likelihood that those technologies would be implemented in UNSE's territory within the 15-year planning horizon. These technologies include:

- Conventional Hydroelectric
- Pulverized coal (subcritical or super critical)

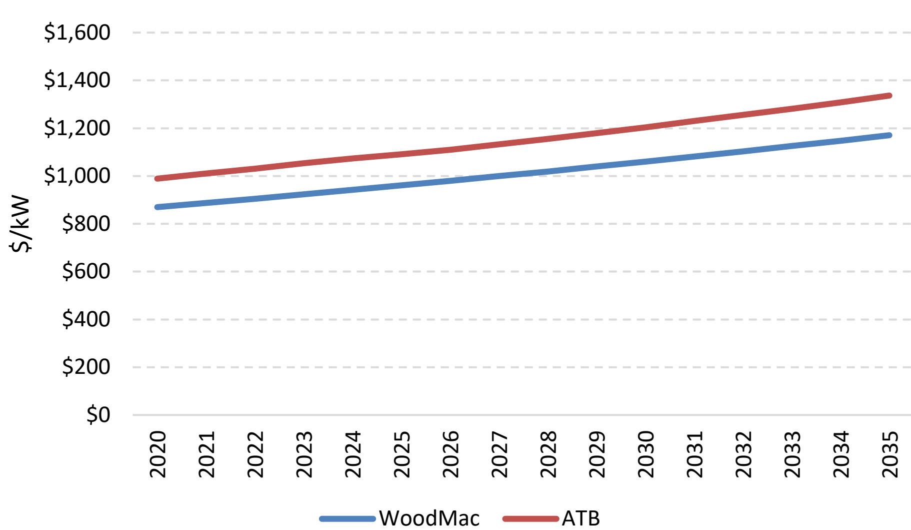
- Integrated Gasification Combined Cycle (IGCC)
- Small Modular Nuclear Reactors

However, in the case that a particular technology is bid into an all-source request for proposal (RFP) issued by UNSE, it would be considered equally with all other technologies based on the specific criteria established in the RFP.

Comparison of Resources

Generation planning and resource analysis requires reliable, independent, and up-to-date information and data regarding the resources to be considered as future additions to the resource portfolio. For UNSE's Final 2020 IRP, data relating to the cost and performance of potential future resources will be based on independent, third-party sources that are widely-used in utility IRPs. Chart 9 through Chart 12 show a comparison of capital cost forecasts, from widely-used third-party sources,[24] for certain thermal and renewable resources. The charts demonstrate the varying range of costs, even within each technology.

Chart 9 - Combustion Turbine Capital Cost Forecast



[24] Wood Mackenzie, *H1 2018 Federal Carbon Case Long Term Outlook;*
National Renewable Energy Laboratory, *2018 Annual Technology Baseline (ATB)*, https://atb.nrel.gov/;
US Energy Information Administration (EIA), *Annual Energy Outlook 2019*, Release date January 24, 2019, https://www.eia.gov/outlooks/aeo/

Chart 10 – Solar Single-Axis Tracking Capital Cost Forecast

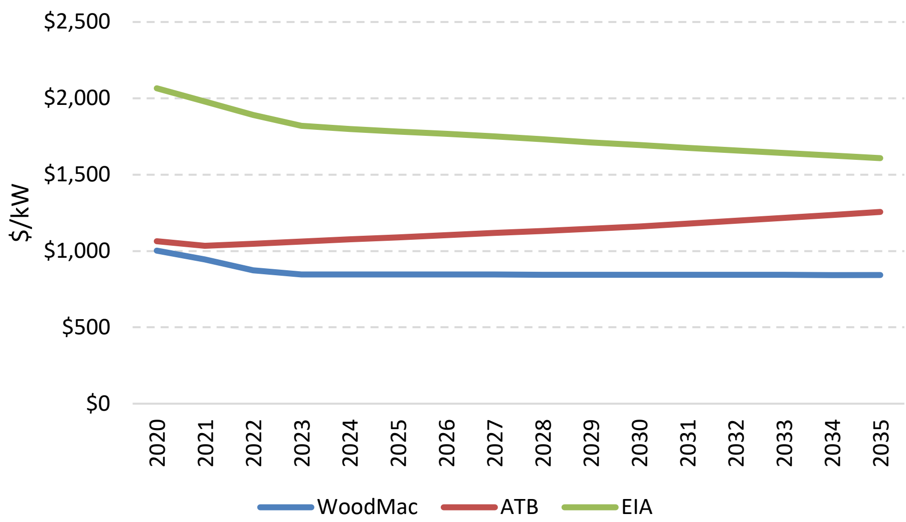


Chart 11 - On-Shore Wind Capital Cost Forecast

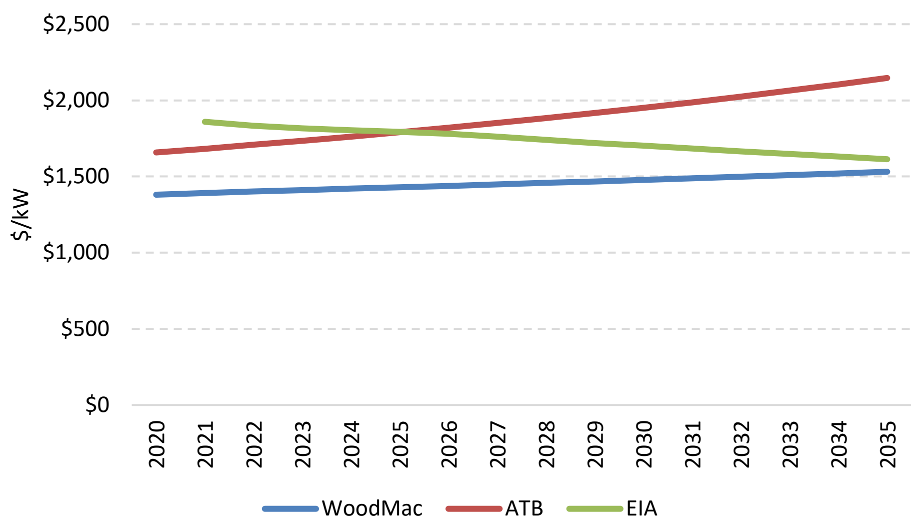
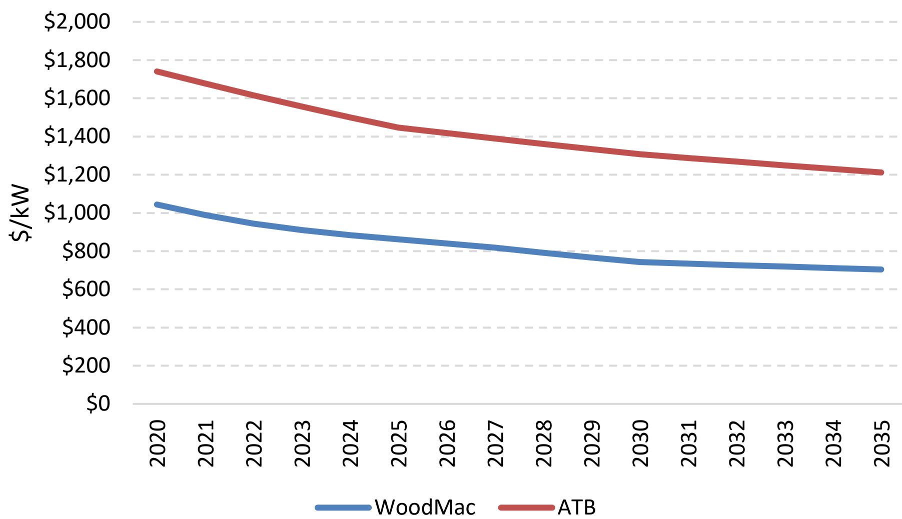


Chart 12 - Battery Storage (4-Hour) Capital Cost Forecast



UNSE intends to use an updated version of the WoodMac LTO as the primary source for future capital cost curves (i.e. the change in nominal capital costs over time) in the Final 2020 IRP. UNSE will collect and evaluate the most current data from other sources to test the reasonableness of the proposed capital cost inputs.[25] Using the derived capital cost projections for each of the technologies being considered, UNSE will calculate yearly nominal capital cost factors for each technology that will be multiplied by the 2019 capital cost to derive the capital cost of that technology in future years. Capital cost factors derived from currently available sources are presented in Appendix B. See Appendix C for a summary of cost and performance data on future resources that will be incorporated into the modeling for the Final 2020 IRP.

UNSE will also consider other sources of cost and performance data identified by stakeholders provided those sources are independent (they do not represent an advocacy position), transparent, and have a history of use in utility IRPs.

[25] Decision No. 76632 requires UNSE and other load serving entities to include in future IRPs "an analysis of a reasonable range of storage technologies and chemistries; and an analysis of anticipated future energy storage cost declines…"

Transmission and Distribution Assumptions

Transmission Overview

UNSE's transmission resources include approximately 336 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 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 transmission planning group to ensure adequate long-term transmission capacity is available to serve the Mohave service territories.

UNSE submits annual ten-year plans to the ACC and participates in the ACC's Biennial Transmission Assessment (BTA) which produces a written decision by the ACC regarding the adequacy of the existing and planned transmission facilities in Arizona to meet the present and future energy needs of the state in a reliable manner. The Commission concluded in its 2018 BTA[26] report that "[b]ased upon the technical study work examined by Staff and ESTA,[27] the existing and proposed transmission system meets the load-serving requirements of Arizona in a reliable manner for the 2018-2027 timeframe."

Regional Planning

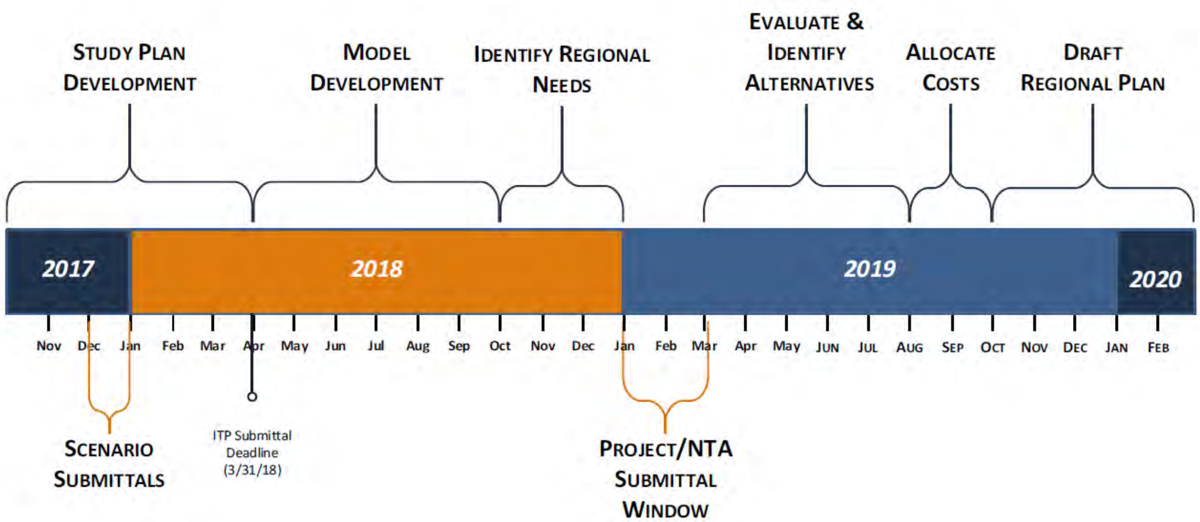
UNSE is represented in the regional transmission planning and cost allocation process of WestConnect by TEP who is an enrolled member of the Transmission Owners with Load Service Obligations ("TOLSO") sector. WestConnect is composed of utility companies providing transmission of electricity in the western United States working collaboratively to assess stakeholder and market needs and to develop cost-effective enhancements to the western wholesale electricity market and provides regional planning activities in compliance with Federal Energy Regulatory Commission (FERC) Order No. 1000.

[26] Decision No. 76975, Tenth Biennial Electric Transmission Assessment for 2018 Through 2027 (November 27, 2018), Docket No. E-00000D-17-0001.

[27] ESTA International, LLC is the Staff consultant that prepared the BTA.

Preparation for the WestConnect biennial regional transmission planning and cost allocation process covering the period January 1, 2018 through December 31, 2019 began in the fourth quarter of 2017. A schedule for the current planning cycle is presented in Figure 2.

Figure 2 - WestConnect 2018-2019 Planning Cycle Timeline



WestConnect assesses transmission planning models incorporating different scenarios to identify the need for new transmission. The key deliverable is a regional transmission plan that selects regional transmission projects to meet identified reliability, economic, or public policy, (or combination thereof) transmission needs. At the February 13, 2019 meeting of the Planning Management Committee (PMC), the PMC voted to approve the recommendation of the Planning Subcommittee that no regional transmission needs were identified in the current planning cycle.

Therefore, UNSE's Final 2020 IRP will not include an assessment of regional transmission projects that could be developed through the WestConnect process.

Control Area Service 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 provides 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 Agreement are approved by and on file with FERC.

Nogales DC Intertie

The Nogales Interconnection Project is a proposed direct current interconnection, commonly known as a "DC tie," which will allow for an asynchronous interconnection between the electric grids in southern Arizona and the northwest region of Mexico. The project will support the reliability of the electric system, including providing bidirectional power flow and voltage support, as well as emergency assistance, as needed, for the electric systems both north and south of the border.

Figure 3 - Nogales DC Intertie Location and Route

The first phase would consist of a new 150 megawatt DC tie located on property currently owned by TEP; a new 3-mile 138 kV transmission line that would originate at UNSE's Valencia Substation in Nogales, Arizona and extend to the west and south to the new Gateway Substation; and a new approximately 2-mile 230 kV transmission line that would extend south from the Gateway Substation to the U.S.-Mexico border where it would interconnect with a transmission line to be constructed in Mexico. The second phase would expand the DC tie capacity to 300 MW. The timing of the second phase has not been determined.

A Certificate of Environmental Compatibility was approved by the ACC in November 2017, and a Presidential Permit, a requirement for interties crossing international borders, was issued by the United States Department of Energy in October 2018. FERC has granted the project authority to sell transmission rights at negotiated rates on the line. Construction of the first phase will commence pending sufficient subscriptions for service.

Other Regional Transmission Projects

Other large projects proposed for interconnection in eastern and southeastern Arizona may influence UNSE's long-term resource planning decisions. UNSE's Final 2020 IRP will evaluate the progress of and prospects for these projects to be completed and the impact a completed project could have on UNSE's resource planning. A list of key regional projects is presented in Table 6.

Table 6 - Regional Transmission Projects

Project Name	Description	Developer	Status
SunZia	Double-circuit 500kV line between central New Mexico, near Ancho and the proposed Pinal Central substation near Casa Grande, Arizona.	Southwestern Power Group II/MMR Group	Project approval by New Mexico Public Utilities Commission (PUC) is being held pending determination of a complete and final route. FERC granted the project authority to sell transmission rights at negotiated rates on the line.
Southline	**New Build** - 345kV double-circuit line between the existing Afton Substation, south of Las Cruces, New Mexico, and the existing Apache Substation, south of Wilcox, Arizona. **Upgrade** - 230kV double-circuit line between the Apache Substation and the existing Saguaro Substation northwest of Tucson, Arizona. The upgrade section will also interconnect at TEP's Vail, Tortolita and DeMoss Petrie substations.	Southline Transmission, L.L.C., a subsidiary of Hunt Power	Certificate of Environmental Compliance was approved by the ACC in February 2017. New Mexico PUC approval was received in August 2017. FERC granted the project authority to sell transmission rights at negotiated rates on the line. Project design of the Upgrade portion is under way with WAPA. Construction will commence pending sufficient subscriptions for service and land acquisition. TEP is working with the project developer on interconnections to the TEP system at three locations.
Western Spirit Transmission Line	Approximately 140-mile transmission line from northwestern New Mexico to the San Juan Substation (at the San Juan Generating Station).	Renewable Energy Transmission Authority of New Mexico ("RETA") and Pattern Development	Approval of the route was received from RETA. Bureau of Indian Affairs issued a Grant of Easement in 2017. FERC granted Pattern authority to sell transmission rights on the line at negotiated rates. PNM announced on May 1, 2019 that it reached agreement to acquire Line from Pattern Development.

Distribution Planning

UNSE is continually modernizing its distribution grids 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 Advanced Distribution Management System (ADMS), a two-way metering system, and an enhanced asset management program. 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 EVs, etc.), which can be used to evaluate how customers' load profiles impact supply-side resource decisions.

Just as our customers' load profiles are evolving, so, too, are customer expectations of 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 – to be performed "in house" at UNSE. With proper analysis, the necessity for capital improvement projects will be readily identified, proposed and budgeted. Additionally, UNSE will begin to explore smart grid technologies. We foresee the formation of a task force to evaluate prospective smart grid equipment vendors and to identify areas of the grid that will reap the greatest reliability benefits from this emerging technology. UNSE will collaborate with TEP in this effort.

The Final 2020 IRP will describe, in greater detail, how UNSE intends to utilize technology to add more sensing and measurement devices and new methods for managing and operating the distribution system, and how the use of this technology can be integrated into the Company's broader resource planning.

Chapter 8

PORTFOLIO SELECTION

This chapter provides a description of how UNSE intends to identify the portfolios that will be analyzed in the 2020 Final IRP. The following conditions must be represented in at least one of the portfolios to be analyzed, according to Decision No. 76632:

- The addition of fossil fuel resources is no more than 20% of all the resource additions.
- Energy storage capacity in the portfolio equals 20% of system peak demand, at least 50% "clean energy resources,"[28] with at least 25 MW of these "clean energy resources" as renewable biomass operating at a minimum 60% capacity factor, and at least 20% of DSM.

Based on previous IRPs and given the general public interest in adoption of renewable and energy storage technology, UNSE anticipates the following portfolios will be of interest.

- High energy storage portfolio
- High renewable energy portfolio

In addition to requiring the two portfolios mentioned above, Decision No. 76632 requires UNSE to hold a public workshop within 60 days after filing this PIRP for the sole purpose of discussing each portfolio that will be analyzed as part of the Final 2020 IRP ("Portfolio Workshop"). UNSE intends to utilize the Portfolio Workshop to present the results of the Resource Adequacy Study discussed in Chapter 2. The Resource Adequacy Study will be key in identifying both the timing of additional resources as well as the specific reliability requirement that additional resources are needed to address. Based on the results of the Resource Adequacy Study and discussion during the Portfolio Workshop and other workshops (see Table 1), UNSE will select a set of portfolios to be analyzed for the Final 2020 IRP.

[28] Clean energy resources refer to resources that operate with zero net emissions beyond that of steam.

Chapter 9

FUEL, MARKET AND DEMAND RISK ANALYSIS

For the Final 2020 IRP, UNSE plans to develop explicit market risk analytics for each candidate portfolio through the use of computer simulation analysis using Aurora. Specifically, a stochastic based dispatch simulation will be used to develop a view on future trends related to fuel prices, wholesale market prices, and retail demand. The results of this modeling will then be employed to quantify the risk uncertainty and evaluate the cost performance of each portfolio. This type of analysis ensures that the selected portfolio not only has a reasonable expected cost, but also is robust enough to perform well against a wide range of possible load and market conditions.

As part of the Company's Final 2020 IRP, UNSE plans to conduct risk analysis around the following key variables:

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

Chapter 10

CLOSING

This PIRP presents UNSE's initial set of assumptions, sources and methodologies to be used in developing the Final 2020 IRP. As such, UNSE views this report as the "starting point" for what we intend to make an interactive and transparent process of shaping UNSE's energy future. UNSE will solicit input from a broad cross-section of interested parties in order to frame a future that delivers high reliability at an affordable rate, while measuring improvement in environmental performance.

APPENDIX A

EXISTING RESOURCES

UNS Electric, Inc. Preliminary Integrated Resource Plan
Appendix A
Existing Resources

Design Characteristics

Resource	Unit Capacity (MW)	Ownership Percentage	UNSE Capacity (MW)	Year In Service	Retirement Date	Fuel Supply	NOx Controls
							NOx
Natural Gas Combustion Turbine							
Black Mountain Unit 1	45	100%	45	2008	2053	UNS Gas, Inc	DLN
Black Mountain Unit 2	45	100%	45	2008	2053	UNS Gas, Inc	DLN
Valencia Unit 1	14	100%	14	1989	2051	UNS Gas, Inc	water injection
Valencia Unit 2	14	100%	14	1989	2051	UNS Gas, Inc	water injection
Valencia Unit 3	14	100%	14	1989	2051	UNS Gas, Inc	water injection
Valencia Unit 4	21	100%	21	2006	2051	UNS Gas, Inc	water injection
Natural Gas Combined Cycle							
Gila River Unit 3	550	25%	137.5	2001	2048	Kinder Morgan/ Transwestern	SCR

| SCR – Selective Catalytic Reduction | DLN - Dry Low-NOx Burner

Operating Characteristics

Resource	Heat Rate (MMBtu/ kWh)	Forced Outage Rate (%)	Must Run (Months)	Ramp Rate (MW/min)	Min Up Time (hours)	Min Down Time (hours)	Emission Rates (lbs/mmBtu)		
							CO2	SO2	NOX
Natural Gas Combustion Turbine									
Black Mountain Unit 1	9,250	5	0	5	4	4	118	0.0020	0.100
Black Mountain Unit 2	9,250	5	0	5	4	4	118	0.0020	0.100
Valencia Unit 1	16,500	8	0	5	4	4	119	0.0006	0.300
Valencia Unit 2	16,500	8	0	5	4	4	119	0.0006	0.300
Valencia Unit 3	16,500	8	0	5	4	4	119	0.0006	0.300
Valencia Unit 4	9,800	5	0	5	4	4	119	0.0006	0.100
Natural Gas Combined Cycle									
Gila River Unit 3	7,400	5	0	7	10	10	119	0.0006	0.008

APPENDIX B

NEW RESOURCE COST FACTORS

UNS Electric, Inc. Preliminary Integrated Resource Plan
Appendix B
New Resources Cost Factors

Year	Gas CT - Aero	Gas CT - Frame	Gas NGCC - Conventional, Wet Cooled	Reciprocating Engines	Geothermal	Solar Thermal - Six Hour Storage	Solar PV - Fixed Tilt (1-20 MW)	Solar PV - Tracking (>20 MW)	Wind - Onshore	Battery Storage
2017	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
2018	1.013	1.013	1.013	1.013	1.019	0.930	0.917	0.917	1.005	0.796
2019	1.034	1.034	1.034	1.034	1.043	0.863	0.855	0.855	1.014	0.751
2020	1.054	1.054	1.054	1.054	1.065	0.793	0.802	0.802	1.023	0.707
2021	1.075	1.075	1.075	1.075	1.088	0.788	0.756	0.756	1.030	0.670
2022	1.097	1.097	1.097	1.097	1.111	0.783	0.699	0.699	1.038	0.639
2023	1.119	1.119	1.119	1.119	1.133	0.777	0.677	0.677	1.045	0.616
2024	1.141	1.141	1.141	1.141	1.156	0.771	0.677	0.677	1.052	0.598
2025	1.164	1.164	1.164	1.164	1.179	0.764	0.677	0.677	1.059	0.583
2026	1.187	1.187	1.187	1.187	1.203	0.757	0.677	0.677	1.066	0.568
2027	1.211	1.211	1.211	1.211	1.227	0.749	0.676	0.676	1.073	0.553
2028	1.235	1.235	1.235	1.235	1.251	0.741	0.676	0.676	1.080	0.535
2029	1.260	1.260	1.260	1.260	1.276	0.731	0.676	0.676	1.087	0.519
2030	1.285	1.285	1.285	1.285	1.302	0.722	0.676	0.676	1.095	0.503
2031	1.311	1.311	1.311	1.311	1.328	0.736	0.675	0.675	1.103	0.497
2032	1.337	1.337	1.337	1.337	1.354	0.751	0.675	0.675	1.110	0.492
2033	1.364	1.364	1.364	1.364	1.381	0.766	0.675	0.675	1.118	0.487
2034	1.391	1.391	1.391	1.391	1.409	0.781	0.674	0.674	1.126	0.482
2035	1.419	1.419	1.419	1.419	1.437	0.797	0.674	0.674	1.134	0.477

Base Year: 2017

APPENDIX C

NEW RESOURCE COST AND PERFORMANCE DATA

UNS Electric, Inc. Preliminary Integrated Resource Plan
Appendix C
New Resource Cost and Performance Data

Input Assumption	Unit	Gas CT - Aero	Gas CT - Frame	Gas NGCC - Conventional Wet Cooled	Reciprocating Engines	Geothermal	Solar Thermal Six Hour Storage	Solar PV - Fixed Tilt (1-20 MW)	Solar PV - Tracking (>20 MW)	Wind - Onshore	Battery Storage
Capacity Degradation	%/yr	0.05%	0.05%	0.00%	0.00%	variable	1.00%	0.50%	0.50%	0.00%	5.00%
US Avg Installed Cost	$/kW	$ 1,250	$ 825	$ 1,000	$ 1,000	$ 5,200	$ 6,925	$ 1,850	$ 1,250	$ 1,350	$ 1,477
Fixed O&M	$/kW-yr	$ 29.30	$ 30.05	$ 33.30	$ 12.00	$ 120.00	$ 80.00	$ 10.00	$ 13.00	$ 30.00	$ 16.00
Variable O&M	$/MWh	$ 3.50	$ 3.75	$ 2.00	$ 4.50	$ 5.00	$ .00	$ .00	$ .00	$ .00	$ .00
Heat Rate	Btu/kWh	9,800	10,500	7,200	8,500						
Property Tax	%	1.00%	1.00%	1.00%	1.00%	1.00%	0.50%	0.50%	0.50%	0.50%	0.50%
Insurance	%	0.50%	0.50%	0.50%	0.50%	0.50%	0.01%	0.25%	0.01%	0.01%	0.01%
Resource Life	yrs	30	30	30	30	25	35	20	20	30	20
MACRS Term	yrs	20	20	20	20	5	5	5	5	5	5

Base Year: 2017