TUCSON ELECTRIC POWER COMPANY

2020 Integrated Resource Plan

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List of Acronyms

ACRONYMS

ACC – Arizona Corporation Commission
ACE – Area Control Error
ADEQ – Arizona Department of Environmental Quality
ADMS – Advanced Distribution Management System
AECC – Arizonans for Electric Choice and Competition
AEO – Annual Energy Outlook
AGC – Automatic Generation Control
AMI – Automated Metering Infrastructure
APS – Arizona Public Service Company
ATB – Annual Technology Baseline
AZ WRF – Arizona Weather Research & Forecast
BA – Balancing Authority
BAAL – Balancing Authority ACE Limit
BES – Bulk Electric System
BESS – Battery Energy Storage System
BEV – Battery Electric Vehicles
BTA – Biennial Transmission Assessment
Btu – British Thermal Unit
C&I – Commercial and Industrial
CAES – Compressed Air Energy Storage
CER – Customer-Sited Energy Resource
CAISO - California Independent System Operator CO_2 –
Carbon Dioxide
CPS – Control Performance Standard
CSP – Concentrating Solar Power
CT – Combustion Turbine
DC – Direct Current
DCS – Disturbance Control Standard
DER – Distributed Energy Resources
DG - Distributed Generation
DOE – U.S. Department of Energy (Federal)
DMS – Distribution Management System
DR – Demand Response
DSM – Demand Side Management
E3 – Energy and Environmental Economics
EE – Energy Efficiency
EGU – Electric Generating Unit
EHV – Extra High Voltage
EIA - Energy Information Administration

EIM – Energy Imbalance Market
EMS – Energy Management System
EPA - Environmental Protection Agency
EPNG – El Paso Natural Gas
EPRI – Electric Power Research Institute
EV – Electric Vehicles
FERC – Federal Energy Regulatory Commission
FF – Fabric Filter
FRM – Frequency Response Measure
GHG – Greenhouse Gas
GW – Gigawatt,
GWh – Gigawatt-Hour
HEV – Hybrid Electric Vehicle
HRI – Heat Rate Improvement
HRSG – Heat Recovery Steam Generator
HVAC – Heating Ventilation Air Conditioning
Hz – Hertz
IBEW - International Brotherhood of Electrical Workers
ICE – Internal Combustion Engine
IRP – Integrated Resource Plan
ISD – In Service Date
ITC – Investment Tax Credit
kW – Kilowatt
kWh – Kilowatt-Hour
LCOE – Levelized Cost of Energy
LGS – Large General Service
LPS – Large Power Service
LTO – Long Term Outlook
MMBtu – Million British Thermal Units, also shown as MBtu
MBtu – Million British Thermal Units, also shown as MMBtu
MGS – Medium General Service
MVA – Megavolt-ampere
MW – Megawatt
MWh – Megawatt-Hour
NAAQ – National Ambient Air Quality Standards
NEC – Navopache Electric Cooperative
NERC - North American Electric Reliability Corporation
NGCC – Natural Gas Combined Cycle
NOAA – National Oceanic and Atmospheric Administration
NO_X – Nitrogen Oxide(s)
NPV – Net Present Value
NPVRR – Net Present Value Revenue Requirement
NREL – National Renewable Energy Laboratory
NTUA – Navajo Tribal Utility Authority
NWP – Numerical Weather Prediction
O&M – Operations and Maintenance
PHEV – Plug-in Hybrid Electric Vehicles
PM - Particulate matter

PNM – Public Service Company of New Mexico
PPA - Purchased Power Agreement
PPFAC – Purchased Power Fuel Adjustment Clause
PRM – Planning Reserve Margin
PTC – Production Tax Credit
PSD – Prevention of Significant Deterioration
PV – Photovoltaic
RES – Renewable Energy Standard
RFP – Request for Proposal
RICE – Reciprocating Internal Combustion Engine
RMR – Reliability Must Run
RTP – Real Time Pricing
RUCO - Residential Utility Consumer Office
SAT – Single-Axis Tracking
SCADA – Supervisory Control and Data Acquisition
SCR – Selective Catalytic Reduction
SDA – Spray Dryer Absorber
SGS – Springerville Generating Station (aka Springerville)
SIP – State Implementation Plan
SJCC – San Juan Coal Company
SMR – Small Modular (Nuclear) Reactor
SNCR – Selective Non-Catalytic Reduction
SO_2 – Sulfur Dioxide
SRP – Salt River Project
SRSG – Southwest Reserve Sharing Group
SWAT – Southwest Area Transmission
SWEEP – Southwest Energy Efficiency Project
TEP – Tucson Electric Power Company
TORS – Tucson Electric Power Owned Residential Solar
TOU – Time-of-Use
TOUA - Tohono O'odham Utility Authority
TRICO – Trico Electric Cooperative
TWh – Terawatt-Hour
UA – University of Arizona
UAIE – University of Arizona Institute of the Environment
UES – UniSource Energy Services (Parent Company of UNS Electric)
U.S. – United States
VAR – Volt-Ampere Reactive; Reactive Power
WAPA – Western Area Power Authority
WECC - Western Electricity Coordinating Council
WRA – Western Resource Advocates

Forward

Sustainable, Reliable, Affordable Energy for the Future

As an energy provider, our plans for the future must account for market trends, regulatory directives, technological advancements, environmental concerns, customer behavior, local preferences and global realities. While these forces often push us in different directions, we seek a balance that benefits our customers and the communities we serve.

This balance is reflected in Tucson Electric Power's 2020 Integrated Resource Plan. Both ambitious and realistic, our plan allows us to address climate change without compromising our safe, reliable and affordable service.

This plan calls for a dramatic expansion of our solar, wind and storage resources and the gradual retirement of our last coal-fired power plants. By 2035, we plan to provide more than 70 percent of our power from renewable resources with a portfolio that requires 70 percent less water and produces 80 percent less carbon dioxide (CO_2). Our carbon reduction goal, developed in partnership with the University of Arizona's Institute of the Environment, represents our fair share of worldwide efforts to limit warming to well below 2 degrees Celsius under the 2015 Paris Agreement.

Our plan emerged from a process that evaluated 24 potential portfolios, including some designed to achieve certain clean energy benchmarks and others suggested by stakeholders. After reviewing the portfolios at a public workshop, we developed a final portfolio for the 2020 IRP that represents the best balance of cost, performance, environmental impact, and risk.

That portfolio calls for ramping down and ultimately retiring our two units at the coal-fired Springerville Generating Station (SGS) over the next 12 years. We plan to begin cycling one of our units offline during cooler months beginning in 2023 before retiring Unit 1 in 2027 and continuing seasonal operations of Unit 2 until 2032.

This decision was not made lightly, as SGS has helped power our community's growth for decades. But coal generation is under increasing pressure nationwide due to depressed natural gas prices, low-cost renewable energy resources, climate concerns and other environmental impacts. The planned closure of other coal-fired power plants also has increased the risk of regional coal mine closures that could limit the availability of fuel for Units 1 and 2. Our team at SGS, well aware of these forces, has committed itself to making our eastern Arizona plant the most reliable, well-run coal plant in the country. Their success and commitment will allow us to transition to less carbon-intensive resources at a cost-effective pace while working toward a thoughtful transition for our employees and their community.

Over time, we'll offset the output of SGS with new wind, solar and energy storage systems. This expansion is already underway, with a combined 447 megawatts from the Oso Grande and Borderlands Wind Projects in New Mexico and the Wilmot Energy Center solar plus storage project in Tucson scheduled to come online by next year. We also plan to complete construction of a 10 MW solar array in Tucson next year to support our GoSolar Home community solar program.

These additions, which will more than double our current community-scale renewable generating resources, are just the beginning. Through the remainder of our planning period, we anticipate adding another 2,000 MW of wind and solar power as well as 1,400 MW of energy storage systems. We also plan to continue providing cost-effective energy efficiency programs that target reductions in on-peak energy use.

Our portfolio was created with significant input from community members who participated in our IRP Advisory Council. The panel included a diverse group of customers, local government representatives and interest group advocates who met regularly with our resource planning team to discuss different aspects of our plan. Their contributions, combined with comments received during public workshops, have helped ensure that our IRP represents a plan not just for TEP, but for our community.

We know our customers want safe, reliable energy from resources that are both affordable and environmentally responsible. TEP's 2020 Integrated Resource Plan will help us maintain that delicate balance as we proceed down a path toward a sustainable energy future.

David G. Hutchens
CEO

CHAPTER 1

EXECUTIVE SUMMARY

Introduction

Since 2014, Tucson Electric Power's (TEP or "Company") primary resource planning strategy has been to achieve greater diversity in the resources it uses to meet our customers' energy needs. This strategy focused on achieving a cleaner mix of energy resources that we are now in a position to reach within the next two years, which is eight years earlier than previously planned.

Now the Company's focus is shifting from the mix of resources we utilize, to the impact that those resources have on our customers, our local community and the planet. The TEP 2020 Integrated Resource Plan (IRP) includes the **goal of reducing our carbon dioxide ("CO_2" or "carbon") emissions 80 percent below 2005 levels by 2035**. This aggressive, yet achievable goal is a key milestone in our journey to rapidly and responsibly transition to 100 percent clean energy resources.

To achieve these aggressive reductions in emissions, TEP must continue to reduce and eventually eliminate its reliance on coal-fired generation. To date, TEP has retired 468 Megawatts ("MW") of coal-fired generation, as part of the first phase of coal plant retirements, which we will complete in 2022 with the retirement of an additional 170 MW at San Juan Generating Station ("San Juan"). These early coal retirements were made possible through strategic acquisitions of efficient and flexible natural gas resources to cost-effectively replace the lost coal capacity.

The exit from the remaining coal units will take more time. While coal is no longer the least-cost energy resource, it still provides cost–effective capacity, reliability and ancillary services. To optimize the value of our coal units, the Springerville Generating Station (SGS) Units 1 and 2 will begin operating on a seasonal basis within the next three years.

The exit of all of our ownership interests in coal plants will occur over the next 12 years. These planned closures are summarized below.

Facility	Location	Operator	TEP Ownership Interest	Scheduled Closure
San Juan Unit 1	Farmington, NM	PNM	170 MW / 50%	2022
Four Corners Units 4 & 5	Farmington, NM	APS	110 MW / 7%	2031
Springerville Units 1 & 2	Springerville, AZ	TEP	793 MW/ 100%	2027, 2032

TEP has partial ownership interests in units at San Juan and the Four Corners Power Plant ("Four Corners"), which are operated by Public Service Company of New Mexico ("PNM") and Arizona Public Service Company ("APS"), respectively. TEP is committed to continuing its participation with the other owners in plant closure and transition activities at these facilities.

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

As we retire older fossil-fuel generation resources, **all of the new replacement resources will be a combination of renewable resources, energy storage and energy efficiency**. TEP's Preferred Portfolio calls for 70 percent of our energy coming from renewable resources, 1,400 MW of new energy storage, and 2.5 times more energy efficiency than originally planned by 2035. In addition to the carbon emission reductions, the plan will result in the elimination of surface water use for power generation and a 70 percent decrease in groundwater consumption.

TEP's 2020 IRP identifies the risks and opportunities facing the utility industry, and TEP specifically, and outlines a plan to meet our customers' energy needs in a more sustainable fashion. The IRP presents a snapshot of our current loads and resources and projects future energy and capacity needs through 2035. Our 2020 Preferred Portfolio was developed through extensive analysis and in-depth stakeholder engagement.

Advisory Council

TEP's 2020 IRP was developed with the guidance of a group of diverse stakeholders formed as an IRP Advisory Council. TEP believes that broad stakeholder involvement is essential if the IRP is to reflect the values of the community we serve. However, the means by which TEP solicits input on its resource plan must account for the fact that integrated resource planning is becoming increasingly more complicated. The economic value that various resources provide is shifting; conventional fossil-fuel resources have been replaced by renewables as the lowest cost sources of energy, but maintain their traditional roles in providing reliability, capacity, and ancillary services.

What seems to be clear is that the resources supplying energy to the electrical grid are changing. There are more frequent announcements of coal plant closures due to economics, or new projects for solar energy with storage at record low pricing. However, headlines do not convey the myriad of other considerations that need to be weighed in making resource decisions. Given the uncertainty regarding the optimal pace for this transformation, TEP recognized the need for greater education and stakeholder input regarding the implications of resource planning decisions. Formation of the IRP Advisory Council allowed us to take a deeper dive into these issues.

The Advisory Council was formed to provide representation of a broad variety of perspectives. TEP believed that balance was essential. However, the size of the Council was limited to a small set of stakeholders to allow for adequate time for dialogue among all the members. We focused membership on the local community including customers, governmental agencies, and advocacy groups. The list of members of the Advisory Council is provided in the table below.

Advisory Council Membership

	Category	Organization
Customers	Large/Industrial	Port of Tucson
	Commercial	GLHN, Architects and Engineers
	Residential	RUCO
	Low Income	Wildfire AZ
	Senior	Pima Council on Aging / AARP
Government	City	City of Tucson
	County	Pima County
	State	University of Arizona
	Federal	Davis Monthan AFB
Advocacy	Environment	Sierra Club / Western Resource Advocates
	Energy Efficiency	SWEEP
	Economic Development	Sun Corridor
	Distributed Generation	Technicians for Sustainability

The Advisory Council met eight times between May 2019 and March 2020. Meetings addressed specific topics with discussion lead by subject matter experts from within TEP as well as Advisory Council members or invited outside experts. The list of topics covered at the Advisory Council meetings is shown in the table below.

Advisory Council Meeting Topics

Meeting Topics	
Planning for Uncertainty	Modeling Assumptions
Load Forecast	Grid Enhancements
Existing Resource Attributes	Customer Resources
Proposed Resource Additions	Coal Plant Economics
Future Resource Costs	CO_2 Emission Reductions
Resource Adequacy	Electric Vehicles
Revenue Requirement	Demand Side Management

One of the primary objectives of the Advisory Council engagement was for Advisors to provide TEP with alternative combinations of resources ("Resource Portfolios" or "Portfolios") or alternative future conditions ("Scenarios") for evaluation as part of the IRP. This ensured that our IRP is responsive to the needs and values of the community. Portfolio and Scenario alternatives that were offered by Advisory Council members included:

- Pima County – use a load forecast that excludes the potential future mining load,
- Sierra Club – evaluate early retirement of coal plants,
- Western Resource Advocates (WRA) – evaluate various levels of CO_2 emission reductions,
- Southwest Energy Efficiency Project (SWEEP) and WRA – evaluate higher levels of energy efficiency.

TEP also received suggestions that were not specific to portfolios and scenarios. For example, Pima County encouraged TEP to consider siting future solar facilities on State Trust Land within the departure zone of Davis-Monthan Air Force Base.[1] While the specific location of future resources that are not currently planned is outside of the scope of the IRP, TEP acknowledges the suggestion, and will work with local jurisdictions to site new renewable facilities in ways that meet mutually beneficial goals.

The Advisory Council engagement culminated at TEP's public IRP workshop on May 20, 2020. At that workshop, which was held virtually, Advisory Council members provided statements for the public to hear and for TEP to consider as it finalized its IRP. These statements offered recommendations for TEP regarding the nature and pace of our energy transformation. While it's not feasible to capture every sentiment expressed by Advisory Council members, following are some of the key messages that TEP heard from the Advisors.

- TEP should accelerate its transition away from coal-fired generation.
- The transition away from coal should not result in an over-reliance on generation from natural gas.
- TEP needs to address a just transition for communities that are impacted by the closure of coal plants.
- TEP's utilization of natural gas to replace coal-fired generation maintains reliability while providing a platform for additional renewables.
- TEP needs to maintain affordable rates and acknowledge that many members of the community have fixed income with limited flexibility to absorb cost increases.
- As TEP transitions to new resources, it should not undervalue the role that existing resources play.
- TEP and the Arizona Corporation Commission need to drive innovations by finding ways to incentivize market-based solutions.
- TEP's preferred portfolio should account for a broad set of criteria including CO_2 emissions, groundwater use, local emissions of NOx that can contribute to ozone formation, customer bills, and siting of resources.
- TEP should set an aggressive CO_2 reduction goal with a specific date (i.e. greater than 60 percent reduction by 2030).
- TEP's plan should provide for resiliency in the face of factors that include the potential for substantially higher natural gas prices.
- Electricity rates must remain competitive with other regions to avoid driving customers away.

[1] Letter from C. H. Huckelberry, Pima County Administrator, dated August 12, 2019; https://docket.images.azcc.gov/E000002483.pdf

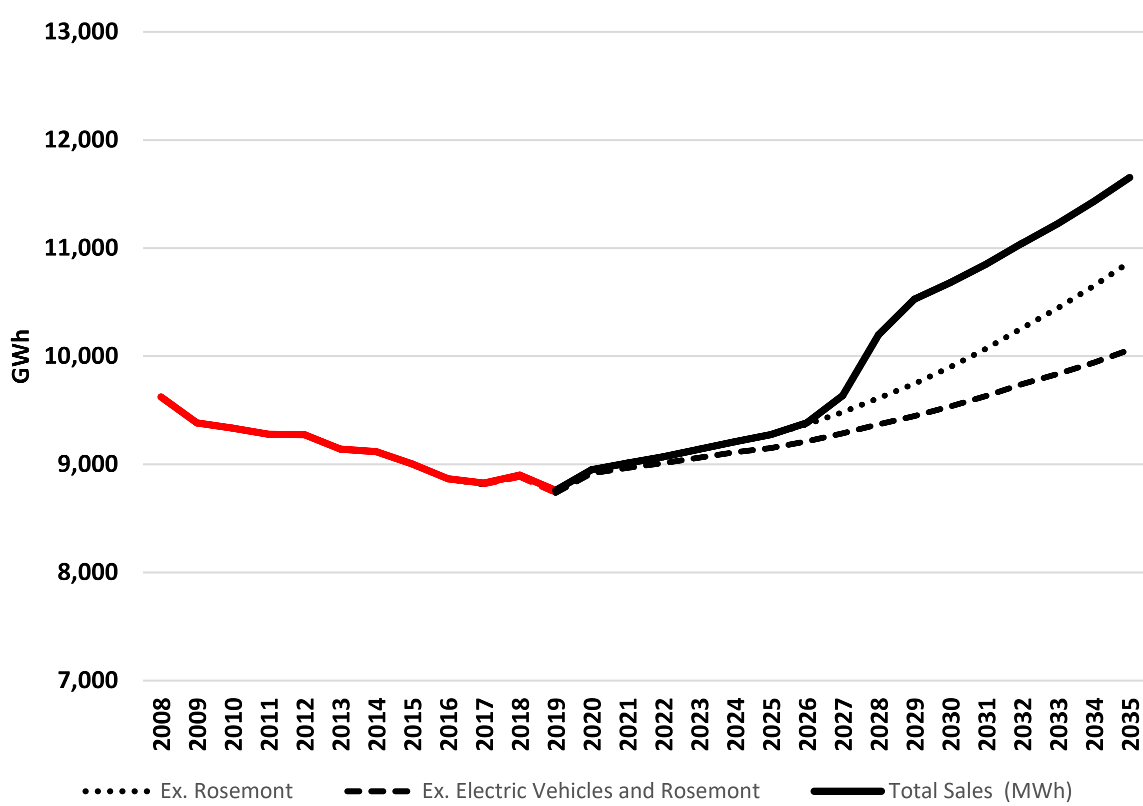
- TEP's transition to "greener" technologies should proceed at a measured pace without sacrificing reliability or resiliency.
- TEP needs to have more robust consideration of customer-sited resources.
- TEP's science-based approach to establishing carbon reduction target is appropriate and should be supported.

The presentations for all of the meetings of the Advisory Council are posted on TEP's Resource Planning page. https://www.tep.com/resource-planning/

Load Forecast and Reserve Margin Requirement

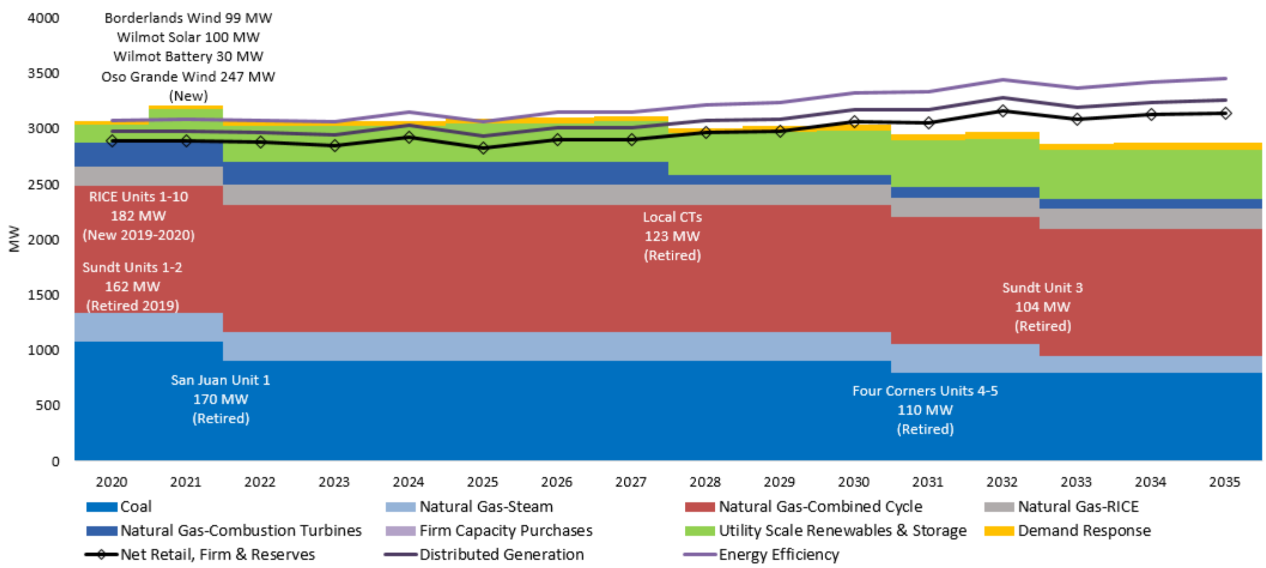
TEP's underlying sales forecast shows an expected annual growth rate of 0.8 percent in the 2020 to 2035 period. Incremental growth in electric vehicle use is expected to increase the annual growth rate to 1.3 percent and the proposed Rosemont mine project would increase the annual growth rate to 1.7 percent starting in 2028. These forecasted growth rates shown on the chart below are still lower than the historical growth rate of 2.5 percent that occurred prior to the Great Recession of 2008.

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



TEP must maintain sufficient resource capacity to meet its load obligations, which includes the retail load presented above as well as firm wholesale commitments and a 15 percent planning reserve margin. The chart below shows how the Company's firm resources compare to its firm load obligations as we entered this IRP process.

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



Resource Adequacy

In addition to meeting peak load, TEP'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 TEP brings more renewable energy onto its system. This IRP presents an in-depth approach to assessing the system's flexibility needs and flexible capacity.

Based on the results presented in this IRP, the following conclusions can be made about TEP's ability to integrate additional renewable resources:

- Achieving a renewable penetration of 30 percent is within TEP's current resource capabilities. However, additional flex capacity might be needed if the system turndown limit cannot be kept below 400 MW during the day-time hours of the non-summer months.
- Achieving a renewable penetration of 50 percent is within TEP's current resource capabilities, but with the following caveats:
  - **Peak Net Load** – Retiring any resources beyond San Juan Unit 1 could lead to a capacity shortfall and should prompt a re-examination of capacity needs and options.
  - **3-Hour Ramps** – Achieving a 50 percent penetration strictly through solar power could strain the ability of the system when major units are off line in the non-summer months.
  - **10-Minute Ramps** – Additional research is warranted given the nature of results so far, and TEP should track the impact on 10-minute ramps as more renewable resources are brought onto its system.
  - **Over Generation** – Over generation is likely to be significant at penetrations beyond 35 percent, making it more difficult or expensive to achieve a specific renewable energy goal as

opposed to a CO_2 emissions reduction goal, which can be achieved at various levels of renewable penetration.

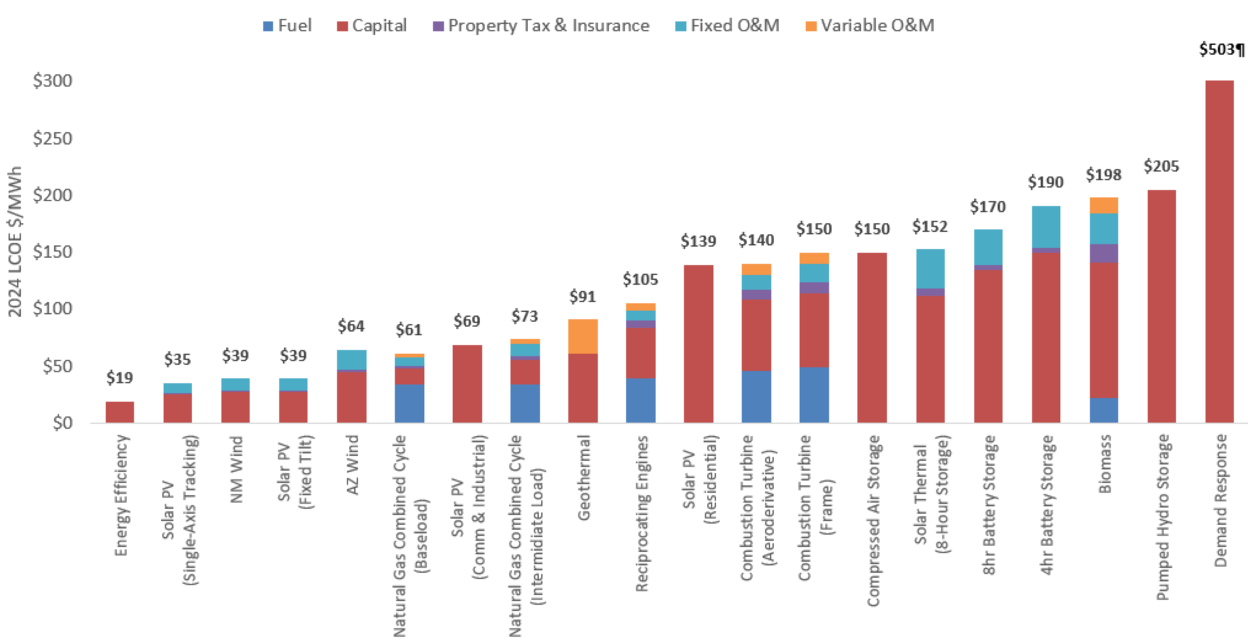
Customer-Sited Resources and Distribution Modernization

Technology improvements are resulting in greater alignment between Customer–sited Energy Resources ("CERs") and the specific needs of TEP's system. TEP is continually modernizing the distribution grid in order to operate the grid more safely, efficiently, and reliably while integrating CERs 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), Automated Metering Infrastructure (AMI), and enhanced systems that improve situational awareness for field personnel.

Future Resource Alternatives

TEP evaluated a wide range of resource as potential additions to the TEP 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 (LCOE) for various resource options.

Levelized Cost of Energy Resources



The Development of TEP's Preferred Portfolio

For the 2020 IRP, TEP undertook an extensive portfolio analysis culminating in the development of 15 independent portfolios. Certain portfolios were required by order of the Arizona Corporation Commission (ACC). Several portfolios are based on proposals relating to the ACC's development of new energy rules. The remaining portfolios were developed by TEP or at the request of Advisory Council members.

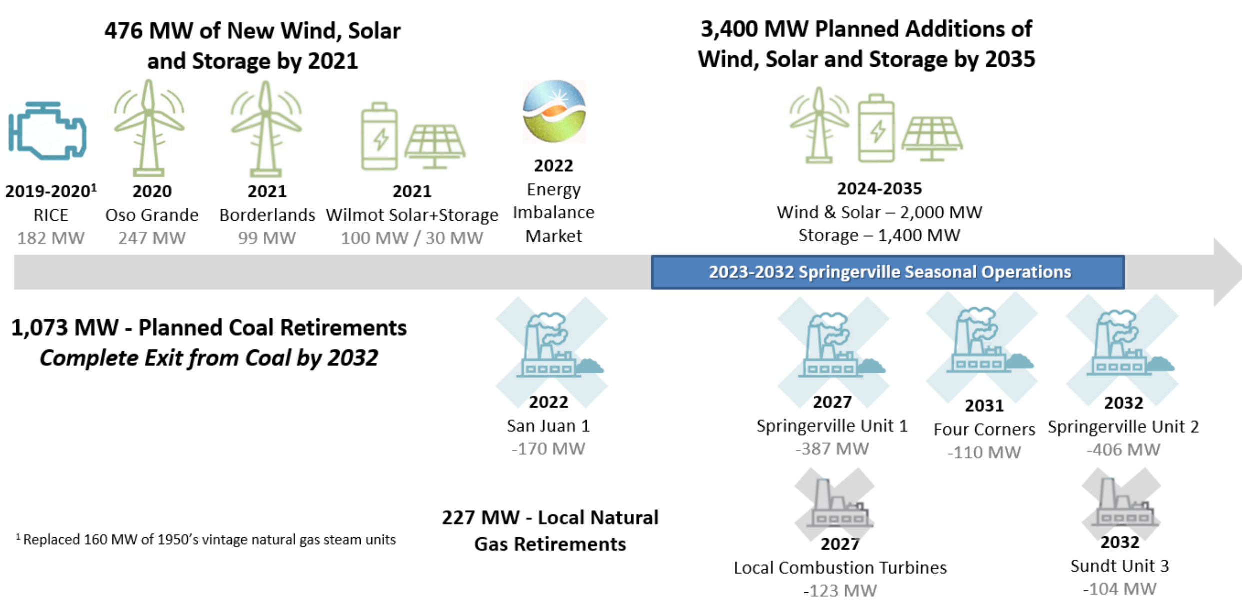
TEP's Preferred Portfolio takes the next step in TEP's pursuit of a more sustainable energy supply. Over the next 12 years TEP will end its use of coal-fired generation entirely, which represents a key milestone in the Company's energy transition. There were several factors that contributed to this decision.

- The very real possibility that TEP may be unable to find a future coal supply for Springerville Units 1 and 2 that is economical and allows the units to meet certain environmental requirements.
- The realization that the economics of coal-fired generation have shifted.
- The need to make cost-effective reductions in CO_2 emissions.

TEP's 2020 IRP Preferred Portfolio

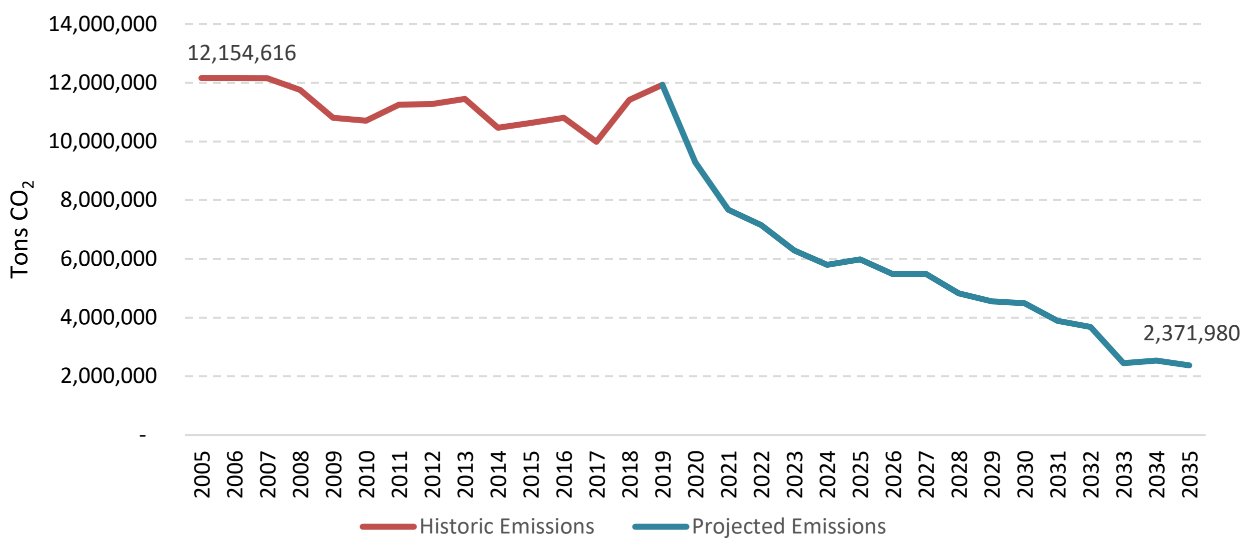
TEP's 2020 IRP Preferred Portfolio calls for 70 percent of our customer's energy coming from renewable resources. Between 2020 and 2022, TEP will bring online 476 MW of new wind, solar and energy storage resources. Beyond 2022, TEP plans to add an additional 2.0 gigawatts (GW) of new renewables and 1.4GW of new energy storage resources. Finally, TEP plans to implement cost-effective EE programs consistent with historical levels targeting 1.5 percent incremental energy savings over the prior year's retail load in each year through 2024. The figure below details the 2020 – 2035 timeline.

TEP's 2020 IRP Preferred Portfolio Timeline



TEP's Preferred Portfolio will result in significant reductions in CO_2 emissions reaching 80 percent below 2005 levels by 2035 or earlier as shown on the chart below.

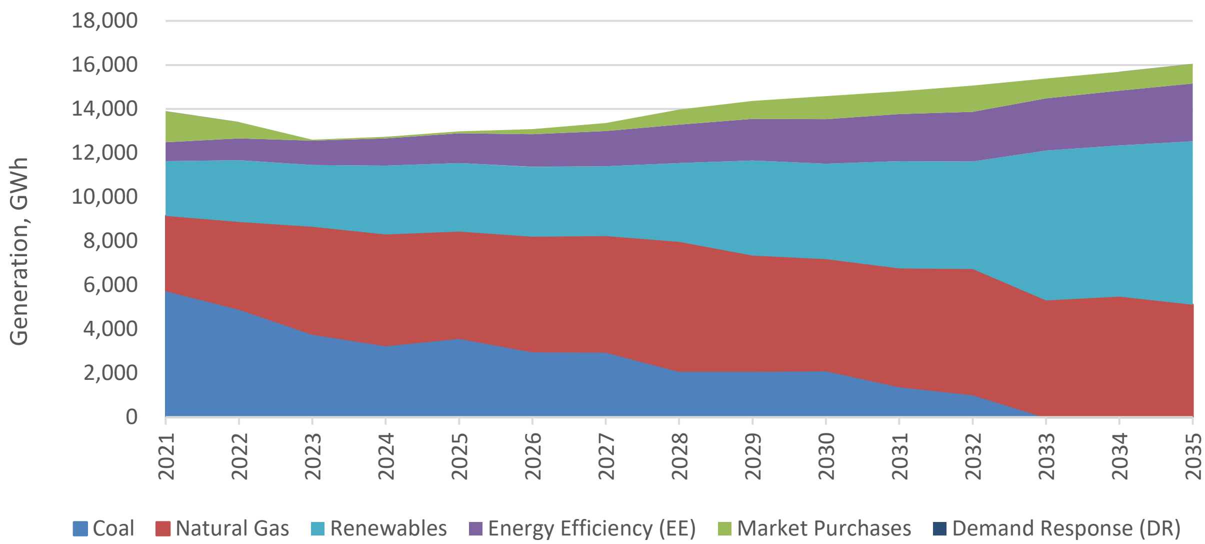
TEP's Historic and Projected Preferred Portfolio CO_2 Emissions



Furthermore, based on TEP's cumulative emissions through 2050, and according to the methodology developed by the University of Arizona Institute of the Environment, TEP's preferred portfolio is consistent with the goals of the Paris Climate Agreement to maintain global temperature rise at levels "well below 2°C".

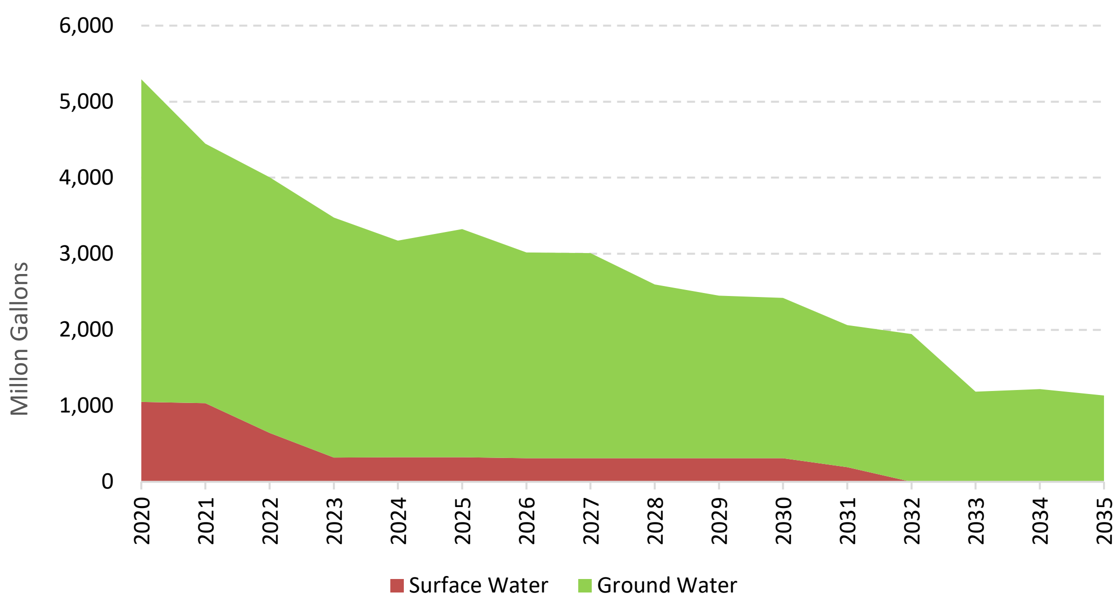
TEP's Preferred Portfolio results in a significant expansion in renewable energy. The plan calls for the addition of over 2,400 MW of new solar and wind resources through 2035. This high penetration of renewable resources is balanced by 1,400 MW of energy storage systems. In addition, TEP will continue to develop and implement of cost-effective energy efficiency programs. The chart below shows the shift in energy mix over the planning period including the elimination of coal in 2032.

TEP's Preferred Portfolio Energy Mix



The plan will also result is the elimination of surface water use for power generation as well as a 70 percent reduction in groundwater use, as shown on the following chart.

TEP's Preferred Portfolio Projected Water Consumption



Five-Year Action Plan

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

- TEP will complete the first phase of coal plant retirements when San Juan Unit 1 closes in June 2022. With that retirement, the Company will have retired 41percent of its coal capacity since 2015.

- TEP will complete the build-out of planned solar and wind projects currently under contract or construction, which will double the Company's renewable energy output. These units will include our first deployment of a utility-scale battery energy storage system capable of reducing peak demand by shifting solar energy output from off-peak to on-peak periods.

- The Company will initiate discussions with the ACC, employees, the International Brotherhood of Electrical Workers (IBEW), and leaders of the communities that will be impacted by reduced use and ultimate retirement of Springerville Generating Station Units 1 and 2. TEP will also develop flexible coal supply alternatives that will support these operational changes as well as future environmental compliance options.

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

- The Company is committed to procuring future resources through all-source Requests for Proposal (RFPs) based on specific, identified system needs.

- TEP will continue preparations for joining the California Independent System Operator (CAISO) Energy Imbalance Market (EIM) in April 2022.

CHAPTER 2

ENERGY DEMAND AND USE PATTERNS

Load Forecast

In the IRP process, it is crucial to estimate the load obligations for both the short and long-term planning horizons. As a first step in the development of the resource plan, a long-term load forecast was produced. This chapter will provide an overview of the anticipated long-term load obligations at TEP, 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.

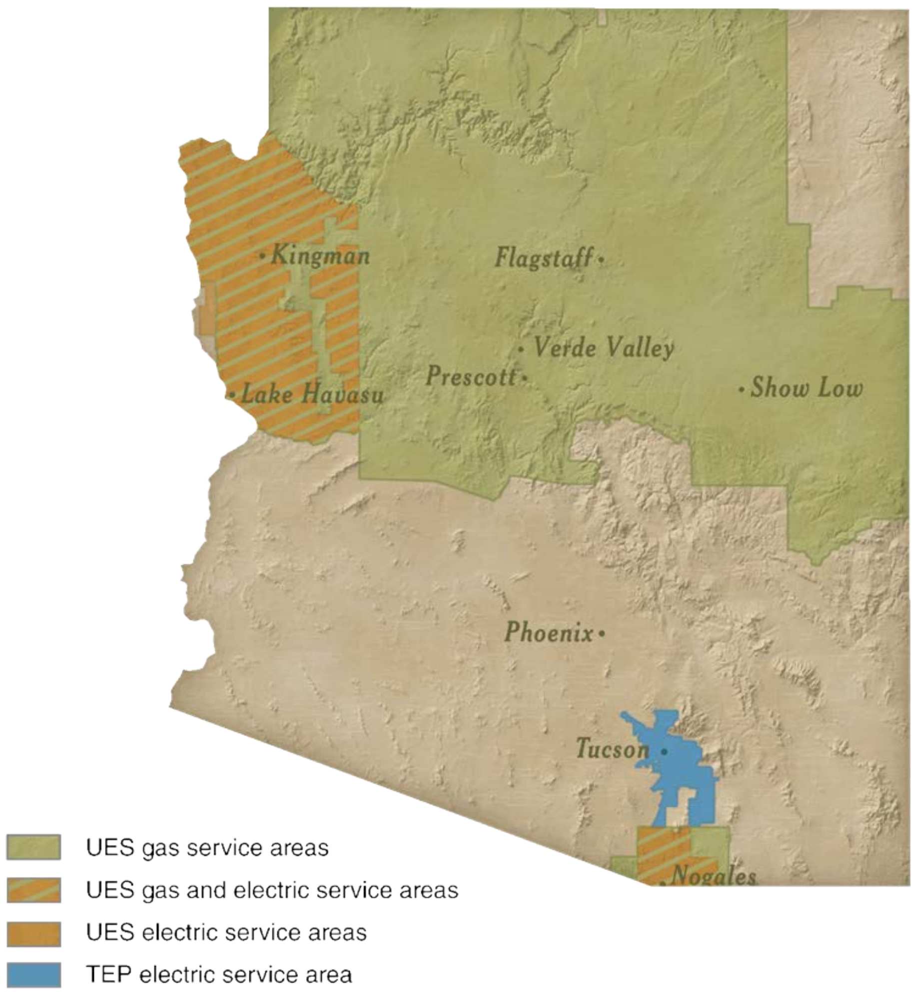
The sections in this chapter include:

- **Company Overview:** TEP geographical service territory, customer base, and energy consumption by rate class
- **Reference Case Plan Forecast:** An overview of the Reference Case forecast of energy and peak demand used in the planning process.
- **Wholesale Obligations:** An outline of the firm system requirements for wholesale electricity sales
- **Rate Design:** An overview of rate design and its role in long-term planning.

Geographical Location and Customer Base

TEP currently provides electricity to more than 425,000 customers in the Tucson metro area (Pima County). Pima County is estimated to have a population of approximately 1,030,000 people.

Map 1 - Service Area of Tucson Electric Power and UniSource Energy Services Utilities[2]

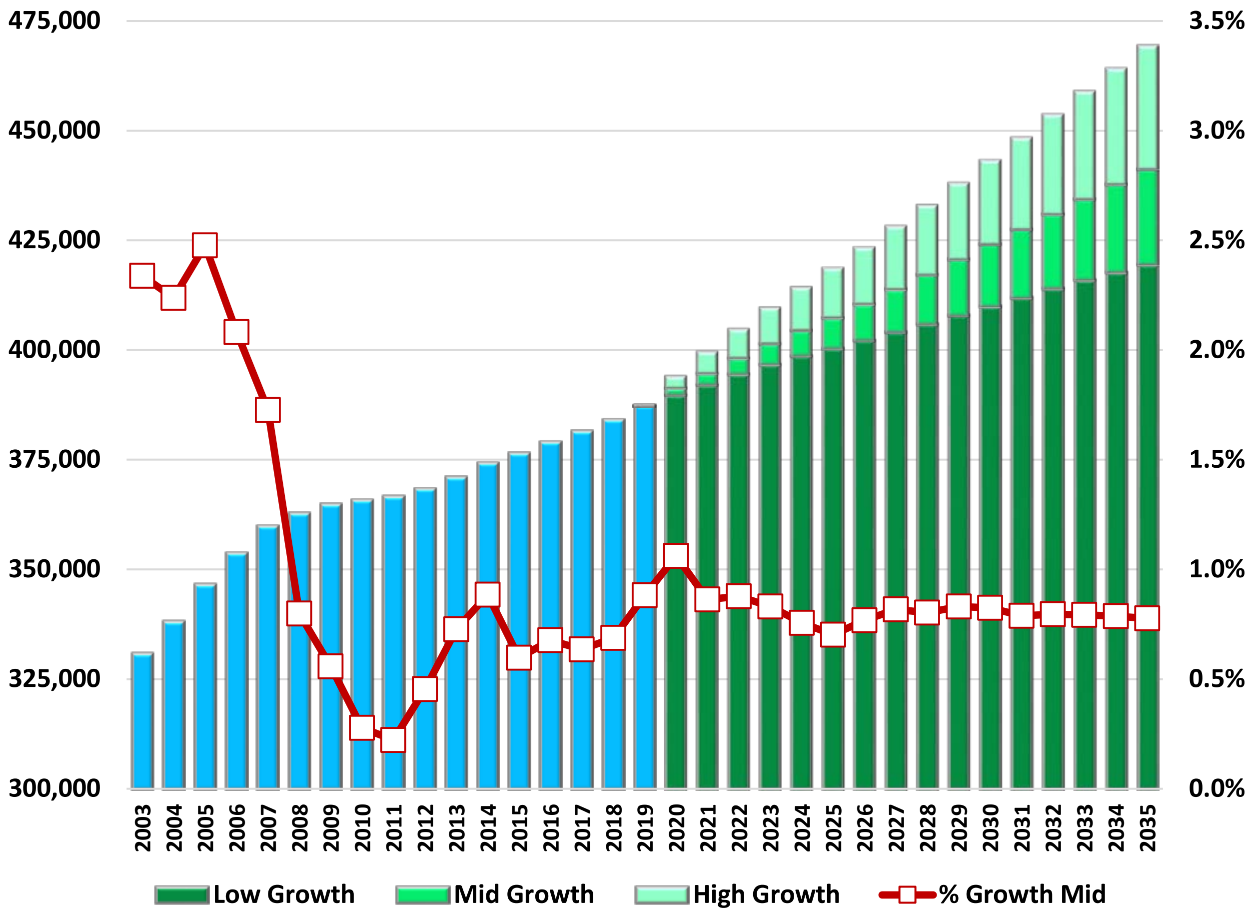


[2] UniSource Energy Services (UES) is an Arizona regulated electric and natural gas utility and is a sister company of TEP.

Customer Growth

In recent years, population growth in Pima County and customer growth at TEP have slowed dramatically compared to periods before 2008 as a result of the severe recession and subsequent economic downturn. While customer growth has rebounded somewhat from its recessionary lows, it is not expected to return to its pre-recession level. Chart 1 outlines the historical and expected customer growth in the residential rate class from 2003-2035. As customer growth is a significant factor behind growth in TEP's load, the continuing customer growth will necessitate additional resources to serve the increased load in the medium to long term.

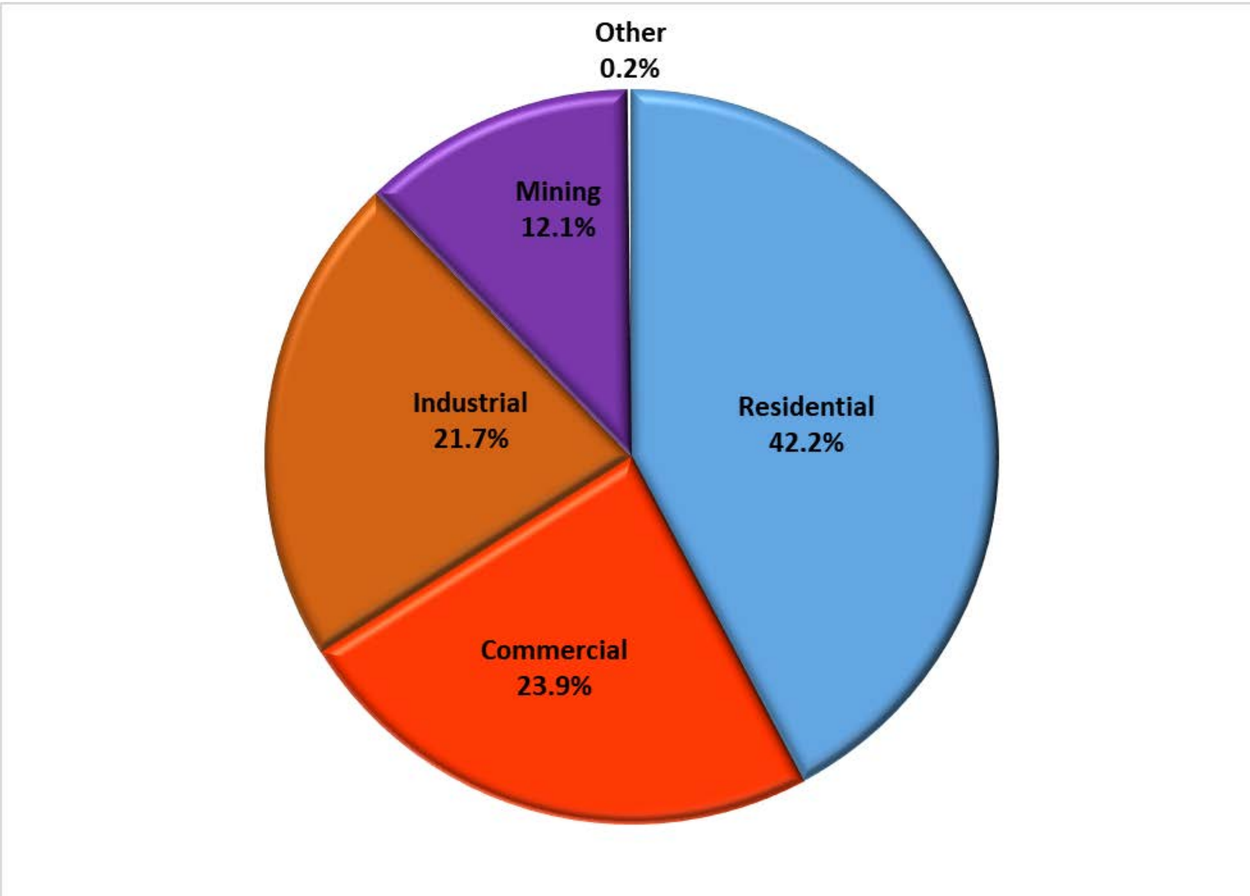
Chart 1 - Estimated TEP Residential Customer Growth 2003-2035



Retail Sales by Rate Class

In 2019, TEP experienced a peak demand of approximately 2,370 MW with approximately 8,750 gigawatt-hours (GWh) of retail sales. Approximately 66 percent of 2019 retail energy was sold to the residential and commercial rate classes, with approximately 34 percent sold to the industrial and mining rate classes. Smaller customer classes such as municipal street lighting 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 (GWh) Percent by Rate Class



Reference Case Forecast

Methodology

The load forecast used in the TEP IRP process was produced using a “bottom up” approach. A separate monthly energy forecast was prepared for each of the major rate classes (residential, commercial, industrial, and mining). As the factors impacting usage in each of the rate classes 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, commercial, and small industrial classes, forecasts were produced using statistical models. Inputs may include factors such as historical usage, weather (e.g. average temperature and dew point), demographic forecasts (e.g. population growth), and economic conditions (e.g. Real Gross Domestic Product and Real Per Capita Personal Income).

2) For the large industrial and mining classes, forecasts were 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.

After the monthly energy forecast for the company is produced, the anticipated monthly energy consumption is used as an input for another statistical model used 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, 60+ years of historical weather scenarios are simulated to generate a probabilistic peak demand forecast.

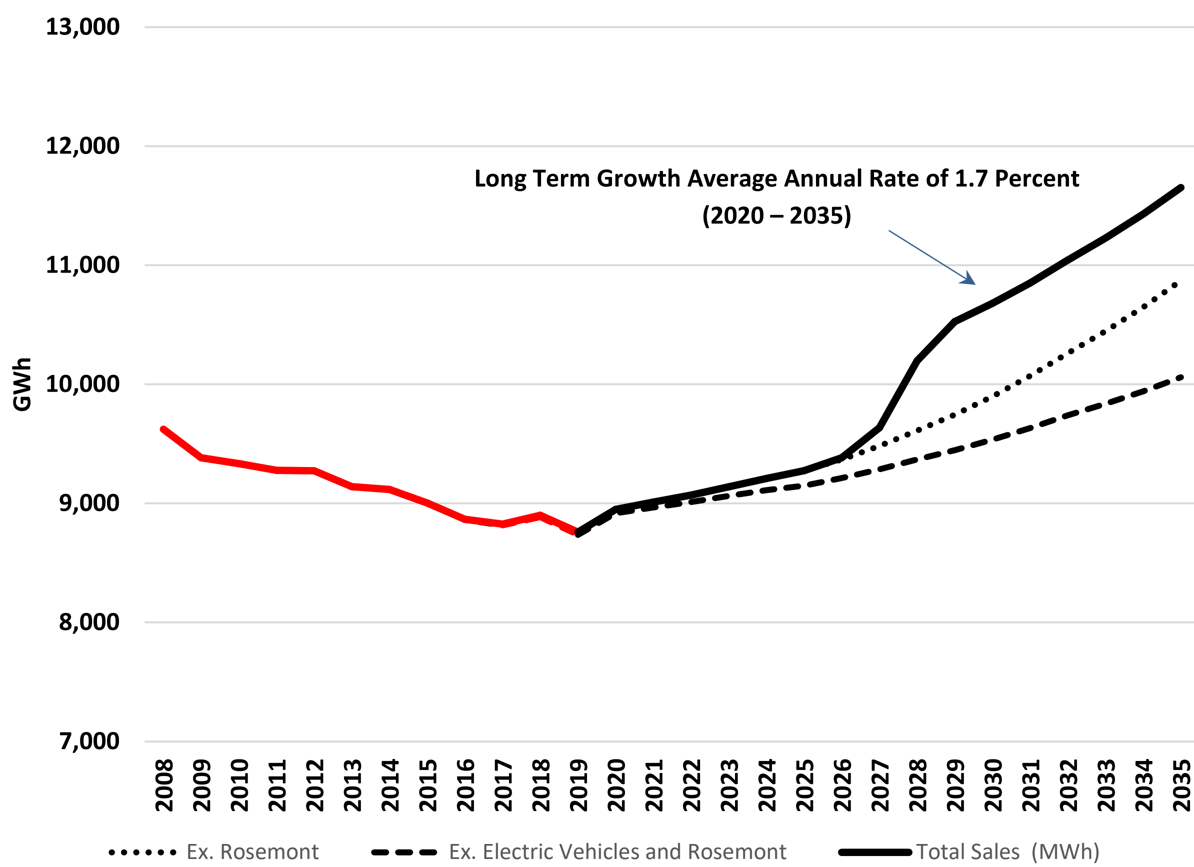
Additional assumptions were also made for forecasting customer-sited distributed generation (DG) and electric vehicle (EV) load growth as these have significant impacts on load projections. Using an econometric model, DG growth is projected to slow, a reflection of the maturation of the current DG market.

The market for EVs is still largely uncertain. To estimate the market penetration of EVs, TEP used various EV forecasts for the United States (U.S.) and made a few assumptions to more closely relate the forecasts to Pima county. The primary assumption is that Pima County is not as economically affluent as most of the country and that vehicles last longer here due to a variety of climatological reasons. Both of these factors suggest that vehicle turnover rates are slower in Pima County so the Company is using an average vehicle age of 14 years instead of the 12 year average in the U.S.

Reference Case Retail Energy Forecast

As illustrated in Chart 3, TEP's weather normalized retail energy sales fell significantly from 2008 to 2017. In 2018, increased economic activity caused weather normalized sales to increase and a rebound in commodity prices allowed mining load to increase to historical levels. In the future, the underlying sales forecast is showing an expected annual growth rate of 0.8 percent in the 2020 to 2035 period. Incremental growth in EV use is expected to increase the annual growth rate to 1.3 percent and the proposed Rosemont mine project would increase the annual growth rate to 1.7 percent. These forecasted growth rates are still below the historical growth rate of 2.5 percent that occurred prior to the Great Recession of 2008.

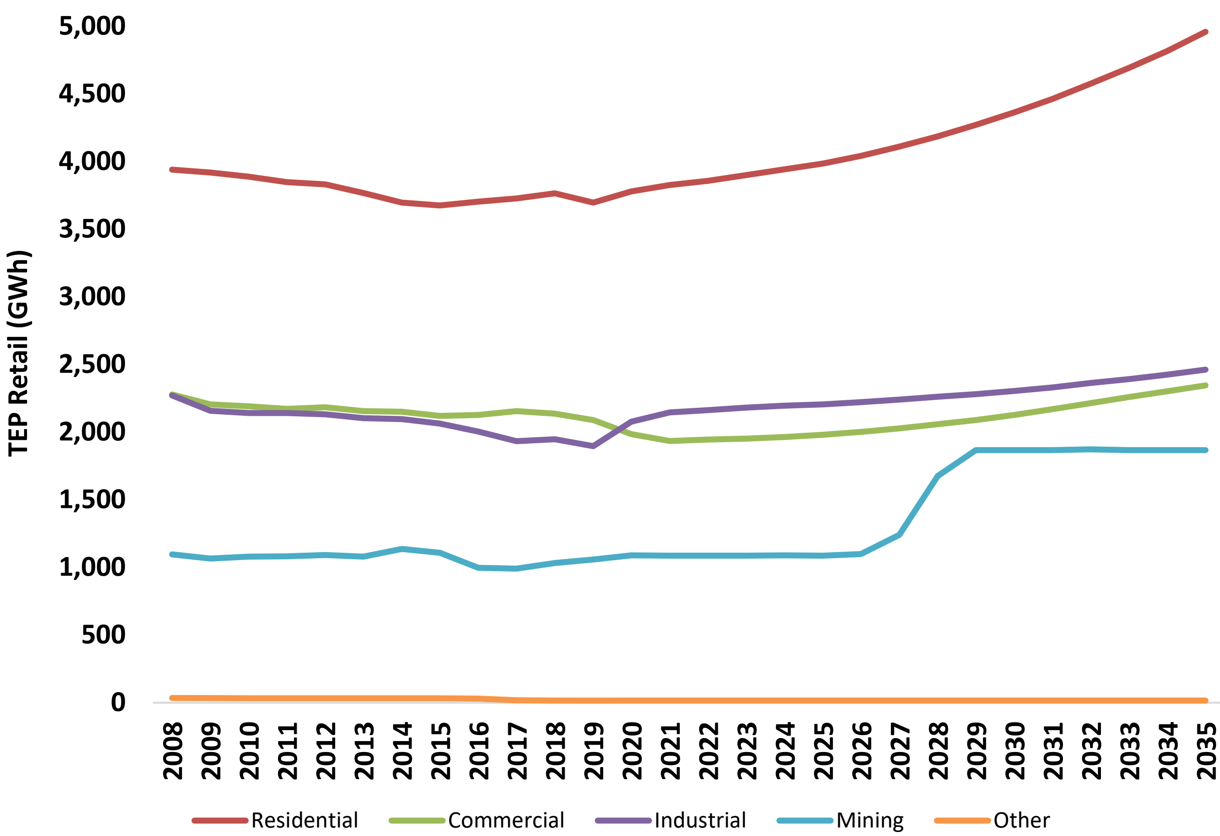
Chart 3 - Reference Case Retail Energy Sales, Weather Normalized Historical



Reference Case Retail Energy Forecast by Rate Class

As illustrated in Chart 4, the Reference Case forecast assumes flat to low growth for the next few years followed by significant short term changes in the mining sector and an increasing residential sector growth rate in the latter half of the decade. 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 Retail Energy Sales by Rate Class

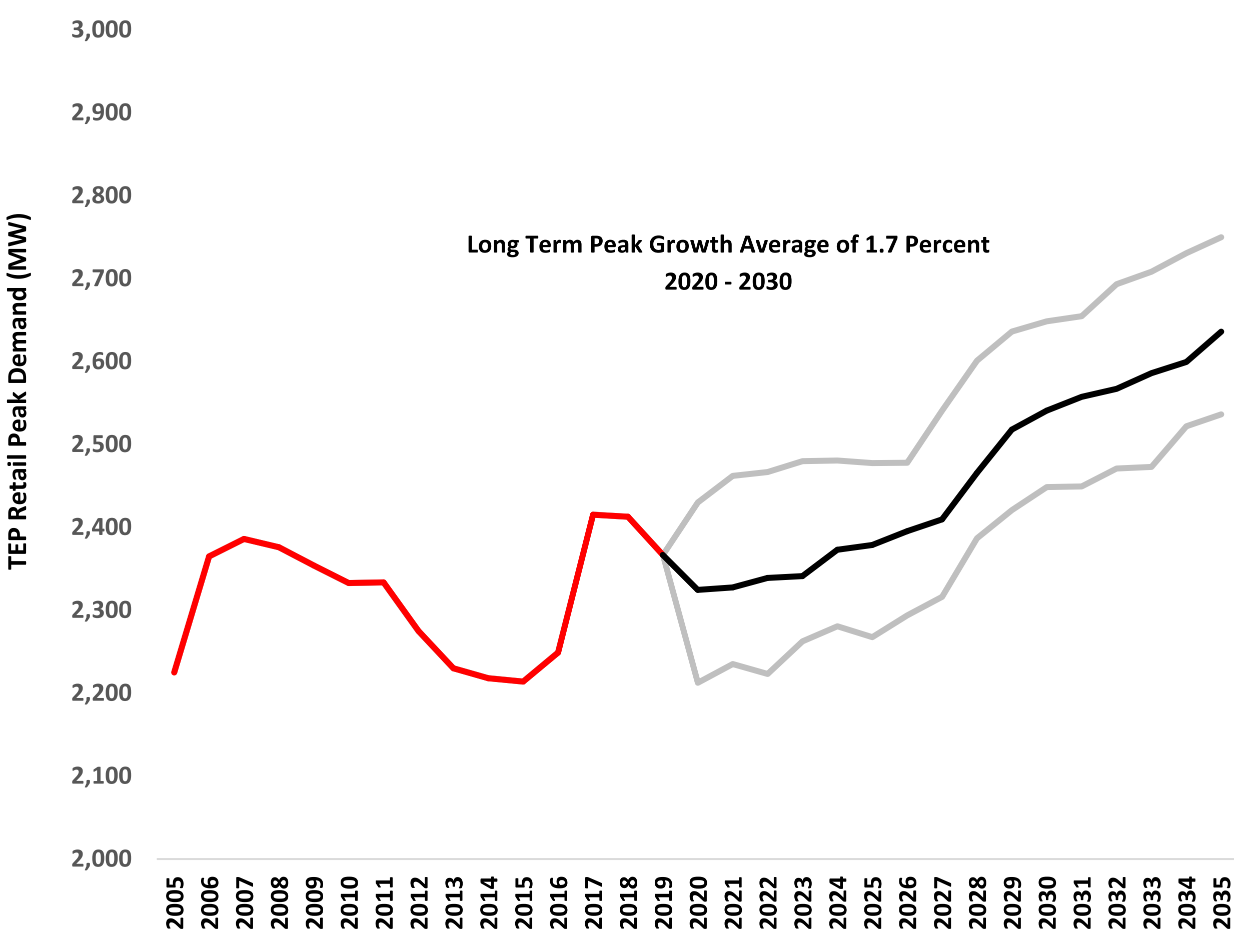


After experiencing consistent year over year growth throughout the past, both residential and commercial plus industrial (combined) energy use was flat to declining from 2008-2019. Both are assumed in the Reference Case to increase steadily after 2019. Mining sales are assumed to expand due to the Rosemont mine project in the latter half of the decade.

Reference Case Peak Demand Forecast

As shown in Chart 5 below, demand dropped in 2019 based on a return to normal weather. Following the same growth rate trends for energy sales, as the mining rate class expands and EV sales increase, the retail peak demand is expected to grow. The gray lines represent extreme weather cases and reflect a range of outcomes produced by one-in-ten-year weather anomalies.

Chart 5 - Reference Case 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.) As shown below, TEP utilizes a number of independent third-party data sources to develop its long-term forecast.

- IHS Global Insight
- 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 with regard to projected load growth. While not all inclusive, some of the key risks to the current forecast are listed below:

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

Because of the large amount of uncertainty underlying the load forecast, it is crucial to consider the implications to resource planning if TEP experiences significantly lower or higher load growth than projected. For this reason, load growth is one of the fundamental factors considered in the risk analysis process undertaken as part of this IRP. Specifically, the performance of select potential resource portfolios is analyzed with the use of Monte Carlo load simulations. A more in-depth discussion of the risk analysis process is provided in Chapter 8.

In addition to the simulation analysis, a more specific discussion of how resource decisions and timing would be affected in the case of sustained higher or lower loads is provided in Chapter 10.

Firm Wholesale Energy Forecast

TEP is currently under contract to provide firm wholesale energy and capacity to four different wholesale customers. These firm obligations are in addition to TEP's commitment to serve its retail customers. The contracts stipulate energy services to the four entities below:

- Navajo Tribal Utility Authority (NTUA) through December 2022
- TRICO Electric Cooperative ("TRICO") through December 2024
- Navopache Electric Cooperative (NEC) through December 2041
- Tohono O'odham Utility Authority (TOUA) through December 2020

TEP's expected firm wholesale obligations are shown in Table 1 below. It is important to note contract extensions have not been assumed. However, there is a possibility that any or all agreements could be extended. This would obviously require current resource plans to be revised to account for the additional energy sales and peak summer demand requirements.

Table 1 - Firm Wholesale Requirements

Firm Wholesale, GWh	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
NTUA	29	21	21				0	0	0	0
TRICO	3	2	1	2	0	0	0	0	0	0
NEC	129	129	129	129	129	129	129	129	129	129
TOUA	13	0	0	0	0	0	0	0	0	0
Total Firm Wholesale	174	152	151	131	129	129	129	129	129	129

Peak Demand, MW	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
NTUA	15	15	15	0	0	0	0	0	0	0
TRICO	85	85	85	85	85				0	0
NEC	44	44	44	44	44	44	44	44	44	44
TOUA	3	0	0	0	0	0	0	0	0	0
Total Firm Demand	147	144	144	129	129	44	44	44	44	44

Summary of Reference Case Load Forecast

Table **2** below includes the effects of distributed generation and energy efficiency.

Table 2 - TEP Reference Case Forecast Summary

Retail Sales, GWh	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Residential	3,791	3,842	3,874	3,918	3,961	4,005	4,062	4,131	4,222	4,308	4,401	4,501	4,611	4,729	4,855	4,995
Commercial	1,991	1,941	1,954	1,961	1,972	1,990	2,013	2,039	2,076	2,108	2,147	2,189	2,233	2,276	2,320	2,363
Industrial	2,083	2,152	2,171	2,191	2,205	2,215	2,234	2,251	2,281	2,301	2,325	2,350	2,381	2,410	2,445	2,479
Mining	1,089	1,086	1,087	1,086	1,089	1,087	1,100	1,240	1,675	1,868	1,868	1,868	1,873	1,868	1,868	1,868
Other	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Total Retail	**8,970**	**9,037**	**9,102**	**9,172**	**9,243**	**9,313**	**9,425**	**9,677**	**10,270**	**10,601**	**10,757**	**10,924**	**11,114**	**11,299**	**11,504**	**11,721**

Residential Sales Growth %	2.5%	1.3%	0.8%	1.1%	1.1%	1.1%	1.4%	1.7%	2.2%	2.0%	2.2%	2.3%	2.4%	2.6%	2.7%	2.9%
Commercial Sales Growth %	-4.7%	-2.5%	0.7%	0.4%	0.6%	0.9%	1.2%	1.3%	1.8%	1.5%	1.9%	2.0%	2.0%	1.9%	1.9%	1.9%
Industrial Sales Growth %	9.8%	3.3%	0.9%	0.9%	0.6%	0.5%	0.9%	0.8%	1.3%	0.9%	1.0%	1.1%	1.3%	1.2%	1.5%	1.4%
Mining Sales Growth %	2.8%	-0.3%	0.1%	-0.1%	0.3%	-0.2%	1.2%	12.7%	35.1%	11.5%	0.0%	0.0%	0.3%	-0.3%	0.0%	0.0%
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 %	2.4%	0.7%	0.7%	0.8%	0.8%	0.8%	1.2%	2.7%	6.1%	3.2%	1.5%	1.6%	1.7%	1.7%	1.8%	1.9%
Customer Count, 000	433	437	440	444	447	450	454	457	461	464	468	472	475	479	483	486

Firm Wholesale, GWh	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
NTUA	48	29	29	0	0	0	0	0	0	0	0	0	0	0	0	0
TRICO	7	0	1	1	2	0	0	0	0	0	0	0	0	0	0	0
NEC	129	129	129	129	129	129	129	129	129	129	129	129	129	129	129	129
TOUA	27	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Wholesale	**211**	**158**	**159**	**130**	**131**	**129**	**129**	**129**	**129**	**129**	**129**	**129**	**129**	**129**	**129**	**129**

Retail Peak Demand, MW	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Retail Demand	2,369	2,368	2,357	2,345	2,416	2,415	2,483	2,479	2,532	2,545	2,616	2,612	2,705	2,636	2,672	2,690
Retail Demand Growth %	0.1%	0.0%	-0.5%	-0.5%	3.0%	0.0%	2.8%	-0.1%	2.1%	0.5%	2.8%	-0.2%	3.6%	-2.6%	1.4%	0.7%

Firm Wholesale Peak Demand, MW	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
NTUA	15	15	15	0	0	0	0	0	0	0	0	0	0	0	0	0
TRICO	85	85	85	85	85	0	0	0	0	0	0	0	0	0	0	0
NEC	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44
TOUA	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Demand	147	144	144	129	129	44	44	44	44	44	44	44	44	44	44	44

Total Retail & Firm Wholesale	2,516	2,512	2,501	2,475	2,545	2,459	2,527	2,523	2,576	2,589	2,660	2,656	2,749	2,680	2,716	2,734

Rate Design Influence on the Long-Term Load Forecast

TEP supports an evolution in rate design to offer customers more options and choices. Customers may want to have access to real-time pricing 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 TEP'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 the 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 can provide 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.

TEP Rate Design

Currently, TEP offers optional TOU rates to all retail customer classes except Large Power Service (LPS), which includes only a TOU rate option. Residential and Small General Service customers have historically taken service on two-part rates, while Large General Service (LGS) and LPS customer classes take service under three-part demand rate structures. TEP also has a Medium General Service (MGS) customer class. Most customers in this class are currently on a three-part demand rate and the remainder will move to that same three-part demand rate following a transition period. Finally, TEP expanded its rate plans for Residential and Small General Service customers to include three-part demand rate options. These demand rate options have either flat or TOU variants for energy charges. All Residential and Small General Service demand rate options define billing demand as the maximum one-hour measured kW demand during on-peak periods.

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

Alternative Rate Plans and Programs

TEP 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 TEP's ability to obtain additional benefits from customer-sited and new grid technologies.

The trend of declining costs for renewable technologies has precipitated new challenges and opportunities. Both TEP 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 can 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 TEP will continue to carefully review which products make the most sense for its service territory and balance the interests of all stakeholders. TEP 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 TEP offers could expand.

Enhancing Rate Design Around the Higher Use of Solar Generation

The increased penetration of generation from solar resources on TEP's system, both DG and utility-scale, creates integration challenges for both system operations and system capacity planning. Therefore, the Company recognizes the need to adapt its rate design to helps address these challenges. The peak period for solar production occurs during midday and does not coincide with TEP'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.

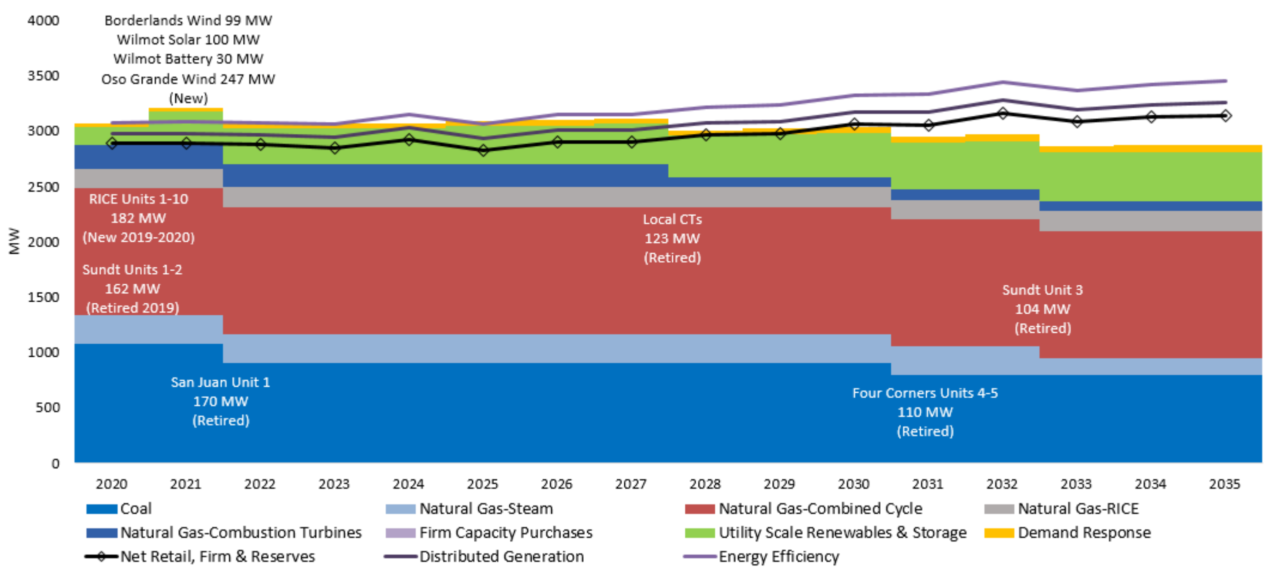
CHAPTER 3

OPERATIONAL REQUIREMENTS AND RESOURCE ADEQUACY

Load and Resource Adequacy

A critical component of the IRP planning process is the assessment of available firm resource capacity to meet firm load obligations and to maintain a planning margin above a utility's forecasted load. As part of TEP's long-term planning process, the Company targets a 15 percent planning reserve margin in order to cover for forecasting variances and any system contingencies related to unplanned outages on its generation and transmission system. Chart 6 combines data from Table 3 and Table 4 on the following pages to show how the Company's firm resources compare to its firm load obligations.

Chart 6 - TEP Loads and Resources



Firm Load Obligations

Table 3 summarizes TEP's annual gross retail peak load by year and customer class based on its December 2019 forecast. The table also includes TEP's forecast of firm wholesale load. Firm wholesale load, as well as the load reductions from distributed generation and energy efficiency, are calculated based on their expected contribution at the time of system retail peak demand. Finally, Table 3 summarizes the Company's reserve margin positions based on the existing capacity resources shown in Table 4.

Table 3 - Firm Load Obligations, System Peak Demand (MW)

Demand, MW	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Residential	1,516	1,522	1,522	1,521	1,569	1,574	1,619	1,621	1,655	1,667	1,715	1,717	1,777	1,740	1,766	1,781
Commercial	528	530	530	530	547	548	564	565	577	581	597	598	619	606	615	621
Industrial	441	443	443	443	457	458	471	472	482	485	499	500	517	506	514	518
Mining	62	62	62	62	64	64	66	66	68	68	70	70	72	71	72	73
Other	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Gross Retail Peak Demand	2,549	2,559	2,559	2,558	2,639	2,646	2,722	2,726	2,784	2,803	2,883	2,887	2,987	2,925	2,969	2,995
Distributed Generation	-87	-91	-94	-97	-100	-103	-105	-108	-109	-111	-113	-114	-116	-117	-118	-119
Energy Efficiency	-93	-100	-108	-115	-122	-128	-134	-140	-141	-147	-154	-160	-167	-173	-179	-186
Net Retail Peak Demand	2,369	2,368	2,357	2,346	2,417	2,415	2,483	2,478	2,534	2,545	2,616	2,613	2,704	2,635	2,672	2,690
Firm Wholesale	147	144	144	129	129	44	44	44	44	44	44	44	44	44	44	44
Total Forward Sales	325	175	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Planning Reserve Requirements	377	377	375	371	382	369	379	378	386	388	399	398	412	402	407	410
Total Firm Load Obligation	2,893	2,889	2,876	2,846	2,928	2,828	2,906	2,900	2,964	2,977	3,059	3,055	3,160	3,081	3,123	3,144
Reserve Margin	553	697	566	593	523	628	571	595	429	437	377	403	222	188	153	137
Reserve Margin, %	22%	28%	23%	24%	21%	26%	23%	24%	17%	17%	14%	15%	8%	7%	6%	5%

System Capacity

Table 4 summarizes TEP's firm resource capacity based on its initial planning assumptions related to its coal and natural gas resources and its 2017 goal of serving 30 percent of its retail load with renewable energy by 2030. The table also includes capacity contributions from DR programs and energy storage. All capacities are based on their expected contribution at the time of system peak demand.

Table 4 – 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
Four Corners	110	110	110	110	110	110	110	110	110	110	110	110				
San Juan	170	170														
Springerville	793	793	793	793	793	793	793	793	793	793	793	793	793	793	793	793
Coal Resources	1,073	1,073	903	903	903	903	903	903	903	903	903	903	793	793	793	793
Sundt 3-4	260	260	260	260	260	260	260	260	260	260	260	260	260	156	156	156
Luna Energy Facility	184	184	184	184	184	184	184	184	184	184	184	184	184	184	184	184
Gila River Power Station	962	962	962	962	962	962	962	962	962	962	962	962	962	962	962	962
RICE Units	182	182	182	182	182	182	182	182	182	182	182	182	182	182	182	182
DeMoss Petrie CT	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71
North Loop CT 1-4	91	91	91	91	91	91	91	91	20	20	20	20	20	20	20	20
Sundt CT 1-2	50	50	50	50	50	50	50	50								
Natural Gas Resources	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,679	1,679	1,679	1,679	1,679	1,575	1,575	1,575
Utility Scale Renewables	147	262	288	287	286	302	311	328	337	354	363	383	401	400	399	399
Demand Response	34	36	38	40	42	44	46	48	50	52	54	57	59	61	64	66
Renewable & EE Resources	181	298	326	327	328	346	357	376	387	406	417	440	460	461	463	465
Future Storage Resources	15	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38
Total Firm Resources	3,069	3,209	3,067	3,068	3,069	3,087	3,098	3,117	3,007	3,026	3,037	3,060	2,970	2,867	2,869	2,871

Balancing Authority Operations and Standards

To describe TEP's utility operation with respect to the electric grid requires a review of electric grid fundamentals. There are several interconnections on the North American continent – the Eastern, Electric Reliability Council Of Texas, Quebec, and the Western. These are each part of the North American Electric Reliability Corporation ("NERC"), see Figure 1 below. In addition, Centro Nacional de Control de Energia operates the national grid of Mexico. Within the Western Interconnection, there are 38 balancing authorities (BA), Figure 2 on the next page. Each BA is responsible for balancing its loads and resources so that the interconnection's alternating current frequency remains at or near 60 hertz (Hz), or 60 cycles per second. This resource balance is important for the safe and reliable operation of generation resources and end-use equipment. Simply put, a BA is the collection of loads and resources within a metered boundary, connected to other BAs through transmission ties for the purpose of maintaining frequency. Figure 3 details TEP's BA boundaries and has 47 ties to six adjacent BAs.

Figure 1 - NERC Interconnections

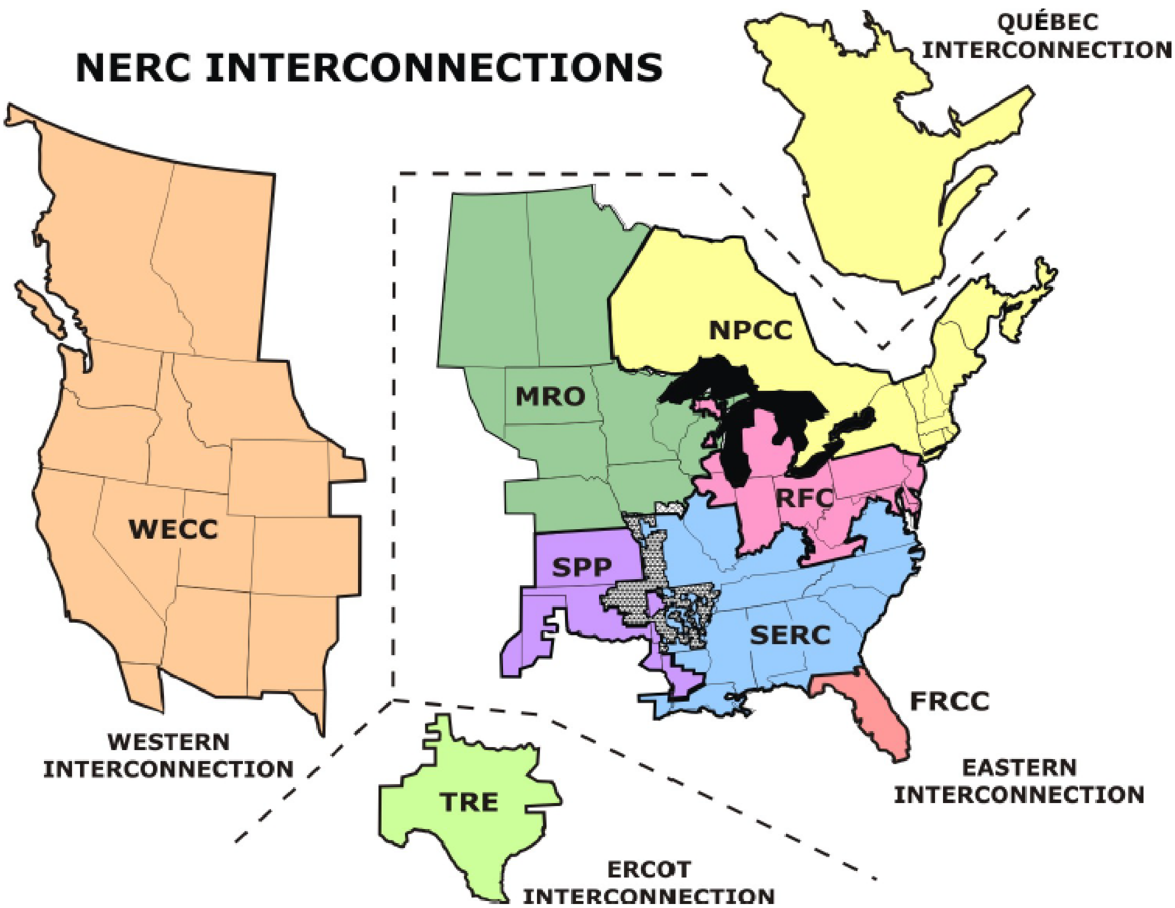
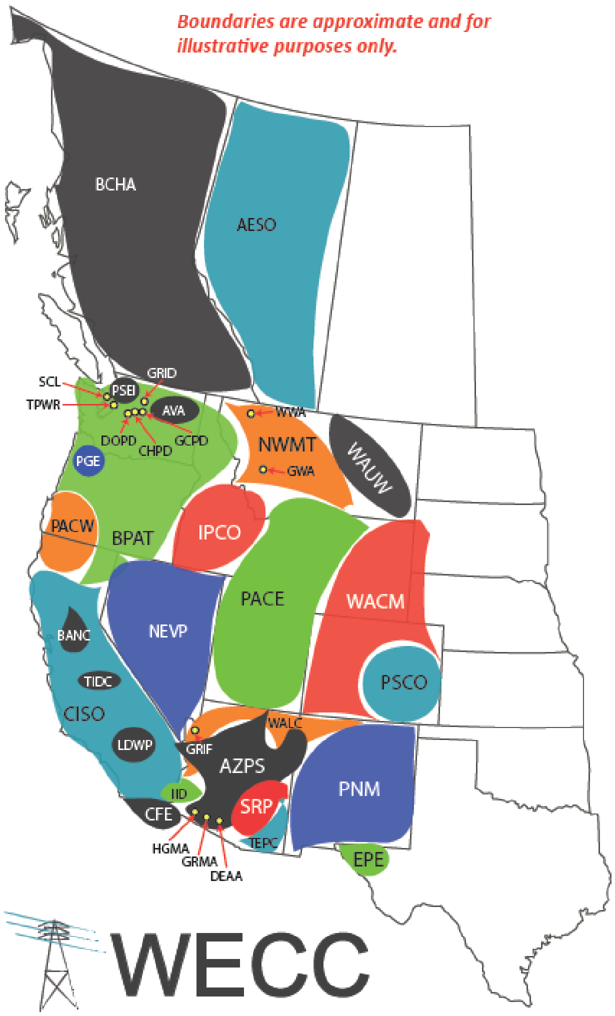


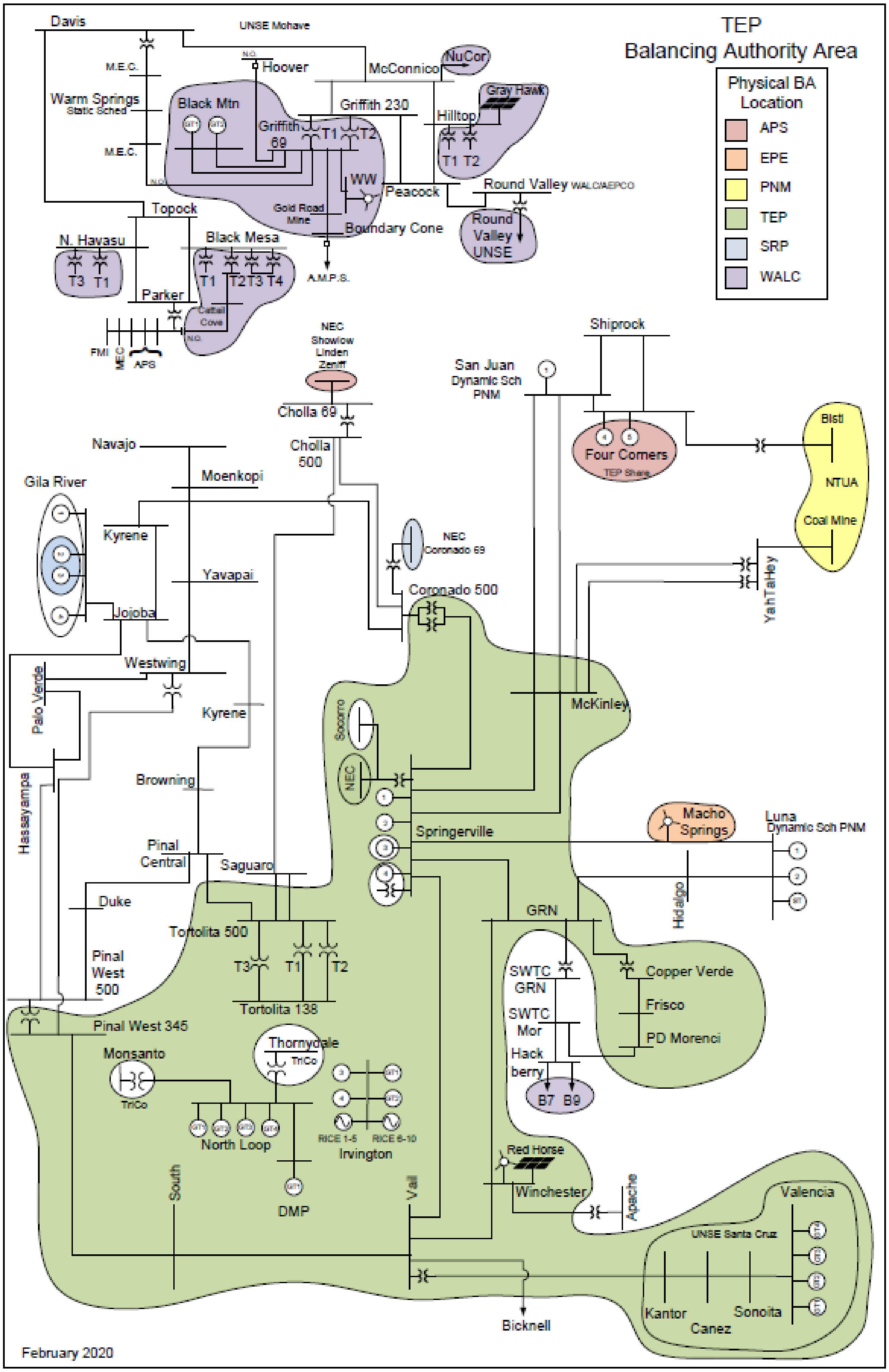
Figure 2 - Western Interconnection Balancing Authorities



Western Interconnection Balancing Authorities

AESO - Alberta Electric System Operator
AVA - Avista Corporation
AZPS - Arizona Public Service Company
BANC - Balancing Authority of Northern California
BCHA - British Columbia Hydro Authority
BPAT - Bonneville Power Administration - Transmission
CFE - Comision Federal de Electricidad
CHPD - PUD No. 1 of Chelan County
CISO - California Independent System Operator
DEAA - Arlington Valley, LLC
DOPD - PUD No. 1 of Douglas County
EPE - El Paso Electric Company
GCPD - PUD No. 2 of Grant County
GRID - Gridforce
GRIF - Griffith Energy, LLC
GRMA - Sun Devil Power Holdings, LLC
GWA - NaturEner Power Watch, LLC
HGMA - New Harquahala Generating Company, LLC
IID - Imperial Irrigation District
IPCO - Idaho Power Company
LDWP - Los Angeles Department of Water and Power
NEVP - Nevada Power Company
NWMT - NorthWestern Energy
PACE - PacifiCorp East
PACW - PacifiCorp West
PGE - Portland General Electric Company
PNM - Public Service Company of New Mexico
PSCO - Public Service Company of Colorado
PSEI - Puget Sound Energy
SCL - Seattle City Light
SRP - Salt River Project
TEPC - Tucson Electric Power Company
TIDC - Turlock Irrigation District
TPWR - City of Tacoma, Department of Public Utilities
WACM - Western Area Power Administration, Colorado-Missouri Region
WALC - Western Area Power Administration, Lower Colorado Region
WAUW - Western Area Power Administration, Upper Great Plains West
WWA - NaturEner Wind Watch, LLC

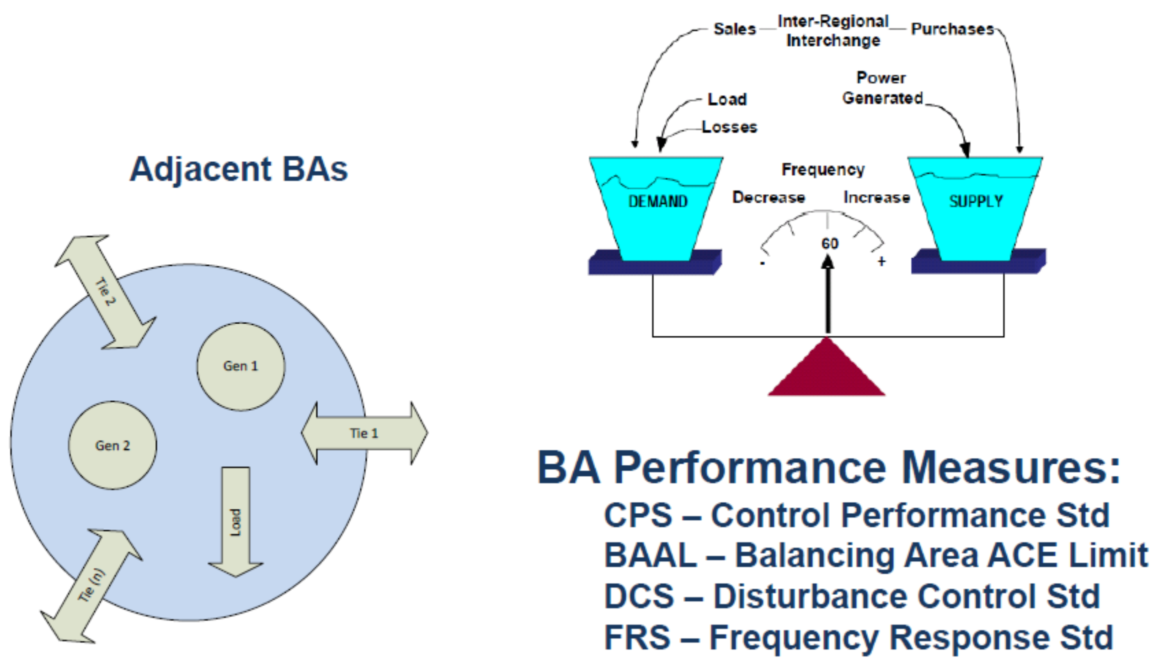
Figure 3 - TEP's Balancing Authority Area



The primary quantity established by NERC for determining a BA's reliability performance is Area Control Error (ACE). ACE is the instantaneous measure of a BA's ability to manage its load obligations and support the interconnection frequency, see Figure 4 below. The following measures of ACE over time are the standards that each BA is expected to meet:

- **Control Performance Standard (CPS)**
  CPS is a measure of a BA's ACE over time with respect to frequency. The BA helps frequency by over generating when frequency is low, and under generating when frequency is high. This is known as having ACE on the opposite side of frequency.
- **Balancing Authority ACE Limit (BAAL)**
  BAAL is a measure of how long a BA remains with an ACE that is hindering frequency. It is understood that no BA can always support frequency, but it is expected that a BA experiencing difficulties does not lean on the interconnection longer than it takes to resolve the issue.
- **Disturbance Control Standard (DCS)**
  DCS is a measure of a BA's ability to replace its generating resources following the unplanned loss of a resource.
- **Frequency Response Measure (FRM)**
  FRM is a measure of a BA's ability to provide frequency response during a disturbance. Frequency response typically comes from governor response on generators with capacity to increase output, inductive loads, and, more recently, inverters connected to batteries or renewable resources with capacity to respond.

Figure 4 - Balancing Area Function



Operating Reserves

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

Operating Reserves Versus Planning Reserves

Operating reserves should not be confused with planning reserves. Planing reserves are used by resource planners to ensure that adequate capacity will be available to meet peak demand each year over a long-term planning horizon. TEP targets a planning reserve margin (PRM) of 15 percent above forecasted annual peak loads. This margin provides the extra resources necessary to account for peak loads that are higher than forecasted and for unplanned outages of generation and transmission resources.

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

Frequency Regulation

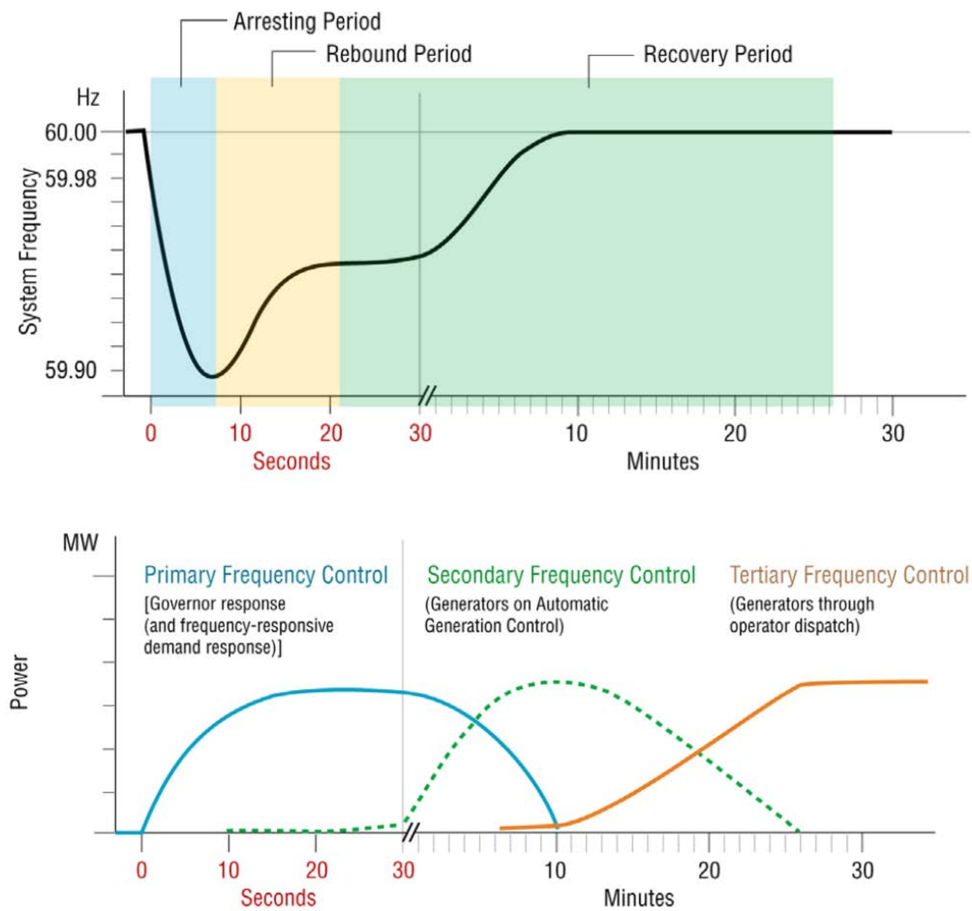
Frequency regulation refers to a BA's actions to regulate power over a five to ten-minute timeframe to follow the load in its BA area. If each BA does not continuously balance its supply and demand, then the frequency of the entire Western Interconnect will be affected. To ensure this does not happen,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

Utilities rely on a mix of generation resources tied into their Energy Management Systems (EMS) that provides Automatic Generation Control (AGC) to manage their load following requirements. However, as more intermittent and variable renewable energy is brought onto the grid, responding to changes in energy supply becomes more challenging than responding to changes in demand. Moving cloud cover and variations in wind speed can, within minutes, cause large swings in renewable power, creating a need for fast-ramping resources that can, with proper AGC, ramp up and down quickly in order to maintain performance measures and regulate frequency.

Frequency Response

Frequency response is an ancillary service requirement, as opposed to an energy or capacity service, that is similar to regulation except that frequency response automatically reacts to a system disturbance in seconds rather than minutes. Frequency disturbances occur when there is a sudden loss of a generating unit or a transmission line, disrupting the load and resource balance. As a result, other generating resources that are online must respond to counteract this sudden imbalance between load and generation and to maintain the system frequency and stability of the grid. The first response, within the initial seconds, is called primary frequency control and is provided by system inertia, the governor action on turbine-based generating units, and inverter-based systems such as storage and renewable energy resources operating below their full capabilities. Primary frequency control is provided automatically and helps arrest and recover from a drop in frequency, as shown in the arresting and rebound periods in the upper portion of Figure 5. This is followed over a longer duration by secondary frequency controls. These responses are initiated by AGC and span a half a minute to several minutes, as shown by the dotted line in the lower portion of Figure 5.

Figure 5 – Sequential Actions of Frequency Controls



System inertia provides the initial response in primary frequency control and influences the amount and timing of subsequent control needed to restore frequency. Inertia is provided by the rotating mass of generators, their prime movers, motors and their load, which together oppose changes in frequency. The magnitude of inertia in the system is changing as the industry moves from large centralized steam plants to a more distributed network of gas turbines and renewable systems. As the inertia declines, the rate of change of frequency increases. The contribution to inertia from TEP's renewable resources and their inverters is yet to be quantified and is sometimes referred to as synthetic inertia.

Voltage Support

Another reliability requirement for electric grid operations is to maintain grid voltage within specified limits. To manage reactance at the grid level, system operators need voltage support resources to offset reactive effects so that the transmission and distribution networks can be operated in a stable manner. Normally, designated power plants are used to generate reactive power ("volt-ampere reactive", or VAR) to offset reactance in the grid. As these power plants are displaced, new VAR resources will need to be placed strategically within the grid.

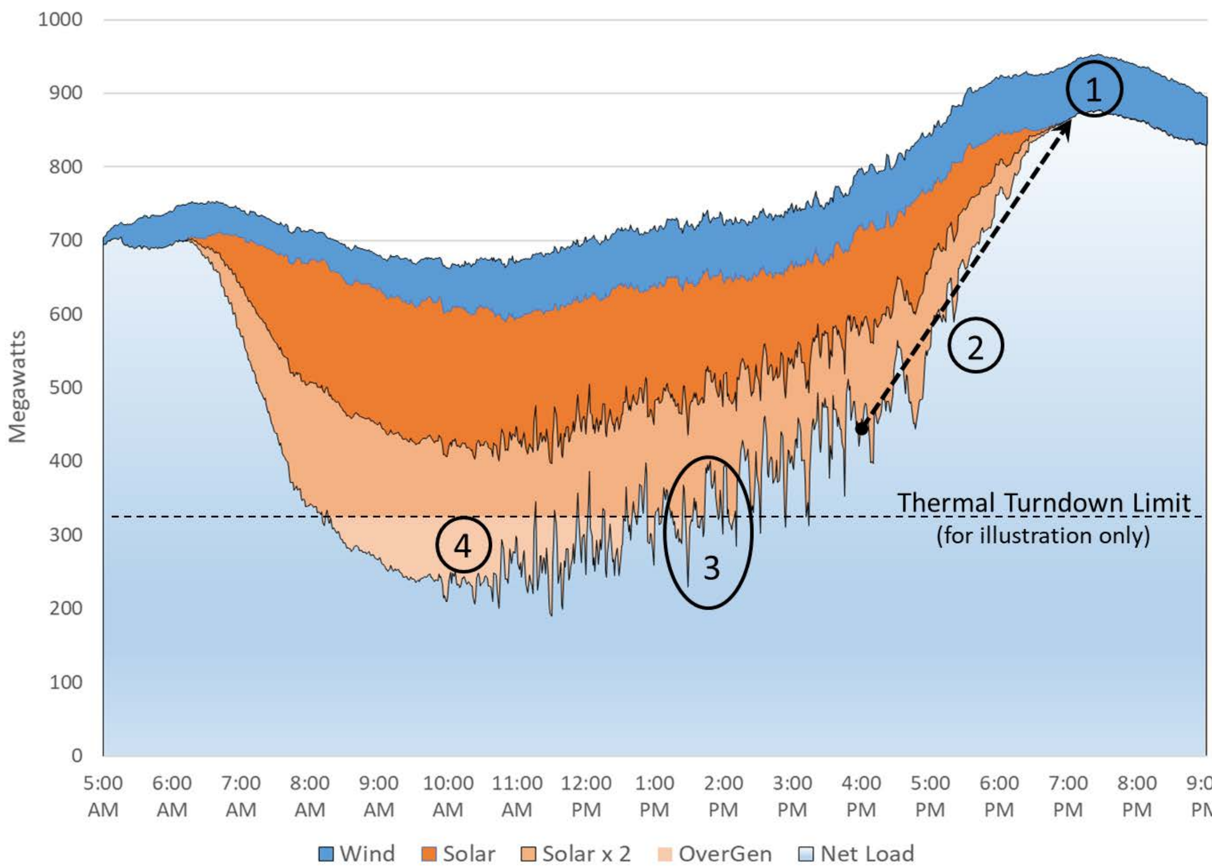
Resource Adequacy and Renewable Resource Integration

As part of the work done in this IRP, TEP plans to target a CO_2 reduction goal of 80 percent by 2035. This aggressive target will escalate the challenges of integrating renewable energy onto TEP's system. There are many such challenges – including 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 following section focuses on resource adequacy and system-level operational issues that must be taken into account in long-term resource planning activities. Since these operational issues are very much affected by the weather, this section also includes a summary of how TEP conducts weather and renewable power forecasting.

Operational Challenges

Chart 7 shows the actual retail load and renewable energy production on TEP's system on April 13, 2020 and illustrates the four system-level resource adequacy metrics considered in this IRP. An important concept in understanding these metrics is "net load," which is the load incumbent upon dispatchable resources to serve after accounting for the contribution of renewable energy resources, which can be highly variable over the course of minutes or hours.

Chart 7 – TEP Retail Net Load, April 13, 2020



The top line shows retail demand, which follows a relatively smooth diurnal pattern. The dark blue area shows the contribution of wind power to meeting demand. While wind power is often highly variable, it provides a relatively steady power supply on this particular day. The dark orange area shows the contribution of solar power, which significantly reduces net load over the course of the morning and increases it in the afternoon. The solar power also introduces short-term variability in net load, on the order of a few minutes. However, under a future scenario where TEP's solar resource capacity increases by another 200 MW, the light orange area shows the increased need for both short-term and multi-hour ramping resources. Finally, the peach-colored area beneath the dashed line represents the over generation that would occur on this day if the solar resource capacity increased by 200 MW and TEP could not sell the excess generation into the wholesale market. This over generation is due to the turndown limit of thermal, dispatchable resources that must remain online for reliability purposes, including the necessity to provide power as soon as renewable resources cannot. In this chart, for illustration purposes, the thermal turndown limit is assumed to be slightly over 300 MW.

The first metric shown in Chart 7 is the peak net load. On April 13, wind power reduced TEP's retail peak load by about 80 MW, whereas solar power made no contribution to meeting peak load. In this example, TEP's resources would be adequate for meeting the first resource metric if its non-renewable resources, including energy storage and purchased power, can generate 870 MW at approximately 7:30 PM, while having some additional capacity for operating reserves.

The second resource adequacy metric is the 3-hour ramp in net load. This metric is used by the California Independent System Operator to ensure adequate flex capacity. The change in net load is downward in the morning, and upward in the afternoon, as shown by the dashed arrow in Chart 7, however, the 3-hour change is usually more significant in the afternoon. In this example, TEP's resources would be adequate for meeting the second resource adequacy metric if its non-renewable resources can decrease generation output by 450 MW between 7:30 AM and 9:30 AM while increasing generation output by 400 MW between 4:00 PM and 7:00 PM.

The third resource adequacy metric is the 10-minute ramp in net load. This time period was chosen because it is consistent with how reserves are measured and maintained within the Western grid. In Chart 7, TEP's resources would be adequate for meeting the third resource adequacy metric if its non-renewable resources can ramp up and down by 170 MW in 10 minutes.

The fourth resource adequacy metric is the amount of over generation. Over generation per se is not a reliability issue because it can be curtailed if necessary, but it is an indicator of system inflexibility and lost opportunities to reduce cost because any renewable energy not used must be supplied by resources with fuel and operating costs, unless energy storage resources are procured to store the over generation for use later in the day. In addition, any renewable energy that is curtailed cannot be used to comply with renewable energy standards, meaning that energy storage must be utilized or that additional renewable capacity must be procured to generate the requisite renewable energy at other times of the day.

TEP's ability to meet these metrics under various scenarios of high renewable energy penetration is evaluated later in this chapter. To the extent that any metric cannot be met with current resources, a number of potential solutions are available, including:

- Energy storage, including EVs and customer-sited batteries
- Upgrading the ramping and turndown capabilities of existing thermal generators
- Daily and seasonal cycling of coal plants
- Quick-start and fast-response generation technology
- Load shape modification through rate design
- Participation in the 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 and wind)

Weather Forecasting to Support System Operations

Weather is a large determinant of both customer demand and renewable energy generation. With good weather forecasts, TEP can reduce its operating costs by scheduling the least-cost dispatchable resources around the expected amounts of demand and renewable energy.

There are different weather forecast products available, but the main product TEP uses is a regional-specific form of a Numerical Weather Prediction (NWP) model. A NWP model is a numerical representation of the different land and atmospheric processes that affect the weather. Specifically, the NWP that TEP uses is the Arizona Weather Research & Forecast ("AZ WRF") model. This model, created by the University of Arizona, was developed in partnership with TEP and is maintained with continued support from TEP and other Southwest utilities.

The AZ WRF is unique because it is highly customized for use in the Southwest. This customization includes more detailed resolution and better representation of the terrain, allowing smaller-scale weather phenomena to be captured, like wind events, clouds, and monsoonal thunderstorms created by the surrounding mountains. The end result is a better forecasts than what would otherwise be available.

In addition to a weather forecast, using information provided by TEP regarding its utility-scale and distributed generation resources, the University of Arizona (UA) also provides TEP with a renewable power forecasts. This power forecast is an ensemble of multiple runs of the North American Model, the Global Forecast System model, and the Rapid Refresh model. The renewable power forecasts range from two to seven days and are updated up to eight times a day. TEP's Wholesale Marketing Department uses these power forecasts to make decisions regarding how much power to buy or sell in the real time and day ahead markets.

Below are two examples of these forecasts. Chart 8 is a forecast of the power output of TEP's utility-scale solar facilities. Chart 9 is a forecast of the power output of TEP's wind facilities.

Chart 8 - TEP Utility-Scale Solar Power Forecast (June 3-4, 2020)

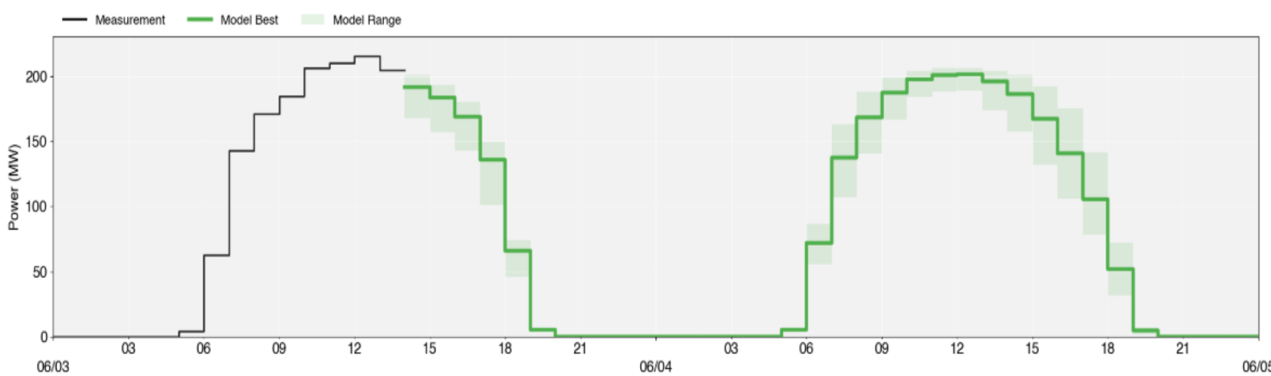
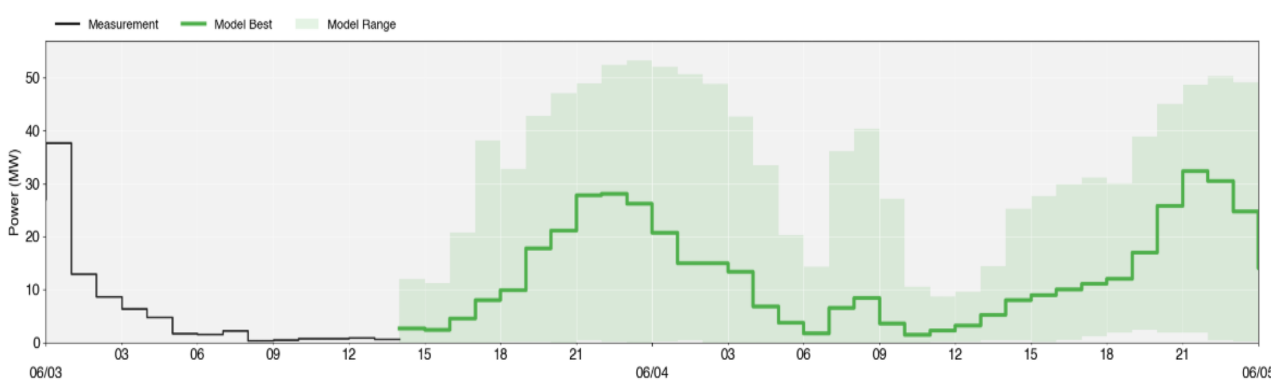


Chart 9 - TEP Wind Power Forecast (June 3-4, 2020)



The green lines represent the best estimate of the power output, and the green shaded areas represent the confidence intervals of the forecasts. The confidence intervals are reliable through three days, after which the forecasts become less reliable. Most of the uncertainty after three days comes from the uncertainty in global weather conditions.

Going forward, as the amount of renewable power on TEP's system increases, more precise weather forecasting will be needed. Weather changes affect both customer load and renewable energy generation. Thus, balancing electricity demand and supply becomes more of a moving target. For this reason, better weather forecasting is needed to better manage TEP's hourly dispatch decisions.

Resource Adequacy

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

This section also includes an assessment of system flexibility. As discussed above, in addition to having adequate capacity at the time of peak loads, the TEP 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 TEP brings more renewable energy onto its system. Thus, in this IRP, compared to prior IRPs, TEP has taken a more innovative and in-depth approach to assessing its flexibility needs and flexible capacity. This approach and its results are presented after summarizing TEP's load obligations and system capacity.

System Flexibility

To evaluate the adequacy of TEP's system flexibility, TEP hired Siemens Industry, Inc. to conduct a flexible resource adequacy study. The study was designed to answer two basic questions: Does TEP have adequate flex capacity to integrate enough renewable energy to achieve its corporate goal of serving 30 percent of its retail load with renewable energy, and if so, how much more renewable energy can be integrated before additional flexibility resources are needed?

To answer these questions, the study evaluated six scenarios ("Cases") of renewable energy penetration ranging from 28 to 50 percent, as described further below. 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 TEP's 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 TEP would likely begin adding additional renewable resources to achieve its carbon reduction goal.

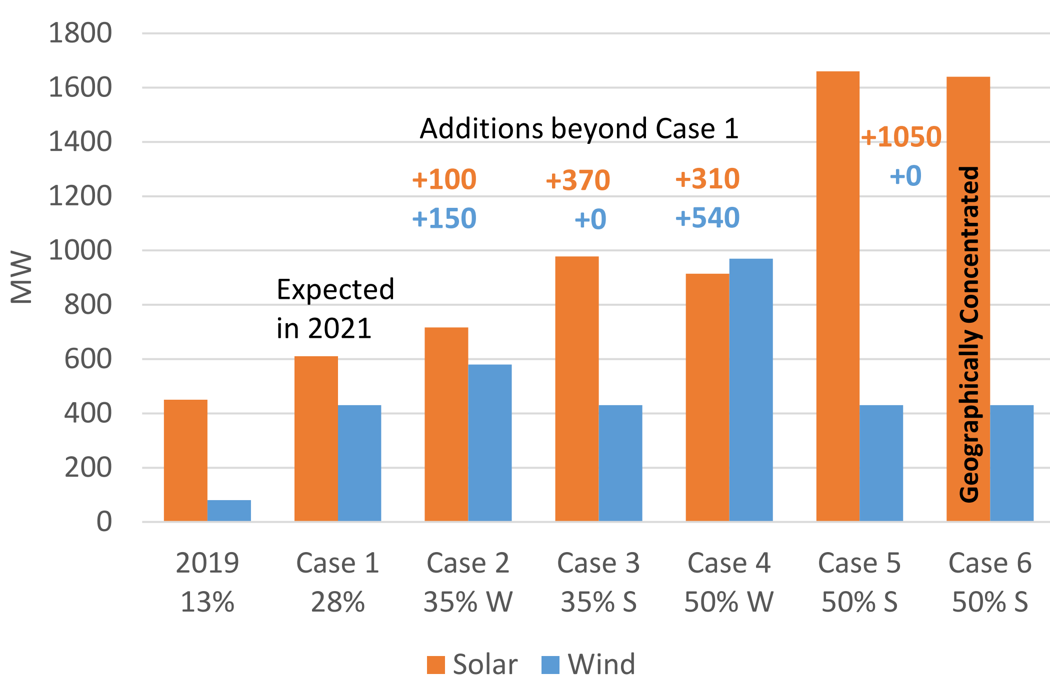
This system flexibility study is the first study in which TEP has investigated a suite of resource adequacy metrics beyond meeting peak load, and the first time that it has employed stochastic analysis and sub-hourly dispatch modeling to evaluate resource adequacy. The study takes a two-pronged analytical approach. First, using a Monte Carlo stochastic analysis, 250 iterations of net load over a one-year period are simulated to determine 99th percentile values of peak net load, 3-hour net load ramps, 10-minute net load ramps, and over generation. These "maximum values," for each penetration case, are then compared to the capacity and flexibility of the resources expected in TEP's 2024 portfolio to determine if TEP's resources are likely to be adequate for the cases studied.

The second approach uses TEP's production cost model, Aurora, to simulate customer demand, renewable energy generation, and resource dispatch at 10-minute intervals for each case over a one-year period. This approach is more analytically intensive than the Monte Carlo approach but explicitly accounts for resource constraints that can limit TEP's capacity and flexibility, such as minimum generation limits, minimum up and down times for non-cycling units, maximum ramp rates, planned and unplanned unit outages, transmission limits, local minimum generation requirements, and load forecast uncertainties. Aurora's output is then analyzed to determine the presence, frequency, and magnitude of capacity and flexibility shortfalls. By employing two, independent analytical techniques, TEP gains further insight into the flexibility of its system and its ability to integrate increasing amounts of renewable energy.

Each type of analysis uses one-minute, quality-assured load and renewable generation data from July 2018 through June 2019. The Monte Carlo analysis includes additional one-minute data from July 2017 through June 2018 to improve the modeling of the variability component of the analysis – for example, how much a solar plant's generation is likely to deviate from its actual generation at a particular time in the study period.

System flexibility was evaluated against six renewable energy penetration cases ranging from 28 to 50 percent of retail sales. Chart 10 shows the solar and wind capacities assumed in each case. For reference, the first pair of bars shows the amount of wind and solar, including distributed generation, on TEP's system in 2019. The energy generated from these resources was approximately 13 percent of retail sales. Case 1 represents the renewables expected on TEP's system in 2021 based on projects currently under development. With the addition of these projects, TEP is expected to serve 28 percent of its retail sales with renewable energy. The remaining cases achieve penetration levels of 35 and 50 percent. Case 2 achieves 35 percent by adding mostly wind power to the 2021 portfolio. Case 3 achieves 35 percent by adding only solar power. The "W" and "S" under each case number identify which cases add mostly wind and which add mostly solar. 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 within the Tucson valley, as opposed to a more geographically dispersed scenario. This geographically concentrated case is included to account for the increase in ramping 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 300 MW by 2024, from approximately 240 MW in 2019.

Chart 10 - Solar and Wind Capacities Assumed for Each Penetration Case



Most of the solar power assumed in each case is modeled on generation profiles at four existing single-axis tracking plants in TEP's portfolio. About a quarter of the solar power is modeled on profiles at three existing fixed tilt plants. About two-thirds of the wind power is modeled on a generation profile from the Oso Grande area in eastern New Mexico. The remaining wind power is modeled on profiles from three existing wind plants in TEP's and UNS Electric's portfolio.

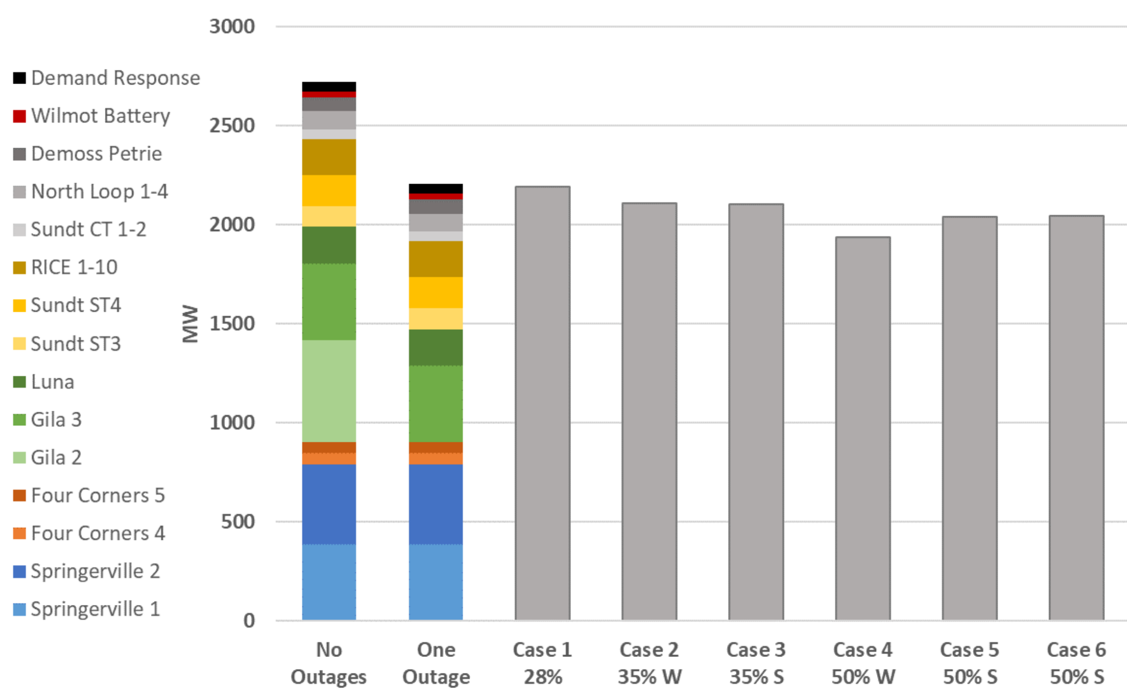
Given these generation profiles and the amount of future solar and wind capacities assigned to each one, enough renewable energy would be generated to achieve the penetration levels shown in Chart 10. However, when over generation (i.e., renewable curtailment) occurs in a case, then the penetration rates (renewable energy delivered as a percent of retail sales) would not be fully achieved unless the over generated energy is stored for later use, or the system turndown limit is lowered, or additional renewable capacity is added to make up for the curtailed energy at other times of the day and year. The amount of over generation, therefore, is an indicator that more flexibility and/or renewable capacity would be needed to achieve the stated amounts of renewable energy penetration.

Peak Net Loads. The first resource adequacy metric analyzed is the peak net load. Chart 11 compares TEP's retail peak net load for each case (the annual peak load after subtracting the contribution of renewable energy at the time of the peak) to TEP's dispatchable summertime capacity. The first bar shows TEP's generation capacity when all dispatchable units are fully available. The second bar assumes TEP's single largest hazard – an unplanned outage at the Gila River 2 generating unit. Under these conditions, TEP should be able to meet its peak net load in the mid-2020s. Results from Aurora confirm this finding. Results from each analysis assume no further retirements of resources other than what has already been announced for San Juan unit 1 in 2022.

As renewable penetration increases, the peak net load decrease slightly, making it somewhat easier for TEP to meet peak demand with existing resources. This "contribution to peak" tends to diminish as more solar power is added because the peak net load is shifted to the evening, when there is no solar power. Case 4, however, shows a more significant contribution to peak because the wind resources modeled in this study tend to increase generation in the late afternoon and evening hours.

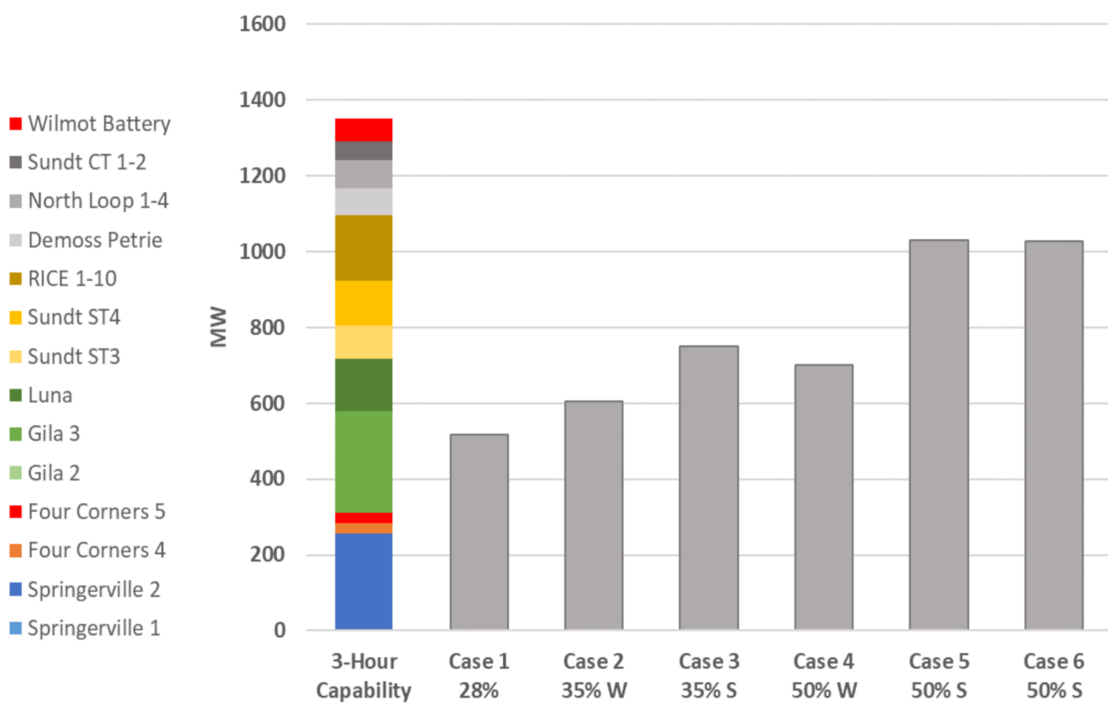
Finally, it is worth noting that between 2017 and 2032, TEP is retiring 13 dispatchable units at various locations while adding only Gila River Unit 2 and 10 new reciprocating internal combustion engine (RICE) units located in Tucson. The probability of outages, therefore, in conjunction with the intermittency of renewable resources, must continue to be carefully considered when assessing the ability of TEP to meet peak customer demand, especially as further retirements of fossil-fueled generation resources are contemplated. For example, TEP should continue maintaining at least a 15 percent planning reserve margin regardless of this analysis of net load.

Chart 11 - Dispatchable Summertime Capacity Versus Case 1-6 Peak Net Loads (Monte Carlo Results)



3-Hour Ramps. Chart 12 compares the maximum 3-hour ramps in net load for each case to TEP's 3-hour ramping capability. The 3-hour ramps are greatest in the spring and fall, when low demand and high solar power production during the day depress the net load and increase the ramp that occurs in the late afternoon. These are also the seasons when maintenance is conducted on TEP's generating units, which can last several weeks. Thus, this comparison assumes that one unit at Gila River is unavailable and that one unit at Springerville is either unavailable or operating seasonally. Under these assumptions, TEP should be able to meet its maximum 3-hour ramps in all six cases. Results from Aurora confirm this finding.

Chart 12 - Typical Springtime 3-Hour Ramp Capability Versus Maximum 3-Hour Net Load Changes (Monte Carlo Results)



10-Minute Ramps. Chart 13 compares the maximum 10-minute ramps in net load for each case to TEP's 10-minute ramping capability. The 10-minute ramps are greatest in the summer afternoons, when cloud cover is highly variable. These are also times of high customer demand. Thus, this comparison assumes that at the time of maximum ramps, one Gila River unit, one Springerville unit, and half the RICE units are unavailable for ramping because they are likely to be at or near full capacity. Also, TEP's combustion turbines (all but one of which are under 25 MW) are not considered ramping resources because they are designed primarily to operate at full load for one or more hours.

At its current penetration level of 13 percent, it is not uncommon for TEP to experience 10-minute ramps greater than 100 MW, so it is reasonable to expect that the maximum 10-minute ramps in Case 1 would be close to 300 MW. It is counterintuitive, however, that these ramps would only increase marginally in Cases 4-6. Thus, TEP should continue studying the impact of renewable integration on 10-minute ramps, especially in cases where renewable penetration may exceed 35 percent.

Chart 14 shows that the Aurora modeling identifies a relatively small number of 10-minute periods in which net load ramps cannot be met (fewer than 25 periods out of approximately 4,300 per month). This is a further indication that TEP's 10-minute ramping capability may become insufficient in high renewable cases and should continue to be studied.

Chart 13 - Typical Summertime 10-Minute Ramp Capability Versus Max 10-Minute Net Load Changes (Monte Carlo Results)

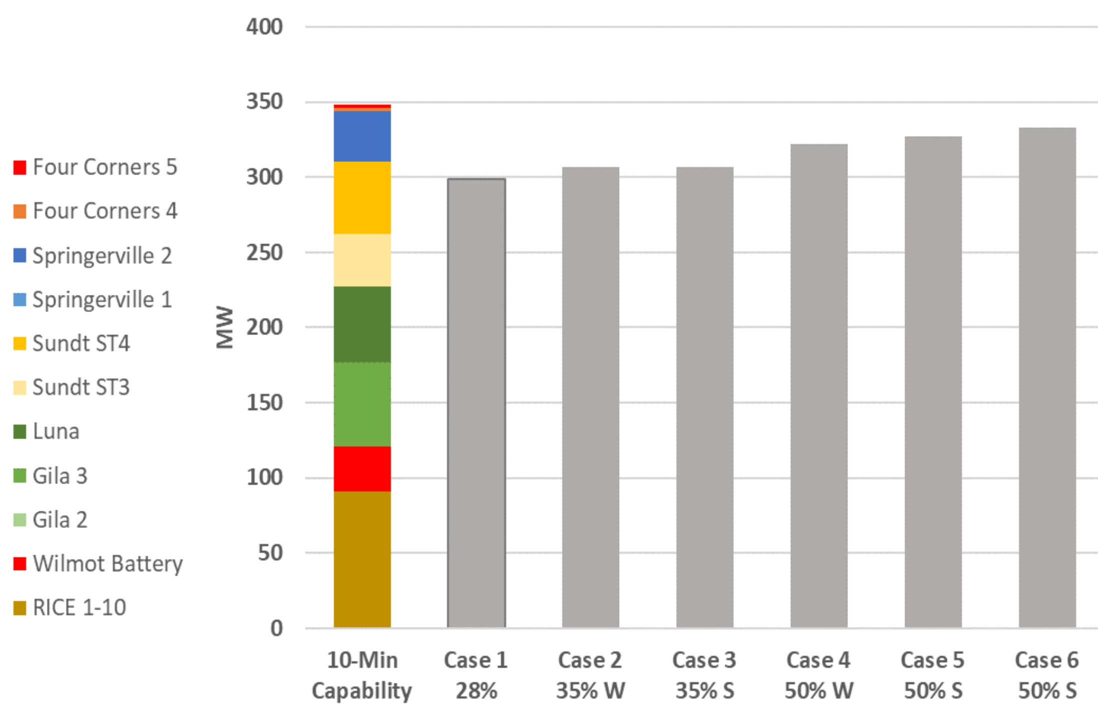
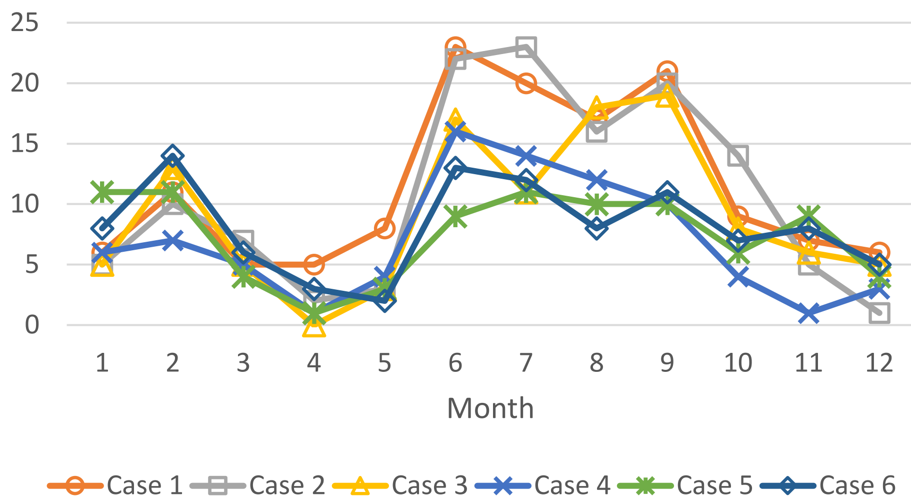


Chart 14 - Monthly Count of 10-Minute Ramping Insufficiencies (Aurora Results)



Over Generation. Chart 15 - shows the amount of over generation expected in each case assuming alternative turndown limits of 200, 300, and 400 MW. Over generation is greatest during daytime in the spring and fall. It is reasonable to expect that the thermal units normally operating during these times in the mid 2020s would have a combined turndown limit of 300 MW, in which case over generation begins to occur in Cases 2 and 3 and is significant in Cases 4 through 6, especially in the high solar cases. For example, in Case 5 nearly 15 percent of the renewable energy would need to be curtailed, meaning that the amount of retail sales actualy served by renewable resources would be reduced from 50 to 42.5 percent. While reducing the system turndown limit can mitigate this effect, a renewable target such as 50 percent cannot be met without additional measures such as energy storage, increasing demand during periods of over generation (e.g., load shifting), and building additional renewable resources to make up for the curtailed energy at other times of the day and year.

Chart 16 shows that the Aurora modeling also predicts over generation. The annual amount of curtailment predicted by Aurora is very close to the amount predicted by the Monte Carlo analysis assuming a turndown limit of 300 MW.[3]

[3] In Aurora, minimum generation levels are determined dynamically every 10 minutes depending on the resources that are economically dispatched to meet demand.

Chart 15 - Annual Renewable Curtailment Required Given Alternative Turndown Limits (Monte Carlo Results)

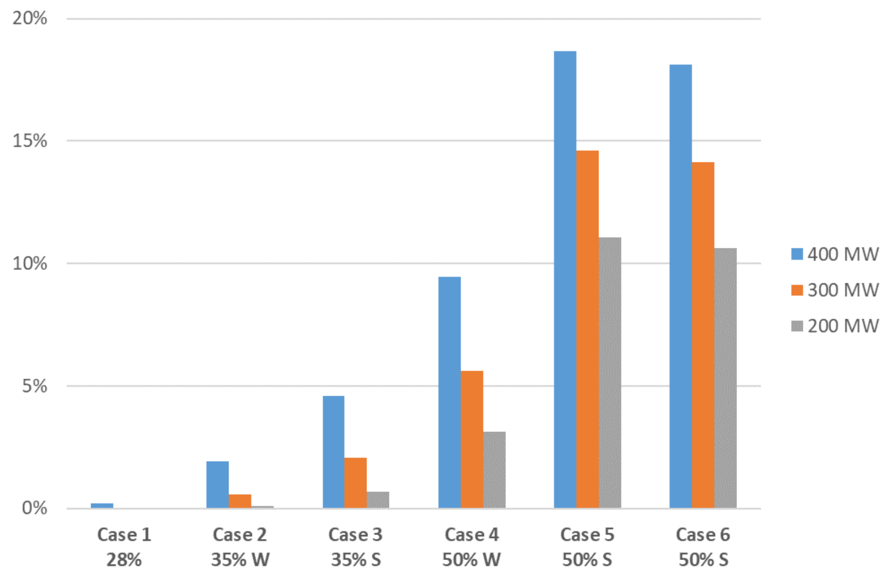
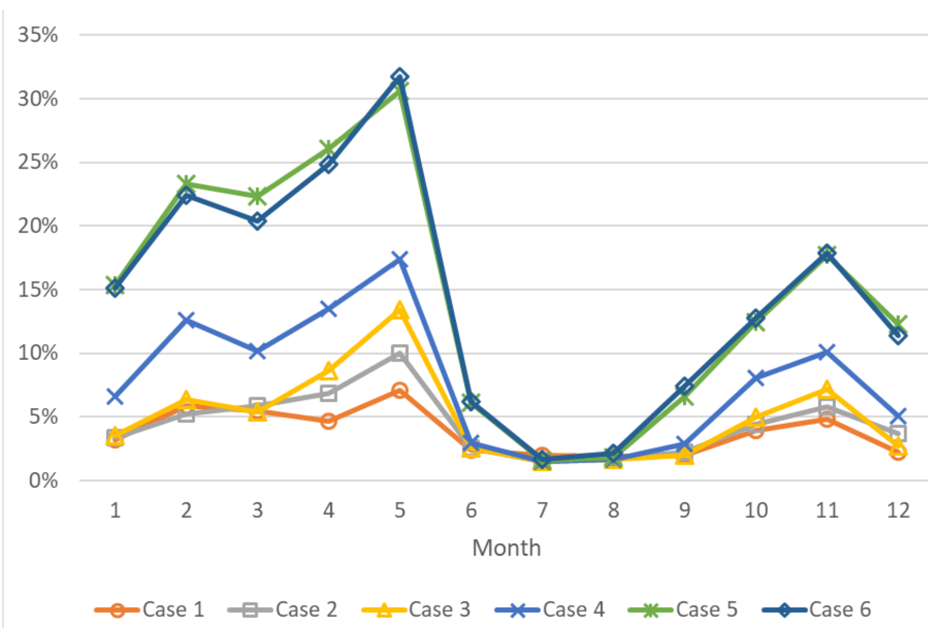
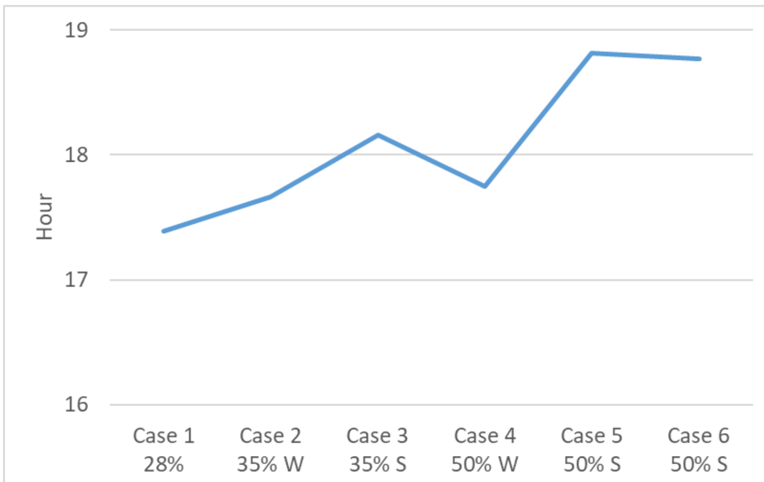


Chart 16 - Monthly Renewable Energy Curtailment (Aurora Results)



Finally, the Monte Carlo results were analyzed to determine the average time of occurrence of the peak net load. The results for each case are shown in Chart 17. As the renewable penetration increases, especially with solar power, the time of the peak net load is shifted to later in the evening. This shift is 1.5 hours between Cases 1 and 5. This happens because solar power can reduce net load while the sun is up, but less so as sunset approaches. At some point, additional solar capacity will do nothing to reduce net load because it has already been shifted to sunset – that is, additional solar resources will provide no incremental capacity value. Adding wind capacity, however, if it tends to generate more power in the late afternoon and evening, as is the case with wind resources in parts of eastern New Mexico, will have the effect of shifting the net load to an earlier time, when solar power can still provide capacity value. Thus, a more diversified renewable portfolio has the potential to meet renewable energy targets while also reducing the need for energy storage or other dispatchable resources to meet peak demand.

Chart 17 - Time of Peak Net Load



Conclusions. Based on the Monte Carlo and Aurora results above, the following conclusions can be made about TEP's ability to integrate additional renewable resources:

- Achieving a renewable penetration of 30 percent is within TEP's current resource capabilities. However, additional flex capacity might be needed if the system turndown limit cannot be kept below 400 MW during the day-time hours of the non-summer months.
- Achieving a renewable penetration of 50 percent is within TEP's current resource capabilities, but with the following caveats:
    - **Peak Net Load** – Retiring any resources beyond San Juan Unit 1 could lead to a capacity shortfall and should prompt a re-examination of capacity needs and options.
    - **3-Hour Ramps** – Achieving a 50 percent penetration strictly through solar power could strain the ability of the system when major units are off-line in the non-summer months.
    - **10-Minute Ramps** – Additional research is warranted given the nature of results so far, and TEP should track the impact on 10-minute ramps as more renewable resources are brought onto its system.
    - **Over Generation** – Over generation is likely to be significant at penetrations beyond 35 percent, making it more difficult or expensive to achieve a specific renewable energy goal as opposed to a CO_2 emissions reduction goal, which can be achieved at various levels of renewable penetration.

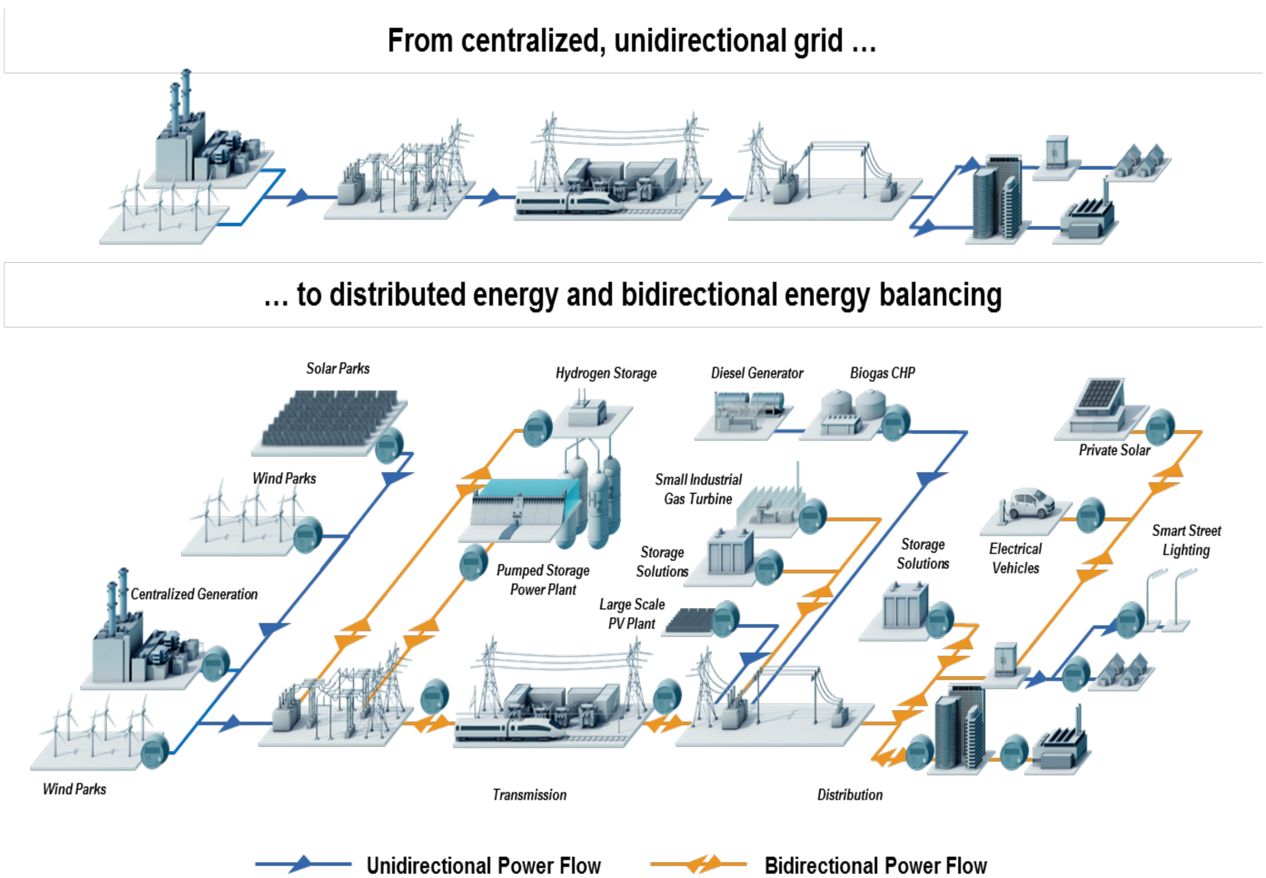
CHAPTER 4

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.

TEP 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 TEP'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, TEP 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 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 distributed generation, which are small-scale, renewable resources often sited on utility customer premises. The Arizona Renewable Energy Standard (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

TEP has been interconnecting solar DG for the past two decades. By the end of 2019, TEP had approximately 335 MW_{DC} of rooftop solar photovoltaic ("PV") systems. DG is expected to supply approximately 540 GWh of energy in 2020. TEP has offered several programs for customers to utilize DG.

3rd-Party Solar Photovoltaic

Both residential and commercial customers are able to interconnect to TEP'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 purchased power agreement (PPA) or solar service agreement. These systems are typically sized with a kW capacity that will offset nearly all of the energy needs at a customer's premises over the course of a year.

Tucson Electric Power Owned Residential Solar ("TORS")

TEP received ACC approval for a pilot program that offered residential customers the opportunity to have TEP install a company-owned solar PV system on their roof. Participating customers agreed to pay a fixed monthly charge for electric service based on their average annual usage at the time they signed up for the program. So long as their actual annual usage does not exceed that benchmark level by more than 15 percent, their monthly payment remains unchanged for up to 25 years. This program was suspended in 2017.

GoSolar Shares

For nearly 10 years, TEP has offered its customers the opportunity to offset some or all of their annual energy usage from the Company's GoSolar Shares (formerly Bright Community Solar) community solar program. Customers can elect to purchase 150 kWh shares for a $0.01/kWh premium. The cost of shares remains fixed for 20 years and remains exempt from renewable energy and fuel and purchased power surcharges.

GoSolar Home

TEP recently offered residential customers the opportunity to participate in this unique solar program, which allowed them to purchase all their energy from a local TEP solar array at a fixed monthly price. That price was based on their average annual energy use when they signed up for the program and will remain fixed for up to 10 years if their actual annual usage does not vary from that benchmark by more than 15 percent. This program is fully subscribed by TEP customers.

Table 5 shows the rates of adoption for the various programs available to customers.

Table 5 - Current Adoption of TEP DG Programs

	Total All-Time Customers Through 2019	Total MW
3rd-Party Residential DG	24,631	189
3rd-party Non-Residential DG	811	160
TORS	476	2.7
GoSolar Shares	1,475	6.0
GoSolar Homes	793	5.0

Energy Efficiency Resources

TEP recognizes that energy efficiency and demand response can provide cost-effective benefits. TEP 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 TEP and other affected utilities to achieve a cumulative annual energy savings through its DSM programs by the end of each calendar year.[4] 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.

TEP 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, Combined Heat and Power Credit, and Pre-rule Credit.

[4] Arizona Administrative Code R14-2-2401 et seq.

2021 Implementation Plan, Goals, and Objectives

TEP remains committed to helping customers reduce energy use and demand through its DSM programs. TEP is filing an Implementation Plan covering the 2021 and 2022 program years, consistent with ACC rules.[5] This Plan proposes continued DSM program operation in the residential, C&I, and utility improvement sectors.

TEP'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

TEP filed its 2018 EE Implementation Plan on August 1st, 2017, for approval of EE and DSM programs with the ACC (Docket No. E-01933A-17-0128). TEP received the final order for approval for these programs from the ACC in Decision No. 77085 on February 20, 2019 augmenting Decision No. 75450 (February 11, 2016).

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

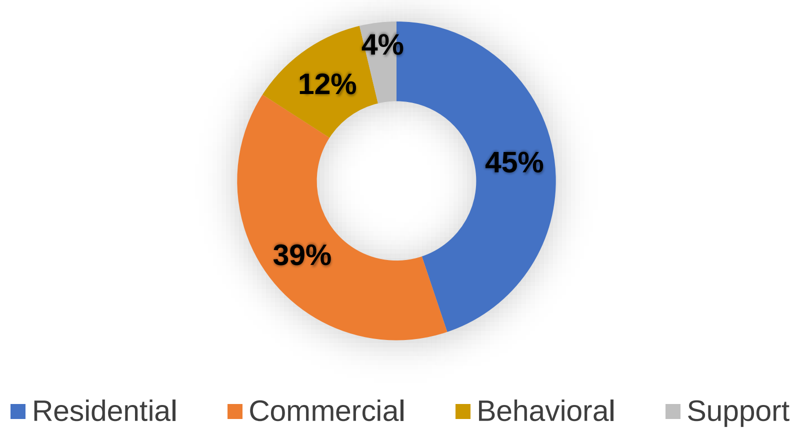
[5] Arizona Administrative Code R14-2-2405

Figure 6 – Current TEP DSM Programs

Sector	Program
Residential Sector	Efficient Products
	Existing Homes
	Low Income Weatherization
	Multi-Family Homes
	Residential New Construction
	Shade Trees
Commercial & Industrial Sector	Small Business Direct Install and School Facilities
	C&I Comprehensive
	Commercial New Construction
	Schools Energy Efficiency Pilot Program
	Combined Heat & Power
	C&I Direct Load Control
Behavioral Sector	Behavioral Comprehensive
	Home Energy Reports
	Consumer Education and Outreach
Support Sector	Energy Codes and Standards
Utility Improvement Sector	Conservation Voltage Reduction
	Generation Improvement and Facilities Upgrade

Chart 18 shows the actual segmentation of energy savings across sectors resulting from the implementation of these program during 2019. The utility improvement sector did not lead to any reported energy savings in 2019.

Chart 18 – 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. TEP'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, Combined Heat and Power 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. TEP'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 impersistance 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 TEP'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 TEP'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, TEP has prepared a single monthly energy and peak reduction forecast for all years in the IRP planning period. For this IRP, TEP built four of these forecasts, each based around a distinct scenario that assumes a different blend of efficiency measures. TEP is using these four 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.

TEP 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 TEP's DSM savings target is achieved using the existing blend of measures.

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). TEP assumes that the DSM savings target is achieved using the existing mix of measures.

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.

4. **Scenario D: Modeling performed by Strategen Consulting ("Strategen") under a collaborative project between TEP and SWEEP**
   For this project, TEP provided Strategen with the input data that TEP used for modeling portfolios for the 2020 IRP. Strategen used those inputs to run a capacity expansion simulation of TEP's system using EnCompass. The Strategen modeling resulted in a suite of DSM programs that the EnCompass model selected as cost effective additions to TEP's portfolio including the option to retire existing TEP assets. TEP then used the results of Strategen's modeling (in terms of cost, annual savings, and hourly shape) in its own production cost model to evaluate the performance relative to the other portfolios in the 2020 IRP.

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 TEP'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 TEP's DSM target using a certain measure blend.

Estimation of First Year Energy Savings

TEP'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 TEP 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).

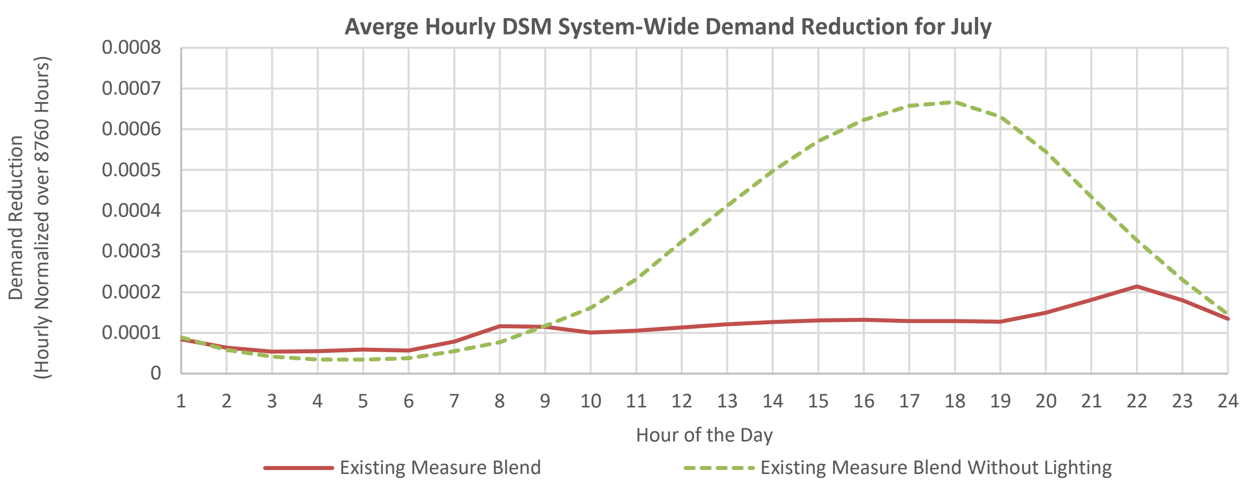
Determining Cost of First Year Energy Savings ($/MWh)

The EE Standard required the cumulative first-year savings from TEP's DSM programs to exceed a certain percentage of the previous year's energy sales. TEP 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. TEP'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 TEP 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 four 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 19 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 19 - Load Reduction Comparison for Potential Measure Blends



The removal of lighting measures (i.e., 2023-2030 for "Scenario C") increases the cost of meeting TEP's DSM savings target by increasing reliance on HVAC measures to meet this target. However, Chart 19 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 TEP 2017 Integrated Resource Plan.[6]

[6] https://docket.images.azcc.gov/0000178618.pdf, pp. 112-113

Peak Coincident Capacity Contribution

Energy savings for measures in each program are aggregated to develop the cumulative reduction to load for each hour. Since Tucson's peak demand 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 TEP's DSM programs is greatest between 8:00 PM and midnight. However, TEP's forecasted system load during the summer is greatest between 4:00 PM and 7:00 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 TEP's system load shape, specifically with regard to load during peak periods, informs the coincident and non-coincident peak demand reduction. Within TEP's engineering workbooks, each DSM measure's demand reduction coincident with system peak is calculated by multiplying a "coincident demand savings factor" by the maximum energy savings for that year and month. The coincident demand savings factor is calculated for each measure by averaging the shape's normalized load between 4:00 PM and 7:00 PM each day during June through August.

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 TEP to evaluate DSM as a resource for replacement of generation. This modeling of DSM measures as a resource in TEP's cost production model indicates their potential cost savings by displacing energy and capacity from conventional resources. This analysis allows TEP 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, to reduce their energy demand based on TEP'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. Customers enter into DR agreements voluntarily and in doing so receive a financial incentive, such as a reduced electricity rate, in exchange for committing some portion of their energy demand to the utility's control. These agreements typically have limitations including the amount of energy demand the customer commits to the utility, as well as the number and duration of events during which the utility can call on the demand reductions. Some agreements provide customers the option to "opt out" of a particular call event, which makes the DR capacity less than 100 percent dispatchable.

Strategies used by customers under DR agreements include:

- Reduction of HVAC load
- Reduction of other mechanical load (compressors, motors)
- Reduction of lighting load
- Curtailment of production lines

The specific strategies that customers use to meet their DR commitments will depend on certain external conditions such as time of day, season, and weather and can also depend on the amount of advance notice provided by the utility. Because customers have energy needs specific to their line of business, DR programs are most effective at meeting predictable utility needs such as summer peak where a utility can provide a day-ahead notice based on high forecast temperatures. DR is less effective at meeting unexpected or intermittent energy demands.

Capital Deferment Through High Levels of Demand Response

Through its engagement with the IRP Advisory Council, TEP received a request from the Residential Utility Consumers Office (RUCO) to evaluate high levels of DR with respect to the potential for reducing customer rates through the deferment of capital expenditures relating to new resources for meeting system peak. Specifically, RUCO suggested evaluating a DR program with a total capacity reaching 40 percent of retail load by 2035. While the analysis was initially considered for inclusion in the IRP Portfolio Analysis, TEP determined that it did not have sufficient data to determine the cost of achieving that high level of DR. However, TEP is able to estimate the level of capital spending that could be deferred based on an assumed level of DR.

In order to achieve that high level of DR, the program would need to be very broad, including residential as well as C&I customer classes. In addition, it is assumed that the program would be designed to target air conditioning load as that is the primary contributor to TEP's system peak demand, though other measures such as pool pumps could be included. Given these assumptions of a broad-based program focused on air-conditioning load, TEP believes that that the entire program capacity would not be 100 percent dispatchable. Therefore, TEP evaluated two levels of dispatchability at 30 percent and 60 percent. These levels of dispatchability were selected to illustrate the relative "potential" for deferring capital expenses through aggressive DR programs.

This evaluation did not include an assessment of the technical nor economic feasibility of achieving this level of DR nor the respective levels of dispatchability.

Table 6 presents the level of capital expense that could potentially be deferred through high levels of DR.

Table 6 – Deferred Capital Expense from Demand Response

Dispatchability	30%	60%
Firm Load with Reserves (MW)	2,754	2,754
Total Demand Response (MW)	1,102	1,102
Dispatchable Demand Response (MW)	331	661
Firm Load less Demand Response (MW)[7]	2,494	2,093
Total Deferred Capital Expense ($000)	197,748	215,734

[7] Dispatchable Demand Response is subtracted from the highest 80 hours of required generation, assuming a program limit of 80 hours of DR per year. The firm peak load after implementing the demand response in a 30 percent participation scenario is not reduced by 331 MW because the 81st highest hour in 2035 is within 331 MW of the highest hour.

Electric Vehicles

Nationwide, 2019 plug in electric vehicle sales were 330 thousand of the 1.9 million electric vehicles sold. This is double the plug-in electric vehicles that sold in 2017.[8]

EVs are projected to hit 7 percent of global Light Duty vehicles sales by 2023, 10 percent by 2025, 28 percent by 2030, and 58 percent by 2040. The continued growth trend is reliant on many variables, but one key driver is the expected reduction in manufacturing of internal combustion engine (ICE) vehicle models, while EV models increase. In the U.S. EVs are expected to hit 4.5 percent of U.S. Light Duty vehicles sales by 2023, 10 percent by 2025, 28 percent by 2030, and 58 percent by 2040, similar to that of global sales. In order for these growth figures to continue, a price parity between EVs and ICE vehicles would need to take place and that is expected to be reached by the mid-2020s.

Globally China and Europe could represent 72 percent of Light Duty EV sales in 2030 driven by CO_2 regulations as well as China's generous EV credits. This amount of projected sales in the global markets would shift manufacturing at a faster pace and be seen as a contributor to the growth of all transportation electrification. Hybrids are still playing a role that helps drive the EV market, but after 2030 their market share is projected to drop rapidly given that full battery EVs are expected to get more cost effective and would be seen as the better choice for a plug in electric vehicle. Globally, on an annual basis, Light Duty EVs consume 1,290 terawatt-hour (TWh), commercial EVs 389 TWh, and battery electric Buses 216 TWh. In the U.S. electricity demand from EVs is projected to hit 2 percent in 2030 and 10 percent in 2040, if the aforementioned vehicle growth numbers in the respective category are achieved. If current EV projections are met, around 12 million public charging points would be needed globally by 2040. This could put public charging investments at an expected figure of around $111 billion globally by 2040.

Product Development and Evolution

Battery Electric Vehicles (BEV) fully electric, battery only vehicles that do not consume fossil fuel are not only the market leader currently but the direction of transportation electrification. Manufacturers are heavily invested into the market with Tesla still leading the path to longer range battery packages for its EV lineup.

Plug-in Hybrid Electric Vehicles (PHEV) have both an electric motor and an internal combustion engine that burns fossil fuel. Although this type of plug-in vehicle is still in the market, we have seen a substantial reduction of PHEV production.

An additional class of vehicle, the Hybrid Electric Vehicle (HEV), incorporates electric battery technology similar to a PHEV but notably receives its charge via regenerative braking and on-board charging via an internal combustion engine. HEVs in the past had a large share of electrified vehicles operating but do not plug in to the electrical grid[9] for charging and therefor are not considered a factor in future load growth scenarios.

[8] http://insideevs.com/monthly-plug-in-sales-scorecard/
[9] https://www.greentechmedia.com/articles/read/why-general-motors-is-ditching-the-chevy-volt#:~:text=Come%20March%2C%20GM%20will%20no,of%20battery%2Delectric%20vehicle%20architectures.

Picture 2 – Contemporary Amperex Technology Power Pack

Contemporary Amperex Technology Co. Ltd. Electric-car batteries for Tesla Inc. and Volkswagen AG developed a power pack that lasts more than a million miles -- an industry landmark and a potential boon for automakers trying to sway drivers to their EV models. This manufacturer is ready to produce a battery that lasts 16 years and 2 million kilometers. [10]

Future Adoption Rate Influencers

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

- Environment
- Policy
- Future advances in battery technology

[10] https://www.bloomberg.com/news/articles/2020-06-07/a-million-mile-battery-from-china-could-power-your-electric-car

Environment

For many consumers, both real and perceived, environmental benefits are a key factor in the decision to purchase a BEV. The replacement of an ICE engine vehicle with a BEV changes both the level of emissions and the geographic location of those emissions. In most locations, total emissions associated with charging BEVs are lower on a per mile basis than emissions associated with ICE engines. In addition, while emissions from ICE engines are concentrated in urban areas where local ambient air quality impacts large populations, emissions associated with electricity production are often located in remote areas where fewer people are impacted

Policy

The most clearly demonstrable influencer of EV adoption to date has been federal and state policy creating incentives directly reducing the cost of EV purchases. States with the highest incentives, such as California, Oregon and Georgia, have reached EV adoption rates 2 to 4 times above the national average. At the state level, incentive policies are dependent on public support and may be complimented by regulations such as California's Zero Emission Vehicle program requiring automakers to achieve volumetric EV sales goals tied to their total fleet sales numbers.

TEP participates in EV coalitions such as The Alliance for Transportation Electrification, which is a broad and diverse coalition of organizations that advocate for transportation electrification in all states across the country. The Alliance believes that a multi-stakeholder coalition educating and promoting the benefits of transportation electrification is necessary and will benefit the public welfare.

Battery Technology

The opportunity that holds the greatest promise to increase future EV adoption rates is improvements to battery and manufacturing technology that reduce the cost of batteries. Industry analysis ties the price point at which EVs are on parity with contemporary internal combustion engine vehicles to a battery cost of $100/kWh capacity. Projections are that a $100/kWh capacity will be in market by 2024 and $61/kWh by 2030 according to forecasts.

Charging Infrastructure

While soft costs are still an obstacle for EV charging infrastructure, development continues in networks for greater utilization as projections of EV vehicle models continue to rise with manufacturers'commitments.

TEP continues to both learn and explore total costs of charging networks at micro and macro levels for both our customers and the transformation of transportation to a more a sustainable electric fuel source. The Company is working with organizations to develop tools to help future investments in charging networks and gain better understandings of the technology, platforms and total investments that are made in EV charging.

Low EV charger counts and a lack of appropriate working knowledge of first generation EV networks has been a large part of range anxiety. When comparing conventional fossil fueling stations to EV charging ports, as well as average ICE vehicles to BEV driving ranges, customers tend to see this as an obstacle.

TEP Current and Near-Term Programs for EVs

Below are some of the current measures that we have included for the near term for transportation electrification in the TEP territory.

- Rates for Electric Vehicle Owners: TEP currently offers three pricing plans for owners of battery and plug-in hybrid electric vehicles for residential customers.

- Rebates for Residential Customers: TEP residential customers can claim a rebate covering up to 75 percent of the cost of installing an Electric Vehicle Charger.

- Rebates for Business Owners: TEP's Smart EV Charging Program offers generous incentives as well as technical support to commercial businesses, multi-family complexes and nonprofit customers that purchase and install EV charging ports at their location.

- EV Comparison Tool: TEP offers a calculator for comparing EV options and personal estimates for making an informed EV investment

Distribution Modernization

TEP is continually modernizing the distribution grid in order to operate the grid more safely, efficiently, and reliably while integrating new energy technologies. Current modernization programs include: the installation of a foundational communication network, the implementation of an ADMS, AMI, and enhanced systems that improve situational awareness for field personnel.

Advanced Distribution Management System

An ADMS is the central software application that will provide distribution supervisory control and data acquisition, outage management and geographical information in a single interface to TEP distribution operations personnel. By combining the information from these systems into a comprehensive view, an electrical distribution system model can be created for both real-time applications and planning needs. The single view improves situational awareness of the distribution system by providing additional information to operators that was not readily available in the past. Access to more information and system data will allow the opportunity for more in-depth analysis of evolving customer energy use patterns, which can be used to evaluate how customers' use of solar, energy storage, and electric vehicles impact~~s~~ the distribution system and supply-side resource decisions. TEP implemented ADMS in the spring of this year, in parallel operation with its legacy distribution management applications. TEP will convert fully to the ADMS before the end 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

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

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

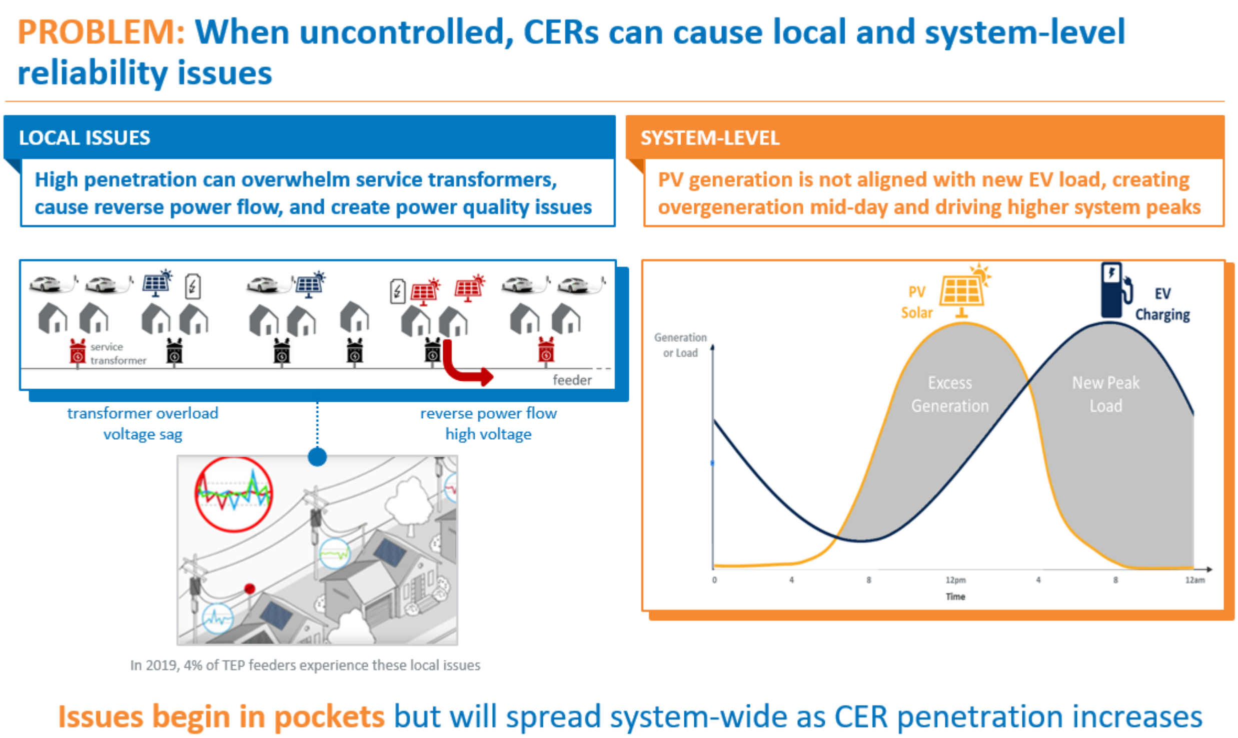
The AMI meters allow for remote connect and disconnect for our customers. This allows TEP to establish a service remotely instead of sending a technician. This typically reduces the time from days to under an hour.

The Future of Customer-Sited Energy Resources ("CER")

With advancements in technology, DER products and devices are becoming more available to customers in our industry and territory. As changes in the supply, demand, and delivery of electricity are remodeling electric distribution systems as noted above, the two-way delivery of energy will need management platforms or a central DER management system.

TEP has been developing strategies and experiments to support these products that can be utilized for load shaping, shifting, and management as they become commercially available. TEP believes that this preparation for new product technology will be essential for CER Management, and conversely applicable for grid responsiveness.

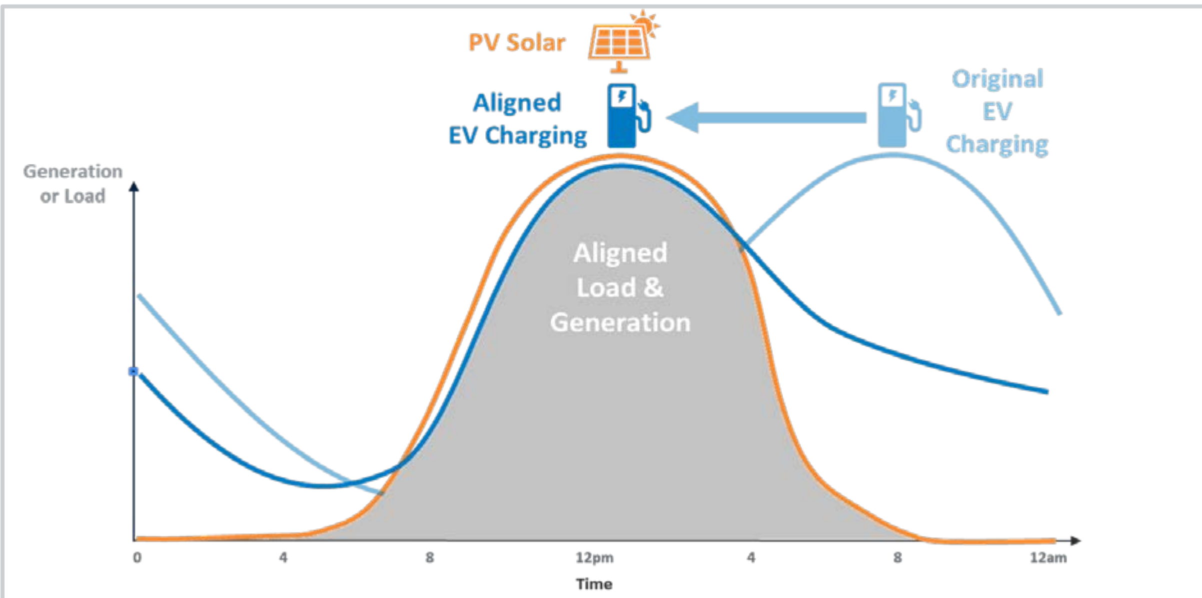
Figure 7 - CER and Grid Misalignment



As TEP prepares for this future supporting these types of external facing DERs and other innovative services and or offerings, without compromising the security of our distribution network in accommodating the variety of DERs and other innovations, we need to understand the regressions that could take place in this type of eclectic product landscape and environment. Smaller scale experimentations to understand these DERs will become critical for our preparedness.

With the continued adoption of CERs, local and system-level reliability issues may be experienced, as shown above. At the local levels, these resources can cause backflow onto transformers, lead to voltage instability, and cause frequency fluctuations. In 2019, approximately 4 percent of TEP feeders experienced these local issues. At the system-level, DERs, such as solar PV systems, only produce energy during day light hours, hitting their peak around noon, and drastically drop off production as the utility's afternoon peak is starting to ramp up. This leads to an incompatibility of system needs vs. the abilities of traditional system resources. It is possible to mitigate both of these types of issues with the deployment of an array of DERs, as well as CERs.

Figure 8 - Align EV Charging to Solar Production



Instead, utilities need to quantify the value of DERs and CERs individually, which in some cases involves experimentation. This in turn supports the smart distribution systems that provide flexibility, capability, speed, and resiliency by taking into account a yield of product availability for actualization of management. This method would align CER operation and bring forth benefits to the customer and utility by increasing grid utilization and managing peaks to shift electricity use f. This would support various generation sources optimally that could in turn defer infrastructure investments. Conversely to Smart Grid management, CERs spread across the grid have the ability to help or hurt grid operations if not managed appropriately. Management can be done by or in coordination with the utility, or through local controls at the device. This is why experimentation of products and offerings will be critical for strategy development and DER/CER alignment to the smart grid.

As noted above, advanced distribution systems include new types of software, networks, sensors, devices, equipment, and resources. A diverse ecosystem of CERs are increasingly common as well that include various protocols and communications that in the pass have not been used by utilities directly. This presents new challenges, as well as opportunities for utilities to both play a role in the value that could be attributed to these products, and the need for proactive approaches to mitigate impacts and understand full potentials of CER devices.

CHAPTER 5

DISTRIBUTION AND TRANSMISSION PLANNING

Distribution Planning

Overview

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

Distribution Planning Analysis

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

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

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

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

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

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

Table 7 outlines major future system additions that have been identified through the distribution planning analysis.

Table 7 – Major Planned Distribution System Additions

Project	Description	Other Notes
Sonoran Substation **In Service Date [ISD]** **2020 (138kV), 2022 (46kV)**	New 138 kV substation with two 167 MVA 138/46 kV transformers and two75 MVA 138/13.8 kV transformers, up to eight 13.8 kV circuits and two switchgear lineups	1) Resolves transformer and circuit contingencies at Irvington and South Loop Substations 2) Supports load growth 3) Improves System Reliability 4) Supports integration of large-scale solar PV and energy storage
22nd St Substation T2 **(ISD 2021)**	New 75 MVA 138/13.8 kV transformer, four 13.8 kV circuits and one switchgear lineup	1) Resolves existing circuit overloads 2) Resolves transformer contingencies at 22nd Street Substation 3) Supports new business 4) Improves System Reliability 5) Supports future retirement of 46 kV Craycroft Substation
Cottonwood Substation **(ISD 2022)**	New 138 kV substation with 2-75 MVA 138/13.8 kV transformers, up to eight 13.8 kV circuits and two switchgear lineups	1) Provides new looped 138kV source for surrounding area 2) Resolves existing circuit and transformer overloads at Midvale Substation 3) Resolves transformer and circuit contingencies at Midvale and Santa Cruz Substations 4) Supports new business load growth 5) Improves System Reliability 6) Supports future retirement of 46 kV Mission Substation

PROJECT	DESCRIPTION	OTHER NOTES
PATRIOT SUBSTATION **(ISD 2022)**	New 138 kV substation with two 75 MVA 138/13.8 kV transformers, up to eight 13.8 kV circuits and two switchgear lineups.	1) Provides new looped 138 kV source for surrounding area 2) Resolves existing circuit overloads at Golf Links Substation 3) Resolves transformer and circuit contingencies at Golf Links and Pantano Substations 4) Meets the Department of Defense (DOD) resiliency Goals 5) Improves System Reliability 6) Supports future retirement of 46 kV DM, South Kolb, and Golf Links Substation
MARANA SUBSTATION **(ISD 2024)**	New 138 kV substation with two 75 MVA 138/13.8 kV transformers, up to eight 13.8 kV circuits and 2 switchgear lineups.	1) Provides new looped 138 kV source for residential and commercial development. 2) Improve transformer contingencies at North Loop Substation 3) Improves System Reliability 4) Support for small and large scale renewable projects 5) Supports future retirement of 46 kV Lateral 7.5 Substation

PROJECT	DESCRIPTION	OTHER NOTES
UA NORTH SUBSTATION **(ISD 2023)**	New 138 kV substation with three 75 MVA 138/13.8 kV transformers, up to twelve 13.8 kV circuits and three switchgear lineups.	1) Provides new looped 138 kV source for residential and commercial development. 2) Resolves transformer contingencies at Tucson, DMP, Sparkman, Country Club, and Olsen Substations. 3) Improves System Reliability 4) Supports future retirement of 46 kV UA Medical and Winnie Substations 5) Supports delivery of renewable energy
SEARS/WILMOT SUBSTATION **(ISD 2025)**	New 138 kV substation with two 75 MVA 138/13.8 kV transformers, up to eight 13.8 kV circuits and two switchgear lineups.	1) Provides new looped 138 kV source for residential and commercial development 2) Resolves transformer and circuit contingencies at East Loop, 22nd St, Arcadia, Van Buren, and Craycroft Substations 3) Improves System Reliability 4) Supports future retirement of 46 kV Sears and Wilmot Substations
PORT SUBSTATION **(ISD 2026)**	New 138 kV substation with two 75 MVA 138/13.8 kV transformers, up to eight 13.8 kV circuits and two switchgear lineups.	1) Provides new looped 138 kV source for residential and commercial development 2) Resolves transformer and circuit contingencies at Robert Bills, Los Reales, and Vail Substations. 3) Improves System Reliability

Transmission Planning Overview

Ten-Year Transmission Plan

TEP's transmission system is planned so that it meets the NERC Transmission Planning System Performance Requirements (TPL-001-4) and the Western Electricity Coordinating Council (WECC) Transmission System Planning Performance Criteria (TPL-001-WECC-CRT-3.2). Using these requirements. TEP annually reviews its transmission system, consisting of Extra High Voltage (EHV) and High Voltage (HV) elements, to identify upgrades to the existing system, as well as new facilities, to meet system performance requirements based on load and resource assumptions for the following ten years. The result of this plan is a list of "planned" and "conceptual" projects with individual project descriptions.

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

Biennial Transmission Assessment

On a statewide basis, TEP participates in the ACC's Biennial Transmission Assessment (BTA) which produces a written decision by the ACC regarding the adequacy of the existing and planned transmission facilities in Arizona to meet the present and future energy needs of the state in a reliable manner. The Commission concluded in its most recent BTA[11] decision that the existing and planned transmission system is adequate to reliably serve the needs of the state during the study period.

Reliability Must Run ("RMR") Assessment

An RMR condition exists for the Tucson load pocket because the TEP load exceeds the system import limit of the existing and planned transmission system. However, the projected load can be served through a combination of power imports and local generation. In the 7th BTA, the Commission ordered the suspension of RMR studies pending review of criteria that will trigger restarting RMR studies. TEP has not met any of the criteria, therefore, RMR studies were not performed for the 10th or 11th BTA.

Extreme Contingency Study

TEP conducted power flow analysis of outages involving TEP corridors that include 3 or more lines and TEP substations that include 3 or more transformers with a low side voltage of 100kV and higher. This evaluation is considered Critical Energy Infrastructure Information and was filed with the Commission under a confidentiality agreement.

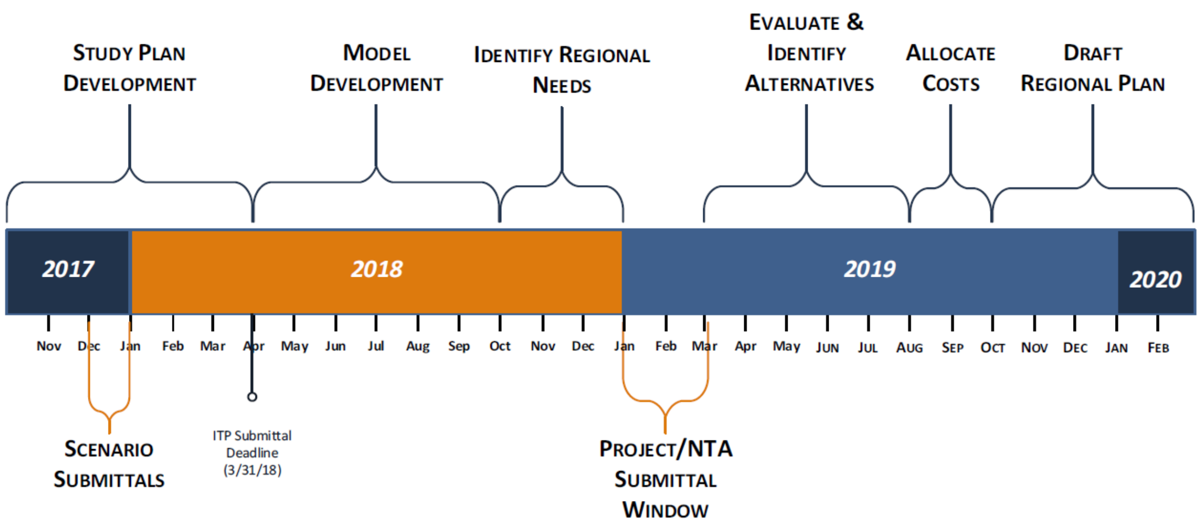
[11] Arizona Corporation Commission Tenth Biennial Electric Transmission Assessment for 2018 Through 2027, Docket No. E-00000D,17-0001, November 27, 2018

Regional Planning

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

Preparation for the 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 this most recently completed planning cycle is presented in Chart 20.

Chart 20 - WestConnect Planning Timeline

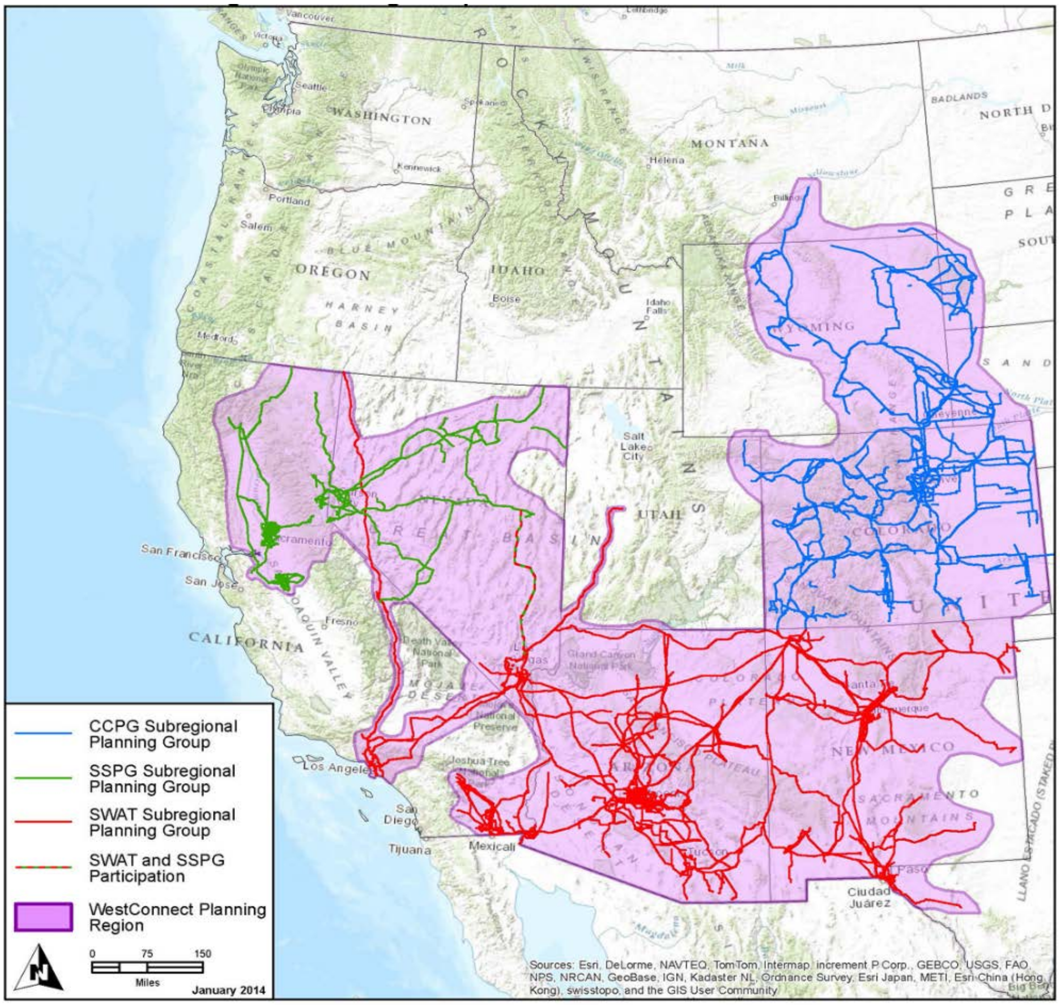


WestConnect assesses transmission planning models incorporating different scenarios to identify the need for new transmission. The key deliverable is a regional transmission plan that selects regional transmission projects to meet identified reliability, economic, or public policy, (or combination thereof) transmission needs. The 2018-19 planning cycle identified no regional needs within the WestConnect footprint.

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

TEP participates in the Southwest Area Transmission ("SWAT") Group that is comprised of transmission regulators/governmental entities, transmission users, transmission owners, transmission operators and environmental entities. SWAT Transmission Owner membership systems are included in the states of Texas (El Paso), New Mexico, Arizona, Nevada and California. SWAT is a sub-regional planning group in the WestConnect region, as shown in Map 2.

Map 2 - WestConnect Sub Regional Planning Groups



WECC

As a member of WECC, TEP participates on its Reliability Assessment Committee and its subcommittees. This committee is currently being restructured to allow for more efficient use of member resources. These include combining the Studies Subcommittee and the Scenario Development Subcommittee into a single subcommittee, eliminating the Modeling and Data subcommittees, and elevating the Model and Validation Work Group and the System Data Work Group to subcommittee levels.

Evolving Resource Mix Challenges

The transmission system was designed to accommodate the large coal generation fleet that is geographically distant from the load centers. The integration of renewable energy projects and the simultaneous reduction of coal resources is likely to have an impact on the operation of the transmission grid. Due to these changes, TEP has placed into service ten Reciprocating Internal Combustion Engine (RICE) generators at its Sundt Generating

Station and 21 MWs of Battery Energy Storage Systems (BESS) at select renewable resource locations to respond to the intermittent output of the renewable resources.

Other Regional Transmission Projects

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

Project Name	Description	Developer	Status
Nogales DC Intertie	300 MW DC, asynchronous interconnection to be developed in two – 150 MW phases between the electric grids in southern Arizona and the northwest region of Mexico	Nogales Transmission L.L.C., an indirect subsidiary of Hunt Power, L.P. and MEH Equities Management Company, a subsidiary of UNS Energy Corporation	Certificate of Environmental Compatibility was approved by the ACC in November 2017. Presidential Permit was received in 2018. FERC granted the project authority to sell transmission rights at negotiated rates on the line. Construction will commence pending sufficient subscriptions for service.
SunZia	Double-circuit 500 kV line between central New Mexico, near Ancho and the Pinal Central substation near Casa Grande, Arizona.	Southwestern Power Group II/MMR Group	Project approval by New Mexico Public Utilities Commission (NMPUC) 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** – 345 kV double-circuit line between the existing Afton Substation, south of Las Cruces, New Mexico, and the existing Apache Substation, south of Wilcox, Arizona **Upgrade** – 230 kV double-circuit line between the Apache Substation and the existing Saguaro Substation northwest of Tucson, Arizona. The upgrade section will also interconnect at TEP's Vail, Tortolita and DeMoss Petrie substations.	Southline Transmission, L.L.C., a subsidiary of Hunt Power	Certificate of Environmental Compatibility was approved by the ACC in February 2017. NMPUC approval was received in August 2017. FERC granted the project authority to sell transmission rights at negotiated rates on the line. Project design of the Upgrade portion is under way with WAPA. Construction will commence pending sufficient subscriptions for service and land acquisition. TEP is working with the project developer on interconnections to the TEP system at three locations. In 2020, TEP acquired the rights to develop the Vail – Tortolita portion of the Southline Transmission Project. More information on this project can be found in Chapter 6.
Western Spirit Clean Line	Approximately 150-mile transmission beginning near Corona, NM and terminating at the Rio Puerco Substation.	Renewable Energy Transmission Authority of New Mexico ("RETA") and Pattern Development	Approval of the route was received from RETA. Bureau of Indian Affairs issued a Grant of Easement in 2017. FERC granted Pattern authority to sell transmission rights on the line at negotiated rates.

CHAPTER 6

TEP EXISTING RESOURCES

This section provides an overview of TEP's existing thermal generation, renewable generation, energy storage and transmission resources. For the thermal generation resources, chapter provides details on each station's ownership structure, fuel supply, environmental controls, historical emissions, and a brief future outlook. For the renewable generation and storage resources, this section provides capacity and technology information as well as details on the construction of the facilities. Information on TEP's existing transmission system is provided in the transmission section below. Finally, this chapter highlights TEP's future plans to join the California Independent System Operator (CAISO) EIM in the Spring of 2022.

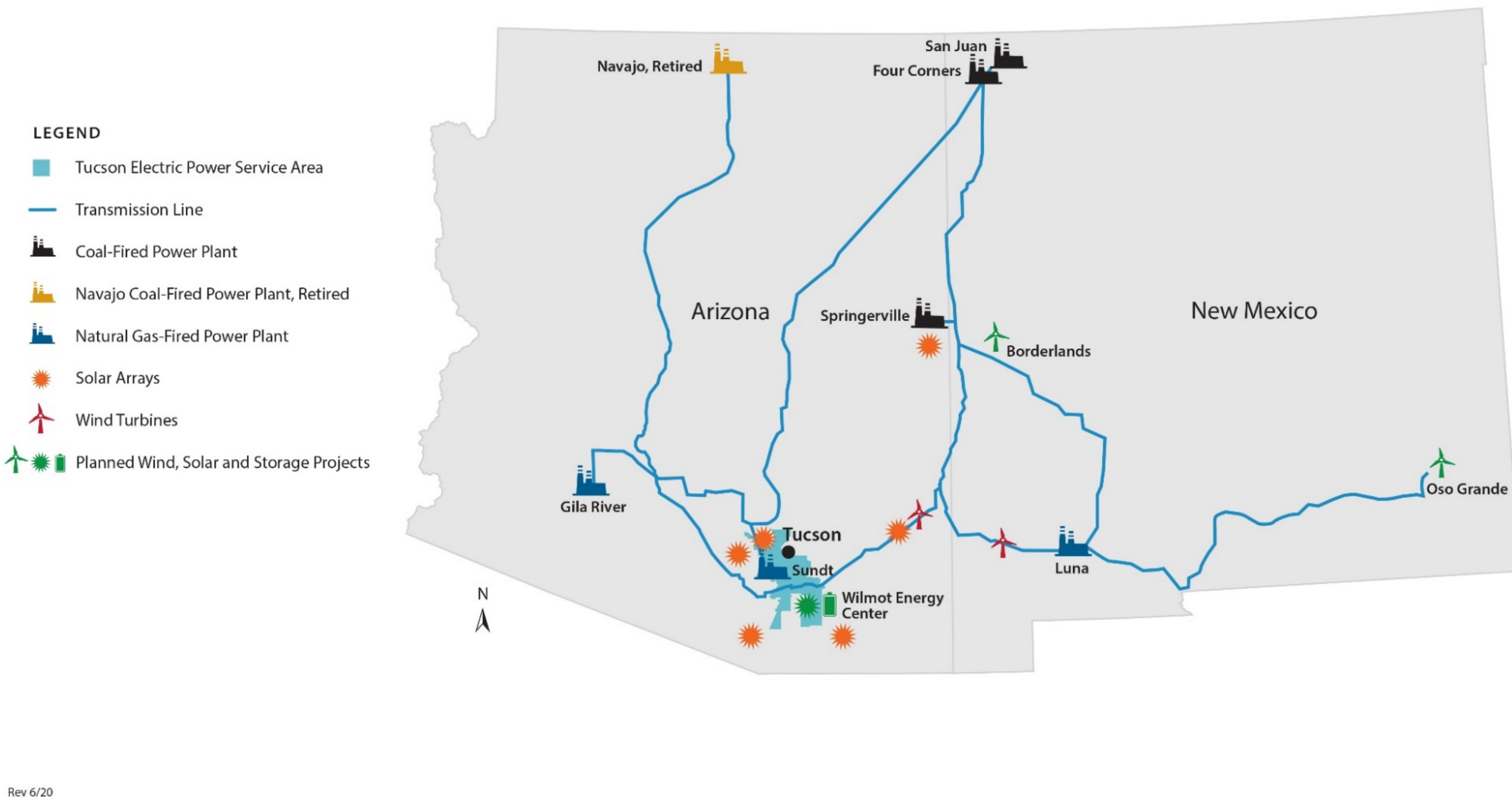
TEP's Existing Resource Portfolio

TEP's existing thermal resource capacity is 2,890 MW. In addition, the Company may utilize the wholesale market for firm capacity PPAs to meet its summer peak obligations. Table 8 below provides a summary of TEP's existing thermal resources.

Table 8 - TEP Existing Thermal Resources

Generating Station	Unit	Fuel Type	Net Nominal Capability MW	Commercial Operation Year	Operating Agent	TEP's Share %	TEP Planning Capacity
Springerville	1	Coal	387	1985	TEP	100	387
Springerville	2	Coal	406	1990	TEP	100	406
San Juan	1	Coal	340	1976	PNM	50	170
Four Corners	4	Coal	785	1969	APS	7	55
Four Corners	5	Coal	785	1970	APS	7	55
Sundt Steam	3 & 4	Gas	260	1962-1967	TEP	100	260
Sundt RICE	1- 10	Gas	188	2019 -2020	TEP	100	188
Luna Energy Facility		Gas	555	2006	PNM	33.3	185
Gila River	2	Gas	550	2003	TEP	100	550
Gila River	3	Gas	550	2003	TEP	75	413
Combustion Turbines		Gas/Oil	210	1972-2001	TEP	100	221
Total Planning Capacity							**2,890**

Map 3 - TEP System Map

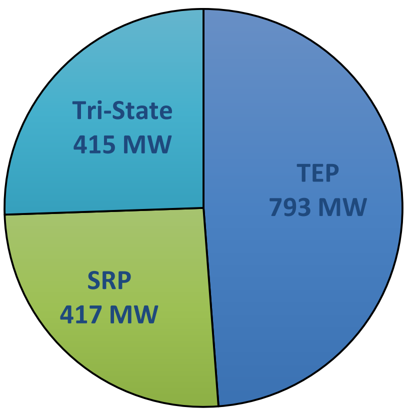


Springerville Generating Station

Springerville Generating Station

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

Ownership Structure:

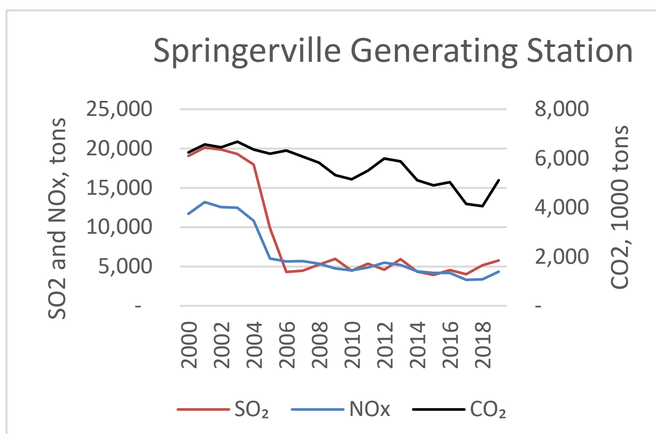


Units	Capacity (MW)	In-Service Date	Planned Retirement
Unit 1	387	1985	2027
Unit 2	406	1990	2032
Unit 3	415	2006	Not Planned
Unit 4	417	2009	Not Planned

Pollution Controls:

Unit	SO_2	NOx	PM	Hg
1	SDA	LNB SOFA	FF	ACI, $CaBR_2$
2	SDA	LNB SOFA	FF	ACI, $CaBR_2$
3	SDA	SCR	FF	ACI, $CaBR_2$
4	SDA	SCR	FF	ACI $CaBR_2$

SDA – Spray Dry Absorber
FF – Fabric Filter (Bag house)
LNB SOFA – Low NOx burners – Separated overfired air
SCR – Selective catalytic reduction
$CaBR_2$ – Calcium bromide (added to coal)
ACI – Activated carbon injection



Participation Agreement:

Expires January 1, 2078

Coal Supply:

Agreement signed June 17, 2003 with Peabody Energy sourced from El Segundo / Lee Ranch, expires December 31, 2020. Currently finalizing a contract extension through 2023.

Outlook:

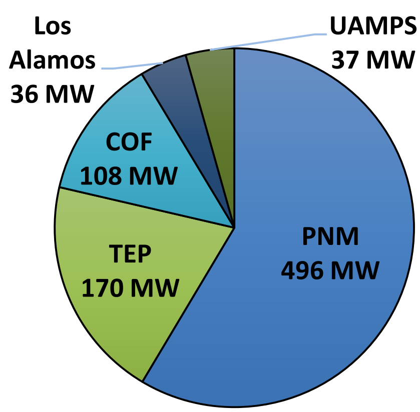
Unit 1 will transition to seasonal operation in 2023 and Unit 2 in 2024. Unit 1 scheduled to retire at the end of 2027. Unit 2 is scheduled to transition to summer only operation in 2030 and retire after the summer of 2032.

San Juan Generating Station

San Juan Generating Station

San Juan Generating Station ("San Juan") is a two-unit, coal-fired steam electric generating station located 17 miles west of Farmington, New Mexico. Public Service Company of New Mexico (PNM) is the operating agent for both units. Unit 1 is owned by TEP and PNM. Units 2 and 3 were retired at the end of 2017. Unit 4 is owned by PNM, the City of Farmington New Mexico, the County of Los Alamos, New Mexico and the Utah Associated Municipal Power System (UAMPS).

Ownership Structure (after 2017):



Units(1)	Capacity (MW)	Entered Service	Planned Retirement
Unit 1	340	1976	2022
Unit 4	507	1982	2022

(1) Units 2 and 3 were retired in 2017.

Participation Agreement:

Expires June 30, 2022

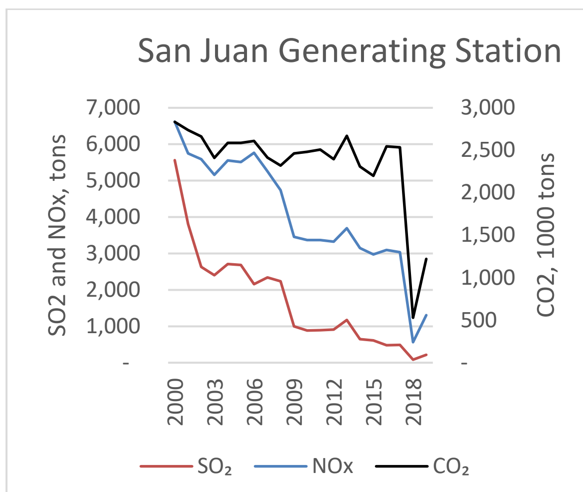
Coal Supply:

Agreement with Westmoreland Coal Company sourced from the San Juan Mine is effective from January 2016 through June 2022.

Pollution Controls:

Unit	SO_2	NOx	PM	Hg
1	FGD	SNCR	FF	ACI
4	FGD	SNCR	FF	ACI

FGD – Flue Gas Desulphurization-wet
FF – Fabric Filter (Bag house)
LNB SOFA – Low NOx burners – Separated overfired air
SNCR – Selective non-catalytic reduction
ACI – Activated carbon injection



Outlook:

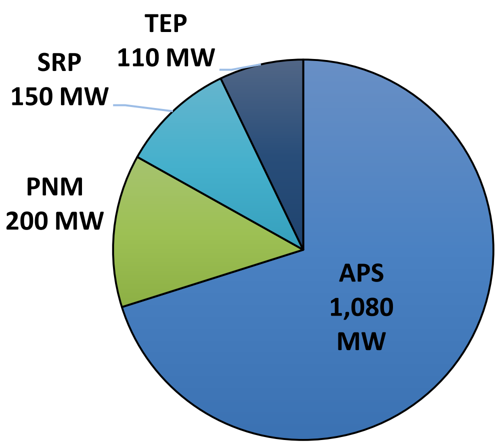
Both units are scheduled to retire at the end of June 2022, coinciding with the expiration of the plant participation agreement and coal supply agreement.

Four Corners Power Plant

Four Corners Power Plant

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

Ownership Structure:



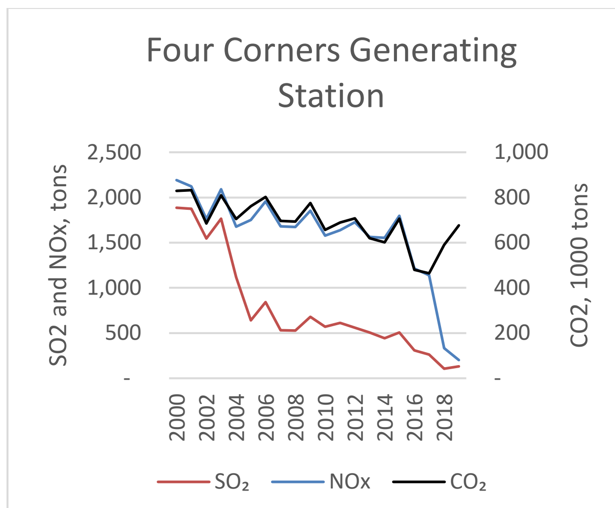
Units(1)	Capacity (MW)	In-Service Date	**Planned Retirement**
Unit 4	770	1969	2031
Unit 5	770	1970	2031

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

Pollution Controls:

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

FGD – Flue gas desulfurization-wet
FF – Fabric Filter (Bag house)
SCR – Selective catalytic reduction
$CaBR_2$ – Calcium bromide (added to coal)



Participation Agreement:

Co-tenancy agreement expires July 2041.

Coal Supply:

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

Outlook:

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

H. Wilson Sundt Generating Station

H. Wilson Sundt Generating Station

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

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

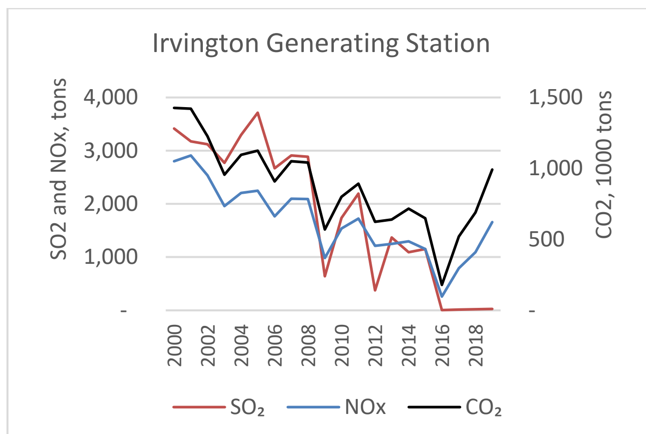
- **Improved efficiency:** RICE units use less natural gas to generate the same amount of energy as a conventional natural gas-fired generator. They are 40 percent more efficient than the units they are replacing.
- **Lower emissions**: Transitioning to the RICE generators will reduce local NOx emissions by 60 percent, contributing to cleaner air.
- **Water savings:** The RICE units reduce the use of water at the Sundt Generating Station by 70 percent, a savings of more than 455 million gallons annually.

Units	Capacity (MW)	In-Service Date	Planned Retirement
RICE Units 1-5	94	2019	Not Planned
RICE Units 6-10	94	2020	Not Planned
Steam Unit 3	415	2006	2032
Steam Unit 4	417	2009	Not Planned

Pollution Controls:

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

SCR – Selective catalytic reduction
LNB SOFA – Low NOx burners – Separated overfire air
NA – Not Applicable



Fuel Supply:

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

Outlook:

In 2015, Sundt Unit 4 permanently eliminated the use of coal. Historically low natural gas prices have resulted in higher utilization of the Sundt units in 2018 and 2019. With the RICE in operation, Sundt Units 3 and 4 will transition to seasonal operation, remaining idle for most of October through March.

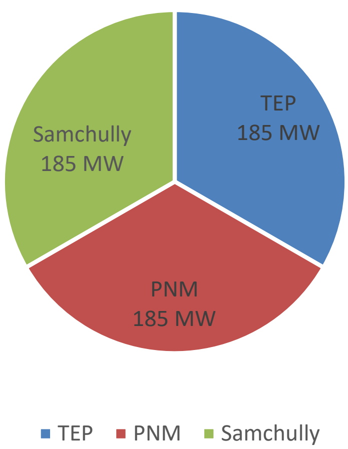
Luna Energy Facility

Luna Energy Facility

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

Ownership:

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



Units	Entered Service	Planned Retirement
Power Block 1	2006	Not Planned

Fuel Supply:

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

Pollution Controls:

Luna Energy Facility is a natural gas-fired combined cycle combustion turbine with dry LNB and SCR for NO_x control. As a greenfield site, a Prevention of Significant Deterioration (PSD) permit was obtained prior to construction. A PSD permit requires that Best Available Control Technology ("BACT") be applied for control of SO_2 and NO_x, and the facility must comply with the Acid Rain program limits for SO_2 and NO_x.

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

SCR – Selective Catalytic Reduction
NA – Not Applicable

Outlook:

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

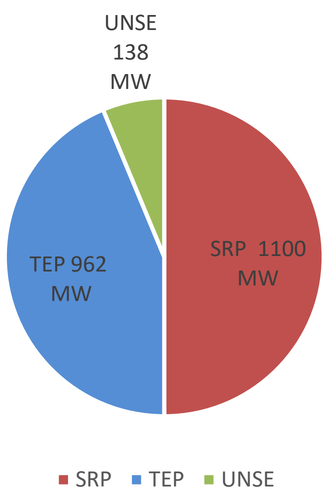
Gila River Generating Station

Gila River Generating Station

Gila River Generating Station ("Gila River") is a 2,200 MW four block, 2 on 1 natural gas-fired combined cycle electric generating station located three miles north of the town of Gila Bend, in Maricopa County, Arizona. The plant is operated by SRP.

Ownership:

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



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

Fuel Supply:

Each Gila River participant manages its own gas supply. TEP and UNSE purchases natural gas on the spot market and through hedging contracts that are consistent with the UNS Energy Hedging policy. The plant has access to two separate pipelines operated by Kinder Morgan and Transwestern.

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 Blocks 2 and 3 some of the lowest cost generation assets for both TEP and UNSE. Gila River's fast ramping capabilities, along with its real-time integration into TEP's balancing authority, provide both TEP and UNS Electric with an ideal resource to support the integration of future renewables.

Combustion Turbines

Combustion Turbines

The Company has 219 MW of gas or oil fired combustion turbines for peaking capacity. This capacity is comprised of 6 units at three locations, 50 MW split between two units at Sundt, 96 MW split between four units at North Loop, and one 75 MW unit at DeMoss Petrie. All locations are in or around Tucson and are all operated from the Sundt Station. TEP owns and operates all the units.

North Loop Generating Station

Ownership:

The combustion turbines are 100 percent owned by TEP.

Units	Capacity (MW)	Entered Service	Planned Retirement
Sundt CT Unit 1	25	1972	2027
Sundt CT Unit 2	25	1973	2027
DeMoss Petrie	75	2001	Not Planned
North Loop Unit 1	25	1972	2027
North Loop Unit 2	25	1972	2027
North Loop Unit 3	23	1972	2027
North Loop Unit 4	21	2001	Not Planned

Fuel Supply:

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

Outlook:

The retirement dates listed for the Sundt and North Loop combustion turbines are estimates based on plant depreciation. Firm retirement will be dependent on the acquisition of replacement capacity as needed. In addition, the Sundt combustion turbines provide black start capability to the Bulk Electric System. An alternative black start resource would be needed before these units can retire.

Environmental Requirements

Overview

The electric generating sector currently faces numerous regulations related to air quality, waste generation, protection of water (both surface waterways and groundwater), and climate change. Fossil fuel-fired power plants, particularly coal-fired power plants, are significant sources of sulfur dioxide (SO_2), nitrogen oxides (NOx), particulate matter (PM), and CO_2 as well as mercury and other hazardous air pollutants. These power plant emissions are limited through several statutory and regulatory programs. As these regulatory programs have evolved, they have had, and will continue to have important implications for public health, for the mix of U.S. generating resources, and for economic growth by driving investment in new and cleaner technologies and contributing to the retirement of the more inefficient and higher emitting plants. The discussion below provides a snapshot of the major environmental regulatory programs facing the electric generating sector that may have an impact on TEP.

Regional Haze

The Environmental Protection Agency's (EPA) Regional Haze Rule[12] establishes a goal to reduce visibility impairment in Class I areas (National Parks, Monuments, etc.) to natural conditions by 2064. Progress toward this long-term goal is measured in 10-year planning periods. For each planning period, states must develop plans that establish goals and emission reduction strategies for improving visibility by reducing emissions from sources located within their respective jurisdictions. States must submit these goals and strategies to the EPA for approval in the form of a State Implementation Plan (SIP). These state plans must achieve "Reasonable Progress" toward the 2064 goal and are reviewed by EPA in relation to that objective. Reasonable Progress is an evaluation on the cost effectiveness of emission reductions for a source based on four factors and in relation to the visibility improvement goals established by the State for that planning period.

In October 2018, the Arizona Department of Environmental Quality (ADEQ) began the stakeholder process to develop a control strategy for making Reasonable Progress toward the national visibility goal for the second implementation period (2018-2028). Neither the Clean Air Act nor any Federal or State regulation expressly requires the evaluation of emission reduction measures for individual facilities, however, the ADEQ indicated that it will perform such facility-specific analyses. During the spring of 2019, ADEQ developed and implemented a Source Screening Methodology[13] for identifying sources to be considered for reasonable potential controls analysis. As a result, ADEQ notified TEP that Sundt (Unit 3) and Springerville (Units 1 and 2) Generating Stations had been selected for potential emissions controls analysis.

In determining what constitutes Reasonable Progress, the Regional Haze rule requires that the analysis consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any existing source subject to the analysis. This analysis is commonly referred to as the four-factor analysis. One of the key metrics for measuring "cost effectiveness" under the evaluation is the cost of the controls divided by amount of emission reductions achieved through implementation of those controls (i.e. $/ton reduced). The higher the $/ ton reduced value, the less likely that those controls will be determined to be "cost effective." TEP submitted the

[12] 40 C.F.R. §§ 51.300 to 51.309.

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

four-factor analysis for Sundt Unit 3 and Springerville Units 1 and 2 to ADEQ in March 2020. Results of those analyses are summarized in Table 9 and Table 10.

Table 9 - Four Factor Analysis Results - Sundt Generating Station Unit 3

Control Measures Evaluated	Results of Evaluation
Combustion Controls (e.g., low-NOx burners, flue gas recirculation)	**Cost effective**
Selective Non-Catalytic Reduction System ("SNCR")	Not cost effective
Selective Catalytic Reduction System ("SCR")	Not cost effective

Table 10 - Four Factor Analysis Results - Springerville Generating Station Units 1 and 2

Control Measures Evaluated	Results of Evaluation
Emissions of SO_2	
Spray Dry Absorber Systems Upgrade	**Technically feasible, cost effective**
Dry Sorbent Injection Systems	Technically feasible, economically inferior
Circulating Dry Scrubber Systems	Technically feasible, not cost effective
Wet Flue Gas Desulfurization	Technically feasible, not cost effective
Emissions of NO_X	
Low-NOX Burners, Overfire Air, and Other Combustion Controls	**Currently installed at Units 1 and 2**
Selective Non-Catalytic Reduction Systems	Technically feasible, not cost effective
Selective Catalytic Reduction Systems	Technically feasible, not cost effective
Emissions of PM	
Fabric Filter Baghouses	**Currently installed; most effective add-on control technology available**
Dry Electrostatic Precipitators	Not superior technology, not feasible
Wet Electrostatic Precipitators	No visibility improvement is feasible
Emissions of NH_3	
Operation without SCR/SNCR	Retro fit of SCR/SNCR would increase NH3 emissions, not feasible
Emissions of VOCs	
Control measure	Emission rates are consistent with rates demonstrated to be achievable

The four factor analyses were submitted to the ADEQ in March 2020 for the agency's use in developing the revised SIP. In June 2020 ADEQ notified TEP that the agency agreed with the results of the four factor analyses as presented by TEP. TEP will continue to work with the agency to determine compliance strategies as needed. The ADEQ must submit the revised SIP to the EPA for approval by July 31, 2021. Based on current Regional Haze requirement timeframes, TEP anticipates that compliance strategies, if any, will likely be required to be implemented three to five years after the 2021 SIP submittal date.

Because Four Corners Power Plan is located on the Navajo Indian Reservation, the facility is not subject to state oversight; the EPA oversees regional haze planning for the units at that plant. TEP will work with APS, the operator of Four Corners Power Plant, to develop compliance strategies, as needed.

Affordable Clean Energy Rule

In June 2019, the EPA repealed the Clean Power Plan, and replaced it with the Affordable Clean Energy Rule ("ACE Rule").[14] The rule established new emissions guidelines for states to use to limit CO_2 emissions from existing coal-fired steam electric generating units (EGU). Under the new rule, EPA set the emission guidelines based on the Best System of Emission Reduction for Greenhouse Gas ("GHG") emissions. The EPA defined Best System of Emission Reduction for GHG emissions from existing coal-fired EGUs as heat-rate improvements (HRI) that can be applied at the source, and identified six candidate technologies and improved operating and maintenance practices for evaluation as shown in Table 11.

Table 11 - Heat Rate Improvement Measures

Neural Network/Intelligent Sootblowers
Boiler Feed Pumps
Air Heater & Duct Leakage Control
Variable Frequency Drives
Blade Path Upgrade (Steam Turbine)
Redesign/Replace Economizer
Improved Operating and Maintenance Practices

The states would then use these emission guidelines to develop a SIP establishing performance standards, considering source specific factors such as the remaining useful life of an individual unit. The ADEQ must submit the SIP to the EPA for approval by July 8, 2022.

The ADEQ began the stakeholder process for development of the SIP in November 2019 and notified subject facilities that HRI analysis would be due to the agency by December 1, 2020. TEP is in the process of conducting the HRI analysis for Springerville Generating Station Units 1 and 2.

The EPA has 12 months to act on a complete state submittal. If a state plan is not approved, or a state fails to submit a plan within the allotted three years, the EPA would have two years to issue a federal plan. Based on current ACE Rule requirement timeframes, TEP anticipates that compliance strategies, if any, will likely be required to be implemented within two years after the 2022 SIP submittal date.

It should also be noted that legal challenges to the rule have been filed and those proceedings could delay the effectiveness and implementation of the new rule.

[14] *Repeal of the Clean Power Plan: Emission Guidelines for Greenhouse Gas Emissions From Existing Electric Utility Generating Units; Revisions to Emission Guidelines Implementing Regulations* – Final Rule, 84 FR 32520, July 8, 2019

Because Four Corners Power Plant is located on the Navajo Indian Reservation, the facility is not subject to state oversight; the EPA oversees the ACE Rule evaluation for this power plant. TEP will work with APS, the operator of Four Corners Power Plant, to develop compliance strategies, as needed.

Ozone

In October 2015, the EPA released the final rule for the 8-hour U.S. National Ambient Air Quality Standards (NAAQS) for ozone. The EPA lowered the standard from 75 parts per billion to 70 parts per billion. If an area does not meet the standard, the area is designated as "non-attainment" and needs to develop a plan to bring the air-shed into attainment. A "non-attainment" designation may slow economic growth in the region. Arizona submitted recommendations for area designations (attainment, non-attainment, or unclassified) to the EPA in September 2016. The EPA completed all area designations as of July 2018. The majority of Arizona counties, including Pima, were designated as "attainment" or "unclassified" except for portions of Gila, Maricopa, Pinal, and Yuma counties.

In 2018, Pima County exceeded the 2015 NAAQS standard for ozone at one monitoring location. If the county continues to exceed the standard, the state could recommend an ozone non-attainment designation for Pima County during the next review period. See Chapter 9 for an evaluation of local NOx emissions (NOx is a contributor to ozone formation) from TEP's Tucson area generation facilities.

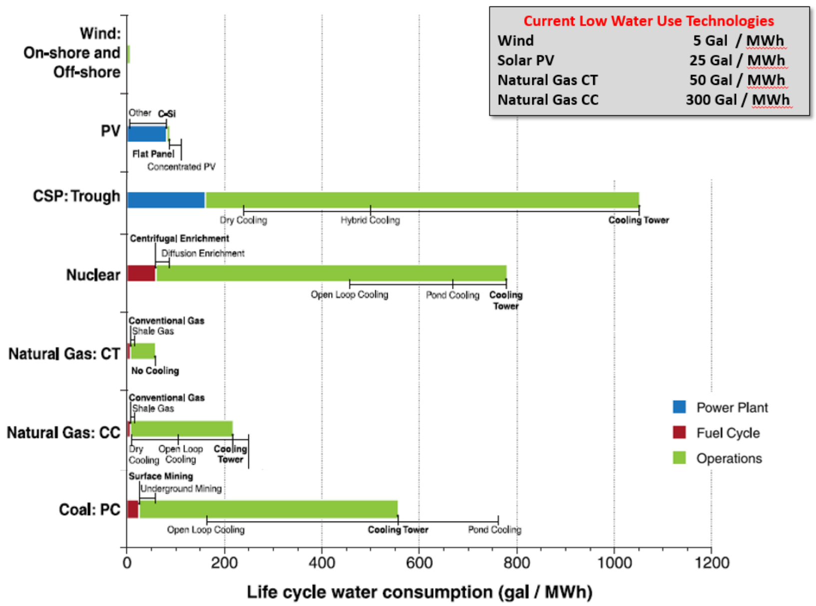
Water Consumption

Water availability is a major issue for utilities operating power plants or planning new resources in the Desert Southwest. For facilities already in operation, utilities need to be cognizant of water use and supply trends in the area immediately surrounding those facilities. While existing facilities have likely secured the legal rights to the water needed for operation, there can be a disconnect between the legal right to water and its physical availability. For this reason, technologies, and strategies to decrease power plant water use can become an important planning goal within the integrated resource planning process. The most effective means of reducing power plant water use is through transitioning to a lower water use generating resource. However, increasing power plant water use efficiency can also be effective. This section provides an overview of TEP's water use at its existing generating facilities and discusses our strategy to reduce overall water consumption.

TEP's resource diversification strategy replaces generation from higher water use coal-fired resources with a corresponding amount of generation from lower water use Natural Gas Combined Cycle (NGCC) plants and zero-water use renewable resources. Chart 21 below for average water consumption rates for various electricity generation technologies. Based on these water consumption rates, TEP's resource diversification will result in lower water consumption for power generation overall.

However, water consumption has a localized environmental impact as well. The availability of water that is withdrawn from surface waters, as in the case of the Four Corners Power Plant (Morgan Lake and the San Juan River) and the San Juan Generating Station (San Juan River), is highly dependent on precipitation and snow pack, as well as other uses. TEP's reference case portfolio calls for retirement of or exit from each of these facilities within the planning period, with the majority occurring within the next two years, which significantly reduces and eventually eliminates any risk of water availability for power generation from surface waters.

Chart 21 - Life Cycle Water Use for Power Generation



The availability of water that is withdrawn from groundwater aquifers, as in the case of Springerville, Sundt, Gila River, and Luna power plants, is dependent on the recharge to and other withdrawals from the aquifer, but is also a function of the hydrogeological characteristics of the aquifer itself.

At Springerville, it is to TEP's advantage, by virtue of an agreement with a local Native American Tribe, to limit withdrawals of groundwater at the plant to 20,000 acre-feet annually. Therefore, there are water conservation measures in place at the plant. For example, the cooling towers for Units 1 and 2 operate at high cycles of concentration, up to 13 cycles before blowdown, which reduces the amount of water used per unit of energy generated. However, the largest reduction in water use will be through reduced operation at the plant through seasonal operations beginning in 2023 through the retirement of the units in 2027 and 2032 (See Chapter 10).

Luna has the ability to reduce groundwater withdrawals by supplementing the well water with treated municipal wastewater provided by the City of Deming, New Mexico. When available, Luna is able to satisfy, on average, 12 percent of its total water demand from municipal wastewater.

Gila River Generating Station is located west of Phoenix, Arizona (in proximity to the Palo Verde Nuclear Generating Station). In this area there is over 6,000 MW of existing NGCC capacity that may see an increase in generation as Arizona utilities like TEP retire coal-fired generation. However, these facilities are too far apart to have a direct impact on each other in terms of groundwater availability.

For the 2020 IRP, TEP includes for each portfolio the change in water consumption over the planning period. For the Preferred Portfolio, the IRP will chart the annual amount of water consumed for power generation along with the source of the water (surface water or groundwater). Increasing water consumption within either of these source categories will be weighed as a risk factor for that portfolio.

Existing Renewable Resources

Over the last several years, TEP has constructed or entered into Purchased Power Agreements ("PPA") for solar and wind resources to provide renewable energy for its service territory. While initially targeting compliance with the Arizona Renewable Energy Standard ("RES") requirement of serving 15 percent of its retail load with renewable energy by 2025, TEP's renewable deployment has far exceeded that requirement. Table 12 below lists TEP's existing solar and wind renewable resources.

Table 12 – TEP's Existing Solar and Wind Renewable Resources

Project Name	Owned or PPA	Location	Operator	Completion/Estimated Date	Capacity MW_{AC}
Fixed Photovoltaic					
Springerville	Owned	Springerville, AZ	TEP	Dec-2010	5.3
Solon UASTP II	Owned	Tucson, AZ	TEP	Jan-2012	4.5
Gato Montes	PPA	Tucson, AZ	Astrosol	Jun-2012	5
Solon Prairie Fire	Owned	Tucson, AZ	TEP	Oct-2012	4.5
TEP Roof tops	Owned	Tucson, AZ	TEP	Dec-2012	0.04
Ft Huachuca I	Owned	Sierra Vista, AZ	TEP	Dec-2014	13.6
Ft Huachuca II	Owned	Sierra Vista, AZ	TEP	Jan-2017	4.4
Iron Horse	PPA	Tucson, AZ	Areva	April-2017	2.04
Single-Axis Tracking Photovoltaic					
Solon UASTP I	Owned	Tucson, AZ	TEP	Dec-2010	1.5
E.ON UASTP	Owned	Tucson, AZ	TEP	Dec-2010	4.8
FRV Picture Rocks	PPA	Tucson, AZ	Macquire	Oct-2012	20
NRG Solar Avra Valley	PPA	Tucson, AZ	First Solar	Oct-2012	25
E.ON Valencia	PPA	Tucson, AZ	Areva	Jul-2013	9.9
Avalon Solar I	PPA	Sahuarita, AZ	Avalon	Dec-2014	29
Red Horse Solar	PPA	Willcox, AZ	Torch	Sep-2015	41
Avalon Solar II	PPA	Sahuarita, AZ	Avalon	Feb-2016	16
Cogenera	PPA	Tucson, AZ	SunPower	Dec-2015	1.1
Concentrated Photovoltaic					
Amonix UASTP II	PPA	Tucson, AZ	Amonix	Apr-2011	2
White Mountain	Owned	Springerville, AZ	TEP	Dec-2014	8.5
Concentrated Solar Power					
Areva Solar	Owned	Tucson, AZ	TEP	Dec-2014	5
Wind					
Macho Springs	PPA	Deming, NM	Element Power	Nov-2011	50.4
Red Horse Wind	PPA	Willcox, AZ	Torch	Sep-2015	30

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

Picture 3 - TEP Solar Facilities Located at the University of Arizona Tech Park

TEP's Energy Storage Projects

The primary advantage of a BESS, in the context of a large utility, is often in its ability to very rapidly change power output levels, much faster than the proportional governor response rate of any conventional thermal generation system. This naturally leads to the use cases of a BESS being centered on short term balancing-type activities. An additional strength is that operating costs of a BESS are generally fixed and independent of usage. In contrast, gas turbine systems have a limited number of start and stop cycles and therefore have an appreciable cost to activate, and they are not necessarily online when needed.

In the spring of 2015, TEP issued a request for proposals for design and construction of a utility-scale energy storage system. TEP sought a project partner to build and own a 10 MW storage facility under a 10-year agreement. TEP was looking for a cost-effective, proven energy storage system that would help integrate renewable energy into its electric grid.

Picture 4 – 10 MW Battery Energy Storage System at DeMoss Petrie

The aggressive nature of the bidding companies far exceeded expectations. In its solicitation TEP received a total of 21 bids; 20 bids for battery technology and one bid for flywheel technology. Within the battery category, there were seven different battery types proposed. Ultimately, TEP was able to select two winning bids. One including a 10 MW, Lithium Nickel-Manganese-Cobalt battery; and a separate one including a 10 MW, Lithium Titanate battery together with a 2 MW solar facility. With these projects, TEP will be able to assess the operational impacts of two of the predominant Lithium technologies available today. Both systems were commissioned during the early months of 2017.

In general, the batteries are used several times a month to respond to frequency deviations and support the greater reliability of the western interconnection. Additionally, the balancing of the grid occasionally requires manual dispatch of these systems. Both Facilities are regularly manually dispatched to ensure reliable operation in both power and energy at critical times.

Transmission

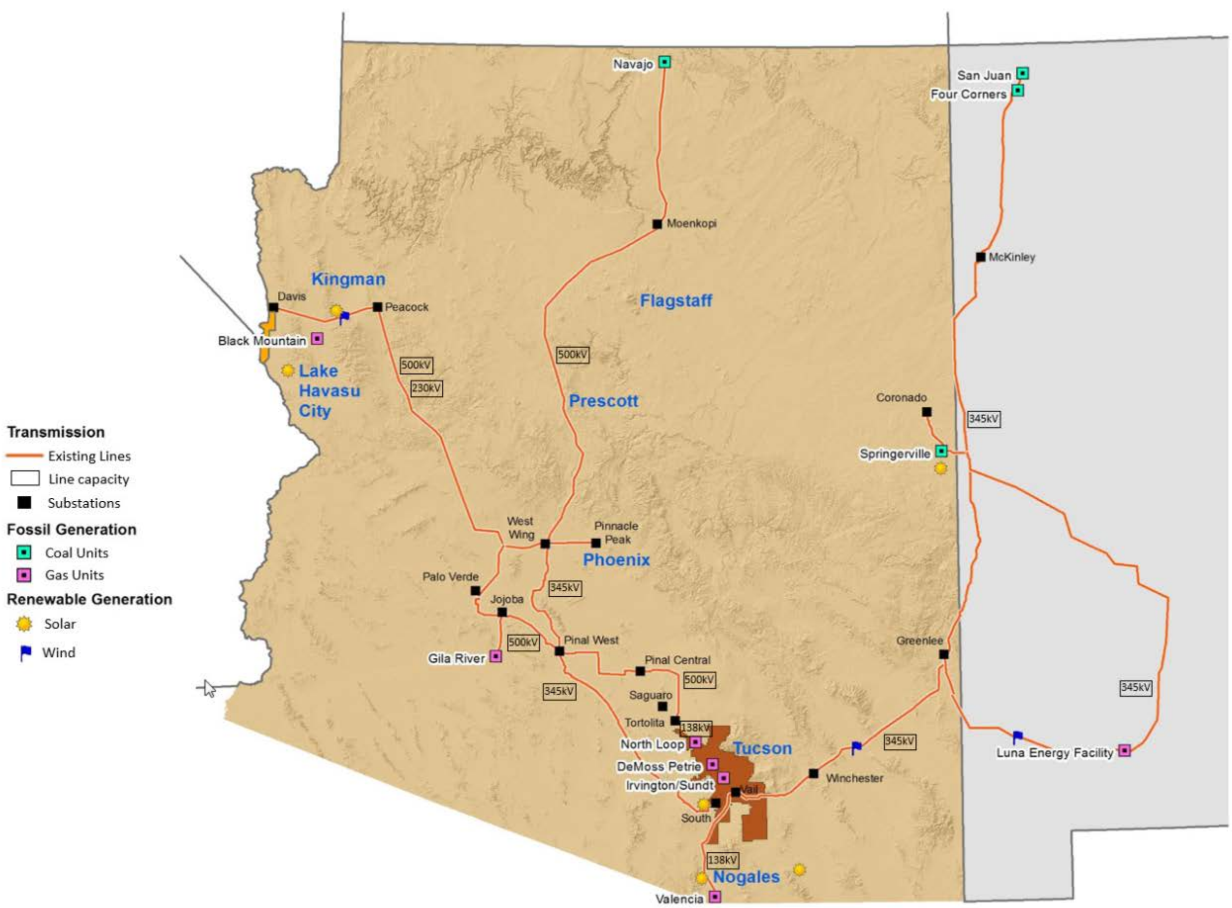
Overview

Transmission resources are a key element in TEP's resource portfolio. Adequate transmission capacity must exist to meet TEP's existing and future load obligations. TEP's resource planning and transmission planning groups coordinate their planning efforts to ensure consistency in development of its long-term planning strategy. On a statewide basis, TEP participates in the ACC's BTA which produces a written decision by the ACC regarding the adequacy of the existing and planned transmission facilities in Arizona to meet the present and future energy needs of Arizona in a reliable manner.

TEP's Existing Transmission Resources

TEP's existing transmission system was constructed over several decades to support the delivery of the base load coal generation resources in northern Arizona and New Mexico. Today, TEP owns approximately 473 miles of 46 kV lines, 425 miles of 138 kV lines, and is owner and part owner of 1,110 miles of 345 kV lines and 657 miles of 500 kV lines. As shown in Map 4Map 4, the Tucson service territory area is interconnected to the Western Interconnection Bulk Electric System via 345 kV interconnections at the South Loop and Vail substations, and a 500 kV interconnection at the Tortolita substation. These three substations interconnect and deliver energy from the EHV transmission network to the local TEP 138 kV system.

Map 4 - TEP's Existing Transmission Resources (includes rights on other systems)



Vail – Tortolita 230kV Project

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

Energy Imbalance Markets

Energy Imbalance Markets are specialized wholesale power markets designed to help Control Areas,[15] such as TEP's, 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 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:

- Produce economic savings to customers through lower production costs
- Improve visibility and situational awareness for system operations in the Western Interconnection
- Improve integration of renewable resources

CAISO Western EIM

In December 2016, Energy and Environmental Economics ("E3") completed a study for TEP, which estimated that joining the CAISO Western EIM could have benefits for TEP of approximately $6 million per year (lower bound). Since then, PNM and SRP, which have significant transmission connections with TEP, have announced their intention to join and have since joined, the Western EIM.[16] The expansion of the Western EIM, including parties connected to TEP's system, will improve the Company's access to EIM market opportunities while reducing real-time non-EIM bilateral trading opportunities as others enter the EIM market. Thus, an updated analysis was completed in November 2018, which estimated annual benefits of $13.6 million. Based on these considerations, TEP signed an agreement with the CAISO in May 2019 to join the Western EIM beginning in April 2022.

[15] 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.

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

CHAPTER 7

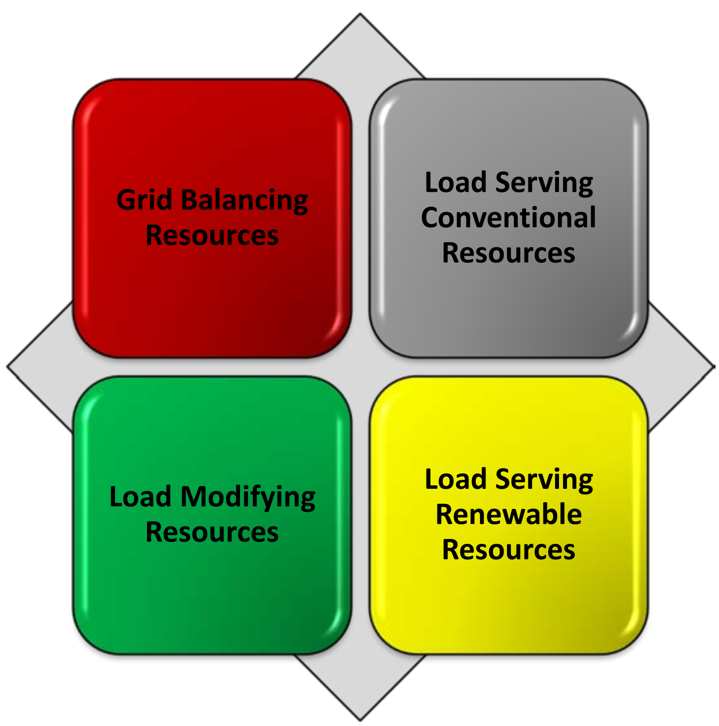
FUTURE RESOURCE ALTERNATIVES

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. Based on this information and TEP's current resource mix and commitment to reducing carbon emissions, only solar, wind, and battery storage were considered as future resources when developing alternative portfolios for analysis. 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 all-source RFP issued by TEP, it would be considered equally with all other technologies based on the specific criteria established in the RFP.

Resource Categories

The TEP 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 TEP'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 9 and are described in more detail below:

Figure 9 – 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 TEP 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, TEP 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 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 13 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 13 – 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	No	High	Low
	Solar PV	Yes	Low	Yes	Medium	Low
	Solar Thermal	Yes	Low	Yes	Medium	Medium
	Biomass	Yes	High	No	High	Medium
	Geothermal	Yes	High	No	High	Medium
Load Serving Conventional Resources	Natural Gas Combined Cycle	No	High	Yes	Medium	High

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

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

Resource Benchmarking and Source Data

Prior to eliminating any resources from consideration or running any detailed simulation models with candidate technologies, TEP 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, TEP 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

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

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

  TEP 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. TEP 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

  TEP 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/

  TEP 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.[17]

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 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.[18]

Forecast Outlook on Conventional Renewable Resources

Renewable energy costs continue to decline, competing with conventional resource technologies.[19] 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

[17] 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.
[18] https://www.eia.gov/todayinenergy/detail.php?id=37817
[19] 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.[20] 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.[21] 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 22 through Chart 25 show the nominal capital cost forecasts used by TEP 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.[22] 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 and in the 2017 IRP.

[20] Lazard's LCOS v5.0
[21] 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.
[22] 8-hour batteries were assumed to have a capital cost 1.8 times greater than 4-hour batteries of the same power rating.

Chart 22 - TEP Capital Cost Forecast for Solar PV Single-Axis Tracking

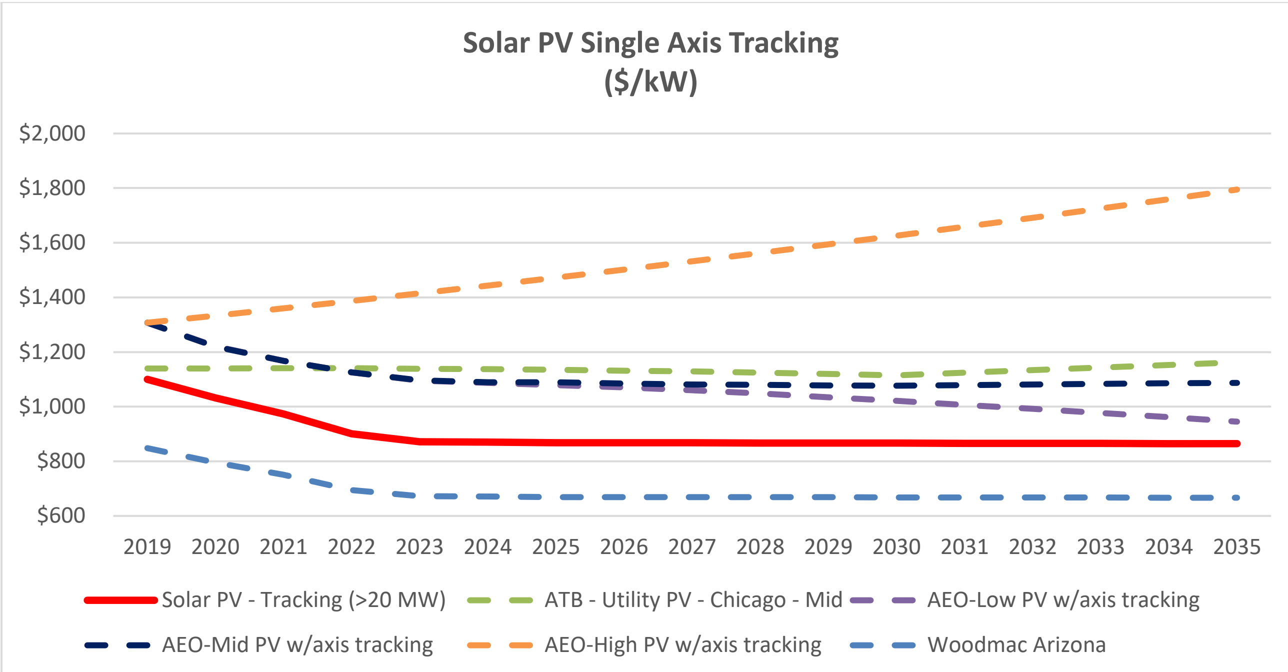


Chart 23 - TEP Capital Cost Forecast for Onshore Wind

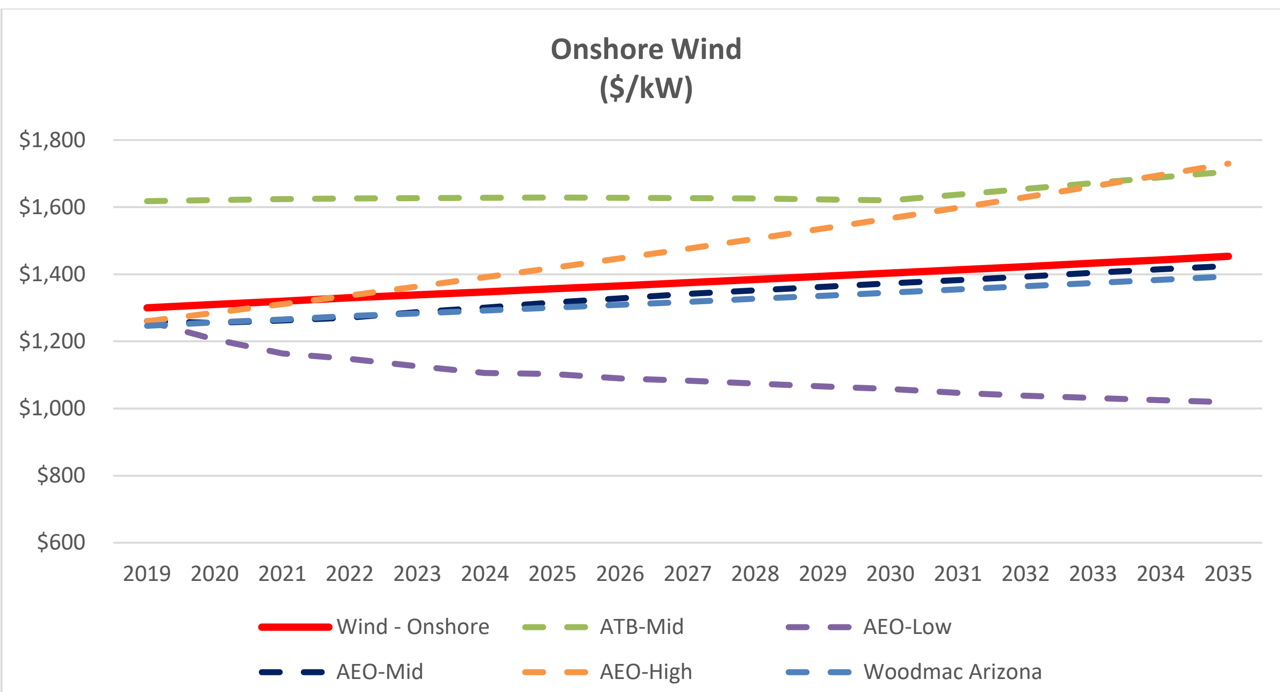


Chart 24 - TEP Capital Cost Forecast for 4-Hour Battery Storage

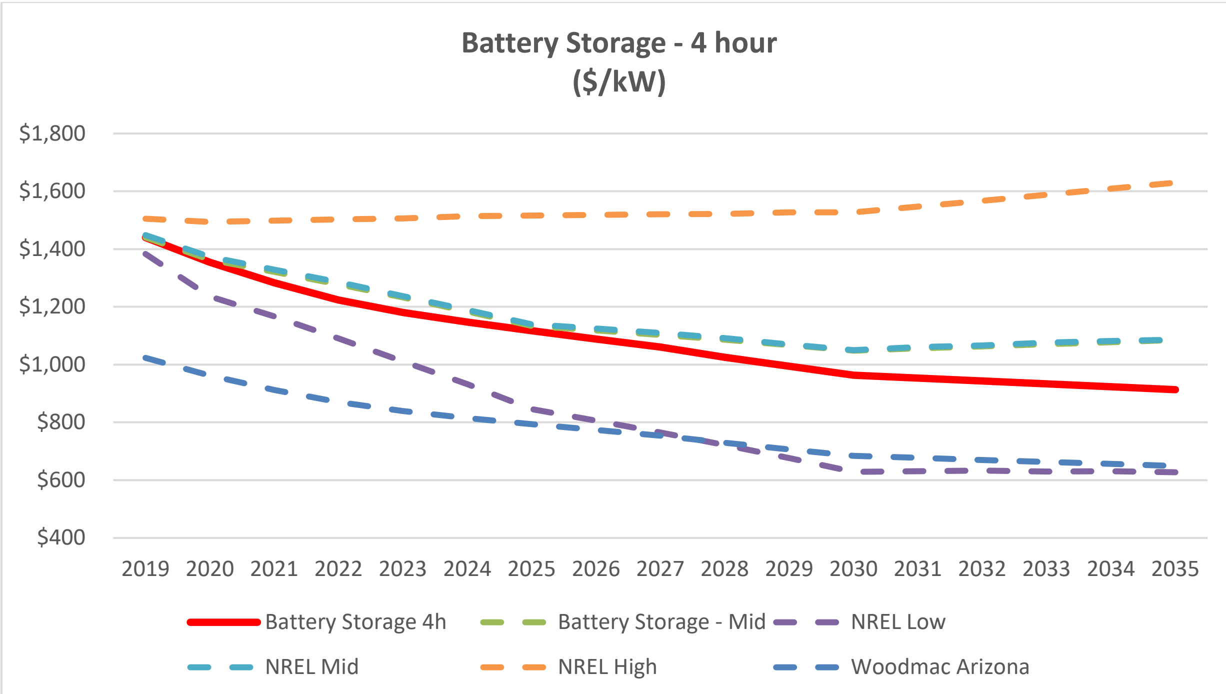
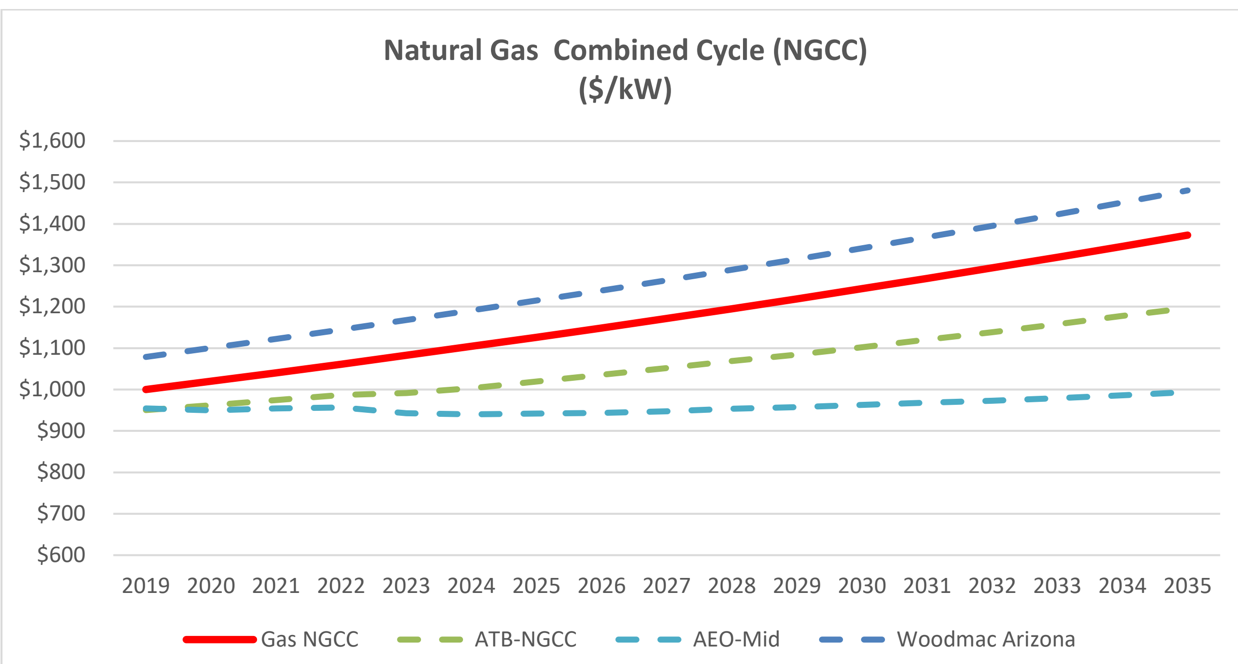


Chart 25 - TEP Capital Cost Forecast for Natural Gas Combined Cycle



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.

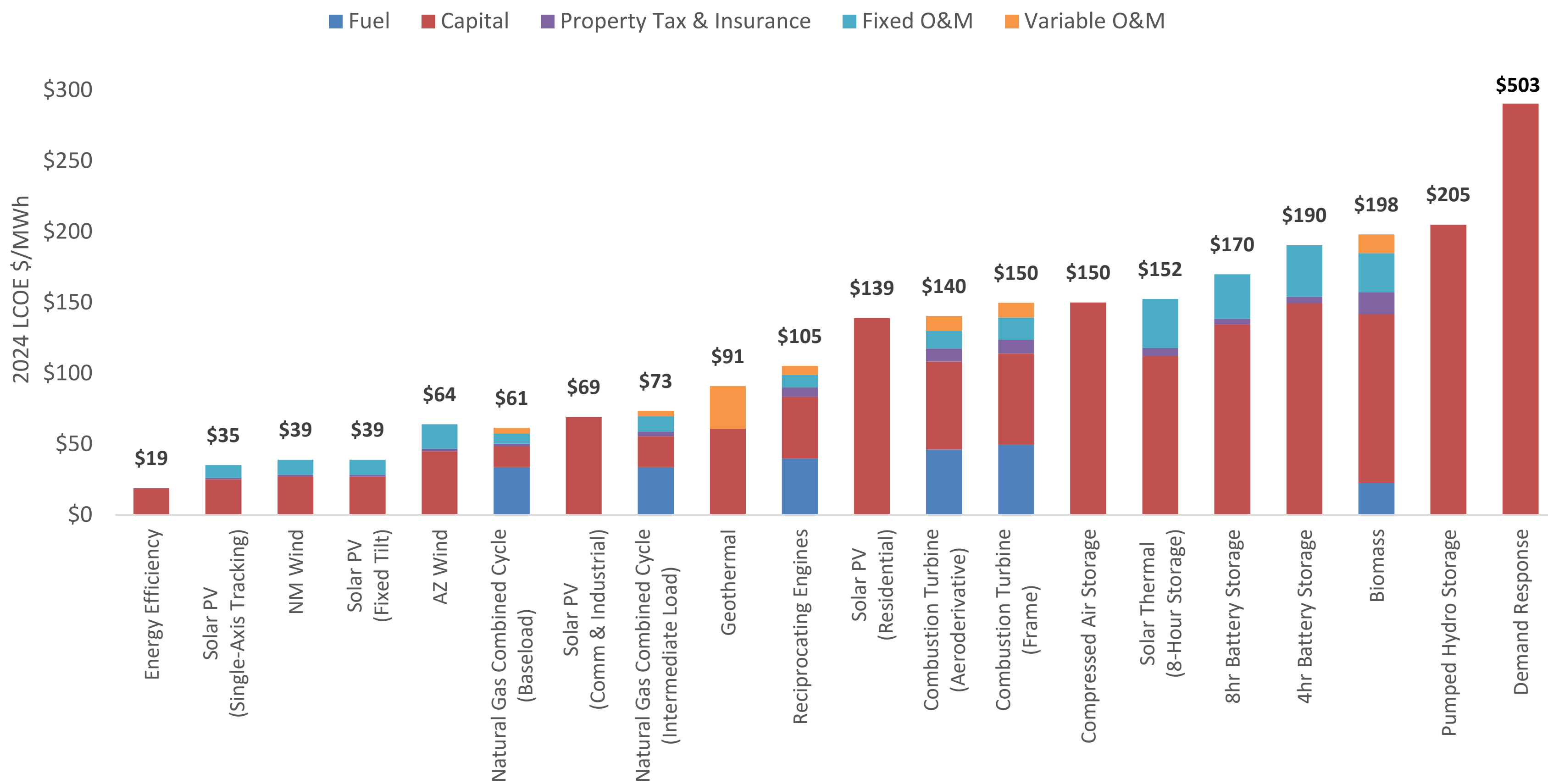
Cost Assumptions for All Resources

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

- Costs are in 2024 dollars and assume installations in 2024, which is the time frame in which many portfolios considered by TEP 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 26 below provides a comparison of the levelized costs of a variety of resources.

Chart 26 - Levelized Costs of All Resources



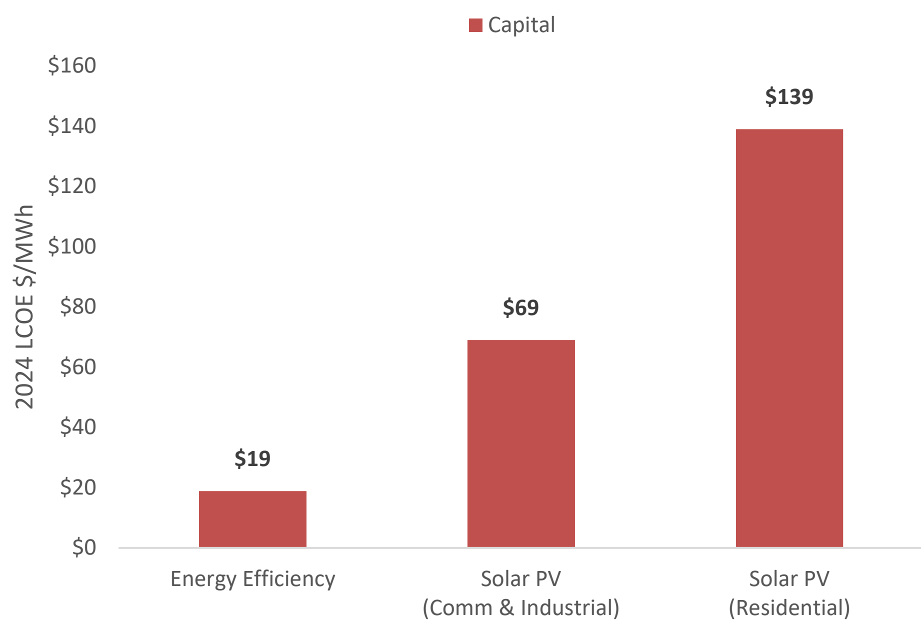
Cost Assumptions for Load Modifying Resources

Table 14 includes the load modifying resource costs for the 2020 IRP.

Table 14 – 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 27 - LCOE for Load Modifying Resources



LCOE Assumptions for Load Modifying Resources:

- Energy efficiency is based on TEP'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

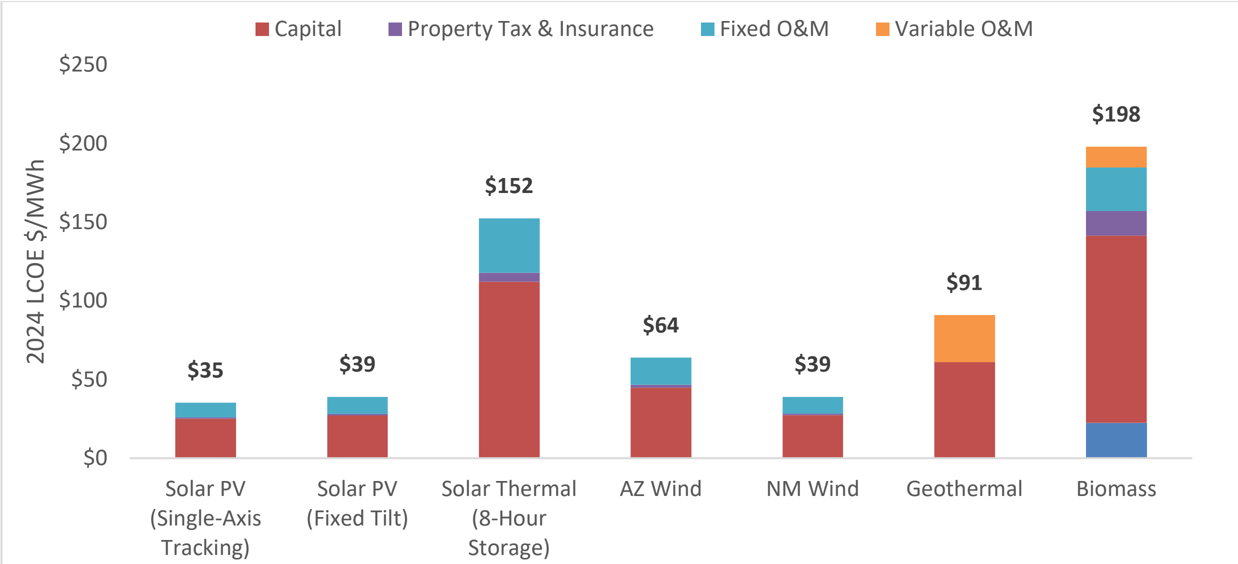
Table 15 includes the load serving renewable resource costs for the 2020 IRP. The levelized costs for biomass and geothermal energy were obtained directly from Lazard. As a result, their component costs are not included in Table 15.

Table 15 – 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[23]	-	-	-	-
Levelized Cost of Energy	$/MWh	$152	$39	$35	$64	$39

[23] 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 28 - 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.

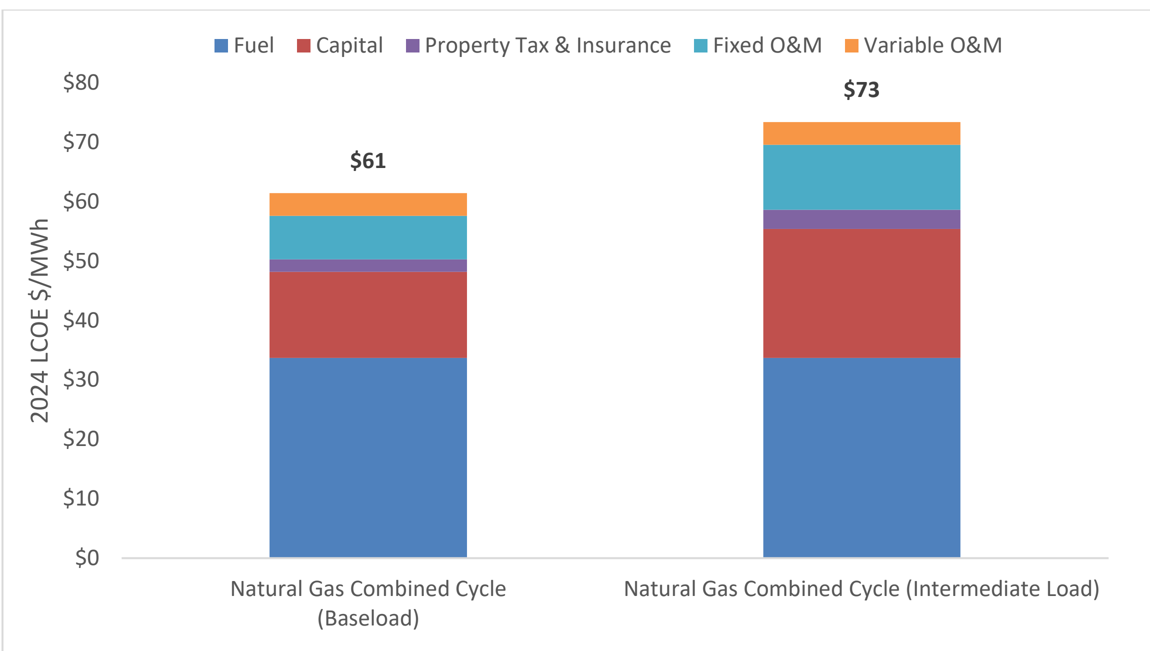
Cost Assumptions for Conventional Load Serving Resources

Table 16 includes the load serving conventional resource cost assumptions for the 2020 IRP.

Table 16 – 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 29 - LCOE for Conventional Load Serving Resources



Cost Assumptions for Grid Balancing Resources

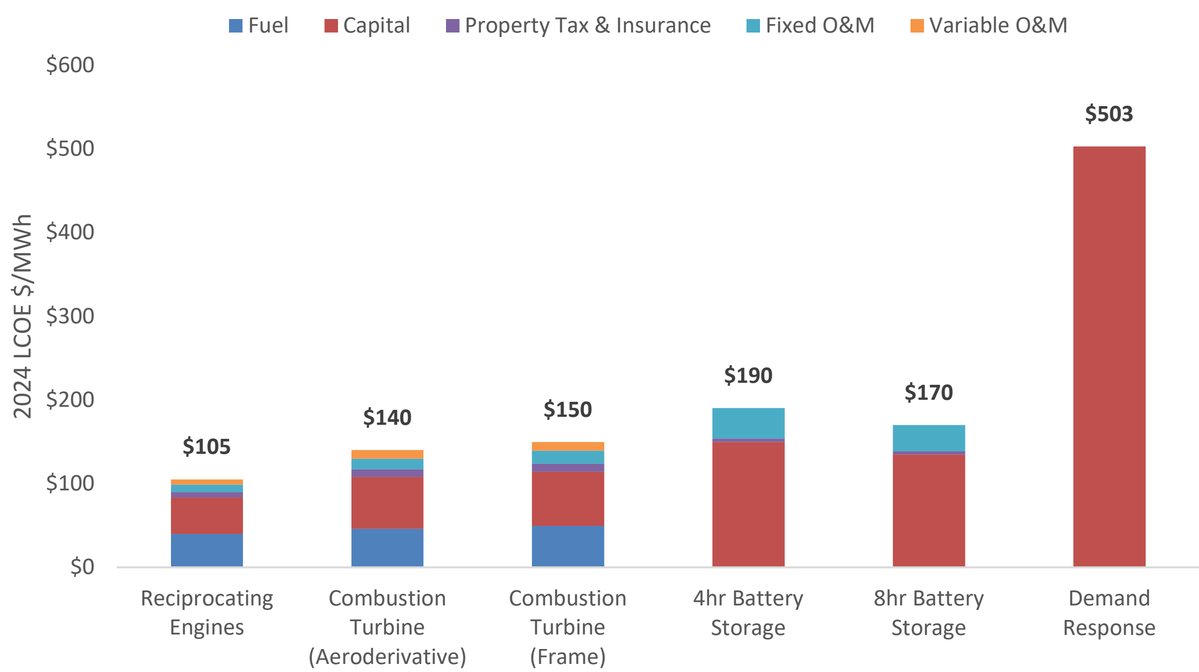
Table 17 includes the grid balancing resource cost assumptions for the 2020 IRP.

Table 17 – 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 30 - 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

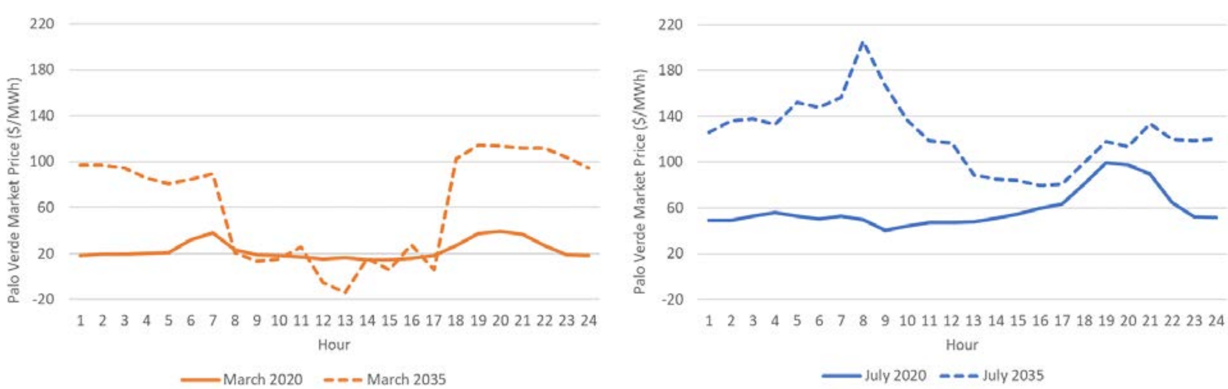
Desert Southwest Wholesale Power and Natural Gas Markets

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 TEP 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 TEP's portfolio modeling is important to account for how wholesale market opportunities are likely to affect TEP's dispatch and operating costs.

To capture this effect, TEP 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 31 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.

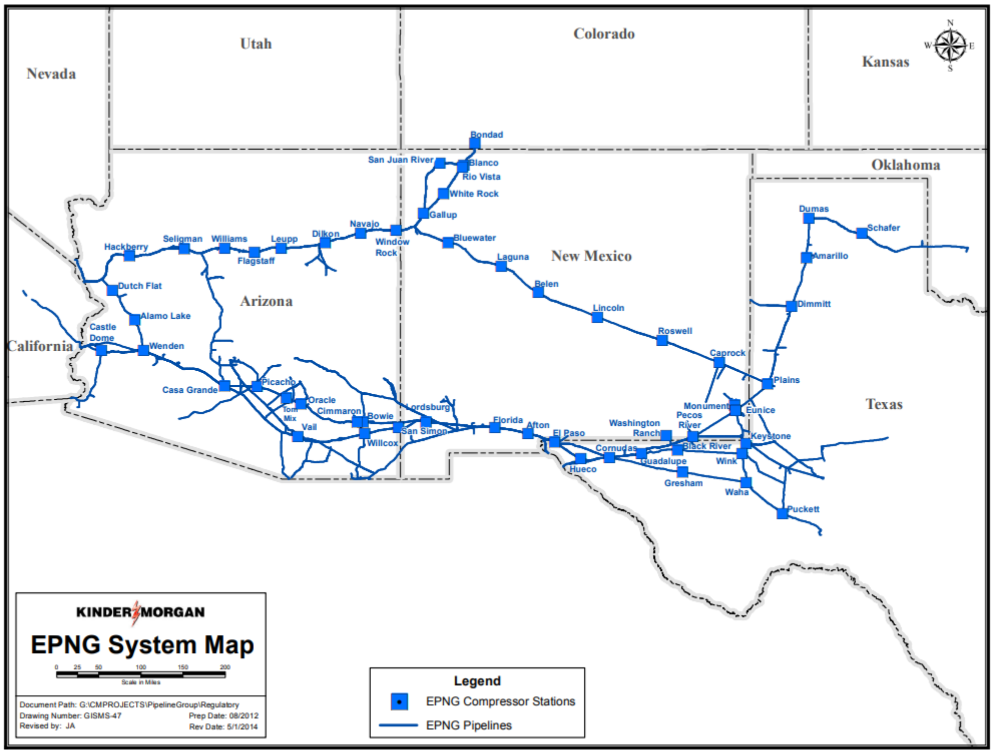
Chart 31 - Palo Verde Wholesale Market Price Forecasts



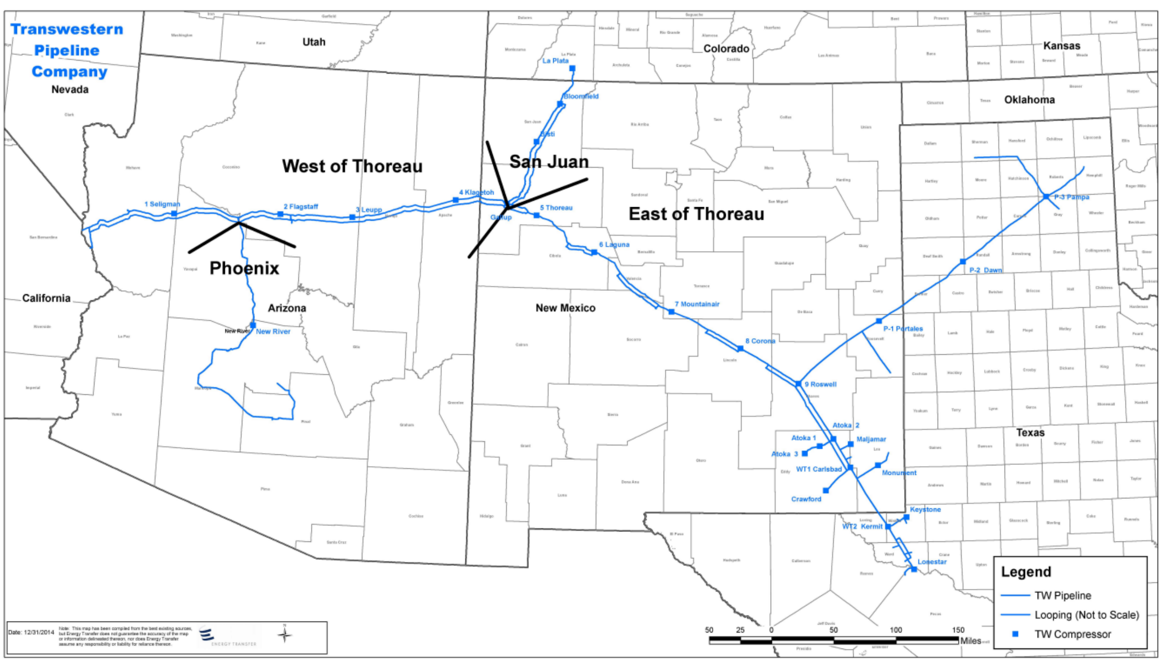
El Paso Natural Gas (EPNG) and Transwestern Pipelines

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

Map 5 – EPNG Pipeline Network Map[24]



Map 6– Transwestern Pipeline Network Map[25]



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

Arizona Natural Gas Storage

As TEP reduces its reliance on coal, cleaner, more efficient natural gas will play a bigger role in maintaining the Company's grid operations. Today, TEP relies on the EPNG and Transwestern pipeline networks to deliver natural gas primarily from the San Juan and Permian supply basins to support its long-term, as well as real-time power generation needs. 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, TEP will continue to evaluate natural gas storage as an option to further support its hourly gas balancing and generation ramping requirements. Ultimately, the decision to 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 TEP's generation fleet.

Forward Fuel and Power Forecasts

Fuel and power forecasts are prepared by TEP using independent third-party sources. Near-term natural gas prices are based on 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. TEP 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.[26] From 2025-2035 the data is extrapolated by using the growth rates of Wood MacKenzie's Henry Hub gas prices.[27] 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.[28] Market information is updated every business day and TEP uses the monthly data from Palo Verde's on and off-peak to develop its long-term forecast assumptions through 2035. Beyond 2035, TEP 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.

[26] 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

[27] 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

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

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.[29] 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 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.[30] 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

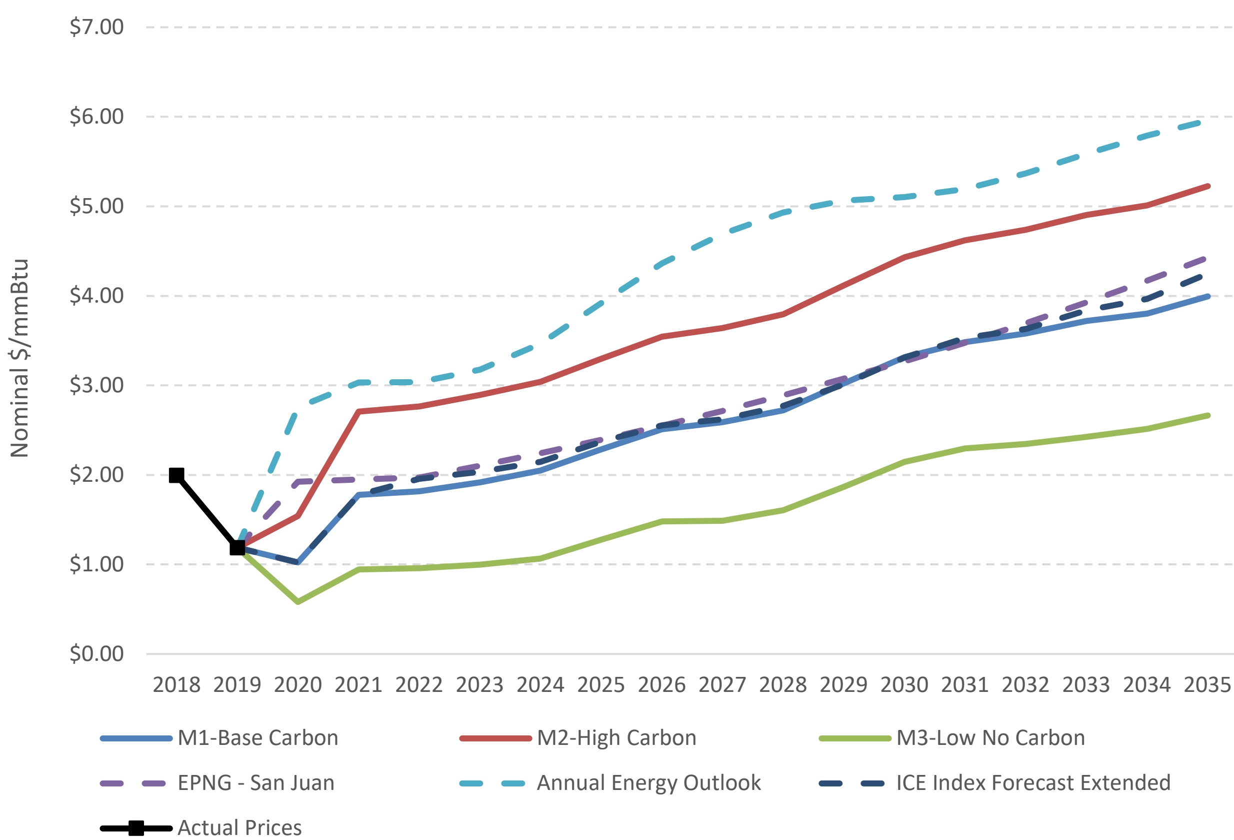
Modeling the performance of a resource portfolio involves making assumptions about future conditions such as economic growth, fuel and wholesale power markets, regulatory conditions (e.g. emission prices), and the pace of technological development. TEP seeks to identify a reference case portfolio that 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.

[29] 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
[30] 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 32 shows the full range of natural gas price sensitivities considered in the 2020 IRP.

Chart 32 - Natural Gas Price Sensitivities



Coal Prices

TEP currently has ownership shares in three coal-fired power plants in Arizona and New Mexico, most of which are under long-term contracts for coal supply.

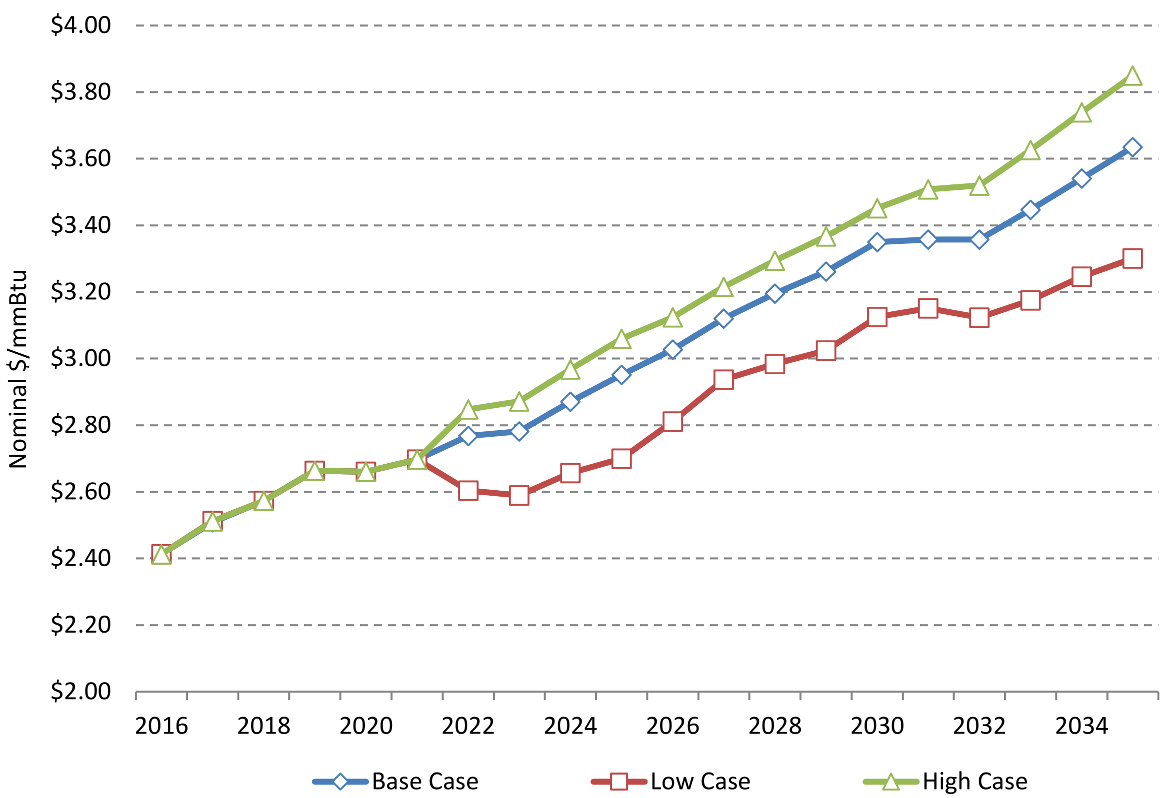
- **San Juan:** The plant is a mine-mouth facility that receives coal from the San Juan mine. It has a short-term contract through July 2022 that expires with planned retirement of San Juan Unit 1.

- **Springerville:** The plant has access to coal from the El Segundo mine in New Mexico via rail deliveries. Springerville can also burn subbituminous coal sourced from Colorado and the Powder River Basin.

- **Four Corners:** The Four Corners Power plant is sourced from the Navajo Coal mine, which is a mine-mouth facility, operated by the Navajo Transitional Energy Company. The Four Corners' coal supply agreement runs through June 2031.

  TEP's assumptions for coal prices are based on contract indices and escalators that are part of existing coal supply agreements. Chart 33 reflects the TEP weighted average coal pricing for the base, low, and high scenarios.

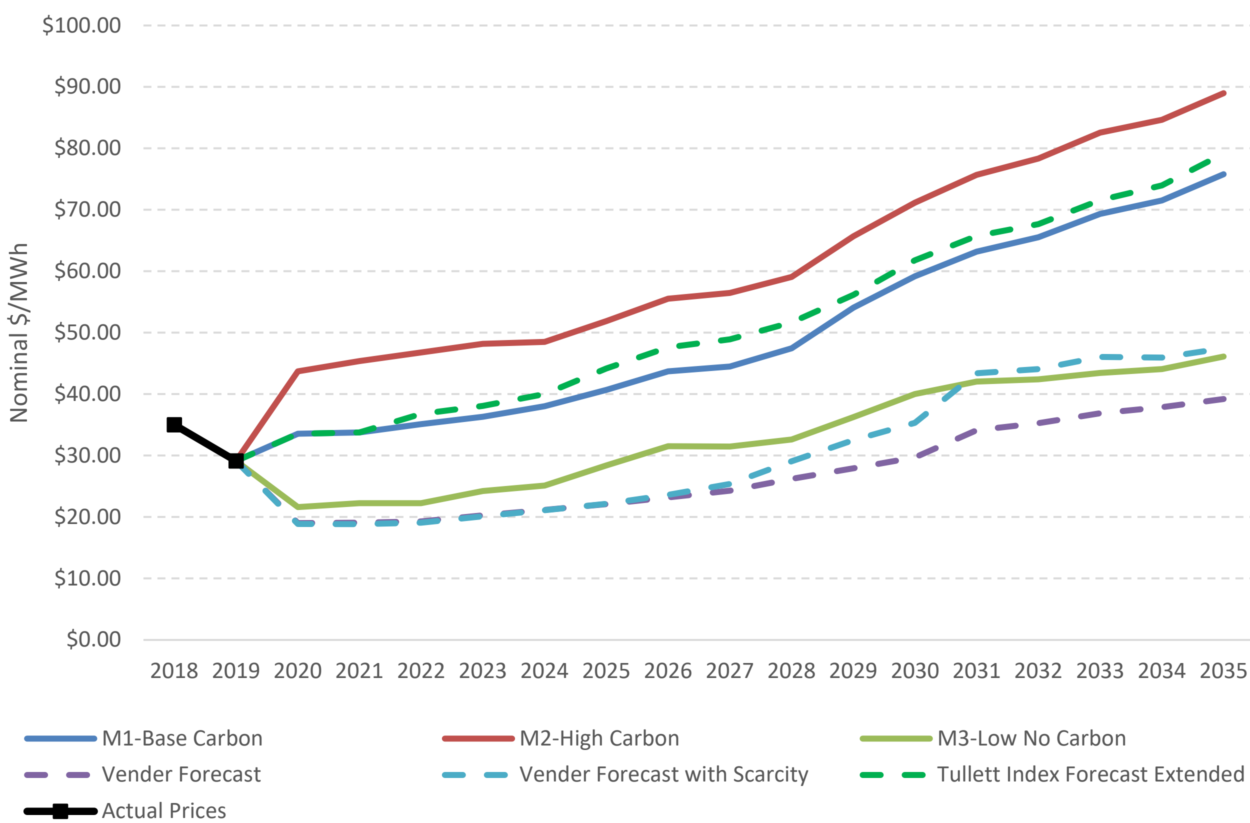
Chart 33 - TEP Coal Price Assumptions



Palo Verde (7x24) Wholesale Market Prices

Chart 34 shows the Palo Verde market price sensitivities considered in the 2020 IRP.

Chart 34 - Palo Verde (7x24) Market Price Sensitivities



Load Growth Scenarios

TEP 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 six load forecasts were identified as presented in Table 18 below.

Table 18 - Load Growth Scenarios

Load Scenario	Description
L1	Base load forecast described in Chapter 2
L2	No load growth as required by Decision 76632.[31] For this scenario, the 2020 net retail load was held constant for the duration of the planning period.
L3	Low (<1%) load growth as required by Decision 76632.[32] For this scenario, TEP excluded the load growth associated with the Rosemont mine and assumed lower than anticipated EV sales.
L4	No Rosemont. An Advisory Council member requested that we evaluate a load growth scenarios that excludes the Rosemont mine.
L5	Low EV Sales. For this scenario, TEP assumed lower than anticipated EV sales.
L6	High EV Sales. For this scenario, TEP assumed higher than anticipated EV sales.

Load Scenarios L4 and L5 were eliminated due to the fact that the assumptions associated with those forecasts were addressed in Load Scenario L3. 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 Preferred Portfolio only. Results of this scenario analysis along with changes that would be required in the Preferred Portfolio are summarized in Chapter 10.

Fuel, Market and Demand Risk Analysis

TEP developed explicit market risk analytics for each portfolio through the use of Monte Carlo computer simulations using Aurora[33]. Specifically a stochastic based dispatch simulation was used to develop a view on future trends related to fuel prices[34], 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.

[31] https://docket.images.azcc.gov/0000186964.pdf; see p. 51, Lines 9-11
[32] ibid
[33] 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/
[34] Both natural gas and coal.

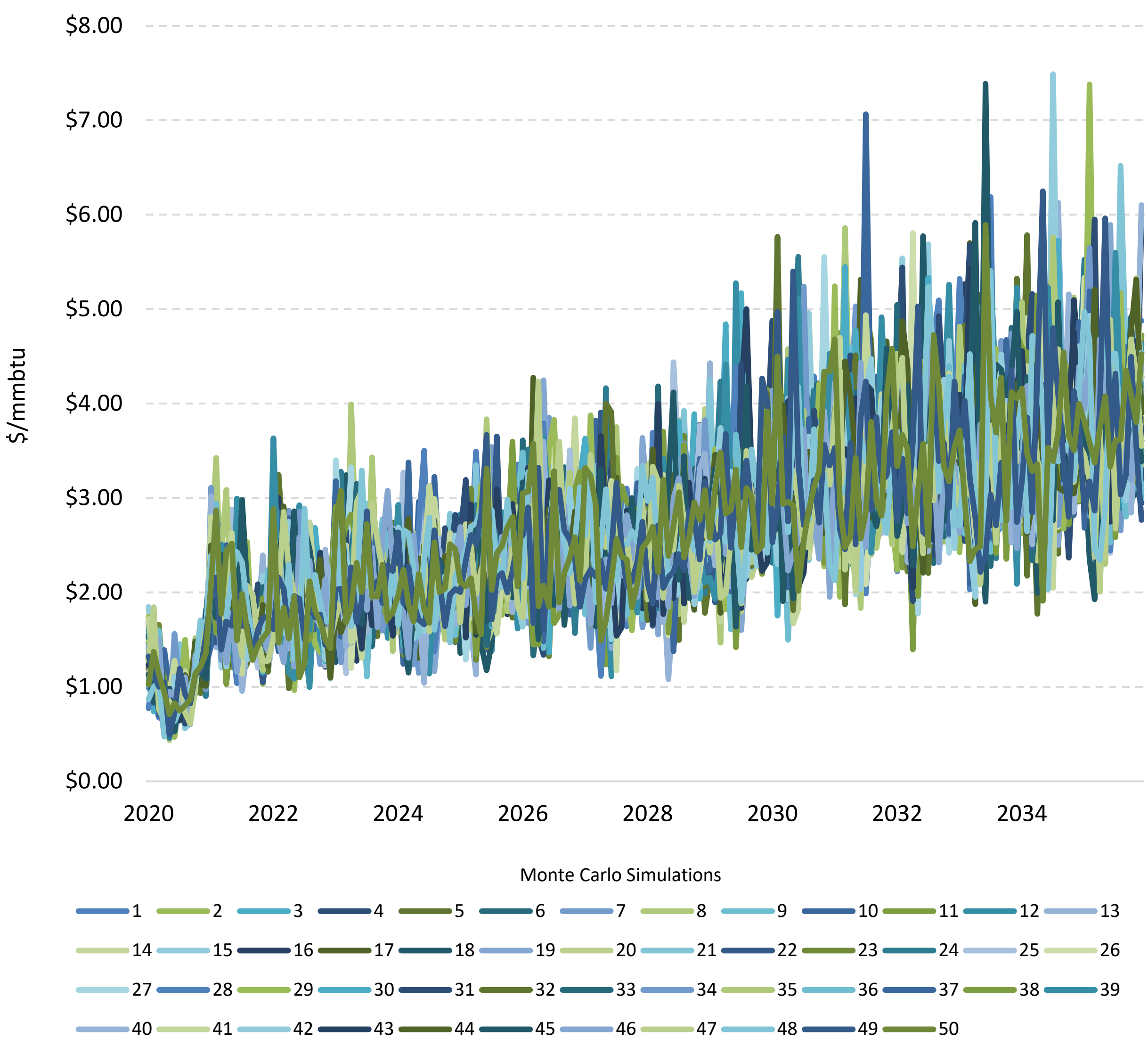
As part of the Company's 2020 resource plan, TEP conducted risk simulations around the following key variables:

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

Permian Basin Natural Gas Prices

As part of the 2020 IRP analysis, TEP ran fifty individual risk simulations to quantify the risk of uncertainty related to Permian Basin natural gas prices. Chart 35 below details the natural gas price simulations against which the portfolios were evaluated.

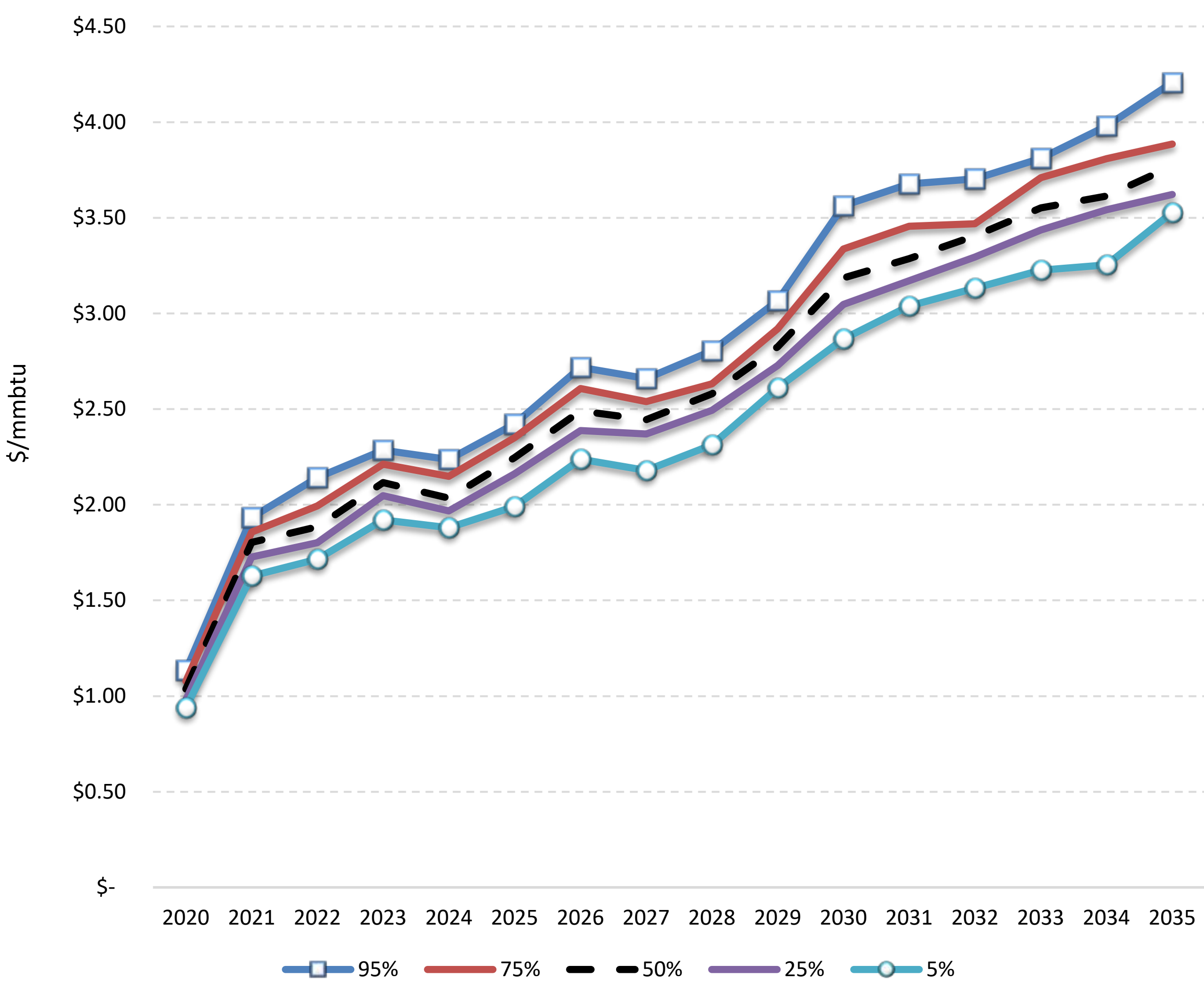
Chart 35 - Permian Basin Natural Gas Price Simulations



Permian Basin Natural Gas Price Distributions

Chart 36 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 35 on the prior page.

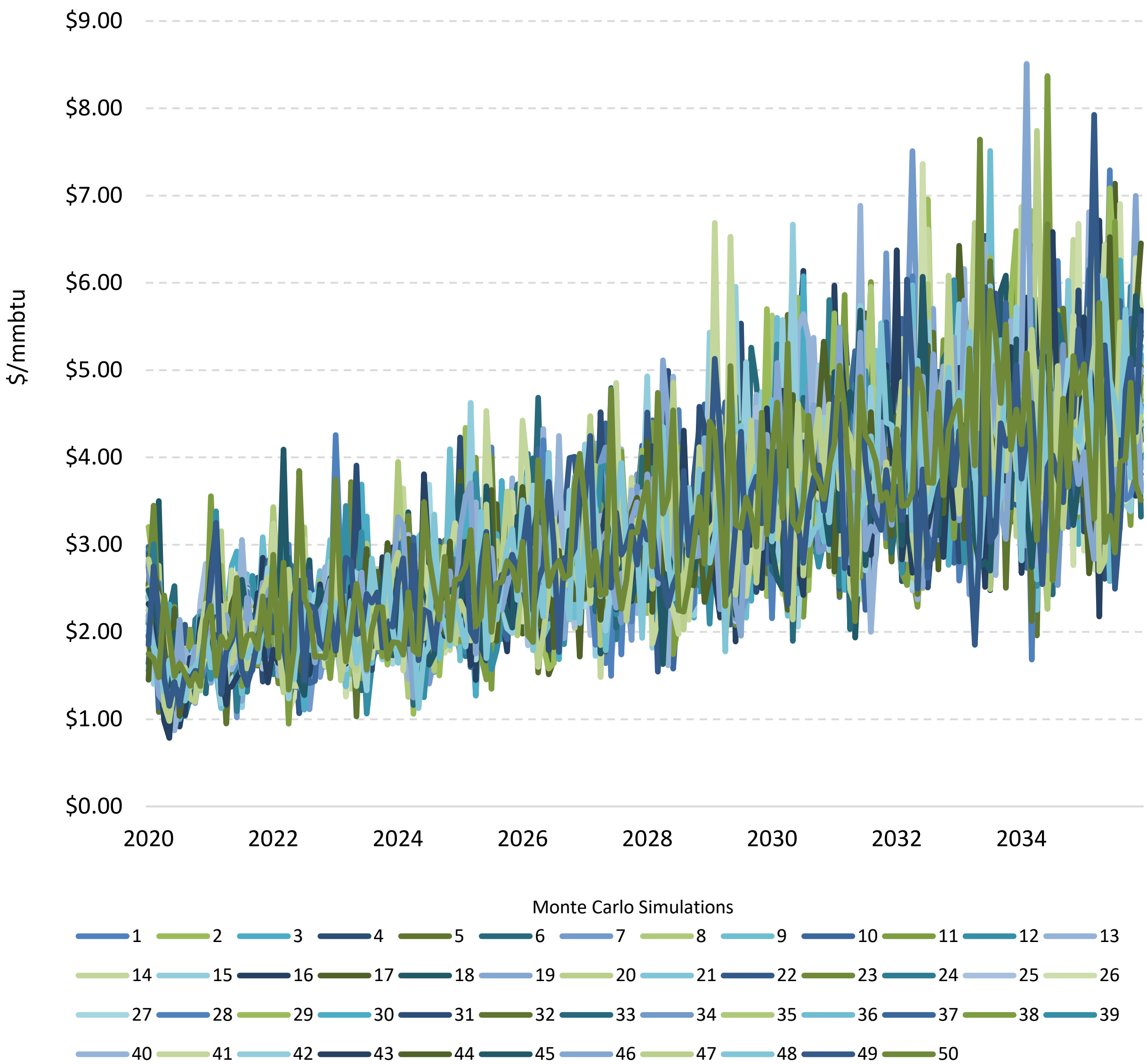
Chart 36 - Permian Basin Natural Gas Price Distributions



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 37 below details the natural gas price simulations against which the portfolios were evaluated.

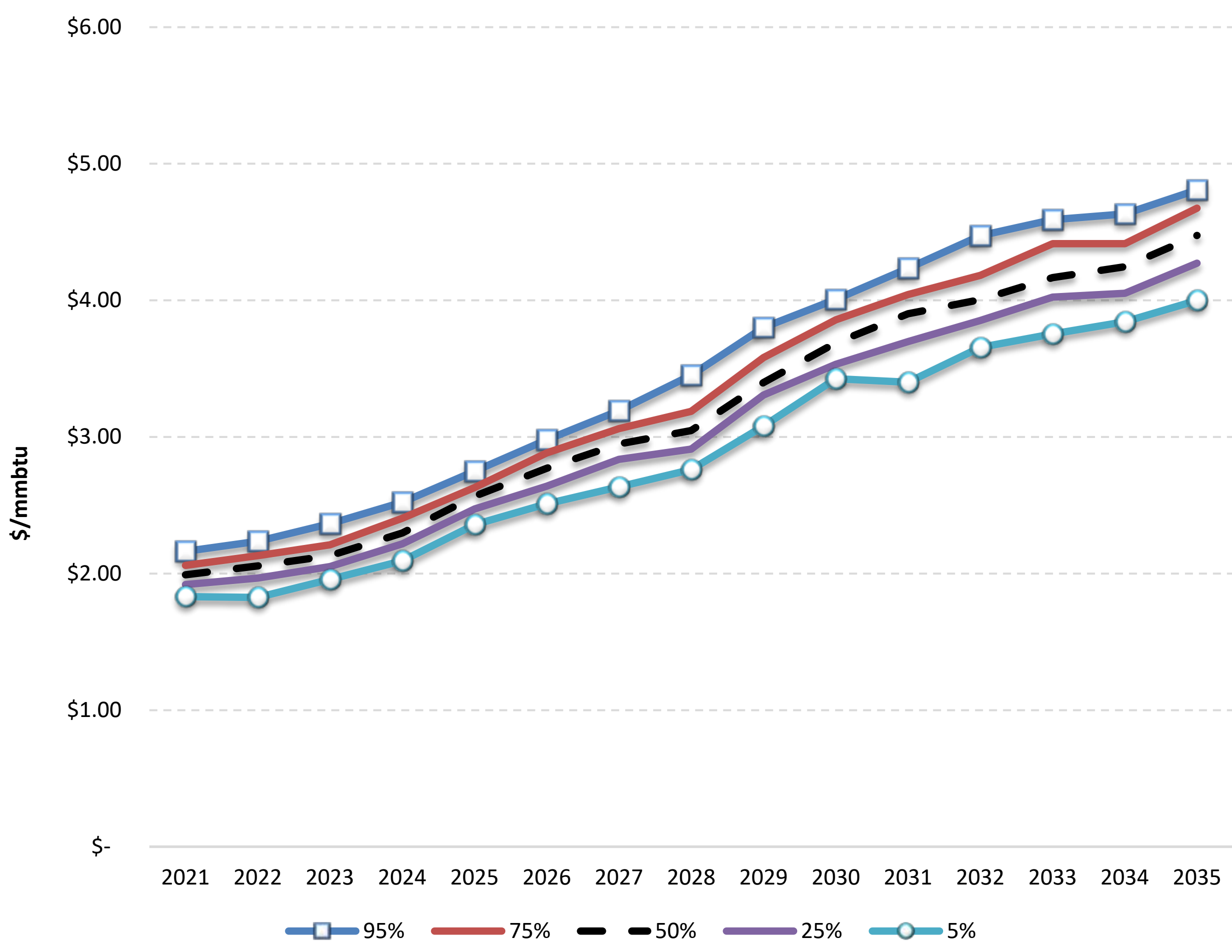
Chart 37 - San Juan Basin Natural Gas Price Simulations



San Juan Basin Natural Gas Price Distributions

Chart 38 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 37 on the prior page.

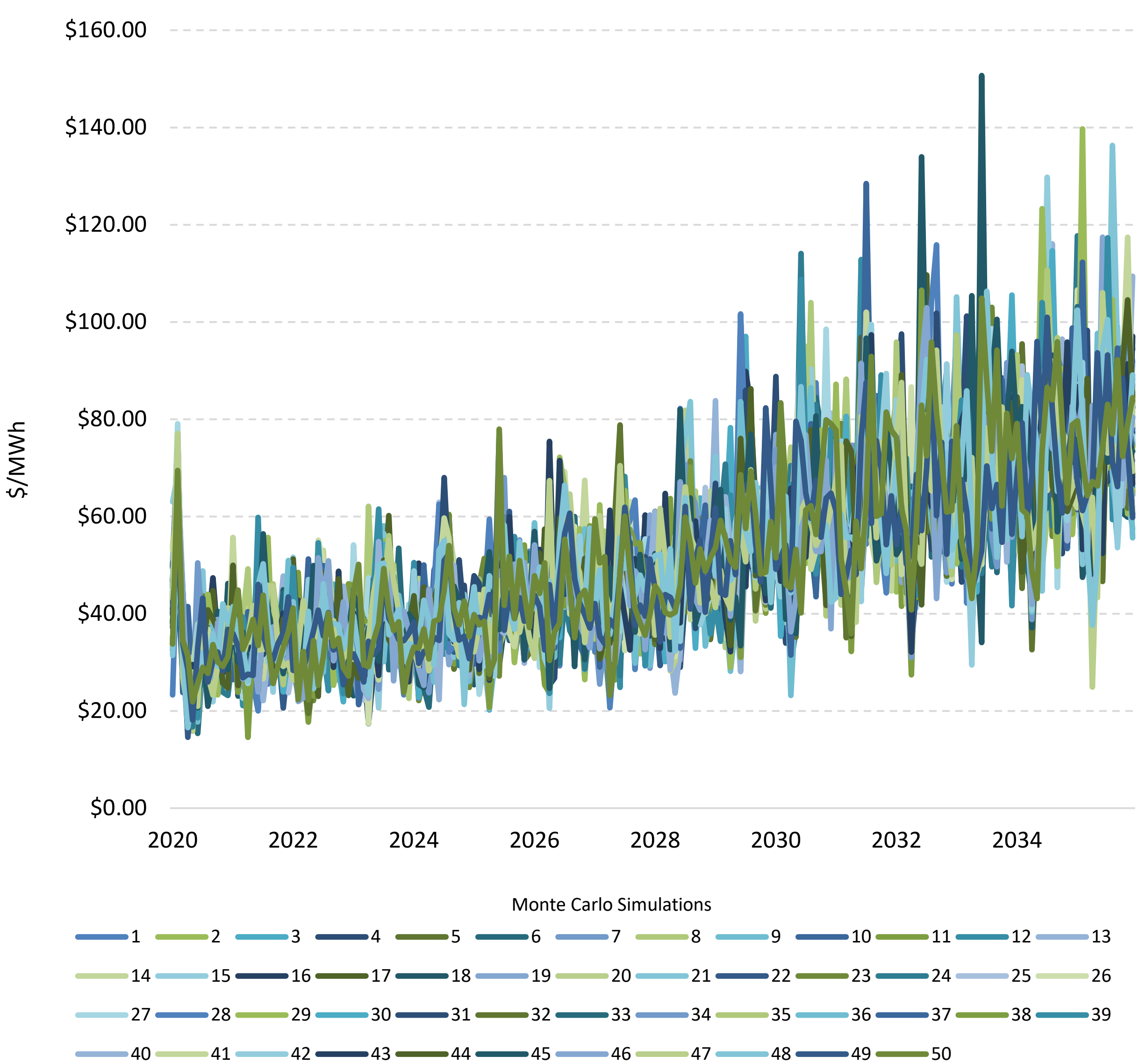
Chart 38 - San Juan Basin Natural Gas Price Distributions



Palo Verde (7x24) Wholesale Power Prices

As part of the 2020 IRP analysis, TEP ran 50 risk simulations to quantify the risk of uncertainty related to wholesale power prices. Chart 39 below details the wholesale power price simulations against which the portfolios were evaluated.

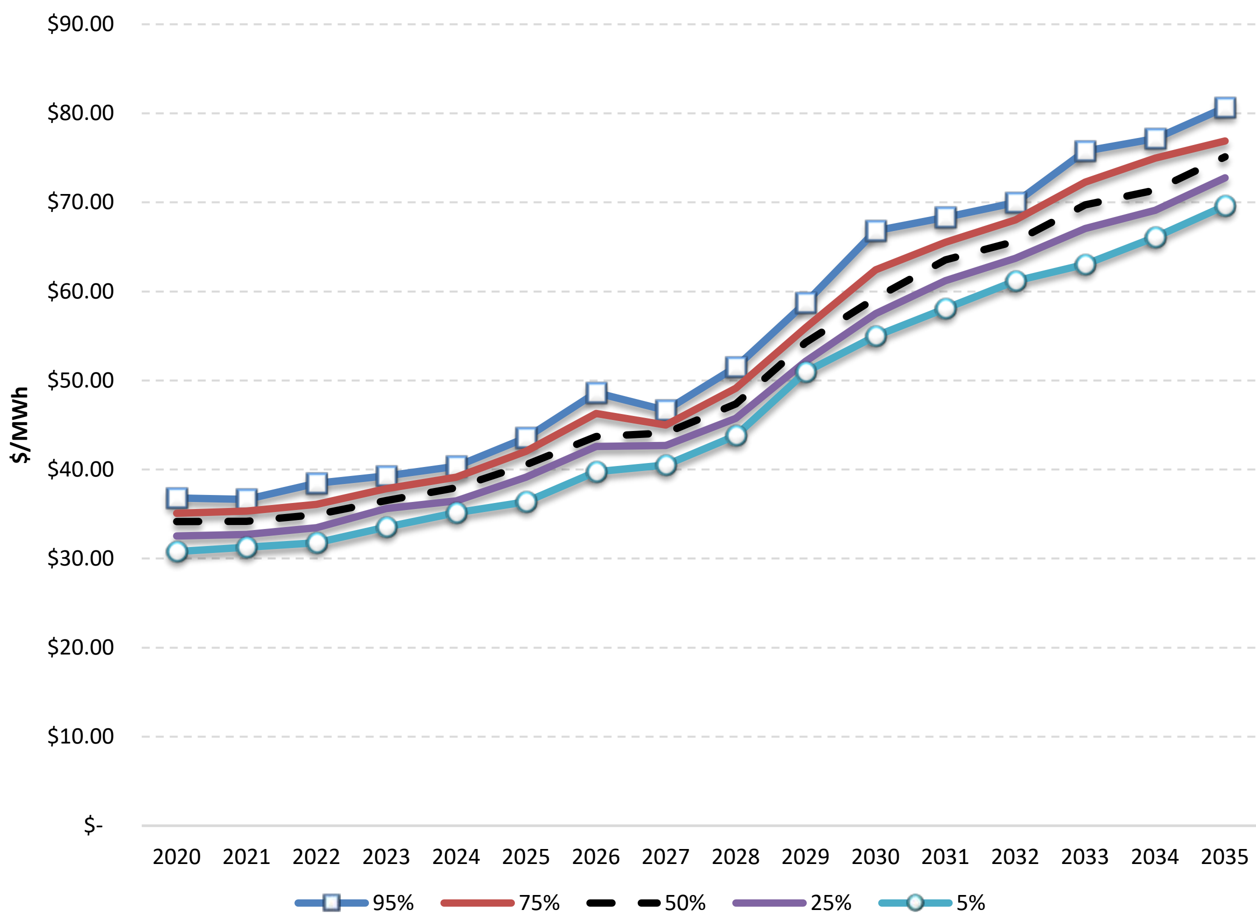
Chart 39 - Palo Verde Wholesale Power Price Simulations



Palo Verde (7x24) Market Price Distributions

Chart 40 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 39 on the page above.

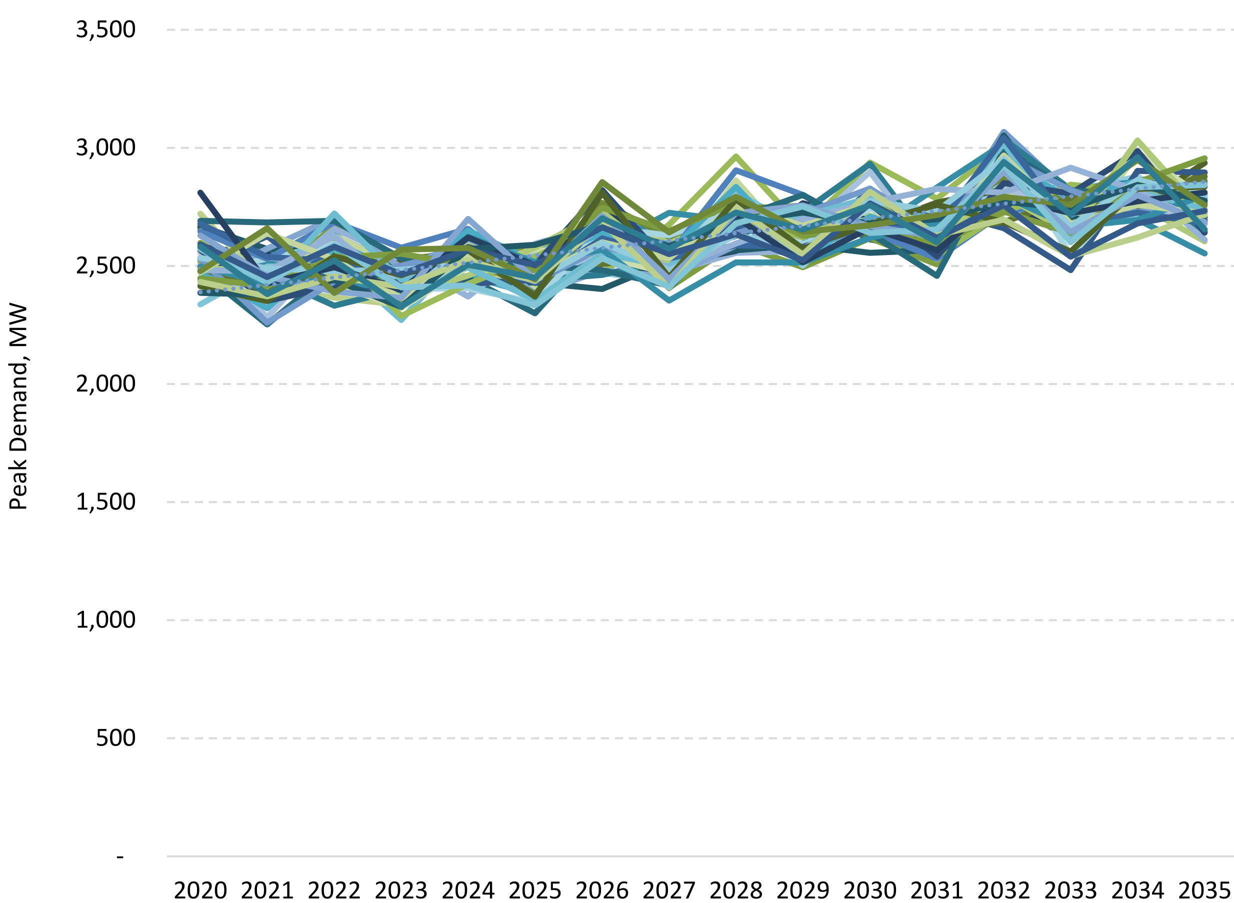
Chart 40 - Palo Verde (7x24) Market Price Distributions



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.

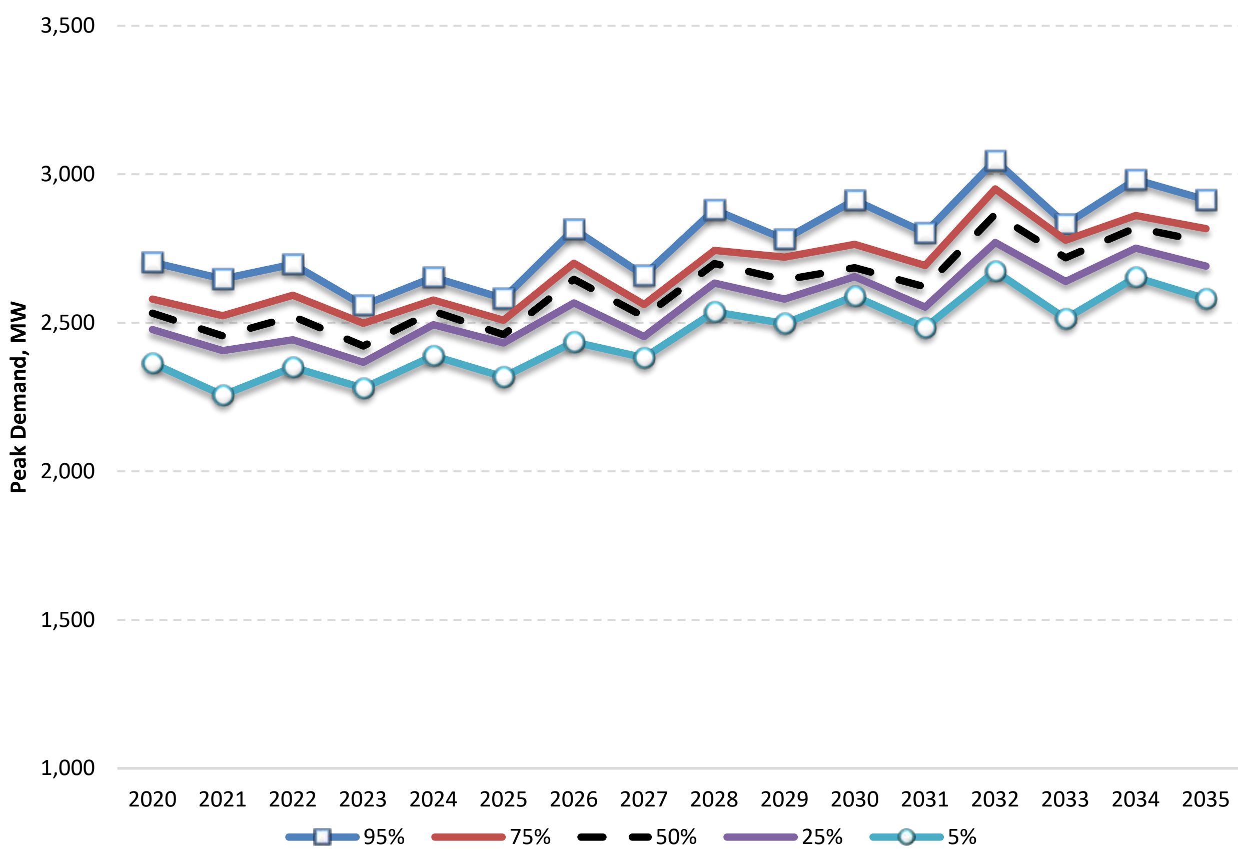
Chart 41 - TEP Peak Retail Demand Simulations



Load Variability and Peak Demand Distributions

Chart 42 shows the expected demand distributions for TEP's peak demand forecast. High EV, EV, and low load growth scenarios fall in between 75th and 5th percentiles. The no load growth scenario falls below the 5th percentile. These distributions are based on the stochastic data simulations shown in Chart 41 on the page above.

Chart 42 - TEP Peak Retail Demand Distributions



CHAPTER 9

PORTFOLIO ANALYSIS

Since 2014, TEP's primary resource planning strategy has been to achieve greater diversity in the resources it uses to meet our customers' energy needs. Resource diversification remains a central theme in the 2020 IRP, however, this diversification is accelerating and evolving. In the TEP 2017 IRP, the Preferred Portfolio called for achieving an energy mix roughly equally balanced between coal, natural gas, and renewables by 2032. With projects currently under contract, TEP will approach that level of diversification in the next couple years.

Given recent declines in the cost of zero-emission renewable technologies and the current outlook that these declines will continue, TEP's long-term strategy is now focused on completing the transition to 100 percent clean energy. What remains to be determined is how quickly this transformation can occur. The TEP 2020 IRP represents a pivotal moment in this transformation as all new resource additions in each of the portfolios evaluated are limited to energy efficiency, renewables and storage.

While an incremental strategy committed to utilizing 100 percent clean energy resources may seem contrary to the idea of a diverse resource portfolio, it is not. The Company intends to balance its renewable portfolio with solar and wind and other technologies as they become commercially available. The Grid Balancing resource category will become the primary focus of TEP's resource diversification efforts. Currently, the most cost effective grid balancing technologies are fast-start, fast-ramping natural gas resources and lithium-ion battery energy storage systems, both of which TEP is currently utilizing. TEP believes that significant improvements in storage technology development are likely, and that appropriately phasing in our clean energy transition will allow additional storage technologies to become cost effective. This phasing will also allow time for a responsible exit from some of our existing fossil resources both in terms of the cost to our customers and the communities that will be impacted by those changes.

Resource Adequacy Assessment

The resource adequacy study discussed in Chapter 3 evaluated increasing levels of renewable generation with respect to four reliability criteria.

- Peak Net Load
- 3-Hour Ramp
- 10-Minute Ramp
- Over Generation

The results of that study indicated that for three of the four study criteria, given our existing resource portfolio, little to no mitigation would be needed to achieve a renewable energy penetration target of 50 percent of the Company's retail load.[35] However, over generation would still likely need some level of mitigation at renewable energy levels as low as 35 percent.

The retirement of existing units beyond those retirements already assumed in the study[36] could necessitate the need for additional peak as well as flex capacity resources, while potentially mitigating over generation. To evaluate the feasibility of various portfolios, TEP developed and hourly spreadsheet model that calculated the impact of various combinations of solar, wind and battery storage in terms of shortfall energy, shortfall capacity and renewable curtailment.

Portfolio Identification

A portfolio analysis is a tool for evaluating the impact of discrete resource decisions on key planning metrics, such as cost to customers and the level of CO_2 emissions. For the 2020 IRP, TEP undertook an extensive portfolio analysis culminating in the development of 15 independent portfolios. Certain portfolios were required by Decision No. 76632[37] from the 2017 IRP. Several portfolios are based on proposals relating to the ACC's development of new energy rules,[38] including proposals from Commissioners[39] as well as Staff's third draft of rules released in February 2020.[40] Then several additional portfolios were developed at the request of Advisory Council members.

Finally, TEP introduced a portfolio to evaluate the impact of the potential unavailability of a coal supply due to early coal mine closures. Over the past couple years, numerous coal plant retirements have taken place or have been announced. As the retirements mount, the customer base for coal mines, as well as the overall demand for coal decreases, which puts economic pressure on the coal mine owners to consolidate assets and close certain mines. The industry is managing this transition through financial restructuring and company mergers, and TEP has an adequate choice of coal supply options. TEP's current coal supply agreement for Springerville Units 1 and 2 expires at the end of 2020. Going forward, TEP will negotiate short-term coal supply agreements with suppliers that can offer competitive pricing with greater flexibility.

[35] This lack of mitigation is dependent on the technological and geographic diversity of the renewable resource mix.
[36] The Resource Adequacy study accounted for the retirement of San Juan Generating Station Unit 1 in 2022
[37] Resource Planning and Procurement in 2015 and 2016, Arizona Corporation Commission Docket ID E-00000V-15-0094, March 29, 2018
[38] In the Matter of Possible Modifications to the Arizona Corporation Commission's Energy Rules, Arizona Corporation Commission Docket ID RU-00000A-18-0284, August 17, 2018
[39] Commissioner Burn's issues a letter dated June 7, 2019, requesting analysis several portfolios identified by Commissioners as part of the Energy Rules docket (RU-00000A-18-0284). https://docket.images.azcc.gov/E000001258.pdf
[40] https://docket.images.azcc.gov/E000004960.pdf

The Springerville units remain cost-effective resources for providing capacity, ancillary services and reliability within TEP's portfolio. In the absence of any nuclear or hydro-electric resources, TEP's coal resources provide a hedge against the potential for medium-term fuel supply disruptions.[41] Over time, improvements in renewable and storage technologies will make those resources cost-effective replacements for the services our coal plants currently provide. Based on these economic factors along with the need for time to transition employees and the communities the coal plants support, TEP selected the year 2030 for evaluating the termination of a coal supply for the Springerville units.

[41] A study prepared Wood Mackenzie for the Western Electricity Coordinating Council reported the possibility of "region-wide reliability issues, resulting in widespread loss of electric load" in the Southwest associated with natural gas supply disruptions; "Western Interconnection Gas-Electric Interface Study", June 2018. https://www.wecc.org/Administrative/WECC%20Gas-Electric%20Study%20Public%20Report.pdf

The complete list of potential portfolios is presented in Table 19.

Table 19 - Complete List of Potential Portfolios

Portfolio Identifier	Source	Design Element
P01	ACC - Commissioner proposals to Energy Rules Docket	(a)80 (b)100 percent Clean Energy by 2050
P02	ACC - Commissioner proposals to Energy Rules Docket	(a)80 (b)100 percent Clean Energy by 2050; 50 percent Renewable by (a)2028 or (b)2030
P03	ACC - Commissioner proposals to Energy Rules Docket	80 percent Clean Energy by 2050; 40 percent renewables by 2035
P04	Decision 76632 to 2017 IRP	Fossil fuel no more than 20 percent of all resource additions
P05	Decision 76632 to 2017 IRP	Energy Storage equal to 20 percent of demand; 50 percent "clean" energy resources; 25MW of biomass; 20 percent DSM
P06	ACC - Draft Energy Rules	45 percent renewables by 2035; 30 percent clean energy during peak by 2035
P07	Advisory Council - SWEEP	Higher reserve sharing
P08	Advisory Council - Sierra Club	(a) Retire all coal by 2027; (b) Retire Springerville 1 in 2024; (c) Retire Four Corners in 2024
P09	Advisory Council - Western Resource Advocates	CO_2 Reduction #1 (based on 2005): 50 percent below by 2025; 60 percent below by 2030; 70 percent below by 2035
P10	Advisory Council - Western Resource Advocates	CO_2 Reduction #2 (based on 2005): 40 percent below by 2025; 50 percent below by 2030; 60 percent below by 2035
P11	Arizonans for Electric Choice and Competition	Buy-through as a resource option
P12	Advisory Council - Sierra Club	100 percent Renewables by 2045
P13	Advisory Council - RUCO	Demand Response 40 percent of peak (low cost)
P14	Advisory Council - RUCO	Demand Response 40 percent of peak (high cost)
P15	Advisory Council - RUCO	Model specific DSM program penetrations (smart thermostats, water heaters, pool pumps)
P16	TEP	Coal supply limits
P17	TEP	Preferred portfolio

Portfolio Naming Convention

TEP developed the following naming convention for identifying portfolios

P01aL1M1E1

Where:

P01 = Portfolio Identifier (P01-P17)
a = Portfolio Variation (a – e)
L1 = Load Scenario (L1 – L6)
M1 = Market Scenario (M1 – M3)
E1 = Emission Scenario (E1 – E2)

Certain portfolios were eliminated due to the fact that they were similar enough to other portfolios such that their evaluation was unlikely to provide additional insights. For other portfolios, it was concluded that the specific point that the portfolio was intended to assess could be better evaluated outside of the simulation analysis. Following is a list of the portfolios that were not carried forward to a full portfolio analysis and the reason for that decision.

- P03 – Similar to P06.
- P04 – None of the portfolios included any additional fossil fuel resources.
- P07 – Reserve sharing currently in place. Further study is needed to evaluate the potential of expanding reserve sharing arrangements.
- P08c – TEP holds a minority interest in the Four Corners and cannot unilaterally make a retirement decision.
- P12 – The difference between P12 and P02b is well outside of the current planning period.
- P13/P14/P15 – Given the uncertainty in the potential for high levels of DR and a lack of independent cost data, TEP did not believe it could develop a defensible portfolio. Data relating to DR and the avoidance of capital expenditures is presented in Chapter 4.

The results of the initial portfolios, including some scenarios, were presented to the Advisory Council in March 2020. Feedback on the initial set of portfolios was incorporated into the analysis resulting in the final list of portfolios.

Overview of Portfolio Assumptions

Table 20 below summarizes the objectives and assumptions for each of the final portfolios. A Summary Dashboard for each portfolio is provided on TEP's Resource Planning web page (https://www.tep.com/resource-planning/).

Table 20 – Portfolio Objectives and Assumptions

Portfolio Identifier	Alternative	Design Element	Coal	Renewables	Storage	Energy Efficiency
P01	a	80% Clean Energy by 2050; 30% Renewables by 2030		895 MW of new fixed tilt and single-axis tracking solar by 2035.	325 MW of 8hr storage by 2035.	Average annual increase of 0.5% of retail load
P01	b	100% Clean Energy by 2050; 50% Renewables by 2028		895 MW of new fixed tilt and single-axis tracking solar and 400 MW of new wind by 2035.	475 MW of 8hr storage by 2035.	Average annual increase of 0.5% of retail load
P02	a	80% Clean Energy by 2050; 50% Renewables by 2028	Springerville 1 retired in December 2027.	1,250 MW of new single-axis solar and 650 MW of new wind by 2035.	150 MW of 4hr storage and 425 MW of 8hr storage by 2035.	Average annual increase of 0.5% of retail load
P02	b	100% Clean Energy by 2050; 50% Renewables by 2030	Springerville 1 retired in December 2029.	1,250 MW of new single-axis solar and 650 MW of new wind by 2035.	75 MW of 4hr storage and 500 MW of 8hr storage by 2035.	Average annual increase of 0.5% of retail load
P02	c	100% Clean Energy by 2050; 50% Renewables by 2030; Higher EE (low cost)	Springerville 1 retired in December 2029.	1,225 MW of new single-axis solar and 600 MW of new wind by 2035.	75 MW of 4hr storage and 500 MW of 8hr storage by 2035.	Average annual increase of 1.3% of retail load; all measures available
P02	d	100% Clean Energy by 2050; 50% Renewables by 2030; Higher EE (high cost)	Springerville 1 retired in December 2029.	1,225 MW of new single-axis solar and 600 MW of new wind by 2035.	75 MW of 4hr storage and 500 MW of 8hr storage by 2035.	Average annual increase of 1.3% of retail load; lighting not available
P02	e	100% Clean Energy by 2050; 50% Renewables by 2030; Higher EE (SWEEP modeling)	Springerville 1 retired in December 2029.	1,225 MW of new single-axis solar and 600 MW of new wind by 2035.	75 MW of 4hr storage and 500 MW of 8hr storage by 2035.	Average annual increase of 1.5% of retail load; SWEEP modeling
P05	a	Energy Storage equal to 20% of demand; 50% "clean" energy resources; 25MW of biomass; 20% EE	Springerville 1 retired in December 2029.	1,225 MW of new single-axis solar and 600 MW of new wind by 2035.	75 MW of 4hr storage and 500 MW of 8hr storage by 2035.	Average annual increase of 1.3% of retail load; all measures available
P06	a	80% Clean Energy by 2050; 45% renewables by 2035; 30% clean energy during peak by 2035	Springerville 1 retired in December 2034.	675 MW of new single-axis tracking solar and 250 MW of new wind by 2035.	650 MW of 4hr storage by 2035.	Average annual increase of 0.5% of retail load
P08	a	Retire all coal by 2027	Springerville 1 and 2 and Four Corners retire in December 2027.	1,500 MW of new single-axis tracking solar and 500 MW of new wind by 2035.	1,400 MW of 4hr storage by 2035.	Average annual increase of 0.5% of retail load
P08	b	Retire Springerville 1 in 2024	Springerville 1 retires at the end of 2024	700 MW of new single-axis tracking solar and 200 MW of new wind by 2035.	975 MW of 4hr storage by 2035.	Average annual increase of 0.5% of retail load
P09	b	CO2 Reduction #1 (based on 2005): 50% below by 2025; 60% below by 2030; 70% below by 2035	Springerville 1 seasonal operation beginning 2025, summer only beginning 2028, retire end of 2029. Springerville 2 seasonal operation beginning 2026, summer only beginning 2032.	1,400 MW of new single-axis tracking solar and 400 MW of new wind by 2035.	700 MW of 4hr storage by 2035.	Average annual increase of 0.5% of retail load
P10	a	CO2 Reduction #2 (based on 2005): 40% below by 2025; 50% below by 2030; 60% below by 2035	Springerville 1 seasonal operation beginning 2029, summer only beginning 2032. Springerville 2 seasonal operation beginning 2030, summer only beginning 2035.	250 MW of new single-axis tracking solar by 2035.	600 MW of 4hr storage by 2035.	Average annual increase of 0.5% of retail load
P16	b	Springerville coal supply ends in 2030	Springerville 1 seasonal operation beginning 2023, summer only beginning 2026, retire end of 2027. Springerville 2 seasonal operation beginning 2024, summer only beginning 2031, retire end of 2033.	1,500 MW of new single-axis tracking solar and 500 MW of new wind by 2035.	1,400 MW of 4hr storage by 2035.	Average annual increase of 0.5% of retail load
P17	a	Preferred Portfolio	Springerville 1 seasonal operation beginning 2023, summer only beginning 2026, retire end of 2027. Springerville 2 seasonal operation beginning 2024, summer only beginning 2030, retire end of 2032.	1,500 MW of new single-axis tracking solar and 500 MW of new wind by 2035.	1,400 MW of 4hr storage by 2035.	Average annual increase of 1.3% of retail load; all measures available

Policy Implications of Portfolios

TEP used the portfolio analysis to evaluate the implications of various policy positions in terms of overall cost and environmental performance. The ACC opened a docket in August 2018 to consider modification to the current rules relating to renewable energy, energy efficiency and integrated resource planning among other matters. Many of the proposals, including from Commissioner's, called for expanding and extending the standards for utilities to procure energy from renewable resources, referred to as "Portfolio Standards."

TEP developed several portfolios designed around different versions of Portfolio Standards in order to evaluate the impact these standards could have on TEP's system (see Table 20). This section compares the results of those portfolios to each other and to a portfolio designed to achieve emission reductions without specifying the level of renewable energy in any year, referred to as a "Carbon Standard."

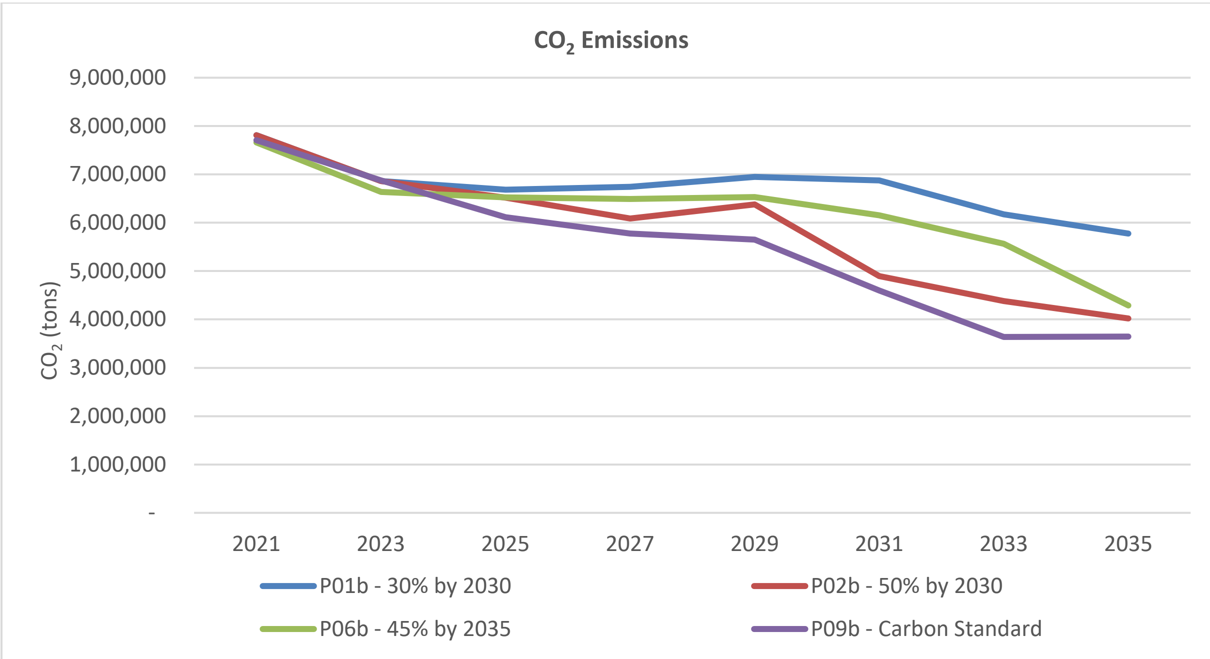
The portfolios included in this analysis are listed in Table 21 below.

Table 21 - Portfolios for Evaluating Policy Implications

Renewable % of Retail Sales	2025	2030	2035
P01b - 30% by 2030	31%	31%	52%
P02b - 50% by 2030	37%	49%	66%
P06b - 45% by 2035	31%	29%	45%
P09b - Carbon Standard	40%	43%	61%

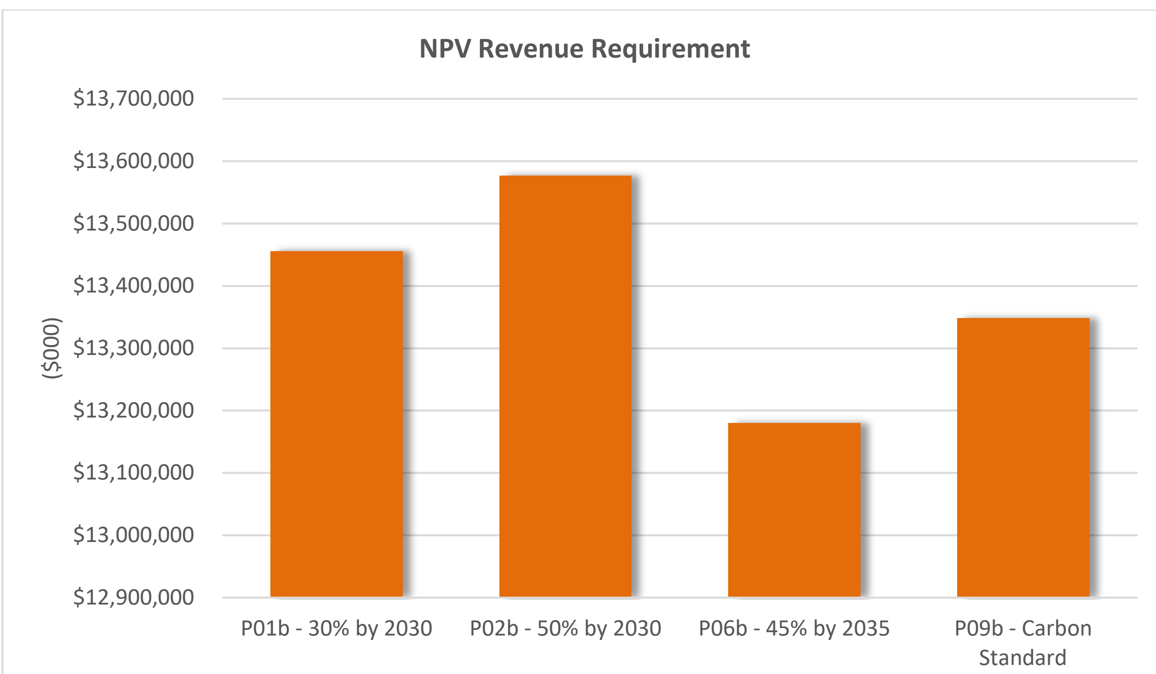
The level of annual CO_2 emissions for each portfolio is presented in Chart 43 below.

Chart 43 - Policy Implications on CO_2 Emissions



The total net present value revenue requirement (NPVRR) of each portfolio is presented in Chart 44 below.

Chart 44 - Policy Implications on Portfolio NPVRR



Comparing Outcomes Related to a Portfolio Standard versus a Carbon Standard

The Company draws two conclusions from its review of these results. The first is that interim targets or requirements matter both in terms of cost and the level of emissions. The two portfolios that have low or no interim portfolio standard targets – P01b, which targets a 30 percent portfolio standard by 2030, and P06b, which has no 2030 portfolio standard – are lower cost portfolios than P02b, which has a portfolio standard of 50 percent by 2030. However, portfolio P02b results in lower cumulative emissions than P01b and P06b. This result is not unexpected as the increase in interim zero emission renewable energy increases costs while lowering emissions.

The second conclusion is that a Carbon Standard can achieve lower emissions at a lower cost than a Portfolio Standard. Looking at P02b and P09b, they both achieve significant reductions in emissions, however, P09b has a much lower cost. The reason for this is that P09b makes adjustments beyond just simply adding renewables. P09b, while adding renewables and energy storage, also reduces the output from coal-fired generation through commitments to seasonal operations which both reduces costs and emissions.

Another policy implication relevant to the Commission's Energy Rules is the impact relating to the difference in achieving 80 percent clean energy by 2050 versus a 100 percent goal. For the purpose of evaluating the difference between these two policy options, TEP extended the forecasts for P02a (80 percent) and P02b (100 percent) to 2050. In order to meet the same reliability criteria as P02a, P02b requires an additional 5,500 MW of renewable capacity and nearly 2,000 MW of additional 8-hour storage capacity to compensate for the 1,336 MW of natural gas fired generation that would need to be retired by 2050. The estimated rate increase between 2020 and 2050 for the 80 percent clean energy portfolio P02, increases by 30 percent, whereas the 100 percent clean energy portfolio P02b, increases by 90 percent.

That said, projections to 2050 are highly uncertain. At this point in time, TEP cannot accurately evaluate the difference in impact on ratepayers between 80 percent versus 100 percent clean energy by 2050. We would need to conduct additional studies to say with confidence that a 100 percent clean portfolio would meet reliability requirements.[42]. Conversely, more cost-effective technologies may become available during that time.

Energy Efficiency

In addition to TEP's base assumptions regarding the level of future EE, TEP modeled a higher level of EE under two scenarios. The first scenario assumed that all of the programs and measures that are currently available for implementing EE would remain available for the duration of the planning period. The second scenario assumed that energy efficient lighting would not qualify for EE savings, which could be the case if Federal standards for lighting became more stringent. These assumptions effect the cost of implementing EE programs. It would be considerably more expensive to achieve the same level of EE savings if energy efficient lighting, which is by far the most cost-effective EE measure, was not available. Further details regarding the assumptions for EE are presented in Chapter 4.

In addition to these portfolios relating to EE, TEP collaborated with SWEEP to evaluate the level of EE that could be achieved cost-effectively based on a capacity expansion simulation. To complete this work, SWEEP retained Strategen Consulting to model TEP's system, with inputs provided by TEP, using EnCompass in a capacity

[42] E3, Long-Run Resource Adequacy under Deep Decarbonization Pathways for California, 2019

expansion simulation. TEP then ran SWEEP's EE program assumptions through our production cost simulation model to evaluate the performance of that portfolio against the other EE portfolios discussed above.

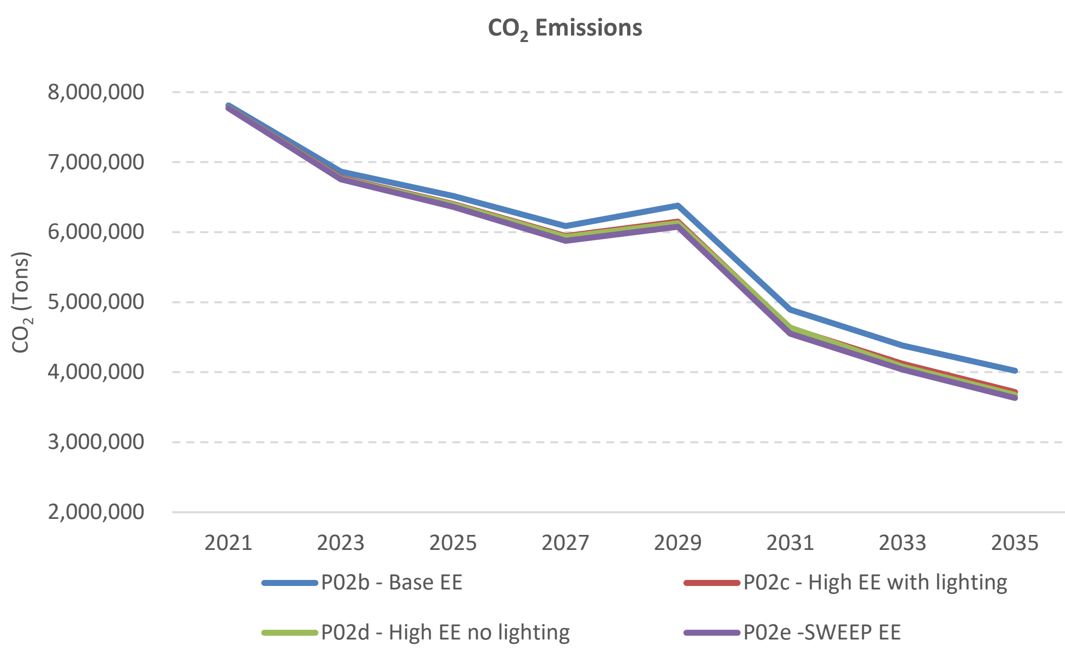
The four portfolios relating to different levels of EE are listed in Table 22 below.

Table 22 - Portfolios for Evaluating Energy Efficiency

Energy Efficiency (GWh)	2025	2030	2035
P02b - Base EE	997	1,193	1,441
P02c - High EE with lighting	1,349	2,031	2,625
P02d - High EE no lighting	1,348	2,030	2,623
P02e -SWEEP EE	1,454	2,183	2,858

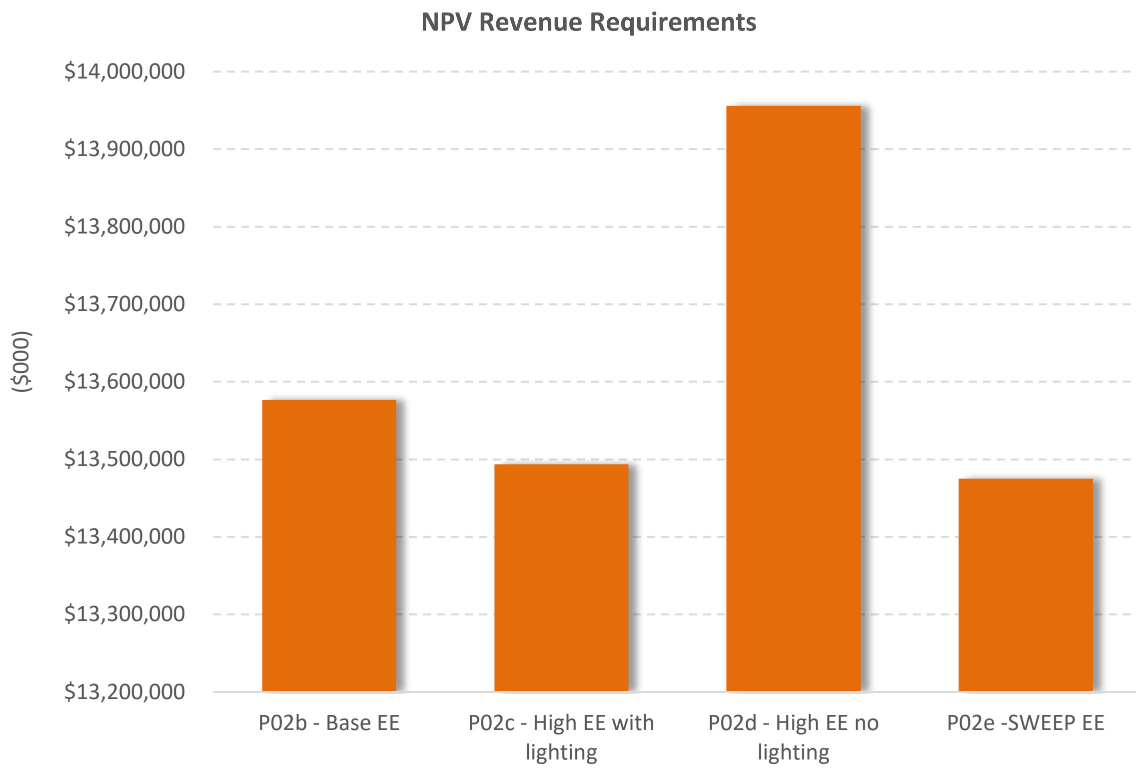
The level of annual CO_2 emissions for each portfolio is presented in Chart 45.

Chart 45 - CO_2 Emissions Relating to Energy Efficiency



The total NPVRR of each portfolio is presented in Chart 46.

Chart 46 - Energy Efficiency Implications on Portfolio NPVRR



The portfolios with higher levels of EE result in lower emissions, however, the difference in emissions is small relative to the difference in energy saved. This is likely due to the fact that reduced need for new resources due to the EE savings results in fewer new renewable resources on the system.

The results do show additional cost savings associated with higher levels of EE for the portfolios where all programs and measures are available. However, the results also show that the cost of achieving the same level of energy savings when low-cost measures such as lighting are not included, results in program costs that are significantly higher.

TEP believes that the modeling done through the collaboration with SWEEP validates the conclusion that higher levels of EE will result in lower cost to customers and lower emissions, again assuming all measures are available. That conclusion notwithstanding, the Company points out two important qualifications relating to Strategen's modeling.

First, Strategen increased the maximum achievable capacity for each of the measures without a corresponding change in the first-year cost per megawatt-hour for these measures. TEP stands by its cost estimates and we believe the relationship between maximum achievable capacity and the first-year cost per megawatt-hour must be maintained. Therefore, there should be additional costs to achieve the amount of energy savings assumed by Strategen. However, the Company does not dispute the overall result that EE programs are likely to be cost effective resource additions at the levels modeled by Strategen.

TEP also points out that while Strategen's modeling selected programs that are cost effective, the capacity expansion simulation is based on economics only and does not consider other factors that should be weighed in developing an EE Implementation plan. For example, Strategen's capacity expansion simulation did not select any Low-Income Assistance programs in any year of the simulation, leaving those measures completely unfunded.

Buy-Through Program Analysis

In response to a request from stakeholders, TEP agreed to develop at least one portfolio in which a buy-through program was considered as a resource option. The parameters for the buy-through programs were structured around specific proposals offered in TEP's pending rate case application[43] and through discussions with representatives of Arizonans for Electric Choice and Competition (AECC). These two buy-through proposals were evaluated under three forward market price scenarios.

For each of the buy-through proposals presented below, the intent of this analysis was to evaluate the costs and benefits that these programs would have on the Company's overall cost to fuel and purchased power, as well as any reduction or increase in costs to non-participating customers. The Company's evaluation is limited to a five-year period (2021 – 2025) due to the experimental nature of the program as well as the fact that participation is determined on an annual basis.

Buy-Through Scenario 1 - TEP's MP-EX Program

TEP's Market Price Experimental (MP-EX) Program

Under the Company's proposal, the MP-EX program offers customers two separate programs that fulfill all the objectives of the Commission's buy-through policy statement.[44] Program eligibility under these two programs is split between 1.) MGS and LGS and 2.) LPS customers. Moreover, under the Company's proposal, total program eligibility is capped at 75,000 kW. Finally, all individual customer participants must have an aggregated peak demand of 3,000 kW and a minimum aggregate load factor of 60 percent.

MP-EX General Service Customers

Under the Company's MP-EX General Service program, program eligibility for MGS and LGS customers will be limited to 25,000 kW. MGS and LGS customers will continue to pay all of their existing tariff charges (basic service and demand charges) while having an option to replace their existing Power Supply Charge[45] with a day-ahead market index price option. The day-ahead market index price will be available on a day-ahead basis to allow customers to adjust their usage.

MP-EX Large Power Service Customers

Under the Company's MP-EX Large Power Service program, program eligibility will be limited to 50,000 kW. LPS customers will continue to pay all of their existing tariff charges (basic service and demand charges) while

[43] In the Matter of Tucson Electric Power Company for the Establishment of Just and Reasonable Rates et. Seq. Docket ID No. E-01933A-19-0028, April 1, 2019.
[44] This new proposal avoids shifting any costs to other customer rate classes while enabling medium general service, large general service and large power service customers to participate in market-based pricing alternatives.
[45] The Power Supply Charge is the sum of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a per kWh adjustment in accordance with Rider-1-PPFAC. PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

having an option to 1.) replacing its existing Power Supply Charge with a hourly market index price option, 2.) procure a 7x24 block of energy and capacity for a 12-month basis or 3.) a combination of options 1 and 2.[46]

Table 23 - TEP's MP-EX Program Options

MP-EX Program Options	LPS	MGS and LGS
Program Participation	50,000 kW	25,000 kW
Minimum Aggregated Peak Demand	3,000 kW	3,000 kW
Minimum Aggregated Load Factor	60 percent	60 percent
Market Index Option	Hourly Market Index	Day-Ahead Market Index
7x24 Block Purchase Option	Yes	No
Basic Service & Demand Charges	Same as Existing Tariff	

Buy-Through Scenario 1 - Modeling Results

Under Buy-Through Scenario 1, TEP modeled the MP-EX program and analyzed the impacts of the different customer class offerings from a fuel and purchased power perspective, as well as any change in costs to non-participating customers. For the MGS and LGS customer classes, TEP calculated the impact of replacing the Power Supply Charge with a day-ahead market price for a 25 MW program size. Under TEP's proposal, participation is limited to customers that have a minimum 60 percent load factor and participants may only nominate a portion of their load to the program. Therefore, the 25 MW program size is assumed to have a 100 percent load factor.

For the LPS customer class, TEP simulated the procurement of a market product to serve the participating customers by modeling a 7x24, 50 MW block of must-take energy. Similar to the MGS and LGS classes, the 50 MW block is assumed to have a 100 percent load factor.

Based on the modeling assumptions shown above, the implementation of the MP-EX program for MGS and LGS class customers will have no change on the actual fuel and purchased power costs for the Company. Under this program, TEP is still obligated to serve these same MGS and LGS class customers, but instead of paying the standard offer Power Supply Charge, customers will pay a day-ahead market price that is dependent on forward market conditions. As a result, MGS and LGS class customers who pay a market rate that is higher than the Company's Power Supply Charge rate will create a reduction for non-participating customers. In contrast, MGS and LGS customers who pay a lower market price will create an increase for non-participating customers under this program.

[46] Under Option 1, LPS Customers can apply the hourly market index against 100 percent of their load. Under Option 2, the Company's Power Supply Charge will apply against the remaining load if the Customer utilizes a 7x24 block of energy and capacity. Under Option 3, the hourly market index will apply against the remaining load if the Customer utilizes a 7x24 block of energy and capacity.

Under base case market price conditions (M1 Base Market) shown in Table 24, as well as high market price conditions (M2 High Market) shown in Table 25, the buy-through program results in a reduction to the fuel and purchased power costs borne by non-participating customers. However, under low market price conditions (M3 Low Market) shown in Table 26, the buy-through program results in an increase in fuel and purchased power costs for non-participating customers.

Table 24 - MP-EX Program (MGS, LGS) - Impact on Non-Participating Customers (M1 Base Market)

MP-EX Program for MGS and LGS	2021	2022	2023	2024	2025
Retail Load, GWh	8,963.5	8,964.4	8,978.9	8,989.7	8,992.1
Total Fuel & Purchased Power (F&PP), $000	$292,843	$291,228	$270,038	$266,118	$275,457
Buy-Through Contribution , $000	-$172	-$429	-$1,295	-$1,855	-$2,194
F&PP After Buy-Through Contribution, $000	**$292,671**	**$290,799**	**$268,743**	**$264,263**	**$273,262**
Power Supply Charge Rate (PSCR), ¢/kWh	3.27	3.25	3.01	2.96	3.06
PSCR (After Buy-Through Contribution), ¢/kWh	3.27	3.24	2.99	2.94	3.04
Benefit to Non-Participating Customers, $000	**$172**	**$429**	**$1,295**	**$1,855**	**$2,194**
M1 – Base Market Conditions, $/MWh	$33.75	$35.11	$36.30	$38.05	$40.68

Table 25 - MP-EX Program (MGS, LGS) - Impact on Non-Participating Customers (M2 High Market)

MP-EX Program for MGS and LGS	2021	2022	2023	2024	2025
Retail Load, GWh	8,963.5	8,964.4	8,978.9	8,989.7	8,992.1
Total Fuel & Purchased Power (F&PP), $000	$326,132	$317,859	$305,441	$307,602	$312,492
Buy-Through Contribution , $000	-$1,939	-$2,441	-$3,115	-$3,174	-$3,782
F&PP After Buy-Through Contribution, $000	**$324,192**	**$315,418**	**$302,326**	**$304,428**	**$308,710**
Power Supply Charge Rate (PSCR), ¢/kWh	3.64	3.54	3.40	3.42	3.48
PSCR (After Buy-Through Contribution), ¢/kWh	3.62	3.52	3.37	3.39	3.43
Benefit to Non-Participating Customers, $000	**$1,939**	**$2,441**	**$3,115**	**$3,174**	**$3,782**
M2 – High Market Conditions, $/MWh	$45.39	$46.78	$48.17	$48.53	$51.90

Table 26 - MP-EX Program (MGS, LGS) - Impact on Non-Participating Customers (M3 Low Market)

MP-EX Program for MGS and LGS	2021	2022	2023	2024	2025
Retail Load, GWh	8,963.5	8,964.4	8,978.9	8,989.7	8,992.1
Total Fuel & Purchased Power (F&PP), $000	$273,332	$271,956	$248,374	$241,946	$248,876
Buy-Through Contribution , $000	$1,845	$1,901	$853	$441	-$119
F&PP After Buy-Through Contribution, $000	**$275,178**	**$273,857**	**$249,227**	**$242,388**	**$248,757**
Power Supply Charge Rate (PSCR), ¢/kWh	3.05	3.03	2.77	2.69	2.77
PSCR (After Buy-Through Contribution), ¢/kWh	3.07	3.05	2.78	2.70	2.77
Benefit to Non-Participating Customers, $000	**-$1,845**	**-$1,901**	**-$853**	**-$441**	**$119**
M3 – Low Market Conditions, $/MWh	$22.28	$22.26	$24.22	$25.11	$28.40

Under the implementation of the MP-EX program for LPS customers, fuel and purchased power costs borne by non-participating customers is higher under all market price scenarios. While implementing the buy-through program for LPS customers does reduce total fuel and purchased power costs for non-participating customers, the corresponding reduction in retail customer load responsible for paying those fuel and purchased power costs results in increase in the fuel cost rate. The results of the modeling and corresponding cost impacts on non-participating customers are shown in Table 27 through Table 29.

Table 27 - MP-EX Program (LPS) - Impact on Non-Participating Customers (M1 Base Market)

MP-EX Program for LPS Customers	2021	2022	2023	2024	2025
Retail Load, GWh	8,963.5	8,964.4	8,978.9	8,989.7	8,992.1
Fuel & Purchased Power (F&PP), $000	$292,843	$291,228	$270,038	$266,118	$275,457
Power Supply Charge Rate (PSCR),¢/kWh	3.27	3.25	3.01	2.96	3.06
7x24 Block Purchases, GWh	438.0	438.0	438.0	439.2	438.0
Reduction from 7x24 Block Purchases, $000	-$5,403	-$4,805	-$6,463	-$7,348	-$8,317
F&PP After 7x24 Block Purchases, $000	$287,440	$286,424	$263,575	$258,770	$267,139
Net Retail Load After 7x24 Block Purchases, GWh	8,526	8,526	8,541	8,551	8,554
PSCR (After 7x24 Block Purchases), ¢/kWh	3.37	3.36	3.09	3.03	3.12
Change in PSCR (After 7x24 Block Purchases), ¢/kWh	-0.10	-0.11	-0.08	-0.07	-0.06
Benefit to Non-Participating Customers, $000	**-$8,907**	**-$9,425**	**-$6,710**	**-$5,653**	**-$5,100**
M1 – Base Market Conditions, $/MWh	$33.75	$35.11	$36.30	$38.05	$40.68

Table 28 - MP-EX Program (LPS) - Impact on Non-Participating Customers (M2 High Market)

MP-EX Program for LPS Customers	2021	2022	2023	2024	2025
Retail Load, GWh	8,963.5	8,964.4	8,978.9	8,989.7	8,992.1
Fuel & Purchased Power (F&PP), $000	$326,132	$317,859	$305,441	$307,602	$312,492
Power Supply Charge Rate (PSCR),¢/kWh	3.64	3.55	3.40	3.42	3.48
7x24 Block Purchases, GWh	438.0	438.0	438.0	439.2	438.0
Reduction from 7x24 Block Purchases, $000	-$10,454	-$10,262	-$11,462	-$12,157	-$12,126
F&PP After 7x24 Block Purchases, $000	$315,678	$307,596	$293,979	$295,445	$300,366
Net Retail Load After 7x24 Block Purchases, GWh	8,526	8,526	8,541	8,551	8,554
PSCR (After 7x24 Block Purchases), ¢/kWh	3.70	3.61	3.44	3.46	3.51
Change in PSCR (After 7x24 Block Purchases), ¢/kWh	(0.06)	(0.06)	(0.04)	(0.03)	(0.04)
Benefit to Non-Participating Customers, $000	**-$5,683**	**-$5,547**	**-$3,556**	**-$2,932**	**-$3,108**
M2 – High Market Conditions, $/MWh	$45.39	$46.78	$48.17	$48.53	$51.90

Table 29 - MP-EX Program (LPS) - Impact on Non-Participating Customers (M3 Low Market)

MP-EX Program for LPS Customers	2021	2022	2023	2024	2025
Retail Load, GWh	8,963.5	8,964.4	8,978.9	8,989.7	8,992.1
Fuel & Purchased Power (F&PP), $000	$273,332	$271,956	$248,374	$241,946	$248,876
Power Supply Charge Rate (PSCR),¢/kWh	3.05	3.03	2.77	2.69	2.77
7x24 Block Purchases, GWh	438.0	438.0	438.0	439.2	438.0
Reduction from 7x24 Block Purchases, $000	-$3,770	-$4,806	-$4,641	-$4,665	-$5,800
F&PP After 7x24 Block Purchases, $000	$269,562	$267,150	$243,732	$237,281	$243,076
Net Retail Load After 7x24 Block Purchases, GWh	8,526	8,526	8,541	8,551	8,554
PSCR (After 7x24 Block Purchases), ¢/kWh	3.16	3.13	2.85	2.78	2.84
Change in PSCR (After 7x24 Block Purchases), ¢/kWh	(0.11)	(0.10)	(0.09)	(0.08)	(0.07)
Benefit to Non-Participating Customers, $000	**-$9,602**	**-$8,584**	**-$7,498**	**-$7,167**	**-$6,338**
M3 – Low Market Conditions, $/MWh	$22.28	$22.26	$24.22	$25.11	$28.40

Buy-Through Scenario 2 – Third-Party Generation Service Providers

At the request of AECC, TEP developed a second buy-through scenario that simulated a 120 MW program similar to APS' AG-X program under which 100 percent of the load is served by a third-party generation service provider. Under this scenario, an aggregated hourly load profile was developed using load shapes from MGS, LGS and LPS. These loads were then assumed to be served by third-party generation service providers thus subtracting the customer demands from TEP's load serving obligations.

Buy-Through Scenario 2 - Modeling Results

As shown in Table 30 through Table 32 the implementation of a buy-through program that enables third-party generation service providers to serve 100 percent of a customer's load will result in a reduction in total fuel costs for non-participating customers, however, the corresponding reduction in retail customer load responsible for paying those fuel and purchased power costs results in an increase in the fuel cost rate. This net increase in costs for non-participating customers is a direct result of the incremental avoided costs being less than the Company's average cost of fuel and purchased power.

Table 30 - AECC Scenario - Impact on Non-Participating Customers (M1 Base Market)

AECC Scenario - M1	2021	2022	2023	2024	2025
Retail Load, GWh	8,963.5	8,964.4	8,978.9	8,989.7	8,992.1
Fuel & Purchased Power (F&PP), $000	$292,843	$291,228	$270,038	$266,118	$275,457
Power Supply Charge Rate (PSCR),¢/kWh	3.27	3.25	3.01	2.96	3.06
Reduction F&PP from Third Party Supply, $000	-$8,695	-$10,240	-$12,178	-$13,523	-$15,513
F&PP After Third Party Supply, $000	$284,148	$280,989	$257,859	$252,595	$259,944
Net Retail Load Third Party Generation, GWh	8,298	8,261	8,224	8,191	8,179
PSCR (After Third Party Generation), ¢/kWh	3.42	3.40	3.14	3.08	3.18
Change in PSCR (After Third Party Generation), ¢/kWh	(0.16)	(0.15)	(0.13)	(0.12)	(0.11)
Benefit to Non-Participating Customers, $000	**-$13,032**	**-$12,607**	**-$10,521**	**-$10,108**	**-$9,384**
M1 – Base Market Conditions, $/MWh	$33.75	$35.11	$36.30	$38.05	$40.68

Table 31 - AECC Scenario - Impact on Non-Participating Customers (M2 High Market)

AECC Scenario - M2	2021	2022	2023	2024	2025
Retail Load, GWh	8,963.5	8,964.4	8,978.9	8,989.7	8,992.1
Fuel & Purchased Power (F&PP), $000	$326,132	$317,859	$305,441	$307,602	$312,492
Power Supply Charge Rate (PSCR),¢/kWh	$3.64	$3.55	$3.40	$3.42	$3.48
Reduction F&PP from Third Party Supply, $000	-$18,676	-$20,380	-$22,008	-$23,448	-$22,922
F&PP After Third Party Supply, $000	$307,456	$297,479	$283,433	$284,154	$289,570
Net Retail Load Third Party Generation, GWh	8,184	8,128	8,155	8,154	8,169
PSCR (After Third Party Generation), ¢/kWh	3.76	3.66	3.48	3.48	3.54
Change in PSCR (After Third Party Generation), ¢/kWh	(0.12)	(0.11)	(0.07)	(0.06)	(0.07)
Benefit to Non-Participating Customers, $000	**-$9,876**	**-$9,553**	**-$6,117**	**-$5,216**	**-$5,703**
M2 – High Market Conditions, $/MWh	$45.39	$46.78	$48.17	$48.53	$51.90

Table 32 - AECC Scenario - Impact on Non-Participating Customers (M3 Low Market)

AECC Scenario - M3	2021	2022	2023	2024	2025
Retail Load, GWh	8,963.5	8,964.4	8,978.9	8,989.7	8,992.1
Fuel & Purchased Power (F&PP), $000	$273,332	$271,956	$248,374	$241,946	$248,876
Power Supply Charge Rate (PSCR),¢/kWh	3.05	3.03	2.77	2.69	2.77
Reduction F&PP from Third Party Supply, $000	-$6,438	-$7,416	-$8,711	-$8,559	-$10,944
F&PP After Third Party Supply, $000	$266,895	$264,540	$239,663	$233,388	$237,932
Net Retail Load Third Party Generation, GWh	8,283	8,227	8,199	8,184	8,167
PSCR (After Third Party Generation), ¢/kWh	3.22	3.22	2.92	2.85	2.91
Change in PSCR (After Third Party Generation), ¢/kWh	(0.17)	(0.18)	(0.16)	(0.16)	(0.15)
Benefit to Non-Participating Customers, $000	**-$14,345**	**-$15,041**	**-$12,877**	**-$13,149**	**-$11,895**
M3 – Low Market Conditions, $/MWh	$22.28	$22.26	$24.22	$25.11	$28.40

Environmental Implications of Portfolios

CO_2 emissions are the primary metric for evaluating the environmental performance of various portfolios. In addition to the direct impact on climate change, the level of CO_2 emissions from a portfolio is generally proportional with the level of fossil generation from that portfolio. The environmental impact from the emission of other hazardous and criteria air pollutants and water consumption are also a direct result of fossil generation. While measuring emissions is important, in the 2020 IRP, TEP took the additional step of evaluating the emissions of CO_2 in relation to global temperature goals. TEP identified the global temperature goals of the Paris Agreement as a relevant indicator. The stated goal of the Paris Agreement is limiting global warming 'to well below 2°C…and pursuing efforts to limit the…increase to 1.5°C'..

To assist with this assessment, TEP engaged the University of Arizona Institute of the Environment ("UAIE") to assist in developing a relationship between the Company's direct CO_2 emissions and the goal of limiting temperature rise to levels consistent with the Paris Agreement.

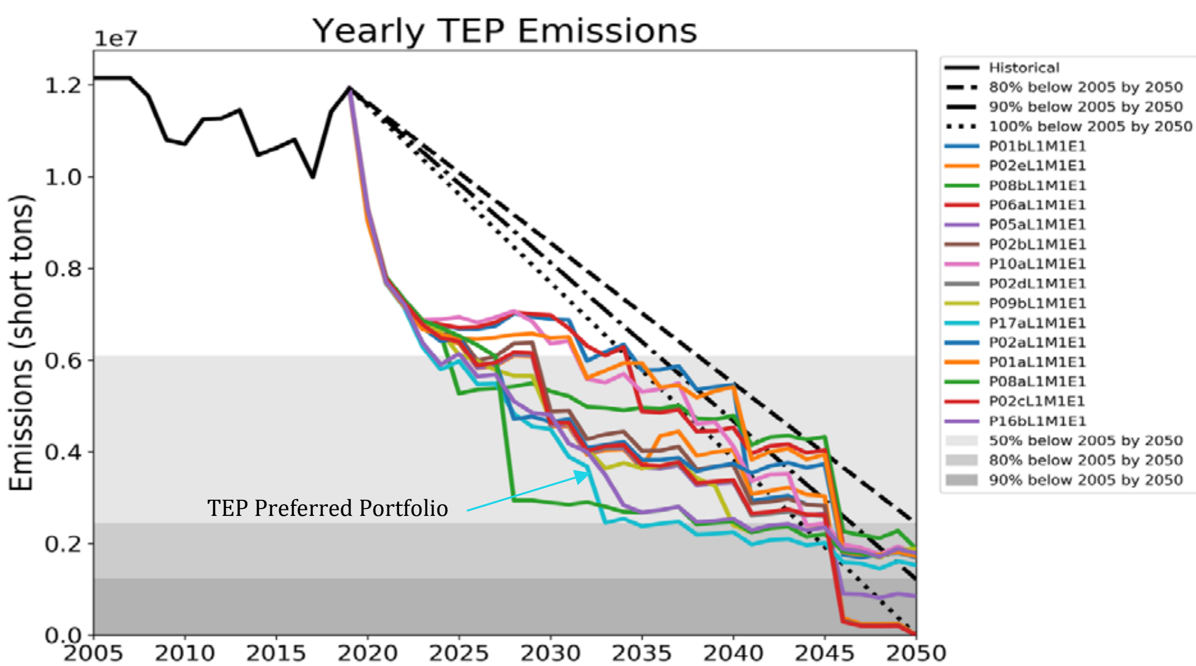
UAIE Phase 1 Study

In November 2019, the UAIE issued its Phase I report.[47] The Phase I report provided a summary on the state of the science relating to global climate change and the history of international efforts to combat climate change. The report also included a survey of U.S. electric utility goals relating to limiting CO2 emissions. The report identified the most common goal among the group of utilities in the survey as being a reduction of 80 percent below 2005 levels by 2050. This target is consistent with, and likely stems from the U.S. Nationally Determined Contribution under the Paris Agreement, which included a mid-century strategy to achieve economy-wide emission reductions of 80 percent below 2005 levels by 2050.

UAIE Phase 2 Study

Phase II of the project was to try to identify a methodology for relating TEP's emissions to a global target of limiting temperature rise. The UAIE methodology involved using the concept of the transient climate response to cumulative carbon emissions ("TCRE") as summarized by Rogelj et. al.[48] From the TCRE, one can identify a range of CO_2 budgets based on a particular temperature target. This budget represents the cumulative emissions from the current date through the target date. Cumulative emissions are an important consideration in evaluating the ambition associated with a carbon reduction target, as it incorporates the timing of the reductions. For example, all of the portfolios that TEP developed in the 2020 IRP achieve substantial emission reductions early in the planning period; 30 percent on average from 2020 to 2024, which is nearly 50 percent below the 2005 baseline year as shown on Chart 47. These early reductions "accumulate" through the years resulting in less warming than would occur if those reductions were delayed until later in the period.

Chart 47 - CO_2 Emissions for TEP's 2020 IRP Portfolios

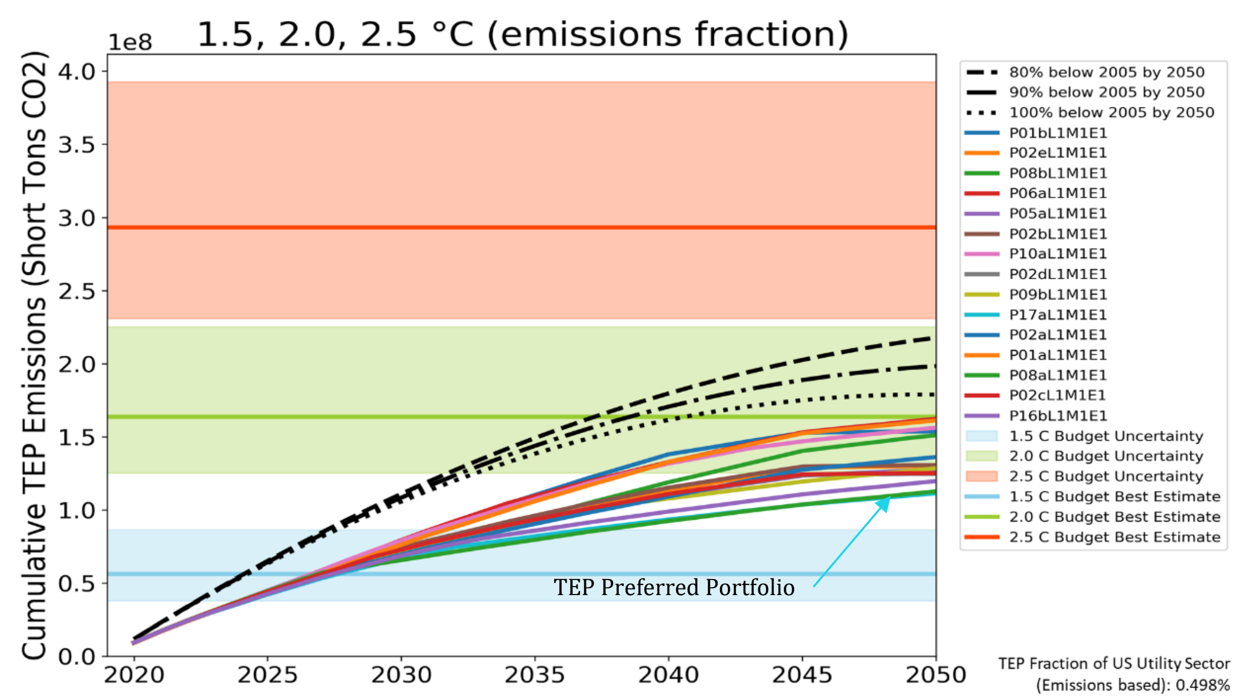


[47] Greenhouse Gas Reduction Goal Planning Report, November 2019; https://www.tep.com/wp-content/uploads/UA-TEP_Report_Phases-1-and-2_July2019_Revised-11.08.19-FINAL.pdf
[48] Rogelj, J., Fricko, O., Meinshausen, M. et al. Understanding the origin of Paris Agreement emission uncertainties. Nat Commun 8, 15748 (2017). https://doi.org/10.1038/ncomms15748

TEP's Share of the Global Carbon Budget

Next, UAIE derived their estimates of ranges for TEP's share of the global carbon budget for different levels of warming. This involved successive steps of "slicing" off portions of a global budget at the country level (United States), sector level (U.S. Electric Sector), and ultimately the company level (TEP). Chart 48 presents the cumulative emissions over time for TEP's alternative portfolios and UAIE's computed budget ranges for different temperature goals.

Chart 48 - TEP Portfolio Emissions in Relation to Temperature Goals



Final Remarks on this Study

As with any analysis that involves projections three decades into the future, there is a great deal of uncertainty in several aspects of this analysis.[49] First, there is a broad range of global budgets consistent with a given temperature target. For instance, EPRI assessed nearly 1,600 emissions projections in the scientific literature and found that global CO_2 changes of +65 percent to -77 percent (relative to 2005) are consistent with limiting warming to 2˚C, and changes of -29 percent to -69 percent are consistent with limiting warming to 1.5˚C[50] Further, the approach only considers physical uncertainty in the carbon budget, via uncertainty in TCRE, while the assumptions embedded in what individual Countries, Sectors and Companies can do to lower their

[49] It should be noted that the "error bands" depicted as shaded areas in Chart 48 represent the uncertainty in the TCRE analysis and do not encompass lack of certainty associated with determining the relationship between TEP's cumulative emissions and global temperature targets.

[50] Rose, S. and M. Scott, 2018. *Grounding Decisions: A Scientific Foundation for Companies Considering Global Climate Scenarios and Greenhouse Gas Goals*, EPRI, Palo Alto, CA. Report #3002014510. Rose, S. and M. Scott, 2020. *Review of 1.5°C and Other Newer Global Emissions Scenarios: Insights for Company and Financial Climate Low-Carbon Transition Risk Assessment and Greenhouse Gas Goal Setting*. EPRI, Palo Alto, CA. 3002018053.

emissions are also highly uncertain. These assumptions involve technical capability, cost effectiveness, the level of cooperation between Countries, Sectors, and Companies, and policy choices that are largely unknowable.

A full accounting of all the uncertainties inherent in an analysis such as this necessitates caution when interpreting the results. UAIE's and TEP's intent with this project was not to provide a definitive correlation between the Company's future emission reduction and global temperature goals. Rather the intent was to provide a framework for how such a correlation could be estimated, with the understanding that those estimates will change over time as TEP and the rest of the globe's paths toward decarbonization become clearer. The UAIE Phase II report is included in Appendix C.

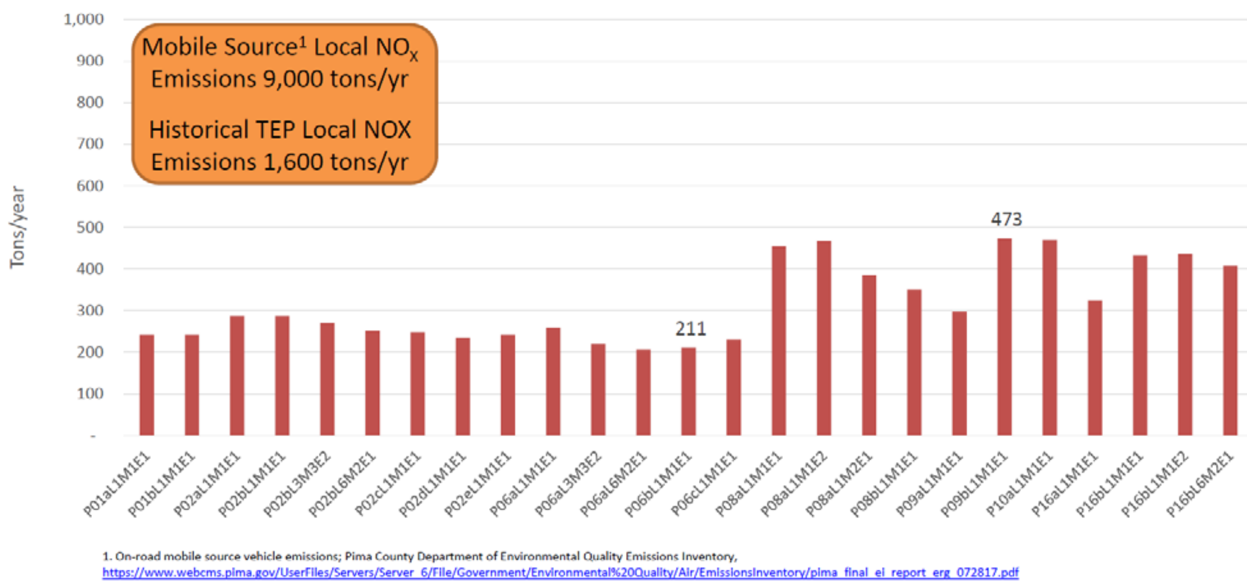
To support this process, TEP and UAIE have made all of the data, assumptions and calculations publicly available, such that others can review, modify, and ultimately improve the analysis. The full methodology and assumptions are available at the following site. https://github.com/CLIMAS-UA/tepcarbon

Local Area NOx Emissions

TEP recognizes that there are other important environmental indicators besides CO_2 emissions and that several stakeholders have expressed interest in TEP's role in improving performance relative to those indicators.

The relative change in TEP's CO_2 emissions is not an accurate indicator of the relative change in TEP's local NOx emissions as TEP's local plants provide a small percentage of TEP's total generation. Emissions of NOx from facilities located in and around Tucson can contribute to formation of ground-level ozone. Through the elimination of coal at the Sundt Generating Station in 2015 and the replacement of old steam boilers with high efficiency RICE generators in 2020, TEP is on target to reduce emissions of NOx from Tucson area facilities by more than 80 percent.[51] It is also important to note that projections of NOx emissions from TEP's Tucson area generating facilities represent just 1.6 percent to 2.7 percent of the NOx emissions that contribute to local ozone formation.[52] While there is some variation in the level of local NOx emissions among the portfolios as shown on Chart 49, this variation is insignificant relative to total NOx emissions that contribute to ozone.

Chart 49 - TEP Local NOx Emissions



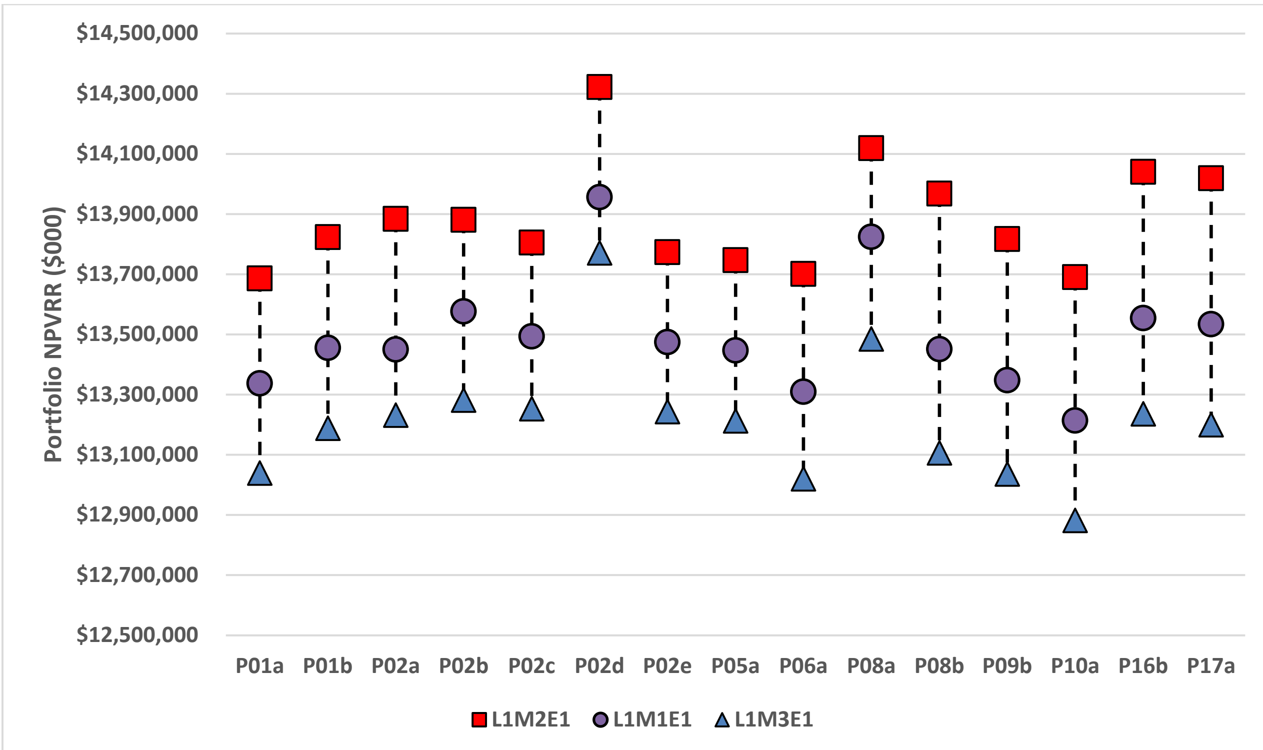
[51] In 2011, prior to the elimination of coal at Sundt Generating Station, emissions of NOx from TEP's Tucson area facilities was over 1,750 tons. Projected emissions of 100 to 300 tons per year (tpy) for TEP's Preferred Portfolio (see Chapter 10) represent a reduction of 94 percent to 83 percent.

[52] Based on TEP's Preferred Portfolio projected highest year total NOx emissions from local facilities (300 tpy) and total emission of 104,824 lbs NOx emission per ozone season day per the PDEQ 2014 Emissions Inventory. The 2.7 percent conservatively assumes all NOx emissions occur during ozone season.

Summary of NPV Revenue Requirements by Scenario

Chart 50 below summarizes the NPVRR for each of the final portfolios modeled in the 2020 IRP under the base, high market, and low market scenarios. Details of the NPVRR for each of the final portfolios are tabulated in Appendix D.

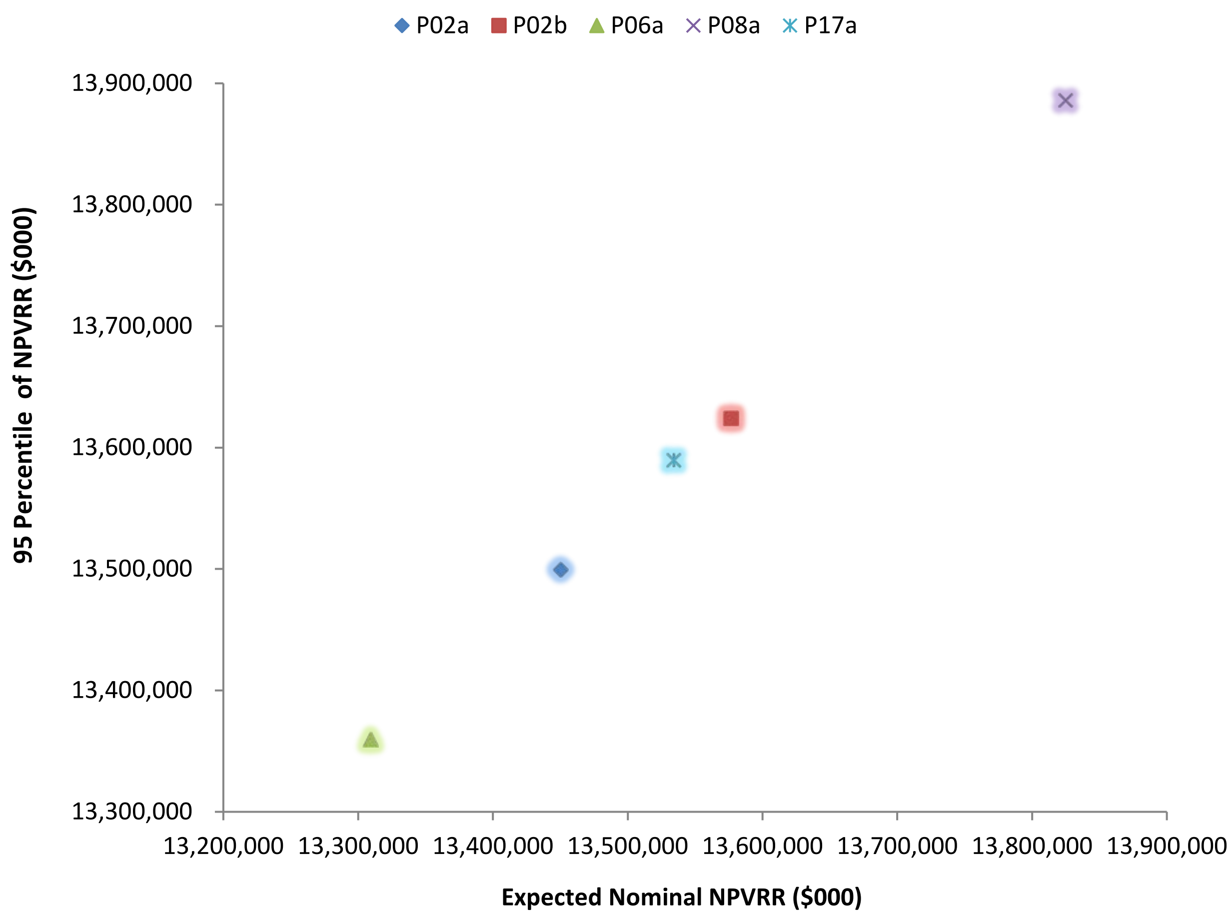
Chart 50 – NPVRR by Market Scenario



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 select portfolios is summarized in Appendix E. Chart 51 summarizes select portfolios with respect to both the expected average NPVRR and the "worst case" outcome risk as represented by the 95th percentile of its NPVRR outcomes. Values lower on the graph and farther to the left, represent lower risk and lower cost portfolios.

Chart 51 - Summary of NPVRR Mean and Risk



CHAPTER 10

PREFERRED PORTFOLIO

Overview

TEP's Preferred Portfolio takes the next step in TEP's pursuit of a more sustainable energy supply. Over the next 12 years TEP will end its use of coal-fired generation entirely, which represents a key milestone in the Company's energy transition. While the Company sets and pursues new goals, we are making these changes responsibly to maintain reliability and affordability which are essential to our customers.

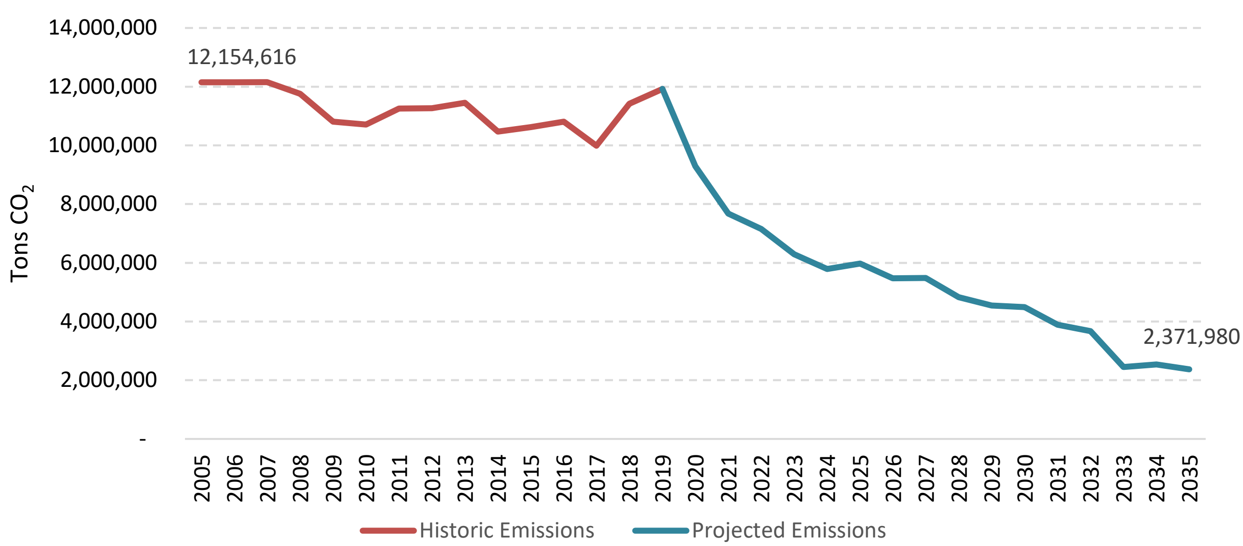
Coal continues to provide value to the system by providing firm capacity combined with the surety of a solid fuel supply, on site that renewables and even natural gas cannot match. Therefore, the reductions in coal capacity will occur in stages that are timed to recognize the value our coal plants provide until such time that those services can be replaced with cleaner resources. During this transition, TEP will work closely with employees and local leaders within these communities to prepare for the units' eventual retirement.

The foundation for this transition was laid over the past two years through TEP's strategic acquisition of Gila River Units 2, a highly efficient 550 MW NGCC plant, and the construction of ten efficient and flexible RICE generators at the Sundt Generating station. These two resource additions set the stage within this 2020 IRP to allow for the eventual elimination of coal while replacing all future capacity with clean resources. Even with the future planned retirement of 1,073 MW of coal capacity and 225 MW of natural gas capacity, TEP's Preferred Portfolio does not include the addition of any new fossil-fuel resources.

CO2 Emission Reduction Goal

TEP's Preferred Portfolio will result in significant reductions in CO_2 emissions reaching 80 percent below 2005 levels by 2035 or earlier. TEP's historic and projected direct CO_2 emissions are presented on Chart 52.

Chart 52 - Historic and Projected Annual CO_2 Emissions



Importantly, these emission reductions begin immediately reaching a 50 percent reduction as early as 2024. These early reductions result in lower cumulative emissions, which as was pointed out in Chapter 9, is the relevant measure of emissions for assessing the impact on climate change. Based on the cumulative emission through 2050, and according to the methodology developed by the UAIE, TEP's Preferred Portfolio is consistent with the goals of the Paris Climate Agreement to maintain global temperature rise at levels "well below 2°C".

These emission reductions are largely driven by changes to coal plant operations as describe below, and ultimately through the retirement of all of TEP's coal-fired plants. The addition of renewable resources further reduces emissions by displacing natural gas-fired generation. Finally, EE also contributes to emission reductions by reducing the amount of load that needs to be served.

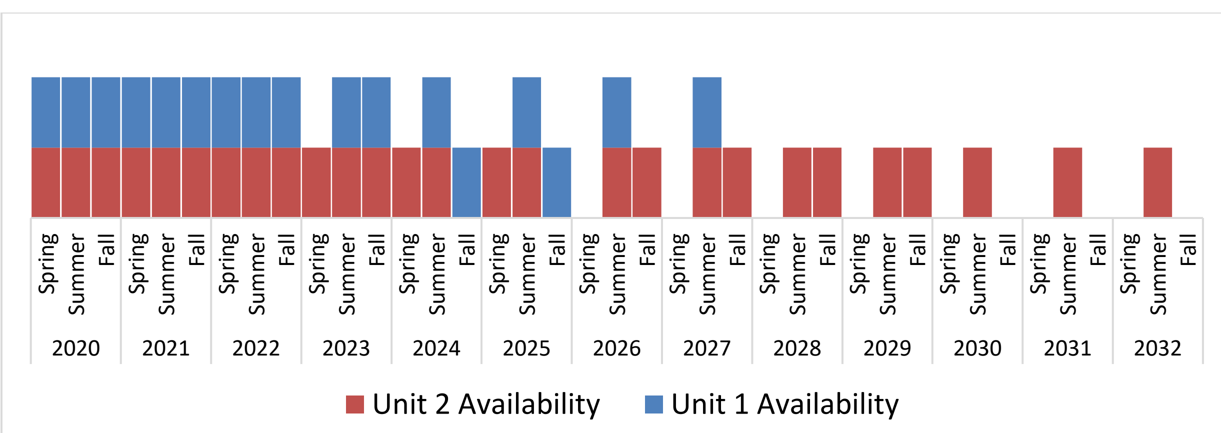
Changes in Coal Plant Operations

The Preferred Portfolio contemplates the very real possibility that Springerville Units 1 and 2 may be unable to find a future coal supply that is economical and allows the units to meet certain environmental requirements. Notwithstanding the coal supply risk, the economics of coal-fired generation have shifted. While the plants still provide necessary and cost-effective support to the system through ancillary services, capacity and reliability, they are no longer the lowest cost resources for energy supply. In addition, although the Springerville units have made significant improvements in reducing turndown limits, there remains a risk of over generation during non-summer months as the level of solar generation increases on TEP's system.

Therefore, the Preferred Portfolio includes beginning seasonal operations at Springerville as early as 2023. Seasonal operation involves taking a unit out of service (i.e. idling) for an extended period of time (3 to 4 months) during the fall, winter, and spring seasons. Initially the units will alternate idling between spring and fall (both seasons include the adjacent winter months), then one of the units will transition to summer only operation prior to full retirement at the end of 2027. The remaining unit will go to summer only operation through its retirement at the end of the 2032 summer season.

The benefits of these changes in operation include maintaining a source of cost-effective capacity for peak summer months, maintaining reliability through a 30 to 90 day supply of fuel at the plant, reductions in O&M and capital expense, mitigation of over generation during low load months by reducing thermal minimum generation levels, and significant reductions in emissions and water use (without surrendering the capacity and reliability mentioned above). Initial plans for seasonal operation are presented on Chart 53 below.

Chart 53 - Springerville Seasonal Operation



Technology Considerations for Resource Additions

As expected with the current technology cost declines, current tax incentive policies, and solar insolation values in southern Arizona, utility-scale PV single-axis tracking solar is the least cost supply-side resource on an energy-only basis, followed closely by higher-capacity factor wind resources located in the eastern region of New Mexico. These are the resource additions included in the Preferred Portfolio.

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 Preferred Portfolio. However, the Company views the dominance of Li-ion technology as a risk to diversity in the grid balancing resource category, and a motivation to both explore and promote newer, fast-acting storage technologies to mitigate system variability due to intermittent resources. The measured pace of TEP's integration of new energy storage resources 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.

In order to achieve the Company's stated goals, the Company continues to evaluate on an on-going basis, the most cost-effective renewable energy 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 technologies to facilitate greater renewable penetration, as well as existing and planned transmission availability for regions located outside the Company's service territory. For all resource additions, these and other factors will be addressed through all-source RFPs. The all-source RFPs will identify the specific nature of the system needs that the new resources are intended to cure. However, they will be technology neutral, including supply- and demand-side resources, and will not unduly exclude any commercially available resource that can demonstrate adequate performance and cost-effectiveness.

Future Energy Efficiency

TEP's Preferred Portfolio will continue to incorporate high levels of EE. Based on the results of the Portfolio Analysis in Chapter 9, including the modeling performed by Strategen as part of TEP's collaboration with SWEEP, TEP believes that incorporating EE at levels consistent with recent historical years (incremental annual increases of 1.3 percent to 1.5 percent of the previous year's retail load) is cost-effective for both participating customers as well as non-participating customers, provided 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 TEP's DSM programs to effectuate incremental savings above and beyond these standards will diminish. While customers are still benefiting from these efficiency improvements, TEP may no longer be able to "claim" energy savings credits associated with these measures.

Demand Response

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

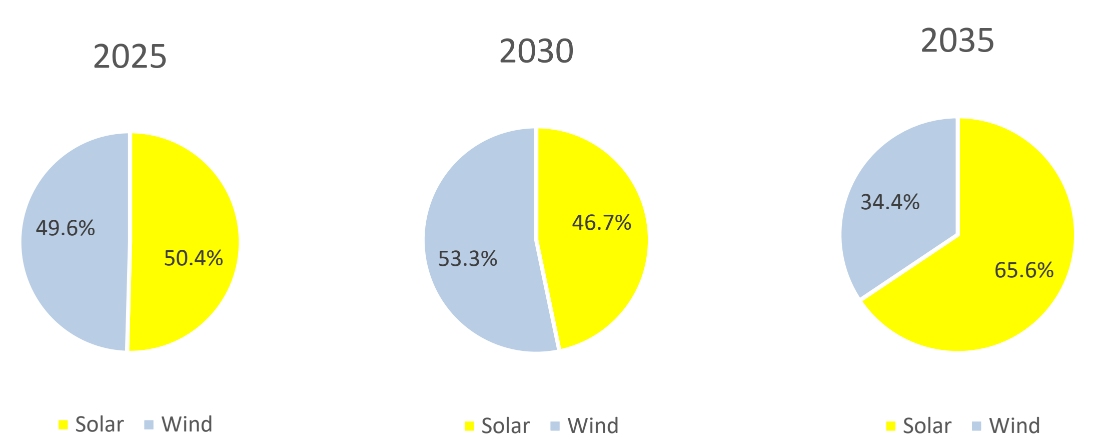
The C&I Demand Response program, marketed as the "SmartDR" program, is designed to manage peak demand and mitigate system emergencies through a C&I load curtailment program. The program is delivered in-house through agreements with multiple customers. The customer committed loads are aggregated to provide TEP a confirmed capacity load reduction available upon request. The program is available for up to 80 hours per year, with a typical load control event lasting 3 to 4 hours.

For planning purposes, TEP assumes approximately 4 percent annual growth in DR capacity after 2021 resulting in 66 MW available in 2035 with a 2 percent annual increase in fees needed to achieve that level of growth. These growth assumptions would likely require expanding DR beyond the C&I sector.

Future Renewable Energy Resources

TEP's Preferred Portfolio results in a significant expansion in renewable energy. The plan calls for the addition of 2,000 MW of new solar and wind resources through 2035 beyond those already included in our base assumptions. TEP maintains diversity in it renewable asset base by adopting solar and wind resources. The percentage of solar versus wind resources over time is presented in Chart 54.

Chart 54 - Preferred Portfolio – Renewable Capacity Mix



Future Grid Balancing Resources

The Preferred Portfolio assumes the implementation of 1.4 GW of new BESS by 2035 (in addition to the 50 MW that is in-service or under contract today), representing 84 percent of the grid balancing resources in TEP's portfolio.[53] In general, the BESS additions are timed to coincide with renewable energy additions to take advantage of potential efficiencies in procurement as well as potential tax incentives, or with reductions in capacity due to the retirement of existing thermal resources. As discussed above, the BESS installations are staged to take advantage of anticipated steep declines in the cost of these systems with 67 percent of the BESS capacity going into commercial operation in 2030 or later.

[53] In 2035, TEP's Preferred Portfolio includes 91 MW of simple-cycle combustion turbines and 188 MW of RICE generators.

Reference Case Plan Summary and Timeline

Chart 55 shows the Preferred Portfolio resource capacity additions and retirements through the planning period, which gives an indication of the source of replacement and make-up power due to unit retirements and increasing load. Chart 56 details the significant resource planning decisions assumed for the 2020 IRP Reference Case Plan.

Chart 55 - Preferred Portfolio – Additions and Retirements

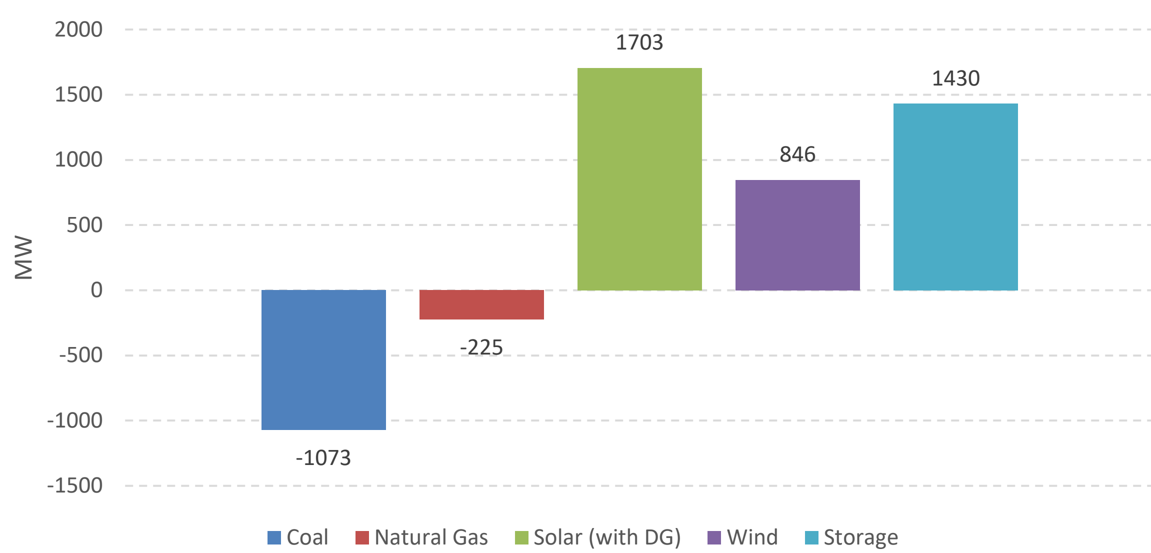
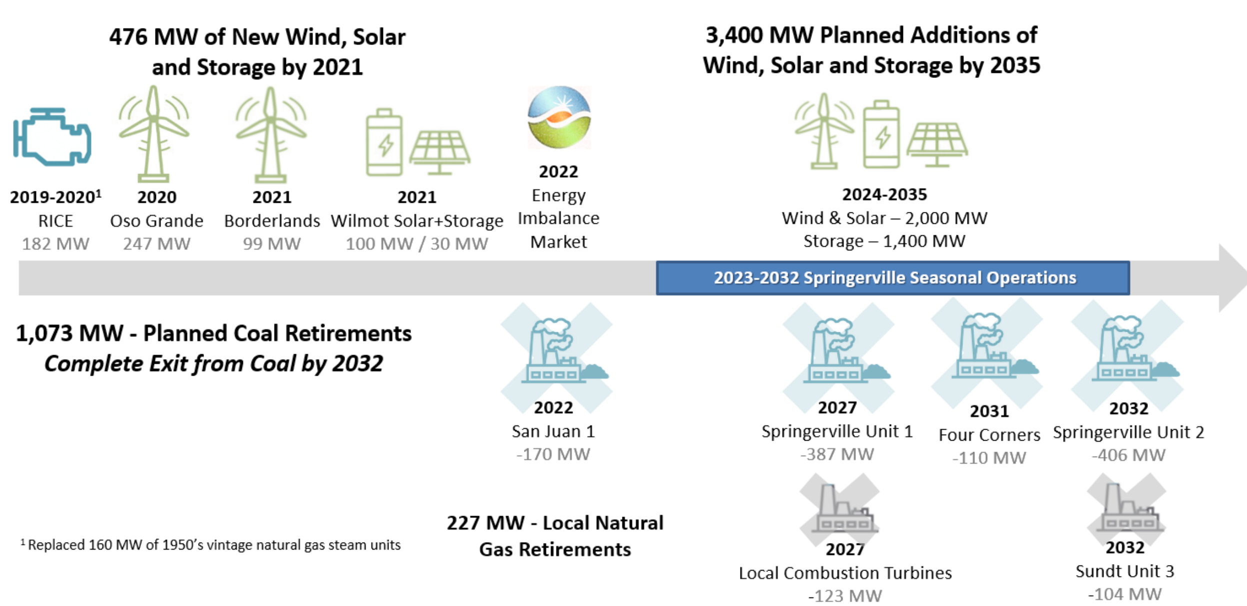


Chart 56 - 2020 IRP Reference Case Plan Resource Timeline

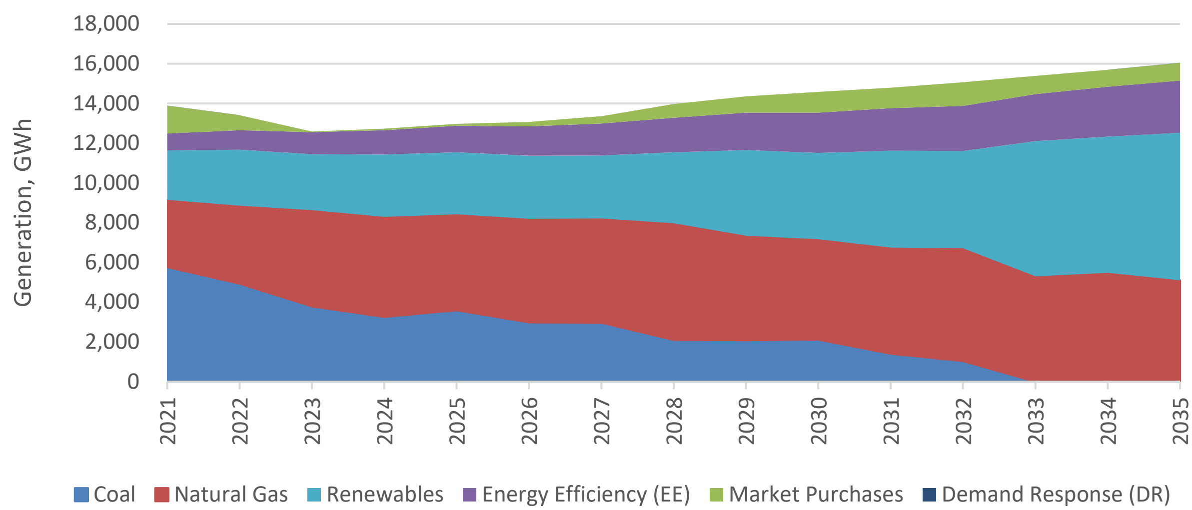


For modeling purposes, the 2020 IRP Preferred Portfolio does not include any significant new transmission upgrades for energy supply over the 15-year timeframe. However, a transmission cost is include for new wind generation facilities. The TEP Ten-Year Transmission Plan only includes one "Planned" EHV project, which is a relatively small project anticipated for construction in 2021-2022.[54] Several "Planned" HV projects are identified in the plan, however, these projects are generally related to system reinforcements or extending service to customers.

Reference Case Plan Attributes

The primary objective of the Preferred Portfolio is to provide a portfolio of resources that reliably meets our customers' energy needs at an affordable rate, while identifying and addressing potential risks to cost and reliability. TEP's 2020 Reference Case Plan achieves all of these objectives while transitioning to a more sustainable portfolio. Chart 57 below shows the shift in energy mix over the planning period including the elimination of coal in 2032.

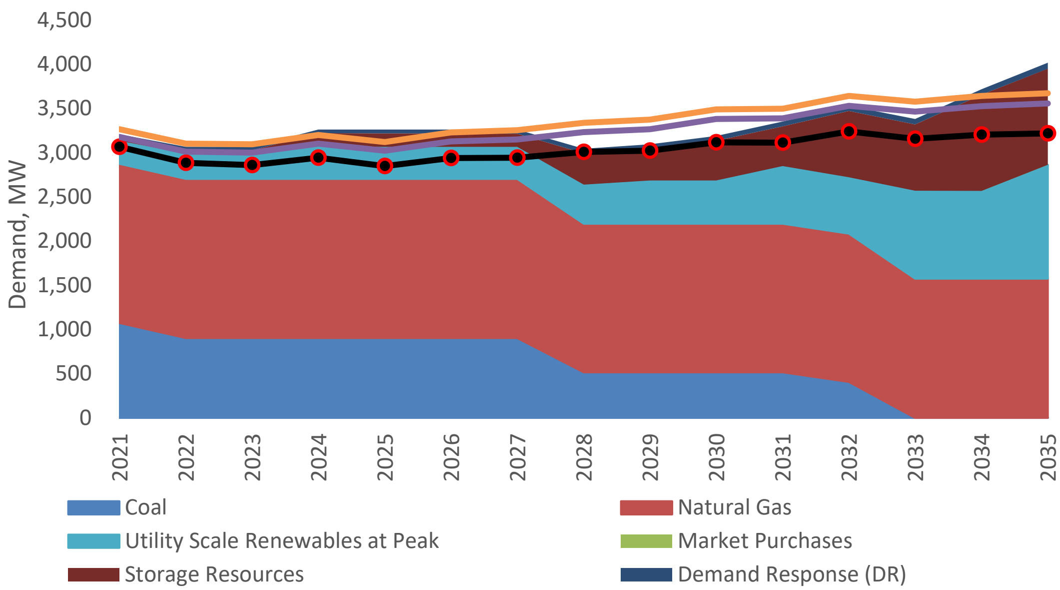
Chart 57 - Preferred Portfolio, Annual Energy by Resource Type



[54] Hassayampa – Pinal West – project is a 500kV line loop-in of 3 spans or less to connect an existing line to the Jojoba Switchyard -

Chart 58 below shows final Load and Resources assessment of the Preferred Portfolio.

Chart 58 - Preferred Portfolio, Load and Resources



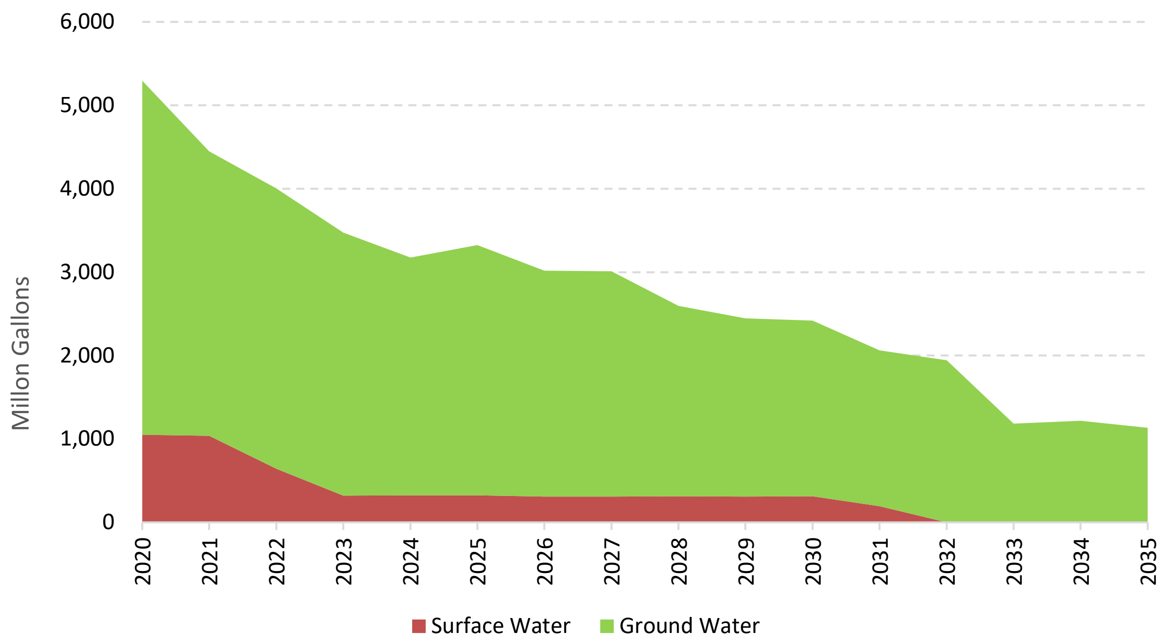
Environmental Attributes

For the 2020 IRP, TEP worked with the Advisory Council to identify key environmental attributes that should be weighed in evaluating the overall suitability of a particular resource portfolio. In addition to CO_2 emissions which is discussed earlier in this Chapter, local area NOx emissions and water consumption associated with energy generation were identified as the key environmental attributes.

Local NOx emissions can contribute to the formation of ground-level ozone and the Tucson area is at risk of exceeding the NAAQS for ozone as described in Chapter 6. TEP's preferred portfolio maintains the greater than 80 percent reduction in local NOx emissions that TEP has achieved through prior actions.

Water availability for power generation is an ongoing concern, especially in the Desert Southwest. Low surface water levels due to drought and changing weather patterns suggest that a long-term goal to reduce surface water and groundwater consumption is appropriate. TEP believes that the elimination of surface water consumption and over 70 percent reduction in groundwater consumption realized under the Preferred Portfolio represent a significant outcome in terms of managing future water supply risk. See Chart 59 for the annual water consumption under TEP's Preferred Portfolio.

Chart 59 - Preferred Portfolio - Annual Water Consumption Associated with Generation



Load Growth Scenario Analysis

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

- No Load Growth (L2) – hold 2021 retail load constant throughout the planning period
- Less than 1 percent Load Growth (L3) – assumes lower than expected EV sales and removes the Rosemont mine load from the load forecast

In addition, TEP evaluated one high load growth scenario (L6) in which EV sales are assumed to be higher than expected.

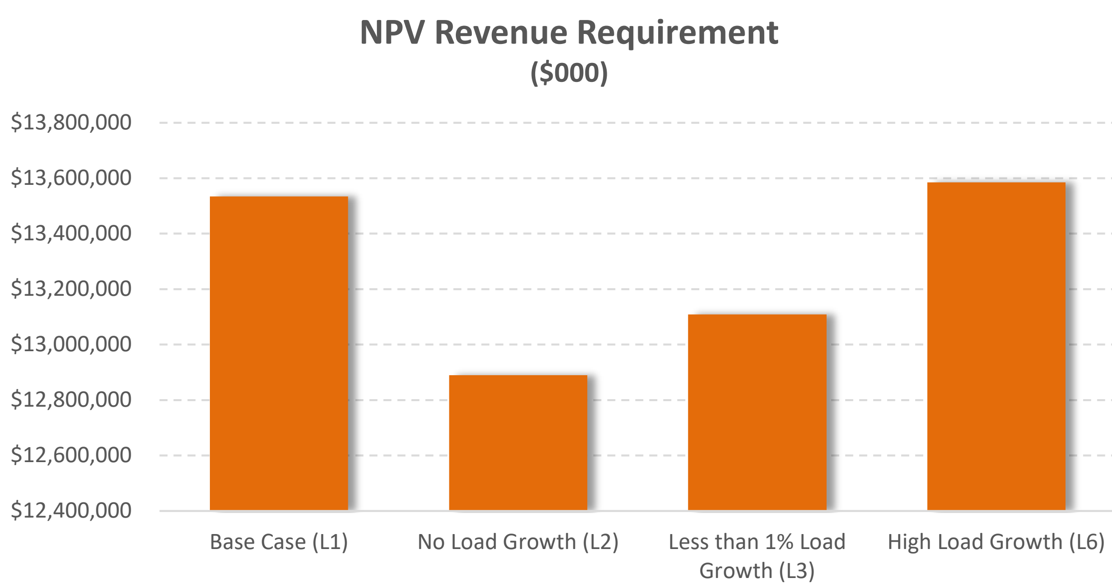
The reduction in resource additions associated with the two low load growth scenarios are presented in Table 33 below. There were no additional resources required for the high load scenario as the increase in EV sales assumed in that scenario was relatively small in relation to the overall load.

Table 33 - Changes in Resource Capacity Associated with Load Growth Scenarios

Capacity By 2035 (MW)	Base Case (L1)	No Load Growth (L2)	Less Than 1% Load Growth (L3)	High Load Growth (L6)
Solar	1610	1060	1060	1610
Wind	846	646	746	846
Storage	1430	1030	1230	1430

The NPVRR for each of these load scenarios is presented in Chart 60 below.

Chart 60 - Preferred Portfolio NPV Revenue Requirement for Various Load Scenarios



CHAPTER 11

FIVE-YEAR ACTION PLAN

The 2020 Preferred Portfolio is based on current forecasts and assumptions. TEP 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. TEP's action plan includes the following:

- In line with its efforts to diversify its resource portfolio, TEP will complete the first phase of coal plant retirements when San Juan Unit 1 closes in June 2022. With that retirement, the Company will have retired 638 MW of coal-fired generation since 2015, representing a 41percent reduction in capacity.

- TEP will complete the build-out of planned solar and wind projects currently under contract or construction. The Oso Grande and Borderlands wind projects, along with the Wilmot solar and storage project, will double the Company's renewable energy output reaching 30 percent of retail load by 2023. The Wilmot project will also be the Company's first deployment of a utility-scale battery energy storage system capable of reducing peak demand by shifting load from off-peak to on-peak periods.

- At the Springerville Generating Station, seasonal operations will begin in 2023. The Company will initiate discussions with the ACC, employees, the IBEW Union, and leaders of the communities that will be impacted by the operational changes at the plant including the ultimate closure of both units. Those discussions will include cost recovery, transition of employees and support for local communities. TEP will also develop flexible coal supply alternatives that will support these operational changes as well as future environmental compliance options.

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

- TEP 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 all-source RFPs based on specific, identified system needs.

- TEP will continue preparations for joining the CAISO EIM, which is scheduled for April 2022. TEP's preparations will be focused on a smooth transition, and the ability to maximize the operational and financial benefits of market participation.

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, TEP plans to communicate any major change in its anticipated resource plan with the ACC as part of its ongoing planning activities. TEP hopes this dialog will engage the Commission on important resource planning issues while providing TEP with greater regulatory certainty with regards to future resource decisions. TEP requests that the Commission approve its 2020 Integrated Resource Plan as provided in A.A.C. R14-2-704.B. and the associated actions herein.

APPENDIX A

SIEMENS RESOURCE ADEQUACY STUDY

TEP-UNSE 2020 Flexible Resource Adequacy Study

May 26, 2020

Siemens Energy Business Advisory

Report Outline

- Executive Summary
  - Project objectives
  - Study results
  - Conclusions
  - Recommendations
- Project Description and Results
  - Data collection and preparation
  - Time series and correlation coefficient analysis and results
  - Monte Carlo simulations analysis and results

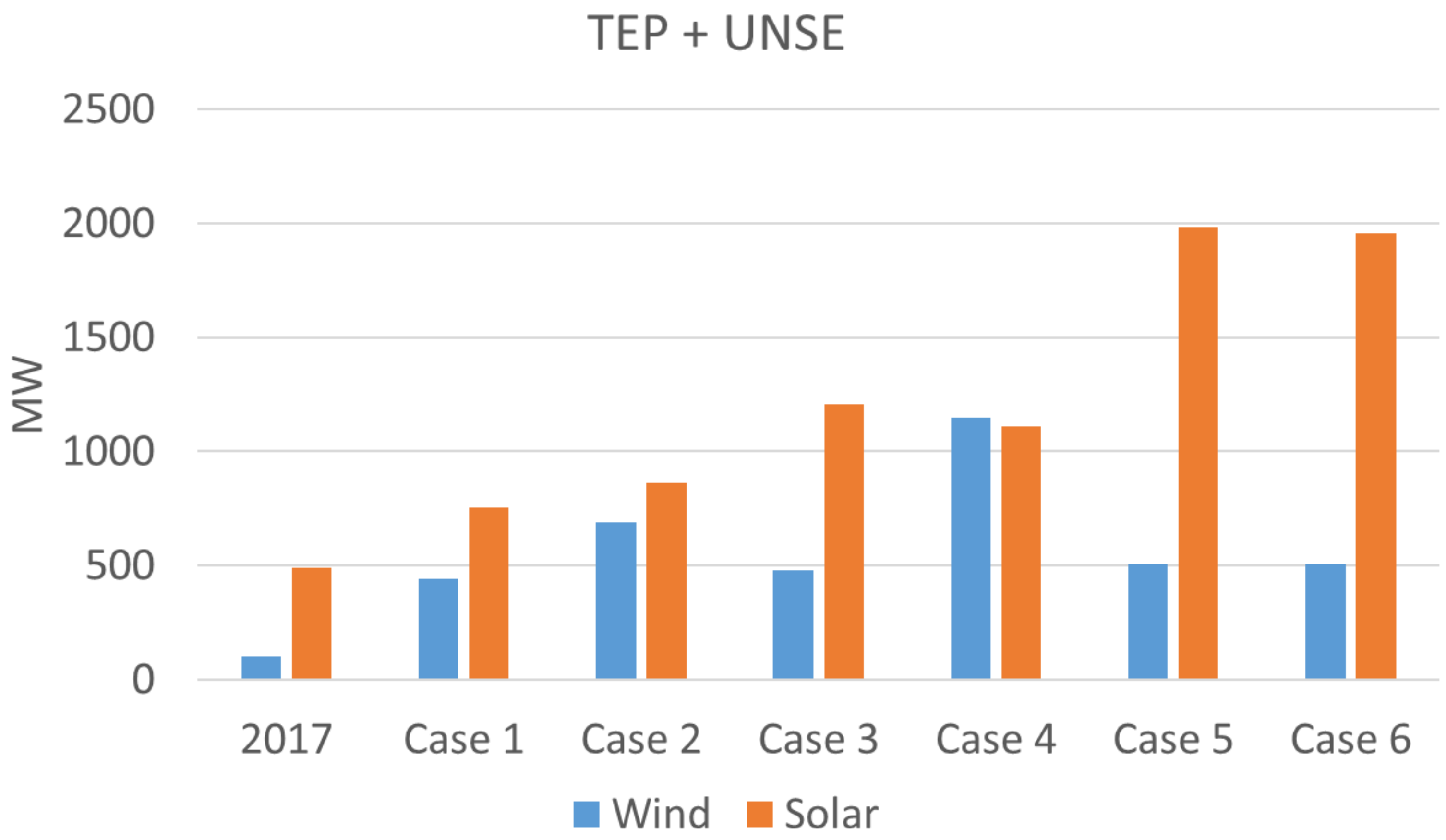
Executive Summary

Phase 2 Project Objectives

- Build on Phase 1 study, which focused on TEP-only resource adequacy for high renewable energy cases
- Assess capacity and flexibility requirements under six high-renewable energy scenarios for TEP balancing area (BA)
  - Expand study to include load and renewable sites from UNS Electric service area
  - Update historical data to July 1, 2017 through June 30, 2019 (Phase 1 used 2016-2017)
- Assess spatial and temporal correlations of renewable variability
- Deliverables
  - Kickoff meeting and periodic project update meetings
  - Final report: draft for review and final
  - Analysis data and results

Renewable Energy Scenarios for Study

Case	RE as % of 2024 Sales	Resources Beyond Case 1
1	25%	----
2	35%	Majority Wind
3	35%	Majority Solar
4	50%	Majority Wind
5	50%	Majority Solar
6	50%	Majority Solar Geographically Concentrated



This analysis is generally applicable to any year between 2024 and 2030, assuming no retirements are made in this time frame.

Resource Assessment Criteria

- Seasonal peak net load
- Annual overgeneration in terms of peak (MW) and total energy (MWh)
- Monthly max 3-hour net load ramp
- Monthly max 10-minute net load ramp

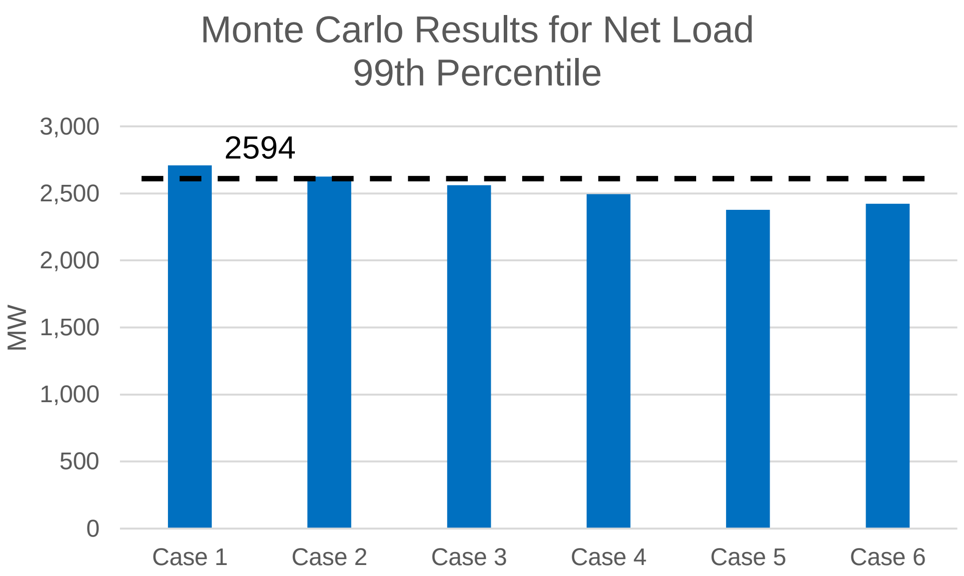
- Net load defined as retail load plus distributed generation minus total renewable generation

TEP BA's Peak Net Load

SIEMENS

2024 Resources	Summer Capacity (MW)
Springerville 1	387
Springerville 2	406
Four Corners 4	55
Four Corners 5	55
Gila 2	516
Gila 3	516
Luna	185
Sundt ST3	105
Sundt ST4	156
RICE 1-10	182
Demoss Petrie	72
North Loop 1-3	73
Sundt CT 1-2	50
Wilmot Battery	30
Black Mountain 1	44
Black Mountain 2	45
Valencia 1-4	55
Demand Response	50
TOTAL	2982
TOTAL*0.87	2594

Monte Carlo Results for Maximum Net Load (Net Load Requirements adjusted for TX losses)		
	99th Percentile (MW)	BA Has Adequate Capability?
Case 1	2,709	No
Case 2	2,625	No
Case 3	2,562	Yes
Case 4	2,495	Yes
Case 5	2,378	Yes
Case 6	2,423	Yes



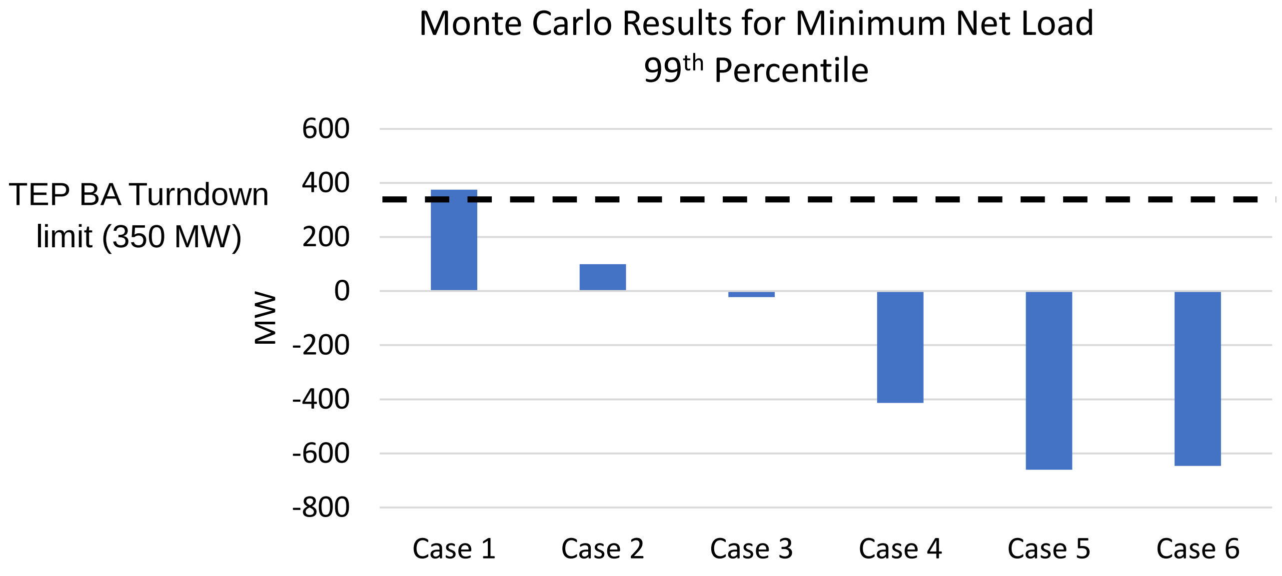
- To take into account a planning reserve margin of 15%, the total dispatchable capacity was determined as 87% of effective capacity.
- Each utility is required to procure enough capacity to meet its own peak demand regardless of their combined loads and resources. While TEP has sufficient dispatchable capacity to meet its peak net load, UNSE has historically relied on market purchases to meet a substantial amount of its peak load, which are not shown here because they have not yet been procured for the time period analyzed. Thus, the combined loads and resources of the two utilities shows a slight lack of peak capacity in Cases 1 and 2.

TEP BA Non-Cycling and Storage Minimum Generation v. Minimum Net Load

2024 Resources	Min Generation (MW)
Springerville 1	150
Springerville 2	150
Four Corners 4	28
Four Corners 5	28
Gila 2	156
Gila 3	156
Luna	47
Sundt ST3	19
Sundt ST4	36
RICE 1-10	10
Wilmot Battery	-30

Over Generation (with respect to turndown limit)

	TEP Overgeneration (MWh)	TEP BA (Minimum Net Load MW) (P99)	TEP BA Overgeneration (MWh)
Case 1	53	375	1,130
Case 2	21,236	100	50,057
Case 3	78,786	-22	128,770
Case 4	306,926	-413	452,671
Case 5	789,542	-660	926,853
Case 6	762,244	-646	898,663



- Negative minimum net load means over-generation will occur if there is inadequate flex capacity (e.g., storage) to absorb the surplus energy generation, or if there is no market for exporting the surplus energy. Therefore, TEP BA is facing a potential over-generation situation when renewable penetration increases to 35% and especially to 50%, as in Cases 3, 4, 5, and 6.
- NOTE: Over-generation occurs when renewable generation is greater than demand minus the turndown limit of resources which must stay on line for reliability purposes. These limits are shown in the top table to the left.

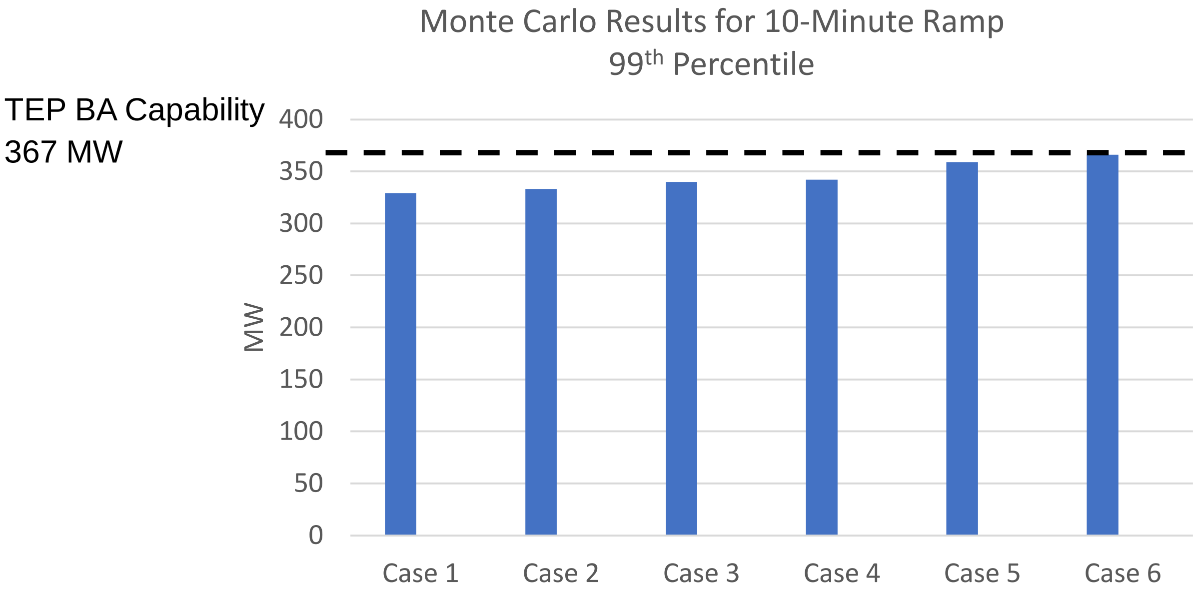
10-Minute Ramping Capabilities of TEP BA Resources

SIEMENS

2024 Resources	10-Minute Ramping Capability (MW)
Springerville 1	34
Springerville 2	34
Four Corners 4	2
Four Corners 5	2
Gila 2	75
Gila 3	75
Luna	50
Sundt ST3	35
Sundt ST4	48
RICE 1-10	182
Demoss Petrie	0
North Loop 1-4	0
Sundt CT 1-2	0
Wilmot Battery	30
Black Mountain 1	0
Black Mountain 2	0
Valencia 1-4	0
TOTAL Ramping Capability	**567**

BA 10-Minute Ramp Capability v. Maximum 10-Minute Ramp

Monte Carlo Results for 10-Minute Ramp		
	99th Percentile (MW)	BA Has Adequate Capability?
Case 1	329	Yes
Case 2	333	Yes
Case 3	340	Yes
Case 4	342	Yes
Case 5	359	Yes
Case 6	366	Yes



- The total ramping capability exceeds the 10-minute maximum ramp requirement in all six cases, however, the available ramping capability at any given time is a function of the resources available at that time and their level of output. Accordingly, the graph above assumes that one Springerville unit, one Gila unit, and half the RICE units are unavailable to ramp because the peak ramps occur in the summer afternoons (see later slides), when these units are likely to be operating at or near full capacity.
- The Monte Carlo results suggest that the maximum 10-minute ramps will increase only modestly relative to the doubling of renewable capacity between Cases 1 and 6.

TEP BA’s 3-Hour Ramping Capability

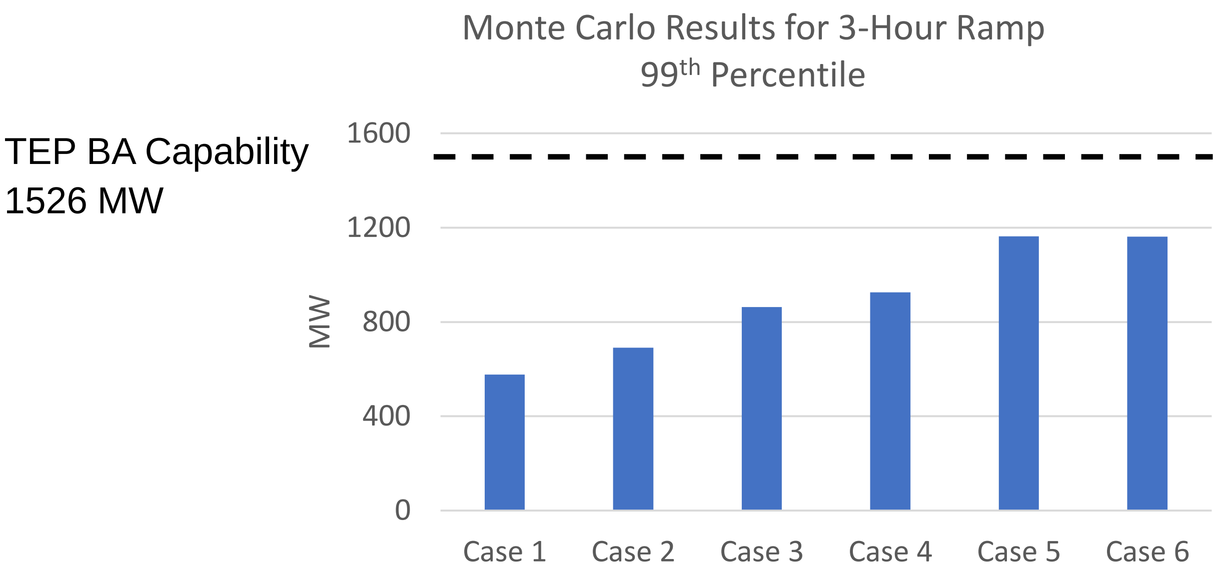
SIEMENS

2024 Resources	3-Hour Ramping, (MW)	3-Hour Ramping, If Cycling (MW)
Springerville 1	197	N/A
Springerville 2	216	N/A
Four Corners 4	27	N/A
Four Corners 5	27	N/A
Gila 2	360	516
Gila 3	360	516
Luna	138	185
Sundt ST3	86	105
Sundt ST4	120	156
RICE 1-10	172	182
Demoss Petrie	72	72
North Loop 1-4	73	73
Sundt CT 1-2	50	50
Wilmot Battery	60	60
Black Mountain 1	44	44
Black Mountain 2	45	45
Valencia 1-4	55	55
Total Ramping Capability	**2102**	**2059**

TEP BA's 3-Hour Ramping Capability v. Maximum 3-Hour Ramp

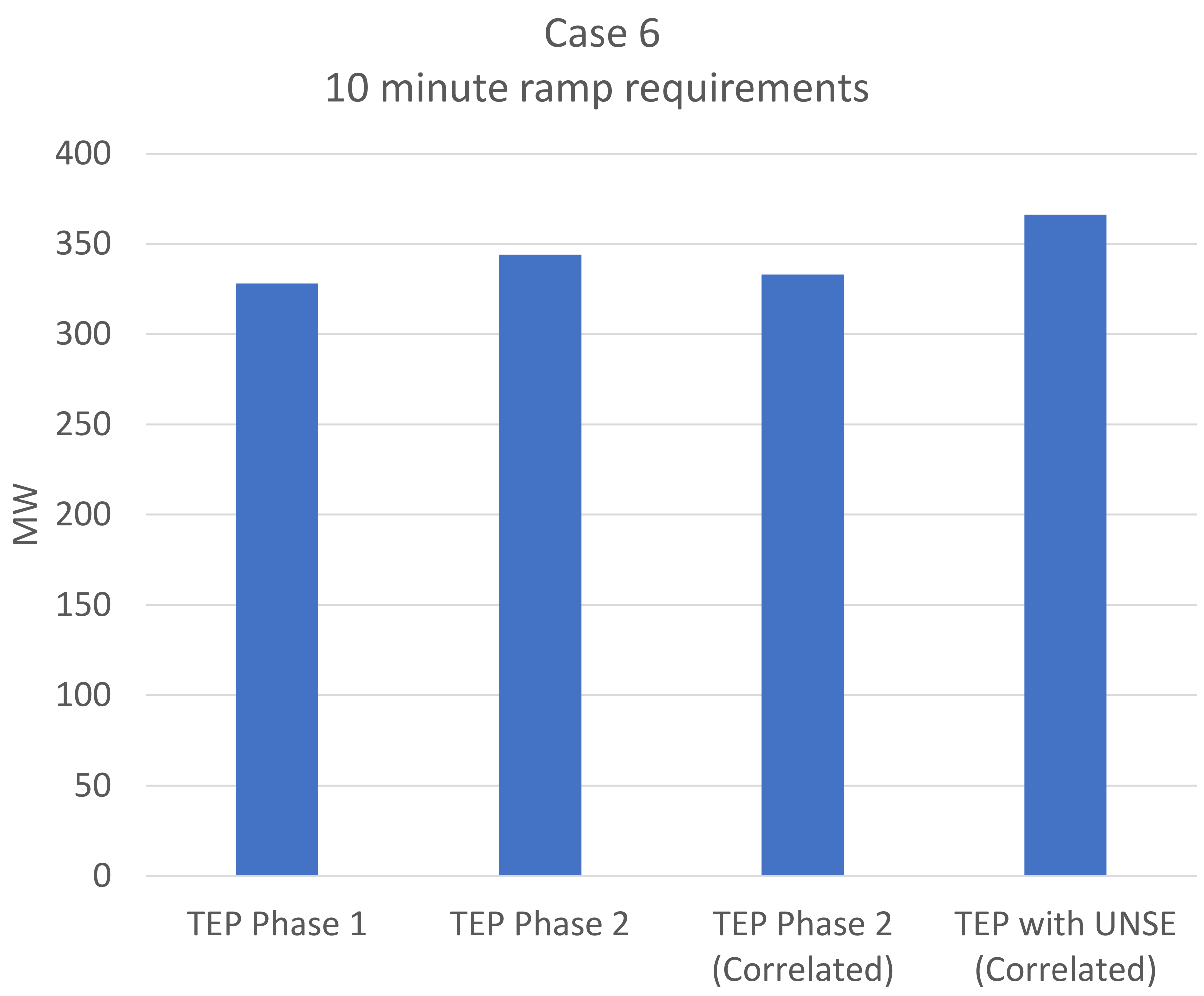
SIEMENS

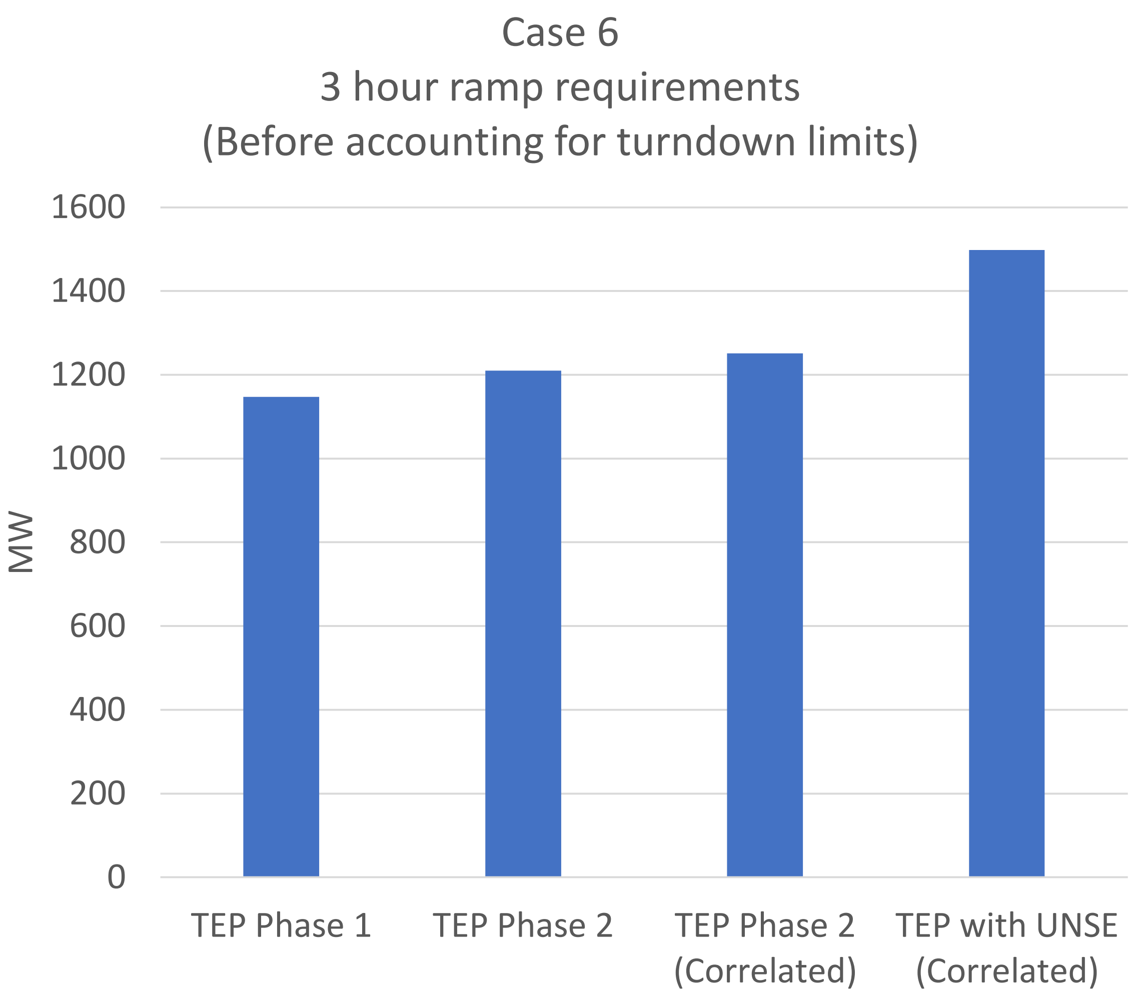
Monte Carlo Results for 3-Hour Ramp		
	99th Percentile (MW)	**< 3-Hour Ramping Capability**
Case 1	672	Yes
Case 2	799	Yes
Case 3	1000	Yes
Case 4	1020	Yes
Case 5	1160	Yes
Case 6	1158	Yes



- The total ramping capability exceeds the 3-hour maximum ramp requirement in all six cases, however, the available ramping capability at any given time is a function of the resources available at that time and their level of output. Accordingly, the graph above assumes that one Springerville unit and one Gila unit will be unavailable to ramp because the peak ramps occur in the spring and fall (see later slides), when these units are likely to be unavailable due to maintenance outages and/or seasonal operation.
- It is recommended that TEP also consider the full ramp requirement from its turndown limit to its daily peak load, regardless of the number of hours in the ramp.
- Required amount of controllable resources to follow 3-hour ramps 99% of the time varies between 576 MW for Case 1 and 1160 MW for Case 5.

Progression Results from Phase 1 through Phase 2





Conclusions

- The maximum 10-minute ramp for TEP is 333 MW in July for Case 6.
- The maximum 10-minute ramp for TEP BA is 366 MW (an increase of 33 MW compared to TEP only) in July for Case 6.
- The maximum 3-hour ramp for TEP is 1029 MW in October for Case 5.
- The maximum 3-hour ramp for TEP BA is 1160 MW (an increase of 131 MW compared to TEP only) in January for Case 5.

Conclusions (Continued)

- For the cases and timeframe studied, the TEP BA can meet all 99th percentile 10-minute and 3-hour net load ramps, assuming most of the BA's ramping resources are available at the time of the highest ramps.
- The TEP BA may experience some over-generation at 35% renewables and is expected to experience substantial over-generation at 50% renewables (Case 3, 4, 5, and 6). The maximum over-generation is 660 MW in Case 5.
- Assuming none of the resources included in this study are retired, TEP has sufficient capacity for all scenarios, but UNSE may require some additional firm summer capacity in Cases 1 and 2.
- Higher load and renewables have a balancing effect for the TEP BA compared to just TEP system that results in netting out of renewable variability from more diverse system load.

Recommendations

- The Monte Carlo results suggest that the maximum 10-minute ramps will increase only modestly relative to the doubling of renewable capacity between Cases 1 and 6, but TEP should track the impact on actual ramps as it implements more renewable resources to determine if the ramps might increase more than indicated.
- TEP should consider the full ramp requirement from its turndown limit to its daily peak load.
- Over-generation is present at 35% and would require mitigation at 50%, especially if all the renewable energy must serve load in order to satisfy a renewable energy goal or standard.

Data Collection and Preparation

Renewable Energy Scenarios for Study

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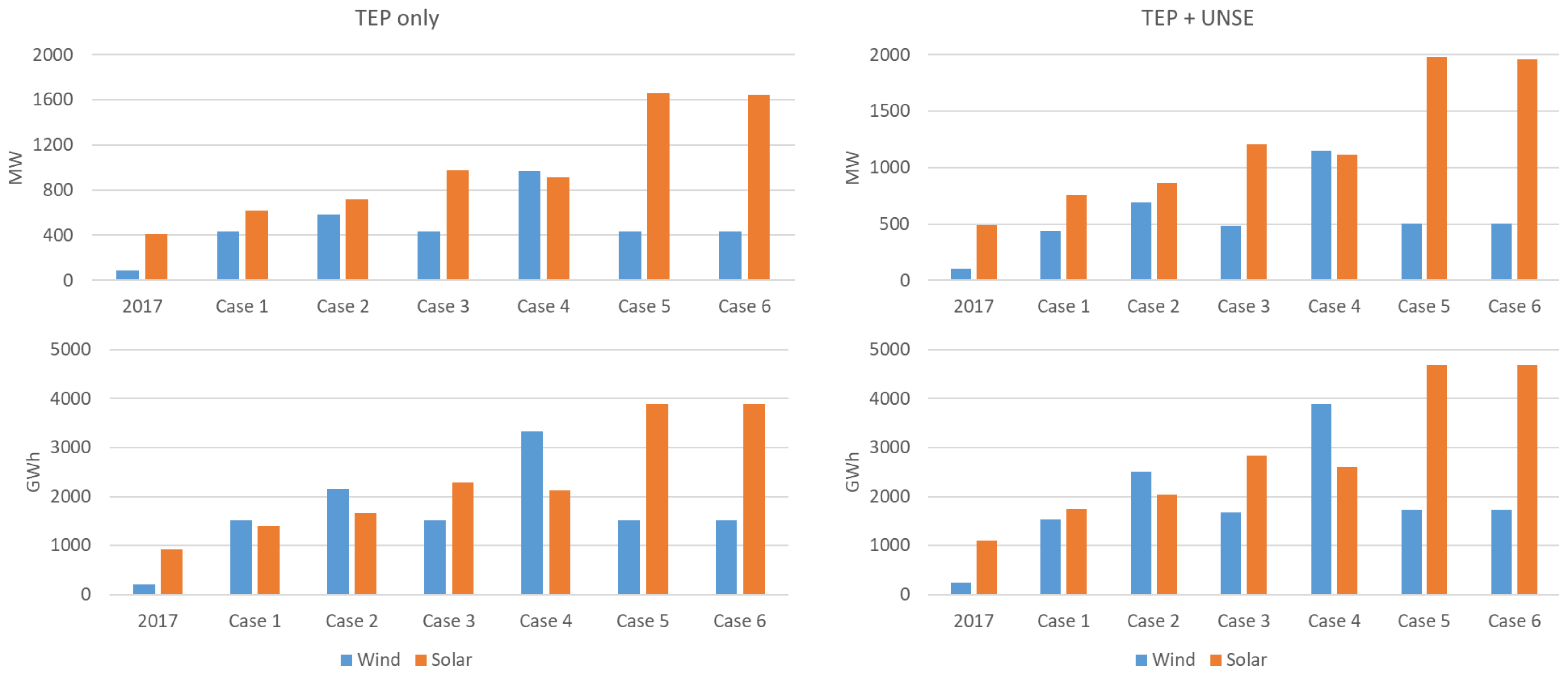
Case	RE as % of 2024 Sales	Resources Beyond Case 1
1	25%	----
2	35%	Majority Wind
3	35%	Majority Solar
4	50%	Majority Wind
5	50%	Majority Solar
6	50%	Majority Solar Geographically Concentrated

Renewable Energy Scenarios for Study Wind vs Solar Capacity (MW) Mix



Capacity and Cases Analyzed

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TEP System
Resource Capacity (MW)

Type	Resource	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
Gross Load	Gross Load	2813	2813	2813	2813	2813	2813
Single Axis PV	AVA1	45	45	80	80	160	80
Single Axis PV	AVRA	145	145	180	180	260	440
Single Axis PV	REDS	60	160	160	160	220	160
Single Axis PV	VALE	17	17	80	17	120	120
Single Axis PV	BLKM	0	0	0	0	140	70
Fixed Tilt PV	PRAI	15	15	80	80	120	300
Fixed Tilt PV	FTHU	18	18	18	18	120	60
Fixed Tilt PV	GATO	16	16	80	80	120	60
Fixed Tilt PV	RIOR	0	0	0	0	100	50
Fixed Tilt PV	TUDG	300	300	300	300	300	300
Wind	KING	0	0	0	120	0	0
Wind	MACH	50	50	50	50	50	50
Wind	REDW	30	30	30	150	30	30
Wind	OSOG	250	400	250	550	250	250
Wind	BORD	100	100	100	100	100	100

Note: Gross Load represents total system load not accounting for distributed generation.

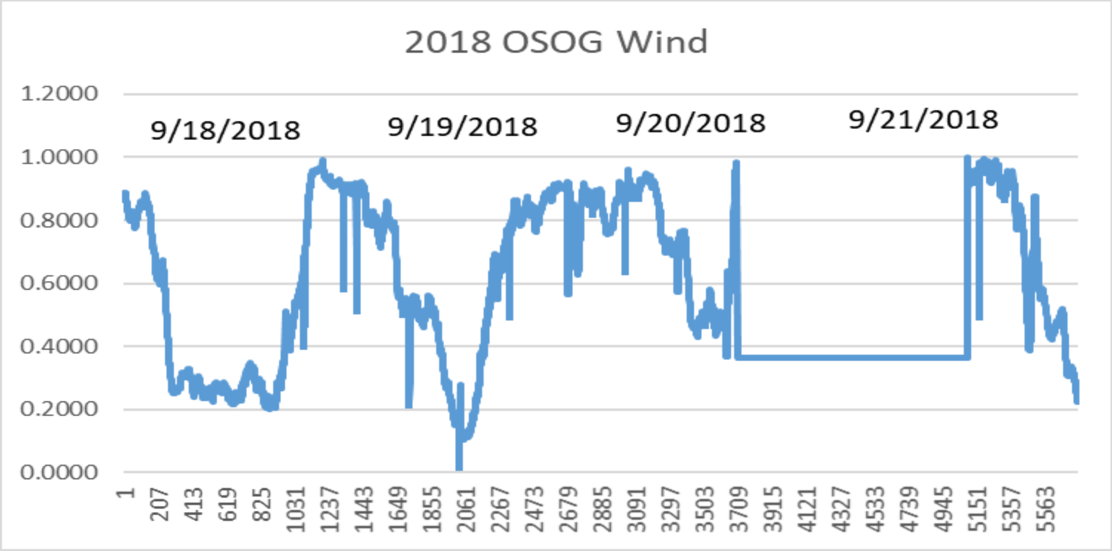
TEP BA System
Resource Capacity (MW)

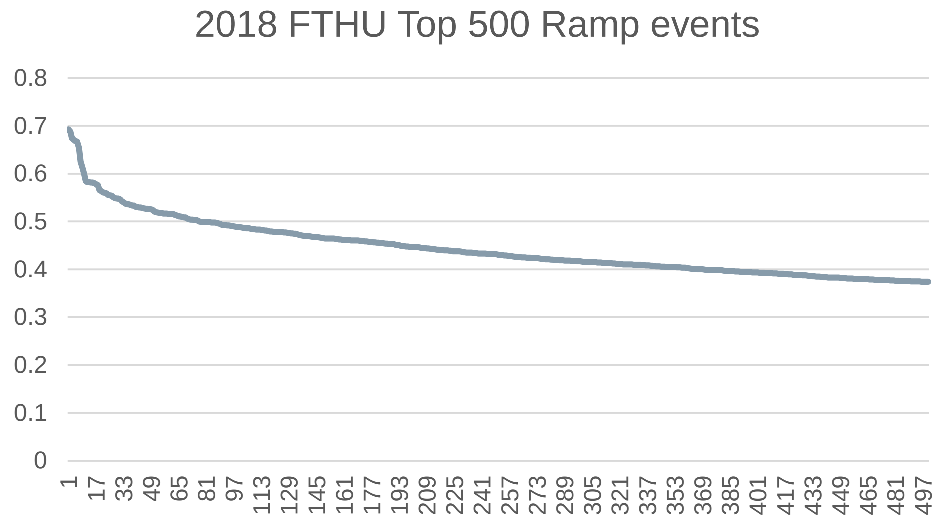
Type	Resource	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
Gross Load	Gross Load	3321	3321	3321	3321	3321	3321
Single Axis PV	AVA1	45	45	80	80	160	80
Single Axis PV	AVRA	145	145	180	180	300	450
Single Axis PV	REDS	90	190	210	190	270	235
Single Axis PV	VALE	17	17	80	17	120	120
Single Axis PV	BLKM	9.5	20	50	40	180	80
Fixed Tilt PV	PRAI	15	15	80	80	120	300
Fixed Tilt PV	FTHU	18	18	18	18	120	60
Fixed Tilt PV	GATO	16	16	80	80	120	60
Fixed Tilt PV	RIOR	6	6	20	20	140	60
Fixed Tilt PV	TUDG	300	300	300	300	300	300
Wind	KING	10	60	25	180	25	25
Wind	MACH	50	50	50	110	75	75
Wind	REDW	30	30	30	150	30	30
Wind	OSOG	250	450	275	610	275	275
Wind	BORD	100	100	100	100	100	100
Fixed Tilt PV	JACO	4	4	20	20	40	70
Single Axis PV	GRAY	46	46	46	46	70	100
Fixed Tilt PV	UNDG	41	41	41	41	41	41

Requested Data for Analysis

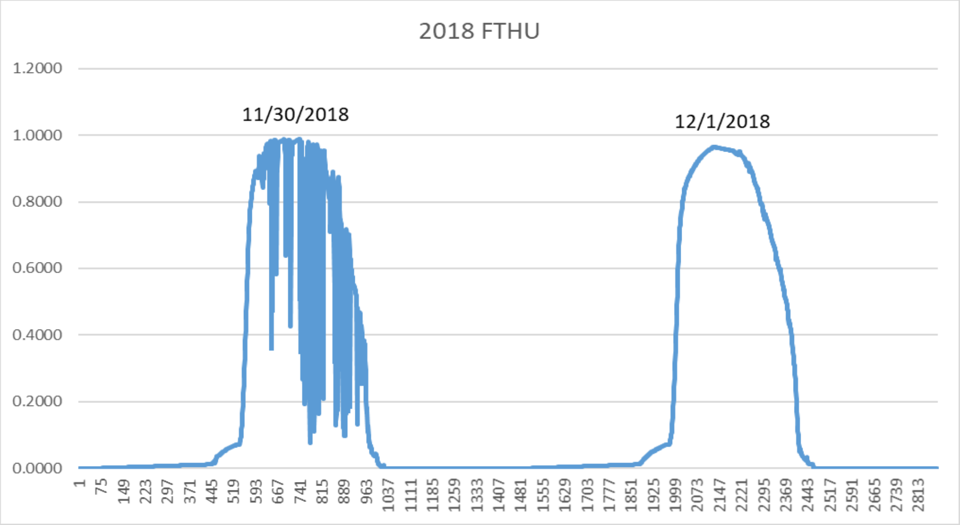
- Technology type, capacity, and location of each renewable project
- One-minute normalized outputs for each renewable project (capacity factor format) over a two-year historical period
- One-minute gross load over the same two-year historical period
- Flexibility expected for non-renewable resources during the assessment period (i.e., ramp rates and minimum generation levels)

Quality Review of Historical Renewable Energy and Load Data





- Wind, solar and load data was analyzed for consistency and outlier events were isolated to check in detail.
- Data inconsistency was minimized by substitution and interpolation where data was missing or faulty data appeared. For example, in figure above, in 2018 OSOG wind profile, several hours of data did not look correct.
- Similarly, solar historical ramps were calculated and days of highest variability were manually checked to see if profiles made sense or if high ramps occurred due to bad data. For example, on the right, 2 consecutive days are plotted with one being highly variable but other being cloud free, but the ramps on 11/30 are plausible.



Variability of Existing Assets Based on Updated Historical Data TEP Only

- New profiles for July 2017 – June 2019 were used in the Phase 2 analysis
- Peak 10-minute ramp for new data is 344 MW in July compared to 328 MW for May in 2016-2017 data
- New data had slightly higher solar variability but lower wind variability
- Load variability remains the same
- Ramp requirements are relatively unchanged for peak month using the updated historical data

Phase 1 TEP Variability Data

p99.0 Ramping MW						
RE Penetration:	28%	35%	35%	50%	50%	50%
New Resource Majority:		Wind	Solar	Wind	Solar	Solar
10min Upward Ramping_mn1	143	166	152	207	179	188
10min Upward Ramping_mn2	144	164	151	205	178	185
10min Upward Ramping_mn3	175	190	188	220	218	221
10min Upward Ramping_mn4	191	205	202	232	229	233
10min Upward Ramping_mn5	295	303	304	321	323	328
10min Upward Ramping_mn6	295	302	299	318	308	309
10min Upward Ramping_mn7	288	295	297	308	316	323
10min Upward Ramping_mn8	190	199	201	217	225	232
10min Upward Ramping_mn9	283	293	291	312	311	315
10min Upward Ramping_mn10	180	195	188	226	211	215
10min Upward Ramping_mn11	128	150	137	193	164	172
10min Upward Ramping_mn12	127	149	132	194	152	161

Phase 2 TEP Variability Data

p99.0 Ramping MW						
RE Penetration:	28%	35%	35%	50%	50%	50%
New Resource Majority:		Wind	Solar	Wind	Solar	Solar
10min Upward Ramping_mn1	125	162	136	213	171	181
10min Upward Ramping_mn2	137	168	148	212	185	198
10min Upward Ramping_mn3	124	161	140	210	181	192
10min Upward Ramping_mn4	206	226	219	261	248	253
10min Upward Ramping_mn5	226	244	237	274	263	265
10min Upward Ramping_mn6	233	248	241	273	260	262
10min Upward Ramping_mn7	305	314	315	329	339	344
10min Upward Ramping_mn8	241	252	251	271	276	282
10min Upward Ramping_mn9	263	277	273	300	295	301
10min Upward Ramping_mn10	241	257	253	286	279	285
10min Upward Ramping_mn11	125	159	138	207	172	178
10min Upward Ramping_mn12	123	160	130	209	156	164

Task 3 – Time Series and Correlation Coefficient Analysis

Testing of Spatial and Temporal Correlation Coefficients

- Renewable site output correlation factors, if significant, can simulate physical effects like how much solar sites see bright sun or cloud cover at the same time or how wind can blow across a number of wind turbine sites
- Because the conventional approach of non-correlated Monte Carlo produces completely random simulations of generation, it is possible to get some unrealistic ramp behavior of high generation in a minute and very low generation in the next minute. When such behavior is mixed across sites, two spatially adjacent plants might show completely random generation patterns when they should produce very similar outputs
- Correlation matrices affect the standard deviations of dependent profiles to match the base profile’s behavior to the degree defined by the correlation coefficient

Test Results for Spatial and Temporal Correlation Coefficients

Spatial correlation sampling was conducted and found

- Solar – Significant spatial correlation (>0.8) was found among sites during daylight hours, including both Fixed Tilt and Solar SAT technology types
- Wind – Spatial correlation was found to be insignificant (<0.3) among wind sites
- Load – Correlations of load with resources were not significant

Temporal correlation sampling was performed

- Tested each site one-minute output to output X minutes later (up to 120 minutes)
- For solar, temporal correlation is significant out to 60-80 minutes
- For wind temporal correlation is significant to 120 minutes +

Spatial Correlation Coefficient Results

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Fixed Tilt Solar
Spatial Correlation Factor Analysis

	'FTHU'	'GATO'	'PRAI'	'RIOR'	'JACO'
'FTHU'	1.00	0.84	0.84	0.85	0.74
'GATO'	0.84	1.00	0.96	0.86	0.79
'PRAI'	0.84	0.96	1.00	0.86	0.78
'RIOR'	0.85	0.86	0.86	1.00	0.76
'JACO'	0.74	0.79	0.78	0.76	1.00

SAT Solar
Spatial Correlation Factor Analysis

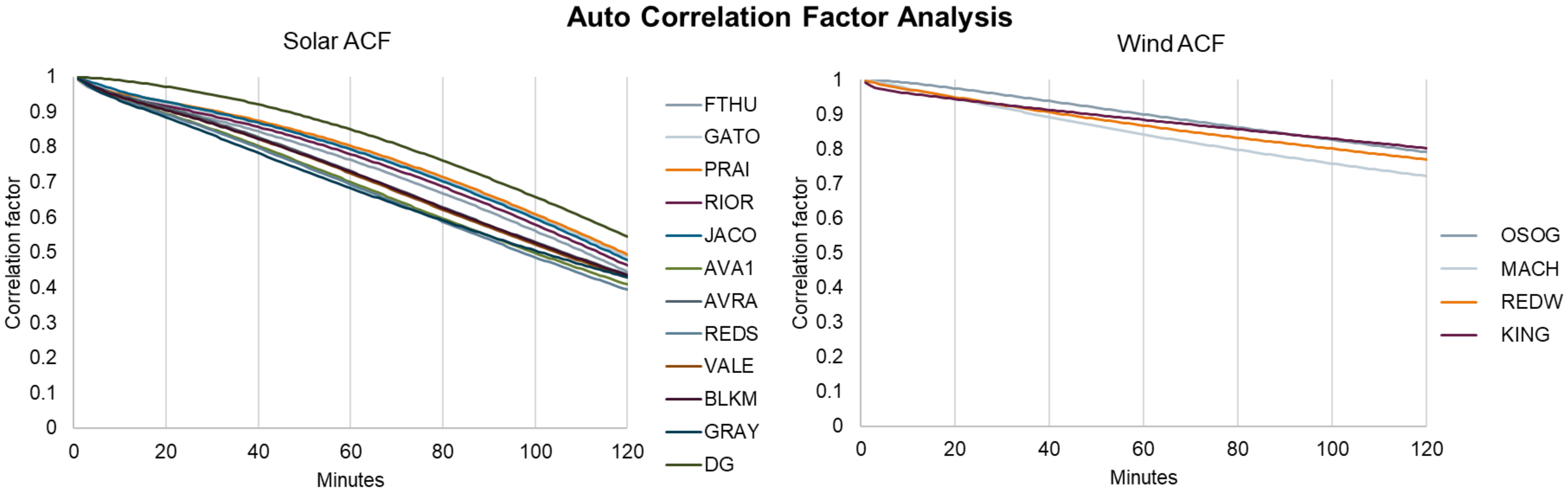
	'AVA1'	'AVRA'	'REDS'	'VALE'	'BLKM'	'GRAY'
'AVA1'	1.00	0.87	0.84	0.88	0.70	0.63
'AVRA'	0.87	1.00	0.82	0.87	0.74	0.67
'REDS'	0.84	0.82	1.00	0.83	0.67	0.62
'VALE'	0.88	0.87	0.83	1.00	0.71	0.64
'BLKM'	0.70	0.74	0.67	0.71	1.00	0.75
'GRAY'	0.63	0.67	0.62	0.64	0.75	1.00

Wind
Spatial Correlation Factor Analysis

	‘OSOG’	‘MACH’	‘REDW’	‘KING’
‘OSOG’	1.00	0.18	0.03	0.03
‘MACH’	0.18	1.00	0.32	0.20
‘REDW’	0.03	0.32	1.00	0.24
‘KING’	0.03	0.20	0.24	1.00

- Spatial correlations analyze similarity in generation profiles between different resources of the same technology type according to geographical diversity. Resources close to each other will have a higher correlation coefficient.
- Correlations are reported as being how similar they are compared to the base resource that lies on the diagonal of the correlation matrix. (FTHU, AVA1 and OSOG in matrices above).
- To calculate correlations, 1-minute daytime only generation for solar assets and all-day 1-minute generation for wind assets were used. Daytime-only generation for solar avoids overstating correlation factors.
- Higher correlation coefficients signify meaningful relationship of generation (>0.6). Wind correlations are less than 35% which implies correlation of wind generation between sites is insignificant.
- Spatial correlation for solar sites is high in most instances. Spatially distant sites can represent high correlation because annual generation is being correlated between sites and high correlation would be displayed in clearer months of spring and fall. Analyzing seasonal correlations using season-specific generation patterns would be more accurate in future studies.

Autocorrelation (Temporal) Coefficient Results



- Temporal correlations were analyzed on individual resource generation profiles for different time lag intervals. High correlation factors are found for smaller time lags, which signifies similar behavior exists for short time periods. Correlations degrade for larger time lags, which signifies generation becomes less predictable and more random for larger time gaps.
- Solar temporal correlations show high correlation factors at 60 minute intervals (~0.75) which degrade through 120 minute lag. (~0.5)
- Wind temporal correlations show very high correlation among all time intervals. This implies wind generation is consistent over time at a site.

Conclusions and Recommendations on Use of Correlation Coefficients

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- Spatial correlation coefficients were applied by technology type to Fixed Tilt and Solar SAT type resources and wind resources.
- The previous method of using normal distribution was changed to use a multivariate normal distribution procedure to generate sets of correlated random numbers during Monte Carlo simulation. This procedure uses a covariance matrix and simultaneously inputs of all the means and deviations of a particular resource family to be simulated together. This method is different from previous implementation where each resource was simulated independently for each hour.
- Adjacent solar plants show very high correlation (e.g., AVRA and AVA1). All spatial correlations are high for solar resources.
- Wind does not show significant spatial correlations. This shows randomness inherent among wind resources.
- The time based (auto) correlations are significant around the 1 hour time frames (>0.8 coefficient). The correlations then degrade over time. This means one hour generation of resources can be analyzed by looking at previous hour's generation.

Task 4 – Monte Carlo Simulations and Analysis

Monte Carlo Simulation Process

- Prepare statistical model of variable behavior based on historical shape.
- Conduct Monte Carlo simulation to compare Phase 1 and 2 results for TEP area only.
- Conduct Monte Carlo simulation to incorporate correlation coefficients for TEP area only.
- Conduct Monte Carlo simulation to add UNSE service area and resources.

Monte Carlo Process to Create 250 Samples of Normally Distributed Data

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1. Inputs of Normal Distribution Calculated from Historical Data

- Standard Deviation: 1-min variability
- Mean: Interpolated 1-min curve
- Correlation/Covariance Matrices by technology type

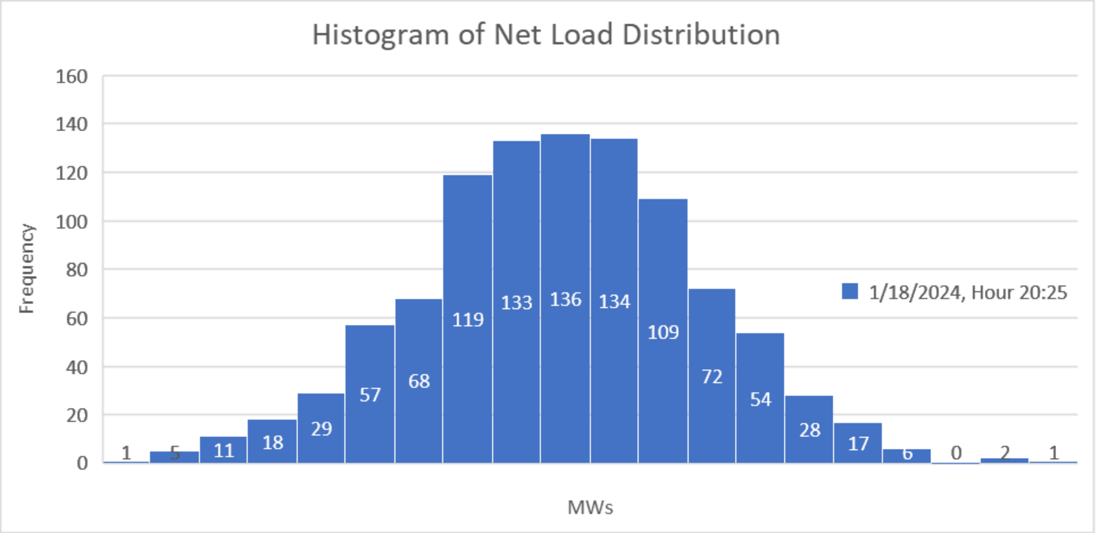
2. Python Program

- Generate 250 multivariate (correlated) normal distribution draws 1-min numbers for each of the profiles below
- 11 TEP and 5 UNSE renewable plants
- 1 system load
- 2 distributed generation profiles

3. Net Load Calculation

- Calculate the 1-min MW output data by multiplying the shape by the MW capacity
- Calculate 1-min net load by subtracting all renewable generation from load
- Calculate hourly average, 3-hour delta, and 10-min delta of the 250 distributions

Illustration of the Steps



	60-minute average net load									
	Iteration 1	Iteration 2	Iteration 3	Iteration 4	Iteration 5	Iteration 6	Iteration 7	Iteration 8	Iteration 9	Iteration 10
8784 Hours										
1	793.21246	821.57177	833.96489	802.18283	769.19535	809.38689	815.05675	801.88763	791.88926	792.3287
2	778.95908	769.49936	775.35137	778.7248	802.00586	770.92294	803.79865	764.24773	777.5675	783.55961
3	795.15782	773.99695	786.80419	763.98579	763.34093	777.15902	749.96823	750.05216	805.87998	745.01499
4	771.0183	778.65082	764.19548	775.98341	774.66051	784.96971	761.91199	752.87722	778.03245	761.77838
5	809.7414	791.3768	814.70429	795.01404	783.79482	786.99972	801.96602	786.70016	781.0206	791.24613
6	842.02289	818.04844	840.98962	830.45325	818.03253	840.09127	837.54522	839.39196	817.15373	823.11947
7	858.74211	851.05734	820.36992	819.28073	829.48039	890.62074	856.77788	825.21558	845.51396	868.36916
8	845.79498	804.70451	793.56885	798.08323	841.76865	834.19821	859.64121	837.0662	843.95238	827.29927
9	712.81495	738.59109	744.06911	735.55263	744.76859	722.73936	757.04282	732.63481	762.58357	745.85587
10	716.30255	740.65467	735.6805	733.11485	738.06612	744.68453	739.2821	741.50679	712.41089	727.7878

Stochastic Solution for Identifying Flex Shortfalls

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Stochastic Synthesis of 1-min RE/Load Profiles

For each of the 18 RE resources

Historical Intra-Hour Renewable Generation
1-min Delta Renewable (RE) Variability
+
1-min Smoothed RE Generation
1-min Stochastic RE Profile
×
For each of the 6 cases
2024 MW Allocated to Profile
2024 1-min RE Generation

Historical Intra-Hour Retail Load
1-min Delta Retail Load Variability
+
1-min Smoothed Retail Load
1-min Stochastic Retail Load Profile
×
2024 Forecasted Load
2024 1-min Retail Load

2024 1-min Retail Load Forecast − 2024 1-min RE Generation = 2024 1-min Net-Load Profile × 250 Iterations

Total Peak Capacity = (2024 Fossil + 2024 Storage) x 0.87	Greater Than	Seasonal Maximum Net-Load	Meet Peak Capacity Requirement
Total Non-curtailable Energy Generation from 2024 Must-run Resources	Less Than	Seasonal Minimum Net-Load	No Over Generation Risk
Total 3-hour Ramping Capability of the 2024 Portfolio	Greater Than	Monthly Maximum* 3-hour Net-Load Delta	Meet 3-hour Flex Needs
Total 10-min Ramping Capability of the 2024 Portfolio	Greater Than	Monthly Maximum* 10-min Net-Load Delta	Meet 10-min Flex Needs

Maximum and minimum defined as 99 and 1 percentile.
***For assessment of ramping down needs, the minimum net-load delta (negative values) will be used instead.**

Study Results – Update of Historical Data
10-Minute Ramps

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Phase 1 TEP data

p99.0 Peak NetLoad/Ramping MW						
RE Penetration:	25%	35%	35%	50%	50%	50%
New Resource Majority:		Wind	Solar	Wind	Solar	Solar
	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
MaxSeasonalNetLoad	2129	2057	2046	1921	1959	1949
MinSeasonalNetLoad	235	74	-11	-274	-574	-557
10min Upward Ramping_mn1	143	166	152	207	179	188
10min Upward Ramping_mn2	144	164	151	205	178	185
10min Upward Ramping_mn3	175	190	188	220	218	221
10min Upward Ramping_mn4	191	205	202	232	229	233
10min Upward Ramping_mn5	295	303	304	321	323	328
10min Upward Ramping_mn6	295	302	299	318	308	309
10min Upward Ramping_mn7	288	295	297	308	316	323
10min Upward Ramping_mn8	190	199	201	217	225	232
10min Upward Ramping_mn9	283	293	291	312	311	315
10min Upward Ramping_mn10	180	195	188	226	211	215
10min Upward Ramping_mn11	128	150	137	193	164	172
10min Upward Ramping_mn12	127	149	132	194	152	161
10min Downward Ramping_mn1	-148	-169	-159	-210	-189	-195
10min Downward Ramping_mn2	-153	-173	-166	-212	-201	-206
10min Downward Ramping_mn3	-148	-165	-152	-198	-176	-180
10min Downward Ramping_mn4	-162	-174	-160	-201	-168	-173
10min Downward Ramping_mn5	-270	-277	-266	-291	-260	-265
10min Downward Ramping_mn6	-280	-288	-279	-305	-281	-282
10min Downward Ramping_mn7	-293	-298	-290	-309	-285	-290
10min Downward Ramping_mn8	-183	-191	-181	-210	-184	-190
10min Downward Ramping_mn9	-264	-272	-263	-290	-264	-270
10min Downward Ramping_mn10	-158	-174	-160	-207	-174	-177
10min Downward Ramping_mn11	-120	-145	-130	-190	-161	-168
10min Downward Ramping_mn12	-127	-150	-137	-194	-164	-175

Phase 2 TEP data

p99.0 Peak NetLoad/Ramping MW						
RE Penetration:	25%	35%	35%	50%	50%	50%
New Resource Majority:		Wind	Solar	Wind	Solar	Solar
	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
MaxSeasonalNetLoad	1996	1919	1927	1782	1869	1872
MinSeasonalNetLoad	336	157	37	-208	-534	-528
10min Upward Ramping_mn1	125	162	136	213	171	181
10min Upward Ramping_mn2	137	168	148	212	185	198
10min Upward Ramping_mn3	124	161	140	210	181	192
10min Upward Ramping_mn4	206	226	219	261	248	253
10min Upward Ramping_mn5	226	244	237	274	263	265
10min Upward Ramping_mn6	233	248	241	273	260	262
10min Upward Ramping_mn7	305	314	315	329	339	344
10min Upward Ramping_mn8	241	252	251	271	276	282
10min Upward Ramping_mn9	263	277	273	300	295	301
10min Upward Ramping_mn10	241	257	253	286	279	285
10min Upward Ramping_mn11	125	159	138	207	172	178
10min Upward Ramping_mn12	123	160	130	209	156	164
10min Downward Ramping_mn1	-130	-165	-144	-215	-179	-187
10min Downward Ramping_mn2	-143	-174	-159	-217	-199	-209
10min Downward Ramping_mn3	-122	-158	-139	-207	-180	-189
10min Downward Ramping_mn4	-178	-199	-176	-235	-185	-191
10min Downward Ramping_mn5	-204	-222	-200	-251	-200	-204
10min Downward Ramping_mn6	-216	-231	-213	-256	-215	-218
10min Downward Ramping_mn7	-301	-310	-299	-324	-297	-303
10min Downward Ramping_mn8	-228	-242	-227	-263	-229	-235
10min Downward Ramping_mn9	-246	-261	-244	-283	-247	-251
10min Downward Ramping_mn10	-215	-232	-214	-261	-222	-230
10min Downward Ramping_mn11	-115	-153	-128	-203	-167	-176
10min Downward Ramping_mn12	-124	-162	-136	-211	-169	-178

Study Results – Update of Historical Data
3-Hour Ramps

Phase 1 TEP data

p99.0 Ramping MW						
RE Penetration:	28%	35%	35%	50%	50%	50%
New Resource Majority:		Wind	Solar	Wind	Solar	Solar
	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
3hour Upward Ramping_mn1	538	612	733	754	1138	1137
3hour Upward Ramping_mn2	518	614	721	773	1155	1147
3hour Upward Ramping_mn3	520	623	721	808	1176	1164
3hour Upward Ramping_mn4	455	542	641	701	1074	1067
3hour Upward Ramping_mn5	512	559	580	645	934	926
3hour Upward Ramping_mn6	577	592	583	615	803	812
3hour Upward Ramping_mn7	476	504	533	525	751	755
3hour Upward Ramping_mn8	478	504	534	566	816	821
3hour Upward Ramping_mn9	502	525	542	563	879	879
3hour Upward Ramping_mn10	427	469	573	600	958	952
3hour Upward Ramping_mn11	437	513	622	663	1021	1007
3hour Upward Ramping_mn12	451	522	629	645	995	983
3hour Downward Ramping_mn1	-533	-594	-726	-727	-1165	-1151
3hour Downward Ramping_mn2	-520	-597	-725	-736	-1178	-1172
3hour Downward Ramping_mn3	-451	-533	-667	-688	-1161	-1135
3hour Downward Ramping_mn4	-393	-462	-572	-619	-1064	-1049
3hour Downward Ramping_mn5	-496	-530	-509	-593	-941	-941
3hour Downward Ramping_mn6	-649	-698	-644	-778	-765	-766
3hour Downward Ramping_mn7	-583	-610	-576	-652	-622	-626
3hour Downward Ramping_mn8	-559	-600	-555	-669	-677	-685
3hour Downward Ramping_mn9	-503	-522	-500	-554	-806	-796
3hour Downward Ramping_mn10	-418	-444	-434	-495	-891	-881
3hour Downward Ramping_mn11	-328	-384	-491	-519	-918	-894
3hour Downward Ramping_mn12	-388	-449	-568	-566	-958	-951

Phase 2 TEP data

p99.0 Ramping MW						
RE Penetration:	28%	35%	35%	50%	50%	50%
New Resource Majority:		Wind	Solar	Wind	Solar	Solar
	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
3hour Upward Ramping_mn1	517	603	752	754	1202	1194
3hour Upward Ramping_mn2	522	604	765	741	1220	1210
3hour Upward Ramping_mn3	462	549	708	688	1171	1159
3hour Upward Ramping_mn4	442	529	688	684	1157	1142
3hour Upward Ramping_mn5	379	438	569	553	1012	986
3hour Upward Ramping_mn6	512	535	519	539	812	802
3hour Upward Ramping_mn7	491	527	533	547	735	739
3hour Upward Ramping_mn8	441	463	510	490	858	858
3hour Upward Ramping_mn9	492	511	547	544	924	925
3hour Upward Ramping_mn10	416	487	640	632	1070	1063
3hour Upward Ramping_mn11	436	523	668	655	1097	1078
3hour Upward Ramping_mn12	458	534	681	653	1106	1075
3hour Downward Ramping_mn1	-474	-550	-709	-679	-1171	-1171
3hour Downward Ramping_mn2	-540	-644	-770	-802	-1259	-1252
3hour Downward Ramping_mn3	-388	-459	-641	-609	-1136	-1122
3hour Downward Ramping_mn4	-368	-415	-554	-534	-1046	-1033
3hour Downward Ramping_mn5	-455	-493	-487	-516	-969	-939
3hour Downward Ramping_mn6	-553	-595	-551	-635	-817	-802
3hour Downward Ramping_mn7	-530	-553	-522	-580	-644	-632
3hour Downward Ramping_mn8	-546	-572	-540	-594	-714	-700
3hour Downward Ramping_mn9	-509	-528	-506	-546	-844	-835
3hour Downward Ramping_mn10	-385	-422	-504	-503	-990	-980
3hour Downward Ramping_mn11	-325	-401	-548	-544	-996	-973
3hour Downward Ramping_mn12	-412	-469	-607	-570	-1021	-996

Summary of Results – Update of Historical Data

- The historical data was updated to use metered profiles for July 2017 – June 2019.
- The effect of including multiple years of data is to account for a greater set of generation patterns to produce more realistic variability and generation shape inputs.
- The change in ramping behavior is not significant for peak months between the two phases, which implies the new data is statistically similar to Phase 1 data sets for planning purposes.

Study Results – Addition of Correlation Factors
TEP-Only 10-Minute Ramps

p99.0 Peak NetLoad/Ramping MW						
RE Penetration:	25%	35%	35%	50%	50%	50%
New Resource Majority:		Wind	Solar	Wind	Solar	Solar
	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
MaxSeasonalNetLoad	2113	2031	2030	1869	1965	1970
MinSeasonalNetLoad	290	105	2	-234	-547	-542
10min Upward Ramping_mn1	140	174	149	213	178	190
10min Upward Ramping_mn2	152	179	162	216	192	206
10min Upward Ramping_mn3	133	167	147	207	183	192
10min Upward Ramping_mn4	221	240	234	269	261	265
10min Upward Ramping_mn5	242	261	253	284	280	282
10min Upward Ramping_mn6	249	265	256	286	273	278
10min Upward Ramping_mn7	299	307	307	322	327	333
10min Upward Ramping_mn8	233	246	244	266	272	275
10min Upward Ramping_mn9	267	283	278	300	297	303
10min Upward Ramping_mn10	269	283	280	304	305	307
10min Upward Ramping_mn11	140	170	152	207	183	185
10min Upward Ramping_mn12	130	166	137	207	162	170
10min Downward Ramping_mn1	-142	-174	-154	-213	-186	-194
10min Downward Ramping_mn2	-156	-183	-170	-219	-205	-214
10min Downward Ramping_mn3	-128	-163	-145	-203	-185	-193
10min Downward Ramping_mn4	-199	-215	-192	-242	-195	-201
10min Downward Ramping_mn5	-226	-243	-221	-264	-219	-222
10min Downward Ramping_mn6	-233	-246	-231	-266	-231	-234
10min Downward Ramping_mn7	-296	-307	-292	-323	-290	-297
10min Downward Ramping_mn8	-230	-244	-226	-262	-225	-230
10min Downward Ramping_mn9	-251	-264	-250	-282	-251	-253
10min Downward Ramping_mn10	-241	-256	-238	-278	-243	-249
10min Downward Ramping_mn11	-124	-160	-134	-200	-167	-175
10min Downward Ramping_mn12	-132	-168	-142	-209	-173	-182

p99.0 Peak NetLoad/Ramping Time Occurrence						
RE Penetration:	25%	35%	35%	50%	50%	50%
New Resource Majority:		Wind	Solar	Wind	Solar	Solar
	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
MaxSeasonalNetLoad	15	19	18	19	18	18
MinSeasonalNetLoad	13	8	13	9	11	10
10min Upward Ramping_mn1	10	14	15	21	16	16
10min Upward Ramping_mn2	21	11	6	12	16	15
10min Upward Ramping_mn3	6	3	17	17	17	17
10min Upward Ramping_mn4	13	13	15	16	15	13
10min Upward Ramping_mn5	16	13	17	17	18	13
10min Upward Ramping_mn6	15	14	17	14	18	17
10min Upward Ramping_mn7	13	16	19	16	11	15
10min Upward Ramping_mn8	18	17	12	16	15	18
10min Upward Ramping_mn9	16	20	12	18	15	14
10min Upward Ramping_mn10	17	10	14	12	17	15
10min Upward Ramping_mn11	14	6	18	16	15	12
10min Upward Ramping_mn12	8	10	5	14	16	6
10min Downward Ramping_mn1	8	7	7	12	7	8
10min Downward Ramping_mn2	8	2	9	8	7	14
10min Downward Ramping_mn3	9	10	7	8	6	9
10min Downward Ramping_mn4	12	21	16	16	13	7
10min Downward Ramping_mn5	16	16	15	16	14	19
10min Downward Ramping_mn6	20	17	9	20	7	15
10min Downward Ramping_mn7	18	14	15	13	21	15
10min Downward Ramping_mn8	19	17	21	17	7	11
10min Downward Ramping_mn9	20	9	21	9	14	9
10min Downward Ramping_mn10	16	12	15	18	21	14
10min Downward Ramping_mn11	14	1	8	6	7	8
10min Downward Ramping_mn12	1	6	7	9	10	8

Study Results – Addition of Correlation Factors
TEP-Only 3-Hour Ramps

SIEMENS

p99.0 Ramping MW

RE Penetration:	28%	35%	35%	50%	50%	50%
New Resource Majority:		Wind	Solar	Wind	Solar	Solar
	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
3hour Upward Ramping_mn1	550	635	789	784	1247	1251
3hour Upward Ramping_mn2	504	592	743	740	1206	1190
3hour Upward Ramping_mn3	424	507	661	635	1122	1117
3hour Upward Ramping_mn4	461	548	681	697	1131	1123
3hour Upward Ramping_mn5	435	468	580	544	1018	997
3hour Upward Ramping_mn6	614	639	597	610	778	770
3hour Upward Ramping_mn7	484	507	545	534	768	750
3hour Upward Ramping_mn8	488	500	542	522	858	859
3hour Upward Ramping_mn9	475	497	572	548	940	938
3hour Upward Ramping_mn10	442	485	621	610	1032	1027
3hour Upward Ramping_mn11	440	523	666	662	1099	1074
3hour Upward Ramping_mn12	452	528	669	637	1094	1063
3hour Downward Ramping_mn1	-598	-658	-778	-771	-1229	-1228
3hour Downward Ramping_mn2	-476	-563	-704	-712	-1200	-1187
3hour Downward Ramping_mn3	-451	-509	-629	-625	-1096	-1089
3hour Downward Ramping_mn4	-382	-428	-558	-528	-1061	-1044
3hour Downward Ramping_mn5	-488	-510	-503	-516	-982	-953
3hour Downward Ramping_mn6	-610	-658	-608	-701	-804	-787
3hour Downward Ramping_mn7	-568	-594	-560	-631	-672	-663
3hour Downward Ramping_mn8	-556	-578	-551	-613	-706	-695
3hour Downward Ramping_mn9	-498	-521	-497	-537	-896	-888
3hour Downward Ramping_mn10	-433	-476	-478	-542	-954	-947
3hour Downward Ramping_mn11	-315	-384	-515	-509	-966	-943
3hour Downward Ramping_mn12	-366	-418	-557	-513	-960	-946

p99.0 Ramping Time Occurrence

RE Penetration:	28%	35%	35%	50%	50%	50%
New Resource Majority:		Wind	Solar	Wind	Solar	Solar
	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
3hour Upward Ramping_mn1	14	15	14	14	14	14
3hour Upward Ramping_mn2	15	14	15	14	15	14
3hour Upward Ramping_mn3	14	15	14	15	15	15
3hour Upward Ramping_mn4	15	11	15	16	15	15
3hour Upward Ramping_mn5	9	15	16	16	16	15
3hour Upward Ramping_mn6	11	9	8	12	15	15
3hour Upward Ramping_mn7	8	8	11	11	16	11
3hour Upward Ramping_mn8	10	12	12	11	15	15
3hour Upward Ramping_mn9	12	9	15	9	15	15
3hour Upward Ramping_mn10	14	13	14	15	14	14
3hour Upward Ramping_mn11	14	14	15	14	14	15
3hour Upward Ramping_mn12	14	15	15	14	15	15
3hour Downward Ramping_mn1	7	20	6	7	7	6
3hour Downward Ramping_mn2	7	6	7	7	6	6
3hour Downward Ramping_mn3	7	6	7	6	6	6
3hour Downward Ramping_mn4	20	6	6	5	5	5
3hour Downward Ramping_mn5	19	19	5	20	5	5
3hour Downward Ramping_mn6	19	21	20	20	5	5
3hour Downward Ramping_mn7	20	19	20	22	4	5
3hour Downward Ramping_mn8	20	19	20	20	5	5
3hour Downward Ramping_mn9	19	20	21	21	6	5
3hour Downward Ramping_mn10	21	20	19	20	6	6
3hour Downward Ramping_mn11	21	7	7	7	7	6
3hour Downward Ramping_mn12	8	21	7	8	7	7

Study Results
Addition of Correlation Factors TEP Only

- Adding correlation factors to the TEP only analysis does not introduce major differences in ramping behavior of the system compared to only introducing Phase 2 profiles.
- The maximum 10 minute ramp requirements decreased around 10 MW at max signifying minimal impact to requirements and more consistent ramping nature among all months.
- The 3 hour ramp requirements were minimally affected in both up and down directions.

10-Minute Ramps – Addition of UNSE to the TEP Balancing Area

SIEMENS

p99.0 Peak NetLoad/Ramping MW						
RE Penetration:	25%	35%	35%	50%	50%	50%
New Resource Majority:		Wind	Solar	Wind	Solar	Solar
	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
MaxSeasonalNetLoad	2,709	2,625	2,562	2,495	2,378	2,423
MinSeasonalNetLoad	375	100	-22	-413	-660	-646
10min Upward Ramping_mn1	129	135	142	150	185	190
10min Upward Ramping_mn2	164	169	174	181	208	215
10min Upward Ramping_mn3	109	120	132	142	182	190
10min Upward Ramping_mn4	221	228	238	244	271	273
10min Upward Ramping_mn5	210	217	226	232	257	258
10min Upward Ramping_mn6	239	242	248	251	268	272
10min Upward Ramping_mn7	329	333	340	342	359	366
10min Upward Ramping_mn8	284	289	296	299	317	324
10min Upward Ramping_mn9	230	236	243	248	269	276
10min Upward Ramping_mn10	200	208	215	222	243	252
10min Upward Ramping_mn11	105	114	122	131	160	166
10min Upward Ramping_mn12	113	120	124	133	154	163
10min Downward Ramping_mn1	-137	-146	-157	-164	-198	-202
10min Downward Ramping_mn2	-174	-184	-195	-204	-239	-244
10min Downward Ramping_mn3	-113	-127	-142	-152	-195	-198
10min Downward Ramping_mn4	-185	-185	-179	-182	-192	-196
10min Downward Ramping_mn5	-179	-179	-175	-179	-188	-191
10min Downward Ramping_mn6	-216	-218	-214	-218	-220	-224
10min Downward Ramping_mn7	-317	-318	-315	-318	-318	-322
10min Downward Ramping_mn8	-266	-267	-264	-267	-269	-273
10min Downward Ramping_mn9	-210	-210	-207	-210	-217	-222
10min Downward Ramping_mn10	-174	-177	-179	-184	-207	-214
10min Downward Ramping_mn11	-99	-110	-123	-132	-169	-177
10min Downward Ramping_mn12	-113	-123	-132	-141	-172	-183

p99.0 Peak NetLoad/Ramping Time Occurrence						
RE Penetration:	25%	35%	35%	50%	50%	50%
New Resource Majority:		Wind	Solar	Wind	Solar	Solar
	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
MaxSeasonalNetLoad	20	15	17	17	19	18
MinSeasonalNetLoad	9	13	9	12	13	10
10min Upward Ramping_mn1	6	16	5	16	6	16
10min Upward Ramping_mn2	6	7	23	5	12	16
10min Upward Ramping_mn3	5	16	6	15	17	16
10min Upward Ramping_mn4	17	16	14	12	17	15
10min Upward Ramping_mn5	18	15	16	15	15	15
10min Upward Ramping_mn6	14	14	17	13	13	13
10min Upward Ramping_mn7	14	17	18	18	18	15
10min Upward Ramping_mn8	15	14	14	18	16	18
10min Upward Ramping_mn9	16	16	13	14	15	16
10min Upward Ramping_mn10	15	16	17	16	16	16
10min Upward Ramping_mn11	17	15	13	17	16	9
10min Upward Ramping_mn12	17	18	14	16	16	9
10min Downward Ramping_mn1	18	7	22	8	9	9
10min Downward Ramping_mn2	8	5	7	6	7	7
10min Downward Ramping_mn3	8	7	8	8	8	7
10min Downward Ramping_mn4	19	18	14	15	15	12
10min Downward Ramping_mn5	13	16	15	6	6	7
10min Downward Ramping_mn6	12	19	13	8	14	21
10min Downward Ramping_mn7	13	13	19	9	14	11
10min Downward Ramping_mn8	18	14	17	16	20	17
10min Downward Ramping_mn9	18	19	15	18	7	13
10min Downward Ramping_mn10	13	14	14	7	7	20
10min Downward Ramping_mn11	8	11	9	8	7	7
10min Downward Ramping_mn12	10	8	10	10	8	9

3-Hour Ramps – Addition of UNSE to the TEP Balancing Area

SIEMENS

p99.0 Ramping MW

RE Penetration:	28%	35%	35%	50%	50%	50%
New Resource Majority:		Wind	Solar	Wind	Solar	Solar
	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
3hour Upward Ramping_mn1	644	765	945	1036	1435	1395
3hour Upward Ramping_mn2	672	800	1001	1054	1498	1443
3hour Upward Ramping_mn3	557	706	870	990	1366	1316
3hour Upward Ramping_mn4	505	627	823	900	1332	1280
3hour Upward Ramping_mn5	437	565	715	835	1180	1120
3hour Upward Ramping_mn6	637	674	646	704	961	895
3hour Upward Ramping_mn7	619	655	668	738	817	854
3hour Upward Ramping_mn8	573	592	626	670	894	921
3hour Upward Ramping_mn9	580	588	618	671	941	955
3hour Upward Ramping_mn10	524	680	800	946	1188	1207
3hour Upward Ramping_mn11	533	668	801	915	1176	1196
3hour Upward Ramping_mn12	573	702	821	904	1188	1184
3hour Downward Ramping_mn1	-608	-713	-907	-989	-1391	-1336
3hour Downward Ramping_mn2	-678	-817	-994	-1128	-1499	-1476
3hour Downward Ramping_mn3	-515	-659	-836	-968	-1345	-1294
3hour Downward Ramping_mn4	-448	-666	-786	-1036	-1285	-1234
3hour Downward Ramping_mn5	-443	-511	-655	-815	-1176	-1091
3hour Downward Ramping_mn6	-681	-769	-682	-829	-1007	-930
3hour Downward Ramping_mn7	-720	-772	-708	-835	-732	-707
3hour Downward Ramping_mn8	-636	-668	-628	-689	-756	-737
3hour Downward Ramping_mn9	-594	-607	-585	-663	-871	-863
3hour Downward Ramping_mn10	-408	-518	-649	-785	-1104	-1105
3hour Downward Ramping_mn11	-462	-580	-721	-837	-1124	-1121
3hour Downward Ramping_mn12	-511	-630	-751	-847	-1123	-1106

p99.0 Ramping Time Occurrence

RE Penetration:	28%	35%	35%	50%	50%	50%
New Resource Majority:		Wind	Solar	Wind	Solar	Solar
	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
3hour Upward Ramping_mn1	15	14	14	14	14	15
3hour Upward Ramping_mn2	15	15	15	15	15	15
3hour Upward Ramping_mn3	15	15	15	15	15	15
3hour Upward Ramping_mn4	15	15	15	15	15	15
3hour Upward Ramping_mn5	15	16	16	15	16	16
3hour Upward Ramping_mn6	10	8	11	15	16	15
3hour Upward Ramping_mn7	11	10	9	10	11	14
3hour Upward Ramping_mn8	9	11	14	15	15	15
3hour Upward Ramping_mn9	9	11	10	14	15	15
3hour Upward Ramping_mn10	15	15	15	16	14	15
3hour Upward Ramping_mn11	15	15	14	15	14	14
3hour Upward Ramping_mn12	15	14	15	15	15	15
3hour Downward Ramping_mn1	7	7	6	6	7	6
3hour Downward Ramping_mn2	7	6	6	7	6	6
3hour Downward Ramping_mn3	6	6	6	6	6	6
3hour Downward Ramping_mn4	19	6	5	6	5	5
3hour Downward Ramping_mn5	20	19	5	5	5	5
3hour Downward Ramping_mn6	20	21	21	22	5	5
3hour Downward Ramping_mn7	19	20	20	22	5	21
3hour Downward Ramping_mn8	20	19	19	21	6	5
3hour Downward Ramping_mn9	20	20	20	19	6	6
3hour Downward Ramping_mn10	6	6	6	6	6	6
3hour Downward Ramping_mn11	7	7	7	7	7	6
3hour Downward Ramping_mn12	7	7	7	7	7	8

Study Results - Addition of UNSE to the TEP Balancing Area

- UNSE's additional resources and load in addition to TEP resources and load increased 10-minute ramps by 33 MW for Case 6 additions. Overall, with UNSE's loads and resources added into the resource mix, ramp requirements do not rise significantly given the renewable mix.
- Ramp characteristics are the same as TEP only system, mainly evening time regulation ramps upwards.
- Results indicate that adding high levels of renewables create a diminishing addition to regulation and 3-hour ramp requirements.
- Ramp behaviors of different types of resources counteract each other. This results in ramp requirement increase to not be directly proportional to the resource capacities added to the portfolio.

3-Hour Ramps –TEP System
Addressing Turndown Limit (300 MW)

SIEMENS

No Turndown Limit

p99.0 Ramping MW						
RE Penetration:	28%	35%	35%	50%	50%	50%
New Resource Majority:		Wind	Solar	Wind	Solar	Solar
	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
3hour Upward Ramping_mn1	550	635	789	784	1247	1251
3hour Upward Ramping_mn2	504	592	743	740	1206	1190
3hour Upward Ramping_mn3	424	507	661	635	1122	1117
3hour Upward Ramping_mn4	461	548	681	697	1131	1123
3hour Upward Ramping_mn5	435	468	580	544	1018	997
3hour Upward Ramping_mn6	614	639	597	610	778	770
3hour Upward Ramping_mn7	484	507	545	534	768	750
3hour Upward Ramping_mn8	488	500	542	522	858	859
3hour Upward Ramping_mn9	475	497	572	548	940	938
3hour Upward Ramping_mn10	442	485	621	610	1032	1027
3hour Upward Ramping_mn11	440	523	666	662	1099	1074
3hour Upward Ramping_mn12	452	528	669	637	1094	1063

Turndown Limit of 300 MW

p99.0 Ramping MW						
RE Penetration:	28%	35%	35%	50%	50%	50%
New Resource Majority:		Wind	Solar	Wind	Solar	Solar
	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
3hour Upward Ramping_mn1	517	604	751	702	919	923
3hour Upward Ramping_mn2	504	592	743	630	916	905
3hour Upward Ramping_mn3	424	507	661	566	858	859
3hour Upward Ramping_mn4	444	532	681	616	1023	1013
3hour Upward Ramping_mn5	380	438	570	544	983	963
3hour Upward Ramping_mn6	511	534	518	538	778	770
3hour Upward Ramping_mn7	484	507	532	534	735	738
3hour Upward Ramping_mn8	441	463	508	487	856	855
3hour Upward Ramping_mn9	475	497	546	542	922	922
3hour Upward Ramping_mn10	415	485	621	610	1029	1027
3hour Upward Ramping_mn11	436	523	666	654	985	980
3hour Upward Ramping_mn12	452	528	669	637	893	888

- Accounting for turndown limits reduces the maximum 3-hour ramps, especially in the winter, because the turndown limit sets a floor on the thermal generation and limits the extent to which the net load can ramp from its nadir to its apex.

3-Hour Ramps –TEP Balancing Authority (TEP and UNSE) Addressing Turndown Limit (350 MW)

SIEMENS

No Turndown Limit

p99.0 Ramping MW						
RE Penetration:	28%	35%	35%	50%	50%	50%
New Resource Majority:		Wind	Solar	Wind	Solar	Solar
	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
3hour Upward Ramping_mn1	644	765	945	1036	1435	1395
3hour Upward Ramping_mn2	672	800	1001	1054	1498	1443
3hour Upward Ramping_mn3	557	706	870	990	1366	1316
3hour Upward Ramping_mn4	505	627	823	900	1332	1280
3hour Upward Ramping_mn5	437	565	715	835	1180	1120
3hour Upward Ramping_mn6	637	674	646	704	961	895
3hour Upward Ramping_mn7	619	655	668	738	817	854
3hour Upward Ramping_mn8	573	592	626	670	894	921
3hour Upward Ramping_mn9	580	588	618	671	941	955
3hour Upward Ramping_mn10	524	680	800	946	1188	1207
3hour Upward Ramping_mn11	533	668	801	915	1176	1196
3hour Upward Ramping_mn12	573	702	821	904	1188	1184

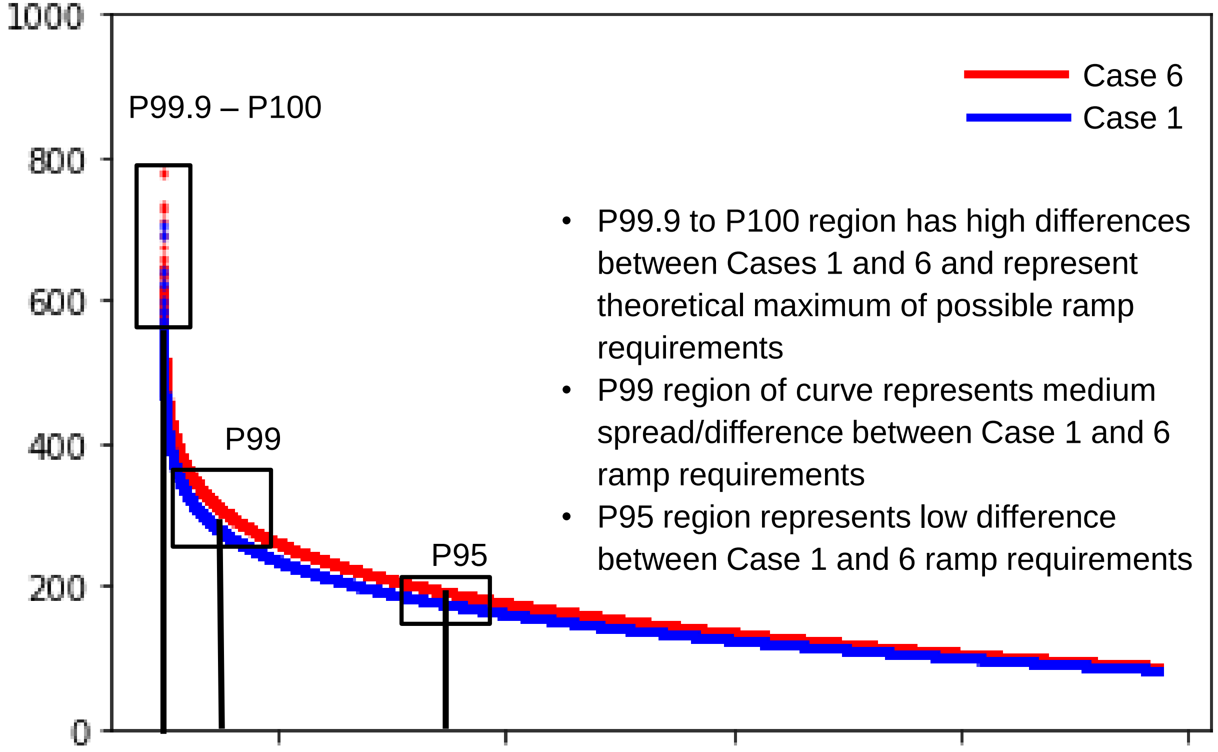
Turndown Limit of 350 MW

p99.0 Ramping MW						
RE Penetration:	28%	35%	35%	50%	50%	50%
New Resource Majority:		Wind	Solar	Wind	Solar	Solar
	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
3hour Upward Ramping_mn1	644	765	945	998	1160	1158
3hour Upward Ramping_mn2	672	799	1000	1020	1092	1064
3hour Upward Ramping_mn3	557	704	835	805	1014	999
3hour Upward Ramping_mn4	505	627	823	810	1141	1125
3hour Upward Ramping_mn5	437	565	715	796	1102	1041
3hour Upward Ramping_mn6	637	674	646	704	961	895
3hour Upward Ramping_mn7	619	655	668	738	816	854
3hour Upward Ramping_mn8	573	592	626	670	894	921
3hour Upward Ramping_mn9	580	588	618	670	941	955
3hour Upward Ramping_mn10	524	680	800	899	1082	1097
3hour Upward Ramping_mn11	533	668	801	870	1037	1067
3hour Upward Ramping_mn12	573	702	821	869	995	1093

- Accounting for turndown limits reduces the maximum 3-hour ramps, especially in the winter, because the turndown limit sets a floor on the thermal generation and limits the extent to which the net load can ramp from its nadir to its apex.

Study Results – TEP Balancing Authority (TEP and UNSE) P99 vs P95

Case 1 vs 6 ramp distribution for month of July
Highest ramp requirement month for TEP BA



- P99.9 to P100 region has high differences between Cases 1 and 6 and represent theoretical maximum of possible ramp requirements
- P99 region of curve represents medium spread/difference between Case 1 and 6 ramp requirements
- P95 region represents low difference between Case 1 and 6 ramp requirements

- This report does not make a judgment on the appropriate probability threshold for capturing extreme ramp events.
- P99 captures many of the extreme ramp events, however, higher ramping events could occur.

	10 Minute Ramp Distribution Magnitude (MW)		Peak Seasonal Net Load Distribution Magnitude (MW)		3 Hour Ramp up Distribution Magnitude (MW)	
Ramp Percentile	Case 1	Case 6	Case 1	Case 6	Case 1	Case 6
90	161	178	2,241	1,890	410	779
95	211	235	2,400	2,086	488	972
99	329	366	2,709	2,423	614	1,220
99.5	382	420	2,770	2,508	651	1,287

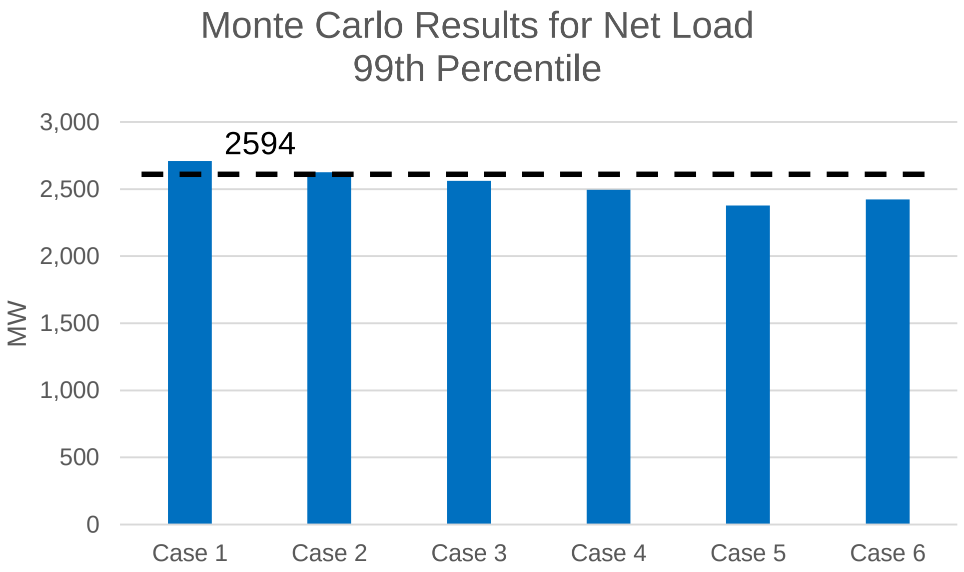
Comparison of Monte Carlo Results with TEP's Flexible Capacity

TEP BA’s Peak Net Load

SIEMENS

2024 Resources	Summer Capacity (MW)
Springerville 1	387
Springerville 2	406
Four Corners 4	55
Four Corners 5	55
Gila 2	516
Gila 3	516
Luna	185
Sundt ST3	105
Sundt ST4	156
RICE 1-10	182
Demoss Petrie	72
North Loop 1-3	73
Sundt CT 1-2	50
Wilmot Battery	30
Black Mountain 1	44
Black Mountain 2	45
Valencia 1-4	55
Demand Response	50
TOTAL	**2982**
TOTAL*0.87	**2594**

Monte Carlo Results for Maximum Net Load (Net Load Requirements adjusted for TX losses)		
	99th Percentile (MW)	BA Has Adequate Capability?
Case 1	2,709	No
Case 2	2,625	No
Case 3	2,562	Yes
Case 4	2,495	Yes
Case 5	2,378	Yes
Case 6	2,423	Yes

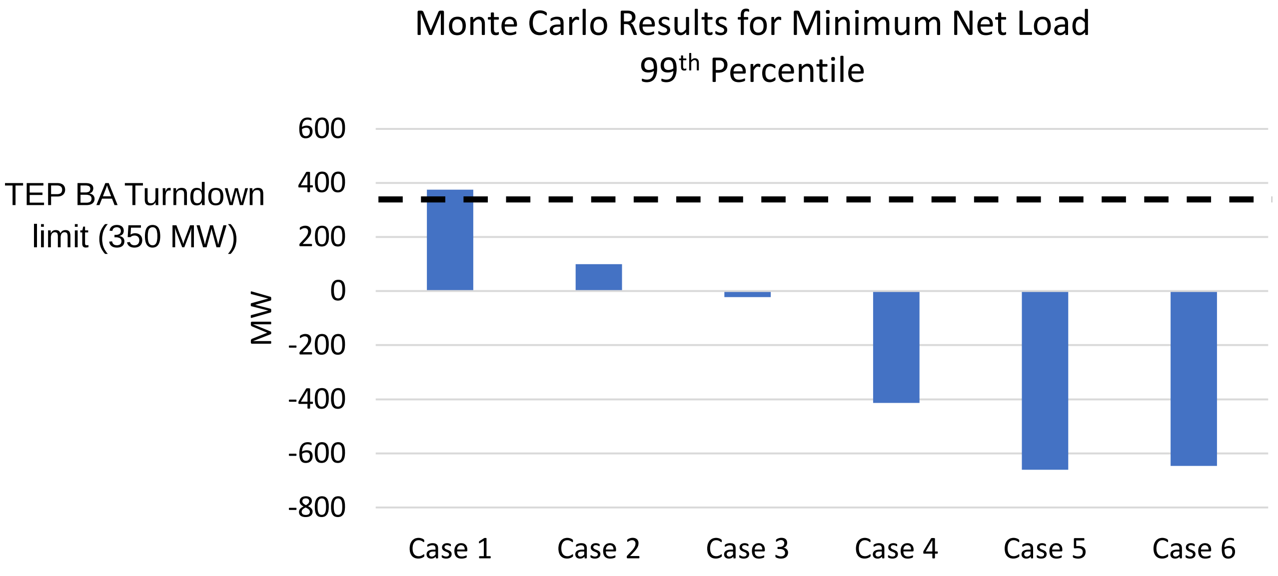


- To take into account a planning reserve margin of 15%, the total dispatchable capacity was determined as 87% of effective capacity.
- Each utility is required to procure enough capacity to meet its own peak demand regardless of their combined loads and resources. While TEP has sufficient dispatchable capacity to meet its peak net load, UNSE has historically relied on market purchases to meet a substantial amount of its peak load, which are not shown here because they have not yet been procured for the time period analyzed. Thus, the combined loads and resources of the two utilities shows a slight lack of peak capacity in Cases 1 and 2.

TEP BA Non-Cycling and Storage Minimum Generation v. Minimum Net Load

2024 Resources	Min Generation (MW)
Springerville 1	150
Springerville 2	150
Four Corners 4	28
Four Corners 5	28
Gila 2	156
Gila 3	156
Luna	47
Sundt ST3	19
Sundt ST4	36
RICE 1-10	10
Wilmot Battery	-30

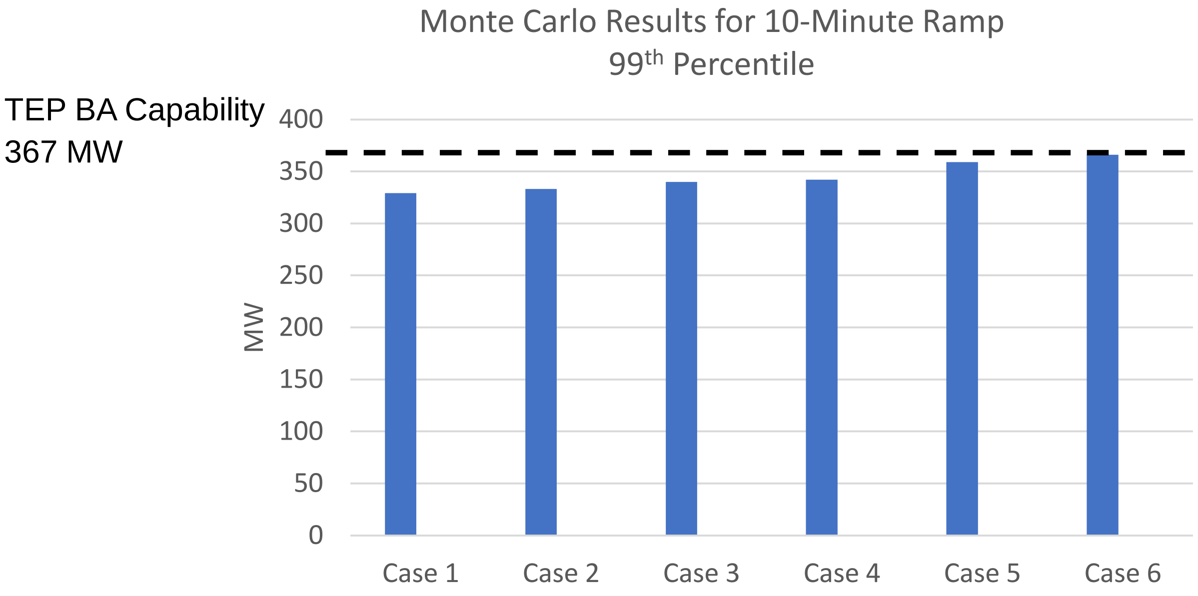
Over Generation (with respect to turndown limit)			
	TEP Overgeneration (MWh)	TEP BA (Minimum Net Load MW) (P99)	TEP BA Overgeneration (MWh)
Case 1	53	375	1,130
Case 2	21,236	100	50,057
Case 3	78,786	-22	128,770
Case 4	306,926	-413	452,671
Case 5	789,542	-660	926,853
Case 6	762,244	-646	898,663



- Negative minimum net load means over-generation will occur if there is inadequate flex capacity (e.g., storage) to absorb the surplus energy generation, or if there is no market for exporting the surplus energy. Therefore, TEP BA is facing a potential over-generation situation when renewable penetration increases to 35% and especially to 50%, as in Cases 3, 4, 5, and 6.
- NOTE: Over-generation occurs when renewable generation is greater than demand minus the turndown limit of resources which must stay on line for reliability purposes. These limits are shown in the top table to the left.

BA 10-Minute Ramp Capability v. Maximum 10-Minute Ramp

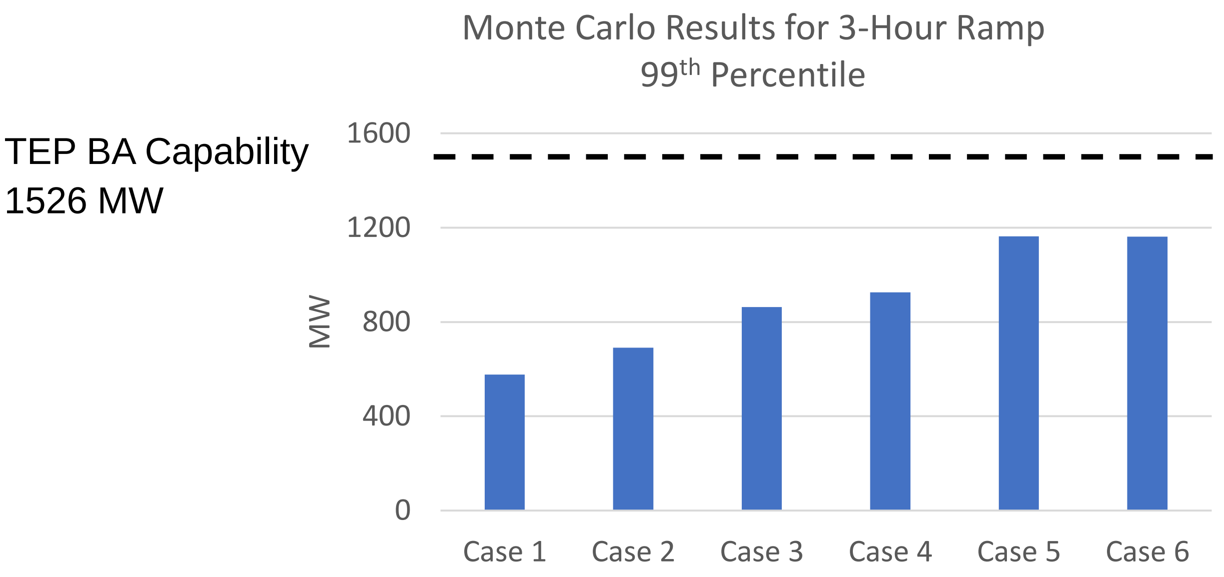
Monte Carlo Results for 10-Minute Ramp		
	99th Percentile (MW)	BA Has Adequate Capability?
Case 1	329	Yes
Case 2	333	Yes
Case 3	340	Yes
Case 4	342	Yes
Case 5	359	Yes
Case 6	366	Yes



- The total ramping capability exceeds the 10-minute maximum ramp requirement in all six cases, however, the available ramping capability at any given time is a function of the resources available at that time and their level of output. Accordingly, the graph above assumes that one Springerville unit, one Gila unit, and half the RICE units are unavailable to ramp because the peak ramps occur in the summer afternoons (see later slides), when these units are likely to be operating at or near full capacity.
- The Monte Carlo results suggest that the maximum 10-minute ramps will increase only modestly relative to the doubling of renewable capacity between Cases 1 and 6.

TEP BA's 3-Hour Ramping Capability v. Maximum 3-Hour Ramp

Monte Carlo Results for 3-Hour Ramp		
	99th Percentile (MW)	**< 3-Hour Ramping Capability**
Case 1	672	Yes
Case 2	799	Yes
Case 3	1000	Yes
Case 4	1020	Yes
Case 5	1160	Yes
Case 6	1158	Yes



- The total ramping capability exceeds the 3-hour maximum ramp requirement in all six cases, however, the available ramping capability at any given time is a function of the resources available at that time and their level of output. Accordingly, the graph above assumes that one Springerville unit and one Gila unit will be unavailable to ramp because the peak ramps occur in the spring and fall (see later slides), when these units are likely to be unavailable due to maintenance outages and/or seasonal operation.
- It is recommended that TEP also consider the full ramp requirement from its turndown limit to its daily peak load, regardless of the number of hours in the ramp.
- Required amount of controllable resources to follow 3-hour ramps 99% of the time varies between 576 MW for Case 1 and 1160 MW for Case 5.

Conclusions and Recommendations

Conclusions

- The maximum 10-minute ramp for TEP is 333 MW in July for Case 6.
- The maximum 10-minute ramp for TEP BA is 366 MW (an increase of 33 MW compared to TEP only) in July for Case 6.
- The maximum 3-hour ramp for TEP is 1029 MW in October for Case 5.
- The maximum 3-hour ramp for TEP BA is 1160 MW (an increase of 131 MW compared to TEP only) in January for Case 5.

Conclusions (Continued)

- For the cases and timeframe studied, the TEP BA can meet all 99th percentile 10-minute and 3-hour net load ramps, assuming most of the BA's ramping resources are available at the time of the highest ramps.
- The TEP BA may experience some over-generation at 35% renewables and is expected to experience substantial over-generation at 50% renewables (Case 3, 4, 5, and 6). The maximum over-generation is 660 MW in Case 5.
- Assuming none of the resources included in this study are retired, TEP has sufficient capacity for all scenarios, but UNSE may require some additional firm summer capacity in Cases 1 and 2.
- Higher load and renewables have a balancing effect for the TEP BA compared to just TEP system that results in netting out of renewable variability from more diverse system load.

Recommendations

- The Monte Carlo results suggest that the maximum 10-minute ramps will increase only modestly relative to the doubling of renewable capacity between Cases 1 and 6, but TEP should track the impact on actual ramps as it implements more renewable resources to determine if the ramps might increase more than indicated.
- TEP should consider the full ramp requirement from its turndown limit to its daily peak load.
- Over-generation is present at 35% and would require mitigation at 50%, especially if all the renewable energy must serve load in order to satisfy a renewable energy goal or standard.

APPENDIX B

FUTURE RESOURCE TECHNOLOGY SUMMARIES

Batteries

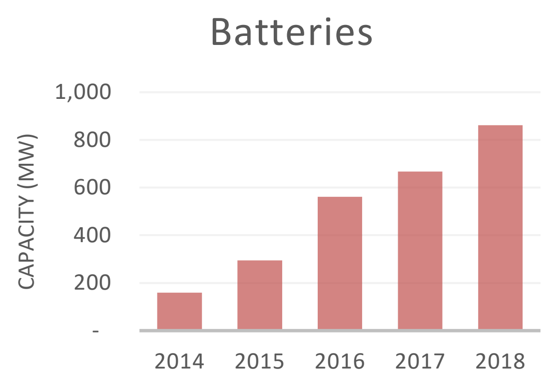
General Description

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

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

Market Trends

Most energy storage in the U.S. is in the form of water reservoirs (i.e., pumped hydro), but battery prices are declining, and the technology is becoming more advanced and standardized. The chart below shows the recent increase in U.S. battery deployment. Wood Mackenzie is forecasting deployments to increase more than 400% from 2020 to 2024.[1]



Source: EIA-923/860
https://www.eia.gov/electricity/data.php

Economics

Prices for most battery types, especially Li-ion are rapidly declining due to an expanding manufacturing base. Flow battery prices are also declining, but not as fast. Levelized costs of all battery types are still higher than other forms of energy storage, but they provide superior services, some of which are difficult to monetize.

Environmental and Siting

Batteries offer a high degree of flexibility in terms of siting, although safety considerations will often limit where large-scale batteries can be located. Decommissioning and disposal after their useful life is also an issue needing more attention.

Operational Characteristics

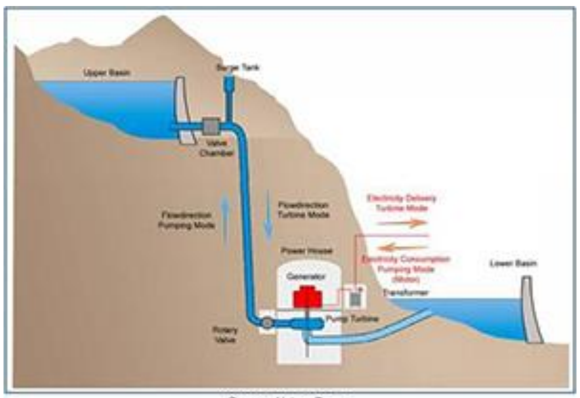
Batteries have a high degree of flexibility in terms of application and scalability. Single systems can serve multiple purposes. While Li-ion batteries are currently the preferred type, flow batteries offer the benefit of having no degradation in the amount of energy they can store. Although batteries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

[1] Wood Mackenzie Power & Renewables/U.S. Energy Storage Association, December 2019.

Pumped Hydro Power

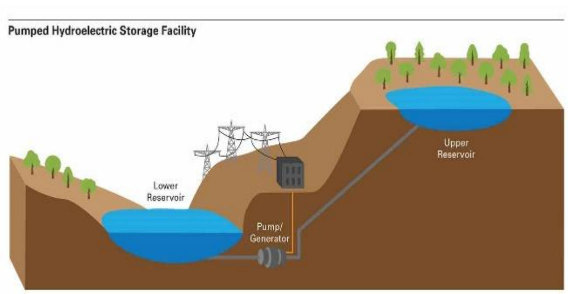
General Description

Pumped hydro technology has been in use for nearly a century worldwide. Pumped hydro accounts for most of the installed storage capacity in the United States. Pumped hydro plants use lower-cost, off-peak electricity to pump water from a low-elevation reservoir to a higher reservoir. When the utility needs the electricity or when power prices are higher, the plant releases the water to flow through hydro turbines to generate power.



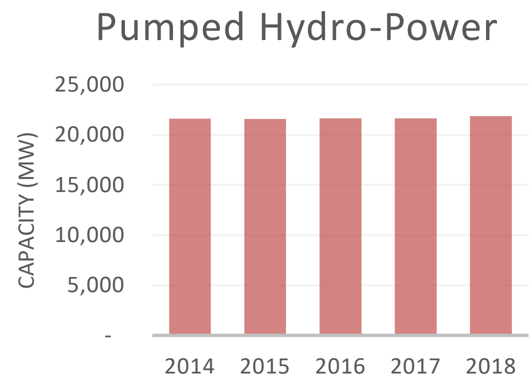
Source: Alstom Power

Pumped hydro is economical only on a large scale (250-2,000 MW) and can take several years to construct. The technology can be characterized as open loop, where there is ongoing connection to a body of water, or closed loop, where the reservoirs are not connected to an outside body of water.



Market Trends

Pumped hydro currently accounts for most energy storage capacity in the U.S. but has not increased in recent years. The chart below shows the total annual nameplate capacity.



Source: EIA-923/860
https://www.eia.gov/electricity/data.php

Economics

Installation costs of these systems tend to be high and permitting and siting requirements pose additional challenges.

Environmental and Siting

Pumped hydro requires sites with suitable topography, where reservoirs can be situated at different elevations and where sufficient water is available.

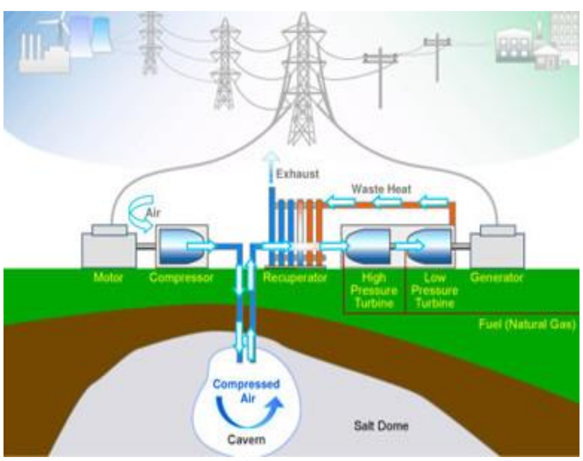
Operational Characteristics

Typical pumped hydro facilities can store enough water for up to 10 or more hours of energy storage. Pumped hydro plants can absorb excess electricity produced during off-peak hours, provide frequency regulation, and help smooth the fluctuating output from other sources. Pumped hydro is a proven technology with high peak use coincidence. The round-trip efficiency of these systems usually exceeds 70 percent.

Compressed Air Energy Storage (CAES)

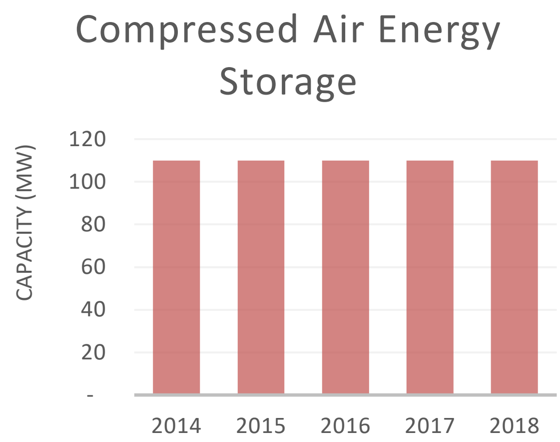
General Description

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



Market Trends

CAES has not seen any growth in applications. From 2014 to 2018, there was no increase in the net nameplate capacity in the U.S. The chart below shows the total annual nameplate capacity over that time frame.



Source: EIA-923/860
https://www.eia.gov/electricity/data.php

Economics

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

Environmental and Siting

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

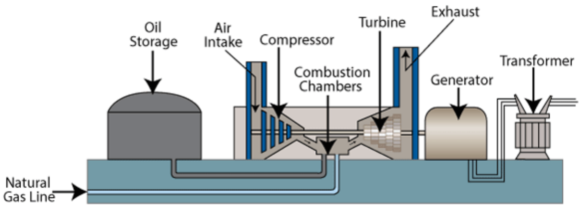
Operational Characteristics

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

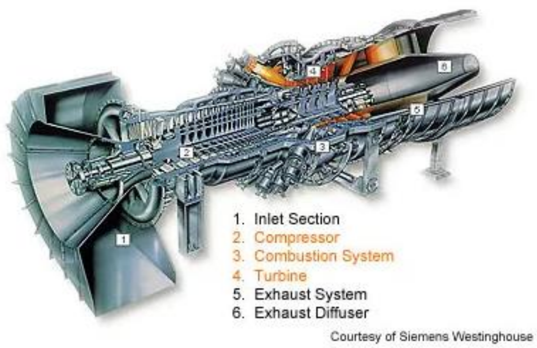
Combustion Turbines

General Description

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

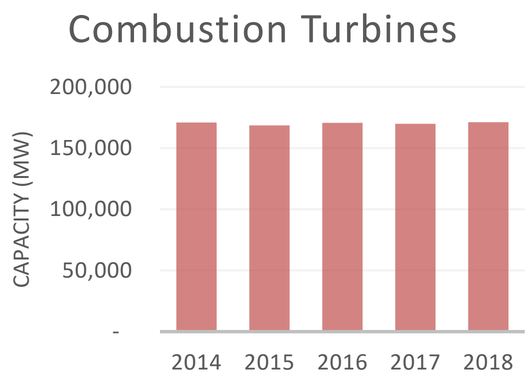


Typical start times for frame CTs are longer than aeroderivative CTs, but equipment options from manufacturers can bridge much of that gap. Frame CTs can meet a need for intermediate and base-load applications.



Market Trends

Combustion turbines are a very mature technology. In 2019, combustion turbines supplied about 3.5% of the total U.S. generation. From 2014 to 2018, the net nameplate capacity was nearly constant. The chart below shows the total annual nameplate capacity over the past few years.



Source: EIA-923/860
https://www.eia.gov/electricity/data.php

Economics

Frame CTs are cheaper on a per kW basis. The operating costs of both types are subject to natural gas price volatility.

Environmental and Siting

Because they are more compact, aeroderivative CTs can be sited locally and avoid some transmission costs. Frame CTs have higher power outputs, but they can produce more emissions.

Operational Characteristics

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

Reciprocating Internal Combustion Engines (RICEs)

General Description

RICEs used for electricity generation are fundamentally the same technology that is used in motor vehicles, construction equipment, and backup power applications, and can be either spark-ignited or compression-ignited.

RICEs have quicker start-up and ramping capabilities than most CTs and are not as affected by ambient temperatures and elevation. Like CTs, their capacity can range in size. These engines have a proven performance record as they have been used in marine crafts for decades.

Market Trends

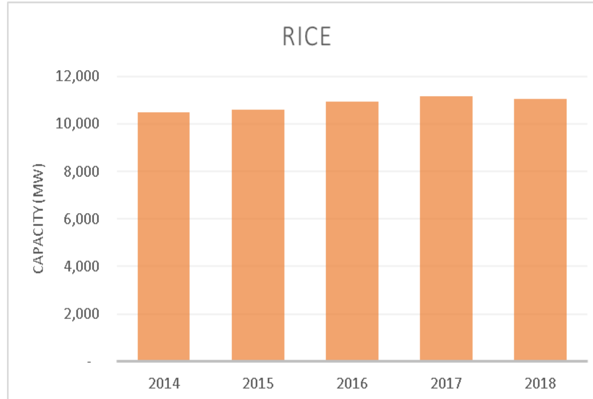
Internal combustion engines have helped electric utilities maintain reliability, sustainability, and intermittency throughout the years as renewable resource reliance increases. In 2019, RICEs supplied roughly 0.4% of the total U.S. generation. From 2014 to 2018, nearly 0.6 GW of net nameplate capacity was added to the U.S. electricity grid. The chart below shows the total annual nameplate capacity over that time frame.

Economics

Operating costs are subject to natural gas price volatility.

Environmental and Siting

RICEs use a closed-loop cooling system that requires minimal water use.



Source: EIA-923/860
https://www.eia.gov/electricity/data.php

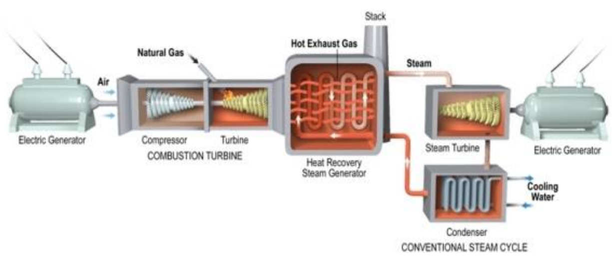
Operational Characteristics

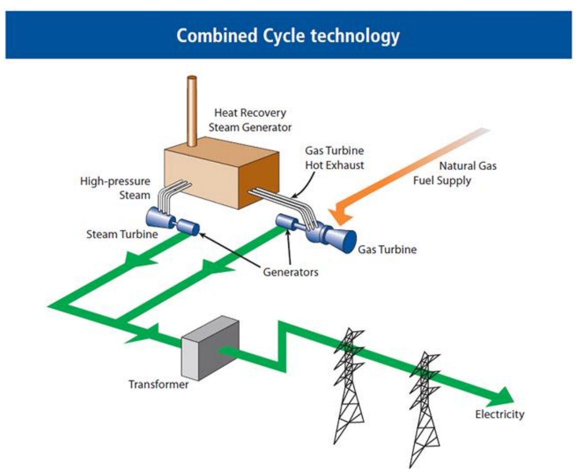
RICEs are not a new technology, but technological advances have made them more efficient and more flexible. They can operate over a wide range of loads without compromising efficiency, are capable of being on-line at full load within 5 minutes and can cycle their operation with no additional costs. Rather, RICE maintenance cycles depend on the hours of operation, not by the number of starts, which is not the case with CTs.

Natural Gas Combined Cycle (NGCC)

General Description

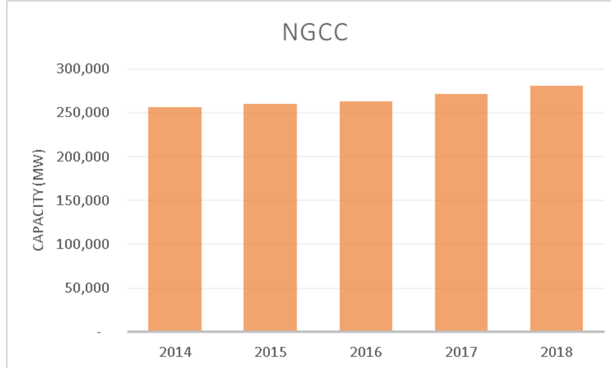
Natural gas combined cycle technology is the most efficient and cost-effective way of generating electricity from natural gas. NGCC plants use CT exhaust to produce steam for an additional turbine and generator, thus extracting more energy from a given amount of fuel.





Market Trends

In 2019, NGCC supplied 31% of the U.S. electricity production. From 2014-2018, nearly 25 GW of net nameplate capacity was added to the U.S. electricity grid. The chart below shows the total annual nameplate capacity over that time frame.



Source: EIA-923/860
https://www.eia.gov/electricity/data.php

Economics

Advances in natural gas exploration and development, such as directional drilling and hydraulic fracturing, have dramatically increased the amount of proven reserves in the US and reduced prices to about one-fourth of their peak in 2008. But over the long term, NGCC operational costs are subject to natural gas price volatility and greenhouse gas regulations.

Environmental and Siting

NGCCs have lower emission rates than coal-fired generating plants. The use of both gas and steam turbines in a single plant results in higher conversion efficiencies and lower emissions.

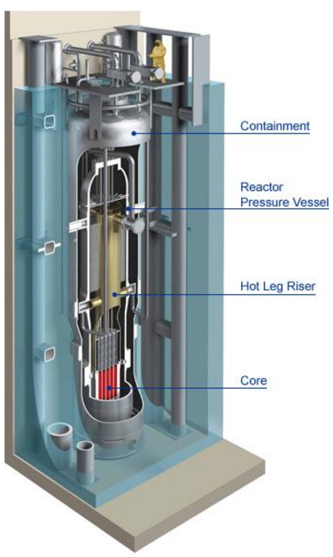
Operational Characteristics

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

Small Modular Nuclear Reactors (SMR)

General Description

SMRs are approximately one-third the size of traditional nuclear units (300 MW or less) and are expected to offer many benefits in design, scale, construction, and costs relative to the current fleet of nuclear plants. As the name implies, the size of the facility can be scaled by the number of modules, which can be largely constructed at the factory and transported to a designated site. This reduces construction time and capital costs.



The design relies on passive concepts, which makes it less reliant on active safety systems, additional pumps, and an external AC power source for accident mitigation. The modular design and small size also facilitate decommissioning.

Market Trends

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

Economics

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

Environmental and Siting

SMRs have zero emissions and lower cooling water requirements, providing more flexibility in siting and opening more opportunities for application, such as mining and desalination.

Operational Characteristics

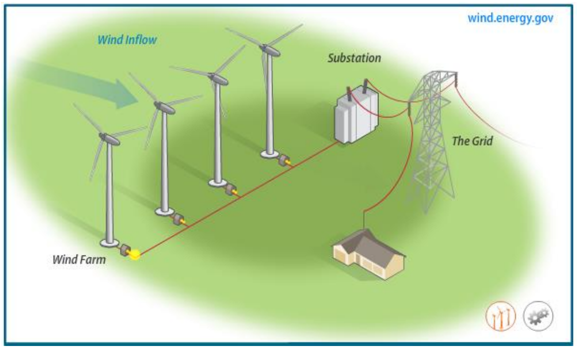
SMRs can potentially be located underground or underwater, providing more protection from hazards such as tsunamis and aircraft impacts.

The scalability of SMRs allows for small utilities to consider their viability while lessening the financial risk. SMRs have high capacity factors.

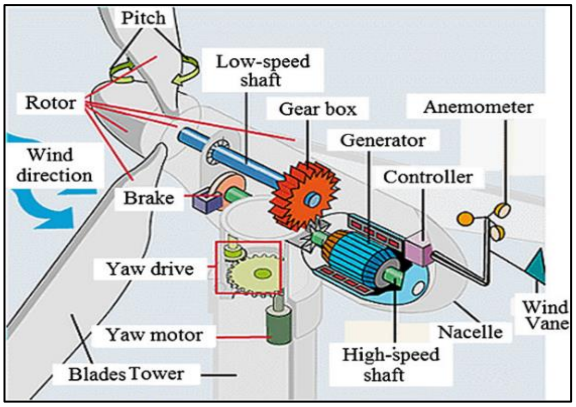
Wind

General Description

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



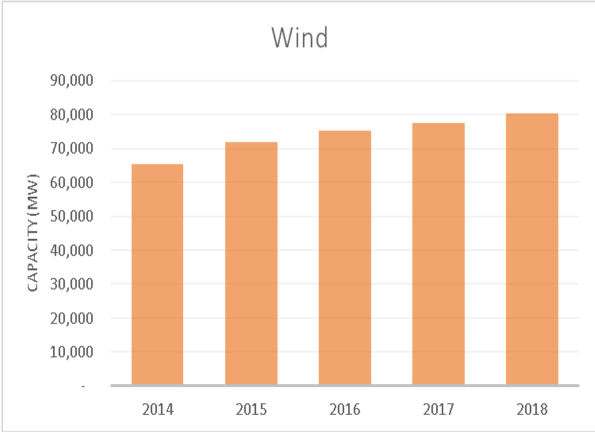
Yaw motors direct the turbines to face into the wind. The blades are shaped with an airfoil cross section (similar to an aircraft wing), which causes air to move more quickly over one side than the other. This difference in speed causes a difference in pressure, which in turn causes the blade to move,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



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

Market Trends

Over the last twenty years, the use of wind power has increased rapidly, making it the predominant form of new renewable generation. In 2019, wind supplied over 7% of the total U.S. electricity generation. From 2014 to 2018, nearly 15 GW of net nameplate capacity was built in the U.S. The chart below shows the total annual nameplate capacity over that time frame.



Source: EIA-923/860
https://www.eia.gov/electricity/data.php

Economics

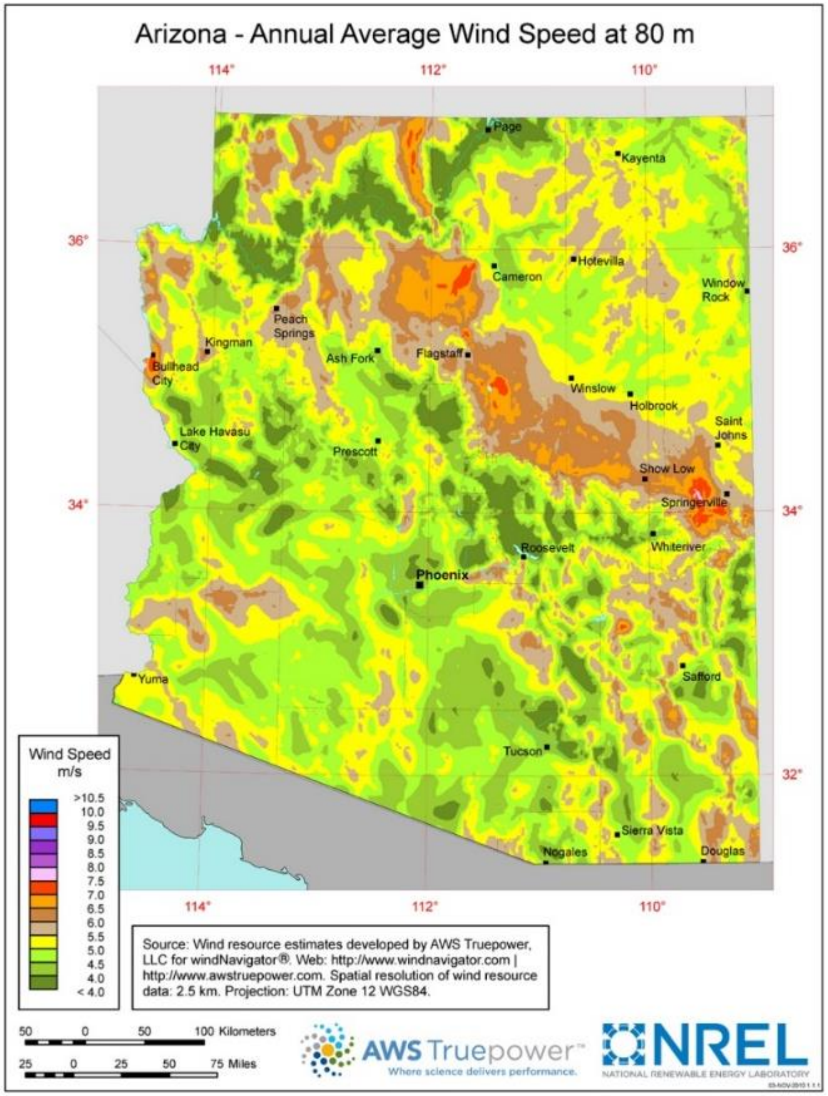
Major advances in wind power technology were achieved in the 1990s and 2000s, allowing much larger turbines to be developed that are more efficient and reduce generation costs.

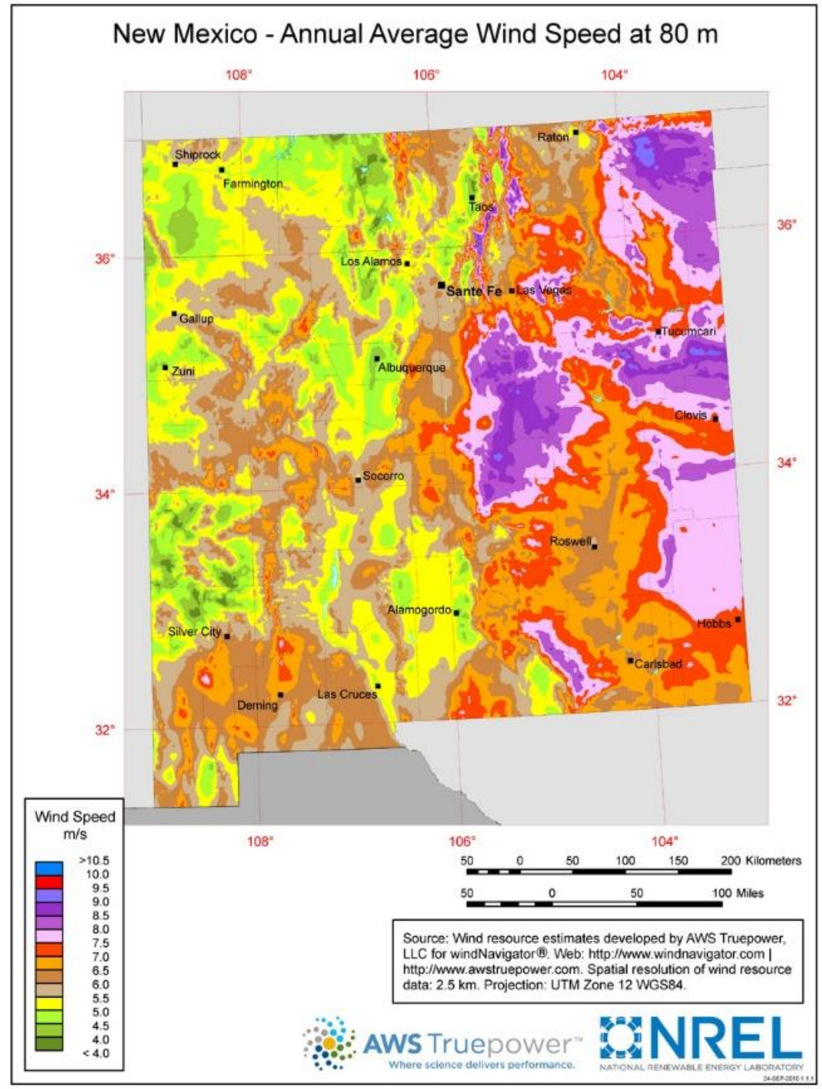
Environmental and Siting

Areas with annual average wind speeds of 6 m/s or more at 80 m height are considered to be suitable for wind development (see the two maps below). Utility-scale, land-based wind turbines are typically installed between 80m and 100m high. Wind power has no emissions.

Operational Characteristics

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

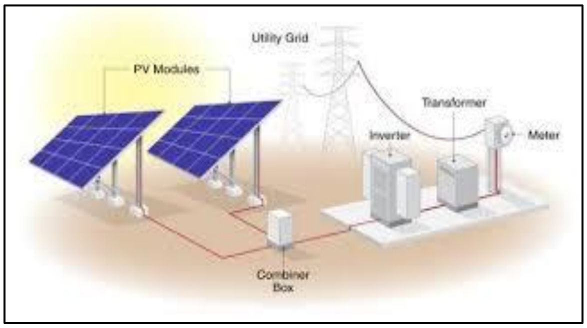

Arizona - Annual Average Wind Speed at 80 m
114°
112°
110°
36°
34°
32°
Page
Kayenta
Hotevilla
Cameron
Window Rock
Peach Springs
Kingman
Bullhead City
Ash Fork
Flagstaff
Winslow
Holbrook
Saint Johns
Lake Havasu City
Prescott
Show Low
Springerville
Whiteriver
Roosevelt
Phoenix
Yuma
Safford
Tucson
Sierra Vista
Nogales
Douglas
Wind Speed m/s
>10.5
10.0
9.5
9.0
8.5
8.0
7.5
7.0
6.5
6.0
5.5
5.0
4.5
4.0
< 4.0
Source: Wind resource estimates developed by AWS Truepower, LLC for windNavigator®. Web: http://www.windnavigator.com | http://www.awstruepower.com. Spatial resolution of wind resource data: 2.5 km. Projection: UTM Zone 12 WGS84.
50 0 50 100 Kilometers
25 0 25 50 75 Miles
AWS Truepower
Where science delivers performance.
NREL
NATIONAL RENEWABLE ENERGY LABORATORY


New Mexico - Annual Average Wind Speed at 80 m
108°
106°
104°
36°
34°
32°
Raton
Shiprock
Farmington
Taos
Los Alamos
Sante Fe
Las Vegas
Gallup
Tucumcari
Zuni
Albuquerque
Clovis
Socorro
Roswell
Alamogordo
Hobbs
Silver City
Carlsbad
Las Cruces
Deming
Wind Speed m/s
>10.5
10.0
9.5
9.0
8.5
8.0
7.5
7.0
6.5
6.0
5.5
5.0
4.5
4.0
< 4.0
50 0 50 100 150 200 Kilometers
50 0 50 100 Miles
Source: Wind resource estimates developed by AWS Truepower, LLC for windNavigator®. Web: http://www.windnavigator.com | http://www.awstruepower.com. Spatial resolution of wind resource data: 2.5 km. Projection: UTM Zone 12 WGS84.
AWS Truepower
Where science delivers performance.
NREL
NATIONAL RENEWABLE ENERGY LABORATORY

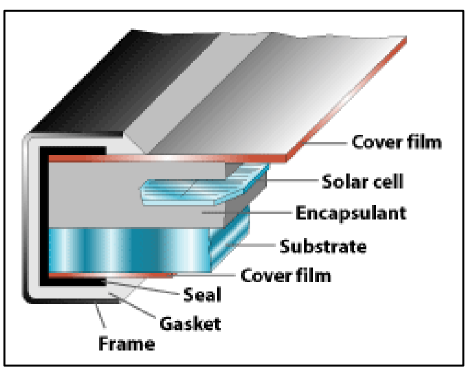
Utility Scale Solar Photovoltaic (PV) – Fixed Tilt and Single Axis Tracking (SAT)

General Description

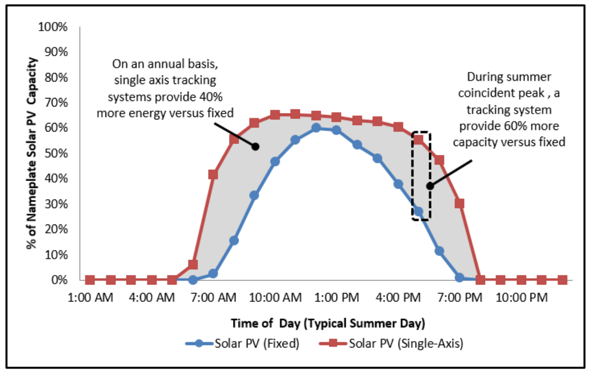
Solar PV cells convert sunlight into direct current electricity. These PV cells are the building blocks of PV modules, or panels, and the modules are the building blocks of PV arrays. Inverters convert the direct current into alternating current, which can then be tied to the electric grid and used by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



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

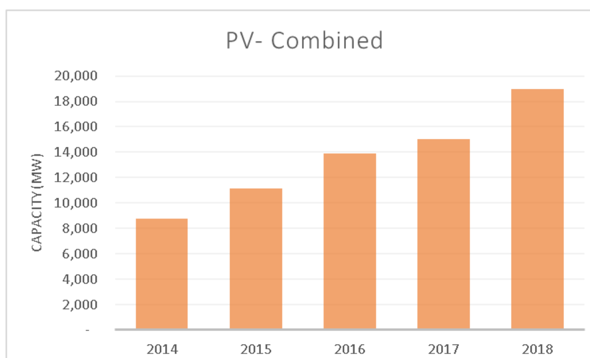


The SAT PV systems are designed to track the sun from east to west. They are used with flat-plate systems and sometimes with concentrator systems. These systems track the sun's daily course. Because they can track the sun, SAT PV systems are able to generate more energy per panel than fixed tilt systems.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



Market Trends

The total amount of solar energy in the U.S. has increased significantly in the past few years. In 2019, solar PV supplied roughly 1.7% of the U.S. electricity generation. From 2014 to 2018, over 10 GW of net nameplate capacity was installed. The chart below shows the total annual nameplate capacity over that time frame.



Source: EIA-923/860
https://www.eia.gov/electricity/data.php

Economics

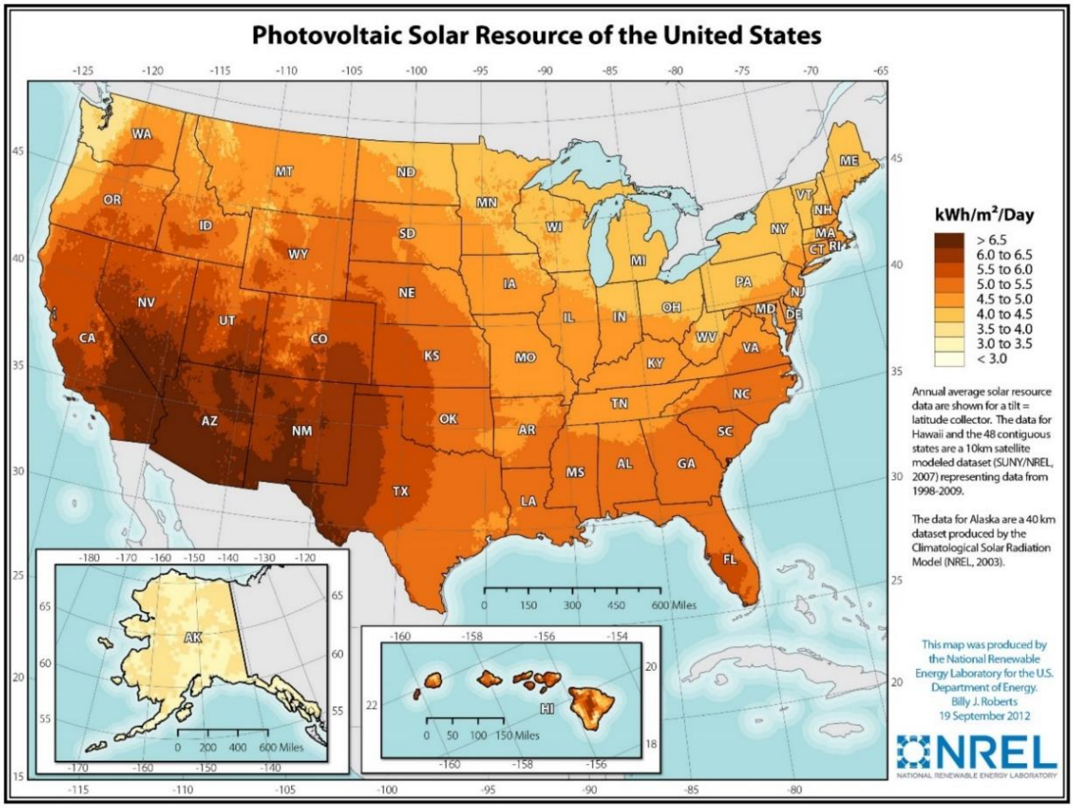
The costs of building and implementing solar PV has decreased over the past several years and forecasts expect further decreases. The fixed array does not require much maintenance, so the costs are low. SAT systems require more maintenance since they have motors and moving parts. Solar power is not subject to changing fuel prices.

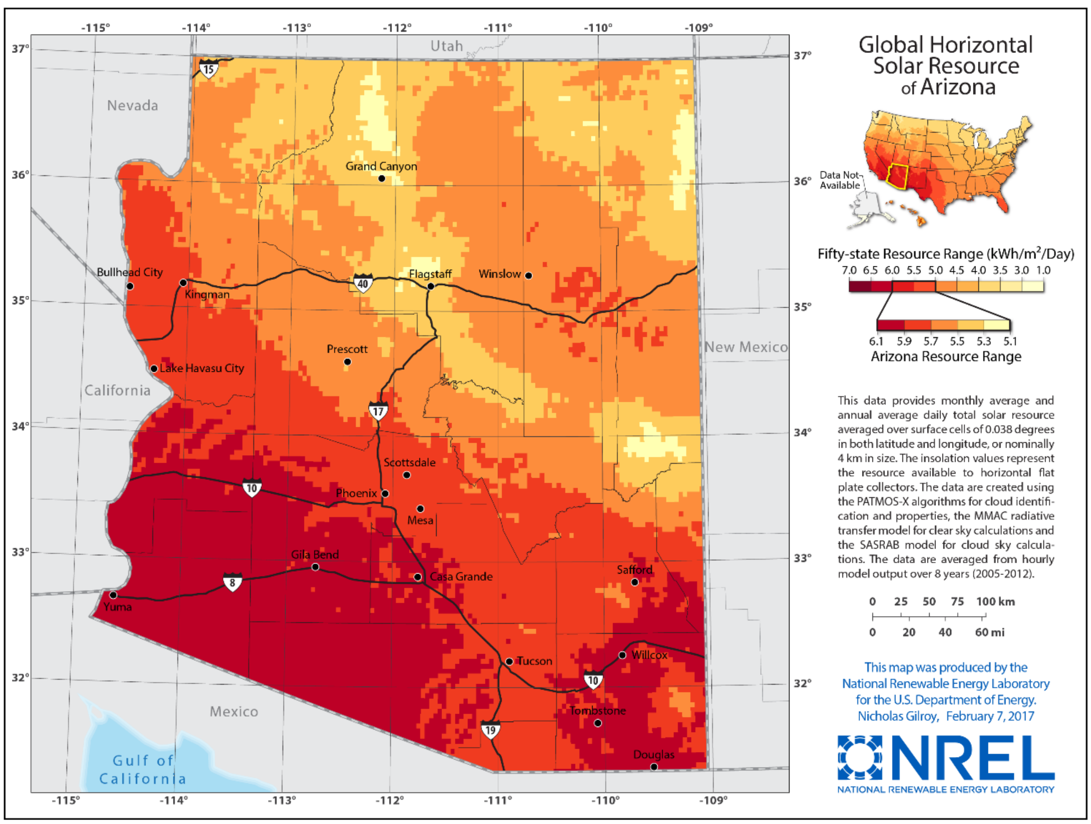
Environmental and Siting

Solar PV emits no air pollution and consumes no water. It requires a fair amount of land, which affects siting. The following two maps show the solar power potential in areas across the U.S. and Arizona.

Operational Characteristics

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

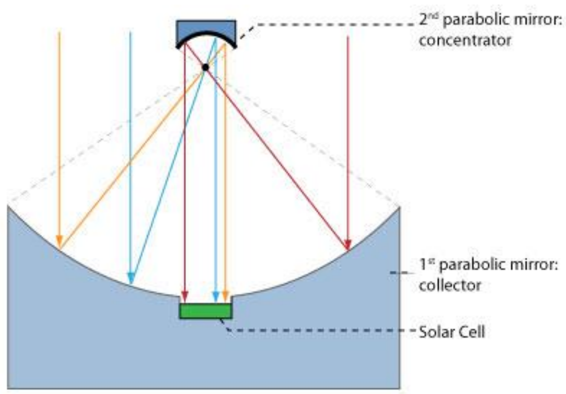

Photovoltaic Solar Resource of the United States
kWh/m²/Day
> 6.5
6.0 to 6.5
5.5 to 6.0
5.0 to 5.5
4.5 to 5.0
4.0 to 4.5
3.5 to 4.0
3.0 to 3.5
< 3.0
Annual average solar resource data are shown for a tilt = latitude collector. The data for Hawaii and the 48 contiguous states are a 10km satellite modeled dataset (SUNY/NREL, 2007) representing data from 1998-2009.
The data for Alaska are a 40 km dataset produced by the Climatological Solar Radiation Model (NREL, 2003).
This map was produced by the National Renewable Energy Laboratory for the U.S. Department of Energy. Billy J. Roberts 19 September 2012
0 150 300 450 600 Miles
0 200 400 600 Miles
0 50 100 150 Miles
WA
OR
CA
ID
NV
MT
WY
UT
AZ
CO
NM
ND
SD
NE
KS
OK
TX
MN
IA
MO
AR
LA
WI
IL
MI
IN
OH
KY
TN
MS
AL
GA
FL
SC
NC
VA
WV
PA
NY
VT
NH
ME
MA
CT
RI
NJ
DE
MD
AK
HI
NREL
NATIONAL RENEWABLE ENERGY LABORATORY


Global Horizontal Solar Resource of Arizona
Data Not Available
Fifty-state Resource Range (kWh/m²/Day)
7.0 6.5 6.0 5.5 5.0 4.5 4.0 3.5 3.0 1.0
6.1 5.9 5.7 5.5 5.3 5.1
Arizona Resource Range
This data provides monthly average and annual average daily total solar resource averaged over surface cells of 0.038 degrees in both latitude and longitude, or nominally 4 km in size. The insolation values represent the resource available to horizontal flat plate collectors. The data are created using the PATMOS-X algorithms for cloud identification and properties, the MMAC radiative transfer model for clear sky calculations and the SASRAB model for cloud sky calculations. The data are averaged from hourly model output over 8 years (2005-2012).
0 25 50 75 100 km
0 20 40 60 mi
This map was produced by the National Renewable Energy Laboratory for the U.S. Department of Energy. Nicholas Gilroy, February 7, 2017
NREL
NATIONAL RENEWABLE ENERGY LABORATORY
Utah
Nevada
California
New Mexico
Mexico
Gulf of California
Grand Canyon
Bullhead City
Kingman
Flagstaff
Winslow
Prescott
Lake Havasu City
Scottsdale
Phoenix
Mesa
Gila Bend
Casa Grande
Safford
Yuma
Tucson
Willcox
Tombstone
Douglas

Concentrating Photovoltaics (CPV)

General Description

Concentrating photovoltaic (CPV) systems use lenses or mirrors to concentrate sunlight onto high-efficiency solar cells. These solar cells are more expensive than conventional cells used for flat-plate PV systems. However, the increased cell efficiency requires less cell area to produce a given amount of power. Advantages of CPV technology are: no intervening heat transfer surface, near-ambient temperature operation, and no thermal mass; fast response.



Market Trends

The CPV market is still young and not well developed. Recently, the CPV industry has struggled to compete with PV prices, leading CPV companies exiting the market, while others face challenges in raising the capital required to scale the technology.

Economics

The levelized cost of CPV systems are two to three times higher than more traditional solar and wind resources.

Environmental and Siting

CPV uses less land than conventional PV systems and has no emissions or water consumption.

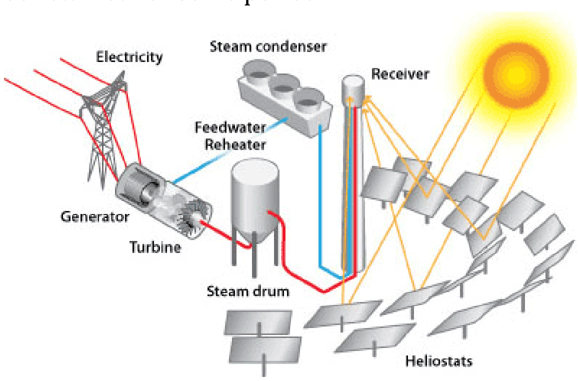
Operational Characteristics

Potential for solar cell efficiencies are greater than 40%. Efficiency is not affected by high ambient temperatures. Trackers allow for high levels of power production throughout the day. CPV systems are scalable to a range of sizes.

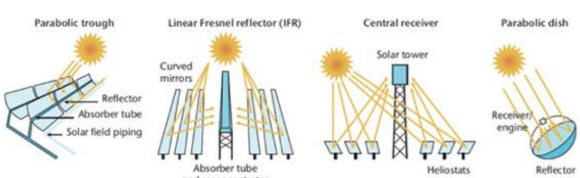
Concentrating Solar Power with Storage (Thermal) (CSP)

General Description

Concentrating solar power (CSP) uses mirrors to reflect and concentrate sunlight onto receivers that collect the solar energy and convert it into thermal energy. This thermal energy can then be used to produce electricity via a steam turbine or heat engine driving a generator. In virtually all applications, CSP is large in scale, on the order of 100 MW or larger. These large systems are similar to traditional coal, natural gas, or nuclear generators in that they utilize synchronous generators to produce electricity. While the CSP systems generally do not operate 24/7 because of the diurnal nature of the sun, they do provide grid support when they are operational because of the synchronous generation and because the heat can be retained for some period.

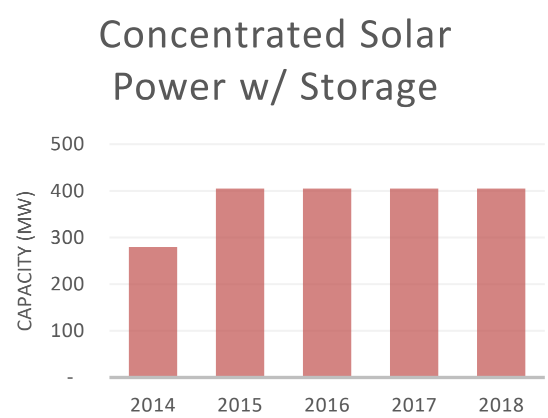


There are three generic CSP system architectures: line-focus (trough systems), point-focus central receiver (power towers), and point-focus distributed receiver (dish-engine systems).



Market Trends

CSP markets are still fairly new. The chart below shows the total annual nameplate capacity from 2014-2018.



Source: EIA-923/860
https://www.eia.gov/electricity/data.php

Economics

Costs are two to three times higher than more conventional solar technologies.

Environmental and Siting

CSP systems have no emissions but can consume water.

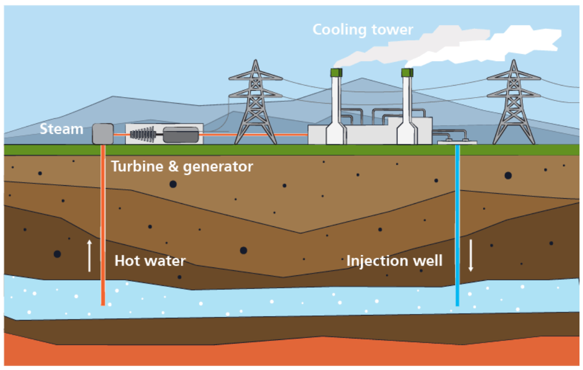
Operational Characteristics

Electric generators can be synchronized to the grid, thereby providing a form of inertia that PV systems cannot. CSP technologies can use thermal storage to address intermittency issues and provide power after sunset.

Geothermal

General Description

Geothermal energy uses heat from a variety of sources that are under the Earth's surface. This includes hot water or steam reservoirs deep underground, and more shallow geothermal reservoirs.

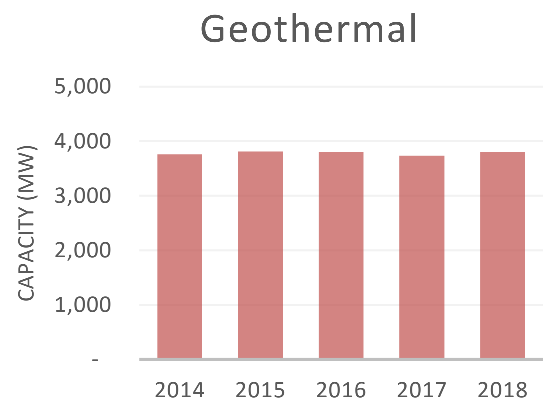


The hot water reservoirs can exist at varying temperatures and depths. Wells are used to bring the steam or hot water to the surface for energy use. Additional wells are used to return the geothermal fluids to the reservoir.

There are two types of geothermal plants: flash and binary. In flash steam power plants, a pump pushes hot fluid into a tank at the surface, where it cools. As it cools, the fluid quickly turns into vapor which drives a turbine to power a generator. Binary cycle plants use two types of fluid: the hot fluid from underground and a heat transfer fluid. The second fluid is the one that vaporizes to drive a turbine.

Market Trends

Geothermal technology used to be limited to places where the reservoirs were close to the Earth's surface, but new drilling technology is allowing plants to reach deeper reservoirs. In 2019, geothermal supplied about 0.4% of the U.S. electricity generation. From 2014 to 2018, the net nameplate capacity was nearly constant. The chart below shows the total annual nameplate capacity from 2014-2018.



Source: EIA-923/860
https://www.eia.gov/electricity/data.php

Economics

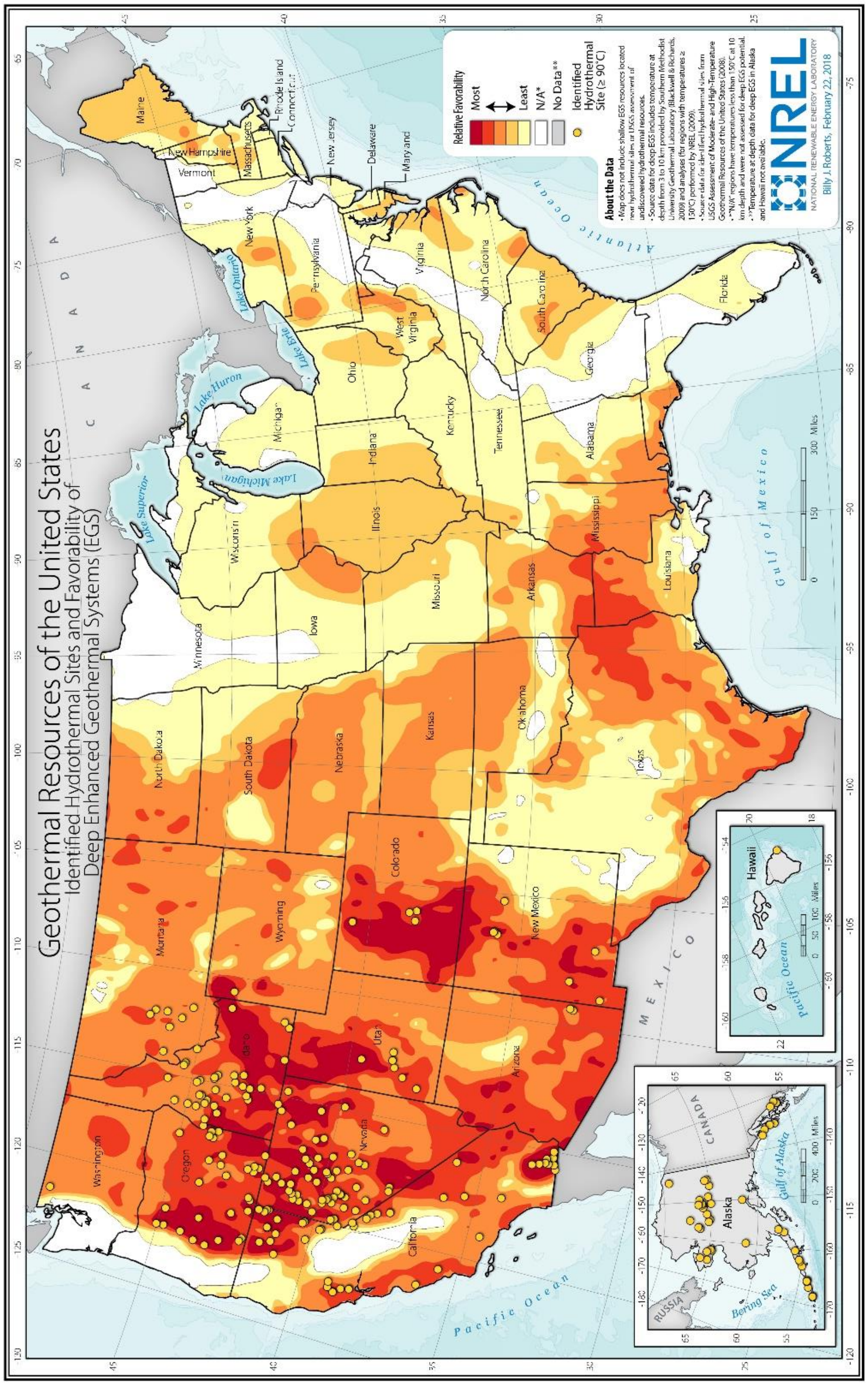
Some plants do produce solid waste, but that waste may contain minerals that can recovered and sold, which lowers the cost of the power.

Environmental and Siting

Modern closed-loop geothermal plants emit no greenhouse gasses and consume less water than traditional power sources. The next page shows the geothermal resources in the United States.

Operational Characteristics

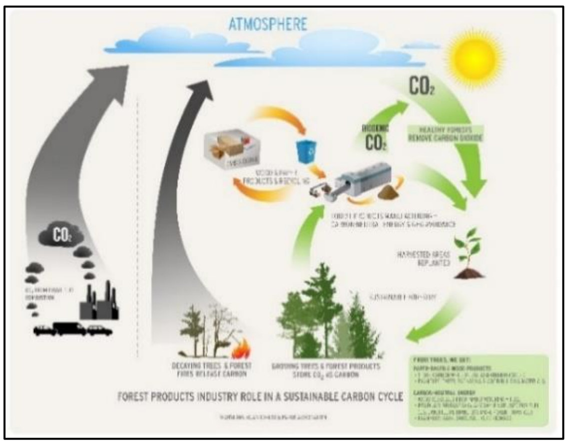
Geothermal energy is a resource that is available 24/7.

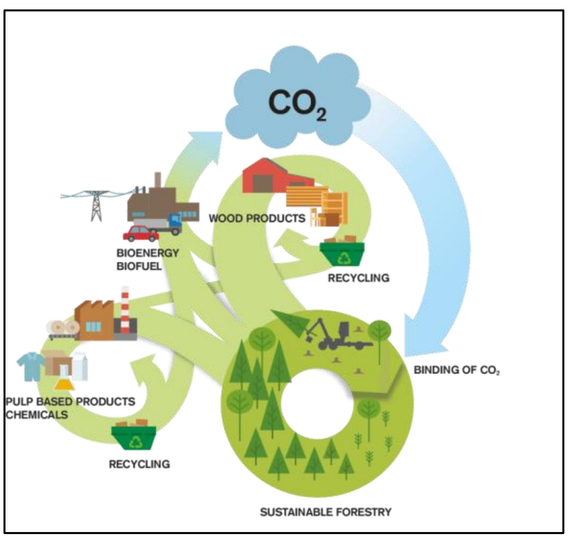

Geothermal Resources of the United States
Identified Hydrothermal Sites and Favorability of Deep Enhanced Geothermal Systems (EGS)
Relative Favorability
Most
Least
N/A*
No Data**
Identified Hydrothermal Site (≥ 90°C)
About the Data
NREL
NATIONAL RENEWABLE ENERGY LABORATORY
Billy J. Roberts, February 22, 2018
Alaska
Hawaii
Pacific Ocean
Atlantic Ocean
Gulf of Mexico
CANADA
MEXICO

Biomass

General Description

Biomass includes all solid biological materials, including forest biomass and agricultural waste. Biomass power plants operate similarly to other thermal resources, such as coal and natural gas plants. Heat from biomass combustion produces steam that powers a turbine and generator to produce electricity. Biomass can also be blended with other fuels at a thermal power plant.





Economics

Biomass is currently one of the most costly renewable resources.

Environmental and Siting

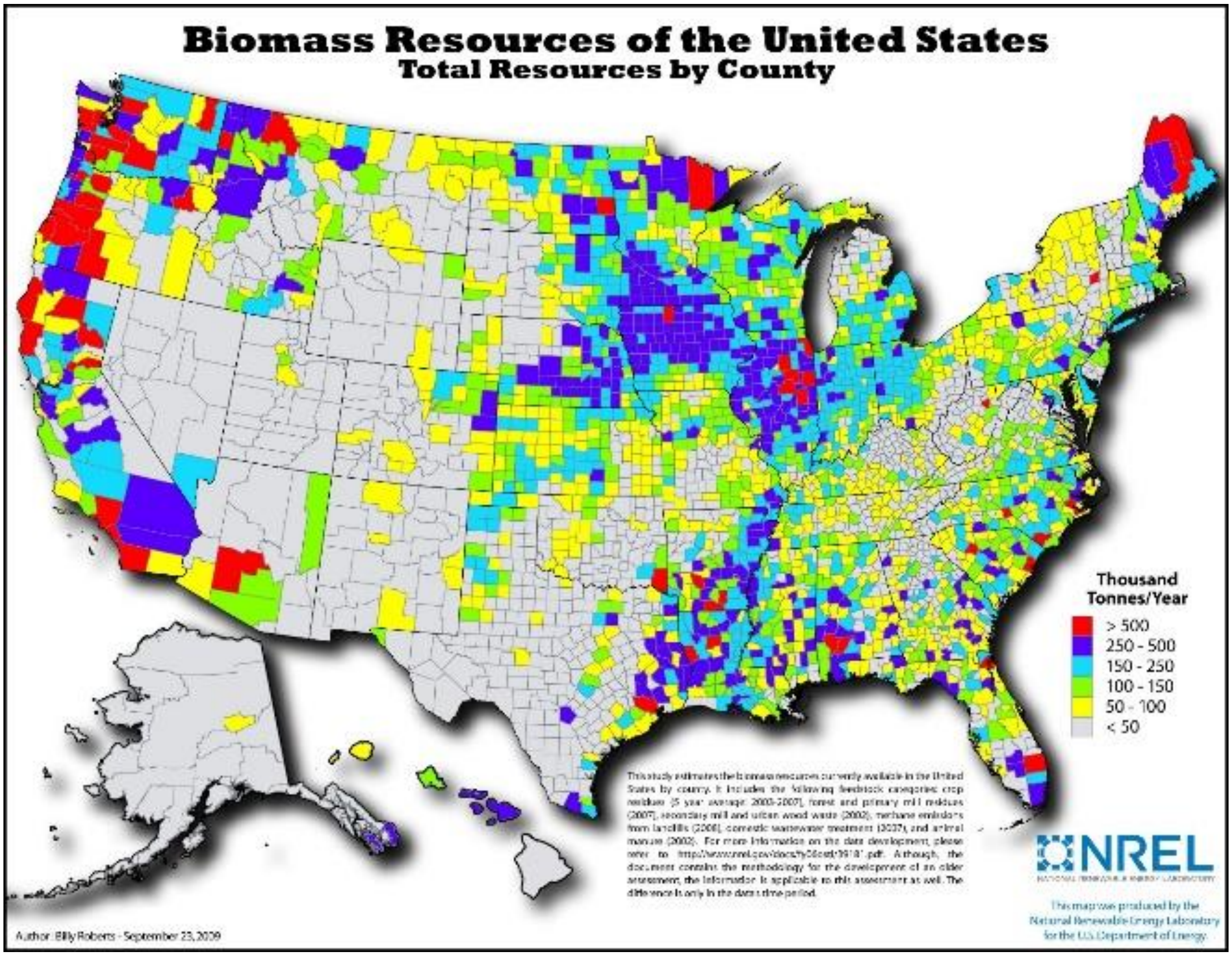
To minimize costs, biomass plants need to be located near their fuel source, which may not be near load centers or existing transmission lines.

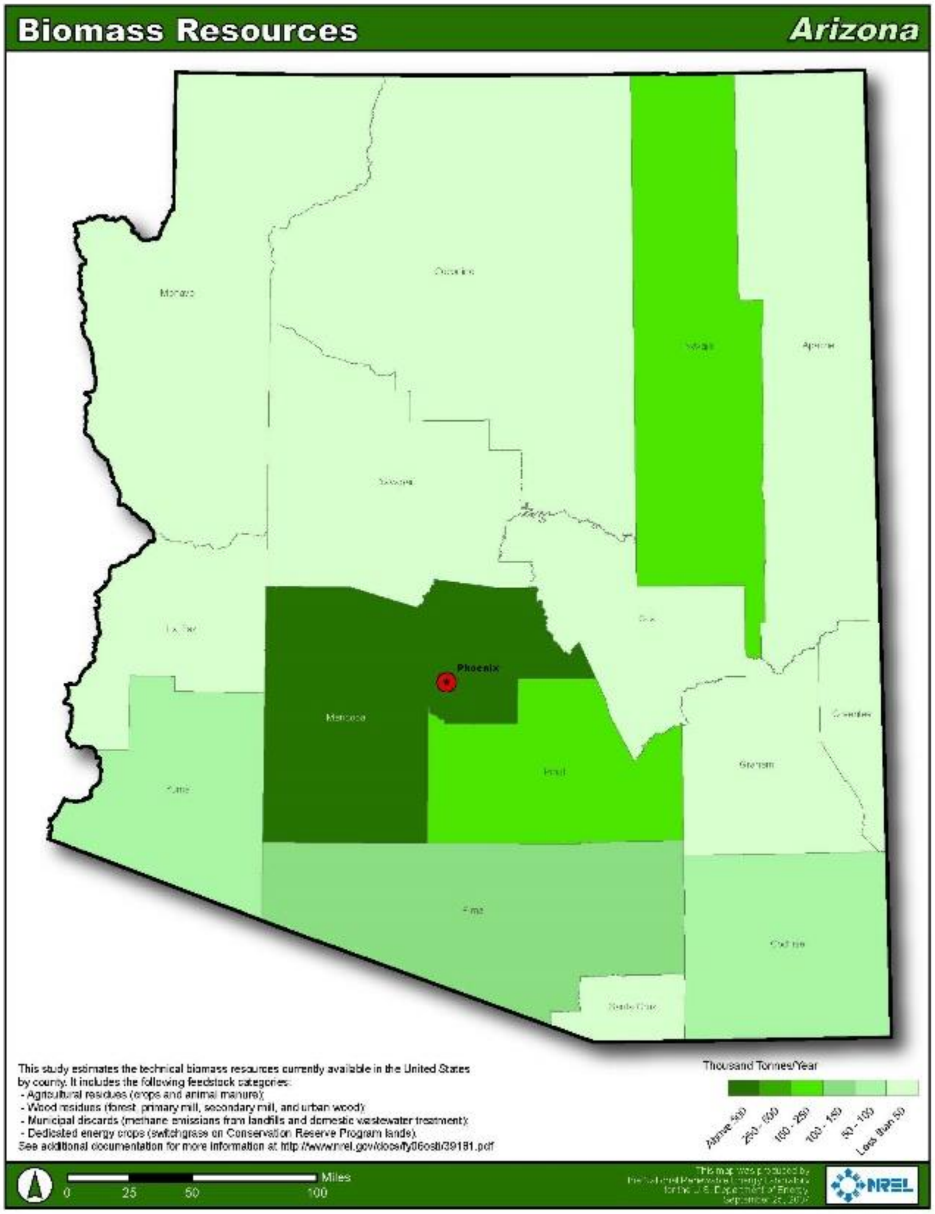
The principal environmental advantages of biofuels are their reduction of forest fire risks and their carbon neutrality. While biofuel combustion releases CO_2, a nearly equal amount is sequestered from the atmosphere as natural growth replaces the biofuel. The combustion process, however, creates nitrogen oxides and particulate matter pollution, which must be limited with pollution control equipment. In addition, biomass can have other environmental impacts if the fuel is not collected in a sustainable manner.

The maps on the following pages show the biomass potential in the U.S. and Arizona.

Operational Characteristics

In contrast to solar and wind power, biomass power plants are dispatchable and can provide "baseload" power. Direct-fired biomass power plants often operate at capacity factors of 85% or more, similar to coal and natural gas-powered plants.


Biomass Resources of the United States
Total Resources by County
Thousand Tonnes/Year
> 500
250 - 500
150 - 250
100 - 150
50 - 100
< 50
This study estimates the biomass resources currently available in the United States by county. It includes the following feedstock categories: crop residues (5 year average: 2003-2007), forest and primary mill residues (2007), secondary mill and urban wood waste (2002), methane emissions from landfills (2006), domestic wastewater treatment (2007), and animal manure (2002). For more information on the data development, please refer to http://www.nrel.gov/docs/fy06osti/39181.pdf. Although, the document contains the methodology for the development of an older assessment, the information is applicable to this assessment as well. The difference is only in the data time period.
NREL
This map was produced by the National Renewable Energy Laboratory for the U.S. Department of Energy.
Author: Billy Roberts - September 23, 2009


Biomass Resources
Arizona
Phoenix
This study estimates the technical biomass resources currently available in the United States by county. It includes the following feedstock categories:
- Agricultural residues (crops and animal manure);
- Wood residues (forest, primary mill, secondary mill, and urban wood);
- Municipal discards (methane emissions from landfills and domestic wastewater treatment);
- Dedicated energy crops (switchgrass on Conservation Reserve Program lands).
See additional documentation for more information at: http://www.nrel.gov/docs/fy06osti/39181.pdf
Thousand Tonnes/Year
Above 500
250 - 500
150 - 250
100 - 150
50 - 100
Less than 50
Miles
0
25
50
100

APPENDIX C

UNIVERSITY OF ARIZONA INSTITUTE OF THE ENVIRONMENT REPORT

Climate and TEP Resource Portfolios – Emissions Reduction and Cumulative Carbon Budgets

Prepared for Tucson Electric Power

June 2020

Institute of the Environment, Arizona Institutes for Resilience

University of Arizona

Ben McMahan, Will Holmgren, Andrea Gerlak

With assistance and input from:

Zack Guido, Kathy Jacobs, Chris Knudson, Derek Lemoine, & Stanley Reynolds

Contents

Project Overview

This report is a technical summary of Phase 2 of the TEP/UA Greenhouse Gas Emissions Reductions Targets project. We completed Phase 1 and published that report in Fall 2019 (Knudson et al., 2019). The Phase 1 report includes two elements. First, it provides an overview of the state of the climate and the implications for the U.S. Southwest. Second, it offers a preliminary review of utility practices for setting greenhouse gas emissions reductions targets. Phase 2 further explores emissions reductions guidelines for companies, the logic behind science-based targets for emissions reduction, and sector-specific practices consistent with targeted limits to warming. We expanded the analysis to include the role of discrete carbon budgets that set limits on carbon emissions based on specific warming targets (e.g., 1.5 C, 2 C, etc.). We evaluated TEP Integrated Resource Plan portfolio scenarios provided by TEP and informed by input from TEP's Stakeholder Advisory Council. Our evaluation focused on 1) emissions reductions targets associated with current scientific guidance regarding general and sector-specific emissions reductions required to keep global warming under various targets, and 2) a calculation of the relationship between discrete carbon emissions budgets developed by TEP and specific warming targets (1.5 C, 2 C, etc.). For an overview of the TEP IRP process and the role of the Stakeholder Advisory Council, please refer to https://www.tep.com/resource-planning/.

Background & Context of GHG Reduction Efforts

This project is informed by the framing of the Paris Climate Agreement – which is broadly focused on the emissions reductions and changing practices required to limit warming to well below 2 C above pre-industrial levels, with a target of 1.5 C. While the current state of the U.S. commitment within that agreement is in flux, the initial U.S. Nationally Determined Contribution (or US NDC) was framed as the intention to "*achieve an economy-wide target of reducing its greenhouse gas emissions by 26%-28% below its 2005 level in 2025 and to make best efforts to reduce its emissions by 28%.".* This initial target was to be followed by "deep, economy-wide" transformations to achieve 80% reductions under 2005 emissions by 2050.

The Science Based Targets Initiative (SBTI) expands on this framework with a goal of "institutionalizing" the use of science-based targets (SBTs) for emissions reduction across countries and sectors. By standardizing the process, their goal is to help companies and organizations set practical but sufficiently ambitious targets. SBTs are helpful for setting overall goals, and the sectoral guidance is useful across sectors. Still, one limitation of this approach is that it applies uniform goals across all companies instead of addressing different companies and their unique circumstances. These include current investments in generating resources or geographic variability in the feasibility and availability of renewable resources (hydropower, wind, solar, etc.). The SBTI is the result of a collaboration between the Climate Disclosure Project (CDP), the United Nations Global Compact, the World Resources Institute (WRI) and the World Wide Fund for Nature (WWF). According to their protocol, a greenhouse gas reduction target is "science-based" if it would lead to the decarbonization necessary to meet the Paris Agreement's goals, namely, to limit warming to 1.5 C or well below 2°C compared to pre-industrial levels (SBTI 2015, SBTI 2019).

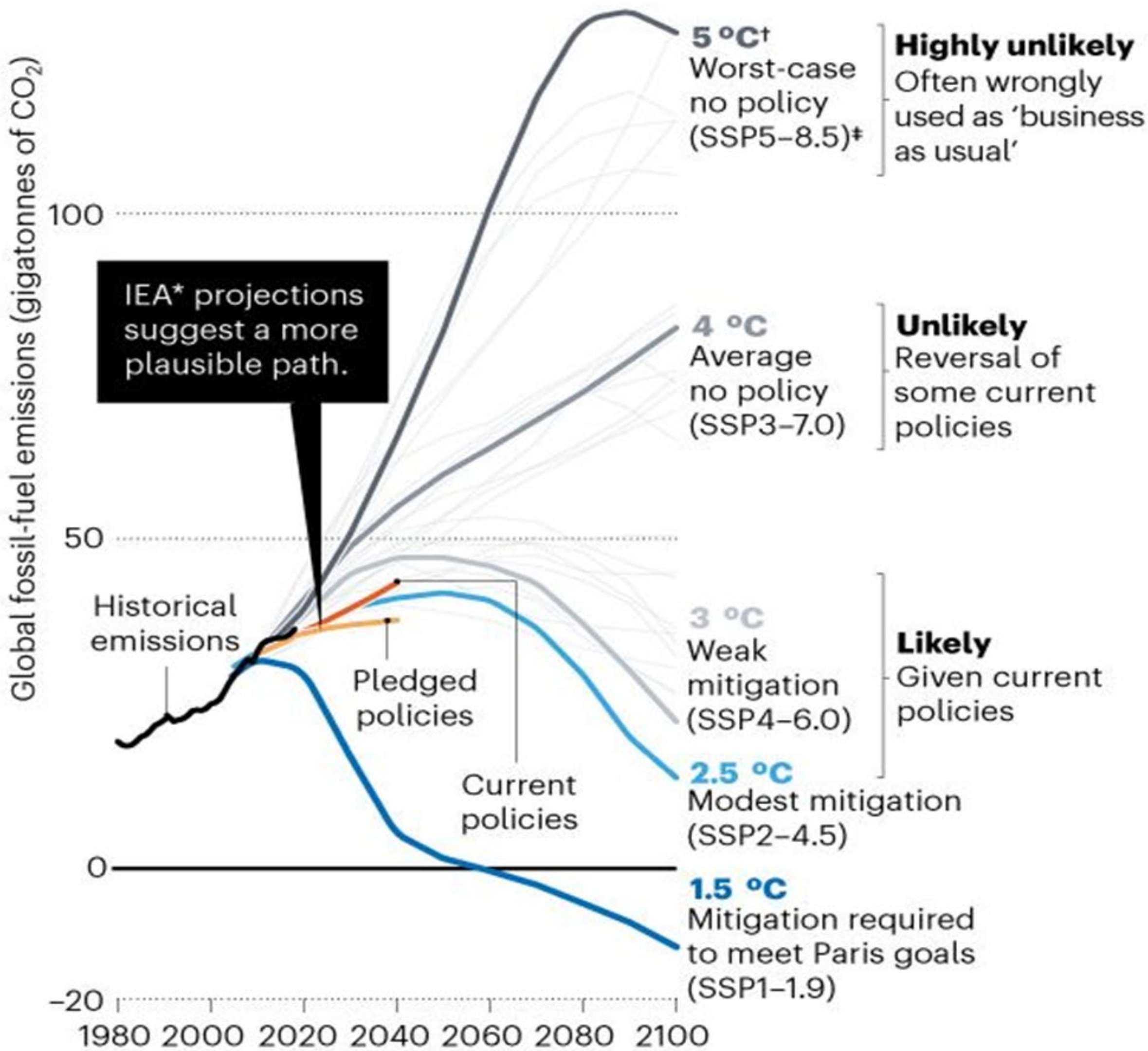


Figure 1 – Historical Emissions and Projected Emissions Trajectories

Reductions targets and commitments are showing promise in the effort to limit global warming. A recent report by the International Energy Agency (IEA) - summarized by Hausfather and Peters in Nature (2020) – highlights progress in limiting warming based on actual emissions reductions (current policies) as well as country and sector commitments to future reductions (pledged policies). Figure 1 shows that after the historical emissions leading up to the present in 2020, the pledged policies are consistent with 3 C warming, and they describe this as the current "likely" scenario. This is an improvement on the worst-case scenarios for warming (4C or 5C by 2100), which they describe as less likely than if these reductions had not been implemented or pledged. The IEA also highlights that reductions to a 2 C warming limit require more aggressive and ambitious action, while the 1.5 C target would require negative emissions (carbon sequestration, carbon capture, and storage) given the amount of historical warming that has already taken place (for more information on negative emissions see Minx et al., 2018; Fuss et al., 2018, and Nemet et al. 2018).

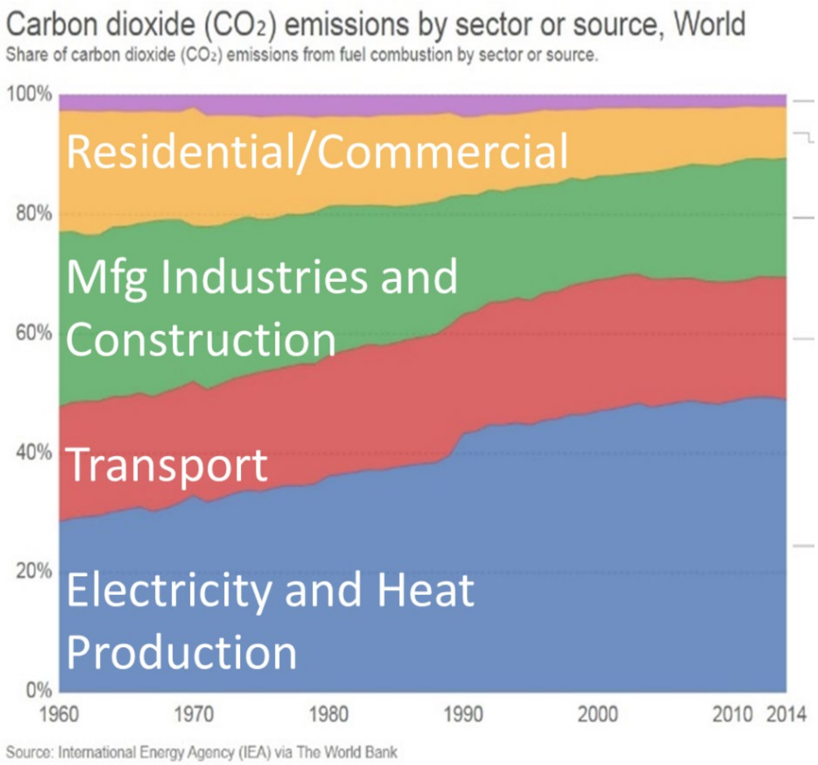


Figure 2 - Global CO2 by Sector

Global contributors to carbon dioxide emissions by sector or source as a percent of the global share over the last fifty years (Figure 2) demonstrate that the proportion of residential-commercial emissions has declined and the proportion of manufacturing-industries-construction and transportation has remained relatively constant. The proportion of emissions linked to electricity and heat production has increased over this same period. This sector also has considerable potential to make significant reductions that will make substantive impacts in terms of reducing global emissions. Their capacity to make these substantive reductions is enhanced by ongoing technological developments in renewable energy and other low-carbon sources of energy. Their need to make these changes is necessitated by an increasingly electrified future (electric vehicles, homes/appliances, etc.) extending the trend shown in Figure 2 (see Ritchie and Roser 2017 for details), and likely to lead to increased emissions if this power is not derived from low carbon sources.

The SBTI recognizes the differences across sectors. Their sectoral decarbonization approach (or SDA) is based on the recognition that different sectors make different contributions to global carbon emissions, and that the pathways to reductions consistent with limits to 1.5 C or well below 2 C warming will vary based on these differences between sectors. This approach advocates for a concerted effort across sectors to set sector-specific reductions targets that are consistent with limiting warming to 1.5 C or well below 2 C. Figure 3 shows the carbon budget for different sectors going out to 2050 and demonstrates the reductions necessary to achieve decarbonization consistent with limiting warming to 1.5 C or well below 2 C. Note the dramatic reduction in percent share of emissions for the power generation sector compared to other sectors. This reduction occurs despite the aforementioned increase in demand associated with demographic growth and increasing electrification (of transportation in particular).

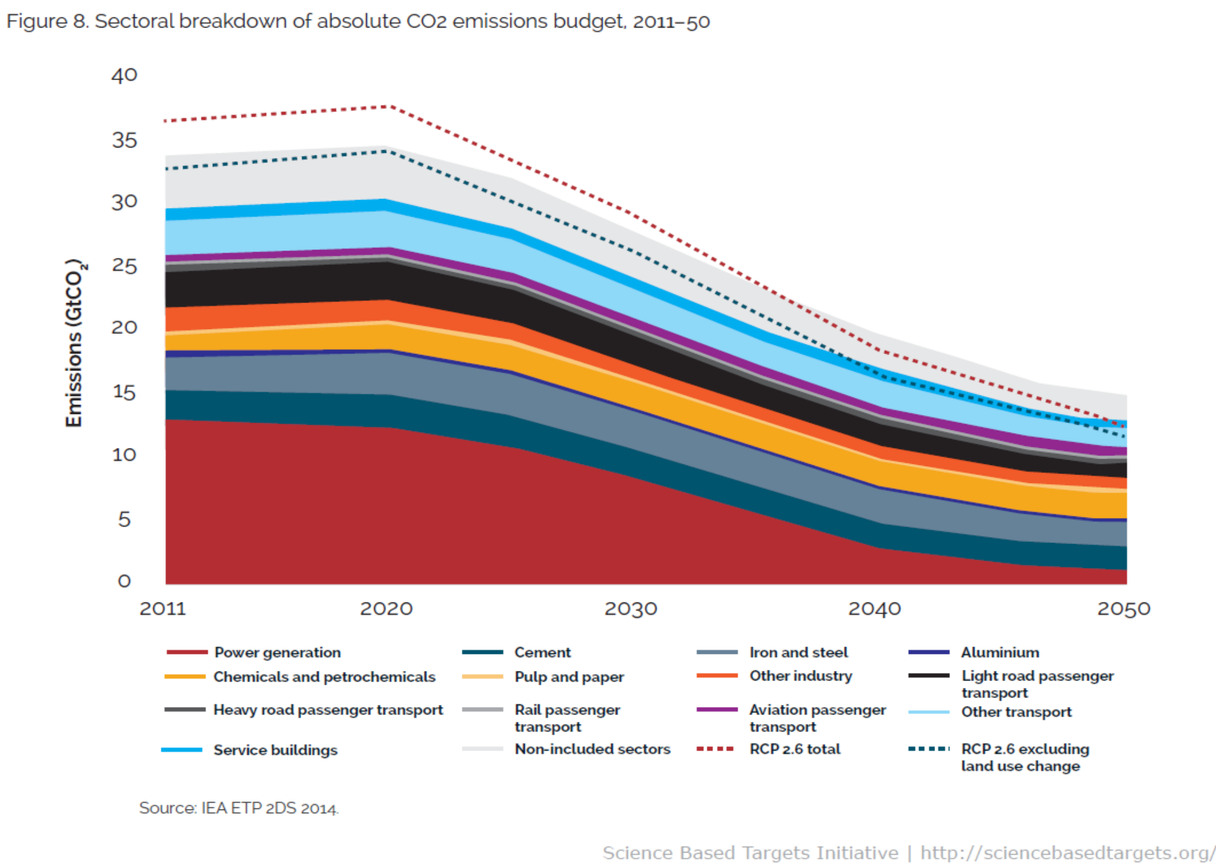


Figure 3 - Sectoral Carbon/Emissions Budgets, 2011-2050

The sectoral decarbonization approach (SDA) for U.S. electricity generation expands on the baseline of an 80% reduction of 2005 levels by 2050. For the electricity generation sector, the updated SBTI SDA documentation suggests an approximately 90% reduction of 2005 levels by 2050 is consistent with the well below 2 C warming targets (SBTI SDA 2015). The emissions reduction framework – typically expressed as a percent reduction from a baseline year (typically 2005) by a target year (often 2050) helps set the overall reductions targets. Still, it does not specify when or how these targeted reductions would occur, nor does it account for all of the uncertainties associated with these reductions and their associated limits to warming (see EPRI 2018).

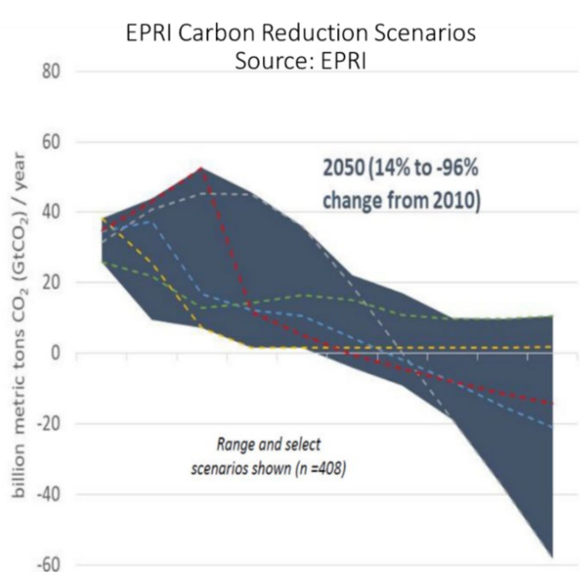


Figure 4 - Range for over 400 global emissions pathways consistent with limiting warming to 2C (EPRI Rose and Scott 2018).

The Electric Power Research Institute (EPRI) addressed emissions reductions scenarios in their 2018 report (Rose and Scott, 2018), and revisited the 1.5 C targets in their 2020 follow up report (Rose and Scott, 2020). In the 2018 report, they presented a cluster of hypothetical scenarios for emissions pathways (Figure 4), meant to demonstrate numerous possible pathways to temperature targets, based on timing, fuel source, load growth, etc. They highlighted the numerous pathways that could conceivably hit a temperature target and offered some guidance on what utility emissions reductions targets should emphasize. In the 2020 report, they provided a critique of global scenarios as benchmarks, given embedded assumptions and missing uncertainties, along with the variable contexts of different companies and the multiple pathways to hit warming targets identified in the 2018 report.

As part of our phase 1 report and review of utility-based emissions reduction strategies, (Knudson et al., 2019), we reviewed the 2018 EPRI report. We identified four key insights for creating emissions reductions targets, summarized as 1) a focus on the specific context of the company, 2) an emphasis on the scientific understanding of climate goals and the companies' relationship to those climate goals, 3) the variability of what would constitute a cost-effective target across companies, and 4) the need to develop "flexible" strategies that made sense given the companies' history and future. These insights are in line with the initial conclusions from our phase 1 report, which identifies that different utilities have different starting points for their emissions reduction based on historical emissions and baselines, current practices, and opportunities for their transition to a low-to-zero carbon future portfolio. They also have different futures and uncertainties regarding their pathway to hitting these temperature targets, each with risks and opportunities. These insights also reflect on an issue discussed below – namely the importance of timing, and how different emissions reductions pathways can hit similar percent reduction targets but vary considerably under other metrics.

Emissions Reductions Targets – Percent reduction of baseline year emissions with a future target

The typically used metric for emissions reductions is a percent decrease by a target year, using a baseline year, and occasionally with an interim target year and percent reduction. These emissions reductions are linked to different warming scenarios within the SBTI and SDA frameworks. Phase 1 of our report identified 2005 as the most common baseline year within the electrical utility sector, while the most common reduction by 2050 was 80-percent. This corresponds to initial sectoral guidance that identified an 80% reduction of 2005 emissions by 2050 was likely needed to reach the 'well below 2 C' warming limits. Revised estimates for the sectoral decarbonization approach have shifted, and the power generation sector is now estimated to need to reduce their 2050 emissions by approximately 91% compared to the 2005 baseline (to achieve the well below 2C target).

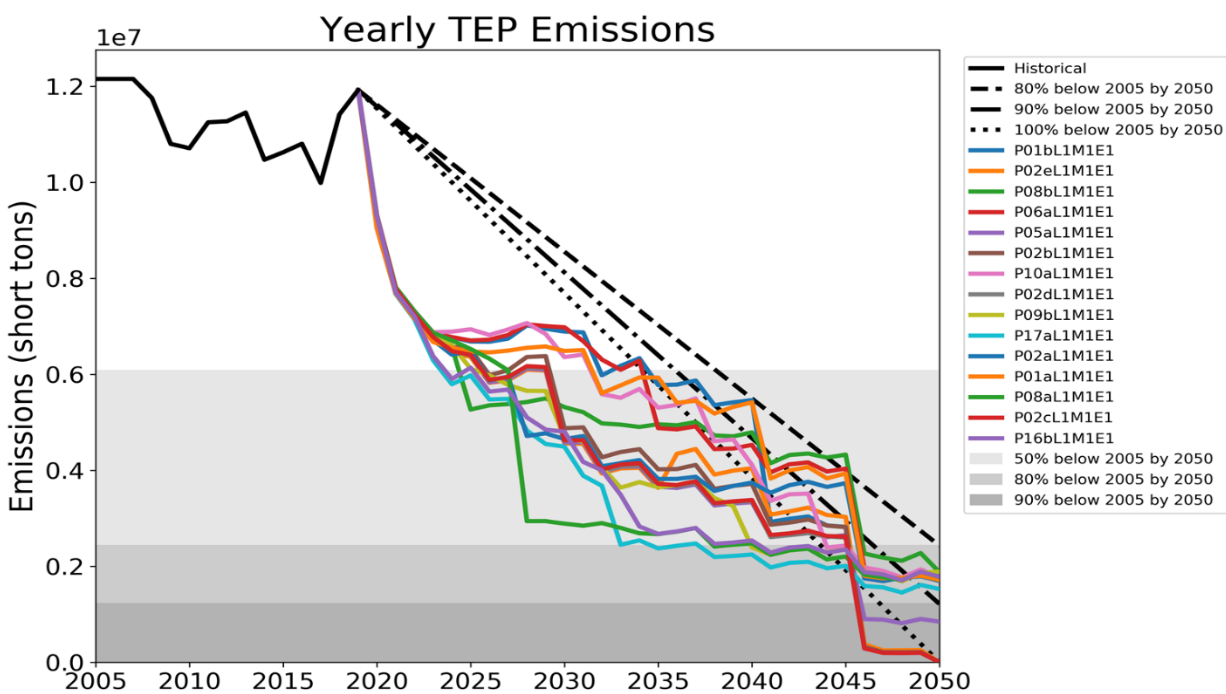


Figure 5 - TEP Emissions - Historical and Forecast (from IRP Portfolio Scenarios)

The portfolio scenarios from TEP can be analyzed using the percent-emissions-reduction framework. This framework demonstrates the extent to which various portfolio scenarios eventually settle on similar percent reduction targets, despite varied paths to these reduction percentages. The solid black line in Figure 5 is annual emissions by TEP from 2005-2018. The multi-colored lines are the annual emissions of various portfolios from 2020-2050. The dashed black line shows the linear reduction of annual emissions required to reach the 80-percent reduction of 2005 levels, given the current (as of 2018) level of annual emissions (and the other two dash-dot and dotted lines correspond to 90- and 100-percent reductions). The background shading shows the percent reduction targets frequently discussed in the emissions reduction literature (50%, 80%, and 90% in light, medium, and dark grey, respectively). This demonstrates the point highlighted in the EPRI report – namely that multiple portfolio scenarios can ultimately hit the same or very similar percent reduction targets, despite taking relatively different pathways to get there.

Carbon Budgets

We used a cumulative carbon budget framework that allows us to estimate the relationship between the global carbon budget and TEP's modeled portfolios. This framework sets TEP's carbon budgets for different global warming targets (1.5C, 2.0C, 2.5C) based on TEP's share of the U.S. electric utility sector, the electric utility sector's share of the U.S. national emissions, and the U.S. national emissions share of global emissions. We also calculated the expected amount of warming for each portfolio if all other countries, sectors, and utilities were to scale their cumulative carbon emissions proportionally to TEP's emissions. We analyzed the portfolios independent of their composition (% renewables, cost, coal retirement, etc.) and solely based on whether they were expected to hit the different warming targets and the expected warming for each portfolio.

We adapted the transient climate response to cumulative carbon emissions (TCRE) framework presented by Rogelj et al. (2019). This expands on work by Matthews et al. (2009) and the 5th National Climate Assessment Report (2018). Rogelj et al. (2019) describe the framework for analyzing the transient climate response to cumulative carbon emissions (TCRE) in detail. This framework establishes a limit on remaining CO2 emissions that would keep global warming under various targets (1.5 C, 2 C, etc.). Essentially, this sets a carbon emissions budget and allows for planning based on these discrete carbon emissions targets. The following equation describes the calculation of this carbon budget (B_{lim}).

$$B_{lim} = \frac{T_{lim} - T_{hist} - T_{nonCO2} - T_{ZEC}}{TCRE} - E_{sfb}$$

- **B_{lim}**: cumulative carbon emissions budget
- **T_{lim}**: global warming target level (e.g., 1.5C, 2C, etc.)
- **T_{hist}**: historical warming since pre-industrial period (currently ~1.0C)
- **T_{nonC02}**: warming from non-CO2 forcing (~0.0-0.2 C)
- **T_{zec}**: Zero Emissions commitment
- **TCRE**: transient climate response to cumulative carbon emissions
- **E_{sfb}**: additional earth system feedback

We can simplify this equation with T_{rem} – the remaining warming

$$T_{rem} = T_{lim} - T_{hist} - T_{nonCO2} - T_{ZEC}$$

The cumulative carbon emissions budget limit (B_{lim}) is the remaining carbon budget allowed under different warming targets based on the TCRE.

$$B_{lim} = \frac{T_{rem}}{TCRE} - E_{sfb}$$

In practice, this sets a starting point for the carbon emissions budget based on historical warming since the pre-industrial period (approximately 1.0 C). This also sets a target for remaining carbon emissions (the remaining carbon budget) given the specified warming target.

An emissions budget for TEP (BTEP) can be constructed from the global emissions budget, the national and sectoral share of cumulative CO2 emissions for the different warming targets, and TEP's fraction of the national sectoral share. The TEP emissions budget is described in the following equation:

$$B_{TEP} = B_{lim} F_{US} F_{USElec} F_{TEP}$$

- **B_{lim}**: Global carbon budget based on the specified warming target
- **F_{US}**: U.S. fraction of global emissions
- **F_{USElec}**: the U.S. Electricity Sector's fraction of U.S. Emissions
- **F_{TEP}**: TEP's fraction of the U.S. Utility Sector

F_{US} is estimated at 8.5%. This is the average of the allocated U.S. fraction of global emissions (2020-2050) under the staged scenario for 2 C of warming (Climate Action Tracker 2020).

F_{USElec} is estimated at 25%. The baseline is historical emissions data from the EIA (2020)[1]. The 25% estimate is an approximation of the fraction of carbon emissions (2020-2050) consistent with a well below 2 C target (SBTI 2015, IEA 2014).

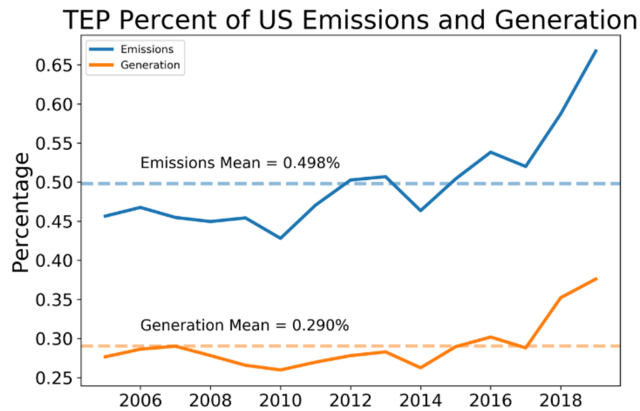


Figure 6 - TEP Percent of US Emissions and Generation

F_{TEP} is estimated two ways: 1) based on TEP's share of utility sector emissions over the past ten years (0.498%), and 2) based on TEP's share of utility sector generation over the past ten years (0.290%). Using the emissions share results in a larger carbon budget than the generation share, but both are reasonable estimates of TEP's percentage of the U.S. utility fraction.

Key Takeaway: The carbon budget calculation sets a quantitative limit on carbon emissions based on TEP's contribution to established warming targets. It scales TEP's cumulative emissions by its fraction of the U.S. utility sector, the U.S. utility sector's fraction of the U.S. total emissions, and the U.S. share of global emissions. In practice, this asks the question: "how much global warming would occur if TEP emitted this much carbon through 2050 – given its share of the U.S. utility sector, the U.S. utility sector share of total U.S. emissions, and the U.S. share of global emissions – and all other utilities, sectors, and countries followed their similarly prescribed cumulative carbon budgets?"

It is important to note that our approach only quantifies uncertainty in the TCRE calculation, as this was the only term in the equation with a robust and quantifiable estimate for uncertainty. This approach estimates the cumulative fraction for F_{US} and F_{USElec} as a single term (via methods described above), but does not account for uncertainty in these estimates. This is an area where these calculations can be improved as these terms are better defined and understood. This is particularly true for F_{USElec}, as TEP and other utilities will likely be confronted with numerous factors that may shift these fractions, including emergent or maturing technologies, shifts in energy markets, and the role of federal policies.

[1] The EIA reference case in their Annual Energy Outlook reflects a relatively flat share of emissions for the U.S. Electrical Utility Sector (EIA 2020). This reference case reflects an approximation of recent practices, and they update these trajectories each year. Recent literature suggests more aggressive 2050 decarbonization targets are required for this sector to remain consistent with the well below 2 C warming target (see IEA 2020).

Cumulative Emissions: The dashed black line in Figure 7 shows the cumulative emissions that would result if TEP enacted a linear 80%, 90%, and 100% reduction of 2005 emissions by 2050 (these are the same dashed, dash-dotted, and dotted black line as shown in Fig. 5, above). The solid black horizontal line is the 2.0 C budget best estimate based on the TCRE calculation above. The grey bands characterize the uncertainty of this calculation based only on uncertainty in TCRE.

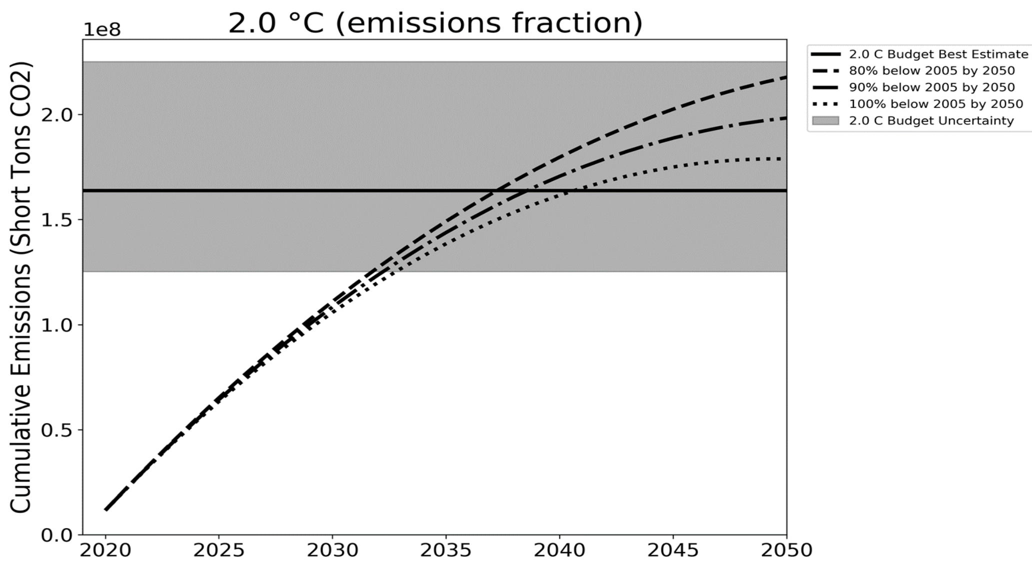


Figure 7 - Cumulative Emissions - 80% reduction of 2005 Emissions by 2050

Figure 8 includes the same data as Figure 7 but adds cumulative emissions for the TEP IRP portfolios. This demonstrates the range of cumulative carbon emissions associated with each portfolio, and where they fall in comparison to the cumulative emissions of the 80%, 90%, and 100% linear reduction targets(2020-2050), as well as the 2.0 C budget best estimate and uncertainty.

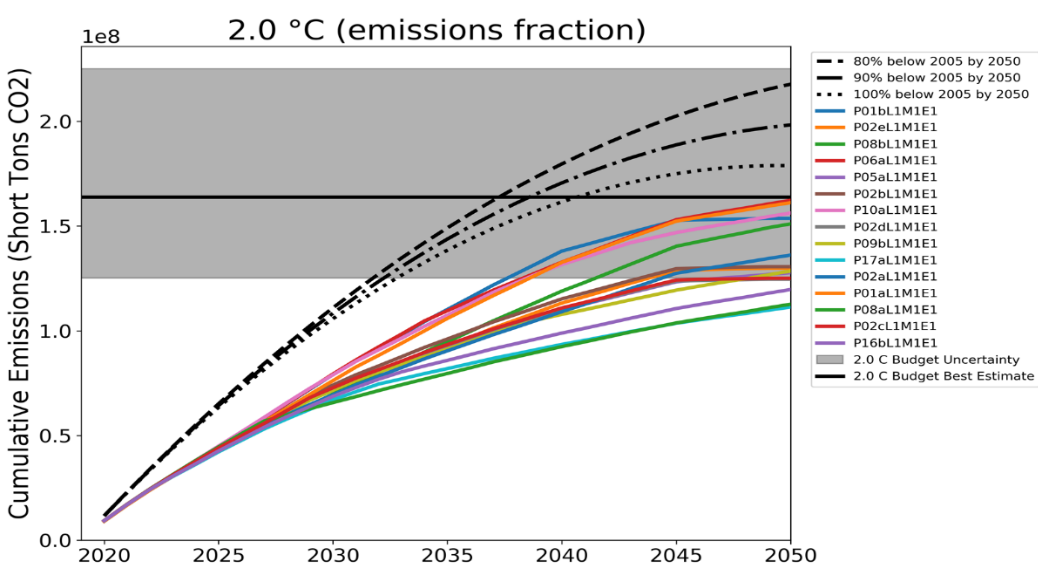


Figure 8 - Cumulative Emissions - 80% reduction by 2050 & TEP IRP Portfolios

Figure 9 is the same data as Figure. 8 but adds the 1.5 C and 2.5 C budget best estimates and uncertainty bands. This figure is based on the emissions-based estimate of TEP's fraction of the U.S. Utility Sector (0.498%), which results in a larger carbon budget for TEP (to hit the various warming targets).

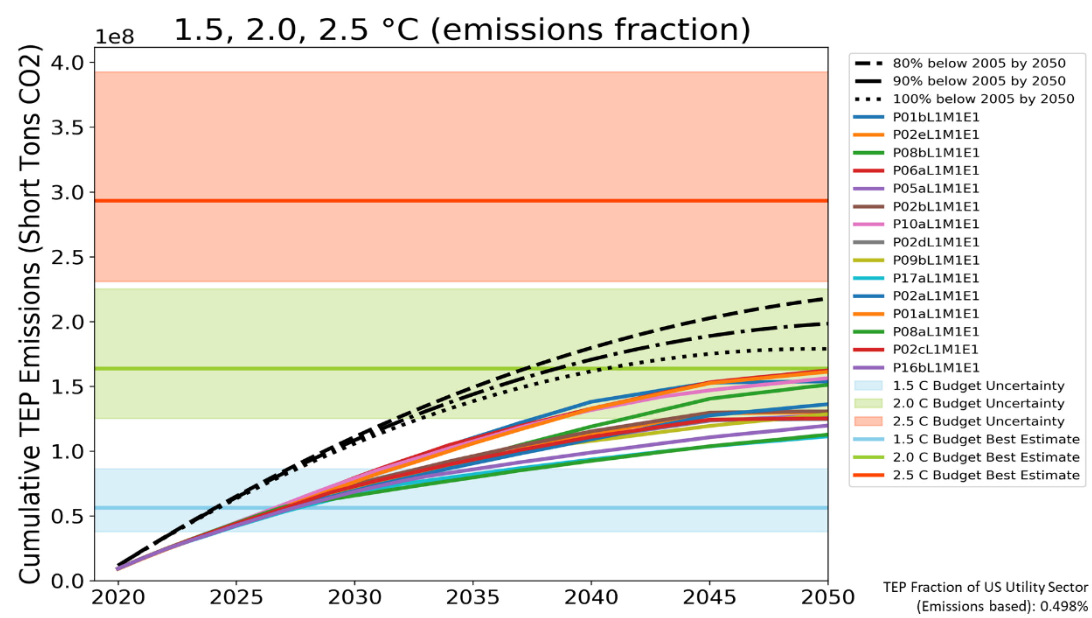


Figure 9 - Cumulative Emissions - 1.5, 2.0, 2.5 C Warming Targets (Emissions Based Calculation)

Figure 10 uses the same cumulative emissions data as Figure 9, showing the 1.5, 2.0 and 2.5 C budget best estimates and uncertainty bands. This figure is based on the generation-based estimate of TEP's fraction of the U.S. utility sector (0.290%), which results in a lower carbon budget compared to the estimation in Figure 9. *Note: the cumulative emissions totals are identical for the portfolios in Figures. 9-10, only the warming targets best estimate and bands have moved.*

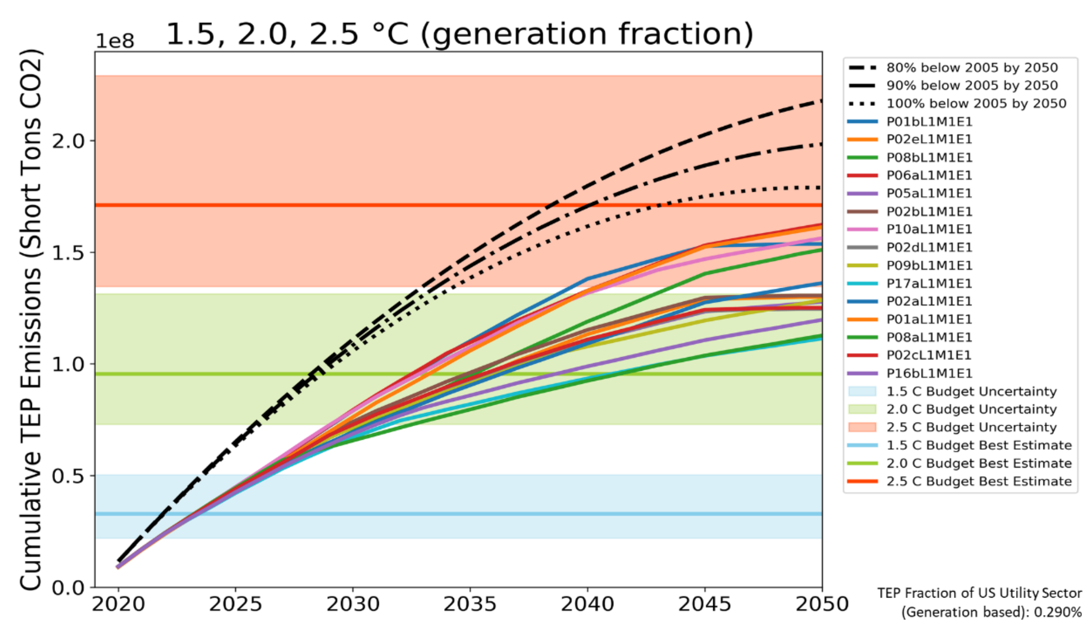


Figure 10 - Cumulative Emissions - 1.5, 2.0, 2.5 C Warming Targets (Generation Based Calculation)

Figure 11 estimates the global warming through 2050 for the portfolio scenarios in Figure 9 using an emissions-based estimate of TEP's fraction of utility emissions (top) and the portfolio scenarios in Figure 10 based on the generation-based estimate of TEP's fraction of utility emissions (bottom). Note: The portfolios in Figures 9-11 are the same portfolios, and the two methods for estimating TEP's fraction do not change the relationship between portfolios (i.e., the order of the portfolios listed, from lowest warming estimate to highest is the same, only the range of values changes)

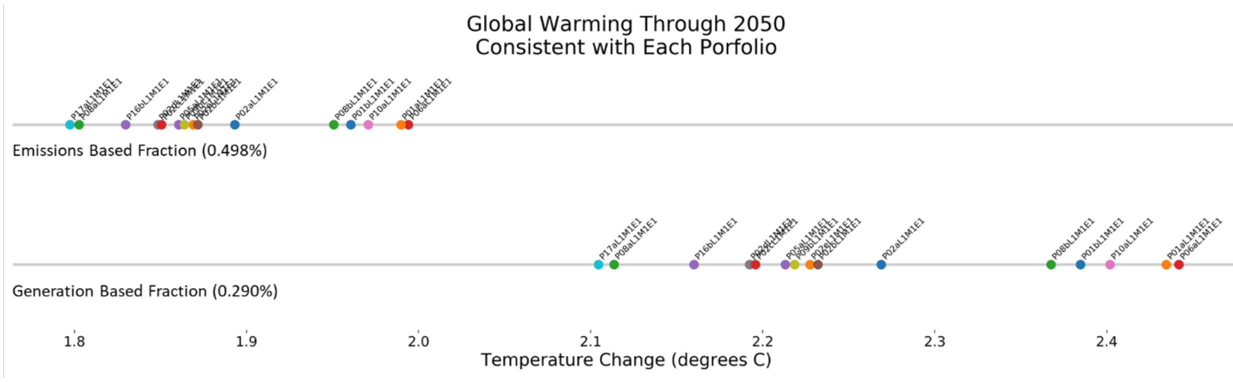


Figure 11 - Global Warming Through 2050 Consistent with Each Portfolio - Emissions (top) & Generation (bottom) Based Estimates

GitHub repository and transparent, replicable framework

We used a transparent modeling process – all the assumptions, code, documentation, and results are available on our public GitHub repository.

https://github.com/CLIMAS-UA/tepcarbon/

The code is open source and fully transparent. Anyone can replicate, test, or improve our analysis, or update it based on new information or data.

Key Report Takeaways

Cumulative Emissions and Carbon Budget Analysis

Cumulative emissions offer a robust and quantitative method to assess the warming impact of these portfolio scenarios. They assess both the timing and intensity of emissions reductions and highlight the additional emissions reductions that result when reductions move more quickly than a straight linear reduction. This emphasizes that the way these targets are achieved may be just as important as the targets themselves. The cumulative emissions framework also emphasizes that utilities have flexibility in how they meet the budget and does not prescribe anything about technologies or interim goals. This flexibility also takes into account the lack of certainty associated with future U.S. policies, the availability and feasibility of new or updated low carbon or renewable resources, and the market conditions that will drive many of these adaptations and innovations.

All of the portfolios presented demonstrate a lower amount of estimated global warming than the linear 80%, 90%, and 100% reduction of 2005 emissions by 2050. Based on the cumulative emissions approach and the assumptions embedded therein, the estimated warming for many of the presented portfolios is consistent with a well below 2 C target using the estimation based on TEP's emissions based fraction of the U.S. utility sector, while none of the generation based estimates of TEP's fraction fall in the well below 2 C range. It is again important to note; these estimations only include modeled uncertainty for the TCRE calculation and do not include modeled uncertainty for the F_{US} or F_{USElec} terms of the equation. As such, they are an as-current best estimate using available data and information for these estimations of warming. These estimates are useful guides for ranges of estimated warming and decision support regarding future climate impacts. Still, they are not a definitive forecast for the warming associated with these portfolios. There is room to improve how we define these terms and to incorporate modeled uncertainty for these terms in future analyses, both of which will improve our understanding of a) the warming associated with the portfolios, and b) the uncertainty associated with these estimations.

A note on emissions vs. generation based estimates of carbon budgets: The generation method allocates a carbon budget to utilities regardless of their actual emissions, so utilities with low-emissions fleets will have excess budget and utilities with high-emissions fleet may struggle to meet the budget. We speculate that the emissions method may be more appropriate when each utility sets its own goals, while the generation method may be more appropriate under a coordinated system such as cap and trade. We present both estimations, as they serve as a useful range of estimations of global warming through 2050 consistent with each portfolio.

Based on the cumulative emissions approach and the assumptions embedded therein, none of the presented portfolios are consistent with a limit to 1.5 C warming, and this is subject to the same caveats about uncertainty described above. With the warming observed since the pre-industrial period (calculated here at approximately 1.0 C), this is not unexpected given there is only 0.5 C warming remaining for the 1.5 C target. This is consistent with the literature on warming targets and emissions, which suggest that negative emissions (e.g. carbon sequestration, carbon capture and storage) are a necessary element of hitting the 1.5 C warming target (IEA 2020). The cumulative emissions associated with 80-,90-, and 100-percent linear reductions of 2005 levels by 2050 help validate the results of the cumulative emissions calculation. We would expect that the cumulative emissions associated with an 80% reduction would fall in the 2-3 C warming range, while the 90% linear reduction is associated with a 2C to well-below-2C warming limit.

Percent Reduction vs. Cumulative Carbon Emissions and Budgets

Our cumulative emissions and carbon budget approach addresses both the quantity and timing of emissions reductions and sets a budget for carbon emissions for TEP. This identifies the amount of carbon emissions allowed to stay under the warming targets, and facilitates an assessment of these carbon budgets in terms of their temperature targets. Emissions reduction targets (e.g. 80% by 2005, etc.) that do not account for the timing of those reductions could lead to higher emissions and more warming despite hitting the target. A key finding from our analysis is a wide range of portfolios could reach a similar percent reduction in emissions based on the 2005 baseline (see Figure. 5, above). The cumulative emissions framework highlights the benefit of starting those reductions sooner. Essentially how you get to those percent reductions targets may be just as important as the targets themselves.

The cumulative carbon budget framework represents an empirical approach that estimates the expected warming for each of the portfolios, rather than relying on the estimated correspondence between a percent reduction target and these warming targets. The percent reduction targets are a useful point of comparison, especially across companies and sectors. By adding this cumulative carbon budget framework, this encourages an assessment of the discrete impacts of a given range of portfolios. This focuses expected warming under a range of scenarios, rather than relying solely on the percent reduction framework.

A note on portfolio composition vs. cumulative emissions. In terms of reducing contributions to warming, the absolute reduction of cumulative emissions is the most effective way to limit warming. The specific portfolio composition (percent clean energy, percent renewables, etc.) or the mechanisms that reduce cumulative emissions (timing of coal retirements, etc.) are less important than the absolute reduction in cumulative emissions. Portfolio characteristics are still useful for communications and setting tangible goals, but the cumulative emissions framework emphasizes that utilities have flexibility in how they meet the budget and does not prescribe anything about technologies or interim goals.

Electrification

Increased electrification of other sectors is a fundamental part of the various scenarios advanced by the IPCC and IEA, and others that are anticipated to limit warming to at most 2 C, and ideally well below 2 C (or even 1.5 C)[2]. This increased electrification will increase the load for electrical utilities. Under most decarbonization scenarios, power generation bears a much larger reduction in overall emissions compared to other sectors that may be harder to decarbonize (See Figure 3, above). It is important that companies identify strategies that anticipate this increased load, and to minimize the emissions associated with this increased load such as increased use of renewables or plans for coordinated charging. Otherwise, the expected load increases associated with electrification and demographic growth could lead to higher emissions inconsistent with a well below 2 C warming target.

Electrification also presents opportunities for carbon emissions reductions in the transportation sector, as light-, medium- and heavy-duty internal combustion engine vehicles (ICEVs) are replaced by battery electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs). This carbon emissions reduction may counteract increased carbon emissions for the load required to charge these vehicles. Coordinated charging and increased use of renewables could even lead to a net reduction in emissions despite the

[2] Numerous assumptions are embedded within these scenarios, and while most see increased electrification as a necessary step in reducing overall carbon emissions, the timing and speed of these transitions is difficult to predict

increased load (Jansen et al., 2010). This has potential positive impacts on local air quality (particularly NOx and Ozone) if local emissions from conventional vehicles are reduced as the vehicle mix includes more BEVs and PHEVs and fewer ICEVs (see Holland et al. 2016). Recent literature addresses carbon balance, increased load associated with electrification, and the counterbalancing effect of reduced carbon emissions (Jiusto et al., 2006; Graff et al., 2014). There is considerable potential for additional work in this arena: specifically, a precise accounting of net emissions associated with increased load for BEVs and PHEVs, the decreased emissions associated with reduced use of ICEVs, and the impact of this shift on local air quality (particularly in areas where Ozone attainment status is an ongoing concern).

Negative Emissions and the 1.5 C Warming Target

Given the historical warming to date of approximately 1.0 C, a warming target of 1.5 C is difficult to envision with emissions reductions alone. Most of the scenarios that achieve the 1.5 C limit to warming include aggressive decarbonization and call for changes as soon as possible. 1.5 C consistent scenarios also generally include negative emissions such as carbon sequestration (removal of emitted carbon from the atmosphere) and carbon capture and storage (capture and storage of point source carbon emissions) (see Hausfather and Peters, 2020). These technologies are not yet available to scale, but there is optimism that these technologies will become financially viable either as costs go down, or the social/economic cost of carbon emissions increases (or is included at all in company financial and risk management planning). For more information on negative emissions see Minx et al. (2018), Fuss et al. (2018), and Nemet et al. (2018).

Coordinated Emissions Reductions Efforts and Ambition of Warming Targets

The cumulative carbon budget calculation is based on an empirical calculation of TEP's fraction of the global emissions carbon budget (based on their cascading share of the U.S. utility sector emissions, the U.S. utility sector's share of U.S. national emissions, and the U.S. share of global emissions).

Figure 12 - Climate Action Tracker - Reductions Rating Tool

This corresponds with the "fair share range" described by the Climate Action Tracker (Figure 12), and maps onto the ranges described by Hausfather and Peters (2020) and shown Fig. 1 (above). Essentially this argues that if all parties (companies, sectors, nations) contributed the least stringent reductions within their "fair share" range, we can roughly expect warming between 2 C and 3 C. This is again consistent with the current outlook suggested by both current and pledged policies in Hausfather and Peters (2020). More stringent action within the fair share range is more likely to limit warming to below 2 C, while the most stringent action in the fair share range is consistent with the Paris Agreement targets.

This does not mean that only the most aggressive reductions are consistent with a well below 2 C world, but it does mean that earlier and more aggressive action is more likely to lead to a well below 2 C world, especially if these actions are implemented across sectors.

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APPENDIX D

SUMMARY OF NPV REVENUE REQUIREMENT BY PORTFOLIO

Years 2021 to 2035 - Base Market

Non Fuel Revenue Requirements, $000	P01aL1M1E1	P01bL1M1E1	P02aL1M1E1	P02bL1M1E1	P02cL1M1E1	P02dL1M1E1	P02eL1M1E1	P05aL1M1E1	P06aL1M1E1	P08aL1M1E1	P08bL1M1E1	P09bL1M1E1	P10aL1M1E1	P16bL1M1E1	P17aL1M1E1
Existing T&D Resources	$3,934,867	$3,934,867	$3,934,867	$3,934,867	$3,934,867	$3,934,867	$3,934,867	$3,934,867	$3,934,867	$3,934,867	$3,934,867	$3,934,867	$3,934,867	$3,934,867	$3,934,867
Existing Generation Resources	$3,824,672	$3,868,572	$3,665,765	$3,761,253	$3,761,253	$3,761,253	$3,761,253	$3,709,665	$3,835,414	$3,505,742	$3,665,765	$3,616,457	$3,749,675	$3,586,276	$3,558,457
New Thermal Resources	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Storage Resources	$155,783	$205,038	$334,181	$347,240	$332,948	$299,585	$332,948	$332,948	$195,504	$786,671	$529,402	$323,804	$225,809	$601,476	$618,262
New Renewable Resources	$805,485	$847,690	$1,336,400	$1,260,871	$1,148,614	$1,148,614	$1,148,614	$1,175,266	$719,342	$1,478,035	$883,493	$1,149,933	$580,514	$1,146,455	$1,146,455
Existing Transmission Expenses	$376,562	$376,562	$376,562	$376,562	$376,562	$376,562	$376,562	$376,562	$376,562	$376,562	$376,562	$376,562	$376,562	$376,562	$376,562
Total Non-Fuel Revenue Requirements	$9,097,368	$9,232,728	$9,647,775	$9,680,793	$9,554,244	$9,520,881	$9,554,244	$9,529,308	$9,061,689	$10,081,877	$9,390,088	$9,401,622	$8,867,427	$9,645,636	$9,634,603

Fuel & Purchased Power, $000	P01aL1M1E1	P01bL1M1E1	P02aL1M1E1	P02bL1M1E1	P02cL1M1E1	P02dL1M1E1	P02eL1M1E1	P05aL1M1E1	P06aL1M1E1	P08aL1M1E1	P08bL1M1E1	P09bL1M1E1	P10aL1M1E1	P16bL1M1E1	P17aL1M1E1
Total Fuel and Market Purchases	$3,675,598	$3,658,224	$3,237,329	$3,331,007	$3,212,886	$3,208,290	$3,175,773	$3,190,993	$3,682,649	$3,177,881	$3,496,559	$3,381,493	$3,781,501	$3,343,185	$3,172,180

Energy Efficiency and Renewables, $000	P01aL1M1E1	P01bL1M1E1	P02aL1M1E1	P02bL1M1E1	P02cL1M1E1	P02dL1M1E1	P02eL1M1E1	P05aL1M1E1	P06aL1M1E1	P08aL1M1E1	P08bL1M1E1	P09bL1M1E1	P10aL1M1E1	P16bL1M1E1	P17aL1M1E1
Energy Efficiency	$98,537	$98,537	$98,537	$98,537	$260,409	$760,567	$278,779	$260,409	$98,537	$98,537	$98,537	$98,537	$98,537	$98,537	$260,409
Demand Response	$45,796	$45,796	$45,796	$45,796	$45,796	$45,796	$45,796	$45,796	$45,796	$45,796	$45,796	$45,796	$45,796	$45,796	$45,796
Total Energy Efficiency	$144,333	$144,333	$144,333	$144,333	$306,205	$806,363	$324,575	$306,205	$144,333	$144,333	$144,333	$144,333	$144,333	$144,333	$306,205

Total Renewable Purchased Power	$420,461	$420,566	$420,495	$420,569	$420,404	$420,485	$420,388	$420,400	$420,566	$420,561	$420,574	$421,018	$421,018	$421,018	$421,018

Total Energy Efficiency and Renewables	$564,794	$564,898	$564,828	$564,901	$726,609	$1,226,849	$744,963	$726,605	$564,898	$564,894	$564,907	$565,351	$565,351	$565,351	$727,223

Total System Revenue Requirements	**$13,337,760**	**$13,455,851**	**$13,449,931**	**$13,576,701**	**$13,493,738**	**$13,956,019**	**$13,474,980**	**$13,446,906**	**$13,309,236**	**$13,824,651**	**$13,451,554**	**$13,348,466**	**$13,214,278**	**$13,554,172**	**$13,534,006**

Years 2021 to 2035 - High Market

Non Fuel Revenue Requirements, $000	P01aL1M2E1	P01bL1M2E1	P02aL1M2E1	P02bL1M2E1	P02cL1M2E1	P02dL1M2E1	P02eL1M2E1	P05aL1M2E1	P06aL1M2E1	P08aL1M2E1	P08bL1M2E1	P09bL1M2E1	P10aL1M2E1	P16bL1M2E1	P17aL1M2E1
Existing T&D Resources	$3,934,867	$3,934,867	$3,934,867	$3,934,867	$3,934,867	$3,934,867	$3,934,867	$3,934,867	$3,934,867	$3,934,867	$3,934,867	$3,934,867	$3,934,867	$3,934,867	$3,934,867
Existing Generation Resources	$3,824,672	$3,868,572	$3,665,765	$3,761,253	$3,761,253	$3,761,253	$3,761,253	$3,709,665	$3,835,414	$3,505,742	$3,665,765	$3,616,457	$3,749,675	$3,586,276	$3,558,457
New Thermal Resources	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Storage Resources	$120,671	$205,038	$334,181	$347,240	$332,948	$299,585	$332,948	$332,948	$195,504	$786,671	$529,402	$323,804	$225,809	$601,476	$601,476
New Renewable Resources	$805,485	$847,690	$1,336,400	$1,260,871	$1,148,614	$1,148,614	$1,148,614	$1,175,266	$719,342	$1,478,035	$883,493	$1,149,933	$580,514	$1,146,455	$1,146,455
Existing Transmission Expenses	$376,562	$376,562	$376,562	$376,562	$376,562	$376,562	$376,562	$376,562	$376,562	$376,562	$376,562	$376,562	$376,562	$376,562	$376,562
Total Non-Fuel Revenue Requirements	$9,062,256	$9,232,728	$9,647,775	$9,680,793	$9,554,244	$9,520,881	$9,554,244	$9,529,308	$9,061,689	$10,081,877	$9,390,088	$9,401,622	$8,867,427	$9,645,636	$9,617,817

Fuel & Purchased Power, $000	P01aL1M2E1	P01bL1M2E1	P02aL1M2E1	P02bL1M2E1	P02cL1M2E1	P02dL1M2E1	P02eL1M2E1	P05aL1M2E1	P06aL1M2E1	P08aL1M2E1	P08bL1M2E1	P09bL1M2E1	P10aL1M2E1	P16bL1M2E1	P17aL1M2E1
Total Fuel and Market Purchases	$4,059,068	$4,025,612	$3,670,984	$3,634,416	$3,523,516	$3,573,435	$3,473,485	$3,489,754	$4,073,769	$3,472,080	$4,012,690	$3,850,439	$4,257,635	$3,667,766	$3,673,906

Energy Efficiency and Renewables, $000	P01aL1M2E1	P01bL1M2E1	P02aL1M2E1	P02bL1M2E1	P02cL1M2E1	P02dL1M2E1	P02eL1M2E1	P05aL1M2E1	P06aL1M2E1	P08aL1M2E1	P08bL1M2E1	P09bL1M2E1	P10aL1M2E1	P16bL1M2E1	P17aL1M2E1
Energy Efficiency	$98,537	$98,537	$98,537	$98,537	$260,409	$760,567	$278,779	$260,409	$98,537	$98,537	$98,537	$98,537	$98,537	$260,409	$260,409
Demand Response	$45,796	$45,796	$45,796	$45,796	$45,796	$45,796	$45,796	$45,796	$45,796	$45,796	$45,796	$45,796	$45,796	$45,796	$45,796
Total Energy Efficiency	$144,333	$144,333	$144,333	$144,333	$306,205	$806,363	$324,575	$306,205	$144,333	$144,333	$144,333	$144,333	$144,333	$306,205	$306,205

Total Renewable Purchased Power	$421,018	$421,018	$421,018	$421,018	$421,018	$421,018	$421,018	$421,018	$421,018	$420,984	$421,018	$421,018	$421,018	$421,018	$421,018

Total Energy Efficiency and Renewables	$565,351	$565,351	$565,351	$565,351	$727,223	$1,227,381	$745,593	$727,223	$565,351	$565,316	$565,351	$565,351	$565,351	$727,223	$727,223

Total System Revenue Requirements	**$13,686,675**	**$13,823,691**	**$13,884,109**	**$13,880,559**	**$13,804,982**	**$14,321,697**	**$13,773,321**	**$13,746,285**	**$13,700,808**	**$14,119,272**	**$13,968,129**	**$13,817,411**	**$13,690,413**	**$14,040,625**	**$14,018,946**

Years 2021 to 2035 - Low Market

Non Fuel Revenue Requirements, $000	P01aL1M3E1	P01bL1M3E1	P02aL1M3E1	P02bL1M3E1	P02cL1M3E1	P02dL1M3E1	P02eL1M3E1	P05aL1M3E1	P06aL1M3E1	P08aL1M3E1	P08bL1M3E1	P09bL1M3E1	P10aL1M3E1	P16bL1M3E1	P17aL1M3E1
Existing T&D Resources	$3,934,867	$3,934,867	$3,934,867	$3,934,867	$3,934,867	$3,934,867	$3,934,867	$3,934,867	$3,934,867	$3,934,867	$3,934,867	$3,934,867	$3,934,867	$3,934,867	$3,934,867
Existing Generation Resources	$3,824,672	$3,868,572	$3,665,765	$3,761,253	$3,761,253	$3,761,253	$3,761,253	$3,709,665	$3,835,414	$3,505,742	$3,665,765	$3,616,457	$3,749,675	$3,586,276	$3,558,457
New Thermal Resources	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Storage Resources	$120,671	$205,038	$334,181	$347,240	$332,948	$299,585	$332,948	$332,948	$195,504	$786,671	$529,402	$323,804	$225,809	$601,476	$601,476
New Renewable Resources	$805,485	$847,690	$1,336,400	$1,260,871	$1,148,614	$1,148,614	$1,148,614	$1,175,266	$719,342	$1,478,035	$883,493	$1,149,933	$580,514	$1,146,455	$1,146,455
Existing Transmission Expenses	$376,562	$376,562	$376,562	$376,562	$376,562	$376,562	$376,562	$376,562	$376,562	$376,562	$376,562	$376,562	$376,562	$376,562	$376,562
Total Non-Fuel Revenue Requirements	$9,062,256	$9,232,728	$9,647,775	$9,680,793	$9,554,244	$9,520,881	$9,554,244	$9,529,308	$9,061,689	$10,081,877	$9,390,088	$9,401,622	$8,867,427	$9,645,636	$9,617,817

Fuel & Purchased Power, $000	P01aL1M3E1	P01bL1M3E1	P02aL1M3E1	P02bL1M3E1	P02cL1M3E1	P02dL1M3E1	P02eL1M3E1	P05aL1M3E1	P06aL1M3E1	P08aL1M3E1	P08bL1M3E1	P09bL1M3E1	P10aL1M3E1	P16bL1M3E1	P17aL1M3E1
Total Fuel and Market Purchases	$3,412,166	$3,391,226	$3,019,727	$3,035,967	$2,972,472	$3,023,958	$2,944,308	$2,957,348	$3,393,461	$2,838,185	$3,151,846	$3,069,739	$3,449,478	$2,863,135	$2,854,952

Energy Efficiency and Renewables, $000	P01aL1M3E1	P01bL1M3E1	P02aL1M3E1	P02bL1M3E1	P02cL1M3E1	P02dL1M3E1	P02eL1M3E1	P05aL1M3E1	P06aL1M3E1	P08aL1M3E1	P08bL1M3E1	P09bL1M3E1	P10aL1M3E1	P16bL1M3E1	P17aL1M3E1
Energy Efficiency	$98,537	$98,537	$98,537	$98,537	$260,409	$760,567	$278,779	$260,409	$98,537	$98,537	$98,537	$98,537	$98,537	$260,409	$260,409
Demand Response	$45,796	$45,796	$45,796	$45,796	$45,796	$45,796	$45,796	$45,796	$45,796	$45,796	$45,796	$45,796	$45,796	$45,796	$45,796
Total Energy Efficiency	$144,333	$144,333	$144,333	$144,333	$306,205	$806,363	$324,575	$306,205	$144,333	$144,333	$144,333	$144,333	$144,333	$306,205	$306,205

Total Renewable Purchased Power	$420,459	$420,459	$420,483	$420,483	$420,408	$420,377	$420,419	$420,406	$420,454	$420,469	$420,540	$421,018	$421,018	$421,018	$421,018

Total Energy Efficiency and Renewables	$564,792	$564,792	$564,816	$564,816	$726,613	$1,226,740	$744,994	$726,611	$564,787	$564,802	$564,872	$565,351	$565,351	$727,223	$727,223

Total System Revenue Requirements	$13,039,214	$13,188,746	$13,232,317	$13,281,575	$13,253,329	$13,771,580	$13,243,546	$13,213,267	$13,019,937	$13,484,863	$13,106,807	$13,036,712	$12,882,256	$13,235,994	$13,199,992

APPENDIX E

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 (NPV) revenue requirements of a cross section of portfolios considered in this IRP. In this anlayis, 50 iterations were performed on each portfolio, in which retail demand, natural gas prices, and Palo Verde market prices were randomly varied while perserving a high degree of correlation between gas and market prices. The lower right chart 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.