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An Integrated Resource Plan for Tucson Electric Power Company, 2020-2050

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This Capstone Project

An Integrated Resource Plan for Tucson Electric Power Company, 2020-2050

by

Tim Sheehan, Danny Zepeda

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in

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Image Credit: TEP

AN INTEGRATED RESOURCE PLAN FOR TUCSON ELECTRIC POWER COMPANY

2020-2050

TIM SHEEHAN, DANNY ZEPEDA
UNIVERSITY OF SAN FRANCISCO
Energy Systems Management
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LIST OF ABBREVIATIONS

Abbreviation	Definition
ACC	Arizona Corporation Commission
ATB	Annual Technology Baseline
CapEx	Capital Expediture
CCGT	Combined Cycle Gas Turbine
CRF	Capital Recovery Factor
CT	Combustion Turbine
EIA	U.S. Energy Information Administration
EPA	Environmental Protection Agency
FC	Fuel Cell
GHG	Greenhouse Gases
GW	Gigawatts
GWh	Gigawatt-hours
IOU	Investor-Owned Utility
IPP	Independent Power Producer
IRA	Inflation Reduction Act
IRP	Integrated Resource Plan
ITC	Investment Tax Credit
kV	Kilovolts
KW	Kilowatts
KWh	Kilowatt-hours
MMT	Million Metric Tons
MW	Megawatts
MWh	Megawatt-hours
NG	Natural Gas
NREL	National Renewable Energy Laboratory
PPA	Power Purchase Agreement
PTC	Production Tax Credit
PV	Photovoltaic
REST	Renewable Energy Standards and Tariff
RPAC	Resource Planning Advisory Council
RPS	Renewable Portfolio Standard
SAM	System Advisor Model
SOFC	Solid Oxide Fuel Cell
T&D	Transmission and Distribution
TEP	Tucson Electric Power
TW	Terawatts
TWh	Terawatt-hours
WACC	Weighted Average Cost of Capital
WEIM	Western Energy Imbalance Market

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EXECUTIVE SUMMARY

Following massive growth to a global economy that was driven by fossil fuel energy in the 1900s, the twenty-first century has seen many nations begin to address the growing concern that human activities are the primary cause of climate change. With the problem broadly acknowledged, governments, public and private industry, as well as global citizens are increasing political will while directing financial resources to mitigate the problem. Over time, anthropogenic greenhouse gas emissions (GHG) have increased, trapping heat in the Earth's atmosphere, and causing a rise in surface temperatures. In the United States, the electric power industry is responsible for approximately 25% of all GHG emissions (EPA, 2021). As a result, current federal and state environmental regulatory policy focuses on mandates which force electric utilities to reduce emissions by decreasing reliance on fossil fuel power generation.

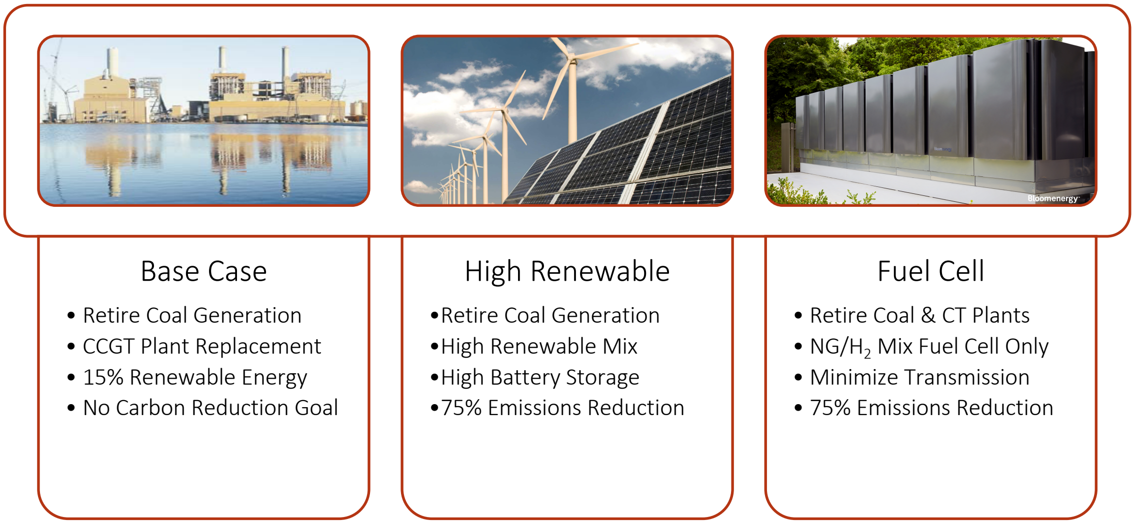
An Integrated Resource Plan (IRP) is the primary method by which electric utilities plan all aspects of future electricity supply and demand. Often governed by a state's public utilities commission, most utilities are obligated to provide IRPs every two to three years, presenting how the company will deliver reliable and affordable energy to ratepayers while meeting statutory requirements.

This report provides IRP scenarios through 2050 for Tucson Electric Power (TEP), an electric utility in southern Arizona which serves approximately 1,000,000 people. In 2020, the company's energy sales were just under 9,000 GWh while peak demand was approximately 2,400 MW. Compared to neighboring states such as California, Arizona's renewable energy portfolio standard (RPS) is conservative - 15% clean energy generation by 2025. However, TEP, a subsidiary of Fortis Inc., is compelled by corporate mandates to greatly reduce emissions while increasing renewable generation sources. In 2020, the company's most recent IRP outlined an aggressive strategy to reduce emissions through a plan to retire all coal-generation plants by 2032 while shifting resources to solar, wind and battery storage. In 2023, as TEP prepares a new IRP, the company continues with aggressive clean energy goals while navigating the fallout from supply chain problems caused by the COVID pandemic as well as highly volatile natural gas fuel prices due to the war in Ukraine.

TEP's recent challenges highlight the importance of access to a diverse portfolio of generation capacity. In this report, three future scenarios are considered for TEP. The first is a base case scenario, which achieves the state's 15% RPS, allows for coal-plant retirement, but relies on a high percentage of natural gas thermal generation for system operability. The second scenario analyzes a generation portfolio that deploys a high percentage of renewable generation paired with battery storage. Finally, the third scenario adds renewable generation but utilizes fuel cell technology as the primary dispatchable source for reliability.

As the cost of wind and solar generation decreases, it is no wonder that utilities look to these sources to meet clean energy goals. However, renewables' intermittency is a challenge that must be overcome to deliver on reliability. For this reason, dispatchable generation will continue to be an integral component of a utility's IRP, despite downsides such as harmful emissions from gas turbines or the political challenges of nuclear energy. One potential alternative to conventional thermal generation is a solid oxide fuel cell (SOFC) system. Traditionally deployed for single-site industrial or commercial applications and different types of transportation, this technology, while more expensive than gas turbines, features zero emissions when using hydrogen fuel and minimal transmission needs, among other benefits. The goal of this IRP and analysis is to determine if nascent fuel cell technology is a viable solution to help TEP deliver cost-effective, reduced-emissions electricity in the energy transition away from fossil fuels.

Reference Figure 0-1 below for a scenario summary of the TEP IRP.



Base Case

- Retire Coal Generation
- CCGT Plant Replacement
- 15% Renewable Energy
- No Carbon Reduction Goal

High Renewable

- Retire Coal Generation
- High Renewable Mix
- High Battery Storage
- 75% Emissions Reduction

Fuel Cell

- Retire Coal & CT Plants
- NG/H_2 Mix Fuel Cell Only
- Minimize Transmission
- 75% Emissions Reduction

FIGURE 0-1 SUMMARY OF THREE IRP SCENARIOS

Photo credit: TEP, Bloom Energy

Table 0-1 highlights the key metrics and results for each scenario's 2050 optimized model year. TEP's actual data from 2020 is also provided for comparison. A complete results table is displayed in section 3.1 Results Summary, Table 3-1.

Metric	TEP 2020	Base Case	High Renewable	Fuel Cell
Nameplate Capacity (MW)	3,172	4,166	9,512	8,554
Peak Gross Load (MW)	2,369	3,032	3,032	3,032
Load Served (GWh)	8,970	13,608	13,608	13,608
Renewable Energy %	8%	15%	80%	72%
CO_2 Emissions (MMT)	3.61	4.07	0.96	1.01
Carbon Intensity (g/kWh)	402	299	70	74
Curtailment (%)	0%	0%	23.9%	12%
Revenue Requirement (M$)	$1,530	$2,047	$2,341	$2,902
Average Rate ($/kWh)	$0.171	$0.150	$0.172	$0.213

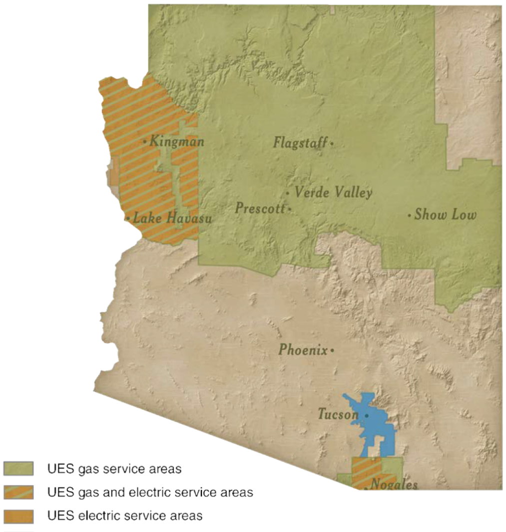
TABLE 0-1 2050 SCENARIO RESULTS SUMMARY

The IRP model determined that the lowest cost scenario in 2050 is the base case at a $0.150 per kWh average rate. This system features mostly new CCGT generation and is low-cost but emits more than four times the amount of carbon compared to the other two scenarios. The high renewable scenario results in 80% delivered renewable energy, the lowest emissions, and an average rate of $0.172/kWh. Finally, the fuel cell case adds 72% renewable energy which is paired with dispatchable fuel cell systems, delivering lowered emissions but the highest average rate of $0.213.

1 Utility Overview

1.1 Background

Tucson Electric Power’s foundational roots date back more than 130 years to the late 19th century when the city of Tucson, Arizona terminated a street light agreement with a local gas company, opting to award a new contract to Tucson Electric Light Company (Siner, 2015). Many iterations of the company evolved during the 20th century as the area’s population grew and energy needs changed. Currently, in 2023, Tucson Electric Power (TEP) operates as a subsidiary of Tucson-based UNS Energy, which is a subsidiary of parent company Fortis Inc., the largest investor-owned electric and gas utility located in Canada. Fortis acquired UNS Energy/TEP in 2013. The utility serves 442,000 customer accounts over an area of 1,155 square miles around Tucson, Arizona in Pima County, which has an estimated population of 1,000,000 people. Tucson Electric Power’s service area is highlighted in blue in Figure 1-1.



Source: TEP IRP 2020

Figure 1-1 Map of TEP service area (blue) alongside Unisource Energy Service Utilities (sister company)

1.2 TEP’s Challenges

Over the past three years, TEP, like many other utilities, has faced extraordinary challenges due to unprecedented circumstances triggered by the COVID pandemic as well as the Russian invasion of Ukraine. TEP’s 2020 IRP, which was formulated in 2019, could not have predicted the volatility and challenges of the ensuing years. Planned solar and storage projects were delayed or cancelled altogether due to supply chain issues caused by the pandemic. Multiple Independent Power Producers (IPPs) who had signed PPA contracts with TEP to deliver renewable energy were forced to exercise *force majeure* clauses due to undelivered system components. The supply chain problem deteriorated further in early 2022 when the U.S. Department of Commerce initiated an investigation into anti-dumping claims made by California solar panel assembler Auxin Solar against four Southeast Asian countries which used cheaper Chinese-produced parts while circumventing antidumping duties established in 2012 (Gheordhiu, 2022). In addition, the utility faced difficulties with gas suppliers and prices as a result of the macroeconomic effects of the war in Ukraine. TEP manages fuel prices in the short and medium term with a series of ‘gas forwards' futures contracts which are two years in length. As these contracts expired, the utility was faced with declining natural gas supplies while prices tripled. Collectively, the impact of all these factors resulted in a delay to TEP's overall plan to accelerate adoption of cleaner generation technologies and reduced emissions.

Renewable energy projects often require significant investment in added transmission. Unsurprisingly, transmission is another challenge faced by TEP as the utility shifts from mostly thermal generation dispatch to renewable energy. However, adding transmission isn't only inhibited by access to investment capital. TEP faces permitting and siting challenges due to community and environmental opposition. In addition, the area has many Indian Reservations and restricted lands which prohibit this type of infrastructure build-out. Further, TEP faces a related problem referred to as "load pockets," which are areas of the electric grid with limited ability to import electricity due to high demand concentration or insufficient transmission capabilities. According to Eric Wilson, Pima County Energy Program Manager, TEP's "load pocket" issue has a history of disproportionately impacting lower-income, underserved communities, which is an equity issue (Wilson, 2023).

At a Resource Planning Advisory Council (RPAC) meeting in January 2023, TEP acknowledged the main challenge of integrating large amounts of renewable energy on the grid: "Geographical diversity for solar and wind is very important…heavy solar with storage pairing wind <can be> used as a backup. Our service area has transmission constraints that need to be considered. Some <renewable> projects may be cheaper as far as pricing but there is a heavy transmission constraint" (Tucson Electric Power, 2023).

1.3 POLICY AND REGULATORY ENVIRONMENT

TEP is regulated by the Arizona Corporation Commission (ACC), which oversees the electric power industry in the state of Arizona. Similar to a public utilities commission found in other states, the ACC owns jurisdiction over the quality of service, utility rates, and utility finance in Arizona. Rates are established by the commission with the goal of allowing TEP to recover the cost of providing utility services to customers in addition to the ability to earn a reasonable rate of return. Beginning in the year 2000, the ACC initiated a requirement by utilities to file biennial 10-year transmission plans "to evaluate the adequacy and reliability of the Arizona transmission system" (ACC, 2018). The commission also requires each public utility to submit biennial Integrated Resource Plans (IRP) to ensure each load-serving entity is in compliance with ACC rules while meeting "the future electric needs of its customers in a way that considers environmental impacts along with the concerns of customers, regulators, stockholders and all other stakeholders" (Global Energy & Water Consulting, LLC and Evans Power Consulting, Inc., 2014)

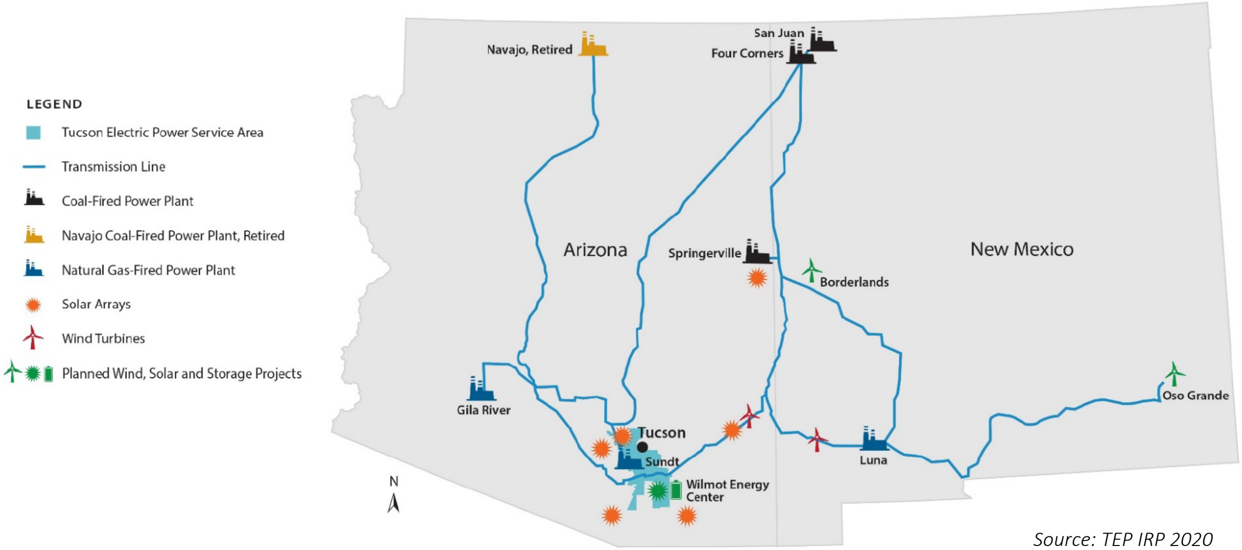
Across the world, the beginning of the 21st century brought an increased focus on global climate issues and solutions to address the mounting concern that anthropogenic sources were the cause of climate change. While the United States failed to join binding international climate treaties such as the Kyoto Protocol, at the state level, many governments and public utility commissions initiated more aggressive clean energy policies. Arizona was no exception. In 2006, the ACC codified rules under Arizona Administrative Code R14-2-1801 which required regulated utilities operating in the state to adopt a renewable resource generation commitment of 15% by the year 2025. Referred to as the Renewable Energy Standard and Tariff (REST), this policy stipulates that utilities encourage the increased use of clean technologies such as solar, wind, geothermal, and biomass to deliver a cleaner electricity system for future generations in Arizona. In addition, REST also requires that distributed generation account for 30% of the renewable energy requirement. TEP is required by the ACC to file an annual Renewable Energy Standard implementation plan for approval.

1.4 TEP IRP and Clean Energy Targets

The utility published its most recent Integrated Resource Plan (IRP) on June 26, 2020 and is scheduled to release a new IRP later in 2023. TEP currently owns access to more than 1 GW of renewable nameplate capacity and already meets Arizona's 15% renewable generation standard. The company's IRP published in 2020 looks beyond the state's renewable standard with ambitious goals to "address climate change without compromising our safe, reliable and affordable service" (Tucson Electric Power, 2020) The utility's plan calls for aggressive expansion of wind, solar, and storage resources in parallel with the eventual retirement of all coal-fired generation sources. TEP's overlying generation and emissions goals are guided by the utility's parent company, Fortis Inc., which has committed to a 2050 net-zero goal for GHG emissions.

1.5 TEP System

TEP's current generation system is comprised of coal and natural gas-fired plants, solar arrays, and wind turbines. The utility's transmission and distribution facilities are located across Arizona and neighboring New Mexico. The system is comprised of more than 2,200 miles of transmission lines and just under 8,000 miles of distribution lines. Reference figure 1-2 for a system resource map.



Source: TEP IRP 2020

Figure 1-2 TEP System Map, 2020

1.5.1 DEMAND

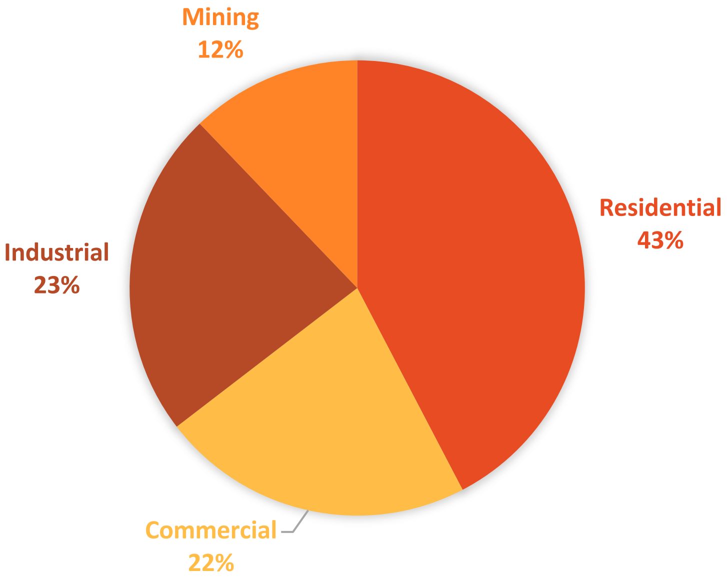


FIGURE 1-3 TEP RETAIL SALES BY CUSTOMER SEGMENT, 2020 IRP

The utility's 442,000 customers are segmented into four different rate class groups and retail sales: residential, commercial, industrial, and mining. In 2020, the TEP system peak demand was 2,369 MW while energy sales for the year totaled just under 9,000 GWh. Approximately 90% of TEP's retail customer accounts are residential and just under 10% are commercial accounts. There are also a fractional number of industrial accounts which account for a significant portion of retail sales. Annual energy consumption across these segments is more diversified as displayed in figure 1-3. In the 2020 IRP, TEP forecasts that customer growth will increase approximately 0.8% annually through 2035.

In the coming decades, TEP's load demand will be impacted by multiple factors including population growth rates, regional economics, and consumer usage trends. Recent population growth rates in Tucson lag well behind the statewide average – 0.5% vs 1.4%. The local economy, compared to the Phoenix area, is less dynamic and more reliant on employment with federal, state, and local governments (Fischer, 2023). Therefore, load demand increases driven by population growth are moderate when compared to the rest of the state.

1.5.1.1 Electric Vehicle Impact

In the 2020 IRP, TEP acknowledged the significant potential impact of EV growth on load forecasting while also considering local economics. Since Pima County is less economically affluent than other parts of the country and vehicle stock turn-over rates are longer, the utility projected a slower adoption of EVs compared to national averages. Notwithstanding this outlook, TEP has implemented programs to increase adoption of electric vehicles, which still may shift peak load demand and total energy consumption in the coming decades. In February 2023, the utility initiated a three-year Transportation Electrification Implementation Plan which, according to TEP, "…provides a roadmap for preparing our grid for extra energy loads, driving EV adoption and building an equitable charging infrastructure." (Tucson Electric Power, 2023) The plan builds on existing incentive programs, working to improve accessibility to electric transportation and increase the public's awareness about electric-vehicle technology and benefits. As part of the initiative, TEP will conduct an 8-month grid impact planning study to evaluate the impact that increased transportation electrification will have on forecasted load growth and the utility's entire electrical system.

1.5.2 GENERATION RESOURCES

As of 2020, the utility's IRP outlined a mix of generation resources including legacy coal and natural gas alongside growing solar, wind and storage assets. The IRP reported a thermal resource capacity of 2,890 MW and a renewable resource capacity of nearly 285MW_{AC} from wind and solar. Figure 1-4 below highlights TEP's 2020 capacity resources. While TEP owns and operates thermal assets, some of which are shared by other neighboring utilities, 80% of wind and solar generation is derived from PPA agreements with third party independent power producers (IPP). Since the 2020 IRP was published, TEP has been actively planning for the retirement of coal-fired generation while implementing an energy future dominated by renewable generation.

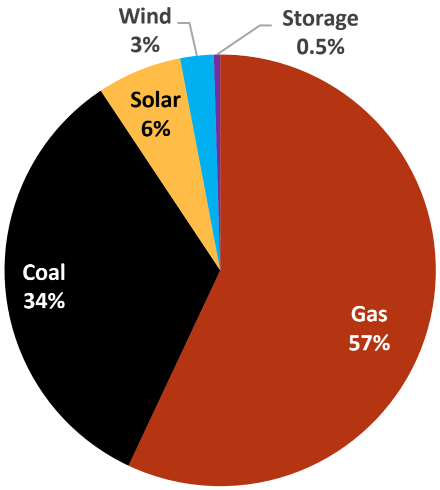


FIGURE 1-4 TEP CAPACITY RESOURCES, 2020 IRP

To date, the utility has retired more than 600MW of thermal coal-generation assets with plans to retire the rest, an additional 1000MW, between now and 2032. In parallel, in 2021, TEP entered into three wind-generation PPA agreements with IPPs in New Mexico, totaling 450MW of capacity. The Wilmot Energy Center (WEC), located south of the Tucson International Airport, went online in April 2021 with a 100MW solar-array covering 1,130 acres. Developed, owned, and operated by NextEra Energy Resources, the solar resources are paired with a 30MW battery energy storage system to shift the delivery of renewable energy later in the day (Tucson Electric Power, 2021). The utility's focused growth on renewable generation sources will continue in the coming decades. In February 2022, TEP announced a clean energy generation peak during a brief period when TEP's wind and solar resources generated 95% of coincidental energy demand – 634MW out of 662MW (Tucson Electric Power, 2022).

1.5.3 *TRANSMISSION*

TEP's existing transmission system reaches across Arizona and into New Mexico, connecting all types of generation resources. The utility owns approximately 473 miles of 46kV lines, 425 miles of 138kV lines and is part owner of 1,110 miles of 345kV lines and 657 miles of 500kV lines. The South Loop, Vail, and Tortolita substations are critical to the TEP system as they interconnect the service area with the Western Interconnection, which stretches from Western Canada to Baja, Mexico and east over the Rocky Mountains to the Great Plains (Tucson Electric Power, 2020).

1.5.4 *OTHER RESOURCES*

1.5.4.1 Western Energy Imbalance Market (WEIM)

In May 2022, TEP joined California's Western Energy Imbalance Market which enables the utility to buy and sell power in real-time at market prices across a large geographical area in the western part of the United States. Operated by California ISO since 2014, the exchange leverages diverse and flexible energy resources between its 19 participants to deliver the lowest-cost energy to participants. Susan Gray, president and CEO of TEP commented on the agreement, "We're proud to join the Western Energy Imbalance Market because it provides opportunities to achieve cost savings and lower carbon emissions for our customers. We're working toward a dramatic expansion of renewable resources, and participating in the WEIM provides another way to increase our use of wind and solar energy." (California ISO, 2022) According to energy consultancy firm, Energy and Environmental Economics ("E3"), TEP's estimated annual benefit of joining WEIM is $13.6M. (Tucson Electric Power, 2020)

1.6 RESOURCE NEEDS ASSESSMENT

From 2020 through 2035, TEP projects modest peak load growth of 0.8% in its service territory. Projecting this growth through 2050, the resource gap, including the required 15% reserve margin, reaches nearly 1800MW by 2050. Figure 1-5 shows the capacity and load resources needs. Nearly 75% of this deficiency is due to the impact of planned coal plant retirements, which will occur over the next ten years. The final planned retirement is the Springerville Generating Station #2, which will result in the loss of 406MW of dispatchable, thermal capacity in 2032. Annual energy sales in 2020 were less than 9,000GWh, but are projected to growth 50% over the next 30 years, reaching more than 13,600 GWh by 2050.

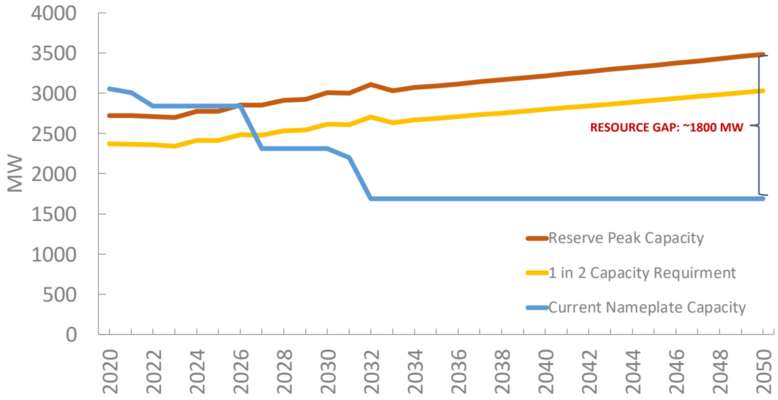


Figure 1-5 Capacity and Load Resource Assessment

2 IRP SCENARIO DESCRIPTIONS

2.1 OVERVIEW

For IOUs, the overall objective of an IRP is to determine an ideal, “preferred” portfolio of energy resources after detailed study and consideration of a multitude of factors which impact a utility’s requirement to deliver reliable, affordable electricity to ratepayers while earning a ‘fair, just, and reasonable return’ for shareholders. A balance must be struck between the interests of ratepayers and shareholders while meeting regulatory requirements as well as corporate objectives. In the 2020 TEP IRP, a preferred portfolio and numerous alternative scenarios were outlined alongside various economic and demographic sensitivities which may impact outcomes.

In this IRP study, three alternative scenarios are considered across 2030, 2040, and 2050: a base case, a high renewable case, and a fuel cell case. The analysis focuses on comparing different generation mixes which all meet the fundamental system objectives of reliability, operability, and compliance. Reliability is defined by the system’s ability to meet a 15% planning reserve margin above each annual peak load. Operability means that TEP’s system will have enough generation capacity available to deliver electricity in all 8,760 hours of every year. Each scenario must also adhere to TEP’s plan to retire all coal-generation resources by 2032 and meet the ACC’s minimum renewable energy standard of 15% (ACC, 2018). Unique to each scenario are constraints regarding CO_2 emissions as well as the deployment varying generation technology capacity. Each scenario model, adhering to objectives and constraints, aims to determine the least-cost option. Reference Figure 2-1 below for a summary of the three IRP scenarios considered in this analysis.

2.2 CASE DESCRIPTIONS

Base Case
- Retire Coal Generation
- CCGT Plant Replacement
- 15% Renewable Energy
- No Carbon Reduction Goal

High Renewable
- Retire Coal Generation
- High Renewable Mix
- High Battery Storage
- 75% Emissions Reduction

Fuel Cell
- Retire Coal & CT Plants
- NG/H_2 Mix Fuel Cell Only
- Minimize Transmission
- 75% Emissions Reduction

FIGURE 2-1 SUMMARY OF THREE IRP SCENARIOS

Photo credit: TEP, Bloom Energy

2.2.1 BASE CASE

The *Base Case* scenario for this IRP is a model which deploys a generation mix most similar to TEP's existing portfolio. However, generation resource capacity expansion is constrained by TEP's stated plan to retire all coal-fired generation plants by 2032 (Tucson Electric Power, 2020). While many utilities are currently considering extending the lifetime of some thermal resources due to volatile markets, this option is considered unrealistic given TEP's corporate commitment to reduce emissions. Therefore, the base case continues with the plan to retire 387 MW Springerville Generating Station #1 in 2027, followed by an additional retirement of 516 MW of coal plant capacity by 2032. Combined cycle gas turbine (CCGT) plants are deployed to replace coal plant capacity as well as most of the load growth through 2050. Since the TEP system already utilizes more than 700 MW of renewable capacity, only a modest amount renewable capacity expansion is needed by 2050 to maintain adherence to Arizona's 15% renewable energy generation standard.

2.2.2 ALTERNATIVE CASE 1: HIGH RENEWABLE (HR)

The *High Renewable* scenario models a system which deploys a high percentage of renewable capacity through out-of-state wind resources and in-state solar arrays while paired with battery storage. Coal plant retirement occurs, as scheduled, while the DeMoss Petrie CT plant, 75 MW, is kept operating for peaking and reserve purposes. The high percentage of renewable generation and battery storage is also balanced with added CCGT capacity to ensure TEP's 15% planning reserve margin is met in every yearly scenario model. Like the *Fuel Cell* case, the HR case is constrained by a 75% carbon emissions reduction when compared to the 2050 base case scenario.

2.2.3 ALTERNATIVE CASE 2: FUEL CELL (FC)

The *Fuel Cell* scenario model aims to answer the research question "*What is the potential of fuel cell technology as a solution to achieve cost-effective, reduced emissions in the energy transition?*" While fuel cell technology is not new, its application in the world of utility-scale energy generation is currently limited. However, as a thermal resource in a system with growing intermittent renewable capacity, fuel cell technology can add a diversified, dispatchable resource to bolster system reliability. In this scenario, coal and CT generation are completely retired. Fuel cells that allow for mixed gas operation are deployed as the primary source of dispatchable energy. A further sensitivity analysis is used to determine the optimal fuel mix between natural gas and hydrogen while considering the impacts of both cost and emissions. Reference figure 3-11 in the Results section below for the fuel cell sensitivity analysis. While the fuel cell is the featured comparison technology, this scenario greatly increases the renewable generation mix compared to the base case as the primary pathway to achieve the 75% carbon emissions reduction compared to the 2050 base case scenario.

3 RESULTS

3.1 RESULTS SUMMARY

Table 3-1 below summarizes the key metrics across all three scenarios for TEP in 2050.

TEP 2050	Base Case	High Renewable	Fuel Cell
System Capacity (MW)			
Nameplate	4166	9512	8554
Peak Gross Load	3032	3032	3032
CCGT & CT (Natural Gas)	3367	2463	0
Fuel Cell (Mix H_2 & 100% H_2)	0	0	2825
Photovoltaic	450	4050	2950
Wind	349	1749	1649
Storage	50	1250	1130
Energy (TWh)			
Load Served	13.6	13.6	13.6
Energy from Gas Generation	11.5	2.7	0
Energy from Fuel Cells	0	0	3.8
Energy from PV and Wind	2.1	14.6	11.7
Total Generation	13.6	17.3	15.5
Curtailment (%)	0%	23.9%	12%
System Costs (M$)			
Variable	309	73	237
Fixed O&M	116	165	191
CapEx	210	410	831
T&D	1,062	1,062	1,062
Interconnection Charge	0	281	230
Other Cost	350	350	350
Total System Cost	2,047	2,341	2,902
Average Rate ($/kWh)	$0.150	$0.172	$0.213
Change from 2020 Rate (%)	-12.2%	+0.6%	+24.6%
Emissions			
Carbon Emissions (MMT)	4.07	0.96	1.01
Carbon Intensity (g/kWh)	299	70	74
NOX Emissions (MT)	125	29	2
SO_2 Emissions (MT)	31	7	0

TABLE 3-1 DETAILED RESULTS

3.2 SYSTEM CAPACITY

In an IRP, existing system capacity and projected capacity in both type and size are a critical metric around which plans evolve. Decisions concerning generation capacity greatly impact many other areas of a utility's operations such as transmission and distribution planning, emissions targets, and total system costs. As utilities add large amounts of renewables to their systems, capacity planning increases in complexity due to the careful balancing needed to manage the intermittency of renewables and the requirement for an operable, reliable system in every hour of the year. Lee Alter, Sr. Resource Planner at TEP, comments on the planning challenge: "Power companies are big, complex organizations. We have facilities in different states which all serve Tucson. It's not just technology, it's also the regulatory environment…keeping everyone safe. Always on, 24/7, every hour of the year" (Alter, 2023).

Deploying a high percentage of renewable capacity also results in a large increase in nameplate capacity. Though it is important to understand that, due to intermittency, the energy generated from this added capacity is far less than what would be generated from the same dispatchable resource capacity. To account for this, ELCC, or 'Effective Load Carrying Capability', is applied to renewables by grid planners and utilities. The IRP applies a specific, hourly load shape to the renewable resource to provide a realistic estimate of energy generation in each hour. For TEP, on average, effective solar capacity is 27% and wind capacity is 33%. In measuring system capacity, battery storage is included in the overall calculation since and is utilized to spread renewable generation delivery across more hours of the day. Figure 3-1 compares the mix and overall nameplate capacity of the 2020 system to the three IRP scenarios in 2050.

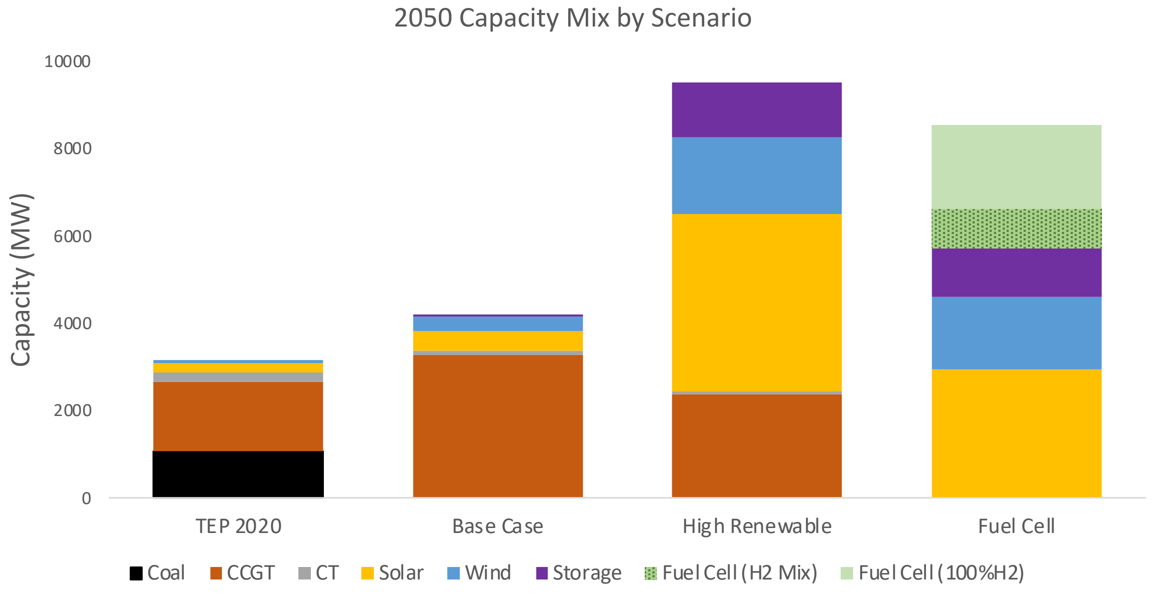


FIGURE 3-1 2050 CAPACITY MIX BY SCENARIO

In the base case scenario, capacity increases from 3,172 MW in 2020 to 4,166 MW by 2050. While some renewable generation and storage is added to maintain the 15% renewable energy generation constraint, the majority of added capacity by the year 2050 is through natural gas-fired CCGT power generation. Between 2025 and 2050, 1,800 MW of CCGT capacity is added to the mix. Just over 900 MW of this added capacity replaces retiring coal plants in 2027, 2031 and 2032. In this scenario, no additional wind capacity is needed while 350 MW of solar capacity is added in 2045 to compensate for aged-out solar resources. Because the percentage of solar and wind generation is low, the base case system has no curtailment to consider.

In the HR scenario, capacity increases to 9,512MW by 2050, triple the amount compared to 2020 and 250% higher than the base case scenario in the same year. Compared to the base case, renewable capacity expands significantly to 4050MW solar capacity and 1749MW wind capacity; this calculates to 61% of the high renewable scenario system's total nameplate capacity. Also included in the capacity numbers is an additional 1250MW of 6-8 hour duration battery storage to manage curtailment. However, even with over 1.2GW of battery storage, the high renewable scenario results in a curtailment level of 23.9%, which is not uncommon in systems with large amounts of renewable capacity. The reliability of the system is based on 2,200MW of added natural gas CCGT generation between 2025 and 2050. This thermal resource replaces all retired coal and most CT plants, delivers energy during hours with positive net load, and allows the system to meet the 15% planning reserve margin requirement. The newest existing CT plant, DeMoss Petrie (75MW), is kept on-line as a peaker-plant to ensure the planning reserve margin constraint is satisfied.

In the FC scenario, capacity more than doubles from the base case to 8,554 MW. By 2050, all coal and CT are retired. CCGT was also retired to help meet the emissions constraint, leaving fuel cells as the only dispatchable resource. Due to the fuel flexibility of fuel cells, capacity planning allows for different fuel mixes. Initially, in 2030, only natural gas fuel cells are deployed since the assumption is made that pipeline hydrogen will not be available in 2030. By 2040, approximately half of the fuel cells use a 50/50 volumetric blend of natural gas and hydrogen and the other half uses 100% hydrogen, totaling 1825MW of total fuel cell capacity. By 2050, another 1,000MW of 100% hydrogen fuel cells are added to the system, increasing fuel cells' total capacity share to 33%. The rest of the capacity is made up with a combination of solar and wind resources totaling nearly 4,600MW paired with 1,130MW of 8-hour duration battery storage. While renewable deployment is not as high compared to the HR scenario, it remains significant, resulting in a curtailment level of 12%.

3.3 ENERGY GENERATION

The energy generation for each scenario depends on the capacity resources available to the model which dispatches resources based on lowest cost. In all models, renewable resources are dispatched first when available. During the hours when renewable generation exceeds load, the excess energy is utilized to charge battery storage; otherwise, it is curtailed. Dispatchable generators including coal, CCGT, CT and fuel cells are dispatched depending on fuel costs. Figure 3-2 below compares TEP's 2020 generation mix with the 2050 generation mix across the three different scenarios.

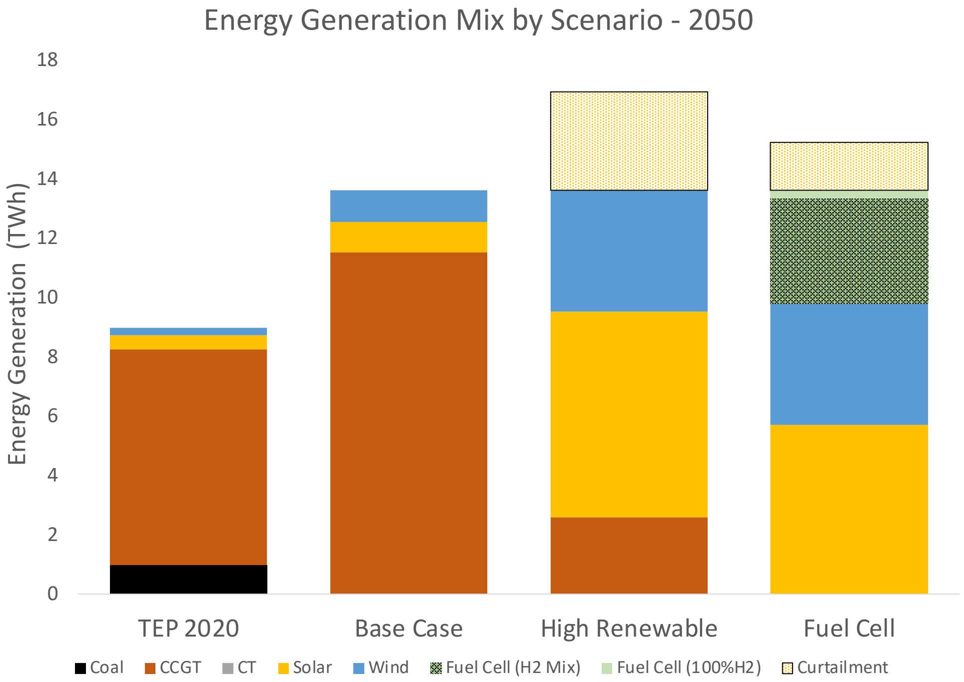


Figure 3-2 Energy Generation Mix by Scenario

In the Base Case scenario in 2050, with a forecasted load demand of 13.6 TWh, 85% of energy is delivered from gas-fired CCGT while 15% comes from renewable resources, equaling the Arizona state mandate set for 2025. Coal plant generation has been retired and a single remaining CT plant is kept on-line to meet the 15% planning reserve constraint. Due to the comparatively low percentage of wind and solar capacity in the base case scenario, all renewable energy is consumed by the load when available, leaving the system with 0% curtailment. The base case system produces the exact amount of energy demanded by the load. Figure 3-3 displays the month-hour average dispatch for the base case scenario in 2050.

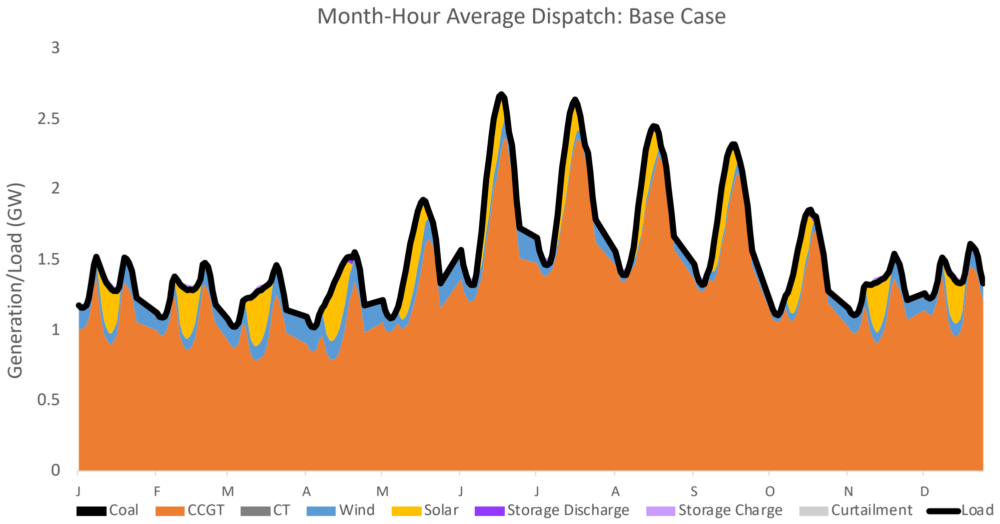


Figure 3-3 2050 Month-Hour Average Dispatch for Base Case

In the High Renewable scenario, total energy generation increases by 27% compared with the base case to 17.3 TWh in 2050. Renewable resources generate 14.6 TWh of energy, which is greater than the total load for the year; however, 24% must be curtailed due to over-production. In high renewable resource generation portfolios, this is a common occurrence given intermittency and the limitations of installed battery storage. Figure 3-4 shows high levels of curtailment during the early months of the year when overall load is low but renewables continue producing energy. Predictably, dispatch of CCGT is lower during these months, only utilized in the earliest hours of the day when renewables are least productive, and storage has been depleted. When Tucson experiences its warmest temperatures during peak load months of June through September, a greater amount of generation comes from CCGT beginning in the early evening and lasting through to late morning. During these peak days, as TEP customers face high temperatures which last well into the evening and necessitate heavy air-conditioner use, CCGT generation deploys in most hours of the day, contributing as much as one-third of the total generation. Over the entire year, thermal generation accounts for just under 20% of the required load.

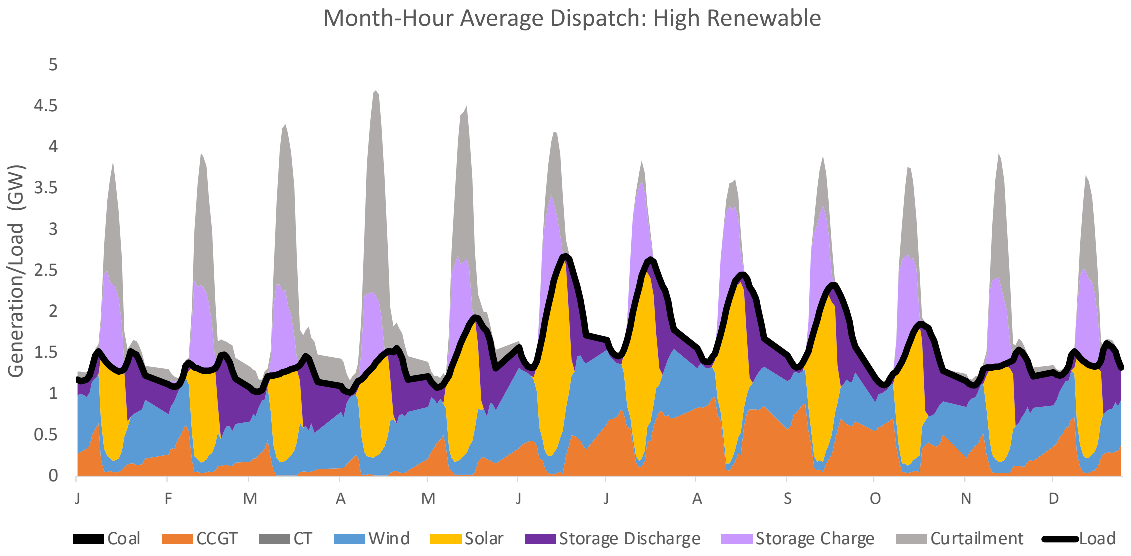


Figure 3-4 2050 Month-Hour Average Dispatch for High Renewable Case

For the Fuel Cell case, the total energy produced is approximately 10% less than the high renewable scenarios at 15.5 TWh. This scenario also utilizes a high amount of renewable energy resources, producing 11.7 TWh in 2050. Of this amount, 12% of this energy is curtailed due to over-production. Figure 3-5 displays the Month-Hour Average dispatch during 2050. The thermal generation used in the high renewable scenario is replaced with fuel cells as the lone dispatchable generator. The dispatch patterns are very similar to that of the CCGT dispatch in the HR case where fuel cells are used more heavily during the peak temperature months of June through September to account for larger loads. However, since the fuel cell scenario utilizes fewer renewable resources, curtailment is lower and the dispatchable fuel cells account for a higher percentage of total energy delivered over the year – 28%. There are two different fuel mixes deployed in this scenario. One uses a 50/50 volumetric blend of natural gas and hydrogen and the other uses pure hydrogen as fuel. The mixed gas fuel cell is dispatched more frequently due to lower fuel cost. In this case, pure hydrogen fuel cells are deployed for peaking purposes. However, 100% hydrogen fuel cells could be dispatched if carbon emission constraints are tightened in the future.

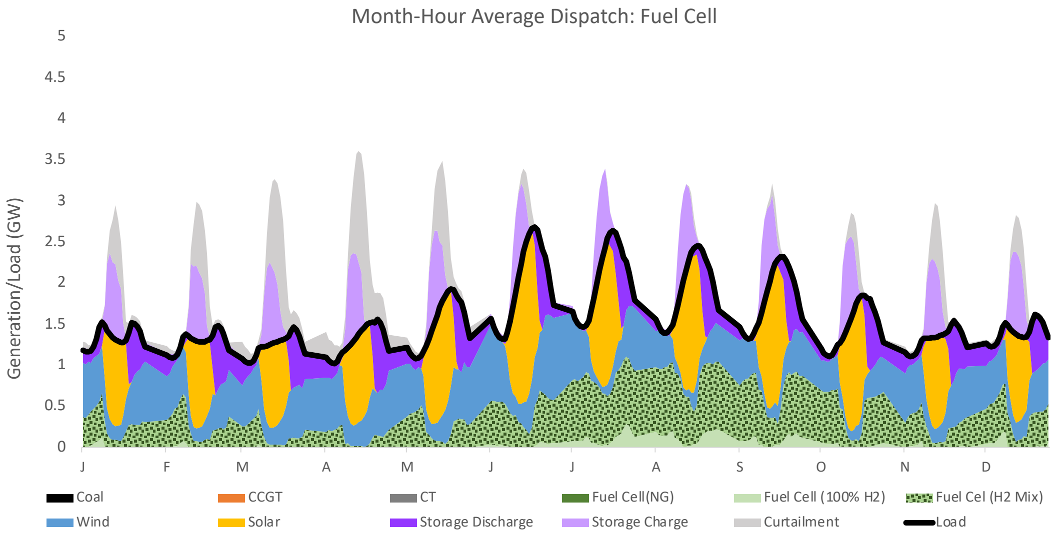


FIGURE 3-5 2050 MONTH-HOUR DISPATCH FOR FUEL CELL CASE

3.4 EMISSIONS

3.4.1 *CARBON*

Carbon emissions from electricity production is a major contributing source of increases in GHGs in the United States and around the world. For this IRP analysis, all three scenarios are constrained by carbon emissions limits. However, the base case proposes the least restrictive limit, matching the Arizona mandate of 15% renewable energy generation. The HR and FC cases target a 75% reduction in carbon emissions compared to the base case in 2050. Reference figure 3-6 below, which shows the carbon emissions of all three scenarios from 2020 through 2050. The base case, since it is comprised mostly of added CCGT generation to compensate for increased loads in future years, shows an overall increase in carbon emissions between 2020 and 2050. The HR and FC scenarios reduce emissions by more than 75% compared to the 2050 base case. In an era of net-zero emissions targets, even these large reductions appear conservative. However, both HR and FC generation technologies will have the option to use pure hydrogen fuel in the future to reach net-zero emissions. Figure 3-11 demonstrates the emissions and cost impact of different fuel mixes used in fuel cells.

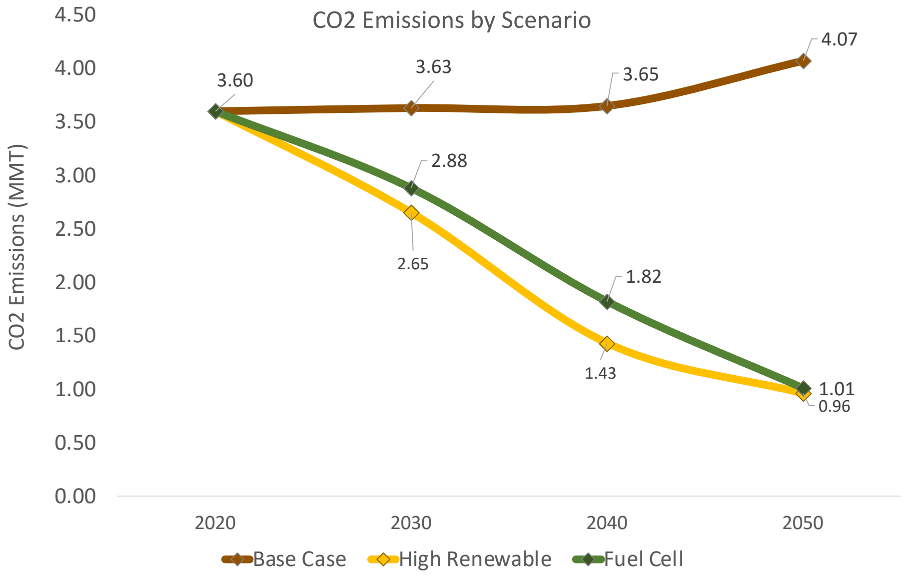


FIGURE 3-6 CO_2 EMISSIONS BY SCENARIO AND YEAR

Another gauge of carbon emissions which is commonly used is emission intensity, which measures the emissions for every unit of energy produced. This metric is useful to compare the emission-reduction efficiency between different generation technologies or portfolios. Table 3-2 below displays the carbon intensity of each portfolio, measured in grams of CO_2 per kilowatt-hour of energy produced.

Year	Base Case (g/kWh)	High Renewable (g/kWh)	Fuel Cell (g/kWh)
2020	402	402	402
2030	337	246	268
2040	296	116	149
2050	299	70	74

TABLE 3-2 CARBON EMISSIONS INTENSITY (G/KWH)

The variance in carbon intensity across scenarios is due to the changing capacity mix over time. As more renewables are added to the generation options, emissions intensity decreases due to the fact that wind and solar emissions from energy generation are zero. The remaining emissions for HR and FC scenarios are the result of using natural gas for dispatchable generation. If hydrogen fuel is used, emissions intensity would decrease to near zero.

3.4.2 NOX AND SO_2

Alongside the long-term, global reaching impact of increasing GHG emissions, poor air quality is an immediate and direct threat to local health. Therefore, municipal and state governments are often very concerned about sources of local air pollution. Fossil fuel combustion used in the production of electricity is one source of harmful pollutants. Nitrogen and sulfur oxides are two bi-products of combustion which impact local air pollution. As shown in figures 3-7 and 3-8 below, SOFC systems emit negligible amounts of NOX and SO_2 compared to the base case and high renewable scenarios. This is due to the fact that both base and HR cases utilize thermal CCGT generation whereas the FC case uses no thermal generation. In the HR scenario, NOX and SO_2 emission levels oscillate up and down as CCGT is dispatched throughout the year during hours when renewable generation is unavailable. The base case emissions never reach zero since 85% of delivered energy is derived from thermal generation.

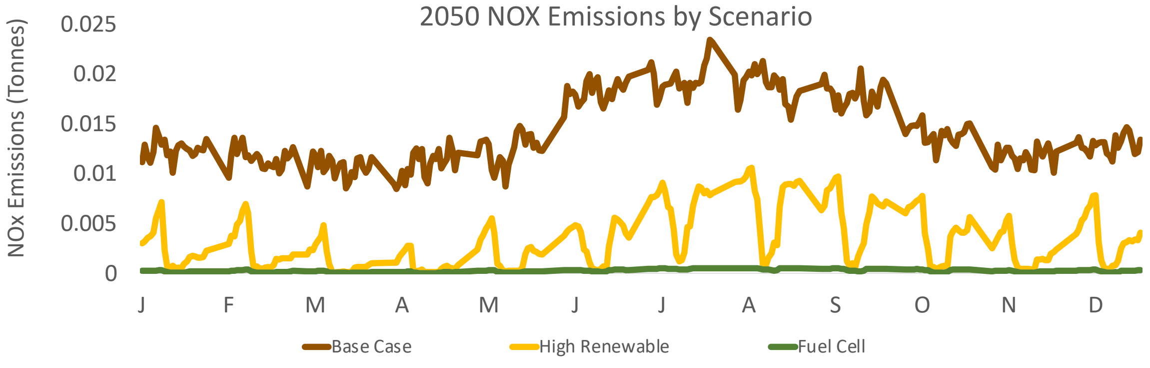


Figure 3-7 Month-Average NOX Emissions by Scenario

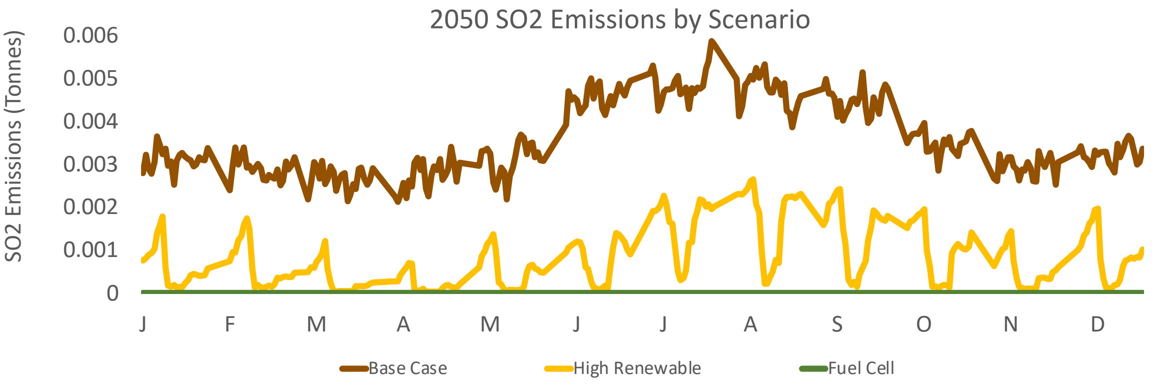


Figure 3-8 Month-Average SO2 Emissions by Scenario

Minimal NOX and SO_2 emissions are comparatively advantageous for the FC case because it enables TEP the option to deploy generation sources close to population centers without negatively impacting local air quality.

3.5 System Costs

One of the main tenets of IOUs is to ensure not only system reliability but also affordability. Ultimately, capital investment in a utility's system will be borne by ratepayers. Further, the process of setting rates is typically overseen by a public utility commission to safeguard residents and businesses against investment mismanagement by the utility. Therefore, this IRP analysis considers total investment spend and the impact on ratepayers in addition to other limitations and constraints. The primary outputs regarding system cost are the required revenue and the average rate.

In 2050, the base case, which deploys a high percentage of newly built CCGT plants, achieves the lowest annual revenue requirement of \$2.05 billion. The average rate is \$0.150/kWh, which represents a 12%

rate reduction compared to TEP’s 2020 average rate of $0.171. The HR case, which adds large quantities of wind and solar resources to the system, maintains an almost flat average rate of $0.172 in 2050 compared to the 2020 rate. The HR case revenue requirement increases to $2.34 billion. The costliest of the three different scenarios is the FC case, which requires $2.90 billion in required revenue and increases average rates nearly 25%, from $0.171 to $0.213 per kWh. The large increase in revenue requirement and average rate is due to the higher capital investment of fuel cell equipment and installation costs. Figures 3-9 and 3-10 below demonstrate the changes of revenue requirement and average rates for each scenario by decade through 2050.

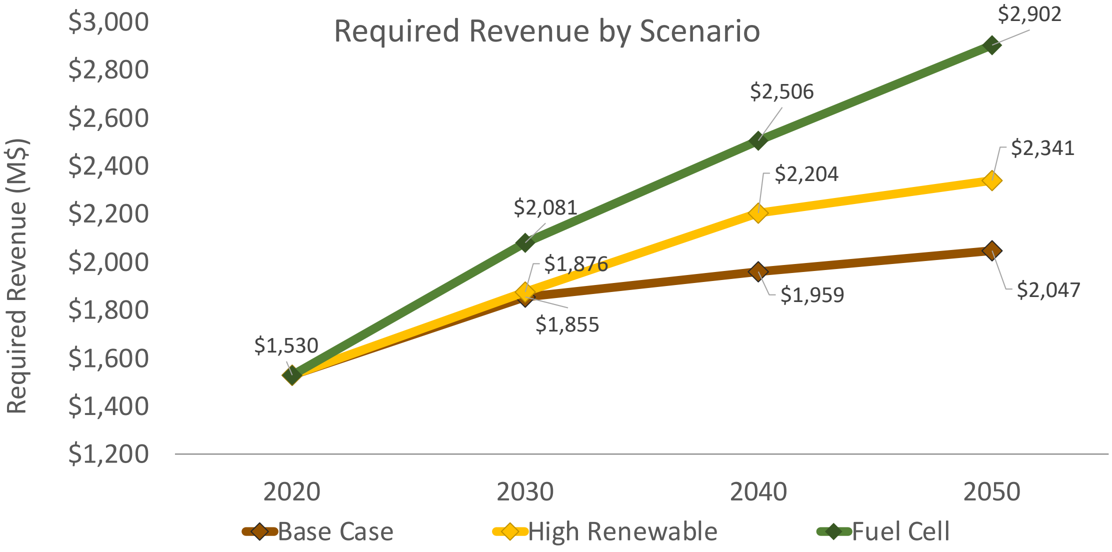


Figure 3-9 Required Revenue by Scenario

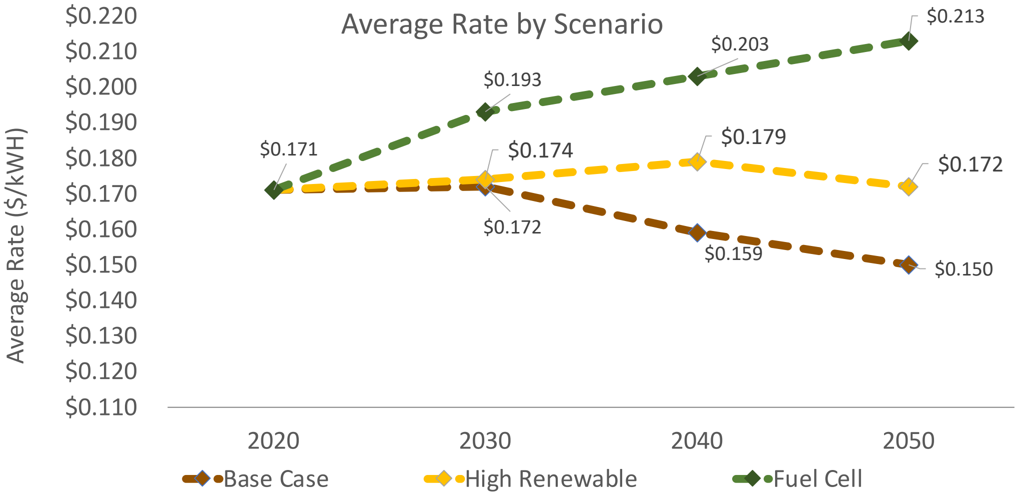


Figure 3-10 Average Rate by Scenario

In table 3-3 below, 2050 cost detail for each scenario is displayed alongside 2020 for comparison. Variable costs are lowest in the HR case due to the minimal use of fuel compared to all other scenarios. In this IRP analysis, fuel cost is the primary component for variable costs. CapEx is highest for the FC case due to the high cost of SOFC systems and installation, as mentioned in the section above. To incentivize clean energy investment, solar, wind, storage, and fuel cell technologies all qualify for ITC/PTC under the Inflation Reduction Act. T&D and 'Other' expenses are calculated on a set rate based on delivered energy; therefore, these charges are consistent across all three scenarios. An 'Interconnection Adder' is included to account for the additional costs required to connect large amounts of renewable capacity to the transmission system.

Cost Category	TEP 2020	Base Case	High Renewable	Fuel Cell
Variable (M$)	233	309	73	237
Fixed O&M (M$)	138	116	165	191
CapEx (M$)	233	210	410	831
Transmission & Distribution (M$)	700	1,062	1,062	1,062
Interconnection Adder (M$)	0	0	281	230
Other (M$)	231	350	350	350
Total (M$)	**1,535**	**2,047**	**2,341**	**2,902**
Average Rate ($/kWh)	**0.171**	**0.150**	**0.172**	**0.213**

TABLE 3-3 2050 COST DETAIL BY SCENARIO

3.6 ANALYSIS: FUEL CELL ADVANTAGES AND DISADVANTAGES

As the costs for renewable generation and battery storage decrease, IOUs are planning for greater amounts of renewable capacity on the grid. However, the intermittency and unpredictability of renewables increases the threat to system reliability. Dispatchable power, therefore, continues to be a vital resource for utilities.

For TEP, the advantage of fuel cells lies in the capability to install power generation near loads, by-passing the transmission capacity issue while adding dispatchable diversity to the IOU's generation capacity. The modular nature of the technology enables widely distributed, small generation power plants which can mitigate localized "load pocket" issues without adding transmission. Fuel cell units feature quiet operation, small footprints, and negligible air pollution. As such, when compared to traditional thermal generation plants, siting and permitting is both simpler and quicker. Lastly, in anticipation of more stringent corporate or governmental emissions mandates, fuel cells can be retrofitted for 100% hydrogen gas with minimal modifications, enabling net-zero operation. A fuel cell sensitivity analysis is found in section 3.6.1 below.

The nimbleness of fuel cell technology may also help facilitate positive economic impacts in the Tucson area. Recently, interest from server farm companies and an industrial copper mining outfit have considered Tucson as a potential growth area. However, according to TEP resource planner Lee Alter, adding this type of economic growth in Tucson would require significant generation capacity expansion – as much as 800 MW (Alter, 2023). Given the capability to deploy near a load with minimal siting and permitting obstacles, fuel cell technology is a dynamic asset, potentially helping the city of Tucson grow economically by delivering a targeted, scalable solution for the critical energy needs of new businesses.

While there are benefits, utilizing SOFC for utility-scale application has disadvantages which must be considered. Most apparent is the cost of purchasing and installing fuel cells. This analysis estimates that in 2030, the $/kW cost of a fuel cell will be more than three times the cost of an equivalent CCGT generator. The cost difference is even greater when compared to the expected development expenses for solar and wind generation. In addition to cost, TEP must also consider the inherent advantages of deploying existing CCGT thermal generation technology, which is widely used and can also, potentially, be retrofitted to burn hydrogen gas. Finally, the biggest obstacle for fuel cell technology may simply be the fear of the "unknown." Utilities are tightly regulated, risk-averse companies with many different stakeholder interests. Therefore, pushing for the adoption of a new generation technology that is three times more expensive than existing solutions may be a risk TEP management is unwilling to accept.

3.6.1 FUEL CELL FUEL MIX SENSITIVITY

One of the advantages of fuel cells is the technology's flexibility to use different types of fuel to generate electricity. Fuel cell systems, which do not use combustion, have the capacity to utilize natural gas, biogas, hydrogen, or a mixed blend. This flexibility enables utilities to install fuel cell capacity in the short term, using natural gas for generation, while planning for cleaner fuels and reduced emissions in the future. Figure 3-11 examines fuel cells at the intersection of gas mix, average rates, and CO_2 emissions. As the mix of hydrogen increases, emissions decrease while average rates increase due to the higher price of hydrogen. In this IRP analysis, the fuel cell case deploys both hydrogen mix and pure hydrogen in the portfolio to meet the emissions constraint. The 50% hydrogen mix option is priced closely to the fuel cell case because the model's fuel cell dispatch is mostly a hydrogen-natural gas mix due to cost. Increased availability of cleaner biogas and hydrogen in the future will support utility decarbonization efforts in the coming decades. Fuel cell technology adaptability allows for both short- and long-term solutions to grow generation capacity while planning for a net-zero future.

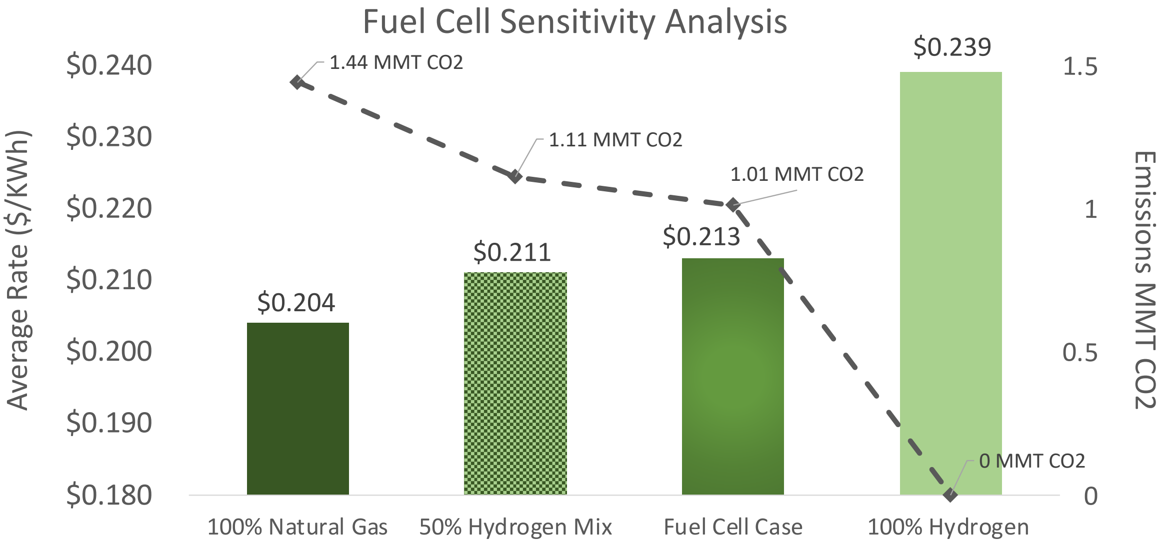


FIGURE 3-11 FUEL MIX SENSITIVITY ANALYSIS

4 METHODOLOGY

The IRP's objective is to determine the optimal generation capacity deployment from 2030 through 2050 which meets the identified constraints of each scenario while delivering revenue requirements, retail rates, and emissions data. Figure 4-1 displays the basic IRP methodology employed.

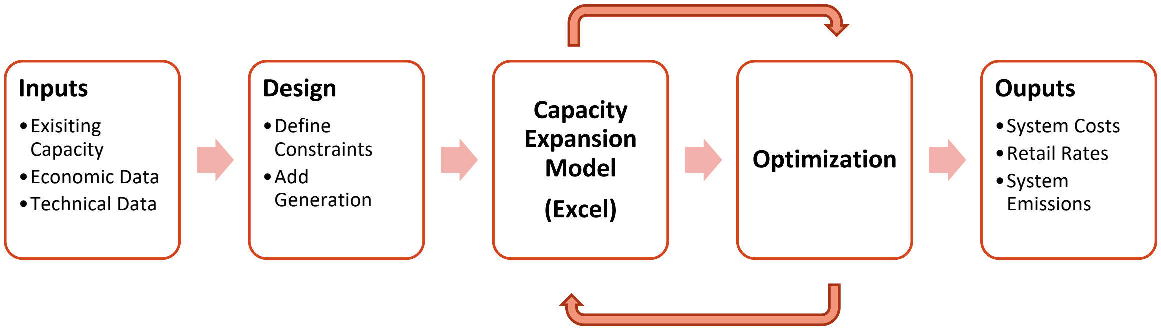


FIGURE 4-1 IRP METHODOLOGY USED

4.1 LOAD FORECAST

TEP's 2020 IRP projected a long-term load growth of approximately 0.8% through 2035. When compared to the larger metropolitan area of Phoenix, Tucson's regional growth in terms of population and economics is much less dynamic but more stable and predictable. According to the U.S. Census Bureau, population growth in Pima County over the ten-year period from 2010 to 2020 increased just 6.4%, approximately 0.64%, annually (U.S. Census Bureau, 2023). Pima County has a large number of government workers in addition to a U.S. Air Force base and a major university, University of Arizona. Therefore, economic growth in TEP's service area is historically stable, but slower growing compared to the rest of the state. At a high level, population, demographics, and economic factors have the largest influence of a region's load forecast. According to TEP, variances in the accuracy of shorter-term demand forecasting are usually due to weather patterns while economic factors drive differences in longer-term load forecasting.

For this IRP analysis, TEP's peak load forecast from the 2020 IRP is implemented through 2035 and extended through 2050 using a 0.8% annual growth rate. This load forecast is slightly higher than the historical population growth to account for a moderate increase in load due to market factors such as EV adoption. Similarly, the utility's energy forecast through 2035 is used from the 2020 IRP along with the same 0.8% annual growth factor through 2050. TEP's specific hourly load data was downloaded from FERC Form 714 and used in the model to provide an hourly load shape for all 8,760 hours of the year. The historical load shape is then scaled to the forecasted peak load and energy to provide an hourly load demand for future years.

4.2 TECHNICAL DATA

The EPA's *Emissions & Generation Resource Integrated Database* (eGRID) provides data about TEP's existing generation assets including capacity, emissions, generation, and heat rates. NREL's 2022 Annual Technology Baseline (ATB) database is the source of the same data for future generator installations.

CO_2 emissions are calculated in the model utilizing heat rate and emissions data from the NREL ATB database. Where available, heat rates of specific TEP generation plants are used for accuracy. NO_X and SO_2 emissions for coal plants are calculated from plant specific emissions data available from the EIA site, under *Emissions by Plant and Region* section. NO_X and SO_2 emissions for CCGT and CT generation uses rates from the NREL ATB report for the specific technology. Fuel Cell NO_X and SO_2 emission rates, which are considered negligible, are taken from Bloom Energy's product datasheet for its *Energy Server 5* platform.

The hourly shape of renewable wind and solar generation sources is generated utilizing NREL's System Advisor Model (SAM). This tool allows the user to develop hourly resource load shapes by specific location with detailed supply curves and capacity factors. For solar output, the shape is modeled using locations within TEP's service footprint near Tucson, Arizona. In this region of southern Arizona, solar output is highly predictable with consistent output levels. Wind output is modeled and averaged across three locations in eastern New Mexico where TEP currently has PPA agreements for wind generation. Due to the region's strong wind profiles and existing transmission, the model assumes additional wind capacity will be generated from these areas, such as the Oso Grande Wind farm in southeast New Mexico. Table 4-1 details technological data used in various model calculations.

Technology	NREL ATB Category	Heat Rate	Emissions (kg CO_2/MMBtu)	Operational Lifetime	Financial Lifetime
Coal	Coal – Moderate	10.94	95.68	50	30
Natural Gas (CT)	NG CT - Moderate	14.99	53.06	40	30
Natural Gas(CCGT)	NG CC - Moderate	6.64-8.00	53.06	40	30
Fuel Cell*	N/A	7.13	53.06	30	30
Wind	LB – Cl 5 Moderate	N/A	0.00	30	30
Solar	Util PV – Cl 5 Moderate	N/A	0.00	30	30
Battery Storage	Util 8hr - Moderate	N/A	0.00	20	20

*FUEL CELL DATA GATHERED FROM BLOOM ENERGY PRODUCT DATASHEETS.

TABLE 4-1 GENERATION TECHNOLOGY TECHNICAL DATA

4.3 ECONOMIC DATA

Technology costs and fuel prices are crucial inputs for IRP planning, which seeks to optimize system costs and rates given all constraints. The most important reference used for this IRP analysis is NREL's ATB, which is an annual report that details current and forecasted cost and performance data for both renewable and thermal generation technologies. CapEx and fixed Operations and Maintenance (O&M) data from the ATB enable the model to project future costs of fixed generation. Fuel cell CapEx and O&M

costs and projections are provided by Bloom Energy, who was interviewed for this IRP report. These costs are annualized using a capital recovery factor (CRF) calculation which is determined by the company's Weighted Average Cost of Capital (WACC) using the shares and rates of equity and debt. For TEP, the share of equity is 54.3% with a 10.3% rate of return. The company's share of debt is 45.7% with a 3.8% cost average. Using a 30-year financial lifetime for generation assets depreciation and a 7.31% WACC, the calculated CRF is 8.31%.

The variable costs of thermal generation assets used in the model are dependent on the fuel type, heat rate, and hours in operation. In this IRP, variable costs are effectively production costs which are calculated by multiplying the dispatched capacity and marginal cost of a specific generator.

Fuel prices for natural gas, the primary fuel used in this IRP are calculated using a combination of historical price data from the EIA as well as the EIA's 2023 Annual Energy Outlook for projected prices through 2050. EIA's future prices are issued in future yearly increments; therefore, a monthly fuel price projection is created by averaging monthly historical pricing shapes and applying them to the EIA's future year fuel forecasts. The use of hydrogen fuel, which is added in 2040 and 2050, is assumed to be available by pipeline in 2040 and beyond. The gas/hydrogen mixture is priced at 200% of natural gas prices in the same year. Pure hydrogen prices are set at 300% of natural gas prices. The price multipliers assume the cost of the hydrogen gas as well as future pipeline charges.

To calculate transmission and distribution costs, current TEP rates for both residential and commercial customers are analyzed, weighted, and averaged to determine a single $/kWh charge based on average consumption. This rate is applied and scaled as energy load increases over time. An interconnection fee of $175/kW is also included for both the high renewable and fuel cell scenarios to account for extra costs associated with adding high quantities of solar, wind, and storage capacity.

4.4 CAPACITY EXPANSION MODEL

A Microsoft Excel-based capacity stack model is used to develop all three scenarios across the years 2030, 2040, and 2050. Considering specific-year energy load requirements as well as identified constraints such as planning reserves and emissions levels, the model uses generation capacity, capacity factors, and numerous economic data points to develop a least-cost dispatch of the system's available resources. Excel's Solver tool is used for optimization to guide capacity choices along with iterative fine-tuning within the model to establish optimized scenarios.

The model prioritizes the dispatch of hourly solar and wind generation. In any given hour, excess renewable generation is utilized to charge battery storage. Over-production beyond hourly load which cannot be used to charge battery storage is curtailed. During hours with a positive net load after renewables and storage, the model dispatches either thermal resources or fuel cells based on available capacity and the lowest marginal cost.

The model calculates carbon, NOX, and SO_2 emissions while tabulating total system costs which are broken down by the following cost categories: Variable, Fixed O&M, CapEx, T&D, Interconnection Adder, and Other.

4.5 ANALYSIS LIMITATIONS

It is important to note that the emphasis of this IRP and scenarios is focused on TEP-controlled supply-side resource decisions. Utility-generated IRPs consider many other factors that are not considered in this analysis such as market- or policy-driven impacts on load demand. TEP also participates in the Western Energy Imbalance Market to take advantage of regional market economics. Further, the utility provides long-term and short-term wholesale electricity contracts to rural electric cooperatives. Neither of these business activities are considered in this analysis. Finally, TEP generation resources can be 100% utility-owned, partially owned or IPP-owned with a contractual PPA to delivery energy. To simplify this IRP analysis, the assumption is made that all resources are capitalized, owned, and operated by TEP. Limiting variables across the different scenarios enables a stronger understanding of the research question examined.

The Excel-based stack model used in this IRP project also has limitations compared to the highly complex software packages utilized by IOUs for resource planning. TEP uses planning software called Aurora, which allows resource planners to incorporate vast amounts of detailed system data and evaluate countless scenarios. Comparatively, the stack model is far from optimal as a capacity expansion model. CapEx cost-estimates from NREL ATB are reasonable; however, region-specific variables such as local construction costs or labor rates may cause inaccuracies in estimating system costs. Generator characteristics in terms of efficiency, emissions, and run times are based on typical operation for the specific technology. By contrast, utility IRPs include operation data unique to specific generation sites. The stack model utilizes a rudimentary accounting method for charging and discharging battery storage which only approximates dispatch and limits the amount of storage on the system relative to the amount of renewable capacity.

5 CONCLUSIONS AND RECOMMENDATIONS

Tucson Electric Power, like many other utilities, employs an IRP process to plan all aspects of future electricity supply and demand while accounting for various system constraints as well as government regulation and policy. While the state of Arizona implemented a conservative renewable energy standard of 15%, TEP is guided by parent company Fortis Inc. to establish a path to net-zero in the coming decades. As such, the company launched aggressive plans to retire coal generation plants while setting a future dependent on ever-increasing amounts of renewable energy and storage. However, whatever the generation source, the central objective for utilities remains the delivery of affordable and reliable energy to ratepayers. While the cost of solar, wind, and storage prices have decreased dramatically over the past decade, the fundamental challenges of renewable energy have not changed: intermittency and delivery. In particular, TEP acknowledges the company's main obstacle to increased deployment of renewables is a "heavy transmission constraint." Therefore, dispatchable power assets remain a critical component of TEP's resource plan and important part of the company's continued desire for diversified resources.

This IRP analysis proposed the consideration of a new technology for dispatchable power by examining the following question:

What is the potential of fuel cell technology as a cost-effective emission reduction solution in the energy transition?

Currently, fuel cell technology is more commonly considered an alternative solution for transportation and single-site commercial or industrial power back-up. The nascent technology's application in power utilities is presently limited. However, Bloom Energy deployed a 30 MW system in Delaware at Delmarva Power and partnered with SK Ecoplant in Korea to build the country's first power project with SOFC (Bloom Energy, 2021). Fuel cells resolve problems which other generation resources cannot. First, the deployment of fuel cells is a distribution-level solution, bringing power close to the load. By doing so, this circumvents the transmission problem while adding dispatchable generation to underserved loads on the grid, wherever they may be. Second, once hydrogen fuel becomes more widely available as a fuel source, hydrogen-powered fuel cells will emit zero carbon, which reduces GHGs, and release negligible NOX and SO_2 emissions which will improve local air quality. This, in turn, will help TEP align itself with Fortis' corporate pledge of net-zero emissions in the coming decades. Adding fuel cell resources also adds diversity to the generation mix, a stated objective from TEP. Finally, since fuel cells are comparatively easier to deploy, they deliver resource flexibility which enhances regional economic growth potential for new commercial or industrial business.

Conversely, fuel cell technology is not without challenges. The most obvious obstacle is the relative capital investment costs compared to traditional thermal gas-fired generation. Although fuel cells qualify for federal tax credit programs such as the Production Tax Credit (PTC) and Investment Tax Credit (ITC) under the Inflation Reduction Act, a fuel cell is more than triple the cost of an equivalent CCGT generator. In this IRP, average rates for the fuel cell scenario increased nearly 25% compared to the high renewable portfolio. Further, thermal generation resources such as CCGT, which are widely used across the utility industry, can be retrofitted to use hydrogen fuel, making these technologies potentially emission-free, as well. Given these facts, adoption of fuel cell technology over existing CCGT generation will be a challenge.

By their nature, utilities are conservative organizations with many different stakeholders to serve. Deploying a nascent technology such as solid oxide fuel cells may be viewed as a risky leap into the unknown by management, investors, and regulators.

Given fuel cell technology benefits and challenges, this IRP analysis concludes that large-scale deployment of fuel cell systems as the sole, dispatchable resource on TEP's system is impractical and not recommended. Instead, TEP should consider implementing a limited, smaller-scale, strategic deployment to leverage the technology's advantages described above while avoiding excessive capital expenditure. By doing so, fuel cells will help TEP mitigate the transmission problem while increasing generation, deliver on future emissions reduction pledges, increase generation diversity, and improve the region's economic activity.

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